BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Increase in Rates by Progress Energy Company	**DOCKET NO. 090079-EI** **Filed: August 10, 2009**

TESTIMONY AND EXHIBITS OF JEFFRY POLLOCK

ON BEHALF OF THE FLORIDA INDUSTRIAL POWER USERS GROUP

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List of Acronyms

AD	Average Demand
A&E	Average and Excess
CCR	Capacity Cost Recovery
CFR	Code of Federal Regulations
CC	Combined Cycle Unit
CP	Coincident Peak
CT	Combustion Turbine
ED	Excess Demand
FERC	Federal Energy Regulatory Commission
FIPUG	Florida Industrial Power Users Group
FPL	Florida Power & Light Company
FPSC	Florida Public Service Commission
FRCC	Florida Reliability Coordinating Council
GCP	Group Coincident Peak
GSD	General Service Demand
kW	Kilowatts
kWh	Kilowatt-hours
LF	Annual System Load Factor
MPSC	Michigan Public Service Commission
NARUC	National Association of Regulatory Utility Commissioners
PEF	Progress Energy Florida
PUCT	Public Utility Commission of Texas
PPA	Purchased Power Agreements
ROR	Rate of Return
RROR	Relative Rate of Return
S&P	Standard & Poor's
SWCP	Summer/Winter Coincident Peak
TECO	Tampa Electric Company

1. INTRODUCTION, QUALIFICATIONS, AND PURPOSE

Q **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

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

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

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

Q **PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

A I have a Bachelor of Science Degree in Electrical Engineering and a Masters in Business Administration from Washington University. Since graduation in 1975, I have been engaged in a variety of consulting assignments, including energy procurement and regulatory matters in both the United States and several Canadian provinces. I have participated in regulatory matters before this Commission since 1976. More details are provided in Appendix A to this testimony.

Q **ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?**

A I am testifying on behalf of the Florida Industrial Power Users Group (FIPUG). Participating FIPUG companies take power from Progress Energy Company (PEF). These customers require a reliable low-cost supply of electricity to power their operations. Therefore, participating FIPUG companies have a direct and significant interest in the outcome of this proceeding.

Q **WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A I will address the following issues:

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- Class cost-of-service study;
- Class revenue allocation;
- Rate design, including the design of the interruptible credit;
- Depreciation-related matters (*e.g.,* the estimated life spans of PEF's coal and combined cycle units and further ratemaking adjustments to reduce the $789 million surplus depreciation reserve); and
- The appropriate common equity ratio for determining PEF's cost of capital.

Q **ARE OTHER WITNESSES PROVIDING TESTIMONY ON FIPUG'S BEHALF?**

A Yes. Mr. Martin Marz will address the storm reserve, incentive compensation and other test year issues.

Q **ARE YOU FILING ANY EXHIBITS IN CONNECTION WITH YOUR TESTIMONY?**

A Yes. I am filing **Exhibits JP-1** through **JP-14**. These exhibits were prepared by me or under my direction and supervision.

Q **IN SOME OF THESE EXHIBITS, YOU HAVE USED PEF'S CLAIMED REVENUE REQUIREMENTS. DOES THIS CONSTITUTE AN ENDORSEMENT OF THE COMPANY'S PROPOSALS?**

A No. My use of PEF's claimed revenue requirements is strictly for illustrative purposes and should not be interpreted as an endorsement of the proposed base revenue increases.

Summary

Q PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A PEF has failed to justify changing the method of allocating production plant-related costs from the Twelve Coincident Peak (12CP) and 1/13th Average Demand (AD) method to the 12CP-50% AD. The 12CP-50% AD method does not reflect cost causation because:

1. PEF has strong summer and winter peaks and experiences its tightest margins during the summer/winter peak months. Therefore, greater emphasis should be placed on the demands during the summer/winter peak months than is provided in the 12CP-50% AD Method.
2. The 12CP-50% AD method is designed to match production plant costs relative to the benefits received. However, PEF fails to apply the same "costs follow the benefits standard" to recognize that some variable costs provide reliability benefits;
3. The higher costs of base load and intermediate capacity are not caused by average demand;
4. Capacity is severely under-valued; and
5. Coincident demand is double-counted.

If the Commission decides to replace 12CP-1/13th AD, it should adopt the Average and Excess (A&E) method because A&E appropriately recognizes the dual functionality of generating plants (*i.e.,* that such plants serve both base and cycling loads) without double-counting peak demand. The Summer/Winter Coincident Peak (SWCP) method should be used to allocate Transmission plant costs.

Second, the Commission should use the results of a proper class cost-of-service study to determine the class revenue allocation. In addition, the following principles, which the Commission has traditionally endorsed, should be applied:

- No rate should receive an increase higher than 150% of the system average base rate increase; and
- No rate should receive a decrease.

Third, PEF's proposed rate design should be revised to:

- Assign no increase to non-fuel energy charges to more closely align the demand and energy charges to reflect the corresponding demand and non-fuel energy-related costs; and
- Increase the Interruptible Demand Credit to at least $10.49 per kW-Month to reflect the costs PEF avoids by providing this service.

Further, the Interruptible Demand Credit should not be load factor adjusted because load factor is not a reasonable proxy for the amount of capacity that a customer curtails, and because curtailments can occur at any time, not just during the hour that PEF's monthly coincident peak occurs. In lieu of measuring the amount of load curtailed, the Credit should not be less than $7.13 per kW-Month of billing demand, which recognizes that the interruptible class has an average 68% (12CP-to-Billing demand) coincidence factor.

Finally, with respect to revenue requirements, I recommend:

- Reductions in depreciation expense based on longer life spans for PEF's coal (at least 55 years) and combined cycle (at least 35 years) units. Further, PEF should reduce the depreciation reserve by $100 million per year to correct the very large ($789 million) surplus in the depreciation reserve to restore generational equity; that is, current ratepayers should be charged only for the assets that are consumed to provide electric service.
- Rejection of PEF's proposal to impute debt associated with purchased power agreements. This would change the common equity portion of PEF's capital structure to 50% on an adjusted basis. A 50% equity ratio is in line with the equity ratios of other comparably-rated electric utilities.

2. CLASS COST-OF-SERVICE STUDY

Background

Q WHAT IS A CLASS COST-OF-SERVICE STUDY?

A A cost-of-service study is an analysis used to determine each class' responsibility for the utility's costs. Thus, it determines whether the revenues a class generates cover the class' cost-of-service. A class cost-of-service study separates the utility's total costs into portions incurred on behalf of the various customer groups. Most of a utility's costs are incurred to jointly serve many customers. For purposes of rate design and revenue allocation, customers are grouped into homogeneous classes according to their usage patterns and service characteristics. The procedures used in a cost-of-service study are described in greater detail in **Appendix B.**

Q HAVE YOU REVIEWED THE CLASS COST-OF-SERVICE STUDY PROGRESS ENERGY FLORIDA FILED IN THIS PROCEEDING?

A Yes.

Q DOES PEF'S CLASS COST-OF-SERVICE STUDY COMPORT WITH ACCEPTED INDUSTRY PRACTICES?

A Yes. With three exceptions, PEF's class cost-of-service study recognizes the different types of costs as well as the different ways electricity is used by various customers. The three exceptions are:

1. The failure to classify any distribution network costs as customer related.
2. Using 12CP-50% AD to allocate production plant-related costs.

3. Using 12CP to allocate transmission plant-related costs.

The problem with PEF's distribution plant classification is discussed in **Appendix B.** However, at this time, I am only addressing the production/transmission plant allocation issues.

Q WHAT CHANGES ARE YOU RECOMMENDING?

A As explained below, PEF has failed to demonstrate that any change in production/transmission plant allocation is warranted. Thus, the Commission should retain the 12CP-1/13th AD method. However, if the Commission decides to change to a method that places more emphasis on average demand, it should adopt the A&E method for production plant. Transmission plant should be allocated using the Summer/Winter Coincident Peak (SWCP) method.

<u>Allocation of Production and Transmission Plant Costs</u>

Q HOW SHOULD THE COMMISSION DETERMINE WHICH METHODOLOGY SHOULD BE USED TO ALLOCATE PRODUCTION AND TRANSMISSION PLANT COSTS?

A The Commission should use the methodology that most accurately reflects cost-causation for PEF.

Q WHAT IS COST CAUSATION?

A Cost causation means allocating production and transmission plant costs to customer classes in a manner that reflects how each class causes PEF to incur them.

Q HOW IS COST-CAUSATION RELEVANT IN DETERMINING THE PROPER METHOD OF ALLOCATING PRODUCTION AND TRANSMISSION PLANT?

A In order to provide reliable service, PEF must size production and transmission plant to meet the maximum expected demands imposed on it. Once installed, this capacity is available to meet customer demands throughout the year. This point is illustrated in **Exhibit JP-1**, which depicts a utility that serves two customer classes (A and B).

Each class uses 2,400 kWh of energy over a 24-hour period. Thus, both classes have an average demand of 100 kWh (2,400 kWh ÷ 24 hours). However, Class A has a cyclical load shape while Class B has a flat load shape. Because of its cyclical load shape, Class A's maximum demand is 200 kW. Class B's maximum demand is 100 kW. In order to serve both classes, the utility would require 300 kW (ignoring reserves). Had the utility provided only 200 kW (which is the combined average load of the two classes), it could not have provided reliable service.

In summary, cost-causation is primarily a function of peak demand. Thus, a proper allocation method for production and transmission plant costs should emphasize the demands imposed during PEF's peak periods.

Q WHAT METHODOLOGY DOES PEF PROPOSE TO ALLOCATE PRODUCTION AND TRANSMISSION PLANT-RELATED COSTS?

A PEF proposes to use the 12CP-50% AD method to allocate production plant costs and the 12CP method to allocate transmission plant-related costs.

Q WHAT IS THE 12CP-50% AD METHOD?

A The 12CP-50% AD method allocates costs partially on a 12CP demand basis and partially on an average demand, or energy, basis. Thus, 12CP-50% AD assumes that production plant-related costs are caused by year-round coincident peaks and average demand. This method is sometimes referred to as the Peak and Average method.

Q WHAT IS THE 12CP METHOD?

A The 12CP method allocates costs relative to each customer class' demand that occurs coincident with PEF's monthly peaks in all twelve months of the test year. Thus, this method improperly assumes that transmission plant-related costs are caused by year-round coincident peaks. This is clearly not the case for PEF as explained below.

Q DOES EITHER THE 12CP-50% AD OR THE 12CP METHOD TRULY REFLECT COST-CAUSATION?

A No. PEF experiences its maximum annual demand for electricity in either the summer or winter months. This is shown in **Exhibit JP-2, page 1**, which is an analysis of PEF's monthly peak demands as a percent of the annual system peak for the years 2004 through 2008 and the 2010 Test Year. The peak demands in the other months are typically well below PEF's summer and winter peak demands. These characteristics are further summarized in **Exhibit JP-2, page 2:**

- PEF's minimum monthly peak is 65% of the annual system peak.
- PEF's average monthly peak demands are only 84% of the annual system peak.

- PEF's average peak month demands are 21% higher than the average non-peak month demands.
- PEF's annual load factor is only 54%.

These ratios confirm that PEF has clear seasonal load characteristics. Thus, electricity demands in the spring and fall months are not relevant in determining the amount of capacity PEF needs to provide reliable service.

Q **ARE THE MONTHLY PEAKS IN THE SPRING/FALL MONTHS IMPORTANT BECAUSE PEF HAS TO REMOVE GENERATION FOR SCHEDULED MAINTENANCE?**

A No. Although PEF does schedule most planned outages during the spring and fall months, this does not make these months important from a cost-causation perspective. Specifically, despite planned outages, PEF generally has higher reserve margins during the non-peak months than during the peak months. This is shown in **Exhibit JP-3**. The reserve margins were calculated as the margin (available capacity less scheduled outages less peak demand) divided by peak demand. PEF's peak month reserve margins, adjusted for scheduled outages, range from 27% to 47% of the corresponding non-peak month reserve margins.

Q **WHAT DO THE PEAK DEMAND AND RESERVE MARGIN ANALYSES DEMONSTRATE?**

A The analyses demonstrate that the summer and winter peak demands determine PEF's capacity requirements and make the other months irrelevant. Thus, the 12CP method does not reflect cost-causation in light of PEF's load and supply characteristics. The SWCP method best reflects PEF's load and supply characteristics and is consistent with cost-causation.

__PEF's Proposed 12CP-50% AD Method__

Q ARE PEF'S REASONS FOR PROPOSING THE 12CP-50% AD METHOD RELATED TO COST-CAUSATION?

A No. PEF witness Slusser argues that:

> There should be no question that a significant portion of the Company's production capacity costs being incurred should be **apportioned in the same manner as the customer realizes the benefits**, i.e. on an energy basis. (*Direct Testimony of William C. Slusser* at 19; emphasis added)

This point was further amplified in discovery:

> For clarification, Mr. Slusser stated that the proposed allocation method, i.e. the 12CP and 50%AD, **is a better matching of a class's fixed allocation with that of a class's realized fuel benefits** from such additional fixed costs. (*PEF's Response to FIPUG's Interrogatory No. 46*; emphasis added)

Q IS 12CP-50% AD A REASONABLE METHOD?

A No. Mr. Slusser is proposing to replace cost-causation with a "costs follow the benefits" standard in judging the reasonableness of the 12CP-50% AD method. As previously discussed, cost-causation is the standard by which a reasonable methodology should be judged. Further, as explained below, Mr. Slusser has failed to fully apply his "costs follow the benefits" standard. 12CP-50% AD is also flawed because:

- The higher costs of base load and intermediate capacity are not caused by average demand;
- Capacity is severely under-valued; and
- Coincident demand is double-counted.

Q HAS MR. SLUSSER APPLIED THE SAME "COSTS FOLLOW THE BENEFITS" STANDARD THROUGHOUT THE CLASS COST-OF-SERVICE STUDY?

A No. Mr. Slusser has applied this standard only to the allocation of production plant costs. He fails to apply the same standard to the allocation of variable costs (of which fuel is the primary component). For example, he is not proposing to change how customers are charged for fuel, which is currently on an equal cents per kWh basis (adjusted for losses). If certain customer classes benefit more from the lower fuel costs of base load and intermediate plants, it follows that they should also pay below-average fuel costs, and vice versa. By failing to apply his theory consistently to both plant and operating costs, his class cost-of-service study is fundamentally flawed and discriminatory.

Q HOW ELSE HAS MR. SLUSSER FAILED TO APPLY HIS "COSTS FOLLOW THE BENEFITS STANDARD" TO ITS LOGICAL CONCLUSION?

A Mr. Slusser has assumed that all variable costs are energy-related. This assumption is flawed because it overlooks the fact that the Company also incurs higher fuel costs:

1. To save plant costs; and
2. To maintain system reliability.

If it is proper to classify 50% of plant-related costs to energy because certain customer classes may realize greater cost benefits than others, it is equally proper to classify some operating costs to demand because they provide reliability benefits. Stated differently, if reducing fuel costs makes some base load plant costs energy related, (*i.e.*, capital substitution) it is equally valid that a portion of the higher variable costs a utility incurs are demand-related because the utility chooses to spend less capital (*i.e.*, fuel substitution).

Q CAN YOU PROVIDE SOME EXAMPLES OF WHEN A UTILITY SUBSTITUTES FUEL COSTS FOR PLANT COSTS?

A Yes. PEF is required to provide ancillary services to maintain system reliability. In providing certain ancillary services, PEF will incur additional fuel costs without generating additional kWh.

Q WHAT ARE ANCILLARY SERVICES?

A Ancillary services are those services necessary to support the transmission of energy from resources to loads while maintaining reliable operation of the transmission grid. Examples of capacity-related ancillary services are regulation and contingency reserves.

Q WHAT IS REGULATION?

A Regulation is provided by resources to follow the minute-to-minute differences between resources and demand.

Q WHAT ARE CONTINGENCY RESERVES?

A Contingency reserves are required to restore resource and demand balance after a contingency event, such as the loss of a major generating unit or transmission line. The latter consists of spinning reserves and supplemental reserves. Spinning reserves are provided by resources that are synchronized to the system and fully available within 15 minutes. Supplemental reserves are provided by resources that are capable of being synchronized to the system and fully available within 15 minutes.

Q ARE FUEL COSTS INCURRED TO PROVIDE CONTINGENCY RESERVES?

A Yes. Providing contingency reserves requires a utility to either maintain additional generation capacity on-line at all hours or to commit additional capacity not actually needed to provide service. Units designated to supply spinning reserves will run at less than full load. This will require the utility to dispatch more expensive generation to meet load. Similarly, providing spinning reserves during low-load periods will require the utility operating certain units at minimum load because it is impractical to cycle the unit completely off. During these periods, the unit is consuming fuel even though it is not generating kWh. Committing additional capacity means starting-up a unit that was otherwise scheduled to be off-line. Start-up requires the utility to burn fuel, again without generating kWh. Thus, absent the need to provide contingency reserves, PEF's fuel costs would be lower.

Q ARE REGULATION AND CONTINGENCY RESERVES ESSENTIAL TO MAINTAINING SYSTEM RELIABILITY?

A Yes. They are required for the continued reliable operation of the system. Thus, they are capacity-related services.

Q **DOES PEF'S COST STUDY RECOGNIZE THESE RELIABILITY-RELATED FUEL COSTS?**

A No. PEF makes no adjustments for these costs and fails to apply its "benefits" theory symmetrically.

Q **ARE THERE OTHER REASONS THAT THE 12CP-50% AD METHOD IS FLAWED?**

A Yes, there are several additional flaws. For example, Mr. Slusser asserts that PEF has spent twice as much capital on base load and intermediate capacity than it would have otherwise spent if it had built only combustion turbine (CT) peaking units. This assertion is based on Exhibit WCS-3, which quantifies the hypothetical cost of capacity had PEF built only CTs instead of a mix of base, intermediate and peaking capacity.

Q **IS THIS ANALYSIS ACCURATE?**

A No, this analysis is flawed because it places a value on capacity of only $209 per kW ($2,249,078 ÷ 10,772 MW). However, the current cost of capacity is at least $329 per kW (*PEF's Response to FIPUG's Production of Documents Request No. 4*). **Exhibit JP-4** demonstrates that by restating the capacity value from $209 to $329 per kW, PEF is spending less than 20% of capital for reasons other than maintaining system reliability.

Q **DOES THIS MEAN THAT 20% OF PEF'S PRODUCTION PLANT SHOULD BE ALLOCATED ON AVERAGE DEMAND?**

A No. Allocating the extra plant investment of those generating units that have lower fuel costs (*e.g.*, base load and intermediate capacity) on energy usage is at odds with the utility planning process. This is because all production from a specific plant (*i.e.*, kWh sales) is not the critical factor in deciding what type of plant to install. It is only the energy up to the economic breakeven point between base/intermediate and peaking capacity that is relevant to the decision.

Q **WHAT DO YOU MEAN BY THE "BREAK-EVEN POINT?"**

A The break-even point is the number of operating hours in which the total cost of base/intermediate and peaking capacity is the same.

Q **WHAT IS THE SIGNIFICANCE OF THE BREAK-EVEN POINT?**

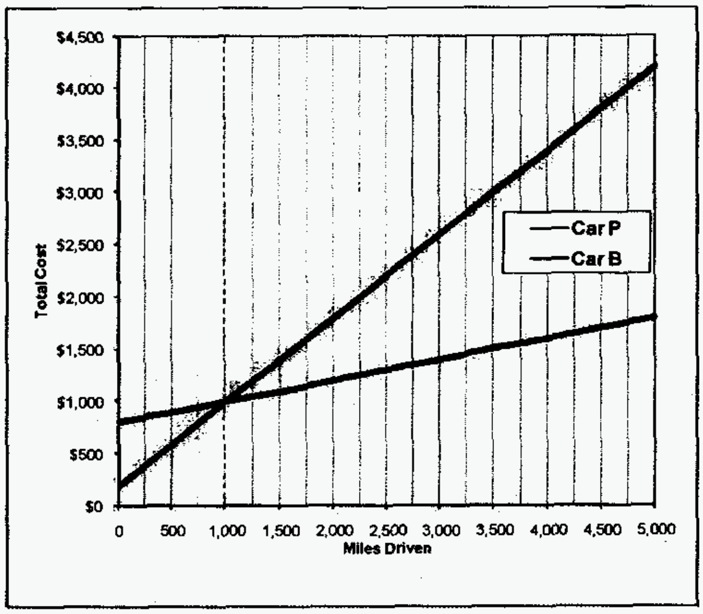
A Once a utility decides that additional production capacity is needed to meet peak demand, if that new capacity is expected to run only a limited number of hours, total costs are minimized by the choice of a peaker. On the other hand, if it is projected that a unit will run for a sufficient number of hours, then the intermediate or base load unit will be more economical.

Therefore, annual energy usage does not cause plant investment. However, load duration up to the break-even point may influence plant investment decisions. Beyond the break-even point, energy utilization is no longer a factor in the decision to select base load capacity or peaking capacity.

To provide an analogy, suppose two different customers are required to rent cars from a fleet that contains only two types of cars, "Car P" and "Car B":

	[redacted]	Car B
Fixed Charge	$200	$800
Mileage Charge	80¢	20¢

Car B has a high fixed charge and gets high mileage (like a base load plant), while the Car P has a low fixed charge but gets poor mileage (like a peaking unit). The graph below shows total cost of both cars over a range of miles driven.



