BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

Docket No. 050078-EI

Submitted for filing: August 5, 2005

**REBUTTAL TESTIMONY OF**
**WILLIAM C. SLUSSER, JR.**

**On behalf of PROGRESS ENERGY FLORIDA**

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**REBUTTAL TESTIMONY OF**

**<u>WILLIAM C. SLUSSER, JR.</u>**

Q. **Please state your name.**

A. My name is William C. Slusser, Jr.

Q. **Did you submit direct testimony in this case on April 29, 2005?**

A. Yes, I submitted direct testimony that addressed the general area of cost of service and rate design.

Q. **What is the purpose of your rebuttal testimony?**

A. My rebuttal testimony primarily focuses on rebutting assertions and positions contained in the testimony of White Springs witness Maurice Brubaker regarding a refinement recommended in my testimony to the traditional cost allocation methodology used by the Commission for allocating fixed production costs to customer classes, and the proposal presented in my testimony to complete the closure of PEF's non-cost-effective Interruptible and Curtailable Rate Schedules IS-1, IST-1, CS-1 and CST-1. I also address the testimony of the Commercial Group witnesses Michael T. O'Sheasy, Mike Culver and Charlie Martin regarding real-time pricing. Finally, I present a revised jurisdictional separation study based on the updated sales forecast presented in the rebuttal testimony of Company witness John B. Crisp.

Q. **Have you prepared any exhibits for use in conjunction with your rebuttal testimony?**

A. Yes, I have prepared or supervised the preparation of the following exhibits:

- Exhibit No. ___ (WCS-7), Development of Fuel Savings Resulting from Existing Generation Fleet as Compared to Peaking Only Resources.
- Exhibit No. ___ (WCS-8), Cost of Production Plant When Allocated Using 12 CP and 25% Energy.
- Exhibit No. ___ (WCS-9), 1983-84 Load Factor/Coincidence Factor Curve.
- Exhibit No. ____ (WCS-10), Revised Jurisdictional Separation Study.

These exhibits are true and accurate.

**<u>Allocation Of Production Capacity Costs</u>**

**Q. What is Mr. Brubaker's position regarding your recommended cost of service study that allocates 75 percent of fixed production costs based on the customer classes' 12 monthly coincident peak demands and 25 percent of these costs based on the classes' average hourly demand, *i.e.*, annual energy usage?**

A. In his testimony, Mr. Brubaker takes the position that the capital costs of production facilities are fixed costs which are traditionally treated as demand-related and should be allocated to customer classes on some form of demand or coincident demand basis, rather than on an energy basis which is traditionally used to allocate cost that vary with production output, such as fuel costs. He contends that the allocation methodology recommended in my testimony addresses only the capital side of the trade-off between capital and fuel in the selection of generation type and ignores the fuel side. This is because he contends a study of the type of generation that would be built to serve each customer class individually, which neither he or I have ever conducted, would show that more base load generation would be installed to serve high load factor classes. He says that this would result in these classes having more fixed costs relative to low load factor classes, but that they would also have lower fuel costs. Mr. Brubaker concludes that the methodology recommended in my testimony lacks the proper symmetry because although it allocates higher fixed costs to high load factor classes consistent with his single-class generating system, my methodology fails to address the allocation of lower fuel costs that he believes these classes should receive in return for their higher fixed costs.

**Q. How do you respond to Mr. Brubaker's criticisms of your allocation methodology?**

A. His criticisms would be valid if the current allocation of fixed production costs (often called production capacity costs) and fuel costs between the high load factor and low load factor customer classes was relatively balanced and even-handed. As Mr. Brubaker correctly recognizes, the methodology I recommend does, in fact, result in the allocation of more overall costs to high load factor classes and less costs to low load factor classes compared to the status quo. However, the current situation is far from balanced with respect to the equitable allocation of production costs between these two groups of customer classes.

