BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Increase in Rates by Florida Power & Light Company	DOCKET NO. 120015-EI Filed: July 2, 2012

TESTIMONY AND EXHIBITS OF JEFFRY POLLOCK

ON BEHALF OF THE FLORIDA INDUSTRIAL POWER USERS GROUP

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LIST OF ACRONYMS

12CP	Twelve Coincident Peak
AD	Average Demand
CC	Cape Canaveral
CCOSS	Class Cost-of-Service Study
CDR	Commercial/Industrial Demand Reduction
CILC	Commercial/Industrial Load Control
CS	Curtailable Service
DSM	Demand Side Management
ECCR	Energy Conservation Cost Recovery
EPACT	Energy Policy Act of 2005
FERC	Federal Energy Regulatory Commission
FIPUG	Florida Industrial Power Users Group
FPL	Florida Power & Light Company
GSLD	General Service Large Demand
HLFT	High Load Factor Time-of-Use Rate
kW	Kilowatts
kWh	Kilowatt-hours
NARUC CAM	National Association of Regulatory Utility Commissioners *Electric Utility Cost Allocation Manual,* January 1992
NCP	Non-Coincident Peak
NERC	North American Electric Reliability Corporation
O&M	Operation & Maintenance Expense
SDTR	Seasonal Demand Time-of-Use Rate
TOU	Time-of-Use

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. My qualifications are documented in **Appendix A.** A partial list of my appearances is provided in **Appendix B** 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 purchase electricity from Florida Power & Light Company (FPL) primarily on the General Service Large Demand (GSLD), Commercial Industrial Load Control (CILC), and Standby tariffs. These customers require an affordable 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:

- Class revenue allocation;
- FPL's class cost-of-service study (CCOSS); and
- Rate design.

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 FPL'S CLAIMED REVENUE REQUIREMENTS. DOES THIS CONSTITUTE AN ENDORSEMENT OF THE COMPANY'S PROPOSALS?

A No. My use of FPL'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 *Class Revenue Allocation*

FPL's proposed class revenue allocation should be rejected. FPL's proposal would allow rates for one class to decrease while subjecting other classes to base rate increases of up to 46%. FPL's proposal also fails to give appropriate recognition to the principle of gradualism. Gradualism constraints are appropriately applied to the percent changes in base rates (not cost-recovery clauses) because only base rates are subject to change in this proceeding. In addition, while clause revenues are changed on an annual basis (or even more frequently if a mid-course correction is sought), base rates often remain in place for many years.

Further, FPL's proposed allocation of the Cape Canaveral (CC) Step increase should be rejected because it is inconsistent with the methodology that FPL uses to allocate production capacity costs in both its CCOSS and in the Capacity Cost Recovery Clause.

If any base rate increase is authorized in this proceeding, it should be allocated in a manner that moves classes closer to cost using an appropriate CCOSS adjusted for the approved revenue requirement. In general, above-cost classes should receive below-average increases (or no increase as in the case of the Standby rates, which are substantially above cost), and vice versa. The CC Step increase should be allocated in the same manner as the 2013 increase, if awarded. This would continue moving rates closer to cost, while recognizing gradualism.

Class Cost-of-Service Study

FPL's CCOSS is inappropriate and should be revised in several important respects. First, there are errors in FPL's quantification of the "incentive payments" associated with the CILC classes. The incentive payments are the difference in the calculated base revenues between the otherwise applicable firm rate and the CILC rate (excluding the Customer charge). The amount of the incentive payments affects the CCOSS results because they are added to the CILC base revenues that determine the earned rates of return from the CILC classes. FPL similarly added back the Rider CDR credits to the GSLD class revenues in the CCOSS. However, FPL understated the incentive payments associated with the CILC-1D and CILC-1T classes and overstated the CILC-1G payments. As a result, FPL's CCOSS understates the earned returns for the CILC-1D and CILC-1T classes and overstates the earned return for the CILC-1G class.

Both the CILC incentives and CDR credits are collected in the Energy Conservation Cost Recovery (ECCR) clause. FPL also pays credits for curtailable load under the Curtailable Service (CS) rates. In its CCOSS, FPL has allocated the CS credits to all loads, including non-firm loads. The CILC and CDR payments are similarly allocated to all loads in FPL's ECCR. Allocating non-firm (*i.e.,* CILC, CDR, CS customers) credits to all loads, including non-firm loads, violates cost causation and FPL's planning principles. Non-firm credits should be allocated only to firm loads.

Third, transmission plant-related costs should not be allocated in the same way as production plant-related costs. FPL uses the Twelve Coincident Peak and 1/13th Average Demand (12CP-1/13th AD) method for both production and transmission costs. The rationale supporting 12CP-1/13th AD is that some capacity costs meet year-round peak demand, while other costs are incurred to save fuel costs. While I disagree with this rationale, there is no similar dual functionality for transmission lines and substations. Transmission plant must be sized to meet peak demand. Further, serving loads throughout the year is a by-product (and not a cost-causer) of serving peak demand. For these reasons, transmission plant should be classified and allocated entirely on a demand basis.

Further, the allocation of both production and transmission plant costs should reflect cost causation. Thus, the allocation methodology should closely reflect FPL's system load characteristics. FPL is a strongly summer peaking utility and experiences its tightest reserve margins during the summer months. This suggests that greater emphasis should be placed on summer month demands than is provided in the 12CP-1/13th AD method FPL uses. However, this Commission has adopted the 12CP-1/13th AD method in past cases, and for this reason, I have no objection to retaining it for production plant-related costs. If the Commission once again approves 12CP-1/13th AD for production plant-related costs, it should approve 12CP for transmission plant-related costs.

Fourth, FPL's classification of production operation and maintenance (O&M) expenses between demand and energy should be revised to comport with the *Electric Utility Cost Allocation Manual* published by the National Association of Regulatory Utility Commissioners (NARUC CAM) in January, 1992. Specifically, $99 million of other production O&M expense should be reclassified from energy to demand.

Rate Design

FPL's proposed GSLD/CILC rate designs are not cost-based and should be rejected because the proposed Demand and non-fuel Energy charges are not closely aligned with the corresponding demand and non-fuel energy-related costs. FPL's proposed CC Step rate design is of particular concern because the entire increase would be collected through higher Energy charges. As a result of this rate design, high load factor GSLD and CILC customers would experience cumulative base rate increases that are higher than the class averages. This result is not cost-based because most of the underlying CC costs are demand-related. Any increases allocated to the GSLD and CILC classes that are not needed to realign the Customer and Energy charges to reflect the corresponding unit costs should be collected in the Demand charge.

The CILC rate should be re-opened. CILC customers are currently receiving an "effective" Demand credit of $3.79 per kW of Load Control demand and $4.79 per kW of Coincident Peak (CP) demand paid for the capacity they provide to FPL. The corresponding credits paid to Rider CDR customers are $4.68 per kW of non-firm demand and $4.90 per CP-kW demand. However, unlike CILC, Rider CDR is *not* closed. In fact, the analysis provided by FPL in its most recent Conservation Goals proceeding (Docket No. 10055-EG) demonstrated that Rider CDR is cost-effective. Therefore, it follows that CILC would also be cost-effective. For this reason, CILC should be re-opened, and the incentive payment should be raised to at least the same level as Rider CDR.

Finally, based on FPL's cost-effectiveness analysis, Rider CDR would remain cost-effective even if the credit is increased to over $12 per kW. Thus, consistent with cost-based ratemaking, the current CILC and Rider CDR Demand credits should be increased in this proceeding.

2. 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 ANY CHANGE IN BASE REVENUES APPROVED IN THIS DOCKET BE APPORTIONED AMONG THE VARIOUS CUSTOMER CLASSES FPL 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 it would result in rate shock to the affected customers.

Q PLEASE EXPLAIN HOW RATE ADMINISTRATION IS RELATED TO RATE CHANGE.

A. Rate administration is a concept that applies when the design of a rate may be tied to the design of other rates to minimize revenue losses when customers migrate from a more expensive to a less expensive rate. FPL applies this concept in designing the GSLD and derivative rates (*e.g.*, SDTR, HLFT).

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 an appropriate 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 most recent Tampa Electric Company 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, a more gradual movement of FPL's rates closer to cost would be consistent with Commission policy rather than what FPL has proposed.

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

A FPL's proposed base revenue increase is shown in **Exhibit JP-1**. Page 1 shows the allocation of the proposed 2013 increase, while page 2 shows the allocation of the CC Step increase.

Referring to page 1, the 2013 increase would be an 11.0% base rate increase. The increases by class would range from a 24% *decrease* for SL-2 to a 34% increase for CILC-1T.

Referring to page 2, the CC Step increase would be an additional 3.7% base rate increase. The proposed step increases would range from 0.9% for SL-1 to 9.1% for CILC-1T.

The cumulative base rate increases are shown on page 3. As can be seen, FPL's proposed cumulative base rate increase is 15.1%. The cumulative increases by rate would range from a 20% *decrease* for SL-2 to an over 46% increase for CILC-1T.

Q IS FPL'S PROPOSED 2013 CLASS REVENUE ALLOCATION REASONABLE?

A No. FPL's proposed 2013 class revenue allocation would not move all classes equally closer to cost. This is shown in **Exhibit JP-2**, which quantifies the percentage movement to cost. As can be seen, the GSLD(T)-3, CILC-1D and CILC-1T rates would be moved more than 100% toward cost; that is, FPL overshot the target by allocating a higher than necessary increase to move these classes closer to cost. Further, some rates would move away from cost (*e.g.*, Residential, SL-1, SST-DST and SST-TST). The SST-TST rate increase is especially puzzling given that this class has the highest parity ratio of any class at current rates (and higher than SL-2, for which FPL is proposing a substantial rate decrease).

Second, by seeking to reduce SL-2 rates, FPL has violated Commission policy, which has traditionally been to maintain the status quo for rates that are currently producing returns above parity, not to decrease rates. Under this policy, no base rate decrease should be awarded to SL-2 and SST-TST.

Q IS FPL'S PROPOSED CAPE CANAVERAL STEP CLASS REVENUE ALLOCATION APPROPRIATE?

A No. The proposed CC Step allocation is unreasonable. First, it was derived irrespective of the 2013 class revenue allocation. This is improper because the CC Step increase is a further extension of this rate case. The same principles used for class revenue allocation should apply equally to both the 2013 and the CC Step increases.

Second, with a few exceptions, the proposed CC Step allocation more closely resembles a pure energy allocation; that is, the increases by class are nearly the same on a per kWh basis (see **Exhibit JP-1**, page 2). An energy allocation bears no semblance to cost-based ratemaking whatsoever. In fact, the allocation factors used to derive the allocated CC Step increase are not consistent with the 12CP-1/13th AD factors that FPL uses to allocate all other production demand-related costs.

Finally, as is evident from the wide disparity between the cumulative proposed base rate increases (from *negative* 20% to 46%) as shown in **Exhibit JP-1,** page 3, FPL has given virtually no recognition to the principle of gradualism.

Q **HAS THE COMMISSION ADDRESSED CLASS REVENUE ALLOCATION IN PRIOR LITIGATED CASES?**

A Yes. The Commission recently addressed class revenue allocation in the prior FPL and Tampa Electric Company rate cases. In both cases, the Commission limited the increases to 150% of the system average. However, in applying the 150% limitation, the Commission included cost recovery clauses in the prior FPL case, whereas in the Tampa Electric case, the 150% limitation was applied to *base rates*, excluding cost recovery clauses. Thus, it does not appear that the Commission has a consistent policy on this. From a policy perspective, cost recovery clauses should not be included in this analysis because they change on an annual basis whereas base rates generally remain in place for a much longer period of time. And, as we have seen recently, fuel prices, for example, may experience great fluctuation in one year and then dramatically change again in the next year. Thus, it would be inappropriate to include and rely on projections of clause revenues for just one year (the test year) in setting base rates.

Q **HOW SHOULD GRADUALISM BE APPLIED?**

A FPL is seeking an increase in base rates. The cost recovery clauses are not at issue in this case. In other words, the increase FPL is now seeking has nothing to do with increases or decreases in fuel, energy conservation, environmental, or capacity costs. For this reason, gradualism should be applied to that portion of the rate that is subject to change in this proceeding—*the base rate*.

Further, gradualism is not a consideration in setting the cost recovery clauses. Thus, a sudden increase or decrease in natural gas prices will not affect how base rates are determined in this case.

The Commission should apply the principle of gradualism to any base revenue increase that may be approved in this case, notwithstanding any predictions about subsequent changes in cost recovery clauses.

Given that the cost recovery clauses are separate ratemaking mechanisms and can have positive or negative impacts on customers depending on the circumstances, any projected short-term changes should not be considered in setting base rates.

Q SHOULD FPL'S PROPOSED CAPE CANAVERAL STEP ALLOCATION BE ADOPTED?

A No. As previously stated, FPL's proposed CC Step class revenue allocation does not recognize either cost-of-service or gradualism principles. This is because the vast majority of the CC costs are demand-related, while FPL's proposed increase more closely resembles a pure energy allocation. To continue moving rates closer to cost, while recognizing gradualism, I recommend that the CC Step increase be allocated in the same manner as the 2013 increase, should an increase be authorized. As discussed later, I am recommending specific changes to FPL's CCOSS that should be made so that it can be used to determine a cost-based revenue allocation and rate design in this proceeding.

Q IF THE COMMISSION APPROVES ANY INCREASE IN FPL'S BASE RATES , HOW SHOULD THEY BE ALLOCATED TO CUSTOMER CLASSES?

A The class revenue allocation should be derived from an approved CCOSS based on the authorized revenue requirement. It should result in classes moving toward cost, subject to appropriate gradualism constraints.

3. CLASS COST-OF-SERVICE STUDY

<u>Background</u>

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

A A CCOSS 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 to conduct a CCOSS are described in **Appendix C**.

Q WHAT KEY PRINCIPLES SHOULD A CLASS COST-OF-SERVICE STUDY INCORPORATE?