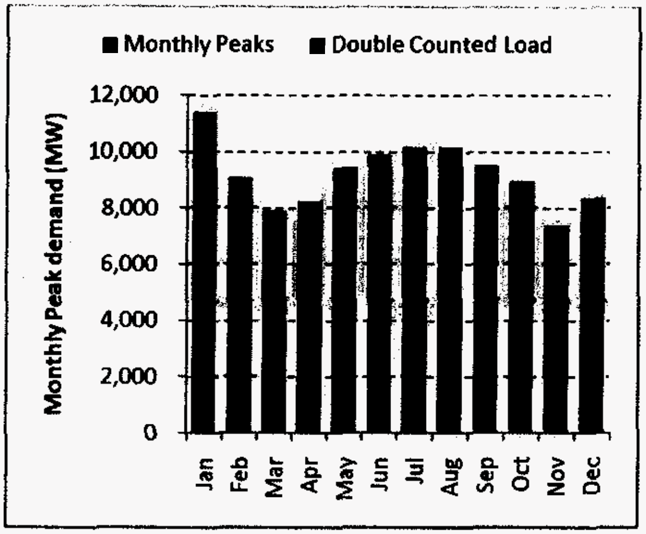
The total cost is also calculated in the following table.

Miles Driven	Total Cost			Best Choice
	[illegible]		Car B	
0	$200		$800	[illegible]
500	$600		$900	[illegible]
1,000	$1,000		$1,000	P or B
1,500	$1,400		$1,100	[illegible]
2,000	$1,800		$1,200	[illegible]
2,500	$2,200		$1,300	[illegible]
3,000	$2,600		$1,400	[illegible]
3,500	$3,000		$1,500	[illegible]
4,000	$3,400		$1,600	[illegible]
4,500	$3,800		$1,700	[illegible]
5,000	$4,200		$1,800	[illegible]

As can be seen, the break-even point between Car P and Car B is 1,000 miles. That is, the higher mileage Car B has a lower total cost per mile than Car P if it operated more than 1,000 miles. If one customer needed to drive 1,500 miles and a second customer needed to drive a car 4,500 miles, both customers would choose the same car, Type B. The 12CP-50% AD, however, would charge the second customer 60% more than actual cost solely because that customer needed to drive three times as many miles. This result is arbitrary and inequitable because the Type B car was the more economical choice for both drivers.

Q WHAT OTHER FLAWS DOES THE 12CP-50% AD METHOD HAVE?

A The 12CP-50% AD method also suffers from a double-counting problem. This is because the method allocates production plant costs partially on average demand and partially on coincident peak demand. Double-counting occurs because average demand (which is the equivalent of year-round energy consumption divided by 8,760 hours) is also a component of the coincident peak demand. This is illustrated in the following chart.



The portion of plant allocated on average demand is the black shaded area of the chart. Coincident demand is represented by the bars. As can be seen, double-counting occurs because the portion of plant allocated on average demand already includes a portion of the coincident peak demands.

By allocating some plant costs relative to average demand and some relative to coincident peak demand, energy is counted twice: once by itself and a second time as a subset of the coincident peak demand. If year-round energy is analogous to base load units, which supply capacity on a continuing basis throughout the year, then it follows that the only time intermediate and peaking units would be needed is to meet system demands when they are in excess of the average year-round demand. Energy allocation advocates improperly allocate the cost of this additional capacity relative to *total* coincident demand, rather than the *excess* demand.

Q HAS THE DOUBLE-COUNTING PROBLEM BEEN CITED AS A CRITICAL FLAW IN ENERGY-BASED ALLOCATION METHODOLOGIES?

A Yes. The Public Utility Commission of Texas (PUCT) has recognized the double-counting problem in numerous cases. For example, the PUCT has said:

> As to double-counting energy, the flaw in Dr. Johnson's proposal is the fact that the allocator being used to allocate peak demand, and 50% of the intermediate demand, includes with it an energy component. Dr. Johnson has elected to use a 4CP demand allocator, but such an allocator, because it looks at peak usage, necessarily includes within that peak usage average usage, or energy.
>
> * * *
>
> A substantial portion of average demand is being utilized in two different allocators, and this "double-dipping" is taking place. (El Paso Electric Company, *Examiner's Report*, Docket No. 7460, at 193)

Q SHOULD 12CP-50% AD BE ADOPTED?

A No. This method would improperly replace the long-standing "cost-causation" standard with a "costs follow the benefits" standard that focuses solely on allocating production plant costs and, thus, is not consistently applied. As such, it fails to recognize the substitution of fuel costs for capital costs in providing certain ancillary services necessary to maintain reliability. Further, capacity is significantly undervalued, the amount of investment spent to save fuel costs is significantly over-stated, and the method double-counts CP demand. For all of the above reasons, 12CP-50% AD should be rejected.

<u>Average and Excess Method</u>

Q IF THE COMMISSION DETERMINES THAT MORE WEIGHT SHOULD BE PLACED ON AVERAGE DEMAND, IS THERE A MORE APPROPRIATE METHODOLOGY (OTHER THAN 12CP-50% AD) FOR DOING SO?

A Yes. Although I disagree with the premise, if more emphasis is to be placed on average demand, my recommendation would be to adopt the A&E method. Under A&E, a portion of production/transmission plant costs equal to the utility's annual system load factor (or 53% as projected by PEF during the 2010 test year) would be allocated on average demand. The remaining costs would be allocated on the difference between a class' maximum demand and its average demand, which is the "Excess Demand" (ED) component of the A&E formula.

Q DOES MR. SLUSSER RECOGNIZE THE AVERAGE AND EXCESS METHOD AS VALID?

A Yes. Mr. Slusser acknowledges that:

> There are a number of utilities of which I am aware that employ a method called the "Average and Excess". This method effectively weights energy responsibility by the utility's load factor which is generally in the 50% to 60% range (*Testimony of William C. Slusser* at 20).

Q HAVE YOU DEVELOPED ALLOCATION FACTORS USING THE A&E METHOD?

A Yes. The derivation of the A&E allocation factors is presented in **Exhibit JP-5**. The primary inputs are the group coincident peak (GCP) and the AD, which are shown in columns 1 and 2, respectively. The A&E allocation factors are derived as follows:

$$A\&E = AD \times LF + ED \times (1 - LF)$$

Where: AD=Average Demand
LF=Annual System Load Factor
ED=Excess Demand

Q DOES THE A&E METHOD RECOGNIZE WHAT MR. SLUSSER CHARACTERIZES AS "THE DUAL PROCESSES THAT GENERATING RESOURCES PERFORM?"

A Yes. A&E recognizes dual cost-causers. First, some plant is required for year-round operation (*i.e.*, Average Demand). High load factor customers that use electricity throughout the year would receive a larger share of the Average Demand. Second, the remaining plant is required for cycling (*i.e.*, Excess Demand). That is, generators must also be capable of load following from the minimum loads that occur at night to the peak loads that occur on hot summer afternoons. Low load factor customers have variable demands, which require more cycling capacity than do high load factor customers. This is reflected in apportioning more Excess Demand to the lower load factor classes.

Q IS AVERAGE AND EXCESS A RECOGNIZED METHOD?

A Yes. A&E is recognized in the NARUC *Electric Utility Cost Allocation Manual*. Specifically, A&E is listed under the category of "Energy-Weighting" methods. That is, it gives substantial weight to average demand or energy in determining cost causation.

Q IS A&E SUPERIOR TO OTHER ENERGY WEIGHTING METHODS?

A Yes. Unlike other energy weighting methods, such as 12CP-50% AD, A&E does not double-count peak demand.

Summer/Winter Coincident Peak Method

Q WHAT IS THE SUMMER/WINTER COINCIDENT PEAK METHOD?

A The SWCP method allocates costs relative to each class's coincident demands during the summer and winter peak months.

Q SHOULD THE SWCP METHOD BE USED TO ALLOCATE TRANSMISSION PLANT COSTS?

A Yes. As previously stated, the PEF system is highly seasonal, with peak demands occurring in both the summer and winter months. Thus, the SWCP method appropriately reflects cost-causation.

Q HAVE YOU DEVELOPED ALLOCATION FACTORS FOR THE SWCP METHOD?

A Yes. The retail class allocation factors under the SWCP method are shown in **Exhibit JP-6**. They were developed using the demand data in MFR Schedule E-9.

Revised Class Cost-of-Service Study

Q HAVE YOU REVISED PEF'S CLASS COST-OF-SERVICE STUDY USING THE A&E METHOD?

A Yes. A revised class cost study at present rates is summarized in **Exhibit JP-7, page 1**. In this study, the A&E method was applied to production plant costs, while the SWCP method was applied to transmission plant costs. I conducted a second revised cost study using 12CP-1/13th AD for production plant and SWCP for transmission plant. This is shown in **Exhibit JP-7, page 2**. In both studies, the results are measured in three ways: (1) rate of return, (2) relative rate of return, and (3) interclass subsidies.

Rate of return (line 7) is the ratio of net operating income (revenues less allocated operating expenses as shown in line 6) to the allocated rate base (line 1). Net operating income is the difference between operating revenues at current rates (line 3) and allocated operating expenses (line 4). If a class is presently providing revenues sufficient to recover its cost-of-service (at the current system rate of return), it will have a rate of return equal to or greater than the total system return of 4.31%.

Relative rate of return (RROR), which is shown on line 8, is the ratio of each class' rate of return to the Florida retail average rate of return. A relative rate of return above 100 means that a class is providing a rate of return higher than the system average, while a relative rate of return below 100 indicates that a class is providing a below-system average rate of return.

Subsidy (line 9) measures the difference between the revenues required from each class to achieve the system rate of return and the revenues actually being recovered. A negative amount indicates that a class is being subsidized each year (*i.e.*, revenues are below cost at the system rate of return), while a positive amount indicates that a class is providing a subsidy each year (*i.e.*, revenues are above cost).

Q WHAT DO THE RESULTS OF YOUR REVISED CLASS COST-OF-SERVICE STUDIES SHOW?

A The A&E cost-of-service study **(Exhibit JP-7, page 1)** demonstrates that the Residential and General Service Demand (GSD) classes are close to cost, the Curtailable/Interruptible and Lighting Energy classes are below cost, and all other classes are above cost. The 12CP-1/13th AD study **(Exhibit JP-7, page 2)** shows that the Residential, General Service Non-Demand, and Lighting Facilities classes are above cost, while all other classes are below cost.

3. CLASS REVENUE ALLOCATION

Q **WHAT IS CLASS REVENUE ALLOCATION?**

A Class revenue allocation is the process of determining how any base revenue change the Commission approves should be apportioned to each customer class the utility serves.

Q **HOW SHOULD A CHANGE IN BASE REVENUES APPROVED IN THIS DOCKET, IF ANY, BE APPORTIONED AMONG THE VARIOUS CUSTOMER CLASSES PEF SERVES?**

A Base revenues should reflect the actual cost of providing service to each customer class as closely as practicable. Regulators sometimes limit the immediate movement to cost based on principles of gradualism and rate administration.

Q **PLEASE EXPLAIN THE PRINCIPLE OF GRADUALISM.**

A Gradualism is a concept that is applied to prevent a class from receiving an overly-large rate increase. That is, the movement to cost-of-service should be made gradually rather than all at once because an abrupt change would result in rate shock to the affected customers.

Q **SHOULD THE RESULTS OF THE COST-OF-SERVICE STUDY BE THE PRIMARY FACTOR IN DETERMINING HOW ANY BASE REVENUE CHANGE SHOULD BE ALLOCATED?**

A Yes. Cost-based rates will send the proper price signals to customers. This will allow customers to make rational consumption decisions.

Q **ARE THERE OTHER REASONS TO APPLY COST-OF-SERVICE PRINCIPLES WHEN CHANGING RATES?**

A Yes. The other reasons to adhere to cost-of-service principles are equity, engineering efficiency (cost-minimization), stability and conservation.

Q **WHY ARE COST-BASED RATES EQUITABLE?**

A Rates which primarily reflect cost-of-service considerations are equitable because each customer pays what it actually costs the utility to serve the customer – no more and no less. If rates are not based on cost, then some customers must pay part of the cost of providing service to other customers, which is inequitable.

Q **HOW DO COST-BASED RATES PROMOTE ENGINEERING EFFICIENCY?**

A With respect to engineering efficiency, when rates are designed so that demand and energy charges are properly reflected in the rate structure, customers are provided with the proper incentive to minimize their costs, which will, in turn, minimize the costs to the utility.

Q **HOW CAN COST-BASED RATES PROVIDE STABILITY?**

A When rates are closely tied to cost, the utility's earnings are stabilized because changes in customer use patterns result in parallel changes in revenues and expenses.

Q HOW DO COST-BASED RATES ENCOURAGE CONSERVATION?

A By providing balanced price signals against which to make consumption decisions, cost-based rates encourage conservation (of both peak day and total usage), which is properly defined as the avoidance of wasteful or inefficient use (not just less use). If rates are not based on a class cost-of-service study, then consumption choices are distorted.

Q DOES COMMISSION POLICY SUPPORT THE MOVEMENT OF UTILITY RATES TOWARD ACTUAL COST?

A Yes. The Commission's support for cost-based rates is longstanding and unequivocal. The Commission reiterated this principle in the recent Tampa Electric Company (TECO) rate case:

> It has been our long-standing practice in rate cases that the appropriate allocation of any change in revenue requirements, after recognizing any additional revenues realized in other operating revenues, should track, to the extent practical, each class's revenue deficiency as determined from the approved cost of service study, and move the classes as close to parity as practicable. The appropriate allocation compares present revenue for each class to the class cost of service requirement and then distributes the change in revenue requirements to the classes. No class should receive an increase greater than 1.5 times the system average percentage increase in total, and no class should receive a decrease. (Docket No. 080317–EI, *Order No. PSC-09-0283-FOF-EI,* Issued: April 30, 2009 at 86-87, footnote omitted).

Therefore, gradual movement of PEF's rates closer to cost would be consistent with Commission policy.

Q HOW IS PEF PROPOSING TO ALLOCATE THE PROPOSED BASE REVENUE INCREASE IN THIS PROCEEDING?

A PEF's proposed base revenue increase is shown in **Exhibit JP-8**. As can be seen in **Exhibit JP-8**, PEF is proposing a 34.2% base rate increase. The increases by class would range from 0% for Lighting Facilities service to 55.15% for the Interruptible (IS-1, IS-2) rate class.

Q IS PEF'S PROPOSED CLASS REVENUE ALLOCATION CONSISTENT WITH THIS COMMISSION'S PRACTICES?

A No. As shown in **Exhibit JP-8**, the proposed relative increases for the GSD-1, IS-1/IS-2, and SS-3 rates would exceed 150% of the system average increase which is the standard the Commission applies. PEF's proposal is clearly contrary to this Commission's practice and precedents and should be rejected. PEF apparently tries to mask this fact by showing that its proposed class revenue allocation would result in no cost-of-service class receiving a <u>relative increase</u> higher than 150% of the FPSC retail average increase (column 4). However, the appropriate standard is to examine the impact on individual rates.

Q HOW SHOULD ANY RATE INCREASE OR DECREASE RESULTING FROM THIS CASE BE ALLOCATED AMONG CUSTOMER CLASSES?

A Consistent with Commission policy and precedent, rates for each class should be set at a level that will recover the cost of serving that class, subject to the policy that no rate should receive an increase greater than 150% of the retail average base rate increase. This is reflected in **Exhibit JP-9** using PEF's proposed 2010 revenue requirement. However, as I noted earlier, this illustration is not an endorsement of the revenue requirement requested. **Page 1** is based on the A&E method, while **page 2** is based on the 12CP-1/13th AD method.

The relative increases to Interruptible and Lighting Energy classes were limited to 150%, while no class received a decrease.

Q WOULD YOUR RECOMMENDED REVENUE ALLOCATION MOVE ALL CLASSES CLOSER TO COST?

A Yes. This is shown in **Exhibit JP-10**, which shows the cost-of-service study results under my recommended class revenue allocation. **Page 1** is based on the A&E method, while **page 2** is based on the 12CP-1/13th AD method. All but one class (due to the 150% constraint) would be moved closer to cost. The remaining classes would produce the same rates of return.

4. RATE DESIGN

Q WHAT RATE DESIGN ISSUES WILL YOU ADDRESS?

A In this section, I will discuss the appropriate design of the firm and non-firm rates. Specifically, I will discuss:

- Demand and Non-Fuel Energy charges; and
- The Interruptible Demand Credits.

<u>**Demand and Non-Fuel Energy Charges**</u>

Q DESCRIBE THE DEMAND AND NON-FUEL ENERGY CHARGES.

A These charges are designed to recover base rate (non-fuel) costs. Demand charges are billed relative to a customer's maximum metered (kW) demand in the billing month, while the non-fuel energy charges are billed on the kWh purchased.

Q DO YOU AGREE WITH HOW PEF HAS PROPOSED TO DEVELOP THE DEMAND AND NON-FUEL ENERGY CHARGES?

A No. Consistent with cost-causation, PEF's demand-related costs should be recovered through the demand charge and energy-related base rate costs should be collected through the energy charge. However, PEF's proposed rate design does not follow this practice. Specifically, PEF has underpriced the demand charges and overpriced the energy charges in Schedules GSD, CS, and IS. The demand and non-fuel energy charges should closely reflect the corresponding demand and non-fuel energy related costs as derived in the class cost-of-service study.

Q WHAT ARE THE UNIT DEMAND AND ENERGY COSTS DERIVED FROM PEF'S CLASS COST-OF-SERVICE STUDY?

A PEF's proposed 2010 unit costs and proposed rates for service provided at transmission delivery for the GSD and Interruptible classes are as follows:

Component	GSD		Interruptible	
	Unit Cost	Proposed Rate	Unit Cost	Proposed Rate
Demand Unit Cost ($ per kW-Month)	$10.88	$2.14	$10.30	$5.20
Non-Fuel Energy Unit Cost (¢ per kWh)	0.508¢	2.274¢	0.499¢	1.070¢

Q HAS PEF EXPLAINED WHY THE NON-FUEL ENERGY CHARGES ARE MUCH HIGHER THAN ACTUAL ENERGY COSTS? THAT IS, HAS PEF EXPLAINED, FOR EXAMPLE, WHY THE PROPOSED GSD NON-FUEL ENERGY CHARGE IS TWO TO FOUR TIMES HIGHER THAN THE ACTUAL COST?

A No and I find it difficult to postulate a scenario where such extreme differentials would be appropriate.

Q HOW DO YOU RECOMMEND THAT THESE EXTREME DIFFERENTIALS BE REMEDIED?

A The current non-fuel energy charges in Schedules GSD, CS, and IS already exceed non-fuel energy unit costs at PEF's proposed rates. Thus, any increase allocated to these rates should be applied only to the demand charges. The current non-fuel energy charges should not change. Similarly, any rate decrease should be used to reduce the current non-fuel energy charges.

Interruptible Demand Credits

Q WHAT ARE INTERRUPTIBLE DEMAND CREDITS?

A Interruptible Demand credits are payments made to customers that purchase interruptible power. These customers agree to curtail service when capacity is needed to serve firm customers. As described below, the utility may shut these customers off with no notice when capacity is needed. Thus, they receive a lower quality of service than do firm customers and therefore pay a lower rate.

Q WHAT IS INTERRUPTIBLE POWER?

A Interruptible power is a tariff option that allows a utility to curtail interruptible load when resources are needed to maintain system reliability; that is, when there are insufficient resources to meet customer demand, a utility can curtail interruptible load. This allows the utility to maintain service to firm (*i.e.*, non-interruptible) customers. Interruptible power, thus, is a lower quality of service than firm power. PEF does not include interruptible load in determining the need for additional capacity. Thus, PEF does not plan capacity additions to serve interruptible load.

Q CAN INTERRUPTIBLE POWER PROVIDE ANY OTHER BENEFITS?

A Yes. The Florida Reliability Coordinating Council (FRCC) requires that all reserve sharing groups and balancing authorities maintain adequate Contingency Reserves to cover the FRCC's most severe single contingency, which is currently 910 MW. Of this amount, PEF's contingency reserve requirement is currently 179 MW (*FRCC Handbook*, FRCC Contingency (Operating) Reserve Policy, Appendix A, November 2008). PEF must supply this reserve when called upon to replace reserve capacity that is no longer available due to sudden forced outages of major generating facilities or the loss of transmission facilities.

Contingency reserves may be comprised of those generating resources and Interruptible Load that are available within 15 minutes. Thus, PEF could count interruptible power in meeting its contingency reserve obligations.

Q **IS INTERRUPTIBLE POWER AN IMPORTANT RESOURCE FOR THE STATE OF FLORIDA?**

A Yes. The interruptible tariffs have been in place for decades. They have been (and currently are) a valuable resource to PEF and to the State as a whole. When capacity is needed to serve firm load customers, interruptible customers, statewide, may be called upon (with or without notice and without limitation as to the frequency and duration of curtailments) to discontinue service so that service will be maintained for the firm customer base. Such interruption often causes production processes of interruptible customers to be shut down resulting in economic losses for the interruptible customer.