Even with the moderate cost shift to the high load factor classes under the allocation methodology I recommend, those classes will still not bear their full cost responsibility for PEF's most efficient, and most capital intensive generating facilities, and they will continue to enjoy a greater than average share of the fuel cost savings produced by these generating facilities by virtue of their high energy usage. In this regard, there is a certain irony in Mr. Brubaker's criticism that my methodology ignores the fuel side of capital/fuel trade-off, since the most compelling reason for proposing this methodology is the failure of the current allocation methodology to require adequate cost responsibility on the high load factor classes for the substantial fuel savings they receive.

**Q. Aside from his criticism of the methodology proposed by PEF for allocating production capacity costs, Mr. Brubaker claims that the application of this methodology would result in over-charging the high load factor customer classes. Do you agree?**

A. No, I do not. Mr. Brubaker's argument is simply another way of expressing his initial argument that if high load factor customer classes have to pay for a greater share of capital intensive generation, then they should receive the benefit of the lower fuel costs associated with this generation. This argument has already been adequately refuted and stating it differently does not make it more meritorious. In any event, no matter how Mr. Brubaker may phrase or rephrase his position, it will not change the fact that the high load factor customer classes will not be over-charged by the application of the Company's production capacity cost allocation methodology. I say this for a number of reasons.

First, the high load factor classes are being under-charged by the current method of allocating capacity costs. As I explained earlier, these classes receive a much greater share of the fuel savings produced by high cost generation than the share of the generation costs that have been allocated to them. The high load factor classes may not receive treatment quite as favorably under the proposed allocation methodology as they currently enjoy, but they certainly will not be over-charged.

Second, even though the high load factor classes have benefited greatly by receiving the system average cost of fuel, Mr. Brubaker complains that these classes should receive the fuel costs of more efficient, capital intensive units. For all intents and purposes, they do. The only generation type with a sufficiently high fuel cost to significantly increase the system average cost of fuel is the Company's peaking units. However, this potential has little chance of being realized because peaking generation provides only 2.6% of the Company's system energy requirements, as can be seen on Mr. Brubaker's Exhibit No. ___ (MEB-6). This small contribution of peaking generation increases the average fuel costs of PEF's other generating units by only about 5%, from $31.38 per megawatt-hour (MWH) to $33.03 per MWH. Furthermore, even during the few hundred hours a year that peaking generation operates, the most it can contribute to the Company's total generation is 27%. During these hours, when all customer classes are likely to be contributing to the peak demand and sharing in the higher cost of fuel, the high load factor classes bear only a portion of this cost responsibility. During the remaining 8,000 or more hours of the year, only non-peaking generation is in operation. This means that the high load factor classes are, in fact, receiving the lower fuel costs from PEF's more efficient, capital intensive generating units over 95% of the year.

Third, most large high load factor customers, including the customer Mr. Brubaker represents, receive interruptible service under PEF's optional Time-Of-Use (TOU) rate. Customers under this rate receive a discount on their fuel charges that averages about $1.00 per MWH below the system average fuel cost charged to all other customers. And, of course, the more consumption these TOU customers shift to off-peak periods, the more savings the discount produces for them. This is another reason why most high load factor customers will continue to fare well under rates set using the Company's proposed cost allocation methodology.

Lastly, the methodology proposed by the Company in this case allocates only 25% of its production capacity costs on an energy basis. However, PEF's actual production investment is about 50% greater than it would be if capacity had been built only to meet peak load. This means that an allocation of 50% of PEF's total production investment on an energy basis would be justified. Thus, if anything, the proposed 25% energy allocation methodology is under-assessing the high load factor classes their full cost responsibility for the fuel savings they receive from this additional investment.