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. Once capacity has been installed to meet peak demand, it can also be used to meet off-peak demand. In other words, supplying off-peak demand is a by-product of serving on-peak demand. Thus, customers that use electricity during the critical peak hours cause the utility to invest in generation and transmission facilities. Cost causation means allocating demand-related costs relative to peak demand.

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. 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.

These three factors explain why some customers pay higher 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) rather 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 utility's distribution system. Instead, transmission customers construct and own their own distribution systems. Thus, distribution system costs are not allocated to transmission level customers. Distribution customers, by contrast, require substantial investments in lower voltage facilities to provide service. Secondary distribution customers require more investment than primary distribution customers. This results in a different cost to serve each type of customer.

Industrial customers typically receive service at transmission voltage. This means that they have invested in their own distribution facilities and impose only minimal distribution costs as compared to the vast majority of other customers.

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 customer would have twice the peak demand of the 80% load factor customer, 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.

All of these factors explain why it is less costly per kWh to serve industrial customers. Industrial customers typically operate at a higher load factor, are larger in size, and receive power at transmission voltage.

FPL's Class Cost-of-Service Study

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

A Yes.

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

A Yes, in many respects. FPL's CCOSS generally recognizes the different types of costs as well as the different ways electricity is used by various customers. However, there are several significant flaws that must be corrected before the study can be used to design rates in this proceeding. The flaws include:

- Understating the amount of incentive payments attributable to each CILC class;
- Allocating the non-firm credits to all loads;
- Using 12CP-1/13th AD method to allocate transmission plant-related costs; and
- Misclassifying $99 million of production O&M expense to energy rather than to demand.

Each of the above flaws is discussed below.

CILC Incentive Payments

Q WHAT IS THE CILC PROGRAM?

A The CILC (Commercial/Industrial Load Control) program is a non-firm tariff option in which customers agree to curtail load at FPL's direction. The curtailment conditions in the CILC tariff are as follows:

> The Customer's controllable load served under this Rate Schedule is subject to control when such control alleviates any emergency conditions or capacity shortages, either power supply or transmission, or whenever system load, actual or projected, would otherwise require the peaking operation of the Company's generators. Peaking operation entails taking base loaded units, cycling units or combustion turbines above the continuous rated output, which may overstress the generators.

By allowing FPL to curtail controllable load when resources are needed to maintain system reliability (that is, when there are insufficient resources to meet customer demand), FPL can maintain service to firm (*i.e.*, non-interruptible) customers. For this reason, FPL removes CILC loads in assessing resource adequacy. Thus, CILC is a lower quality of service than firm power, because it can be interrupted as described above. In exchange for an agreement to curtail load at FPL's control, CILC customers pay a lower base rate than firm customers.

Q HOW ARE CILC CUSTOMERS COMPENSATED FOR THE CAPACITY THEY PROVIDE FPL?

A The Load-Control On-Peak demand charge is a reduced rate that reflects the current value of non-firm capacity. The other applicable demand charges (*i.e.*, Firm On-Peak and Maximum Demand) recover the allocated transmission and distribution demand-related costs and are, thus, similar in concept to FPL's other firm rates.

Q **WHAT ARE THE CILC INCENTIVE PAYMENTS?**

A The CILC incentive payments are the differential in base rate revenues (excluding Customer charges) between the CILC rate and the corresponding firm (*i.e.*, GSD(T), GSLD(T)-1, and GSLD(T)-3) rates.

Q **WHY ARE THE CILC INCENTIVE PAYMENTS RELEVANT IN THE CLASS COST-OF-SERVICE STUDY?**

A FPL's CCOSS assumes that all customer classes receive firm service. This is obviously not the case for CILC customers, which receive non-firm service. Accordingly, to prevent a mismatch between the costing (firm) and pricing (non-firm) assumptions, FPL restates the CILC revenues to the level they would otherwise be if service were provided on a firm basis. The amount of the restated revenues is based on FPL's analysis of the incentive payments to each of the CILC classes.

Q **DOES FPL MAKE SIMILAR REVENUE ADJUSTMENTS FOR ANY OTHER CLASSES?**

A Yes. Many GSLD customers also take non-firm service under either the CDR or Curtailable Service (CS) tariffs. These tariffs provide specific dollar credits to reflect the lower cost of providing non-firm service. FPL restated the GSLD class revenues by adding back the CDR credits. Similarly, FPL reallocated the CS credits to all customer classes in the CCOSS.

Q **WHERE ARE THE NON-FIRM CREDITS RECOVERED?**

A The CILC incentive payments and CDR credits are recovered in the ECCR. The CS credits are recovered in base rates.

Q **DO YOU AGREE IN PRINCIPLE WITH HOW FPL RESTATED THE CILC AND GSLD CLASS REVENUES TO REMOVE THE INCENTIVE PAYMENTS AND CDR CREDITS?**

A Yes. Restating sales revenues to exclude the non-firm credits is appropriate in principle. I disagree, however, with two aspects of FPL's proposed revenue restatement. First, FPL did not appropriately quantify the CILC incentive payments. Second, as discussed later, the non-firm credits (*i.e.*, CILC incentive payments and the CDR/CS credits) are not properly allocated.

Q **HOW DID FPL DETERMINE THE AMOUNT OF THE INCENTIVE PAYMENTS TO EACH CILC CLASS?**

A FPL used historical analysis to determine the proportion of the CILC incentive payments that were assigned to each CILC class. The problem with FPL's analysis is that the restated revenues do not reflect the revenues that each CILC class would generate under the otherwise applicable firm rate. This is shown in **Exhibit JP-3** and in the Table below. Page 1 is a comparison of the incentive payments between FPL's CCOSS and as calculated at present and proposed rates. Detailed calculations at proposed rates are shown on Page 2.

Analysis of CILC Incentive Payments At Proposed Rates ($000)				
CILC Class	GSLD Rate	CILC Rate	Calculated Incentive Payment	Incentive Payment Per FPL
CILC-1T	$29,627	$21,205	$8,423	$7,374
CILC-1D	$86,184	$68,533	$17,650	$16,797
CILC-1G	$5,238	$4,639	$599	$1,026
Total	$121,401	$94,377	$26,672	$25,197

As can be seen, FPL's estimated incentive payments do not accurately reflect the cost differential between firm and non-firm service. Specifically, FPL's incentive payments to the CILC-1T and CILC-1D classes are understated, while the incentive payments to CILC-1G class are overstated.

Q WHAT IS THE IMPACT OF OVER- OR UNDER-STATING THE AMOUNT OF THE CILC INCENTIVE PAYMENTS?

A Understating the CILC-1T and CILC-1D incentive payments means that the earned returns from these classes as derived in FPL's CCOSS are understated. This, in turn, means that the CILC-1T and CILC-1D revenue requirements are overstated. The opposite would be true for the CILC-1G class.

Q SHOULD THE INCENTIVE PAYMENTS BE REVISED?

A Yes. Consistent with the principle that the CILC incentive payments should reflect the cost differential between firm and non-firm service, the calculated incentive payments at proposed rates by class as shown in the Table above should be used.

Allocation of Non-Firm Credits

Q HOW ARE THE NON-FIRM CREDITS ALLOCATED TO CUSTOMER CLASSES?

A FPL proposes to allocate the CS credits to all classes and all loads using its proposed production plant allocator (*i.e.*, 12CP-1/13th AD). FPL uses a similar approach to allocate the CILC incentive payments and CDR credits in its ECCR. As previously stated, the CILC and CDR credits are recovered in the ECCR, while the CS credits are recovered in base rates.

Q IS FPL'S ALLOCATION OF NON-FIRM CREDITS APPROPRIATE?

A No. Using the production demand allocator allocates the non-firm credits to both firm and non-firm customers. This violates the principle of cost causation. It is also inconsistent with FPL's planning principles.

Q WHAT DO YOU MEAN BY COST CAUSATION?

A Cost causation is the principle that governs a CCOSS. Under this principle, costs should be allocated to the customers that cause the costs to be incurred.

Q DO NON-FIRM LOADS CAUSE FPL TO INCUR NON-FIRM CREDITS?

A No. Non-firm customers provide capacity to FPL when FPL needs additional capacity to maintain service to its firm loads. They do so by curtailing service when called upon by FPL. In return for agreeing to curtail load, FPL pays a credit to the non-firm customers. In other words, the non-firm credits are the payment FPL makes for the purchase of capacity from non-firm loads. Thus, the non-firm credits are a cost to provide service to firm loads. Accordingly, they should be allocated only to firm loads and should not be allocated to non-firm loads. The appropriateness of allocating non-firm credits only to firm loads is further illustrated in **Exhibit JP-4**.

Q PLEASE EXPLAIN EXHIBIT JP-4.

A **Exhibit JP-4** shows two different methods of allocating costs to non-firm customers. *Method 1* is to exclude interruptible load from the CCOSS. *Method 2* reflects the basic approach that FPL used in its CCOSS (*i.e.,* to treat non-firm load as firm) except that the non-firm credits are allocated to the firm classes. As can be seen, the two treatments are mathematically equivalent, but only if the credits are allocated to firm loads.

The illustration shows the allocation of $10,000 in production capacity costs to two equal size classes: A and B. Class A is comprised of only firm load, while Class B's load is 50% firm and 50% interruptible. The interruptible load provides $1,500 in revenue. *Method 1* allocates zero production capacity costs to interruptible customers (column 4, line 8). The revenues provided by interruptible customers are used to lower the cost to provide firm service (columns 2 and 3, line 9). This results in allocating the $10,000 as follows: Class A $5,667; Class B $4,333 ($2,833 plus $1,500), of which the firm load would be charged $2,833.

Method 2 treats interruptible load as firm, but allocates the interruptible credits only to firm load. The interruptible credits are the difference between the revenues at firm rates (or $2,500) and the revenues paid by the interruptible customers (or $1,500). Thus, in the illustration, the interruptible credits are $1,000. As can be seen on line 13, the $10,000 of production capacity costs is allocated as follows: Class A $5,667; Class B $4,333 ($2,833 + $1,500), of which firm Class B customers are allocated $2,833. However, this is the same allocation as if no production capacity costs were allocated to interruptible customers in the first place (*i.e., Method 1*).

Q **WHAT DOES EXHIBIT JP-4 DEMONSTRATE?**

A **Exhibit JP-4** demonstrates that non-firm credits should be allocated in proportion to *firm* loads. It would be inappropriate to allocate the credits to total loads, including controllable load, because that would effectively charge CILC, CDR and Curtailable customers for the production plant costs they avoid. This would be contrary to the principle of cost causation and regulatory precedent.

Q **IS THE ALLOCATION OF NON-FIRM CREDITS TO ALL LOADS COMPATIBLE WITH FPL'S OWN SYSTEM PLANNING PRACTICES?**

A No. FPL removes non-firm loads in determining the need for new capacity. Thus, it does not incur production capacity costs to serve interruptible customers, and no such costs should be allocated to them. The fundamental principle of utility cost allocation is that costs are allocated to those customers that cause them to be incurred. Non-firm customers do not cause capacity costs to be incurred, and thus those costs should not be allocated to them.

Q **HAVE YOU DEVELOPED REVISED PRODUCTION DEMAND ALLOCATION FACTORS THAT EXCLUDE NON-FIRM LOADS?**

A Yes. This is shown in **Exhibit JP-5**. The non-firm loads were identified based on the proportion of controllable load (in the case of the CILC classes) and demand subject to either the CDR or CS credits to total billing demand. The allocation factors derived in **Exhibit JP-5** should be used to allocate the CS credits in the

CCOSS and CILC/CDR credits in the ECCR.

Q WOULD YOUR RECOMMENDED ALLOCATION OF NON-FIRM CREDITS CONSTITUTE A CHANGE IN CURRENT PRACTICE?

A Yes. This change is necessary to correct the inequity that non-firm customers are being forced to pay for capacity costs that FPL incurs to serve firm customers. Additionally, requiring non-firm customers to subsidize firm service unnecessarily diminishes the value of non-firm service despite its demonstrated cost-effectiveness (as discussed later), which results in lower rates to firm customers. Further, allocating non-firm credits to firm loads is consistent with cost causation. Thus, it comports with Commission policy, which is to embrace cost causation.

Allocation of Production/Transmission Plant-Related Costs

Q WHAT METHODOLOGY DOES FPL USE TO ALLOCATE PRODUCTION AND TRANSMISSION PLANT-RELATED COSTS?

A FPL uses the 12CP-1/13th AD method to allocate both production and transmission plant-related costs. The 12CP-1/13th AD method allocates costs partially on a coincident peak demand basis and partially on an average demand, or energy, basis. Further, the coincident peak portion is based on customer demands in all twelve months of the calendar year. Thus, 12CP-1/13th AD assumes that production and transmission plant-related costs are caused by year-round coincident peaks and average demand. As discussed later, FPL's predominant seasonal loads indicate that another allocation method that places greater emphasis on summer peak demands is more appropriate than 12CP-

1/13th AD. However, the Commission has consistently approved this method. Thus, I am not contesting its use for allocating production plant costs in this case.

Q DOES IT MAKE SENSE TO USE 12CP-1/13TH AD TO ALLOCATE TRANSMISSION PLANT-RELATED COSTS?

A No. First, transmission plant is sized to meet system peak demands. Energy or average demand does not determine the amount of transmission capacity FPL needs to maintain reliable service. To illustrate, **Exhibit JP-6** assumes that the utility serves two customer classes: Class A and Class B. Each utility 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. 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 cost allocation method should emphasize peak demand.

Second, unlike production plant, there is no difference in the cost of transmission plant as a function of generation technology (*i.e.*, nuclear, hydro, coal, combined cycle gas turbines, combustion turbines). The capital cost/operating cost tradeoffs that are characteristic of production plant is not a factor that determines the cost of transmission plant. For this reason, it does not matter whether a substation is used to step-up power from generators to the transmission grid or to step-down power from the transmission grid to the distribution system.