Q **IS THE VALUE OF INTERRUPTIBLE POWER AFFECTED BY THE FREQUENCY AND DURATION OF PHYSICAL INTERRUPTIONS?**

A No. Interruptible power provides "insurance" in the event that the utility experiences extreme weather, understates load growth, or sustains forced outages of a major resource. As the FERC has found:

> *61804 **[E]ven a limited right of interruption**, if it enables the Company to keep a customer from imposing demands on the system during peak periods, **gives a Company the ability to control its capacity costs.** Therefore, that customer shares no responsibility for capacity costs under a peak responsibility

> method.
>
> It is, thus, the right to interrupt that is critical to the analysis, and not the actual interruptions or even the number or length of such interruptions. If a Company can keep a customer from imposing its load on the system at system peak, as Entergy can do here, then, under the peak responsibility method of cost allocation that Entergy uses, "that customer shares no responsibility for capacity costs...."
>
> 75. . . .When a utility makes a commitment to serve firm load, it commits to serve that load at all times (absent a force majeure event on the system). When a utility makes a commitment to serve interruptible load, it does not commit to serve that load at all times. **To the contrary, it expressly reserves the right to interrupt (even if there is no force majeure event on its system).** Moreover, when it curtails interruptible load, it does so to protect its service to its firm load. That is, it curtails interruptible load precisely because it has not undertaken to construct or otherwise acquire the necessary facilities to serve interruptible load at all times and most particularly when use of the system is peaking; for firm load, in contrast, it has undertaken to construct or otherwise acquire such facilities. (106 FERC ¶61,228, at 14 16; emphasis added).

Q HOW CAN THE COMMISSION NURTURE THIS VALUABLE RESOURCE?

A The Commission should not reduce the interruptible credit by 44% as PEF proposes for Schedule IS-1 customers. As explained below, the credit should be increased to at least $10.49 per kW-month based on PEF's most recent cost-effectiveness analysis.

Q DESCRIBE PEF'S PROPOSAL TO REDUCE THE INTERRUPTIBLE DEMAND CREDIT BY 44%

A Schedule IS-1 customers currently receive a $3.62 per kW-month credit. The corresponding credit for Schedule IS-2 customers is $3.31 per kW-month of load factor adjusted demand. PEF is proposing to eliminate Schedule IS-1 and move customers to Schedule IS-2. The combined IS-1/IS-2 class is projected to have an average billing load factor of about 61%. This would result in an average load-factor adjusted credit of $2.02. Thus, the Company's proposal would result in a 44% reduction in the interruptible credits currently paid to Schedule IS-1 customers, despite the fact that even the current credits are too low.

Q IS IT APPROPRIATE TO REDUCE INTERRUPTIBLE DEMAND CREDITS BY 44% FOR ANY INTERRUPTIBLE CUSTOMER?

A No PEF's proposed reduction would significantly discourage continued participation in this valuable service. In fact, such credits should be increased.

Q HAS PEF CALCULATED THE LEVEL OF INTERRUPTIBLE DEMAND CREDIT THAT WOULD BE COST-EFFECTIVE?

A Yes. PEF provided an updated cost-effectiveness test that shows that the resulting credit for interruptible customers should be $10.49 per kW-Month (*PEF's Response to FIPUG's Production of Documents Request No.34*). A copy of this response is provided in **Exhibit JP-11**.

Q SHOULD THE INTERRUPTIBLE DEMAND CREDIT BE INCREASED?

A Yes. PEF is projecting a need for additional cost-effective non-firm load. It is unreasonable to expect an increase in non-firm load by paying only $3.31 per load factor adjusted kW. The present cost-effective interruptible credit is $10.49 per kW-month. This credit should be implemented in the new Schedule IS.

Q SHOULD THE INTERRUPTIBLE DEMAND CREDIT BE REDUCED BY A CUSTOMER'S LOAD FACTOR?

A No. The customer should be paid the full credit based on the amount of load available for curtailment.

Q IS A LOAD FACTOR ADJUSTMENT VALID?

A No. First, PEF's proposal uses a customer's billing load factor as a proxy for the customer's coincidence factor. This approach assumes that load factor and coincidence factor are the same. They are not. The interruptible class has a 61% billing load factor. However, the average coincidence factor (with PEF's monthly system peaks) is 68%. Thus, the Interruptible Demand Credit should not be less than $7.13 per kW-Month ($10.49 x 68%) of billing demand.

Second, curtailments can occur at any time, not just during the system peaks. Thus, the Interruptible Demand Credit should apply to the amount of load that PEF is not obligated to serve during an interruption event.

Q HOW SHOULD THE INTERRUPTIBLE DEMAND CREDIT BE STRUCTURED?

A To measure this benefit, the amount of interruptible demand subject to the Credit should be based on customer's normal operating demand for a defined "base line" period using actual data from a prior critical period. For example, a customer that operated an average load of 10,000 kW during on-peak hours of the prior calendar year would receive a Credit based on 10,000 kW. Some utilities use this methodology.

Q IS THERE ANOTHER ALTERNATIVE TO DETERMINE THE AMOUNT OF INTERRUPTIBLE LOAD?

A Yes. Another alternative would be to directly measure the amount of interruptible demand in real-time for each customer. The interruptible demand would be average of the daily maximum on-peak demands for the billing month. This process is similar to determining the Generation and Transmission Capacity charges in Rate SS.

Q WHICH OF THESE TWO ALTERNATIVES DO YOU RECOMMEND IN LIEU OF A LOAD FACTOR ADJUSTMENT?

A PEF already measures the daily maximum on-peak demand for billing standby customers. Thus, it should not be burdensome to require the same process in determining the Interruptible Demand Credit.

5. DEPRECIATION

Q WHAT DEPRECIATION ISSUES WILL YOU ADDRESS?

A I will address:

- The life spans of coal and combined cycle (CC) units. Life spans are integral in determining the appropriate depreciation rates;
- Other measures to reduce PEF's large depreciation surplus.

<u>Background</u>

Q WHAT IS DEPRECIATION?

A Depreciation reflects the consumption or use of assets used to provide utility service. Thus, it provides for capital recovery of a utility's current or original investment. Generally, this capital recovery occurs over the average service life of the investment or assets. The most commonly used definition of depreciation is found in the Code of Federal Regulations (CFR):

> Depreciation, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities. (*18 CFR Part 101*)

In addition, the American Institute of Certified Public Accountants in Accounting Research and Terminology Bulletin #1 provides the following definition of depreciation accounting:

> Depreciation accounting is a system of accounting which aims to distribute cost or other basic value of tangible capital assets, less salvage (if any), over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner. It is a process of allocation, not of valuation. Depreciation for the year is the portion of the total charge under such a system that is

> allocated to the year. Although the allocation may properly take into account occurrences during the year, it is not intended to be a measurement of the effect of all such occurrences.

This definition recognizes depreciation as an allocation of cost to particular accounting periods over the life of assets.

Q WHAT ARE THE KEY PARAMETERS THAT DETERMINE THE AMOUNT OF DEPRECIATION RECOGNIZED FOR RATE-MAKING PURPOSES?

A Depreciation accounting provides for the recovery of the original cost of an asset over its life span adjusted for net salvage. As a result, it is critical that appropriate average life span be used to develop the depreciation rates so that present and future ratepayers are treated equitably. In addition to capital recovery, depreciation rates also contain a provision for net salvage. Net salvage is the value of the scrap or reused materials less the removal cost of the asset being depreciated. A utility will reflect in its rates the net salvage over the useful life of the asset.

Q HOW ARE DEPRECIATION RATES CALCULATED?

A Depreciation rates are essentially calculated using the following formula:

$$Remaining\ Life\ Rate = \frac{100\% \ - Reserve\ \% - Avg.Future\ Net\ Salvage\ \%}{Avg.Remaining\ Life\ in\ Years}$$

The above formula is prescribed in Rule 25-6.0436, Florida Administrative Code. Under this method of developing depreciation rates, the un-depreciated portion of the plant in service, adjusted for net salvage, is recovered over the average remaining life of the asset or group of assets. Therefore, at the end of the useful life, the asset is fully depreciated.

<u>PEF's Depreciation Study</u>

Q **HAVE YOU REVIEWED THE DEPRECIATION STUDY FILED BY PEF IN THIS PROCEEDING?**

A Yes.

Q **WHAT DOES THE DEPRECIATION STUDY SHOW?**

A The study recommends higher depreciation rates, which would generate an additional $97.4 million of depreciation expense (*Direct Testimony and Exhibits of Earl M. Robinson,* Exhibit ERM-2, Table 1F). Of this amount, $70 million of the increase is due to increased production depreciation rates, which can be attributed to assumed life spans for production investments.

Q **WHAT ELSE DOES PEF'S DEPRECIATION STUDY SHOW?**

A The study also shows that, based on the assumed average and remaining service lives of its investments and the projected book value as of December 31, 2009, PEF's book depreciation reserve is $789 million higher than the "theoretical reserve." (*Id.* at Table 5F). The theoretical reserve is the amount necessary to allow recovery of the existing investments over their projected remaining life spans. In other words, PEF has accrued a $789 million reserve surplus.

Q **IS THERE ANYTHING NOTEWORTHY ABOUT THE $789 MILLION DEPRECIATION RESERVE SURPLUS?**

A Yes. The $789 million surplus reserve is dependent on PEF's proposed life and salvage parameters. The theoretical reserve calculation is based on PEF's remaining life proposals. If the remaining life is understated, the theoretical reserve will be overstated causing the reserve surplus to be understated. My testimony will address two areas where PEF has understated the remaining lives of assets causing the reserve surplus to be even higher than stated.

Q WHAT IS THE SIGNIFICANCE OF THE SURPLUS?

A The purpose of depreciation is to recover capital investment, including removal costs. Such recovery should, to the extent possible, come from the customers that use the utility service. With the large depreciation surplus, the current generation of ratepayers has paid a disproportionate share of the assets consumed to provide utility services. Thus, PEF's depreciation rates are neither fair nor equitable.

<u>**Life Spans**</u>

Q HAVE YOU REVIEWED THE LIFE SPANS THAT PEF USED TO DETERMINE ITS PROPOSED DEPRECIATION RATES?

A Yes. PEF's proposed life probable retirement years for coal and CC units are shown in Exhibit ERM-2 (Table 2-Loc-Total, p. 2-125 through p. 2-130, and p. 9-60, p. 9-71) and produce average life spans summarized below:

Plant Type	PEF's Proposed Average Life Spans
Coal	52
Combined Cycle	31

Q ARE PEF'S PROPOSED LIFE SPANS APPROPRIATE?

A No. PEF has understated the life spans for these plant types.

Q **ON WHAT DO YOU BASE YOUR OPINION THAT PEF'S PROPOSED LIFE SPANS ARE SIGNIFICANTLY UNDERSTATED?**

A My opinion is based on actual plant lives, life spans used by other utilities for similar assets, and decisions by regulatory commissions.

Q **WHAT LIFE SPAN DOES PEF ASSUME FOR ITS COAL UNITS?**

A PEF owns Crystal River Units 1 and 2 and Crystal River Units 4 and 5. The depreciation study assumes that these facilities will be retired in 2020 and 2035, respectively (*ERM-2* at p. 2-125 through p. 2-126). This translates into an average life span of 52 years.

Q **HAS PEF PROVIDED ANY JUSTIFICATION FOR THE PROPOSED LIFE SPANS?**

A No. The Company has not indicated when it will retire these units (*PEF's 2009 Ten-Year Site Plan*, Schedule 1).

Q **ARE 52-53 YEAR LIFE SPANS REASONABLE FOR COAL UNITS?**

A No. PEF's proposed life spans are shorter than the average lives of coal-fired plants as determined in proceedings. For example:

- 60 years for Indiana-Michigan Power company's Tanner Creek Units 1 through 4 and for its Rockport Unit 1 (Indiana Utility Regulatory Commission, Cause No. 43231, *Interim Order*, 6/13/2007);
- 55 years for coal plants operated by Southwestern Public Service Company (New Mexico Public Regulatory Commission, Case No. 07-00319-UT, *Order*, August 26, 2008);
- 59 to 68 years for coal units owned by AmerenUE (Missouri Public Service Commission, Cause No. ER-2007-0002, *Order*, May 22, 2007);

- 61 years for coal units owned by Rocky Mountain Power (Wyoming Public Service Commission, Docket No. 20000-257-EA-6, *Record No. 10794*, June 12, 2008);
- 60 years for Public Service Company of Oklahoma (Oklahoma Corporation Commission, Cause No. PUD 200600285, *Order No. 545168*, October 9, 2007); and
- 55 years for Georgia Power Company's Plant Scherer Units 1-3 (Georgia Public Service Commission, Docket No. 25060-U, Document 103566, 2007 Rate Case).

Thus, PEF's proposed life spans are shorter than the life spans of actual coal-fired plants. Further, the two biggest operators of coal units in the nation, American Electric Power Company and The Southern Company, have determined that life spans of 60 years or more are achievable (Indiana Utility Regulatory Commission, Cause No. 43231, *Interim Order,* 6/13/2007, Florida Public Service Commission, Docket No. 050381-EI, *Order No. PSC-07-0012-PAA-EI*, January 2, 2007).

Q DO OTHER FLORIDA UTILITIES USE LONGER LIFE SPANS THAN PEF FOR THEIR COAL UNITS?

A Yes. Gulf Power Company extended the lives of the Plant Crist and Plant Smith units to 65 years (Docket No. 050381-EI, *Order No. PSC-07-0012-PAA-EI*, January 2, 2007).

Q WHAT CONCLUSIONS CAN BE DRAWN FROM INDUSTRY EXPERIENCE AND THE SPECIFIC EXAMPLES YOU HAVE DESCRIBED?

A It appears that PEF has understated the life span of its coal units, which results in increased depreciation costs which PEF wants ratepayers to bear. PEF's coal units represent a $2.4 billion investment. Given this significant investment, it stands to reason that these capital intensive investments should be operated as long as possible to obtain the greatest level of economic benefit. Thus, it should normally be cost effective to maintain such equipment in operating condition over the long term.

For all of the above reasons, the Commission should use a life span of *at least* 55 years for PEF's coal units.

Q WHAT IS THE IMPACT OF INCREASING THE LIFE SPANS OF PEF'S COAL UNITS TO 55 YEARS?

A The impact of increasing the life spans would be to decrease the depreciation accruals for the coal plants by approximately $4.1 million annually as shown in **Exhibit JP-12**.

Q HOW DID YOU CALCULATE THE CHANGE IN ANNUAL ACCRUALS?

A I recalculated the depreciation rate by first calculating the ratio of my recommended life spans to PEF's proposed life span by unit. This ratio was then multiplied by the corresponding whole life (by unit by FERC account) to determine the adjusted whole life. The revised remaining life is the sum of (1) the difference between the adjusted whole life and PEF's proposed whole life and (2) PEF's proposed remaining life. The revised depreciation accrual is the ratio of the PEF's proposed remaining life to the revised remaining life multiplied by PEF's proposed accrual.

Q WHAT LIFE SPANS DOES PEF PROPOSE FOR ITS COMBINED CYCLE UNITS?

A The average life span for PEF's CC units is 31 years. This ranges from 29 years for Hines Energy Complex to 41 years for Tiger Bay. The new Bartow CC units are projected to have 30-year life spans (*Direct Testimony and Exhibits of Earl M. Robinson,* Exhibit EMR-2, p. 9-60, p. 9-71).

Q HAS PEF JUSTIFIED THE LIFE SPANS OF ITS COMBINED CYCLE UNITS?

A No. There are no expected retirement dates for these units (PEF's *2009 Ten-Year Site Plan* at Schedule 1). PEF has not explained why it cannot operate these units for much longer than 31 years (30 years for its newest, most efficient Bartow units). The CC units represent a combined $1.8 billion investment. Since these are the most efficient units on PEF's system, it should be economic to maintain them in good operating condition for much longer than 31 years.

Q WHAT IS THE BASIS FOR YOUR OPINION THAT COMBINED CYCLE UNITS ARE CAPABLE OF OPERATING MUCH LONGER THAN 31 YEARS?

A My opinion is based on industry projections and practices, including the following:

- 40 years for PacifiCorp/Rocky Mountain Power's CC units (Utah Public Service Commission, Docket No. 07-035-13 and Public Utility Commission of Oregon UM 1329, *Order No. 08-327*, June 17, 2008);
- Over 60 years for Public Service Company of Oklahoma (Oklahoma Corporation Commission Cause No. 200600285, *Order No. 545168*, October 9, 2007);

- 35 years for Nevada Power Company's Silverhawk and Lenzie CC units (Nevada Public Utilities Commission, Docket No. 06-11023, Modified Order of July 17, 2007);
- 35 years for Georgia Power Company McIntosh CC units (Georgia Public Service Commission, Docket No. 25060-U Document 103566, 2007 Rate Case).

Further, in a study of capacity needs, the Michigan Public Service Commission (MPSC) used a 40-year life span for new CC units (MPSC Docket No. U-14231).

Q **DO ANY OTHER FLORIDA UTILITIES USE LONGER LIFESPANS FOR THEIR COMBINED CYCLE UNITS?**

A Yes. Gulf Power recently extended the life of Plant Smith Unit 3 to 34 years (Docket No. 050381-EI, *Order No. PSC-07-0012-PAA-EI*, January 2, 2007). While conservative in light of the non-Florida examples cited above, this Florida example further demonstrates the unreasonableness of PEF's proposed life spans.

Q **WHAT LIFE SPANS DO YOU RECOMMEND FOR COMBINED CYCLE UNITS?**

A Based on industry practices and recognizing PEF's $1.8 billion investment, the Commission should increase the life span to *at least* 35 years.

Q **WHAT IS THE IMPACT OF INCREASING THE LIFE SPANS OF PEF'S COMBINED CYCLE UNITS TO 35 YEARS?**

A The increase of the life spans would decrease the depreciation accruals for the combined cycle plants by approximately $13.1 million annually as shown on **Exhibit (JP-12)**. This adjustment was quantified using the same methodology as described previously.

Q SHOULD THE COMMISSION TAKE ANY FURTHER STEPS TO RESTORE GENERATIONAL EQUITY?

A Yes. To compensate for the huge reserve surplus, the Commission should order PEF to implement a $100 million annual depreciation expense adjustment. That is, PEF should credit depreciation expense and debit to the bottom line depreciation reserve by at least $100 million per year. This treatment should continue until PEF files its next depreciation study. Assuming PEF's next depreciation study is filed in 2012 (three years from the filing date of this case), the book reserve would be reduced by an additional $300 million. This would still leave nearly $0.5 billion in excess book depreciation reserve.

Q IS THERE ANY PRECEDENT FOR REQUIRING PEF TO TAKE MEASURES NECESSARY TO ELIMINATE THE HUGE (OVER $789 MILLION) SURPLUS IN ITS DEPRECIATION RESERVE?

A Yes. My recommendation to correct a reserve surplus is the same in concept as prior Commission actions allowing Florida Power & Light Company (FPL) to correct reserve deficiencies. For example:

- FPL was to book $126 million (in accord with preliminary implementation approved in Order PSC-95-0672-FOF-EI), an additional $30 million commencing in 1996, and additional expense in 1996 and 1997 equal to 100% of base rate revenues produced by retail sales between its "low band" and "most likely sales forecast" for 1996, and at least 50% of the base rate revenues produced by retail sales above FPL's most likely sales forecast for 1996 to correct a $175.3 million deficiency in the nuclear depreciation reserve and to correct the reserve deficiency existing in FPL's other production facilities, which was calculated to be $60.3 million as of January 1, 1994 (Docket No. 950359-EI, *Order No. PSC-96-0307-PHO-EI*); and
- FPL was ordered to amortize the gain realized from the sale of a combustion turbine from Port St. Joe to be used to offset the

> reserve deficiency at the Suwanee Peaking Plant. (Docket No. 971570-EI, *Order No. PSC-98-1723-FOF-EI*).

More recently, the Commission also adopted a similar approach for FPL to correct a reserve surplus. The Order stated that:

> FPL has the option to amortize up to $125,000,000 annually as a credit to depreciation expense and a debit to the bottom line depreciation reserve over the term of the Stipulation and Settlement and as specified therein. Depreciation rates and/or capital recovery schedules will be established pursuant to the comprehensive depreciation studies as filed in March 2005 and will not be changed during the term of the Stipulation and Settlement. (FPSC Docket No. 050188-EI, *Order PSC-05-0902-S-EI* Paragraph 8)

Since PEF also has a huge reserve surplus, similar adjustments are appropriate and necessary to restore generational equity and to help mitigate the impact of the proposed base rate increases.

Q PLEASE SUMMARIZE YOUR RECOMMENDATIONS ON DEPRECIATION EXPENSE.

A My recommendations are as follows:

Adjustments	Amount ($Millions)
Increase Coal Plant Life Spans to at Least 55 Years	$4.1
Increase Combined Cycle Plant Life Spans to at Least 35 Years	$13.1
Credit Depreciation Expense; Debit Depreciation Reserve	$100.0

6. CAPITAL STRUCTURE

Q WHAT CAPITAL STRUCTURE IS PEF PROPOSING IN THIS PROCEEDING?