**Q. Have you prepared an exhibit that demonstrates the benefits being derived by each rate class as a result of PEF constructing more capital intensive units to achieve fuel savings?**

A. Yes. I have prepared Exhibit No. ___ (WCS-7) that shows an energy allocation, by customer class, of all additional production capacity costs incurred to achieve greater fuel savings, *i.e.*, 50% of total production capacity costs. These energy allocated capacity costs are compared to the fuel savings produced by this additional production capacity, which represent the difference between the fuel costs associated with the Company's existing generating fleet and the fuel costs associated with a generating fleet designed to serve peak demand only. Not only does this exhibit demonstrate the huge benefit derived by PEF for making investments in more capital intensive facilities, it also demonstrates the equity of allocating a portion of the capital cost premium paid for these facilities on an energy basis.

**Q. Mr. Brubaker also claims that the Company's cost allocation methodology is wrong because it allocates the additional capital costs of capacity installed for fuel savings to all energy usage, rather than energy usage up to an economic**

**"break-even point" between the operation of a peaking unit and the unit installed for fuel savings. Do you agree?**

A. I disagree with Mr. Brubaker's conclusion that the Company's cost allocation methodology is wrong. However, I have no difficulty agreeing that the methodology, while based on the outcome of the generating unit selection process, does not utilize the analytical details of the process itself.

To explain what I mean by this, let me begin by saying I agree that from a system planning standpoint, the selection of a high capital cost/low fuel costs generating unit (a base or intermediate-load unit) instead of a low capital cost/high fuel cost unit (a peaking unit) is justified by the base-intermediate unit's hours of operation up to the economic break-even point between the two types of units. One of the reasons PEF's methodology does not employ the specifics of this analytical process is that it represents a marginal cost perspective, *i.e.*, the notion that marginal cost of usage greater than the break-even point requires no additional investment. The problem with this perspective is that, for the most part, utility ratemaking practiced by this Commission is based on average costing principles in order to avoid the inequities and practical difficulties that can result from the use of marginal costing when setting rates.

The kind of equitable and practical difficulties a marginal pricing principle can produce in the ratemaking process is illustrated by Mr. Brubaker's "break-even point" criticism. He uses this form of marginal cost analysis to support his contention that the Company's methodology allocates too much production capacity cost to high load factor customers on the basis of energy. In actuality, however, the opposite is true. As I have explained, the methodology proposed by PEF allocates 25% of its production costs on an energy basis. Yet, the Company's actual production investment made to reduce the cost of energy, *i.e.*, fuel, would justify allocating 50% of its total production investment on an energy basis. Moreover, allocating even this higher level of production costs based on energy usage would still not be excessive, since it would amount to only a fraction of the fuel cost savings achieved by the additional investment, as can be seen in my Exhibit No. __ (WCS-7).

Another reason that the break-even analysis is not used in the Company's methodology is that, while the analysis may be well suited to the initial selection of a generating unit in the planning stage, it does not reflect the unit's actual costs and benefits after it has been placed in service. In actuality, the fuel cost savings produced by a kWh generated after the marginal cost break even point is just as real and valuable as the fuel savings from kWh generated before the break even point is reached. A cost allocation methodology that recognizes the latter but ignores the former is not a proper methodology. I believe that from an equitable and a practical point of view, all customers that benefit from a unit's economic selection decision should also share in the cost to achieve the benefits.

PEF has opted for a moderate, middle ground approach in the allocation of production capacity costs and therefore has not attempted to fully implement the capital substitution concept. Instead, the Company has proposed a cost allocation method that gives a greater recognition to the important role capital substitution plays in the selection of the Company's production capacity. This is intended to result in a better and more equitable allocation of the significant costs that flow from this selection process, while retaining the structure of the current allocation methodology that has been employed by the Commission for many years.

**Q. In his Exhibit No. ___ (MEB-5), Mr. Brubaker attempts to show that using PEF's methodology for allocating production plant investment will result in**

**an above average cost per kW of demand for the high load factor rate classes? Would you comment on this exhibit?**

A. It appears to me that the calculations shown in Mr. Brubaker's exhibit are more for effect than for any insight into the significance of the Company's methodology. To illustrate how variations in presentation can change the appearance of cost allocation results, my Exhibit No. __ (WCS-8) shows a calculation similar to Mr. Brubaker's using the same allocations of production capacity costs to the customer classes, but with the results expressed on an energy basis in terms of cost per MWh. The first six numbered lines of the exhibit contain the same information that Mr. Brubaker presents in his Exhibit No. ___ (MEB-5). The information on lines 7, 8, and 9 shows that the Company's allocation method results in a favorable, below average production capacity cost per MWh for the high load factor rate classes.