Finally, there is also a double-counting problem inherent in an energy-based allocation method that allocates a portion of investment on average demand and a portion on peak demand. The double-counting problem is discussed in **Appendix D**.

Q HOW SHOULD TRANSMISSION PLANT BE ALLOCATED TO DETERMINE THE ALLOCATION OF THESE COSTS TO FPL'S RETAIL CUSTOMER CLASSES?

A For the reasons described above, transmission plant should be allocated on a 100% demand basis. This properly recognizes cost causation.

Q IS 12CP SUPPORTED BY FPL'S LOAD/SUPPLY CHARACTERISTICS?

A No. FPL experiences its maximum annual demand for electricity in either the summer or winter months. This is shown in **Exhibit JP-7**, **page 1**, which is an analysis of FPL's monthly firm peak demands as a percent of the annual system peak for the years 2007 through 2011 and the 2013 Test Year. The peak demands in the other months are typically well below the summer and winter peak demands. These characteristics are further summarized in **Exhibit JP-7**, **page 2:**

- FPL's minimum month peak averages only 70% of the annual system peak.
- Monthly peak demands are only 86% of the annual system peak.
- Summer peak demands average about 18% (or higher) of the non-summer peak demands.
- FPL's annual load factor is below 60%.

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

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

A No. Although FPL 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, FPL generally has higher reserve margins during the non-summer months than during the summer months. This is shown in **Exhibit JP-8**. The reserve margins were calculated as the margin (available capacity less scheduled outages less firm peak demand) divided by firm peak demand. FPL's summer month reserve margins, adjusted for scheduled outages, range from 27% to 63% of the corresponding non-summer month reserve margins.

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

A The analyses demonstrate that the summer peaks (and to a lesser extent, the winter peak) determine FPL's capacity requirements. The other months are irrelevant. Thus, the 12CP method does not reflect cost causation when measured by FPL's load and supply characteristics.

Q PLEASE SUMMARIZE YOUR RECOMMENDATION ON HOW PRODUCTION AND TRANSMISSION PLANT-RELATED COSTS SHOULD BE ALLOCATED?

A Although FPL's load characteristics support a more seasonal allocation methodology, I do not oppose retaining the 12CP-1/13th AD method for allocating production plant costs, since this method has been previously approved in prior FPL rate cases. However, transmission plant-related costs should be allocated on a purely demand basis. If the Commission adopts 12CP-1/13th AD for production plant, it should adopt the 12CP method for transmission plant.

Classification of Production O&M Expense

Q DO YOU AGREE WITH FPL'S CLASSIFICATION OF PRODUCTION O&M EXPENSE?

A No. FPL has classified $99 million of expense to energy which, according to the Electric Utility Cost Allocation Manual published by the National Association of Regulatory Utility Commissions (NARUC CAM), should be classified to demand.

Q HOW ARE PRODUCTION O&M EXPENSES CLASSIFIED IN THE NARUC CAM?

A **Exhibit JP-9** is an excerpt from the NARUC CAM showing how production O&M expenses should be classified. Production O&M expense consists of both labor and materials expense. The former is related to the number of employees, while the latter is based on the materials consumed to operate and maintain the various generating units. The NARUC CAM generally considers labor expenses as demand-related. This is because, in general, operating labor-related expenses are related to the staffing levels at each plant. They do not change with the level of output. Materials expenses are generally considered to be energy-related because they include consumables used in the production of electricity. In addition, certain maintenance expenses are classified either entirely to demand or entirely to energy.

Q WHAT EXPENSES HAVE FPL CLASSIFIED TO ENERGY THAT SHOULD BE CLASSIFIED TO DEMAND?

A For the most part, FPL followed the NARUC CAM in classifying production O&M expense. There are some notable exceptions, including nuclear operation and supervision and other production O&M expenses. Had FPL also followed the NARUC CAM for these expenses, it would have classified 84% (not 69%) of nuclear operation and supervision expense and 98% (not 44%) of other non-fuel production O&M expense to demand.

Q ARE THE DIFFERENCES IN COST CLASSIFICATIONS BETWEEN FPL AND THE NARUC COST ALLOCATION MANUAL SIGNIFICANT?

A Yes. The differences are shown in **Exhibit JP-10**. As can be seen, FPL has classified about $323 million of production O&M expense to demand (column 2), while applying the methodology in the NARUC CAM would result in classifying about $422 million (or $99 million more) to demand (column 7).

Q PLEASE SUMMARIZE YOUR RECOMMENDATION.

A Consistent with the NARUC CAM, $422 million of production O&M expense should be classified to demand.

Revised Class Cost-of-Service Study

Q HAVE YOU CONDUCTED A CLASS COST-OF-SERVICE STUDY THAT INCORPORATES YOUR RECOMMENDED CHANGES TO FPL'S STUDY?

A Yes. The revised CCOSS at present rates is provided in **Exhibit JP-11**. The results are also summarized in the Table below. The revised CCOSS incorporates the following changes:

- The CILC incentive payments were restated to reflect the firm/CILC rate differentials at FPL's proposed 2013 rates;
- CS Credits were allocated relative to firm loads;
- The 12CP method was used to allocate transmission plant-related costs; and
- $99 million of production O&M expense was reclassified from energy to demand.

Q PLEASE EXPLAIN HOW THE CLASS COST-OF-SERVICE STUDY RESULTS SHOWN IN EXHIBIT JP-11 ARE MEASURED.

A The results of the revised CCOSS presented in **Exhibit JP-11** are measured in three ways: (1) rate of return; (2) parity index; and (3) interclass subsidies.

Rate of return is the ratio of net operating income (revenues less allocated operating expenses) to the allocated rate base. Net operating income is the difference between operating revenues and allocated operating expenses. 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 Florida retail jurisdictional return of 5.50% at present rates.

The ***parity index*** is the ratio of each class's rate of return to the Florida retail average rate of return. A parity index above 100 means that a class is providing a rate of return higher than the system average, while a parity index below 100 indicates that a class is providing a below-system average rate of return.

The ***interclass subsidy*** 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).

4. RATE DESIGN

Q WHAT RATE DESIGN ISSUES WILL YOU ADDRESS?

A In this section, I will discuss the appropriate design of the GSLD and CILC rates. Specifically, I will discuss:

- Demand and Non-Fuel Energy charges;
- Why the CILC tariff should be re-opened; and
- The justification for increasing both the CILC and the CDR credits.

Demand and Non-Fuel Energy Charges

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 HOW IS FPL PROPOSING TO CHANGE THE DEMAND AND NON-FUEL ENERGY CHARGES?

A FPL's proposed GSLD(T)-1, GSLD(T)-3 and CILC rate designs are shown in **Exhibit JP-12**. As can be seen, FPL's proposed rate design would substantially increase (by triple digits, in some cases) Energy charges and de-emphasize Demand charges. The only significant change that FPL is proposing for Demand charges is in Rates GSLDT-1 and GSLDT-2. All other demand charges would increase only minimally or decrease (*e.g.,* by 11% in GSLDT-3). There would be a corresponding (but much larger) increase in the Energy charges, especially during on-peak hours. Particularly noteworthy is FPL's proposal to recover the entirety of the CC Step increase through higher energy charges. The resulting post-CC Step energy charges would be 38% to over 200% higher than the current charges.

Q **IS FPL'S PROPOSAL FOR THE DEMAND AND NON-FUEL ENERGY CHARGES APPROPRIATE?**

A No. Coupled with the disproportionately large base rate increases that FPL proposes to allocate to the GSLD(T) and CILC classes, a rate design that substantially de-emphasizes Demand charges would result in high load factor customers receiving larger base rate increases than the corresponding class average. De-emphasizing Demand charges will send the wrong price signals and discourage load management. Allowing demand-related costs to be collected in Energy charges will create revenue (and income) instability. Neither outcome is consistent with cost-based ratemaking.

FPL's proposed CC Step rate design is especially inappropriate given that a substantial portion of the CC Step increase is comprised of demand-related costs.

In summary, FPL has underpriced the Demand charge and overpriced the Energy charges (based on FPL's proposed revenue levels, which I do not endorse but have used for illustrative purposes).

Q **HOW SHOULD THE GSLD/CILC RATES BE DESIGNED?**

A Consistent with cost causation, the Customer, Demand and Energy charges should closely reflect the customer-related, demand-related, and energy-related unit costs as derived in the CCOSS. Ironically, FPL followed this practice in designing the proposed Customer charges, but it ignored this practice in designing the proposed Demand and non-fuel Energy charges.

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

A The 2013 unit energy costs and the corresponding proposed charges for the GSLD-2 and GSLD-3 classes are as follows:

Non-Fuel Energy (¢/kWh)			
Rate	Unit Cost	Present Charge	Proposed Charge
GSLD-1	0.704¢	0.922¢	1.004¢
GSLD-3	0.682¢	0.640¢	1.064¢

As can be seen, FPL's proposed non-fuel Energy charges would be 143% and 156% higher than the corresponding non-fuel energy costs, respectively. The present GSLDT-1 Energy charge already exceeds unit cost. The fact that the proposed standard Energy charges would exceed unit cost means that the corresponding Demand charges are understated, and a significant amount of demand-related costs would be collected in the Energy charge. The proposed time-of-use (TOU) rates, which are derived from the standard rates, were also designed to collect a significant amount of demand-related costs in the proposed On-Peak Energy charges, as shown in the Table below.

Non-Fuel Energy (¢/kWh)					
		Present Rates		Proposed Rates	
Rate	Unit Cost	On-Peak Charge	Off-Peak Charge	On-Peak Charge	Off-Peak Charge
GSLDT-1	0.704¢	2.047¢	0.426¢	1.717¢	0.704¢
GSLDT-3	0.682¢	0.739¢	0.604¢	2.155¢	0.682¢
CILC-1D	0.700¢	0.646¢		2.719¢	0.700¢
CILC-1G	0.710¢	1.175¢		3.479¢	0.710¢
CILC-1T	0.680¢	0.599¢		2.155¢	0.682¢

Q HAS FPL ADEQUATELY EXPLAINED WHY THE NON-FUEL ENERGY CHARGES ARE MUCH HIGHER THAN ACTUAL ENERGY COSTS?

A No. FPL's workpapers indicated that the Energy charges were adjusted to achieve the desired class revenue targets. Further, in response to discovery (SFHHA Interrogatory No. 56), FPL asserts that higher energy charges will be offset by fuel savings. Such an assertion has nothing to do with cost-based ratemaking. In addition, fuel savings are speculative and subject to extreme changes. For example, if natural gas prices returned to the levels experienced prior to the economic recession, FPL's proposed rate design would be especially harmful to those high load factor customers that must compete in both domestic and global markets. Any proposal to link base rate design with speculative fuel cost savings should be rejected.

Q ARE FPL'S PROPOSED ON-PEAK ENERGY CHARGES APPROPRIATE?

A No. As previously stated, the proposed On-Peak Energy charges would recover significant demand-related costs. Rather than triple digit increases in Energy charges, which adversely affect high load factor customers, it would be far more reasonable to allocate most of the increase (over and above any required increase to raise the Energy charges at least up to unit cost) to the Demand charges.

Q PLEASE SUMMARIZE YOUR RECOMMENDED RATE DESIGN.

A The GSLDT-1, GSLDT-3 and CILC rates should be designed so that the charges more closely reflect unit cost. For this reason, I agree with FPL's proposed Customer charges. However, for the reasons stated previously, I disagree with

FPL's proposed Demand and non-fuel Energy charges. Based on my analysis, any increase allocated to the GSLD(T)-1 class should be entirely in the Demand charge. The GSLD(T)-3 and CILC Energy charges should be increased by the amount necessary to reflect the unit cost as indicated in the Table on page 38. Any remaining revenue deficiency should be recovered in the Demand Charge.

Reopening the CILC Rate

Q WHY IS CILC A CLOSED RATE SCHEDULE?

A The CILC rate is currently closed and has been since 1996. The stated reason for closing CILC was that the rate was fully subscribed and that additional CILC load would not be cost-effective at that time (see Order No. PSC-96-0468-FOF-EG in Docket No. 960130-EG).

Q SHOULD THE CILC RATE REMAIN CLOSED?

A No. Circumstances have changed dramatically since 1996, when the CILC rate was closed. Further, FPL has not imposed similar restrictions on Rider CDR.

Q PLEASE EXPLAIN.

A FPL continues to add non-firm load on Rider CDR. As discussed later, Rider CDR has a higher capacity payment than CILC at FPL's proposed 2013 rates, and it is cost-effective.

Further, equipment costs for new generation capacity were much lower in 1996. Now, the cost of new generation capacity has increased dramatically. The avoided unit currently being used to establish the capacity payments in Schedule QS-2 is estimated to cost $930/kW. By comparison, the installed cost of FPL's combustion turbines is only $123/kW. Rising equipment costs mean that additional CILC load is now very cost-effective.

Interruptible power has also received increasing attention from legislative and regulatory policy makers. For example, the Energy Policy Act of 2005 (EPACT 2005) specifically encourages the development of demand response programs, which are a form of non-firm service:

> ``(d) Demand Response.—The Secretary shall be responsible for—
> ``(1) educating consumers on the availability, advantages, and benefits of advanced metering and communications technologies, including the funding of demonstration or pilot projects;
> ``(2) working with States, utilities, other energy providers and advanced metering and communications experts to identify and address barriers to the adoption of demand response programs; and
> ``(3) <<NOTE: Deadline. Reports.>> not later than 180 days after the date of enactment of the Energy Policy Act of 2005, providing Congress with a report that identifies and quantifies the national benefits of demand response and makes a recommendation on achieving specific levels of such benefits by January 1, 2007.``
> (e) <<NOTE: 16 USC 2642 note.>> Demand Response and Regional Coordination. --
> (1) In general.—It is the policy of the United States to encourage States to coordinate, on a regional basis, State energy policies to provide reliable and affordable demand response services to the public.
> (2) Technical assistance.—The Secretary shall provide technical assistance to States and regional organizations formed by two or more States to assist them in—
> (A) identifying the areas with the greatest demand response potential;
> (B) identifying and resolving problems in transmission and distribution networks, including through the use of demand response;
> (C) developing plans and programs to use demand response to respond to peak demand or emergency needs; and
> (D) identifying specific measures consumers can take to participate in these demand response programs.