A PEF's proposed regulatory capital structure is shown in the first column of the chart below:

Component	MFR Schedule D-1A	PEF Test Year Adjusted for PPA	PEF Test Year Unadjusted for PPA
Long-Term Debt	42.28%	45.10%	48.61%
Short-Term Debt	0.62%	0.66%	0.71%
Common Equity	50.52%	53.90%	50.31%
Preferred Stock	0.32%	0.34%	0.37%
Customer Deposits	1.81%		
Deferred Taxes	4.40%		
Investment Tax Credits	0.06%		

The first column is the proposed jurisdictional regulatory capital structure. The common equity percentage reflected in this column includes an adjustment for off-balance sheet obligations associated with purchased power agreements (PPAs). The second and third columns reflect PEF's adjusted 2010 capital structure (*Direct Testimony Thomas Sullivan* at 19), which exclude customer deposits, deferred income taxes, and investment tax credits. The second column shows PEF's adjusted capital structure with the imputed PPAs. The PPA obligations are removed in the third column.

Q WHAT IS THE PROPOSED ADJUSTMENT FOR PURCHASED POWER OBLIGATIONS?

A PEF's proposed regulatory capital structure includes $711.3 million of imputed debt for purchased power obligations. As can be seen in the third column of the above chart, without this imputed debt, PEF's common equity ratio would be 50%. A 50% equity ratio is higher than the industry average. For the reasons explained below, the Commission should set rates based on an adjusted capital structure that excludes imputed debt.

<u>**Imputed Debt for Purchased Power Obligations**</u>

Q WHY DOES PEF IMPUTE $711 MILLION OF DEBT RELATED TO PPAS?

A PEF asserts that the financial community commonly takes into account obligations associated with PPAs. Since PEF has certain long-term PPAs, it is obligated to make certain fixed payments, which, it asserts, the rating agencies regard as equivalent to long-term debt (*Id.* at 17).

Q DO YOU AGREE WITH THIS ADJUSTMENT?

A No. It is unnecessary to impute debt for PPA obligations. The Commission's approval of PPAs is governed by Rule 25-17.0832, Florida Administrative Code (for standard offer and negotiated contracts). Once approved, PEF is allowed full and direct recovery of firm energy and purchased power capacity costs under the Fuel and Capacity Cost Recovery (CCR) clauses. Though such contracts are reviewed in the annual fuel adjustment proceeding, there is minimal recovery risk associated with PPAs.

Second, Moody's does not treat PPAs in the same way as Standard & Poor's (S&P).

Finally, the Commission has very recently addressed precisely this issue. In the Tampa Electric (TECO) recent rate case, TECO made the same argument that PEF puts forth here and it was rejected by the Commission.

Q DO ALL RATING AGENCIES IMPUTE THE FIXED OBLIGATIONS UNDER PPAS IN EVALUATING A UTILITY'S FINANCIAL STRENGTH?

A No. PEF's imputed debt adjustment reflects the methodology outlined by S&P. It is noteworthy that another ratings agency, Moody's, does not make a similar adjustment.

Q HOW DOES S&P RECOGNIZE THE DEBT EQUIVALENT OF PPAS?

A S&P quantifies the debt equivalent as the product of (1) a risk factor and (2) the net present value of the remaining capacity payments under each PPA. The risk factor is based primarily on the method of recovery of capacity payments.

Q WHAT RISK FACTOR HAS PEF USED IN ITS IMPUTED DEBT ADJUSTMENT?

A PEF has used a 25% risk factor (*Id.* at 18). This choice is based on general criteria explained by S&P:

> In cases where a regulator has established a power cost adjustment mechanism that recovers all prudent PPA costs, we employ a risk factor of 25% because the recovery hurdle is lower than it is for a utility that must litigate time and again its right to recover costs. (Exhibit No. TRS-9, Standard & Poor's *Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements* at 3).

Q DOES THIS ACCURATELY REFLECT THE RISKS ASSOCIATED WITH THE RECOVERY OF PURCHASED POWER CAPACITY COSTS IN FLORIDA?

A No. Purchased power capacity costs are subject to dollar-for-dollar recovery through the Capacity Cost Recovery clause (CCR). This includes a true-up procedure that establishes a forward-looking charge, which is then reconciled based on actually incurred costs, with interest. The recovery mechanism is nearly identical to PEF's Fuel Charge.

Q DOES S&P RECOGNIZE THE RELATIONSHIP BETWEEN RISK AND THE TYPE OF COST RECOVERY MECHANISM?

A Yes. S&P states that:

> The NPVs that Standard & Poor's calculates to adjust reported financial metrics to capture PPA capacity payments are multiplied by risk factors. These risk factors typically range between 0% to 50%, but can be as high as 100%. Risk factors are inversely related to the strength and availability of regulatory or legislative vehicles for the recovery of the capacity costs associated with power supply arrangements. The strongest recovery mechanisms translate into the smallest risk factors. (*Id.*)

Thus, S&P does not provide an objective standard for determining the appropriate risk factor. Dollar-for-dollar recovery of purchased power capacity costs is a very strong mechanism with no practical risk. PEF's PPAs have been previously approved for recovery. In fact, the above discussion from S&P, in conjunction with the policies and previous findings in Florida strongly suggest that the obligations under Commission-approved PPAs are risk free, so long as the utility properly manages the contracts.

Q DOES MOODY'S CONSIDER PPAS AS INHERENTLY MORE RISKY FOR ELECTRIC UTILITIES?

A No. Moody's specifically recognizes that the risk of PPAs is directly related to the applicable cost recovery mechanism as well as market dynamics:

> Pass-through capability: Some utilities have the ability to pass through the cost of purchasing power under PPAs to their customers. As a result, the utility takes no risk that the cost of power is greater than the retail price it will receive. Accordingly Moody's regards these PPA obligations as operating costs with no long-term debt-like attributes. PPAs with no pass-through ability have a greater risk profile for utilities. In some markets, the ability to pass through costs of a PPA is enshrined in the regulatory framework, and in others can be dictated by market dynamics. As a market becomes more competitive, the ability to pass through costs may decrease and, as circumstances change, Moody's treatment of PPA obligations will alter accordingly. (Moody's, *Rating Methodology: Global Regulated Electric Utilities*, March 2005 at 9.)

Thus, it is clear that Moody's does not regard PPAs as inherently risky and therefore, it imputes no debt for these contracts where recovery is guaranteed.

Q DOES PEF HAVE THE ABILITY TO PASS THROUGH THE COSTS OF ITS PPAS?

A Yes. As explained earlier, PEF has the ability to directly pass through purchased power capacity costs. In the case of certain purchases mandated by state statute, such as those from renewable energy sources, up-front approval is required for non-standard offer contracts, while standard offer contracts are considered reasonable.

Q DOES MOODY'S CONSIDER PPAS AS BEING LESS RISKY IN CERTAIN CIRCUMSTANCES?

A Yes. Unlike S&P, Moody's recognizes that PPAs can be less risky for a utility:

> Risk management: An overarching principle is that PPAs have been used by utilities as a risk management tool and Moody's recognizes that this is the fundamental reason for their existence. Thus, Moody's will not automatically penalize utilities for entering into contracts for the purpose of reducing risk associated with power price and availability. Rather, we will look at the aggregate commercial position, evaluating the risk to a utility's purchase and supply obligations. In addition, PPAs are similar to other long-term supply contracts used by other industries and their treatment should not therefore be fundamentally different from that of other contracts of a similar nature. (*Id.*)

Q ARE YOU SAYING THAT MOODY'S WILL NOT IMPUTE DEBT ASSOCIATED WITH PPAS?

A No. Moody's states:

> *Methods of accounting for PPAs in our analysis*
>
> According to the weighting and importance of the PPA to each utility and the level of disclosure, Moody's may analytically assess the total obligations for the utility using one of the methods discussed below.
>
> Operating Cost: If a utility enters into a PPA for the purpose of providing an assured supply and there is reasonable assurance that regulators will allow the costs to be recovered in regulated rates, Moody's may view the PPA as being most akin to an operating cost. In this circumstance, there most likely will be no imputed adjustment to the obligations of the utility.

Based on the above statements by Moody's, it seems unlikely that debt will be imputed to PEF based on the cost recovery mechanisms applicable to purchased power capacity costs.

Q IS THE DEBT THAT PEF PROPOSES TO IMPUTE FOR PPA OBLIGATIONS ACTUAL DEBT ON THE COMPANY'S BOOKS AND RECORDS?

A No. PEF does not reflect its PPA obligations as debt in the normal course of accounting.

Q HAS THE COMMISSION PREVIOUSLY RULED ON THIS ISSUE IN A RECENT CASE?

A Yes. The Commission rejected TECO's proposal to impute additional equity in determining its capital structure to recognize the so-called risks associated with PPAs. The Commission stated that:

> The pro forma adjustment to equity proposed by TECO is not an actual equity investment in the utility. If this adjustment is approved for purposes of setting rates in this proceeding, the Company would essentially be allowed to earn a risk-adjusted equity return without having actually made the equity investment. The revenue requirement impact of recognizing this pro forma adjustment to equity in the capital structure is approximately $5 million per year. (*Order No. PSC-09-0283-FOF-EI* at 35)

The Commission went on to find:

> Companies with PPAs are not required by the rating agencies to make the pro forma adjustment in question. As the following passage explains, the Standard & Poors' (S&P) practice with respect to PPAs described in witness Gillette's testimony is strictly for the rating agency's own analytical purposes:
>
> We adjust utilities' financial metrics, incorporating PPA fixed obligations, so that we can compare companies that finance and build generation capacity and those that purchase capacity to satisfy customer needs. The analytical goal of our financial adjustments for PPAs is to reflect fixed obligations in a way that depicts the credit exposure that is added by PPAs. That said, PPAs also benefit utilities that enter into contracts with suppliers because PPAs will typically shift various risks to the suppliers, such as construction risk and most of the operating risk. PPAs can also provide utilities with asset diversity that might not have been achievable through self-build. The principal risk borne by a utility

> that relies on PPAs is the recovery of the financial obligation in rates. (*Id.*)

Further, in rejecting TECO's adjustment, the Commission held:

> With this proposed adjustment, we find that the Company is attempting to take a portion of S&P's consolidated credit assessment methodology and use it for a purpose it was never intended. (*Id.* at 36).

Q SHOULD DEBT ASSOCIATED WITH PPAS BE IMPUTED IN ASSESSING THE PROPER CAPITAL STRUCTURE FOR PEF?

A No. For all of the reasons stated above, imputed debt should not be included in assessing the reasonableness of PEF's capital structure.

<u>Common Equity Ratio</u>

Q DOES PEF PROPOSE TO ADJUST ITS EQUITY RATIO TO RECOGNIZE IMPUTED DEBT?

A Yes. PEF includes an adjustment to its capital structure of $711.3 million to increase common equity. PEF seeks to use the imputation argument to support an increase in its common equity ratio. The PPA adjustment increases the common equity ratio to 53.9%. As discussed below, the cost of common equity is greater than the cost of debt so the adjustment causes an increase to PEF's proposed rate of return. Thus, the Commission should eliminate the PPA adjustment in determining PEF's capital structure. This would reduce PEF's common equity ratio to 50.3%.

Q HOW DOES PEF'S COMMON EQUITY RATIO COMPARE WITH OTHER ELECTRIC UTILITIES?

A **Exhibit JP-13** is a comparison of common equity ratios for the 2006 to 2009 (1st

Quarter) time frame published by SNL Financial. For this period, average common equity ratios for all electric utilities range from 46.1% to 47.6% (line 85). On a comparable basis, the adjusted 2010 test year common equity ratio of 50.3% would be well above the average. Thus, PEF's test year common equity ratio is 345 basis points higher than the electric utility average.

Q WHAT IS THE CONSEQUENCE OF USING MORE EQUITY AND LESS DEBT TO FINANCE THE UTILITY'S RATE BASE?

A Common equity is more expensive than debt. In this instance, PEF is asking for a common equity return that is over 600 basis points higher than its embedded cost of long-term debt. A utility having too much equity in its capital structure has a higher cost of capital than a utility with a more balanced common equity ratio. All else being equal, the higher the overall common equity ratio, the higher the rates all PEF ratepayers will bear.

Q IS A 50% COMMON EQUITY RATIO SUFFICIENT TO MAINTAIN PEF'S CURRENT BOND RATING?

A Yes. PEF is currently rated "A3" by Moody's and "A-" by Fitches and "BBB+" by S&P. The chart below provides a comparison of the common equity ratios for other A-rated electric utilities. I included all electric utilities that had "A" or equivalent bond ratings from at least two of the three bond rating agencies.

Year	All Electric Utilities	A-Rated Electric Utilities
2006	47.6%	50.9%
2007	47.3%	51.0%
2008	46.4%	49.5%
2009 (Q1)	46.1%	49.5%
Average	46.9%	50.2%

Thus, PEF's 50.0% projected test year common equity (without including off balance sheet obligations) is consistent with comparable A-rated electric utilities.

Q WHAT IS YOUR RECOMMENDATION FOR A COMMON EQUITY RATIO FOR PEF?

A PEF's adjusted common equity ratio of 50.3% (excluding the PPA adjustment) should be the basis for setting its cost of capital in this proceeding. This translates into a 46.93% regulatory common equity ratio. Reducing the regulatory common equity ratio to 46.93% lowers PEF's requested 2010 base revenue increase by about $32.9 million, as shown in **Exhibit JP-14**.

Q DOES THIS CONCLUDE YOUR TESTIMONY?

A Yes, it does.

APPENDIX A

Qualifications of Jeffry Pollock

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

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

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

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

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

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

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

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

Q PLEASE DESCRIBE J. POLLOCK, INCORPORATED.

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

Appendix A
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

PROJECT	UTILITY	ON BEHALF OF	Docket	TYPE	Regulatory Jurisdiction	Subject	DATE
90404	CENTERPOINT	Texas Industrial Energy Consumers	36918	Cross Rebuttal	TX	Senate Bill 769 system restoration costs	7/17/2009
90301	FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	080677	Direct	FL	Approval of test year for rate	7/16/2009
90201	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	36956	Direct	TX	Approval to revise energy efficiency cost recovery factor	7/16/2009
90601	VARIOUS UTILITIES	Florida Industrial Power Users Group	VARIOUS DOCKETS	Direct	FL	Conservation goals	7/6/2009
90201	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	36931	Direct	TX	System restoration costs under Senate Bill 769	6/30/2009
90502	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	36966	Direct	TX	Authority to revise fixed fuel factors	6/18/2009
80805	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	36025	Cross-Rebuttal	TX	Cost allocatiion, revenue allocation and rate design	6/10/2009
80805	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	36025	Direct	TX	Cost allocation, revenue allocation, rate design	5/27/2009
81201	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	08-1065	Surrebuttal	MN	Cost allocation, revenue allocation, rate design	5/27/2009
90403	VIRGINIA ELECTRIC AND POWER COMPANY	MeadWestvaco Corporation	PUE-2009-00018	Direct	VA	Transmission cost allocation and rate design	5/20/2009
90101	NORTHERN INDIANA PUBLIC SERVICE COMPANY	Beta Steel Corporation	43526	Direct	IN	Cost allocation and rate design	5/8/2009
81203	ENTERGY SERVICES, INC	Texas Industrial Energy Consumers	ER008-1056	Rebuttal	FERC	Rough Production Cost Equalization payments	5/7/2009
81201	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	08-1065	Rebuttal	MN	Class revenue allocation and the classification of renewable energy costs	5/5/2009
81201	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	08-1065	Direct	MN	Cost-of-service study, class revenue allocation, and rate design	4/7/2009
81203	ENTERGY SERVICES, INC	Texas Industrial Energy Consumers	ER08-1056	Answer	FERC	Rough Production Cost Equalization payments	3/6/2009
80901	ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-333-ER-08	Direct	WY	Cost of service study; revenue allocation; inverted rates; revenue requirements	1/30/2009
81203	ENTERGY SERVICES	Texas Industrial Energy Consumers	ER08-1056	Direct	FERC	Entergy's proposal seeking Commission approval to allocate Rough Production Cost Equalization payments	1/9/2009
80505	ONCOR ELECTRIC DELIVERY COMPANY & TEXAS ENERGY FUTURE HOLDINGS LTD	Texas Industrial Energy Consumers	35717	Cross Rebuttal	TX	Retail transformation; cost allocation, demand ratchet waivers, transmission cost allocation factor	12/24/2008
70101	GEORGIA POWER COMPANY	Georgia Industrial Group and Georgia Traditional Manufacturers Association	27800	Cross Rebuttal	GA	Cost allocation, Demand Ratchet Waivers	12/22/2008
70101	GEORGIA POWER COMPANY	Georgia Industrial Group and Georgia Traditional Manufacturers Association	27800	Direct	GA	Cash Return on CWIP associated with the Plant Vogtle Expansion	12/19/2008
80505	ONCOR ELECTRIC DELIVERY COMPANY & TEXAS ENERGY FUTURE HOLDINGS LTD	Texas Industrial Energy Consumers	35717	Direct	TX	Revenue Requirement, class cost of service study, class revenue allocation and rate design	11/26/2008

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PROJECT	UTILITY	ON BEHALF OF	Docket	TYPE	Regulatory Jurisdiction	Subject	DATE
80802	TAMPA ELECTRIC COMPANY	The Florida Industrial Power Users Group and Mosaic Company	080317-EI	Direct	FL	Revenue Requirements, retail class cost of service study, class revenue allocation, firm and non firm rate design and the Transmission Base Rate Adjustment	11/26/2008
80601	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	35763	Supplemental Direct	TX	Recovery of Energy Efficiency Costs	11/6/2008
80601	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	35763	Cross-Rebuttal	TX	Cost Allocation, Demand Ratchet, Renewable Energy Certificates (REC)	10/28/2008
80601	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	35763	Direct	TX	Revenue Requirements, Fuel Reconciliation Revenue Allocation, Cost-of-Service and Rate Design Issues	10/13/2008
50106	ALABAMA POWER COMPANY	Alabama Industrial Energy Consumers	18148	Direct	AL	Energy Cost Recovery Rate (WITHDRAWN)	9/16/2008
50701	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	35269	Direct	TX	Allocation of rough production costs equalization payments	7/9/2008
70703	ENTERGY GULF STATES UTILITIES, TEXAS	Texas Industrial Energy Consumers	34800	Direct	TX	Non-Unanimous Stipulation	6/11/2008
50103	TEXAS PUC STAFF	Texas Industrial Energy Consumers	33672	Supplemental Rebuttal	TX	Transmission Optimization and Ancillary Services Studies	6/3/2008
50103	TEXAS PUC STAFF	Texas Industrial Energy Consumers	33672	Supplemental Direct	TX	Transmission Optimization and Ancillary Services Studies	5/23/2008
60104	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	33891	Supplemental Direct	TX	Certificate of Convenience and Necessity	5/8/2008
70703	ENTERGY GULF STATES UTILITES, TEXAS	Texas Industrial Energy Consumers	34800	Cross-Rebuttal	TX	Cost Allocation and Rate Design and Competitive Generation Service	4/18/2008
70703	ENTERGY GULF STATES UTILITES, TEXAS	Texas Industrial Energy Consumers	34800	Direct	TX	Eligible Fuel Expense	4/11/2008
70703	ENTERGY GULF STATES UTILITES, TEXAS	Texas Industrial Energy Consumers	34800	Direct	TX	Competitive Generation Service Tariff	4/11/2008
70703	ENTERGY GULF STATES UTILITES, TEXAS	Texas Industrial Energy Consumers	34800	Direct	TX	Revenue Requirements	4/11/2008
70703	ENTERGY GULF STATES UTILITES, TEXAS	Texas Industrial Energy Consumers	34800	Direct	TX	Cost of Service study, revenue allocation, design of firm, interruptible and standby service tariffs; interconnection costs	4/11/2008
41229	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	35038	Rebuttal	TX	Over $5 Billion Compliance Filing	4/14/2008
71202	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Periman Ltd.	07-00319-UT	Rebuttal	NM	Revenue requirements, cost of service study, rate design	3/28/2008
61101	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	35105	Direct	TX	Over $5 Billion Compliance Filing	3/20/2008
51101	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	32902	Direct	TX	Over $5 Billion Compliance Filing	3/20/2008
71202	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Periman Ltd.	07-00319-UT	Direct	NM	Revenue requirements, cost of service study (COS); rate design	3/7/2008
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	34724	Direct	TX	IPCR Rider increase and interim surcharge	11/28/2007
70601	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Traditional Manufacturers Group	25060-U	Direct	GA	Return on equity; cost of service study; revenue allocation; ILR Rider; spinning reserve tariff; RTP	10/24/2007
70303	ONCOR ELECTRIC DELIVERY COMPANY & TEXAS ENERGY FUTURE HOLDINGS LTD	Texas Industrial Energy Consumers	34077	Direct	TX	Acquisition; public interest	9/14/2007
60104	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	33891	Direct	TX	Certificate of Convenience and Necessity	8/30/2007