<u>**Coincident Peaks To Use In Cost Allocation**</u>

**Q. Mr. Brubaker recommends that class coincident peak demand for either the winter peak or the average of the summer and winter peaks be used in lieu of the average of the twelve monthly peaks to establish cost responsibility for production capacity costs. Do you consider this method to be appropriate for PEF?**

A. No. First, Mr. Brubaker attempts to show in his Exhibit No. ___ (MEB-7) and (MEB-8) that PEF experiences a strong winter peak. However, he fails to consider supply-side conditions, which would have shown that the Company's greater winter peak load is totally mitigated by additional resources for the winter period from (a) higher generator capability ratings, (b) ownership of a shared peaking resource, and (c) greater load management capability.

As for his portrayal of lower peak loads during non-winter or non-summer shoulder months, he fails to consider the corresponding reduction in available generation resources because of planned maintenance outages for the Company's larger units. The fact that available generation tends to track seasonal fluctuations in load provides strong support for the recognition of peak demand in all months. For this reason, PEF considers contributions to the average of the 12 monthly peaks to be an appropriate basis for the demand component in the allocation of production capacity costs.

**Interruptible Credits**

**Q. Mr. Brubaker suggests that an interruptible credit be established based on the revenue requirement associated with a combustion turbine? What is your response to this suggestion?**

A. To begin with, I believe Mr. Brubaker has made his suggestion in the wrong forum. PEF's interruptible and curtailable service are Demand-Side Management (DSM) programs. As such, these programs are subject to Commission review and approval every five years in the Conservation Goals proceeding and annually in the Energy Conservation Cost Recovery (ECCR) docket.

As it relates to Mr. Brubaker's suggestion, the cost of PEF's payments for interruptible billing credits are approved by the Commission in the ECCR docket in accordance with cost-effectiveness criteria based on a comparison with the Company's avoided unit or units. It is my understanding that any proposed change to an approved DSM program requires Commission approval in order for the program's cost to be eligible for recovery through a utility's ECCR clause. For this reason, I believe the proper forum for a change in PEF's interruptible billing credit, particularly a major change of the kind proposed by Mr. Brubaker, is the

Commission's ECCR proceeding. In fact, the Commission's action to close the Company's IS-1 and IST-1 rate schedules to new customers was taken in the ECCR proceeding and was based on a finding that the interruptible billing credits in those rate schedules were no longer cost-effective. These are the same interruptible rate schedules that PEF has asked the Commission to close permanently.

In the event the Commission considers Mr. Brubaker's proposal to be within the scope of this proceeding, I will briefly address the merits of his proposed method for establishing the interruptible billing credit. In my opinion, the credit for this DSM program should be established using the same cost-effectiveness criteria and analysis as used for all other DSM programs. From my review of the DSM calculations last used to support the interruptible credit, I have concluded that Mr. Brubaker's suggested method would not be cost-effective. However, a thorough evaluation has not been performed by anyone to my knowledge, and any decision on the merits would therefore be premature at this point.

<u>**Method of Applying the Interruptible Credit**</u>

**Q. Mr. Brubaker claims the Company's method of applying the interruptible credit in its IS-2 and IST-2 rate schedules using a load factor adjustment understates the value of interruptible power and further adds to the increases he claims interruptible customers would experience. Do you agree?**

**A.** No, I do not. Under either rate design, the same total amount of credits is distributed to customers in the rate class. The Company simply believes that the load factor adjusted credits included in the IS-2 and IST-2 rate schedules are more equitable to the customers within the rate class than the unadjusted credits included in the IS-1 and IST-1 rate schedules.