Following the enactment of EPACT 2005, the FERC issued Order No. 693 directing NERC to submit a modification to reliability standard BAL-002, which includes a requirement that explicitly allows demand-side management (DSM) to be used as a resource for contingency reserves provided that it is treated on a comparable basis and meets similar technical requirements as other resources providing this service. Various regional market organizations and independent system operators have been working to integrate demand response into their organized markets that allow non-firm loads to provide capacity when it is needed to maintain system reliability or is more economical than operating generation.

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 FPL 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 the lights will stay on for the firm customer base. Such interruption often causes production to be shut down resulting in losses for the interruptible customer.

Q HOW CAN THE COMMISSION NURTURE THIS VALUABLE RESOURCE?

A The Commission should re-open the CILC rate. Further, it should raise the payments to both CILC and CDR customers to more appropriately compensate them for the capacity they provide. The latter point is discussed below.

Q WHAT EVIDENCE SUPPORTS RE-OPENING THE CILC RATE?

A As previously stated, FPL continues to recruit new non-firm load under Rider CDR. However, Rider CDR customers are paid more for their non-firm capacity than CILC customers. This is demonstrated in **Exhibit JP-13**.

Q PLEASE EXPLAIN EXHIBIT JP-13.

A **Exhibit JP-13** shows the derivation of an "effective" per unit CILC credit. The per unit credit is measured on a per kW of Load Control Demand (column 4) and on a per coincident peak (CP) kW basis (column 5). The starting point for both calculations is the amount of incentive payments (column 1) derived in **Exhibit JP-3**.

A previously stated, CILC customers pay lower Demand charges for their non-firm or load control demand. The load control billing determinants are shown in column 2. The corresponding CP-kW demands are shown in column 3. As can be seen, based on the proposed 2013 rate differentials, the average CILC credit is $3.79 per kW of Load Control demand and $4.79 per CP-kW. However, the corresponding Rider CDR credits are $4.68 per kW and $4.90 per CP-kW.

Therefore, CILC customers are being paid less for capacity than similar non-firm customers on Rider CDR. Yet, as previously stated, Rider CDR remains open.

Q IS THE CDR PROGRAM COST-EFFECTIVE?

A Yes. FPL's Demand Side Management Plan (which was filed in Docket No. 100155-EG) revealed that Rider CDR was producing a 3.1 benefit-to-cost ratio. This is shown in **Exhibit JP-14**. In other words, Rider CDR is cost-effective based on the current $4.68 per kW month credit that FPL is paying CDR customers. Because CILC customers are being paid less, the CILC rate is also cost-effective, and it should be re-opened. Further, to eliminate discrimination, the CILC incentive payments should be increased to at least the same level as Rider CDR.

Q WHY IS IT REASONABLE TO ASSUME THE CILC RATE IS COST-EFFECTIVE JUST BECAUSE THE CDR IS COST-EFFECTIVE?

A Rider CDR is very similar to CILC. For example, under Rider CDR, load may be curtailed under any of the following circumstances:

- Control Condition:
- The Customer's controllable load served under this Rider is subject to control when such control alleviates any emergency conditions or capacity shortages, either power supply or transmission, or whenever system load, actual or projected, would otherwise require the peaking operation of the Company's generators. Peaking operation entails taking base loaded units, cycling units or combustion turbines above the continuous rated output, which may overstress the generators.

Thus, curtailments may occur during shortages of either generation or transmission capacity. These conditions are similar to the ones applicable to CILC customers, as stated previously. Further, FPL, not the customer, makes curtailments under both Rider CDR and CILC.

And, both Rider CDR and CILC customers are required to have load control equipment installed to provide FPL direct control over the customer's electrical load. This equipment is paid for by the customer through an additional Customer charge. CILC customers pay higher Customer charges than the corresponding firm rate customers.

Rider CDR Credit

Q SHOULD THE CDR CREDIT BE INCREASED?

A Yes. The Rider CDR credit has not changed since 2004. However, as previously discussed, costs for new generation capacity, upon which the CDR credit is based, have increased since 2004.

Q WHAT SPECIFIC EVIDENCE INDICATES THAT THE CDR RIDER CREDIT SHOULD BE INCREASED?

A **Exhibit JP-14** shows that the current $4.68 per kW credit produces a 3.1 benefit-to-cost ratio. If this ratio were set at 1.2, the credit would increase by 158% to $12.07 per kW. In other words, Rider CDR would remain cost-effective even if the credit were set at $12.07 per kW.

Q PLEASE SUMMARIZE YOUR RECOMMENDATION.

A The CDR program would remain cost-effective even if the credit is raised to $12.07 per kW. Because CDR and CILC are similar programs, a similar increase in the CILC incentive payments would not only be cost-effective, it would also be consistent with cost-based ratemaking.

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. I have also completed a Utility Finance and Accounting course.

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, Kansas, 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 provided in **Appendix B**.

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. J.Pollock is a registered Class I aggregator in the State of Texas.

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APPENDIX B

Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

PROJECT	UTILITY	ON BEHALF OF	DOCKET	TYPE	REGULATORY JURISDICTION	SUBJECT	DATE
120101	LONE STAR TRANSMISSION, LLC	Texas Industrial Energy Consumers	40020	Direct	TX	Revenue Requirement, Rider AVT	6/21/2012
111102	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	39896	Cross	TX	Class Cost-of-Service Study, Revenue Allocation, and Rate Design	4/13/2012
111102	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	39896	Direct	TX	Revenue Requirements, Class Cost-of-Service Study, Revenue Allocation, and Rate Design	3/27/2012
91023	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	39851	Supplemental Rebuttal	TX	Competitive Generation Service Issues	2/24/2012
91203	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	39851	Supplemental Direct	TX	Competitive Generation Service Issues	2/10/2012
101101	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	39722	Direct	TX	Carrying Charge Rate Applicable to the Additional True-Up Balance and	11/4/2011
110703	GULF POWER COMPANY	Florida Industrial Power Users Group	110138-EI	Direct	FL	Cost Allocation and Storm Reserve	10/14/2011
90404	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	39504	Direct	TX	Carrying Charge Rate Applicable to the Additional True-Up Balance and Taxes	9/12/2011
101101	AEP TEXAS NORTH COMPANY	Texas Industrial Energy Consumers	39361	Cross-Rebuttal	TX	Energy Efficiency Cost Recovery Factor	8/10/2011
101101	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	39360	Cross-Rebuttal	TX	Energy Efficiency Cost Recovery Factor	8/10/2011
100503	ONCOR ELECTRIC DELIVERY COMPANY, LLC	Texas Industrial Energy Consumers	39375	Direct	TX	Energy Efficiency Cost Recovery Factor	8/2/2011
90103	ALABAMA POWER COMPANY	Alabama Industrial Energy Consumers	31653	Direct	AL	Renewable Purchased Power Agreement	7/28/2011
101101	AEP TEXAS NORTH COMPANY	Texas Industrial Energy Consumers	39361	Direct	TX	Energy Efficiency Cost Recovery Factor	7/26/2011
101101	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	36360	Direct	TX	Energy Efficiency Cost Recovery Factor	7/20/2011
90201	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	39366	Direct	TX	Energy Efficiency Cost Recovery Factor	7/19/2011
90404	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	39363	Direct	TX	Energy Efficiency Cost Recovery Factor	7/15/2011
101201	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-10-971	Direct	MN	Surplus Depreciation Reserve, Incentive Compensation, Non-Asset Trading Margin Sharing, Cost Allocation, Class Revenue Allocation, Rate Design	4/5/2011
101202	ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-381-EA-10	Direct	WY	2010 Protocols	2/11/2011
100802	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	38480	Direct	TX	Cost Allocation, TCRF	11/8/2010
90402	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Traditional Manufacturers Group	31958	Direct	GA	Alternate Rate Plan, Return on Equity, Riders, Cost-of-Service Study, Revenue Allocation, Economic	10/22/2010
90404	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	38339	Cross-Rebuttal	TX	Cost Allocation, Class Revenue Allocation	9/24/2010
90404	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	38339	Direct	TX	Pension Expense, Surplus Depreciation Reserve, Cost Allocation, Rate Design, Riders	9/10/2010
100303	NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	10-E-0050	Rebuttal	NY	Multi-Year Rate Plan, Cost Allocation, Revenue Allocation, Reconciliation Mechanisms, Rate Design	8/6/2010

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100303	NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	10-E-0050	Direct	NY	Multi-Year Rate Plan, Cost Allocation, Revenue Allocation, Reconciliation Mechanisms, Rate Design	0714/2010
91203	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	37744	Cross Rebuttal	TX	Cost Allocation, Revenue Allocation, CGS Rate Design, Interruptible Service	6/30/2010
91203	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	37744	Direct	TX	Class Cost of Service Study, Revenue Allocation, Rate Design, Competitive Generation Services, Line Extension Policy	6/9/2010
90201	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	37482	Cross Rebuttal	TX	Allocation of Purchased Power Capacity Costs	2/3/2010
90402	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Traditional Manufacturers Group	28945	Direct	GA	Fuel Cost Recovery	1/29/2010
90201	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	37482	Direct	TX	Purchased Power Capacity Cost Factor	1/22/2010
90403	VIRGINIA ELECTRIC AND POWER COMPANY	MeadWestvaco Corporation	PUE-2009-00081	Direct	VA	Allocation of DSM Costs	1/13/2010
90201	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	37580	Direct	TX	Fuel refund	12/4/2009
90403	VIRGINIA ELECTRIC AND POWER COMPANY	MeadWestvaco Corporation	PUE-2009-00019	Direct	VA	Standby rate design; dynamic pricing	11/9/2009
80601	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	37135	Direct	TX	Transmission cost recovery factor	10/22/2009
80703	MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Energy Consumers	09-MKEE-969-RTS	Direct	KS	Revenue requirements, TIER, rate design	10/19/2009
90601	VARIOUS UTILITIES	Florida Industrial Power Users Group	090002-EG	Direct	FL	Interruptible Credits	10/2/2009
80505	ONCOR ELECTRIC DELIVERY COMPANY	Texas Industrial Energy Consumers	36958	Cross Rebuttal	TX	2010 Energy efficiency cost recovery factor	8/18/2009
81001	PROGRESS ENERGY FLORIDA	Florida Industrial Power Users Group	90079	Direct	FL	Cost-of-service study, revenue allocation, rate design, depreciation	8/10/2009
90404	CENTERPOINT	Texas Industrial Energy Consumers	36918	Cross Rebuttal	TX	Allocation of System Restoration Costs	7/17/2009
90301	FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	080677	Direct	FL	Depreciation; class revenue allocation; rate design; cost	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

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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	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	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	11/26/2008
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	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	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

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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
60303	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Traditional Manufacturers Group	26794	Direct	GA	Fuel Cost Recovery	4/15/2008
71202	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian 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 Permian 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
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

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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,	12/15/2006
60503	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	32766	Direct	TX	Fuel Reconcilation	12/15/2006
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
60601	TEXAS PUC STAFF	Texas Industrial Energy Consumers	32795	Direct	TX	Stranded Cost Reallocation	08/23/06
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 Ba	3/16/2006
41229	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	31994	Direct	TX	Stranded Costs and Other True-Up Ba	3/10/2006
50303	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian 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

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50705	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian 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 Capaci	10/4/2005
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	31315	Direct	TX	Recovery of Purchased Power Capaci	9/22/2005
50705	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian 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 Ba	9/2/2005
50705	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd. Occidental Power Marketing	EL05-19-00; ER05-168-00	Direct	FERC	Fuel Cost adjustment clause (FCAC)	8/19/2005
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
8201	PUBLIC SERVICE COMPANY OF COLORADO	Colorado Energy Consumers	04S-164E	Cross Answer	CO	Cost of Service Study, Interruptible Ra	12/13/2004
8201	PUBLIC SERVICE COMPANY OF COLORADO	Colorado Energy Consumers	04S-164E	Answer	CO	Cost of Service Study, Interruptible Ra	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	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

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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,	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
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 Fran	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 Fran	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

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PROJECT	UTILITY	ON BEHALF OF	DOCKET	TYPE	REGULATORY JURISDICTION	SUBJECT	DATE
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
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 Necess	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,PUE96029 6	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,PUE96029 6	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

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PROJECT	UTILITY	ON BEHALF OF	DOCKET	TYPE	REGULATORY JURISDICTION	SUBJECT	DATE
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
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

Testimony Filed in Regulatory Proceedings
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PROJECT	UTILITY	ON BEHALF OF	DOCKET	TYPE	REGULATORY JURISDICTION	SUBJECT	DATE
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
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 EPAC	1/1/1994

APPENDIX C

Procedures for Conducting a Class Cost-of-Service Study

Q **WHAT PROCEDURES ARE USED IN A CLASS 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 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.