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PROJECT	UTILITY	ON BEHALF OF	Docket	TYPE	Regulatory Jurisdiction	Subject	DATE
61201	ALTAMAHA ELECTRIC MEMBERSHIP CORPORATION	SP Newsprint Company	25226-U	Rebuttal	GA	Discriminatory Pricing; Service Territorial Transfer	7/17/2007
61201	ALTAMAHA ELECTRIC MEMBERSHIP CORPORATION	SP Newsprint Company	25226-U	Direct	GA	Discriminatory Pricing; Service Territorial Transfer	7/6/2007
70502	PROGRESS ENERGY FLORIDA	Florida Industrial Power Users Group	070052-EI	Direct	FL	Nuclear uprate cost recovery	6/19/2007
70603	ELECTRIC TRANSMISSION TEXAS LLC	Texas Industrial Energy Consumers	33734	Direct	TX	Certificate of Convenience and Necessity	6/8/2007
60601	TEXAS PUC STAFF	Texas Industrial Energy Consumers	32795	Rebuttal Remand	TX	Interest rate on stranded cost reconciliation	6/15/2007
60601	TEXAS PUC STAFF	Texas Industrial Energy Consumers	32795	Remand	TX	Interest rate on stranded cost reconciliation	6/8/2007
50103	TEXAS PUC STAFF	Texas Industrial Energy Consumers	33672	Rebuttal	TX	CREZ Nominations	5/21/2007
50701	ENTERGY GULF STATES UTILITES, TEXAS	Texas Industrial Energy Consumers	33687	Direct	TX	Transition to Competition	4/27/2007
50103	TEXAS PUC STAFF	Texas Industrial Energy Consumers	33672	Direct	TX	CREZ Nominations	4/24/2007
61101	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	33309	Cross-Rebuttal	TX	Cost Allocation,Rate Design, Riders	4/3/2007
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	32710	Cross-Rebuttal	TX	Fuel and Rider IPCR Reconcilation	3/16/2007
61101	AEP TEXAS NORTH COMPANY	Texas Industrial Energy Consumers	33310	Direct	TX	Cost Allocation,Rate Design, Riders	3/13/2007
61101	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	33309	Direct	TX	Cost Allocation,Rate Design, Riders	3/13/2007
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	32710	Direct	TX	Fuel and Rider IPCR Reconcilation	2/28/2007
41219	AEP TEXAS NORTH COMPANY	Texas Industrial Energy Consumers	31461	Direct	TX	Rider CTC design	2/15/2007
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	33586	Cross-Rebuttal	TX	Hurricane Rita reconstruction costs	1/30/2007
60104	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	32898	Direct	TX	Fuel Reconciliation	1/29/2007
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	33586	Direct	TX	Hurricane Rita reconstruction costs	1/18/2007
60303	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	23540-U	Direct	GA	Fuel Cost Recovery	1/11/2007
60503	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	32766	Cross Rebuttal	TX	Cost allocation, Cost of service, Rate design	1/8/2007
60503	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	32766	Direct	TX	Cost allocation, Cost of service, Rate design	12/22/2006
60503	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	32766	Direct	TX	Revenue Requirements	12/17/2006
60503	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	32766	Direct	TX	Fuel Reconcilation	12/17/2006
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	32907	Cross Rebuttal	TX	Hurricane Rita reconstruction costs	10/12/06
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	32907	Direct	TX	Hurricane Rita reconstruction costs	10/09/06
60601	TEXAS PUC STAFF	Texas Industrial Energy Consumers	32795	Cross Rebuttal	TX	Stranded Cost Reallocation	09/07/06
60101	COLQUITT EMC	ERCO Worldwide	23549-U	Direct	GA	Service Territory Transfer	08/10/06

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60601	TEXAS PUC STAFF	Texas Industrial Energy Consumers	32795	Direct	TX	Stranded Cost Reallocation	09/07/06
60104	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	32672	Direct	TX	ME-SPP Transfer of Certificate to SWEPCO	8/23/2006
50503	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	32758	Direct	TX	Rider CTC design and cost recovery	08/24/06
60503	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	32685	Direct	TX	Fuel Surcharge	07/26/06
60301	PUBLIC SERVICE ELECTRIC AND GAS COMPANY	New Jersey Large Energy Consumers	171406	Direct	NJ	Gas Delivery Cost allocation and Rate design	06/21/06
60303	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	22403-U	Direct	GA	Fuel Cost Recovery Allowance	05/05/06
50503	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	32475	Cross-Rebuttal	TX	ADFIT Benefit	04/27/06
50503	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	32475	Direct	TX	ADFIT Benefit	04/17/06
41229	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	31994	Cross-Rebuttal	TX	Stranded Costs and Other True-Up Balances	3/16/2006
41229	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	31994	Direct	TX	Stranded Costs and Other True-Up Balances	3/10/2006
50303	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Periman Ltd. Occidental Power Marketing	ER05-168-001	Direct	NM	Fuel Reconciliation	3/6/2006
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	31544	Cross-Rebuttal	TX	Transition to Competition Costs	01/13/06
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	31544	Direct	TX	Transition to Competition Costs	01/13/06
50601	PUBLIC SERVICE ELECTRIC AND GAS COMPANY AND EXELON CORPORATION	New Jersey Large Energy Consumers Retail Energy Supply Association	BPU EM05020106 OAL PUC-1874-05	Surrebuttal	NJ	Merger	12/22/2005
50705	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Periman Ltd. Occidental Power Marketing	EL05-19-002; ER05-168-001	Responsive	FERC	Fuel Cost adjustment clause (FCAC)	11/18/2005
50601	PUBLIC SERVICE ELECTRIC AND GAS COMPANY AND EXELON CORPORATION	New Jersey Large Energy Consumers Retail Energy Supply Association	BPU EM05020106 OAL PUC-1874-05	Direct	NJ	Merger	11/14/2005
50102	PUBLIC UTILITY COMMISSION OF TEXAS	Texas Industrial Energy Consumers	31540	Direct	TX	Nodal Market Protocols	11/10/2005
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	31315	Cross-Rebuttal	TX	Recovery of Purchased Power Capacity Costs	10/4/2005
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	31315	Direct	TX	Recovery of Purchased Power Capacity Costs	9/22/2005
50705	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Periman Ltd. Occidental Power Marketing	EL05-19-002; ER05-168-001	Responsive	FERC	Fuel Cost Adjustment Clause (FCAC)	9/19/2005
50503	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	31056	Direct	TX	Stranded Costs and Other True-Up Balances	9/2/2005
50705	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Periman Ltd. Occidental Power Marketing	EL05-19-00; ER05-168-00	Direct	FERC	Fuel Cost adjustment clause (FCAC)	8/19/2006
50203	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	19142-U	Direct	GA	Fuel Cost Recovery	4/8/2005
41230	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	30706	Direct	TX	Competition Transition Charge	3/16/2005
41230	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	30485	Supplemental Direct	TX	Financing Order	1/14/2005
41230	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	30485	Direct	TX	Financing Order	1/7/2005

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8201	PUBLIC SERVICE COMPANY OF COLORADO	Colorado Energy Consumers	04S-164E	Cross Answer	CO	Cost of Service Study, Interruptible Rate Design	12/13/2004
8201	PUBLIC SERVICE COMPANY OF COLORADO	Colorado Energy Consumers	04S-164E	Answer	CO	Cost of Service Study, Interruptible Rate Design	10/12/2004
8244	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	18300-U	Direct	GA	Revenue Requirements, Revenue Allocation, Cost of Service, Rate Design, Economic Development	10/8/2004
8195	CENTERPOINT, RELIANT AND TEXAS GENCO	Texas Industrial Energy Consumers	29526	Direct	TX	True-Up	6/1/2004
8156	GEORGIA POWER COMPANY/SAVANNAH ELECTRIC AND POWER COMPANY	Georgia Industrial Group	17687-U/17688-U	Direct	GA	Demand Side Management	5/14/2004
8148	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	29206	Direct	TX	True-Up	3/29/2004
8095	CONECTIV POWER DELIVERY	New Jersey Large Energy Consumers	ER03020110	Surrebuttal	NJ	Cost of Service	3/18/2004
8111	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	28840	Rebuttal	TX	Cost Allocation and Rate Design	2/4/2004
8095	CONECTIV POWER DELIVERY	New Jersey Large Energy Consumers	ER03020110	Direct	NJ	Cost Allocation and Rate Design	1/4/2004
7850	RELIANT ENERGY HL&P	Texas Industrial Energy Consumers	26195	Supplemental Direct	TX	Fuel Reconciliation	9/23/2003
8045	VIRGINIA ELECTRIC AND POWER COMPANY	Virginia Committee for Fair Utility Rates	PUE-2003-00285	Direct	VA	Stranded Cost	9/5/2003
8022	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	17066-U	Direct	GA	Fuel Cost Recovery	7/22/2003
8002	AEP TEXAS CENTRAL COMPANY	Flint Hills Resources, LP	25395	Direct	TX	Delivery Service Tariff Issues	5/9/2003
7857	PUBLIC SERVICE ELECTRIC AND GAS COMPANY	New Jersey Large Energy Consumers	ER02050303	Supplemental	NJ	Cost of Service	3/14/2003
7850	RELIANT ENERGY HL&P	Texas Industrial Energy Consumers	26195	Direct	TX	Fuel Reconciliation	12/31/2002
7857	PUBLIC SERVICE ELECTRIC AND GAS COMPANY	New Jersey Large Energy Consumers	ER02050303	Surrebuttal	NJ	Revenue Allocation	12/16/2002
7836	PUBLIC SERVICE COMPANY OF COLORADO	Colorado Energy Consumers	02S-315EG	Answer	CO	Incentive Cost Adjustment	11/22/2002
7857	PUBLIC SERVICE ELECTRIC AND GAS COMPANY	New Jersey Large Energy Consumers	ER02050303	Direct	NJ	Revenue Allocation	10/22/2002
7863	DOMINION VIRGINIA POWER	Virginia Committee for Fair Utility Rates	PUE-2001-00306	Direct	VA	Generation Market Prices	8/12/2002
7718	FLORIDA POWER CORPORATION	Florida Industrial Power Users Group	000824-EI	Direct	FL	Rate Design	1/18/2002
7633	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	14000-U	Direct	GA	Cost of Service Study, Revenue Allocation, Rate Design	10/12/2001
7555	TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	010001-EI	Direct	FL	Rate Design	10/12/2001
7658	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	24468	Direct	TX	Delay of Retail Competition	9/24/2001
7647	ENTERGY GULF STATES, INC.	Texas Industrial Energy Consumers	24469	Direct	TX	Delay of Retail Competition	9/22/2001
7608	RELIANT ENERGY HL&P	Texas Industrial Energy Consumers	23950	Direct	TX	Price to Beat	7/3/2001
7593	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	13711-U	Direct	GA	Fuel Cost Recovery	5/11/2001

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7520	GEORGIA POWER COMPANY SAVANNAH ELECTRIC & POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	12499-U,13305-U, 13306-U	Direct	GA	Integrated Resource Planning	5/11/2001
7303	ENTERGY GULF STATES, INC.	Texas Industrial Energy Consumers	22356	Rebuttal	TX	Allocation/Collection of Municipal Franchise Fees	3/31/2001
7309	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	22351	Cross-Rebuttal	TX	Energy Efficiency Costs	2/22/2001
7305	CPL, SWEPCO, and WTU	Texas Industrial Energy Consumers	22352, 22353, 22354	Cross-Rebuttal	TX	Allocation/Collection of Municipal Franchise Fees	2/20/2001
7423	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	13140-U	Direct	GA	Interruptible Rate Design	2/16/2001
7305	CPL, SWEPCO, and WTU	Texas Industrial Energy Consumers	22352, 22353, 22354	Supplemental Direct	TX	Transmission Cost Recovery Factor	2/13/2001
7310	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	22349	Cross-Rebuttal	TX	Rate Design	2/12/2001
7308	TXU ELECTRIC COMPANY	Texas Industrial Energy Consumers	22350	Cross-Rebuttal	TX	Unbundled Cost of Service	2/12/2001
7303	ENTERGY GULF STATES, INC.	Texas Industrial Energy Consumers	22356	Cross-Rebuttal	TX	Stranded Cost Allocation	2/6/2001
7308	TXU ELECTRIC COMPANY	Texas Industrial Energy Consumers	22350	Direct	TX	Rate Design	2/5/2001
7303	ENTERGY GULF STATES, INC.	Texas Industrial Energy Consumers	22356	Supplemental Direct	TX	Rate Design	1/25/2001
7307	RELIANT ENERGY HL&P	Texas Industrial Energy Consumers	22355	Cross-Rebuttal	TX	Stranded Cost Allocation	1/12/2001
7303	ENTERGY GULF STATES, INC.	Texas Industrial Energy Consumers	22356	Direct	TX	Stranded Cost Allocation	1/9/2001
7307	RELIANT ENERGY HL&P	Texas Industrial Energy Consumers	22355	Direct	TX	Cost Allocation	12/13/2000
7375	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	22352	Cross-Rebuttal	TX	CTC Rate Design	12/1/2000
7375	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	22352	Direct	TX	Cost Allocation	11/1/2000
7308	TXU ELECTRIC COMPANY	Texas Industrial Energy Consumers	22350	Direct	TX	Cost Allocation	11/1/2000
7308	TXU ELECTRIC COMPANY	Texas Industrial Energy Consumers	22350	Cross-Rebuttal	TX	Cost Allocation	11/1/2000
7305	CPL, SWEPCO, and WTU	Texas Industrial Energy Consumers	22352, 22353, 22354	Direct	TX	Excess Cost Over Market	11/1/2000
7315	VARIOUS UTILITIES	Texas Industrial Energy Consumers	22344	Direct	TX	Generic Customer Classes	10/14/2000
7308	TXU ELECTRIC COMPANY	Texas Industrial Energy Consumers	22350	Direct	TX	Excess Cost Over Market	10/10/2000
7315	VARIOUS UTILITIES	Texas Industrial Energy Consumers	22344	Rebuttal	TX	Excess Cost Over Market	10/1/2000
7310	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	22349	Cross-Rebuttal	TX	Generic Customer Classes	10/1/2000
7310	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	22349	Direct	TX	Excess Cost Over Market	9/27/2000
7307	RELIANT ENERGY HL&P	Texas Industrial Energy Consumers	22355	Cross-Rebuttal	TX	Excess Cost Over Market	9/26/2000
7307	RELIANT ENERGY HL&P	Texas Industrial Energy Consumers	22355	Direct	TX	Excess Cost Over Market	9/19/2000
7334	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	11708-U	Rebuttal	GA	RTP Petition	3/24/2000

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7334	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	11708-U	Direct	GA	RTP Petition	3/1/2000
7232	PUBLIC SERVICE COMPANY OF COLORADO	Colorado Industrial Energy Consumers	99A-377EG	Answer	CO	Merger	12/1/1999
7258	TXU ELECTRIC COMPANY	Texas Industrial Energy Consumers	21527	Direct	TX	Securitization	11/24/1999
7246	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	21528	Direct	TX	Securitization	11/24/1999
7089	VIRGINIA ELECTRIC AND POWER COMPANY	Virginia Committee for Fair Utility Rates	PUE980813	Direct	VA	Unbundled Rates	7/1/1999
7090	AMERICAN ELECTRIC POWER SERVICE CORPORATION	Old Dominion Committee for Fair Utility Rates	PUE980814	Direct	VA	Unbundled Rates	5/21/1999
7142	SHARYLAND UTILITIES, L.P.	Sharyland Utilities	20292	Rebuttal	TX	Certificate of Convenience and Necessity	4/30/1999
7060	PUBLIC SERVICE COMPANY OF COLORADO	Colorado Industrial Energy Consumers Group	98A-511E	Direct	CO	Allocation of Pollution Control Costs	3/1/1999
7039	SAVANNAH ELECTRIC AND POWER COMPANY	Various Industrial Customers	10205-U	Direct	GA	Fuel Costs	1/1/1999
6945	TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	950379-EI	Direct	FL	Revenue Requirement	10/1/1998
6873	GEORGIA POWER COMPANY	Georgia Industrial Group	9355-U	Direct	GA	Revenue Requirement	10/1/1998
6729	VIRGINIA ELECTRIC AND POWER COMPANY	Virginia Committee for Fair Utility Rates	PUE960036,PUE960296	Direct	VA	Alternative Regulatory Plan	8/1/1998
6713	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	16995	Cross-Rebuttal	TX	IRR	1/1/1998
6582	HOUSTON LIGHTING & POWER COMPANY	Lyondell Petrochemical Company	96-02867	Direct	COURT	Interruptible Power	1997
6758	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	17460	Direct	TX	Fuel Reconciliation	12/1/1997
6729	VIRGINIA ELECTRIC AND POWER COMPANY	Virginia Committee for Fair Utility Rates	PUE960036,PUE960296	Direct	VA	Alternative Regulatory Plan	12/1/1997
6713	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	16995	Direct	TX	Rate Design	12/1/1997
6646	ENTERGY TEXAS	Texas Industrial Energy Consumers	16705	Rebuttal	TX	Competitive Issues	10/1/1997
6646	ENTERGY TEXAS	Texas Industrial Energy Consumers	16705	Rebuttal	TX	Competition	10/1/1997
6646	ENTERGY TEXAS	Texas Industrial Energy Consumers	473-96-2285/16705	Direct	TX	Rate Design	9/1/1997
6646	ENTERGY TEXAS	Texas Industrial Energy Consumers	16705	Direct	TX	Wholesale Sales	8/1/1997
6744	TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	970171-EU	Direct	FL	Interruptible Rate Design	5/1/1997
6632	MISSISSIPPI POWER COMPANY	Colonial Pipeline Company	96-UN-390	Direct	MS	Interruptible Rates	2/1/1997
6558	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	15560	Direct	TX	Competition	11/11/1996
6508	TEXAS UTILITIES ELECTRIC COMPANY	Texas Industrial Energy Consumers	15195	Direct	TX	Treatment of margins	9/1/1996
6475	TEXAS UTILITIES ELECTRIC COMPANY	Texas Industrial Energy Consumers	15015	DIRECT	TX	Real Time Pricing Rates	8/8/1996
6449	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	14965	Direct	TX	Quantification	7/1/1996

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6449	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	14965	Direct	TX	Interruptible Rates	5/1/1996
6449	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	14965	Rebuttal	TX	Interruptible Rates	5/1/1996
6523	PUBLIC SERVICE COMPANY OF COLORADO	Multiple Intervenors	95A-531EG	Answer	CO	Merger	4/1/1996
6235	TEXAS UTILITIES ELECTRIC COMPANY	Texas Industrial Energy Consumers	13575	Direct	TX	Competitive Issues	4/1/1996
6435	SOUTHWESTERN PUBLIC SERVICE COMMISSION	Texas Industrial Energy Consumers	14499	Direct	TX	Acquisition	11/1/1995
6391	HOUSTON LIGHTING & POWER COMPANY	Grace, W.R. & Company	13988	Rebuttal	TX	Rate Design	8/1/1995
6353	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	14174	Direct	TX	Costing of Off-System Sales	8/1/1995
6157	WEST TEXAS UTILITIES COMPANY	Texas Industrial Energy Consumers	13369	Rebuttal	TX	Cancellation Term	8/1/1995
6391	HOUSTON LIGHTING & POWER COMPANY	Grace, W.R. & Company	13988	Direct	TX	Rate Design	7/1/1995
6157	WEST TEXAS UTILITIES COMPANY	Texas Industrial Energy Consumers	13369	Direct	TX	Cancellation Term	7/1/1995
6296	GEORGIA POWER COMPANY	Georgia Industrial Group	5601-U	Rebuttal	GA	EPACT Rate-Making Standards	5/1/1995
6296	GEORGIA POWER COMPANY	Georgia Industrial Group	5601-U	Direct	GA	EPACT Rate-Making Standards	5/1/1995
6278	COMMONWEALTH OF VIRGINIA	VCFUR/ODCFUR	PUE940067	Rebuttal	VA	Integrated Resource Planning	5/1/1995
6295	GEORGIA POWER COMPANY	Georgia Industrial Group	5600-U	Supplemental	GA	Cost of Service	4/1/1995
6063	PUBLIC SERVICE COMPANY OF COLORADO	Multiple Intervenors	94I-430EG	Rebuttal	CO	Cost of Service	4/1/1995
6063	PUBLIC SERVICE COMPANY OF COLORADO	Multiple Intervenors	94I-430EG	Reply	CO	DSM Rider	4/1/1995
6295	GEORGIA POWER COMPANY	Georgia Industrial Group	5600-U	Direct	GA	Interruptible Rate Design	3/1/1995
6278	COMMONWEALTH OF VIRGINIA	VCFUR/ODCFUR	PUE940067	Direct	VA	EPACT Rate-Making Standards	3/1/1995
6125	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	13456	Direct	TX	DSM Rider	3/1/1995
6235	TEXAS UTILITIES ELECTRIC COMPANY	Texas Industrial Energy Consumers	13575|13749	Direct	TX	Cost of Service	2/1/1995
6063	PUBLIC SERVICE COMPANY OF COLORADO	Multiple Intervenors	94I-430EG	Answering	CO	Competition	2/1/1995
6061	HOUSTON LIGHTING & POWER COMPANY	Texas Industrial Energy Consumers	12065	Direct	TX	Rate Design	1/1/1995
6181	GULF STATES UTILITIES COMPANY	Texas Industrial Energy Consumers	12852	Direct	TX	Competitive Alignment Proposal	11/1/1994
6061	HOUSTON LIGHTING & POWER COMPANY	Texas Industrial Energy Consumers	12065	Direct	TX	Rate Design	11/1/1994
5929	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	12820	Direct	TX	Rate Design	10/1/1994
6107	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	12855	Direct	TX	Fuel Reconciliation	8/1/1994
6112	HOUSTON LIGHTING & POWER COMPANY	Texas Industrial Energy Consumers	12957	Direct	TX	Standby Rates	7/1/1994
5698	GULF POWER COMPANY	Misc. Group	931044-EI	Direct	FL	Standby Rates	7/1/1994

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5698	GULF POWER COMPANY	Misc. Group	931044-EI	Rebuttal	FL	Competition	7/1/1994
6043	EL PASO ELECTRIC COMPANY	Phelps Dodge Corporation	12700	Direct	TX	Revenue Requirement	6/1/1994
6082	GEORGIA PUBLIC SERVICE COMMISSION	Georgia Industrial Group	4822-U	Direct	GA	Avoided Costs	5/1/1994
6075	GEORGIA POWER COMPANY	Georgia Industrial Group	4895-U	Direct	GA	FPC Certification Filing	4/1/1994
6025	MISSISSIPPI POWER & LIGHT COMPANY	MIEG	93-UA-0301	Comments	MS	Environmental Cost Recovery Clause	1/1/1994
5971	FLORIDA POWER & LIGHT COMPANY	Florida Industrial Power Users Group	940042-EI	Direct	FL	Section 712 Standards of 1992 EPACT	1/1/1994

APPENDIX B

Procedures for Conducting a Class Cost-of-Service Study

Q WHAT PROCEDURES ARE USED IN A COST-OF-SERVICE STUDY?