Furthermore, I am not sure that Mr. Brubaker fully understands the Company's rate design when he states in his testimony that a customer with a 75% billing load factor would experience a reduction of 25% in the level of the credit. This is an incorrect statement, since the customer with a 75% load factor in his example will actually receive a greater credit under the Company's rate design employed under IS-2 and IST-2 than under a rate design where the credit is based on a customer's maximum demand, such as in the Company's older IS-1 and IST-1 rate schedules. I will walk through the calculations for the rate design of these two credits in an attempt to demonstrate this point.

Under the Company's rate design, the rate credit for 1 kW coincident with the system peak is $3.08. A customer with a 75% billing load factor would receive a credit for each kW of billing demand equal to 75% of the $3.08, or $2.31.

Under a rate design in which the credit is applied to the customer's billing demand without any adjustment and is designed to provide the class the same total revenue credits as in the Company's rate design described above, the rate credit for 1 kW on a billing demand basis must be equal to $1.85 per kw of billing demand. In rate design work, this is derived by multiplying the value on a coincident demand basis by the ratio of the class's coincident demand to its billing demand. (For the IS class, the ratio of the class's coincident demand to its billing demand is approximately 0.6.) Thus, under this rate design, the customer would receive $1.85 in credit, less than the amount in the Company's rate design.

**Q. Why do you believe the credit rate design employed in the IS-2 and IST-2 rate schedules is more equitable to the customers within the interruptible rate class than the method of applying a credit to the customer's billing demand without any adjustment?**

A. I have prepared my Exhibit No. ____(WCS-9) in order to demonstrate this point graphically. I prepared the exhibit by plotting current information on a graph I recently located from a Commission workshop presentation in 1985 on general service rate design.

The graph shows the typical relationship between a general service customer's monthly demand at the time of system peak and the customer's monthly load factor. This relationship is often referred to as the "Bary" curve – named after Constantine W. Bary, a noted rate engineer, who first established the relationship in the 1930's. The "Bary" curve indicates a curvilinear increase in coincidence factor as monthly load factor increases. PEF performed considerable load research on its general service customers in the mid 1980's and confirmed this relationship. The graph applies the interruptible credit amount of $3.08 per coincident kW to the "Bary" curve data points to derive the appropriate credit due a customer as a function of load factor. The graph then plots the two rate designs over the appropriate "Bary" curve credit relationship. It is obvious that the rate design which provides a credit in proportion to load factor is a superior rate design to the one that provides the same credit to all load factor customers. This rate design provides a more equitable distribution of credits over the load factor range of customers in the class.

## DEVELOPMENT OF INTERRUPTIBLE CREDITS FOR STANDBY RATES

**Q. Mr. Brubaker claims the Company's calculation of the credit for interruptible standby rate service is wrong. Do you agree?**

A. No. I find that the rate credit is a straight forward calculation and is the product of: (a) 10%, which is the expected amount of standby load imposed by a customer having an assumed 10% unavailability of his generation and (b) $3.08 per kw, the value assigned for interruptible load on a monthly CP basis. As I explained in my direct testimony, the standby rate credit in the present SS-2 rate schedule was established to relate to the interruptible credit value being afforded the IS-1 and IST-1 rate schedules. This value was $6.42 per coincident kW, which when multiplied by 10% results in the credit shown in the present SS-2 tariff. With the proposed complete closure of the IS-1 and IST-1 rate schedules, the standby rate credit in the proposed SS-2 rate schedule has been established to be consistent with the interruptible credit value in the IS-2 and IST-2 rate schedules. This value is $3.08 per coincident kW, which when multiplied by 10%, results in the credit shown for the proposed SS-2 tariff.