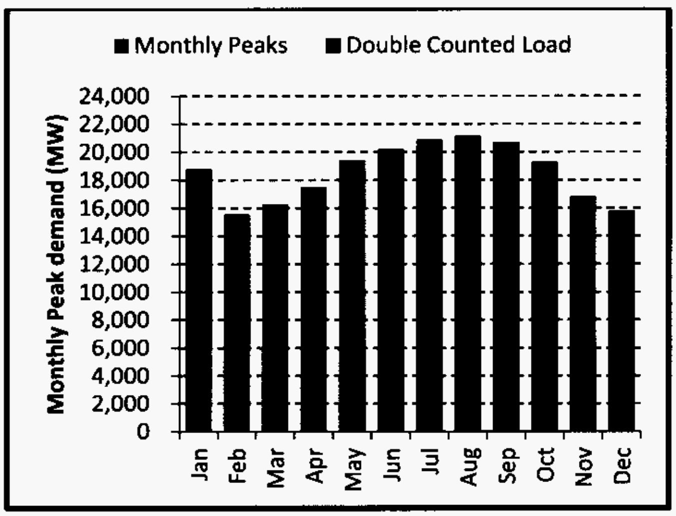
Further, each customer class should be comprised of customers having similar characteristics. The relevant characteristics include the type of end-use customer (*e.g.,* residential, lighting, standby), average size, load factor, coincidence factor and delivery voltage. Allocating costs to homogeneous customer classes will ensure that the rates derived from a CCOSS are just and reasonable and reflect the actual cost to serve.

APPENDIX D

The Double-Counting Problem

Q WHAT DO YOU MEAN BY DOUBLE-COUNTING?

A The peak and average method allocates production/transmission 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.



The double-counting problem is illustrated above using the 12CP-50% AD method. The portion of plant allocated on average demand is the black shaded area of the chart. Coincident demand is represented by the red shaded area. As can be seen, double-counting occurs because the portion of plant allocated on average demand overlaps 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 the 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:

- 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)

FLORIDA POWER & LIGHT COMPANY
Proposed 2013 Class Revenue Allocation
Test Year Ending December 31, 2013
(Dollar Amounts in $000)

Line	Rate Class	Base Revenue at Present Rates	2013 Increase	
			Amount	Percent
		(1)	(2)	(3)
1	Residential	$2,536,696	$272,825	10.8%
2	GS(T)-1	305,129	294	0.1%
3	GSCU-1	1,668	33	2.0%
4	GSD(T)	859,613	89,351	10.4%
5	GSLD(T)-1	306,794	63,753	20.8%
6	GSLD(T)-2	56,514	12,609	22.3%
7	GSLD(T)-3	4,060	565	13.9%
8	CILC-1D	56,580	12,549	22.2%
9	CILC-1G	4,455	308	6.9%
10	CILC-1T	16,138	5,493	34.0%
11	MET	2,892	541	18.7%
12	SL-1	70,717	7,762	11.0%
13	SL-2	1,254	-300	-23.9%
14	OL-1	11,487	1,216	10.6%
15	OS-2	854	122	14.2%
16	SST-DST	369	57	15.5%
17	SST-TST	4,270	724	17.0%
18	Total Electricity Sales	$4,239,490	$467,901	11.0%
19	Other Revenues	167,764	48,620	29.0%
20	Total FPSC Jurisdiction	$4,407,254	$516,521	11.7%

FLORIDA POWER & LIGHT COMPANY
Cape Canaveral Step Revenue Allocation
Test Year Ending December 31, 2013
(Dollar Amounts in Thousands)

Line	Rate Class	Base Revenue at Proposed 2013 Rates	Cape Canaveral Step Increase Factor (per kWh)	Increase Amount	Increase Percent
		(1)	(2)	(3)	(4)
1	Residential	$2,809,521	0.174¢	$92,615	3.3%
2	GS(T)-1	305,423	0.170¢	9,967	3.3%
3	GSCU-1	1,701	0.154¢	58	3.4%
4	GSD(T)	948,964	0.163¢	41,042	4.3%
5	GSLD(T)-1	370,547	0.161¢	18,253	4.9%
6	GSLD(T)-2	69,123	0.154¢	3,784	5.5%
7	GSLD(T)-3	4,624	0.151¢	301	6.5%
8	CILC-1D	69,129	0.153¢	4,384	6.3%
9	CILC-1G	4,763	0.156¢	278	5.8%
10	CILC-1T	21,632	0.147¢	1,979	9.1%
11	MET	3,433	0.163¢	151	4.4%
12	SL-1	78,478	0.127¢	674	0.9%
13	SL-2	954	0.158¢	52	5.4%
14	OL-1	12,703	0.127¢	127	1.0%
15	OS-2	975	0.151¢	19	2.0%
16	SST-DST	426	0.144¢	11	2.6%
17	SST-TST	4,994	0.161¢	157	3.1%
18	Total Electricity Sales	$4,707,391	0.168¢	$173,851	3.7%

FLORIDA POWER & LIGHT COMPANY
Cumulative Proposed and Step Increases
Test Year Ending December 31, 2013
(Dollar Amounts in Thousands)

Line	Rate Class	Base Revenue at Present Rates	Cumulative Increase	
			Amount	Percent
		(1)	(2)	(3)
1	Residential	$2,536,696	$365,440	14.4%
2	GS(T)-1	305,129	10,261	3.4%
3	GSCU-1	1,668	91	5.5%
4	GSD(T)	859,613	130,392	15.2%
5	GSLD(T)-1	306,794	82,006	26.7%
6	GSLD(T)-2	56,514	16,393	29.0%
7	GSLD(T)-3	4,060	866	21.3%
8	CILC-1D	56,580	16,933	29.9%
9	CILC-1G	4,455	586	13.2%
10	CILC-1T	16,138	7,472	46.3%
11	MET	2,892	692	23.9%
12	SL-1	70,717	8,436	11.9%
13	SL-2	1,254	-248	-19.8%
14	OL-1	11,487	1,343	11.7%
15	OS-2	854	141	16.5%
16	SST-DST	369	68	18.5%
17	SST-TST	4,270	881	20.6%
18	Total Electricity Sales	$4,239,490	$641,752	15.1%

FLORIDA POWER & LIGHT COMPANY
Summary of FP&L's Class Cost of Service Study Results
At Present and Proposed 2013 Rates
Test Year Ending December 31, 2013
(Dollar Amounts in Thousands)

		Present Rates		Proposed Rates		Movement
Line	Rate Class	Parity Index	Subsidy	Parity Index	Subsidy	Toward Cost*
		(1)	(2)	(3)	(4)	(5)
1	Residential	100	$5,102	101	$8,026	**-57%**
2	GS(T)	134	38,000	108	11,268	70%
3	GSCU-1	121	113	100	3	97%
4	GSD(T)	105	19,535	103	12,513	36%
5	GSLD(T)-1	71	-48,200	87	-27,727	42%
6	GSLD(T)-2	68	-9,863	87	-5,215	47%
7	GSLD(T)-3	96	-61	103	56	**191%**
8	CILC-1D	91	-3,051	101	595	**119%**
9	CILC-1G	114	328	101	35	89%
10	CILC-1T	79	-2,249	103	478	**121%**
11	MET	82	-267	94	-112	58%
12	SL-1	96	-1,411	95	-2,050	**-45%**
13	SL-2	206	404	115	74	82%
14	OL-1	96	-177	96	-227	**-29%**
15	OS-2	73	-132	77	-141	**-6%**
16	SST-DST	114	23	116	35	**-51%**
17	SST-TST	296	1,906	293	2,390	**-25%**
18	Total FPSC Jurisdiction	100	$0	100	$0	**-15%**

* The highlighted amounts indicate either insufficient or too much movement toward cost.

FLORIDA POWER & LIGHT COMPANY
Analysis of CILC Incentive Payments
Test Year Ending December 31, 2013
(Dollar Amounts in Thousands)

Line	Rate	Per FPL	At Present Rates	At Proposed Rates
		(1)	(2)	(4)
1	CILC-1T	$7,374	$10,264	$8,423
2	CILC-1D	$16,797	$13,681	$17,650
3	CILC-1G	$1,026	$462	$599
4	Total	$25,197	$24,407	$26,672

FLORIDA POWER & LIGHT COMPANY
Proposed Revenue Calculation for CILC Incentive Payments
Test Year Ending December 31, 2013

Line	Type of Charges	Proposed Revenue Calculation Units	Unit Charge	Revenue	CILC Priced at GSLD(T) Units	Unit Charge	Revenue
		(1)	(2)	(3)	(4)	(5)	(6)
	CILC-1T/GSLD(T)-3						
1	On Peak Energy	334,274,651	$ 0.02337	$ 7,811,999	334,274,651	$ 0.02155	$ 7,203,619
2	Off Peak Energy	1,007,203,091	$ 0.00680	$ 6,848,981	1,007,203,091	$ 0.00682	$ 6,869,125
3	Load Control On-Peak	1,880,654	$ 1.30	$ 2,444,850	1,880,654	$ 6.50	$ 12,224,251
4	Firm On-Peak	512,384	$ 8.00	$ 4,099,072	512,384	$ 6.50	$ 3,330,496
5	Total			$ 21,204,902			$ 29,627,491
6	GSLD/CILC Differential						$ 8,422,589
	CILC-1D/GSLD(T)-1						
8	On Peak Energy	754,148,919	$ 0.02719	$ 20,505,309	754,148,919	$ 0.01717	$ 12,948,737
9	Off Peak Energy	2,107,793,706	$ 0.00700	$ 14,754,556	2,107,793,706	$ 0.00704	$ 14,838,868
10	Max Demand	6,864,611	$ 3.10	$ 21,280,294			
11	Load Control On-Peak	4,807,458	$ 1.30	$ 6,249,695	4,807,458	$ 10.50	$ 50,478,309
12	Flrm On-Peak	805,340	$ 7.80	$ 6,281,652	805,340	$ 10.50	$ 8,456,070
13	Transformation Credit	1,922,442	$ (0.28)	$ (538,284)	1,922,442	$ (0.28)	$ (538,284)
14	Total			$ 68,533,223			$ 86,183,700
15	GSLD/CILC Differential						$ 17,650,477
	CILC-1G/GSD(T)-1						
16	On Peak Energy	47,350,221	$ 0.03479	$ 1,647,314	47,350,221	$ 0.03394	$ 1,607,067
17	Off Peak Energy	130,266,148	$ 0.00710	$ 924,890	130,266,148	$ 0.00710	$ 924,890
18	Max Demand	458,889	$ 3.40	$ 1,560,223			
19	Load Control On-Peak	344,050	$ 1.30	$ 447,265	344,050	$ 7.70	$ 2,649,185
20	Flrm On-Peak	7,514	$ 8.00	$ 60,112	7,514	$ 7.70	$ 57,858
21	Transformation Credit	4,305	$ (0.28)	$ (1,205)	4,305	$ (0.28)	$ (1,205)
22	Total			$ 4,638,598			$ 5,237,794
23	GSLD/CILC Differential						$ 599,196

FLORIDA POWER & LIGHT COMPANY
Examples Showing the Allocation of Non-Firm Credits

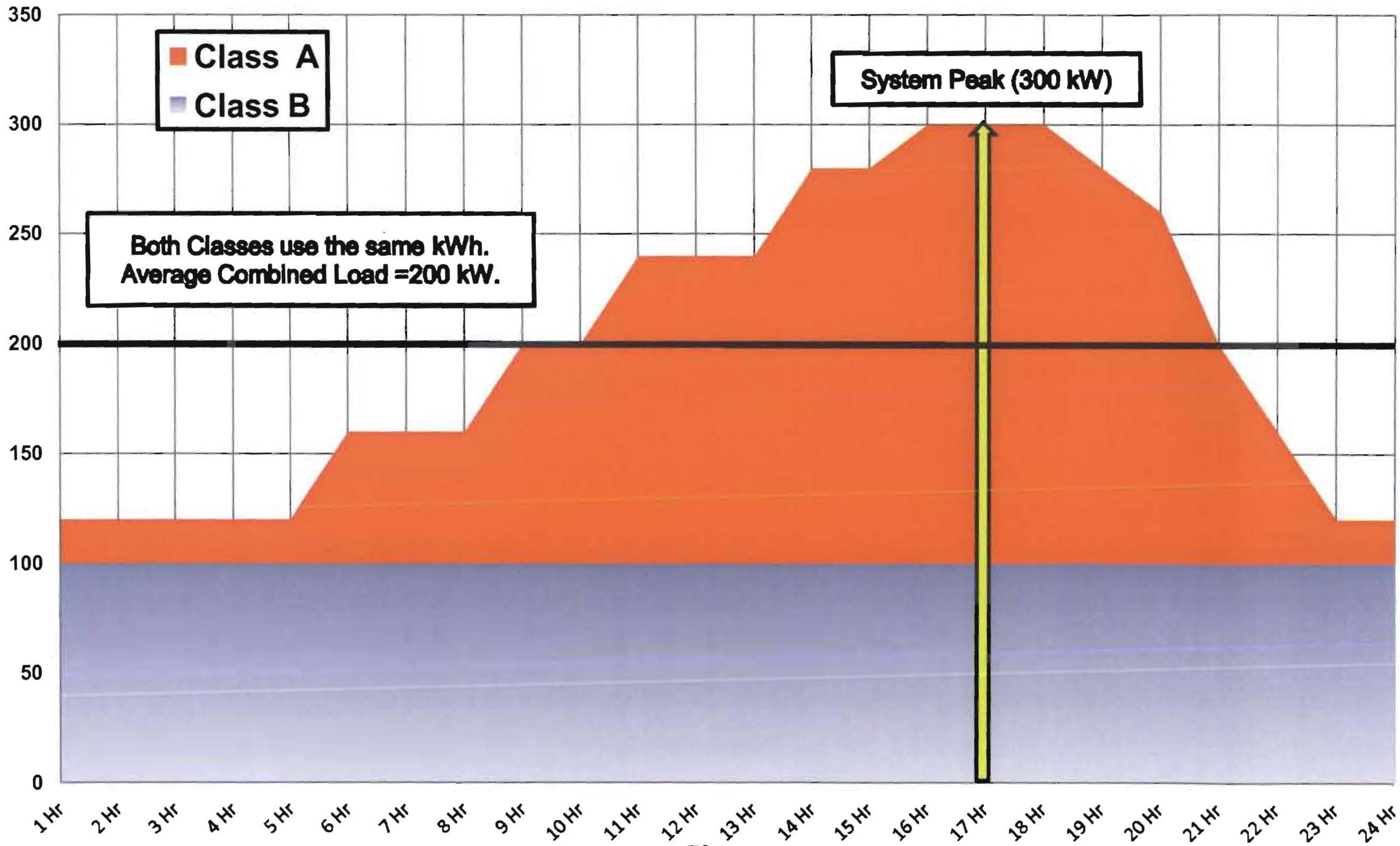
Line	Description	Total	Class A	Class B Firm	Class B Non-Firm
		(1)	(2)	(3)	(4)
	Assumptions				
1	Peak Demand	1,000	500	250	250
2	Percent of Total		50%	25%	25%
3	Firm Peak Demand	750	500	250	-
4	Percent of Total		67%	33%	0%
5	Production Capacity Revenues				$ 2,500
6	Non-Firm Credits				$ (1,000)
7	Net Revenue				$ 1,500
	***Method 1:* Allocate No Production Capacity Costs to Non-Firm Loads**				
8	Production Capacity Costs	$ 10,000	$ 6,667	$ 3,333	$ -
9	Less: Non-Firm Revenue	$ -	$ (1,000)	$ (500)	$ 1,500
10	Revenue Requirement	$ 10,000	$ 5,667	$ 2,833	$ 1,500
	***Method 2:* Treat Non-Firm Load as Firm and Allocate the Non-Firm Credits to Firm Load**				
11	Production Capacity Costs	$ 10,000	$ 5,000	$ 2,500	$ 2,500
12	Non-Firm Credits	$ -	$ 667	$ 333	$ (1,000)
13	Revenue Requirement	$ 10,000	$ 5,667	$ 2,833	$ 1,500