A The basic procedure for conducting a class cost-of-service study is fairly simple. First, we identify the different types of costs (functionalization), determine their primary causative factors (classification), and then apportion each item of cost among the various rate classes (allocation). Adding up the individual pieces gives the total cost for each class.

Identifying the utility's different levels of operation is a process referred to as functionalization. The utility's investments and expenses are separated into production, transmission, distribution, and other functions. To a large extent, this is done in accordance with the Uniform System of Accounts developed by the Federal Energy Regulatory Commission (FERC).

Once costs have been functionalized, the next step is to identify the primary causative factor (or factors). This step is referred to as classification. Costs are classified as demand-related, energy-related or customer-related. Demand (or capacity) related costs vary with peak demand, which is measured in kilowatts (or kW). This includes production, transmission, and some distribution investment and related fixed operation and maintenance (O&M) expenses. As explained later, peak demand determines the amount of capacity needed for reliable service. Energy-related costs vary with the production of energy, which is measured in kilowatt-hours (or kWh). Energy-related costs include fuel and variable O&M expense. Customer-related costs vary directly with the number of customers and include expenses such as meters, service drops, billing, and customer service.

Each functionalized and classified cost must then be allocated to the various customer classes. This is accomplished by developing allocation factors that reflect the percentage of the total cost that should be paid by each class. The allocation factors should reflect cost-causation; that is, the degree to which each class caused the utility to incur the cost.

Q WHAT KEY PRINCIPLES ARE RECOGNIZED IN A CLASS COST-OF-SERVICE STUDY?

A A properly conducted class cost-of-service study recognizes two key cost-causation principles. First, customers are served at different delivery voltages. This affects the amount of investment the utility must make to deliver electricity to the meter. Second, since cost-causation is also related to how electricity is used, both the timing and rate of energy consumption (*i.e.*, demand) are critical. Because electricity cannot be stored for any significant time period, a utility must acquire sufficient generation resources and construct the required transmission facilities to meet the maximum projected demand, including a reserve margin as a contingency against forced and unforced outages, severe weather, and load forecast error. Customers that use electricity during the critical peak hours cause the utility to invest in generation and transmission facilities.

Q WHAT FACTORS CAUSE THE PER-UNIT COSTS TO DIFFER AMONG CUSTOMER CLASSES?

A Factors that affect the per-unit cost include whether a customer's usage is constant or fluctuating (load factor), whether the utility must invest in transformers and distribution systems to provide the electricity at lower voltage levels, the amount of electricity that a customer uses, and the quality of service (*e.g.*, firm or non-firm). In general, industrial consumers are less costly to serve on a per unit basis because they:

1. Operate at higher load factors;
2. Take service at higher delivery voltages; and
3. Use more electricity per customer.

Further, non-firm service is a lower quality of service than firm service. Thus, non-firm service is less costly per unit than firm service for customers that otherwise have the same characteristics. This explains why some customers pay lower average rates than others.

For example, the difference in the losses incurred to deliver electricity at the various delivery voltages is a reason why the per-unit energy cost to serve is not the same for all customers. More losses occur to deliver electricity at distribution voltage (either primary or secondary) than at transmission voltage, which is generally the level at which industrial customers take service. This means that the cost per kWh is lower for a transmission customer than a distribution customer. The cost to deliver a kWh at primary distribution, though higher than the per-unit cost at transmission, is lower than the delivered cost at secondary distribution.

In addition to lower losses, transmission customers do not use the distribution system. Instead, transmission customers construct and own their own distribution systems. Thus, distribution system costs are not allocated to transmission level customers who do not use that system. Distribution customers, by contrast, require substantial investments in these lower voltage facilities to provide service. Secondary distribution customers require more investment than do primary distribution customers. This results in a different cost to serve each type of customer.

Two other cost drivers are efficiency and size. These drivers are important because most fixed costs are allocated on either a demand or customer basis.

Efficiency can be measured in terms of load factor. Load factor is the ratio of average demand (*i.e.*, energy usage divided by the number of hours in the period) to peak demand. A customer that operates at a high load factor is more efficient than a lower load factor customer because it requires less capacity for the same amount of energy. For example, assume that two customers purchase the same amount of energy, but one customer has an 80% load factor and the other has a 40% load factor. The 40% load factor customers would have twice the peak demand of the 80% load factor customers, and the utility would therefore require twice as much capacity to serve the 40% load factor customer as the 80% load factor. Said differently, the fixed costs to serve a high load factor customer are spread over more kWh usage than for a low load factor customer.

Classification of Distribution Network Costs

Q HOW HAS PEF CLASSIFIED PRIMARY AND SECONDARY DISTRIBUTION INVESTMENT?

A PEF has classified all primary and secondary distribution investment to demand. Only meters and service laterals were classified as customer-related.

Q WHAT ARE PRIMARY AND SECONDARY DISTRIBUTION INVESTMENT?

A Primary distribution facilities are those investments contained in FERC accounts 364, 365, 366 and 367. They are generally related to those distribution facilities that are rated between 600 and 34,500 volts. Secondary distribution facilities consist of lower voltage lines and line transformers. Line transformers step electricity down from primary to secondary voltage. The latter investments are booked in FERC account 368.

Q SHOULD ALL PRIMARY AND SECONDARY DISTRIBUTION BE CLASSIFIED AS DEMAND-RELATED?

A No. The primary purpose of the distribution system is to deliver power from the transmission grid to the customer, where it is eventually consumed. Certain investments (e.g., meters, service drops) must be made just to attach a customer to the system. These investments are customer-related. The remaining investment is needed to provide sufficient capacity to meet customer demands when they arise. This portion of the distribution investment is demand-related. Thus, distribution investment can be either demand-related and/or customer-related.

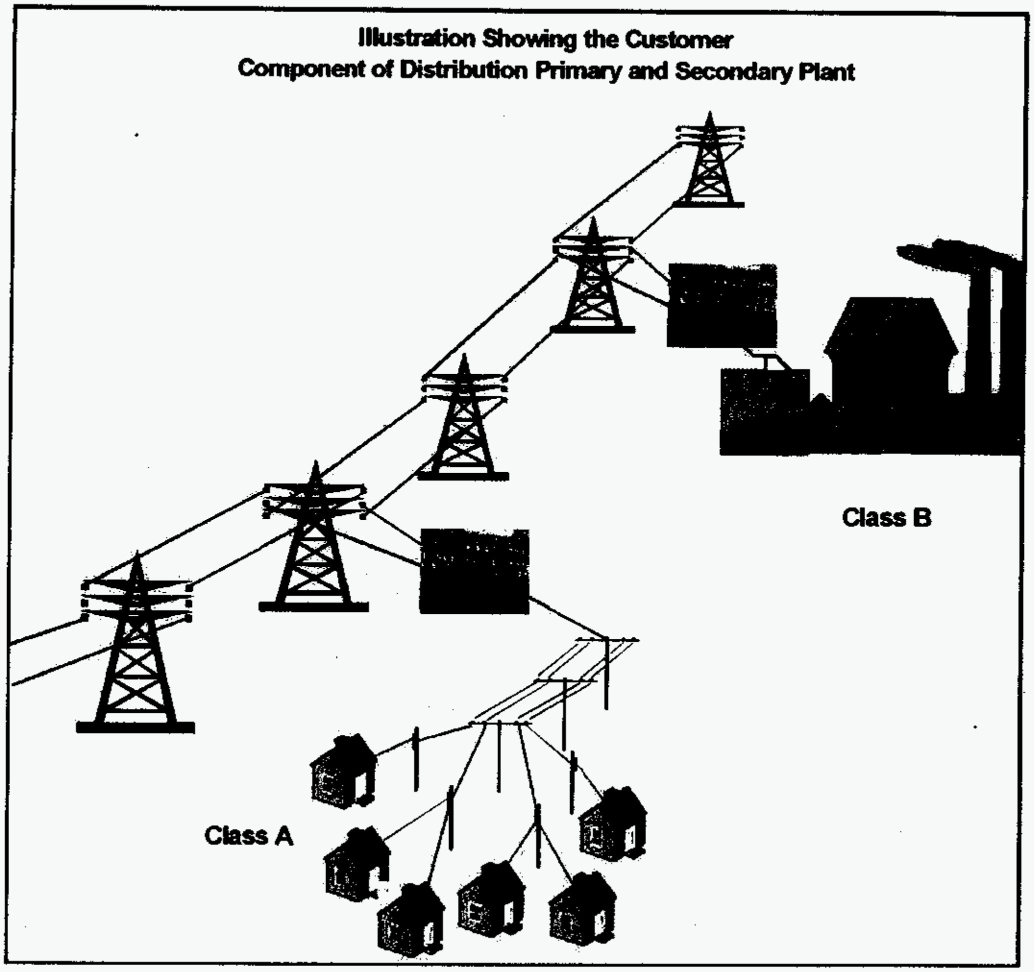
Q ARE CERTAIN DISTRIBUTION INVESTMENTS, OTHER THAN THE METER AND SERVICE DROP, ALSO CUSTOMER-RELATED?

A Yes. A portion of the primary and secondary distribution "network"—consisting of poles, towers, fixtures, overhead lines and line transformers—is also customer-related. Classifying a portion of the distribution network as customer-related recognizes the reality that every utility must provide a path through which electricity can be delivered to each and every customer regardless of the peak demand or energy consumed. Further, that path must be in place if the utility is to meet its obligation to provide service upon demand.

If PEF were to provide only a minimum amount of electric power to each customer, it would still have to construct nearly the same miles of line as it is currently required to serve every customer. The poles, conductors and transformers would not need to be as large as they are now if every customer were supplied only a minimum level of service, but there is a definite limit to the size to which they could be reduced.

Q HOW SHOULD THE CUSTOMER-RELATED PORTION OF THIS INVESTMENT BE DETERMINED?

A This requires an engineering analysis. The customer-related portion is representative of the investment required simply to attach customers to the system, irrespective of their demand and energy requirements. Consider the diagram below. This shows the distribution network for a utility with two customer classes, A and B. The physical distribution network necessary to attach Class A, a residential subdivision for example, is designed to serve the same load as the distribution feeder serving Class B, a large shopping center or



small factory. Clearly, a much more extensive distribution system is required to attach a multitude of small customers than to attach a single larger customer, even though the total demand of each customer class is the same.

Q **IS IT A RECOGNIZED PRACTICE TO CLASSIFY A PORTION OF THE DISTRIBUTION NETWORK AS CUSTOMER-RELATED?**

A Yes. For example, the NARUC Manual states that:

> Distribution plant Accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system. (*NARUC, Electric Cost Allocation Manual at 90).*

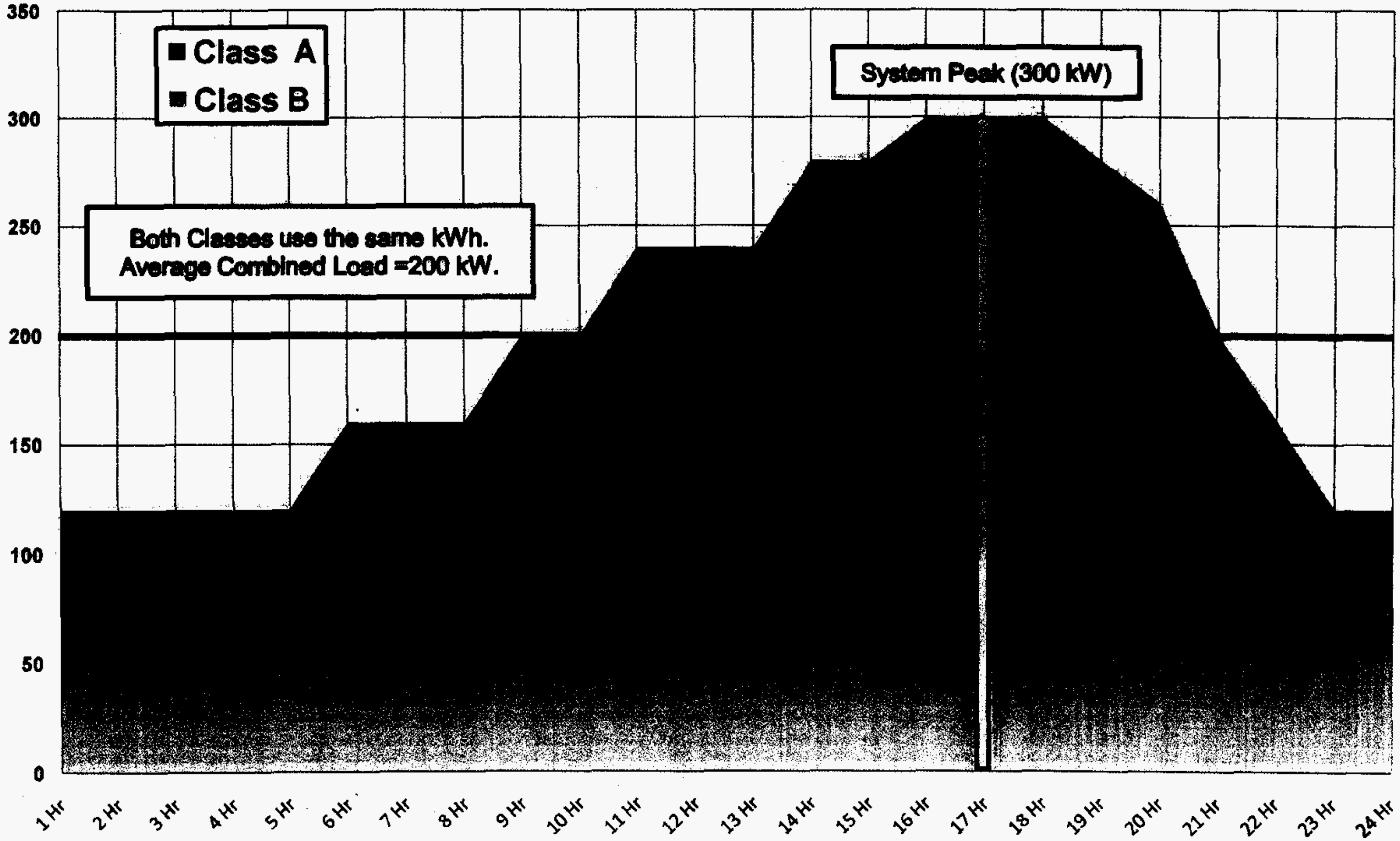
Also, a survey conducted by Duke Power Company to evaluate the distribution costing practices used in the electric utility industry concluded that:

> The accounts (364, 365, 366, 367, 368) which represent conductors and transformers investment are split approximately 70% demand and 30% customer. The remaining accounts (369, 370, 371, 373) are primarily customer-related.

Docket No. 090079-EI
Peak Demand
Illustration
Exhibit JP-1

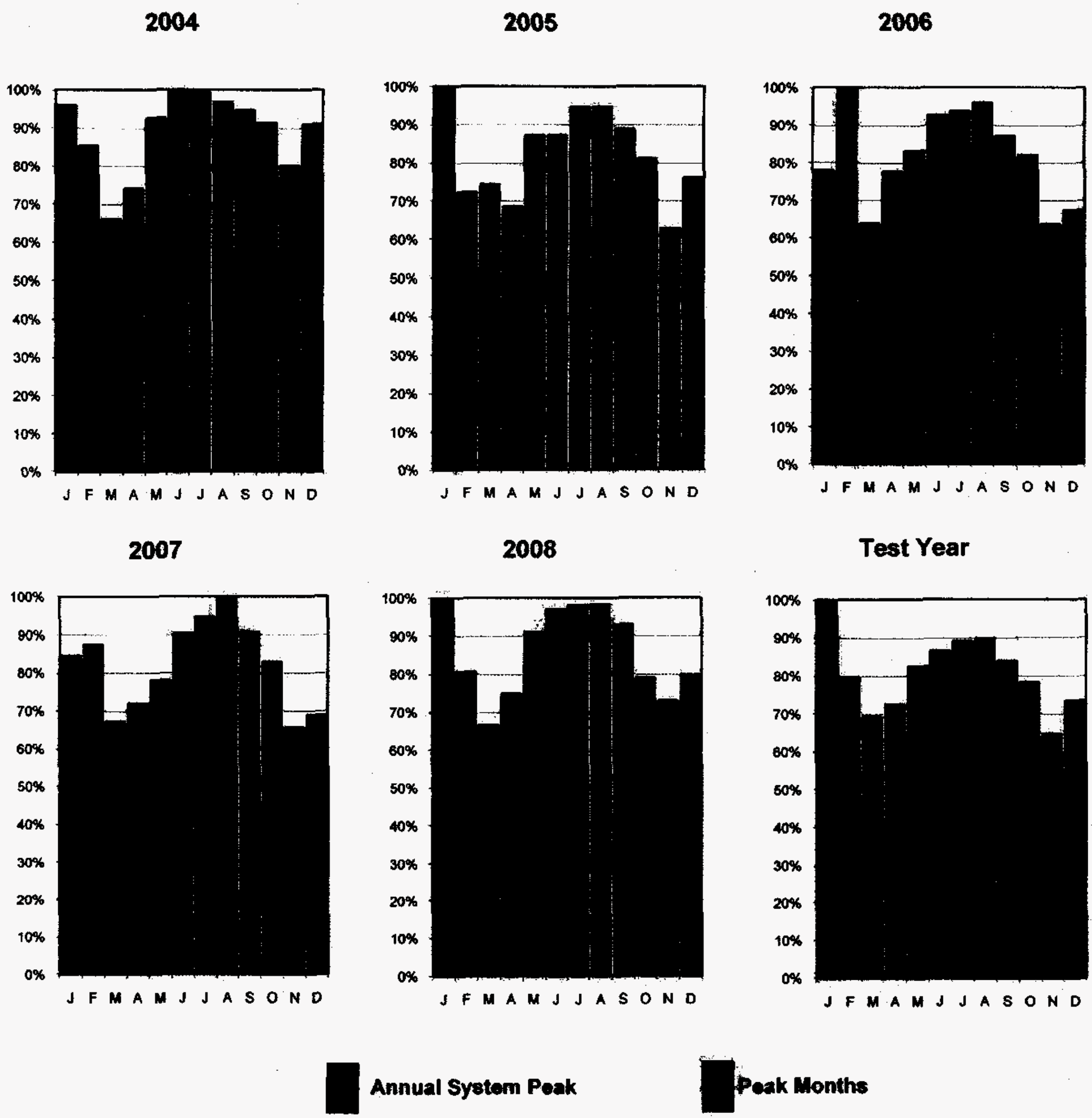
PROGRESS ENERGY FLORIDA

Why Electric Facilities are Sized to Meet Peak Demand



Docket No. 090079-EI
Monthly Peak Demands
Exhibit JP-2
Page 1 of 2

PROGRESS ENERGY FLORIDA
Analysis of Monthly Peak Demands
As a Percentage of the Annual System Peak
<u>for the Years 2004-2008 and Test Year</u>



PROGRESS ENERGY FLORIDA
Analysis of System Peak Load Characteristics
2004-2008 (Actual) and Test Year

Line	Year	Peak Demand	Minimum Demand	Average Demand	Average Peak Months	Average Non-Peak Months
		(1)	(2)	(3)	(4)	(5)
		Peak Demand (MW)				
1	2004	9,125	6,017	8,113	8,880	7,565
2	2005	10,226	6,424	8,420	9,519	7,635
3	2006	10,094	6,414	8,284	9,032	7,749
4	2007	10,405	6,812	8,514	9,578	7,754
5	2008	10,210	6,797	8,773	9,933	7,945
6	Test Year	11,400	7,374	9,210	10,244	8,471

		Ratio Analysis				
		Minimum to Annual Peak	Average to Annual Peak	Peak Months to Non-Peak Months-1	Avg Non-Peak Months to Peak Demand	Annual Load Factor
6	2004	66%	89%	17%	83%	58%
7	2005	63%	82%	25%	75%	53%
8	2006	64%	82%	17%	77%	52%
9	2007	65%	82%	24%	75%	53%
10	2008	67%	86%	25%	78%	53%
11	Average (Actual)	65%	84%	21%	77%	54%
12	Test Year	65%	81%	21%	74%	49%