Some of the confusion with Mr. Brubaker's analysis may be related to the type of kW that the credit applies. Note that above, I cited the derivation of the present SS-2 tariff as being based on the value of $6.42 per coincident peak kW, whereas, the credit provided in the IS-1 and IST-1 rates is $3.70 per billing kW. The $3.70 figure was derived by multiplying the $6.42 by the ratio of the class's coincident kW to its billing kW. For the proposed IS-2, and IST-2 tariffs, the value of an interruptible kW that is completely coincident with the system peak is $3.08. This value is then adjusted for the customer's coincident demand, an estimate of which is determined by the product of billing demand and load factor. This last step is the load factor adjustment and is used to convert billing demand to coincident demand.

<u>REAL TIME PRICING (RTP) RATES</u>

**Q. The Commercial Group's joint witnesses, Mike Culver and Charlie Martin, are asking PEF to consider witness Mike O'Sheasy's RTP rate design for application to commercial customers like J.C. Penny and Lowe's for whom**

**they are respectively employed? What is PEF's response to the application of this rate design?**

A. PEF has been aware of RTP pricing, and in fact, previously developed a rate offering of a form of RTP pricing for application to large general service firm customers. After two years, during which not a single customer had chosen to take service under this offering, the rate was withdrawn for lack of customer interest. Admittedly, Mr. O'Sheasy's rate design is a different form of RTP pricing than previously offered by the Company, but like the Company's previous design, it requires the customer to have the flexibility and capability of altering its load on an hourly basis to be of any value.

The joint witnesses have indicated that their respective companies have made substantial in-house energy management efforts and have built energy efficiencies into their facilities. PEF's general service demand time of use rate offering does provide an incentive for these type of companies to engage in energy management and conservation efforts. These efforts generally result in reduced or fixed shifting of loads, and the ability to further change load on an hour-to-hour basis under RTP pricing incentives is questionable.

Nevertheless, the Company remains open to discuss and work with its customers and their rate consultants such as Mr. O'Sheasy on RTP pricing or any other innovative rate design where it can be demonstrated that there are cost savings with which to justify such an offering.

**EEI Typical Bill Cost Comparisons**

**Q. In the joint Direct Testimony of Mike Culver and Charlie Martin, the witnesses express a belief that something was wrong with the Company's cost of service analysis for commercial users, since they found that PEF's**

**commercial rates were comparable to its residential rates, yet PEF's commercial classes are substantially below parity with respect to the classes' rate of return. Do you share their concern?**

A. Yes, when I read their testimony and reviewed their exhibit, I also found it surprising that PEF's commercial rates were shown to be only comparable and not lower than its residential rates in the witnesses' Exhibit No. ____(CM-1), which is based on data from the Edison Electric Institute's "Typical Bills and Average Rates Report", Summer 2004 and Winter 2005. Upon investigation, I found that PEF had reported erroneous data to EEI regarding the Company's Winter 2005 commercial rates, and as I initially expected, the corrected commercial rates are about 2.0 cents per kwh less than the rate for residential service. The erroneous data also appears in Mr. Brubaker's Exhibit No. ___ (MEB-3), pages 3, 4, and 5, which places PEF's rate level ranking higher (worse) than it should be.

<u>Revised Jurisdictional Separation Study</u>

**Q. What is the purpose of the revised Jurisdictional Separation Study that you have included with your testimony as Exhibit No. ___ (WCS-10)?**

A. I have prepared the revised Jurisdictional Separation Study to recognize two significant factors which were not reflected in the Company's original filing in this proceeding, but which are now the subject of rebuttal testimony by other Company witnesses.

The first factor concerns the change to the Company's system and customer base associated with the sale of its electric distribution system in the City of Winter Park, which was raised principally in the testimony of Office of Public Counsel witness Donna DeRonne, as well as other intervenor witnesses. The witnesses have raised several issues regarding the sale and the related loss of PEF's retail service territory and customers within the City.

The revised separation study reflects Winter Park's 12 coincident peak monthly load of 85,917 MW and its annual system energy requirements of 505,901 MWH as wholesale service under a full requirements service contract entered into between PEF and the City. The study also reflects the changes in distribution and customer-related costs described in the rebuttal testimony of Company witness Javier Portuondo.