FLORIDA POWER & LIGHT COMPANY
Firm Production Demand Allocation Factor
(Test Year Ending December 31, 2013

Line	Class	Proportion of Non-Firm Load	12CP-1/13th Weighted Average Demand (MW) Total	Firm	Firm Production Allocator
		(1)	(2)	(3)	(4)
1	CILC-1D	85.7%	365.5	52.4	0.297%
2	CILC-1G	97.9%	23.5	0.5	0.003%
3	CILC-1T	78.6%	160.9	34.4	0.195%
4	GS(T)-1	0.0%	1,042.0	1,042.0	5.901%
5	GSCU-1	0.0%	4.6	4.6	0.026%
6	GSD(T)-1	1.0%	3,994.5	3,955.2	22.398%
7	GSLD(T)-1	6.1%	1,782.5	1,673.3	9.475%
8	GSLD(T)-2	7.1%	333.1	309.4	1.752%
9	GSLD(T)-3	0.0%	25.8	25.8	0.146%
10	MET	0.0%	16.1	16.1	0.091%
11	OL-1	0.0%	2.8	2.8	0.016%
12	OS-2	0.0%	1.7	1.7	0.010%
13	RS(T)-1	0.0%	10,508.5	10,508.5	59.508%
14	SL-1	0.0%	14.3	14.3	0.081%
15	SL-2	0.0%	4.0	4.0	0.023%
16	SST-DST	0.0%	0.8	0.8	0.004%
17	SST-TST	0.0%	13.2	13.2	0.075%
18	Total Retail		18,293.8	17,659.1	100.000%

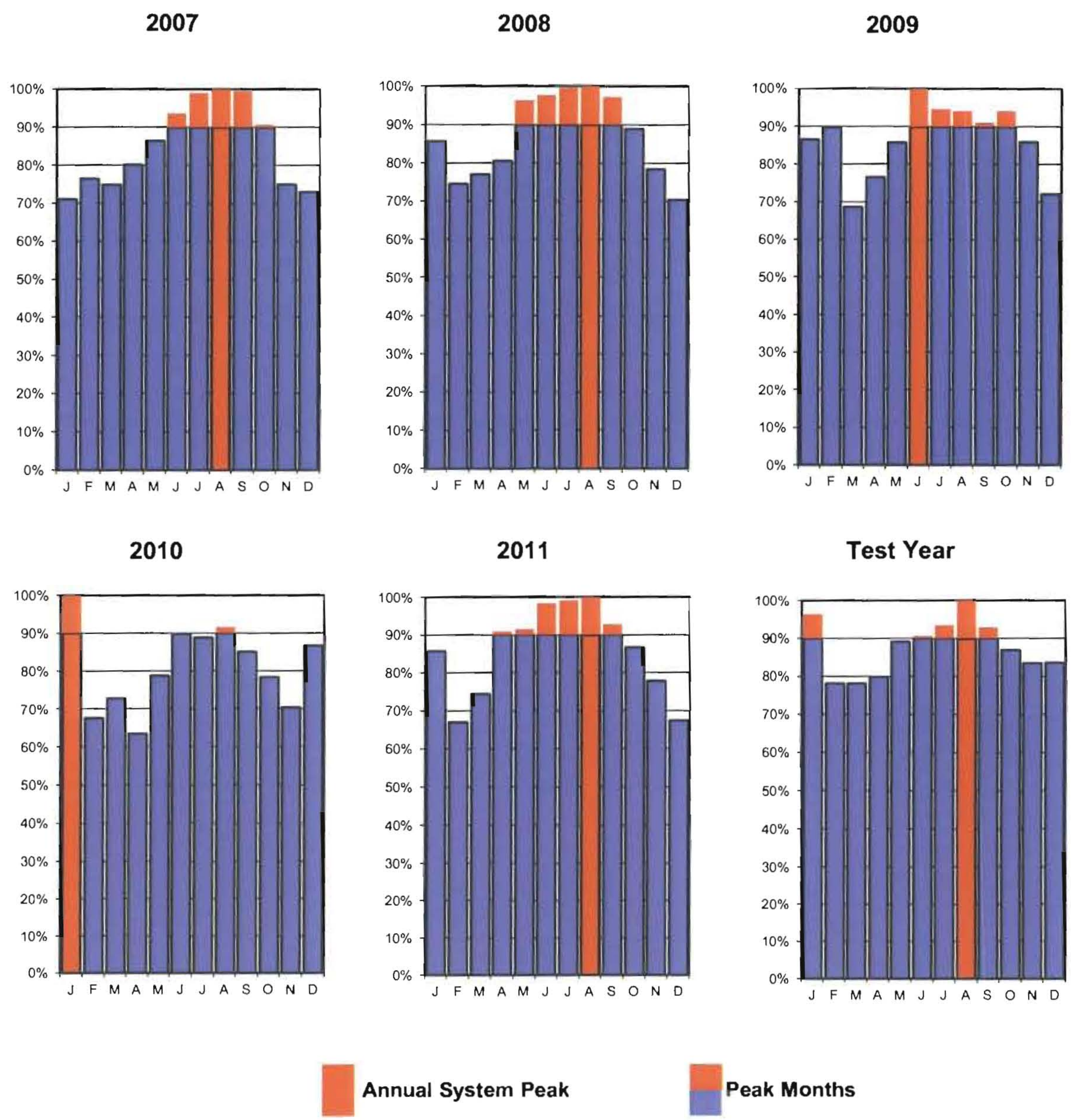
Docket No.120015-EI
Cost Causation
Exhibit JP-6

Why Electric Facilities are Sized to Meet Peak Demand



FLORIDA POWER AND LIGHT COMPANY

Analysis of Monthly Peak Demands
As a Percentage of the Annual System Peak
for the Years 2007-2011 and Test Year



FLORIDA POWER AND LIGHT COMPANY
Analysis of System Peak Load Characteristics
2007-2011 (Actual) and Test Year

Line	Year	Peak Demand	Minimum Demand	Average Demand	Average Summer Demand	Average Non-Summer Demand	Winter Peak Demand
		(1)	(2)	(3)	(4)	(5)	(6)
		Peak Demand (MW)					
1	2007	21,962	15,619	18,665	21,516	17,239	16,815
2	2008	21,060	14,849	18,373	20,758	17,180	18,055
3	2009	22,351	15,347	19,363	21,210	18,440	20,081
4	2010	24,346	15,480	19,763	21,632	18,829	24,346
5	2011	21,619	14,483	18,575	21,063	17,331	18,552
6	Test Year	21,931	17,137	19,233	20,650	18,524	21,101
		Ratio Analysis					
		Minimum to Annual Peak	Average to Annual Peak	Avg Summer % More Than Avg Non-Sum	Avg Summer Peak to Peak Demand	Avg Non-Sum Peak to Peak Demand	Annual Load Factor
7	2007	71%	85%	25%	98%	78%	61%
8	2008	71%	87%	21%	99%	82%	61%
9	2009	69%	87%	15%	95%	83%	58%
10	2010	64%	81%	15%	89%	77%	54%
11	2011	67%	86%	22%	97%	80%	60%
12	Test Year	78%	88%	11%	94%	84%	57%
13	Average	70%	86%	18%	95%	81%	58%

Source: Schedule E-18

FLORIDA POWER AND LIGHT COMPANY

Reserve Margins as a Percent of Firm Peak Demand

Line	Year	Average Summer Months	Average Non-Summer Months	Ratio of Summer to Non-Summer Margins
		(1)	(2)	(3)
1	2007	7%	27%	27%
2	2008	13%	32%	41%
3	2009	14%	27%	53%
4	2010	14%	27%	54%
5	2011	20%	32%	63%

ELECTRIC UTILITY COST ALLOCATION MANUAL

NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS

January, 1992

CHAPTER 4

EMBEDDED COST METHODS FOR ALLOCATING PRODUCTION COSTS

Of all utility costs, the cost of production plant -- i.e., hydroelectric, oil and gas-fired, nuclear, geothermal, solar, wind, and other electric production plant -- is the major component of most electric utility bills. Cost analysts must devise methods to equitably allocate these costs among all customer classes such that the share of cost responsibility borne by each class approximates the costs imposed on the utility by that class.

The first three sections of this chapter discusses functionalization, classification and the classification of production function costs that are demand-related and energy-related. Section four contains a variety of methods that can be used to allocate production plant costs. The final three sections include observations regarding fuel expense data, operation and maintenance expenses for production and a summary and conclusion.

I. THE FIRST STEP: FUNCTIONALIZATION

Functionalization is the process of assigning company revenue requirements to specified utility functions: Production, Transmission, Distribution, Customer and General. Distinguishing each of the functions in more detail -- subfunctionalization -- is an optional, but potentially valuable, step in cost of service analysis. For example, production revenue requirements may be subfunctionalized by generation type -- fossil, steam, nuclear, hydroelectric, combustion turbines, diesels, geothermal, cogeneration, and other. Distribution may be subfunctionalized to lines (underground and overhead) substations, transformers, etc. Such subfunctional categories may enable the analyst to classify and allocate costs more directly; they may be of particular value where the costs of specific units or types of units are assigned to time periods. But, since this is a manual of cost allocation, and this is a chapter on production costs, we won't linger over functionalization or consider costs in other functions. The interested reader will consult generalized texts on the subject. It will suffice to say here that all utility costs are allocated after they are functionalized.

II. CLASSIFICATION IN GENERAL

Classification is a refinement of functionalized revenue requirements. Cost classification identifies the utility operation -- demand, energy, customer -- for which functionalized dollars are spent. Revenue requirements in the production and transmission functions are classified as demand-related or energy-related. Distribution revenue requirements are classified as either demand-, energy- or customer-related.

Cost classification is often integrated with functionalization; some analysts do not distinguish it as an independent step in the assignment of revenue requirements. Functionalization is to some extent reflected in the way the company keeps its books; plant accounts follow functional lines as do operation and maintenance (O&M) accounts. But to classify costs accurately the analyst more often refers to conventional rules and his own best judgment. Section IV of this chapter discusses three major methods for classifying and allocating production plant costs. We will see that the peak demand allocation methods rely on conventional classification while the energy weighting methods and the time-differentiated methods of allocation require much attention to classification and, indeed, are sophisticated classification methods with fairly simple allocation methods tacked on.

The chart below is a basic example of an integrated functionalization/classification scheme.

FUNCTIONALIZED CLASSIFICATION OF ELECTRIC UTILITY COSTS

	Cost Classes			
Functions	Demand	Energy	Customer	Revenue
Production Thermal	X	X	N/A	N/A
Hydro	X	X	N/A	N/A
Other	X	X	N/A	N/A
Transmission	X	X	X	N/A
Distribution OH/UG Lines	X X	X X	X X	N/A N/A
Substations	X	X	X	N/A
Services	N/A	N/A	X	N/A
Meters	N/A	N/A	X	N/A
Customer	N/A	N/A	X	X

III. CLASSIFICATION OF PRODUCTION FUNCTION COSTS

Production plant costs can be classified in two ways between costs that are demand-related and those that are energy-related.

A. Cost Accounting Approach

Production plant costs are either fixed or variable. Fixed production costs are those revenue requirements associated with generating plant owned by the utility, including cost of capital, depreciation, taxes and fixed O&M. Variable costs are fuel costs, purchased power costs and some O&M expenses. Fixed production costs vary with capacity additions, not with energy produced from given plant capacity, and are classified as demand-related. Variable production costs change with the amount of energy produced, delivered or purchased and are classified as energy- related. Exhibit 4-1 summarizes typical classification of FERC Accounts 500-557.