PROGRESS ENERGY FLORIDA

Reserve Margins as a Percent of Firm Peak Demand

Line	Year	Data	Average Peak Months	Average Non-Peak Months	Ratio of Peak to Non-Peak Margins
			(1)	(2)	(3)
1	2004	Actual	14%	39%	35%
2	2005	Actual	10%	35%	27%
3	2006	Actual	21%	46%	47%
4	2007	Actual	18%	49%	38%
5	2008	Actual	17%	48%	36%
6	2010	Test Year	16%	42%	38%

PROGRESS ENERGY FLORIDA

Estimate of Alternative Resource Investment Required to Serve Peak Demand Only
Restated at the Current Cost of Peaking Capacity
(Dollar Amounts in $000)
as of 12/31/08

Line	Plant Name	In Service Year	Nameplate Capacity MW	Actual EPIS Balance	EPIS Balance at Current CT Cost
		(1)	(2)	(3)	(4)
	Steam				
1	Anclote Unit 1	1974	556.2		$182,835
2	Anclote Unit 2	1978	556.2	$314,035	$182,835
3	Bartow Unit 1	1958	127.5		$41,912
4	Bartow Unit 2	1961	127.5		$41,912
5	Bartow Unit 3	1963	239.4	$125,654	$78,696
6	Crystal River Unit 1	1966	440.5		$144,802
7	Crystal River Unit 2	1969	523.8	$448,607	$172,185
7	Crystal River Unit 3	1977	817.4	$831,468	$268,711
8	Crystal River Unit 4	1982	739.3		$243,024
9	Crystal River Unit 5	1984	739.3	$932,514	$243,024
10	Suwannee Unit 1	1953	34.5		$11,341
11	Suwannee Unit 2	1954	37.5		$12,327
12	Suwannee Unit 3	1956	75.0	$36,538	$24,654
	Combined Cycle				
13	Hines Energy Complex 1	1999	546.6		$179,679
14	Hines Energy Complex 2	2003	548.2		$180,205
15	Hines Energy Complex 3	2005	561.0		$184,413
16	Hines Energy Complex 4	2007	610.0	$1,076,008	$200,520
17	Tiger Bay	1997	278.1	$82,413	$91,418
18	University of Florida	1994	43.0	$23,387	$14,135
	Combustion Turbine				
19	Avon Park Peakers 1-2	1968	67.6	$10,082	$22,215
20	Bartow Peakers 1-4	1972	222.8	$27,368	$73,239
21	Bayboro Peakers 1-4	1973	226.8	$24,321	$74,554
22	DeBary Peakers 1-10	1975-76, 92	861.2	$154,350	$283,095
23	Higgins Peakers 1-4	1969-1971	153.4	$19,015	$50,426
24	Intercession City Pkrs 1-14	1974,93,97,00	1,255.3	$254,103	$412,630
25	Rio Pinar Peaker 1	1970	19.3	$3,567	$6,344
26	Suwannee Peakers 1-3	1980	183.6	$32,434	$60,353
27	Turner Peakers 1-4	1970-74	181.0	$25,809	$59,499
28	Total Production Plant		10,772	$4,421,674	$3,540,985

29	**Percentage of Actual Resource Investment Made to Serve Peak Demand Only**	=	**80.1%**
30	**Percentage of Actual Resource Investment Made For Other Reasons**	=	**19.9%**

Docket No. 090079-EI
Derivation of AED
Allocation Factor
Exhibit JP-5

PROGRESS ENERGY FLORIDA

Derivation of Production Plant Allocation Factors
Average and Excess Demand Allocation Method
Test Year Ending December 31, 2010

Line	Rate Class	Group Coincident Peak	Average Demand		Excess Demand		A&E
			Amount	Percent	Amount	Percent	Factors
		(1)	(2)	(3)	(4)	(5)	(6)
1	Residential	4,331	2,383	50.527%	3,647	71.584%	60.437%
2	General Service Non-Demand	236	156	3.302%	187	3.677%	3.478%
3	General Service 100% LF	10	10	0.220%	0	0.008%	0.120%
4	General Service Demand	2,280	1,802	38.198%	1,042	20.446%	29.844%
5	Curtailable/Interruptible	349	323	6.859%	172	3.382%	5.223%
6	Lighting	9	42	0.894%	46	0.903%	0.898%
7	Total Retail	7,215	4,716	100.000%	5,094	100.000%	100.000%

(4) Column (1) - Column (2)

(6) Column (3) x 53% + Column (5) x 47%

PROGRESS ENERGY FLORIDA

Derivation of Production Plant Allocation Factors
Summer/Winter CP Demand Allocation Method
Test Year Ending December 31, 2010

Line	Rate Class	Winter Peak (MW)	Summer Peak (MW)	Average (MW)	Summer Winter CP Factors
		(1)	(2)	(3)	(4)
1	Residential	5,722	4,930	5,326	64.31%
2	General Service Non-Demand	249	322	285	3.45%
3	General Service 100% LF	10	10	10	0.13%
4	General Service Demand	2,031	2,542	2,286	27.61%
5	Curtailable/Interruptible	373	369	371	4.48%
6	Lighting	5	0	3	0.03%
7	Total Retail	8,391	8,172	8,282	100.00%

Source: MFR Schedule E-9

Docket No. 090079-EI
Cost Study
Exhibit JP-7
Page 1 of 2

PROGRESS ENERGY FLORIDA

Summary of Class Cost of Service Study Results at Present Rates
Average and Excess Method for Production Plant,
Summer/Winter Coincident Peak Method for Transmission
Test Year Ending December 31, 2010
(Dollar Amounts In Thousands)

Line	Summary of Results	Total Retail	Residential (RS)	Gen Serv Non Demand (GS-1)	Gen Serv 100% LF (GS-2)	Gen Serv Demand (GSD, SS-1)	Curtailable/ Interruptible (CS,SS-3,IS,SS-2)	Lighting (LS) Energy	Lighting (LS) Facilities
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Total Rate Base	$6,238,627	$3,948,782	$236,046	$9,318	$1,627,717	$244,282	$36,861	$135,620
	Development Of Return:								
2	Present Class Revenue	$1,448,466	$900,586	$64,691	$2,639	$365,172	$48,403	$6,225	$60,750
3	Present Revenue Credits	$69,455	$50,978	$3,498	$243	$12,543	$1,490	$233	$470
4	Total Revenues	$1,517,921	$951,564	$68,189	$2,882	$377,715	$49,893	$6,458	$61,220
5	Less: Total Operating Expenses	$1,249,337	$781,494	$53,352	$2,419	$311,379	$44,274	$7,814	$48,605
6	Equals: Return Earned (L. 4 - L. 5)	$268,584	$170,070	$14,837	$463	$66,336	$5,618	-$1,356	$12,615
7	Rate Of Return Earned (L. 6/ L.1)	4.31%	4.31%	6.29%	4.97%	4.08%	2.30%	-3.68%	9.30%
8	Relative Rate Of Return (L.7 As A Pct Of Total)	100	100	146	116	95	53	(85)	216
9	Subsidy [(L.1 X 4.31%-L.6) X 1.63381]	$0	$110	$7,638	$102	-$6,110	-$8,003	-$4,808	$11,071

Docket No. 090079-EI
Cost Study
Exhibit JP-7
Page 2 of 2

PROGRESS ENERGY FLORIDA

Summary of Class Cost of Service Study Results at Present Rates
12 CP - 1/13th AD Method for Production Plant,
Summer/Winter Coincident Peak Method for Transmission
Test Year Ending December 31, 2010
(Dollar Amounts In Thousands)

Line	Summary of Results	Total Retail	Residential (RS)	Gen Serv Non Demand (GS-1)	Gen Serv 100% LF (GS-2)	Gen Serv Demand (GSD, SS-1)	Curtailable/ Interruptible (CS,SS-3,IS,SS-2)	Lighting (LS) Energy	Lighting (LS) Facilities
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Total Rate Base	$6,238,615	$3,929,217	$235,689	$9,523	$1,644,201	$247,521	$36,855	$135,620
	Development of Return:								
2	Present Class Revenue	$1,448,466	$900,586	$64,691	$2,639	$365,172	$48,403	$6,225	$60,750
3	Present Revenue Credits	$69,452	$51,370	$3,497	$239	$12,270	$1,407	$202	$470
4	Total Revenues	$1,517,918	$951,956	$68,188	$2,878	$377,442	$49,810	$6,427	$61,220
5	Less: Total Operating Expenses	$1,249,371	$777,504	$52,788	$2,502	$318,083	$43,786	$6,105	$48,605
6	Equals: Return Earned (L. 4 - L. 5)	$268,547	$174,452	$15,400	$376	$59,359	$6,024	$322	$12,615
7	Rate of Return Earned (L. 6/ L.1)	4.30%	4.44%	6.53%	3.95%	3.61%	2.43%	0.87%	9.30%
8	Relative Rate of Return (L.7 as a pct of total)	100	103	152	92	84	57	20	216
9	Subsidy [(L.1 X 4.30%-L.6) X 1.63381]	$0	$8,684	$8,585	-$55	-$18,653	-$7,566	-$2,066	$11,072

Docket No. 090079-EI
Revenue Allocation
Exhibit JP-8

PROGRESS ENERGY FLORIDA

Proposed Class Revenue Allocation

Test Year Ending December 31, 2010

Line No.	Rate Schedule	Present Revenues ($000)	Proposed Increase Amount ($000)	Proposed Increase Percent	Relative Increase
		(1)	(2)	(3)	(4)
1	Residential	$900,586	$258,574	28.71%	84
2	GS-I	64,691	20,600	31.84%	93
3	GS-2	2,639	1,187	44.98%	131
4	GSD-I	346,517	181,811	52.47%	153
5	GSDTransferred to GS	18,148	5,539	30.52%	89
6	CS-1,CS-2	3,782	1,129	29.85%	87
7	IS-1, IS-2	41,344	22,802	55.15%	161
8	SS-1	507	142	28.01%	82
9	SS-2	2,937	712	24.24%	71
10	SS-3	341	228	66.86%	195
11	LS-1	6,225	3,198	51.37%	150
12	Lighting Facilities	60,750	0	0.00%	0
13	Total Retail	$1,448,467	$495,922	34.24%	100

Source: MFR Schedule E-5

PROGRESS ENERGY FLORIDA
Recommended Class Revenue Allocation
Average and Excess Method
Test Year Ending December 31, 2010

Line	Rate Class	Base Revenues at Present Rates ($000)	Recommended Allocation Amount ($000)	Recommended Allocation Percent	Relative Increase
		(1)	(2)	(3)	(4)
1	**Residential**	$900,586	$321,153	35.7%	103%
2	**General Service**	64,691	11,566	17.9%	52%
3	**General Service 100% LF**	2,639	656	24.9%	72%
4	**General Service Demand**	365,172	138,537	37.9%	110%
5	**Curtailable/Interruptible**	48,403	25,022	51.7%	150%
	Lighting:				
6	Energy	6,225	3,234	51.9%	150%
7	Facilities	60,750	0	0.0%	0%
8	Total Retail	$1,448,466	$500,169	34.5%	100%

PROGRESS ENERGY FLORIDA
Recommended Class Revenue Allocation
12CP-1/13th AD Method
Test Year Ending December 31, 2010

Line	Rate Class	Base Revenues at Present Rates ($000)	Recommended Allocation Amount ($000)	Recommended Allocation Percent	Relative Increase
		(1)	(2)	(3)	(4)
1	**Residential**	$900,586	$309,555	34.4%	100%
2	**General Service**	64,691	10,394	16.1%	47%
3	**General Service 100% LF**	2,639	822	31.2%	90%
4	**General Service Demand**	365,172	151,054	41.4%	120%
5	**Curtailable/Interruptible**	48,403	25,122	51.9%	150%
	Lighting:				
6	Energy	6,225	3,222	51.8%	150%
7	Facilities	60,750	0	0.0%	0%
8	Total Retail	$1,448,466	$500,169	34.5%	100%

PROGRESS ENERGY FLORIDA

Summary of Class Cost-of-Service Study Results
At Present Rates and Recommended Class Revenue Allocation
Average and Excess Method for Production Plant, Summer/Winter Coincident Peak Method for Transmission
Test Year Ending December 31, 2010

Line	Rate Class	Present Rates: Rate of Return (1)	Present Rates: Relative ROR (2)	Present Rates: Subsidy ($000) (3)	Recommended Allocation: Rate of Return (4)	Recommended Allocation: Relative ROR (5)	Recommended Allocation: Subsidy ($000) (6)
1	**Residential**	4.31%	100	$110	9.28%	101	$4,678
2	**General Service**	6.29%	146	7,638	9.28%	101	280
3	**General Service 100% LF**	4.97%	116	102	9.28%	101	11
4	**General Service Demand**	4.08%	95	(6,110)	9.28%	101	1,928
5	**Curtailable/Interruptible**	2.30%	53	(8,003)	8.57%	93	(2,566)
6	**Lighting:**						
7	Energy	-3.68%	-85	(4,808)	1.69%	18	(4,530)
8	Facilities	9.30%	216	11,071	9.30%	101	198
9	**Total Retail**	4.31%	100	($0)	9.21%	100	($0)

PROGRESS ENERGY FLORIDA

Summary of Class Cost-of-Service Study Results
At Present Rates and Recommended Class Revenue Allocation
12CP-1/13th AD Method for Production Plant,
Summer/Winter Coincident Peak Method for Transmission
Test Year Ending December 31, 2010

		Present Rates			Recommended Allocation		
Line	Rate Class	Rate of Return	Relative ROR	Subsidy ($000)	Rate of Return	Relative ROR	Subsidy ($000)
		(1)	(2)	(3)	(4)	(5)	(6)
1	**Residential**	4.44%	103	$8,684	9.23%	100	$1,345
2	**General Service**	6.53%	152	8,585	9.23%	100	90
3	**General Service 100% LF**	3.95%	92	(55)	9.23%	100	4
4	**General Service Demand**	3.61%	84	(18,653)	9.23%	100	626
5	**Curtailable/Interruptible**	2.43%	57	(7,566)	8.65%	94	(2,281)
6	**Lighting:**						
7	Energy	0.87%	20	(2,066)	9.23%	100	14
8	Facilities	9.30%	216	11,072	9.30%	101	203
9	**Total Retail**	4.30%	100	($0)	9.21%	100	($0)

PROGRESS ENERGY FLORIDA
Cost-Effectiveness of Interruptible Load
Rate Impact Measure (RIM) Test

PROGRAM: **PEF ISCS**

$500 = Program Admin
$307,968 = Annual kW Incentive per Participant
$10.49 = Maximum Monthly Incentive per kW per Participant

	BENEFITS				COSTS								
YEAR	(1) TOTAL FUEL & O&M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) TOTAL BENEFITS $(000)	(5) TOTAL FUEL & O&M INCREASE $(000)	(6) UTILITY PROGRAM COSTS $(000)	(7) INCENTIVE PAYMENTS $(000)	(8) REVENUE LOSSES $(000)	(9) TOTAL COSTS $(000)	(10) NET BENEFITS $(000)	Cumulative Participants	kW per Pa	Max Incentive
2008	0	0	0	0	0	0	0	0	0	0	0		
2009	9,179	0	25,496	34,675	0	75	46,195	338	46,608	-11,934	150	2447	$ 10.49
2010	5,533	0	26,563	32,096	0	75	46,195	225	46,495	-14,398	150	2447	
2011	15,950	0	27,913	43,863	0	75	46,195	225	46,495	-2,632	150	2447	
2012	16,950	0	29,668	46,618	0	75	46,195	215	46,485	133	150	2447	
2013	22,940	0	32,312	55,252	0	75	46,195	1	46,271	8,981	150	2447	
2014	19,064	0	32,252	51,315	0	75	46,195	4	46,274	5,041	150	2447	
2015	17,374	0	33,078	50,452	0	75	46,195	425	46,695	3,758	150	2447	
2016	19,003	0	34,483	53,486	0	75	46,195	557	46,827	6,659	150	2447	
2017	19,178	0	32,826	52,004	0	75	46,195	303	46,573	5,431	150	2447	
2018	20,946	0	36,846	57,792	0	75	46,195	300	46,570	11,222	150	2447	
2019	24,029	0	40,512	64,541	0	75	46,195	8	46,278	18,263	150	2447	
2020	23,204	0	40,936	64,139	0	75	46,195	106	46,376	17,763	150	2447	
2021	21,902	0	41,515	63,417	0	75	46,195	629	46,899	16,518	150	2447	
2022	21,440	0	42,102	63,542	0	75	46,195	429	46,699	16,843	150	2447	
2023	19,709	0	42,559	62,268	0	75	46,195	541	46,812	15,457	150	2447	
2024	23,392	0	46,727	70,119	0	75	46,195	546	46,817	23,303	150	2447	
2025	22,173	0	47,752	69,925	0	75	46,195	430	46,701	23,224	150	2447	
2026	21,491	0	48,817	70,308	0	75	46,195	431	46,702	23,606	150	2447	
2027	19,556	0	49,924	69,480	0	75	46,195	545	46,815	22,665	150	2447	
2028	20,076	0	51,921	71,997	0	75	46,195	433	46,703	25,294	150	2447	
2029	19,147	0	53,998	73,145	0	75	46,195	229	46,499	26,646	150	2447	
2030	18,184	0	56,158	74,342	0	75	46,195	229	46,499	27,843	150	2447	
2031	18,308	0	58,404	76,712	0	75	46,195	229	46,500	30,212	150	2447	
2032	18,191	0	60,740	78,931	0	75	46,195	230	46,500	32,431	150	2447	
2033	17,855	0	63,170	81,025	0	75	46,195	230	46,500	34,525	150	2447	
2034	19,673	0	65,697	85,370	0	75	46,195	230	46,500	38,869	150	2447	
2035	17,359	0	68,325	85,683	0	75	46,195	230	46,501	39,183	150	2447	
2036	17,617	0	71,057	88,674	0	75	46,195	231	46,501	42,173	150	2447	
2037	18,786	0	73,900	92,686	0	75	46,195	351	46,621	46,065	150	2447	
NOMINAL	548,204	0	1,335,653	1,883,857	0	2,175	1,339,659	8,881	1,350,714	533,143			
NPV	169,020	0	403,382	592,402	0	801	493,342	3,050	497,193	95,209			

Utility Discount Rate = 8.48
Benefit Cost Ratio = 1.191

09RC-FIPUGPOD2-39-1

PROGRESS ENERGY FLORIDA
Estimated Impact of Revised Life Spans on Depreciation Expense
Based on Projected Test Year Ended December 31, 2010

Line	Plant Name	Year In-Service	PEF Proposed Accrual (Exh No. PT-9) Retirement	Life Span	Accrual	Recommended Retirement	Life Span	Accrual	Reduction
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Steam - Coal Plants								
1	Crystal River 1 & 2	1968	2020	52	$16,154,730	2023	55	$14,364,800	$1,789,930
2	Crystal River 4 & 5	1983	2035	52	24,595,966	2038	55	22,335,453	2,260,513
3	**Total Steam - Coal Plant**				$40,750,696			$36,700,253	$4,050,443
	Combined Cycle Plants								
4	Hines Energy Complex 1	1999	2028	29	11,609,123	2034	35	9,017,227	2,591,896
5	Hines Energy Complex 2	2003	2033	30	10,631,004	2038	35	8,813,892	1,817,112
6	Hines Energy Complex 3	2005	2035	30	11,405,557	2040	35	9,575,806	1,829,751
7	Hines Energy Complex 4	2007	2037	30	13,438,283	2042	35	11,393,172	2,045,111
8	Tiger Bay	1997	2038	41	1,776,081	2038	41	1,776,081	0
9	University of Florida	1994	2033	39	1,286,999	2033	39	1,286,999	0
10	Bartow CC	2009	2039	30	33,269,192	2044	35	28,457,532	4,811,660
11	**Total Combined Cycle**				$83,416,239			$70,320,709	$13,095,530
12	**Total Existing Plants**				$124,166,935			$107,020,962	$17,145,973