EXHIBIT 4-1

CLASSIFICATION OF PRODUCTION PLANT

CLASSIFICATION OF RATE BASE[1]

Production Plant

FERC Uniform System of Accounts No.	Description	Demand Related	Customer Related
301-303	Intangible Plant	x	-
310-316	Steam Production	x	x
320-325	Nuclear Production	x	-
330-336	Hydraulic Production	x	x[2]
340-346	Other Production	x	-

Exhibit 4-1
(Continued)
CLASSIFICATION OF PRODUCTION PLANT

FERC Uniform System of Accounts No.	Description	Demand Related	Energy Related

CLASSIFICATION OF EXPENSES[1]
Production Plant

Steam Power Generation Operations

500	Operating Supervision & Engineering	Prorated On Labor[3]	Prorated On Labor[3]
501	Fuel	-	x
502	Steam Expenses	x[4]	x[4]
503-504	Steam From Other Sources & Transfer. Cr.	-	x
505	Electric Expenses	x[4]	x[4]
506	Miscellaneous Steam Pwr Expenses	x	-
507	Rents	x	-

Maintenance

510	Supervision & Engineering	Prorated On Labor[3]	Prorated On Labor[3]
511	Structures	x	-
512	Boiler Plant	-	x
513	Electric Plant	-	x
514	Miscellaneous Steam Plant	-	x

Nuclear Power Generation Operation

517	Operation Supervision & Engineering	Prorated On Labor[3]	Prorated On Labor[3]
518	Fuel	-	x
519	Coolants and Water	[illegible]	[illegible] 4
520	Steam Expense	x[4]	x[4]
521-522	Steam From Other Sources & Transfe. Cr.	-	x
523	Electric Expenses	x[4]	x4 4
524	Miscellaneous Nuclear Power Expenses	[illegible]	-
525	Rents	x	-

EXHIBIT 4-1

(Continued)

CLASSIFICATION OF EXPENSES [1]

FERC Uniform System of Accounts No.	Description	Demand Related	Energy Related
	Maintenance		
528	Supervision & Engineering	Prorated on Labor[3]	Prorated on Labor[3]
529	Structures	x	-
530	Reactor Plant Equipment	-	x
531	Electric Plant	-	x
532	Miscellaneous Nuclear Plant	-	x
	Hydraulic Power Generation Operation		
535	Operation Supervision and Engineering	Prorated on Labor[3]	Prorated on Labor[3]
536	Water for Power	x	-
537	Hydraulic Expenses	x	-
538	Electric Expense	x[4]	x[4]
539	Misc Hydraulic Power Expenses	x	-
540	Rents	x	-
	Maintenance		
541	Supervision & Engineering	Prorated On Labor[3]	Prorated On Labor[3]
542	Structures	x	-
543	Reservoirs, Dams, and Waterways	x	x
544	Electric Plant	x	x
545	Miscellaneous Hydraulic Plant	x	x

Exhibit 4-1
(Continued)

FERC Uniform System of Account	Description	Demand Related	Energy Related
	CLASSIFICATION OF EXPENSES[1]		
	Other Power Generation Operation		
546, 548-554	All Accounts	x	-
547	Fuel	-	x
	Other Power Supply Expenses		
555	Purchased Power	x[5]	x[5]
556	System Control & Load Dispatch	x	-
557	Other Expenses	x	-

[1] Direct assignment or "exclusive use" costs are assigned directly to the customer class or group that exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

[2] In some instances, a portion of hydro rate base may be classified as energy related.

[3] The classification between demand-related and energy-related costs is carried out on the basis of the relative proportions of labor cost contained in the other accounts in the account grouping.

[4] Classified between demand and energy on the basis of labor expenses and material expenses. Labor expenses are considered demand-related, while material expenses are considered energy-related.

[5] As-billed basis.

The cost accounting approach to classification is based on the argument that plant capacity is fixed to meet demand and that the costs of plant capacity should be assigned to customers on the basis of their demands. Since plant output in KWH varies with system energy requirements, the argument continues, variable production costs should be allocated to customers on a KWH basis.

B. Cost Causation

Cost causation is a phrase referring to an attempt to determine what, or who, is causing costs to be incurred by the utility. For the generation function, cost causation attempts to determine what influences a utility's production plant investment decisions. Cost causation considers: (1) that utilities add capacity to meet critical system planning reliability criteria such as loss of load probability (LOLP), loss of load hours (LOLH),

Docket No. 120015-EI
Production OM Classification
Exhibit JP-10

FLORIDA POWER & LIGHT COMPANY

Classification of Production O&M Expense

Test Year Ending December 31, 2013

		FPL Method: Total Retail					NARUC Cost Allocation Manual				
					Percent to:					Percent to:	
Line	COSS ID / Description	Total	Demand	Energy	Demand	Energy	Method	Demand	Energy	Demand	Energy
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	STEAM O&M - OPERATION SUPERV & ENG	$7,653,262	$4,651,166	$3,002,096	61%	39%	Steam Oper	$4,652,588	$3,000,673	61%	39%
2	STEAM O&M - FUEL - NON RECV EXP	9,802,801	0	9,802,801	0%	100%	Energy	0	9,802,801	0%	100%
3	STEAM O&M - STEAM EXPENSES	5,856,574	1,828,925	4,027,649	31%	69%	Labor	1,828,925	4,027,649	31%	69%
4	STEAM O&M - ELECT EXPENSES	2,222,931	925,318	1,297,613	42%	58%	Labor	925,318	1,297,613	42%	58%
5	STEAM O&M - MISC STEAM EXP	20,698,622	20,698,622	0	100%	0%	Demand	20,698,622	0	100%	0%
6	STEAM O&M - RENTS	3,420	3,420	0	100%	0%	Demand	3,420	0	100%	0%
7	STEAM O&M - MAINT SUPERV & ENG	8,580,974	1,332,435	7,248,539	16%	84%	Steam Maint	1,333,790	7,247,184	16%	84%
8	STEAM O&M - MAINT OF STRUCTURES	6,024,503	6,024,503	0	100%	0%	Demand	6,024,503	0	100%	0%
9	STEAM O&M - MAINT OF BOILER PLANT	19,609,182	0	19,609,182	0%	100%	Energy	0	19,609,182	0%	100%
10	STEAM O&M - MAINT OF ELECT PLANT	10,395,609	0	10,395,609	0%	100%	Energy	0	10,395,609	0%	100%
11	STEAM O&M - MAINT OF MISC STEAM PLT	2,729,500	0	2,729,500	0%	100%	Energy	0	2,729,500	0%	100%
12	NUCLEAR O&M - OPERAT SUPERV & ENG	102,750,373	70,881,462	31,868,911	69%	31%	Nuke Op	86,216,597	16,533,776	84%	16%
13	NUCLEAR O&M - NUCL FUEL EXP	11,527,551	0	11,527,551	0%	100%	Energy	0	11,527,551	0%	100%
14	NUCLEAR O&M - COOLANTS AND WATER	8,822,561	4,958,411	3,864,150	56%	44%	Labor	4,958,411	3,864,150	56%	44%
15	NUCLEAR O&M - STEAM EXPENSES	63,322,328	54,818,096	8,504,232	87%	13%	Labor	54,818,096	8,504,232	87%	13%
16	NUCLEAR O&M - ELECT EXPENSES	65,135	0	65,135	0%	100%	Labor		65,135	0%	100%
17	NUCLEAR O&M - MISC NUCLEAR PWR EXP	65,170,263	65,170,263	0	100%	0%	Demand	65,170,263	0	100%	0%
18	NUCLEAR O&M - MAINT SUPERV & ENG	108,774,164	12,150,347	96,623,817	11%	89%	Nuke Maint	12,163,341	96,610,823	11%	89%
19	NUCLEAR O&M - MAINT OF STRUCTURES	5,605,070	5,605,070	0	100%	0%	Demand	5,605,070	0	100%	0%
20	NUCLEAR O&M - MAINT OF REACTOR PLANT	29,705,383	0	29,705,383	0%	100%	Energy	0	29,705,383	0%	100%
21	NUCLEAR O&M - MAINT OF ELECT PLANT	11,762,700	0	11,762,700	0%	100%	Energy	0	11,762,700	0%	100%
22	NUCLEAR O&M - MAINT OF MISC NUCL PLT	3,051,790	0	3,051,790	0%	100%	Energy	0	3,051,790	0%	100%
23	OTH PWR O&M - OPERAT SUPERV & ENG	14,824,683	14,824,683	0	100%	0%	Demand	14,824,683	0	100%	0%
24	OTH PWR O&M - FUEL N-RECOV EMISSIONS	2,136,068	0	2,136,068	0%	100%	Energy	0	2,136,068	0%	100%
25	OTH PWR O&M - GENERATION EXPENSES	12,432,002	12,432,002	0	100%	0%	Demand	12,432,002	0	100%	0%
26	OTH PWR O&M - MISC OTH PWR GENERAT	29,447,241	29,447,241	0	100%	0%	Demand	29,447,241	0	100%	0%
27	OTH PWR O&M - MAINT SUPERV & ENG	8,871,630	0	8,871,630	0%	100%	Other Maint	8,871,630	0	100%	0%
28	OTH PWR O&M - MAINT OF STRUCTURES	11,088,148	11,088,148	0	100%	0%	Demand	11,088,148	0	100%	0%
29	OTH PWR O&M - MAINT GENR & ELECT PLT	69,528,221	0	69,528,221	0%	100%	Demand	69,528,221	0	100%	0%
30	OTH PWR O&M - MAINT MISC OTH PWR GEN	4,744,866	0	4,744,866	0%	100%	Demand	4,744,866	0	100%	0%
31	OTH PWR O&M - SYS CNTR & L DISPATCH	3,277,888	3,277,888	0	100%	0%	Demand	3,277,888	0	100%	0%
32	OTH PWR O&M - OTHER EXPENSES	2,907,543	2,907,543	0	100%	0%	Demand	2,907,543	0	100%	0%
33	Total Production O&M Expense	$663,392,984	$323,025,542	$340,367,442	49%	51%		$421,521,165	$241,871,819	64%	36%
34	Subtotal Other O&M Expense	$135,561,975	$59,152,821	$76,409,154	44%	56%		$133,425,908	$2,136,068	98%	2%

FLORIDA POWER & LIGHT COMPANY
FIPUG's Revised Class Cost-of-Service Study
Test Year Ending December 31, 2013
(Dollar Amounts in 000)

Line	Description	Total Retail	CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2	GSLD(T)-3	MET
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
	RATE BASE -											
1	Electric Plant In Service	$30,424,227	$534,901	$36,113	$161,356	$1,769,345	$8,357	$6,071,436	$2,652,189	$481,888	$25,833	$23,252
2	Accum Depreciation & Amortization	-11,901,711	-209,084	-14,092	-65,857	-691,988	-3,267	-2,376,373	-1,037,895	-188,678	-10,545	-9,038
3	Net Plant In Service	18,522,516	325,817	22,022	95,499	1,077,356	5,090	3,695,063	1,614,294	293,210	15,289	14,213
4	Plant Held For Future Use	230,192	4,479	291	1,580	13,541	64	49,041	21,804	4,046	253	197
5	Construction Work in Progress	501,676	9,329	612	3,465	29,575	145	103,559	45,674	8,445	554	403
6	Net Nuclear Fuel	565,229	15,541	974	7,084	32,052	208	137,514	61,965	13,313	1,053	495
7	Total Utility Plant	19,819,614	355,167	23,899	107,628	1,152,524	5,507	3,985,176	1,743,737	319,014	17,149	15,308
8	Working Capital - Assets	3,593,422	68,523	4,481	26,183	233,396	1,545	716,159	309,902	60,422	4,038	2,708
9	Working Capital - Liabilities	-2,376,213	-43,570	-2,860	-16,260	-155,567	-1,022	-464,324	-200,169	-38,594	-2,523	-1,787
10	Working Capital - Net	1,217,209	24,952	1,621	9,923	77,829	522	251,835	109,733	21,828	1,515	921
11	**Total Rate Base**	21,036,823	380,119	25,520	117,551	1,230,353	6,030	4,237,011	1,853,470	340,842	18,665	16,230
	REVENUES -											
12	Sales of Electricity	4,268,091	73,998	5,040	24,452	304,655	1,665	860,848	311,835	57,388	4,043	2,884
13	Other Operating Revenues	140,637	1,455	95	257	8,780	25	19,691	7,392	1,318	42	63
14	**Total Operating Revenues**	4,408,728	75,453	5,136	24,709	313,435	1,690	880,539	319,228	58,705	4,085	2,948
	EXPENSES -											
15	Operating & Maintenance Expense	-1,565,789	-26,558	-1,759	-9,412	-105,783	-715	-292,500	-124,692	-23,646	-1,472	-1,147
16	Depreciation Expense	-803,912	-13,297	-910	-4,399	-47,342	-243	-153,234	-65,598	-11,963	-703	-583
17	Taxes Other Than Income Tax	-371,710	-6,472	-437	-1,947	-22,185	-112	-73,462	-31,919	-5,822	-312	-281
18	Amortization of Property Losses	1,151	23	2	6	49	0	258	117	21	1	1
19	Gain or Loss on Sale of Plant	2,641	52	3		154	1	562	254	45		2
20	**Total Operating Expenses**	-2,737,619	-46,253	-3,102	-15,751	-175,106	-1,069	-518,376	-221,838	-41,365	-2,485	-2,008
21	**Net Operating Income Before Taxes**	1,671,109	29,200	2,034	8,958	138,329	621	362,163	97,390	17,341	1,600	940
22	Income Taxes	-513,908	-8,896	-628	-2,746	-47,432	-208	-114,643	-24,033	-4,183	-511	-248
23	**NOI Before Curtailment Adjustment**	1,157,201	20,304	1,406	6,212	90,897	413	247,520	73,357	13,158	1,089	692
24	Curtailment Credit Revenue	335							245	90		
25	Reassign Curtailment Credit Revenue	-335	-1	0	-1	-20	0	-75	-32	-6	0	0
26	**Net Curtailment Credit Revenue**		-1	0	-1	-20	0	-75	213	84	0	0
27	**Net Operating Income (NOI)**	$1,157,201	$20,303	$1,406	$6,211	$90,877	$413	$247,445	$73,570	$13,243	$1,088	$692
28	**Rate of Return (ROR)**	5.50%	5.34%	5.51%	5.28%	7.39%	6.85%	5.84%	3.97%	3.89%	5.83%	4.26%
29	**Parity Ratio**	1.00	0.97	1.00	0.96	1.34	1.24	1.06	0.72	0.71	1.06	0.77
30	**Subsidy**		-$990	$4	-$416	$37,856	$132	$23,456	-$46,322	-$8,986	$100	-$328

FLORIDA POWER & LIGHT COMPANY
FIPUG's Revised Class Cost-of-Service Study
Test Year Ending December 31, 2013
(Dollar Amounts in 000)

Description	OL-1	OS-2	RS(T)-1	SL-1	SL-2	SST-DST	SST-TST
	(12)	(13)	(14)	(15)	(16)	(17)	(18)
RATE BASE -							
Electric Plant In Service	$85,267	$7,918	$18,038,147	$506,302	$5,889	$2,667	$13,368
Accum Depreciation & Amortization	-33,817	-2,970	-7,072,970	-176,421	-2,309	-967	-5,443
Net Plant In Service	51,450	4,948	10,965,177	329,882	3,580	1,700	7,925
Plant Held For Future Use	128	43	133,801	727	49	19	130
Construction Work in Progress	790	87	293,911	4,705	104	33	284
Net Nuclear Fuel	545	67	290,767	2,915	179	41	515
Total Utility Plant	52,913	5,146	11,683,656	338,228	3,912	1,792	8,854
Working Capital - Assets	6,398	660	2,117,535	38,360	821	255	2,037
Working Capital - Liabilities	-4,418	-440	-1,416,247	-26,462	-524	-168	-1,278
Working Capital - Net	1,980	219	701,288	11,898	296	87	760
Total Rate Base	54,893	5,365	12,384,945	350,127	4,209	1,880	9,614
REVENUES -							
Sales of Electricity	11,479	853	2,532,394	70,674	1,252	369	4,262
Other Operating Revenues	204	38	100,272	877	83	11	33
Total Operating Revenues	11,683	890	2,632,666	71,550	1,334	380	4,296
EXPENSES -							
Operating & Maintenance Expense	-3,236	-302	-954,098	-19,281	-327	-111	-750
Depreciation Expense	-3,196	-208	-482,485	-19,176	-150	-58	-367
Taxes Other Than Income Tax	-985	-96	-221,115	-6,296	-73	-33	-163
Amortization of Property Losses	4	0	642	27	0	0	0
Gain or Loss on Sale of Plant	3	1	1,544	18	0	1	
Total Operating Expenses	-7,410	-604	-1,655,513	-44,709	-549	-201	-1,280
Net Operating Income Before Taxes	4,273	287	977,153	26,841	785	179	3,016
Income Taxes	-1,279	-70	-299,476	-8,000	-296	-58	-1,202
NOI Before Curtailment Adjustment	2,995	217	677,678	18,841	489	121	1,814
Curtailment Credit Revenue							
Reassign Curtailment Credit Revenue	0	0	-200	0	0	0	0
Net Curtailment Credit Revenue	0	0	-200	0	0	0	0
Net Operating Income (NOI)	$2,994	$217	$677,478	$18,841	$489	$121	$1,814
Rate of Return (ROR)	5.46%	4.04%	5.47%	5.38%	11.62%	6.43%	18.86%
Parity Ratio	0.99	0.73	0.99	0.98	2.11	1.17	3.43
Subsidy	-$41	-$128	-$6,197	-$684	$420	$28	$2,096

Docket No. 120015-EI
Proposed Rate Design
Exhibit JP-12

FLORIDA POWER & LIGHT COMPANY
Comparison of Present and Proposed Tariff Charges
GSLD(T)-1, GSLD(T)-3 and CILC Classes

Line	Rate Schedule	Type of Charge	Current Rate*	2013 Increase	CC Step Increase	Percent Increase 2013	Percent Increase CC Step
			(1)	(2)	(3)	(4)	(5)
	GSLDT-1	**General Service Large Demand (≤2000 kW)**					
1		Customer Charge	$50.13	$25.00	$25.00	-50%	0%
2		Demand Charge ($/kW)	$8.25	$10.50	$10.50	27%	0%
3		On-Peak Energy Charge (¢ per kWh)	2.047	1.717	1.878	-16%	9%
4		Off-Peak Energy Charge (¢ per kWh)	0.426	0.704	0.865	65%	23%
	GSLDT-3	**General Service Large Demand (2000 kW+)**					
5		Customer Charge	$1,441.88	$1,500.00	$1,500.00	4%	0%
6		Demand Charge - On-Peak ($/kW)	$7.29	$6.50	$6.50	-11%	0%
7		On-Peak Energy Charge (¢ per kWh)	0.739	2.155	2.306	192%	7%
8		Off-Peak Energy Charge (¢ per kWh)	0.604	0.682	0.833	13%	22%
	CILC-1	**Commercial/Industrial Load Control Program**					
		Customer Charge					
9		(G) 200-499kW	$122.00	$100.00	$100.00	-18%	0%
10		(D) above 500kW	$175.00	$150.00	$150.00	-14%	0%
11		(T) transmission	$1,866.00	$1,975.00	$1,975.00	6%	0%
		Base Demand Charge ($/kW)					
		per kW of Max Demand (All kW)					
12		(G) 200-499kW	$3.20	$3.40	$3.40	6%	0%
13		(D) above 500kW	$3.17	$3.10	$3.10	-2%	0%
14		(T) transmission	None	None	None	N/A	
		per kW of Load Control On-Peak					
15		(G) 200-499kW	$2.01	$1.30	$1.30	-35%	0%
16		(D) above 500kW	$2.04	$1.30	$1.30	-36%	0%
17		(T) transmission	$2.04	$1.30	$1.30	-36%	0%
		per kW of Firm On-Peak Demand (All kW)					
18		(G) 200-499kW	$7.61	$8.00	$8.00	5%	0%
19		(D) above 500kW	$7.81	$7.80	$7.80	0%	0%
20		(T) transmission	$7.54	$8.00	$8.00	6%	0%
		Base Energy Charge (¢ per kWh)					
		On-Peak					
21		(G) 200-499kW	1.175	3.479	3.635	196%	4%
22		(D) above 500kW	0.646	2.719	2.872	321%	6%
23		(T) transmission	0.599	2.337	2.484	290%	6%
		Off-Peak					
24		(G) 200-499kW	1.175	0.710	0.866	-40%	22%
25		(D) above 500kW	0.646	0.700	0.853	8%	22%
26		(T) transmission	0.599	0.680	0.827	14%	22%

FLORIDA POWER & LIGHT COMPANY
Comparison of CILC and Rider CDR Credits
Test Year Ending December 31, 2013

Line	Rate	CILC Incentive Payments ($000)	Avg. Load Control (MW)	Firm 12CP (MW)	Effective Credit: Per kW of Load Control	Effective Credit: Per CP kW
		(1)	(2)	(3)	(4)	(5)
1	CILC-1T	$8,423	156.7	126.7	$4.48	$5.54
2	CILC-1D	$17,650	400.6	314.6	$3.67	$4.68
3	CILC-1G	$599	28.7	23.1	$1.74	$2.16
4	**Total CILC**	$ 26,671	586.0	464.4	**$3.79**	**$4.79**
5	**Rider CDR**				**$4.68**	**$4.90**

FLORIDA POWER & LIGHT COMPANY
Cost Effective Rider CDR Credit
($ in 000's)

Line	Item	Amount
		(1)
1	Total Benefits NPV	$156,076
2	Total Cost NPV	$50,425
3	Current Benefit to Cost Ratio	3.10
4	Cost Effective Benefit to Cost Ratio	1.20
5	Total Cost NPV @ RIM = 1.20	$130,063
6	Cost Effective Increase Factor	2.5793
7	Current CDR Credit ($/KW)	$4.68
8	Cost Effective CDR Credit ($/KW)	$12.07

Source: Appendix A, Docket 100155; MFR A-3

RATE IMPACT TEST

PROGRAM METHOD SELECTED: REV_REQ

PROGRAM NAME: Commercial/Industrial Demand Reduction

PSC FORM CE 2.5

PAGE 1 OF 1

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
YEAR	INCREASED SUPPLY COSTS $(000)	UTILITY PROGRAM COSTS $(000)	INCENTIVES $(000)	REVENUE LOSSES $(000)	OTHER COSTS $(000)	TOTAL COSTS $(000)	AVOIDED GEN UNIT & FUEL BENEFITS $(000)	AVOIDED T&D BENEFITS $(000)	REVENUE GAINS $(000)	OTHER BENEFITS $(000)	TOTAL BENEFITS $(000)	NET BENEFITS $(000)	CUMULATIVE DISCOUNTED NET BENEFITS $(000)
2009	0	0	0	0	0	0	0	0	0	0	0	0	0
2010	0	19	366	4	0	389	10	0	0	0	10	(379)	(348)
2011	0	38	1,098	13	0	1,150	18	0	0	0	19	(1,131)	(1,302)
2012	0	59	1,830	23	0	1,912	41	0	0	1	41	(1,871)	(2,751)
2013	0	81	2,562	34	0	2,677	40	0	0	4	44	(2,634)	(4,625)
2014	0	103	3,292	47	0	3,443	55	0	0	5	60	(3,383)	(6,835)
2015	0	127	4,020	60	0	4,207	85	0	0	7	93	(4,114)	(9,303)
2016	0	152	4,747	74	0	4,974	105	0	0	9	115	(4,859)	(11,981)
2017	0	178	5,475	89	0	5,742	132	0	0	12	144	(5,598)	(14,813)
2018	0	205	6,203	105	0	6,513	152	0	0	15	166	(6,346)	(17,763)
2019	0	210	6,567	117	0	6,894	43,112	0	0	(1,816)	41,296	34,402	(3,080)
2020	0	215	6,567	119	0	6,901	40,074	0	0	(2,660)	37,414	30,513	8,881
2021	0	221	6,567	123	0	6,910	38,484	0	0	(2,944)	35,540	28,630	19,188
2022	0	226	6,567	128	0	6,921	38,273	0	0	(3,404)	34,869	27,948	28,428
2023	0	232	6,567	133	0	6,931	38,921	0	0	(3,748)	35,173	28,242	37,003
2024	0	238	6,567	140	0	6,944	39,367	0	0	(4,270)	35,097	28,153	44,853
2025	0	244	6,567	147	0	6,958	39,293	0	0	(4,866)	34,427	27,469	51,888
2026	0	250	6,567	155	0	6,971	39,561	0	0	(5,254)	34,308	27,337	58,317
2027	0	256	6,567	165	0	6,987	39,884	0	0	(5,905)	33,979	26,992	64,147
2028	0	262	6,567	173	0	7,001	39,705	0	0	(6,426)	33,279	26,277	69,359
2029	0	269	6,567	182	0	7,017	40,730	0	0	(7,221)	33,509	26,492	74,186
2030	0	276	6,567	192	0	7,035	40,729	0	0	(7,984)	32,745	25,711	78,487
2031	0	283	6,567	203	0	7,052	40,433	0	0	(8,649)	31,784	24,732	82,287
2032	0	290	6,567	216	0	7,073	41,691	0	0	(9,432)	32,258	25,186	85,841
2033	0	297	6,567	238	0	7,102	41,600	0	0	(10,963)	30,637	23,535	88,891
2034	0	304	6,567	243	0	7,114	43,527	0	0	(12,089)	31,438	24,324	91,786
2035	0	312	6,567	255	0	7,134	44,191	0	0	(13,158)	31,033	23,899	94,399
2036	0	320	6,567	276	0	7,162	43,794	0	0	(14,351)	29,444	22,282	96,635
2037	0	328	6,567	292	0	7,186	44,733	0	0	(15,531)	29,202	22,016	98,665
2038	0	336	6,567	306	0	7,209	43,483	0	0	(16,825)	26,658	19,449	100,312
2039	0	344	6,567	322	0	7,233	42,744	0	0	(18,284)	24,459	17,226	101,651
2040	0	353	6,567	339	0	7,259	44,590	0	0	(19,752)	24,838	17,579	102,906
2041	0	362	6,567	359	0	7,288	44,171	0	0	(21,269)	22,902	15,614	103,930
2042	0	371	6,567	381	0	7,318	43,417	0	0	(21,263)	22,154	14,836	104,824
2043	0	380	6,567	404	0	7,350	43,567	0	0	(21,257)	22,310	14,960	105,651
NOM.	0	8,141	193,758	6,058	0	207,956	1,040,714	0	0	(259,271)	781,443	573,487	
NPV	0	1,758	47,588	1,079	0	50,425	188,000	0	0	(31,924)	156,076	105,651	

Discount Rate 8.89 %

Benefit/Cost Ratio (Col(12) / Col(7)) : 3.10

Source: Revised Appendix A from Docket 100155

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Increase in Rates by Florida Power & Light Company	DOCKET NO. 120015-EI Filed: July 2, 2012

AFFIDAVIT OF JEFFRY POLLOCK

State of Missouri)
) SS
County of St. Louis)

Jeffry Pollock, being first duly sworn, on his oath states:

1. My name is Jeffry Pollock. I am President of J. Pollock, Incorporated, 12655 Olive Blvd., Suite 335, St. Louis, Missouri 63141. We have been retained by Florida Industrial Power Users Group to testify in this proceeding on its behalf;

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony, Exhibits and Appendices A through D which have been prepared in written form for introduction into evidence in Florida Public Service Commission Docket No. 120015-EI; and,

3. I hereby swear and affirm that the answers contained in my testimony and the information in my exhibits are true and correct.

Jeffry Pollock

Subscribed and sworn to before me this 29th day of June, 2012.

KITTY TURNER
Notary Public - Notary Seal
State of Missouri
Commissioned for Lincoln County
My Commission Expires: April 25, 2015
Commission Number: 11390610

Kitty Turner, Notary Public
Commission #: 11390610

My Commission expires on April 25, 2015.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Increase in Rates by Florida Power & Light Company.	DOCKET NO. 120015-EI FILED: July 2, 2012

CERTIFICATE OF SERVICE

I **HEREBY CERTIFY** that a true and correct copy of the Florida Industrial Power Users Group's Testimony and Exhibits of Jeffry Pollock has been furnished by U.S. Mail this 2nd day of July, 2012, to the following:

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