Table XIII

QUALITY MEASURES-UTILITY OPERATING COMPANIES

		CAPITAL STRUCTURE RATIOS*																Credit Ratings		
		As of: 3/31/2009				As of: 12/31/2008				As of: 12/31/2007				As of: 12/31/2006						
Line	Company	LTD (%)	STD (%)	Prfd (%)	Com Equity (%)	LTD (%)	STD (%)	Prfd (%)	Com Equity (%)	LTD (%)	STD (%)	Prfd (%)	Com Equity (%)	LTD (%)	STD (%)	Prfd (%)	Com Equity (%)	Moody's	Fitch Ratings	S&P
1	AEP Texas Central Company	78.6	5.3	0.2	15.9	77.6	7.2	0.2	15.0	82.1	4.3	0.2	13.5	85.7	2.3	0.2	11.8	Baa2	BBB	BBB
2	AEP Texas North Company	50.7	4.5	0.3	44.4	51.0	4.0	0.3	44.6	42.3	5.3	0.4	52.0	46.0	1.5	0.4	52.2	Baa2	BBB+	BBB
3	Alabama Power Company	51.2	2.1	5.7	40.9	49.1	2.4	6.0	42.5	na	na	na	na	43.3	8.2	6.4	42.1	A2	A	A
4	Appalachian Power Company	55.3	4.4	0.3	39.9	52.5	6.0	0.3	41.2	49.9	9.9	0.3	39.8	48.6	7.7	0.4	43.3	Baa2	BBB	BBB
5	Arizona Public Service Company	49.2	3.5	0.0	47.3	42.5	7.8	0.0	49.7	44.6	3.4	0.0	52.0	47.3	0.0	0.0	52.7	Baa2	BBB-	BBB-
6	Atlantic City Electric Company	63.5	3.5	0.4	32.6	62.9	3.4	0.4	33.3	58.0	9.1	0.4	32.6	63.3	4.7	0.4	31.6	Baa1	BBB	BBB
7	Baltimore Gas and Electric Company	49.0	10.3	4.2	36.1	49.9	10.4	4.7	34.9	45.3	9.1	4.6	40.6	41.2	7.2	5.7	45.9	Baa2		
8	Carolina Power & Light Company	46.3	0.0	0.0	53.0	44.1	1.4	0.7	53.8	42.8	6.1	0.8	50.3	48.8	2.8	0.8	47.5	A3	A-	BBB+
9	CenterPoint Energy Houston Electric, LLC	70.9	3.3	0.0	25.8	70.3	3.3	0.0	26.4	63.7	2.6	0.0	33.7	66.4	2.4	0.0	31.2	Baa3	BBB	BBB
10	Central Hudson Gas & Electric Corp	48.1	4.6	2.4	44.8	48.5	5.3	2.5	43.7	49.6	5.2	2.6	42.6	46.4	6.3	2.9	44.4	A2	A-	A
11	Central Illinois Light Company	26.2	5.2	1.8	66.8	23.3	19.7	1.6	55.5	14.5	30.5	1.7	53.3	18.0	23.5	2.1	56.4	Ba1	BBB	BBB-
12	Central Illinois Public Service Company	44.0	0.0	5.2	50.7	41.6	6.1	4.9	47.3	41.0	12.6	4.5	42.0	44.9	3.3	4.8	47.0	Ba1	BBB-	BBB-
13	Cilcorp Inc	48.0	20.7	0.0	29.5	31.2	24.0	1.1	43.7	30.6	28.8	1.1	39.6	36.9	17.5	1.3	44.3		BBB-	BBB-
14	Cleco Power LLC	52.1	2.9	0.0	45.0	52.0	3.1	0.0	44.9	48.5	0.0	0.0	51.5	42.7	4.1	0.0	53.2			BBB
15	Cleveland Electric Illuminating Company	45.1	11.3	0.0	43.0	44.5	10.6	0.0	44.9	39.6	20.0	0.0	40.4	50.0	9.4	0.0	40.7	Baa3	BB+	BBB
16	Columbus Southern Power Company	46.9	9.7	0.0	43.4	52.3	2.8	0.0	44.9	46.4	8.2	0.0	45.4	53.2	0.2	0.0	46.7	A3	BBB+	BBB
17	Commonwealth Edison Company	41.4	1.5	0.0	57.1	41.9	0.7	0.0	57.4	37.5	6.6	0.0	55.9	37.8	4.7	0.0	57.5	Baa3	BB+	
18	Connecticut Light and Power Company	54.1	2.2	2.2	41.6	51.2	5.6	2.2	41.0	56.4	0.9	2.5	40.2	58.3	6.7	3.0	32.0	Baa1	BBB	BBB
19	Consolidated Edison Company of New York	48.8	2.5	1.1	47.6	46.1	4.0	1.2	48.7	44.0	5.1	1.3	49.5	47.5	2.3	1.5	48.7	A3	BBB+	A-
20	Consumers Energy Company	53.6	2.4	0.5	43.5	49.7	4.9	0.5	44.8	48.5	5.8	0.5	45.1	57.4	1.2	0.6	40.8		BBB-	BBB-
21	Dayton Power and Light Company	36.7	6.3	1.0	56.1	37.4	0.0	1.0	61.6	38.2	0.9	1.0	59.8	38.5	0.0	1.1	60.3	A2	A-	A-
22	Delmarva Power & Light Company	40.9	14.7	0.0	44.4	40.7	14.6	0.0	44.7	35.0	20.4	0.0	44.5	36.8	17.4	1.2	44.6	Baa2	BBB+	BBB
23	Detroit Edison Company	53.5	4.3	0.0	42.3	57.2	2.6	0.0	40.2	52.4	9.8	0.0	37.8	57.3	5.1	0.0	37.6	Baa1	BBB	BBB
24	Duke Energy Carolinas, LLC	46.5	2.1	0.0	51.4	48.4	1.4	0.0	50.1	37.6	7.9	0.0	54.5	44.8	2.0	0.0	53.2	A3		A-
25	Duke Energy Indiana, Inc.	52.7	2.2	0.0	45.1	48.4	4.2	0.0	47.5	45.7	3.2	0.0	51.0	47.6	6.0	0.0	46.5	Baa1		A-
26	Duke Energy Kentucky, Inc.	42.4	0.0	na	na	43.0	3.5	0.0	53.5	37.9	7.0	0.0	55.1	41.9	6.5	0.0	51.6			A-
27	Duke Energy Ohio, Inc.	24.6	3.3	0.0	72.2	20.9	4.2	0.0	75.0	20.9	3.6	0.0	75.5	20.8	4.4	0.0	74.8	Baa1		A-
28	Entergy Arkansas, Inc.	51.3	1.9	0.0	43.3	51.7	1.8	3.6	42.9	47.3	1.7	4.0	47.1	46.2	1.9	3.9	48.0	Baa2	BBB-	BBB
29	Entergy Gulf States, Inc.	53.8	7.0	0.3	38.9	55.2	6.9	0.3	37.6	46.7	18.7	0.3	34.3	51.5	0.5	1.0	47.0	Baa3	BB+	BBB
30	Entergy Louisiana, LLC	43.6	1.8	3.1	51.5	44.9	1.2	3.2	50.7	41.9	1.6	3.6	52.9	45.0	1.5	3.8	49.8	Baa2	BBB-	BBB
31	Entergy Mississippi, Inc.	48.6	1.7	0.0	46.2	49.5	0.1	3.6	46.9	49.8	0.1	3.6	46.5	54.3	0.0	3.4	42.2	Baa3	BBB-	BBB

Source: SNL Financial

Table XIII

QUALITY MEASURES-UTILITY OPERATING COMPANIES

		CAPITAL STRUCTURE RATIOS*																Credit Ratings		
		As of: 3/31/2009				As of: 12/31/2008				As of: 12/31/2007				As of: 12/31/2006						
Line	Company	LTD	STD	Prfd	Com Equity	LTD	STD	Prfd	Com Equity	LTD	STD	Prfd	Com Equity	LTD	STD	Prfd	Com Equity	Moody's	Fitch Ratings	S&P
		(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)			
32	Entergy New Orleans, Inc.	54.0	0.0	0.0	42.1	54.1	0.0	3.9	41.9	54.7	6.0	3.9	35.4	50.5	11.4	4.3	33.8	Ba2	BB+	BBB-
33	Entergy Texas, Inc.	58.3	4.2	0.0	37.5	52.0	4.8	0.0	43.2	45.7	12.8	0.0	41.5	52.4	0.0	0.0	47.6	Ba1	BB+	BBB
34	Florida Power & Light Company	39.8	5.0	0.0	55.2	36.8	7.2	0.0	56.0	37.3	8.1	0.0	54.6	34.0	5.1	0.0	60.9	A1	A	A
35	Florida Power Corporation	50.4	7.4	0.4	41.8	53.1	5.4	0.4	41.0	44.9	8.3	0.5	46.3	47.3	1.7	0.6	50.4	A3	A-	BBB+
36	Georgia Power Company	47.5	4.3	1.7	46.5	47.4	4.3	1.8	46.5	43.8	6.7	2.0	47.5	42.5	8.5	0.4	48.6	A2	A	A
37	Gulf Power Company	46.4	3.3	4.7	45.6	44.3	7.7	5.1	42.9	45.9	2.8	6.1	45.3	46.3	8.0	3.6	42.1	A2	A-	A
38	Hawaiian Electric Company, Inc.	41.9	1.4	1.0	55.1	41.7	1.9	1.6	54.8	43.0	1.4	1.7	53.9	40.9	6.0	1.8	51.2	Baa1		BBB
39	Idaho Power Co.	48.2	6.9	0.0	44.9	46.1	7.6	0.0	46.4	47.7	5.8	0.0	46.5	43.8	6.5	0.0	49.7	Baa1	BBB	BBB
40	Illinois Power Company	42.2	9.2	1.7	46.9	43.4	9.4	1.7	45.5	39.7	9.0	1.8	49.4	37.0	5.4	2.0	55.7	Ba1	BBB-	BBB-
41	Indiana Michigan Power Company	55.4	1.9	0.2	42.4	41.9	15.4	0.2	42.5	48.0	7.5	0.3	44.3	51.3	5.3	0.3	43.2	Baa2	BBB-	BBB
42	Interstate Power & Light Company	36.0	7.7	7.7	48.6	36.3	7.5	7.8	48.5	40.0	1.7	9.7	48.7	35.6	5.4	8.0	50.9	A3		BBB+
43	Jersey Central Power & Light Co.	41.5	0.7	0.0	57.9	34.7	3.4	0.0	61.9	32.9	3.3	0.0	63.7	28.1	4.7	0.0	67.2	Baa2	BBB	BBB
44	Kansas City Power & Light	48.6	5.7	0.0	45.4	40.8	11.2	0.0	47.9	35.2	12.9	0.0	51.9	24.1	20.9	0.0	54.9	Baa1		BBB
45	Kentucky Power Company	42.9	na	na	41.0	44.2	13.9	0.0	41.9	49.0	5.9	0.0	45.2	14.9	41.6	0.0	43.5	Baa2	BBB-	BBB
46	Metropolitan Edison Company	33.7	17.9	0.0	48.4	28.4	16.2	0.0	55.4	28.9	15.2	0.0	55.9	31.0	11.0	0.0	58.0	Baa2	BBB-	BBB
47	Mississippi Power Company	42.3	0.1	2.8	54.8	33.5	6.1	3.0	57.5	30.0	1.2	3.5	65.3	29.2	5.4	3.4	61.9	A1	A+	A
48	Nevada Power Company	58.2	0.1	0.0	41.6	56.2	0.1	0.0	43.6	51.5	0.2	0.0	48.4	52.2	0.1	0.0	47.7	Ba3	BB	BB
49	Northern States Power Company - MN	44.0	4.1	0.0	52.0	44.5	5.2	0.0	50.3	43.8	6.1	0.0	50.1	45.9	1.8	0.0	52.3	A3	A-	BBB+
50	Northern States Power Company - WI	43.9	0.1	0.0	56.0	48.6	0.1	0.0	51.3	28.0	16.6	0.0	55.4	39.0	3.8	0.0	57.1		A-	A-
51	NSTAR Electric Company	41.4	8.9	1.0	48.6	40.3	10.8	1.0	47.9	45.1	8.7	1.1	45.1	42.8	10.2	1.1	45.9	A1	A+	A+
52	Ohio Edison Company	44.5	3.3	0.0	51.8	44.5	4.1	0.0	51.4	30.0	13.8	0.0	56.2	33.2	8.2	0.0	58.6	Baa2	BBB-	BBB
53	Ohio Power Company	50.3	6.7	0.3	42.4	52.7	3.9	0.3	42.8	53.1	3.1	0.3	43.2	51.7	4.5	0.7	43.1		BBB	BBB
54	Oklahoma Gas and Electric Company	44.6	2.6	0.0	52.8	45.6	0.5	0.0	53.9	32.2	13.3	0.0	54.4	37.2	4.5	0.0	58.3	A2	A+	BBB+
55	Orange and Rockland Utilities, Inc.	41.9	9.7	0.0	48.4	47.6	0.3	0.0	52.1	48.3	5.4	0.0	46.4	51.2	6.6	0.0	42.3	Baa1	A-	A-
56	Pacific Gas and Electric Company	49.0	3.5	1.2	46.4	48.7	6.0	1.2	44.0	49.4	4.7	1.3	44.7	48.2	7.7	1.4	42.6	A3	A-	BBB+
57	PECO Energy Company	49.0	9.6	1.5	39.9	52.5	7.3	1.5	38.7	48.6	15.6	1.5	34.3	63.5	6.2	1.5	28.9		BBB+	
58	Pennsylvania Electric Company	30.0	24.0	0.0	46.0	31.5	21.2	0.0	47.3	37.7	10.4	0.0	51.9	23.2	9.7	0.0	67.1	Baa2	BBB-	BBB
59	Portland General Electric Company	43.3	5.0	0.0	51.7	40.7	12.1	0.0	47.3	49.9	0.0	0.0	50.1	40.6	6.4	0.0	53.0	Baa2		BBB+
60	Potomac Electric Power Company	53.9	4.8	0.0	41.3	52.2	6.1	0.0	41.7	45.7	11.8	0.0	42.5	44.5	11.4	0.0	44.1	Baa2	BBB+	BBB
61	PPL Electric Utilities Corporation	37.0	14.4	8.8	39.8	36.3	16.8	8.6	38.3	38.7	13.2	9.1	38.9	39.8	16.7	8.4	35.1	Baa1	BBB	A-
62	Public Service Company of Colorado	37.5	3.3	0.0	59.2	37.5	4.0	0.0	58.6	32.3	9.8	0.0	57.9	34.6	8.9	0.0	56.5	Baa1	BBB+	BBB+
63	Public Service Company of New Hampshire	56.5	2.8	0.0	40.7	57.6	2.9	0.0	39.5	60.6	1.5	0.0	37.9	62.5	2.7	0.0	34.7	Baa2	BBB	BBB

Source: SNL Financial

Table XIII

QUALITY MEASURES-UTILITY OPERATING COMPANIES

		CAPITAL STRUCTURE RATIOS*																Credit Ratings		
		As of: 3/31/2009				As of: 12/31/2008				As of: 12/31/2007				As of: 12/31/2006						
Line	Company	LTD (%)	STD (%)	Prfd (%)	Com Equity (%)	LTD (%)	STD (%)	Prfd (%)	Com Equity (%)	LTD (%)	STD (%)	Prfd (%)	Com Equity (%)	LTD (%)	STD (%)	Prfd (%)	Com Equity (%)	Moody's	Fitch Ratings	S&P
64	Public Service Company of New Mexico	44.3	1.6	0.0	49.5	na	na	na	na	25.8	22.7	0.0	51.0	40.4	10.3	0.5	48.8	Baa3	BB	BB-
65	Public Service Company of Oklahoma	52.0	3.0	0.3	44.7	48.9	7.1	0.3	43.7	58.7	0.1	0.3	40.9	50.2	5.8	0.4	43.6	Baa1	BBB	BBB
66	Public Service Electric and Gas Company	50.3	6.2	0.9	42.5	54.6	3.0	0.9	41.4	54.5	5.8	0.9	38.7	57.3	3.8	1.0	37.9	Baa1	BBB+	BBB
67	San Diego Gas & Electric Co.	43.5	2.1	0.0	50.1	na	na	na	na	na	na	na	na	43.6	3.7	2.1	50.6	A2	A+	A
68	Sierra Pacific Power Company	59.0	0.0	0.0	41.0	61.4	0.0	0.0	38.6	49.6	4.6	0.0	45.8	54.7	0.1	0.0	45.2	Ba3	BB	BB
69	South Carolina Electric & Gas Co.	51.2	2.2	1.7	43.4	na	na	na	na	na	na	na	na	na	na	na	na	A3	BBB+	BBB+
70	Southern California Edison Co.	39.8	11.1	5.6	41.2	43.0	11.8	7.5	37.7	38.6	3.8	10.4	47.2	42.1	3.2	10.4	44.3	A3	A-	BBB+
71	Southern Indiana Gas and Electric Company	na	na	na	na	34.3	18.2	0.0	47.5	39.8	10.1	0.0	50.2	41.8	4.8	0.0	53.4	Baa1		A-
72	Southwestern Electric Power Company	51.4	2.2	0.2	46.2	55.1	1.0	0.2	43.7	56.2	0.8	0.2	42.7	37.8	17.4	0.4	44.4		BBB	BBB
73	Southwestern Public Service Company	50.0	0.0	0.0	50.0	47.2	5.1	0.0	47.6	46.0	7.3	0.0	46.7	47.8	3.1	0.0	49.1	Baa1	BBB	
74	Tampa Electric Company	46.6	2.5	0.0	51.0	47.1	0.9	0.0	52.0	50.2	0.8	0.0	49.0	45.5	5.8	0.0	48.7	BBB	BBB	BBB
75	Texas-New Mexico Power Company	40.0	5.0	0.0	55.0	0.0	43.9	0.0	56.1	22.2	20.2	0.0	57.5	44.8	0.3	0.0	54.9	Baa3	BB+	BB-
76	Toledo Edison Company	33.9	12.0	0.0	53.8	33.6	12.5	0.0	53.9	37.8	1.7	0.0	60.5	35.0	17.9	0.0	47.0	Baa3	BB+	BBB
77	Tucson Electric Power Company	68.4	1.6	0.0	30.0	69.8	1.4	0.0	28.8	60.7	10.4	0.0	28.9	68.6	4.3	0.0	27.0	Baa3	BB	BB+
78	Union Electric Company	51.4	3.8	1.4	43.3	49.0	3.4	1.5	46.0	45.5	3.3	1.6	49.5	46.4	3.8	1.8	48.1	Baa2	BBB+	BBB-
79	Vectren Utility Holdings, Inc.	44.3	4.5	0.0	51.2	41.3	10.5	0.0	48.2	41.9	15.2	0.0	42.9	43.1	12.5	0.0	44.4			A-
80	Virginia Electric and Power Company	45.1	5.0	1.9	48.0	46.3	3.3	2.0	48.4	45.6	4.7	2.2	47.5	32.4	16.9	2.3	48.3	Baa1	BBB+	A-
81	Western Massachusetts Electric Company	52.5	14.3	0.0	33.2	55.7	9.1	0.0	35.2	60.2	2.3	0.0	37.5	59.1	5.0	0.0	35.8	Baa2	BBB	BBB
82	Wisconsin Electric Power Company	50.8	3.9	0.5	44.8	52.0	0.7	0.5	46.7	39.4	7.2	0.6	52.8	37.3	11.7	0.6	50.4	A1	A	A-
83	Wisconsin Power and Light Company	38.6	7.0	0.0	53.7	41.5	2.0	2.8	53.7	34.5	7.5	3.2	54.8	22.8	13.1	3.3	60.8	A2		A-
84	Wisconsin Public Service Corp	41.1	0.5	2.4	56.1	40.6	2.8	2.4	54.2	37.5	3.0	2.5	56.9	34.1	3.8	2.8	59.4	A2		A-
85	**84 Co. Average**	47.3	5.0	0.9	46.1	45.9	6.6	1.2	46.4	43.8	7.7	1.2	47.3	44.2	6.8	1.3	47.6			

Source: SNL Financial

Docket No. 090079-EI
Capital Structure Adj.
Exhibit JP-14

PROGRESS ENERGY FLORIDA

Impact of Capital Structure Adjustment
Test Year Ending 12/31/2010
(Dollar Amounts in Thousands)

Line	Class of Capital	Total Per Books	Specific Adjustments	Pro Rata Adjustments	System Adjusted	FPSC Factor	FPSC Adjusted	Ratio	Cost Rate	Weighted Cost	Pre-Tax Weighted Cost
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Common Equity	$4,603,867	($4,825)	($744,436)	$3,854,606	75.95%	$2,927,761	46.93%	12.54%	5.88%	9.61%
2	Preferred Stock	$33,497	$0	($5,422)	$28,075	75.95%	$21,324	0.34%	4.51%	0.02%	0.03%
3	Long Term Debt-Fixed	$4,443,979	$0	($719,337)	$3,724,642	75.95%	$2,829,047	45.35%	6.42%	2.91%	2.91%
4	Short Term Debt	$72,883	($7,833)	($10,529)	$54,521	75.95%	$41,411	0.66%	5.25%	0.03%	0.03%
5	Customer Deposits Active	$188,256	$0	($30,473)	$157,783	75.95%	$119,844	1.92%	5.95%	0.11%	0.11%
6	Customer Deposits Inactive	$1,902	$0	($308)	$1,594	75.95%	$1,211	0.02%	0.00%	0.00%	0.00%
7	Investment Tax Credits	$6,083	$0	($985)	$5,098	75.95%	$3,872	0.06%	9.50%	0.01%	0.01%
8	Deferred Income Tax	$495,822	$160,089	($106,171)	$549,740	75.95%	$417,554	6.69%	0.00%	0.00%	0.00%
9	FAS 109 DIT - Net	($193,855)	$0	$31,379	($162,476)	75.95%	($123,409)	-1.98%	0.00%	0.00%	0.00%
10	Total	$9,652,434	$147,431	($1,586,282)	$8,213,583		$6,238,617	100.00%		8.97%	12.71%
11	PEF Proposed										13.23%
12	Rate Base										$6,238,617
13	Impact on Revenue Deficiency										**$32,861**

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing Florida Industrial Power Users Group's Testimony and Exhibit of Jeffry Pollock has been served by First Class United States Mail this 10th day of August, 2009, to the following:

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