The second factor reflected in the revised separation study relates to the Company's updated sales forecast described in the rebuttal testimony of Company witness John B. Crisp. The revised separation study includes changes in jurisdictional loads, billing determinants, and resultant sales revenues produced by the updated sales forecast.

**Q. Have you prepared a revised Allocated Class Cost of Service and Rate of Return Study to reflect the revised jurisdictional cost of service which you are now submitting?**

A. No, I have not. In my opinion, it would be more appropriate to prepare a study after the Commission's final decision on overall cost of service and class allocation methodologies. The Company would then endeavor to produce a study as rapidly as practicable for the Commission's use in determining final class revenues and rate design.

**Q. Does this conclude your rebuttal testimony?**

A. Yes, it does.

## Progress Energy Florida
## Development of Fuel Savings Resulting from Existing Generation Fleet as Compared to Peaking Only Resources

| Line | Description | (1) TOTAL RETAIL | (2) RESIDENTIAL (RS) | (3) GEN SERV NON DEM (GS-1) | (4) GEN SERV 100% LF (GS-2) | (5) GEN SERV DEMAND (GSD, SS-1) | (6) CURTAIL-ABLE (CS, SS-3) | (7) INTERRUPT-IBLE (IS, SS-2) | (8) LIGHTING (LS) |
|---|---|---|---|---|---|---|---|---|---|
| | Production Capacity Cost of Service 000's: | | | | | | | | |
| 1 | Peaking Only Component (50%) | $ 291,837 | | | | | | | |
| 2 | Capital Substitution Component (50%) | 291,837 | | | | | | | |
| 3 | Total Production Capacity | $ 583,673 | | | | | | | |
| 4 | mWh Requirements at Generator | 44,139,862 | 21,979,116 | 1,489,353 | 94,542 | 17,126,546 | 282,108 | 2,811,057 | 357,142 |
| | Capital Substitution Cost of Service | | | | | | | | |
| 5 | Allocated on Energy Responsibility | $ 291,837 | $ 145,318 | $ 9,847 | $ 625 | $ 113,234 | $ 1,865 | $ 18,586 | $ 2,361 |
| | Fuel Cost - Per Exhibit MEB-6 $/mWh | | | | | | | | |
| 6 | Fuel Cost at System Average | $ 33.03 | | | | | | | |
| 7 | Fuel Cost of Peaking Generation | $ 94.09 | | | | | | | |
| | Total Fuel Cost - 000's | | | | | | | | |
| 8 | at System Average | $ 1,457,940 | $ 725,970 | $ 49,193 | $ 3,123 | $ 565,690 | $ 9,318 | $ 92,849 | $ 11,796 |
| 9 | at Peaking Cost | $ 4,153,120 | $ 2,068,015 | $ 140,133 | $ 8,895 | $ 1,611,437 | $ 26,544 | $ 264,492 | $ 33,603 |
| 10 | Fuel Savings System Avg vs. Peaking - 000's | $ 2,695,180 | $ 1,342,045 | $ 90,940 | $ 5,773 | $ 1,045,747 | $ 17,226 | $ 171,643 | $ 21,807 |
| 11 | Percent Savings by Class | 64.9% | 64.9% | 64.9% | 64.9% | 64.9% | 64.9% | 64.9% | 64.9% |
| 12 | Ratio Fuel Savings to Capital Substitution Cost | 9.2 | 9.2 | 9.2 | 9.2 | 9.2 | 9.2 | 9.2 | 9.2 |

# PROGRESS ENERGY FLORIDA
## COST OF PRODUCTION PLANT WHEN ALLOCATED USING 12 CP AND 25% ENERGY (EXPRESSED AS COSTS PER MWH) PROJECTED CALENDAR YEAR 2006 DATA, FULLY ADJUSTED

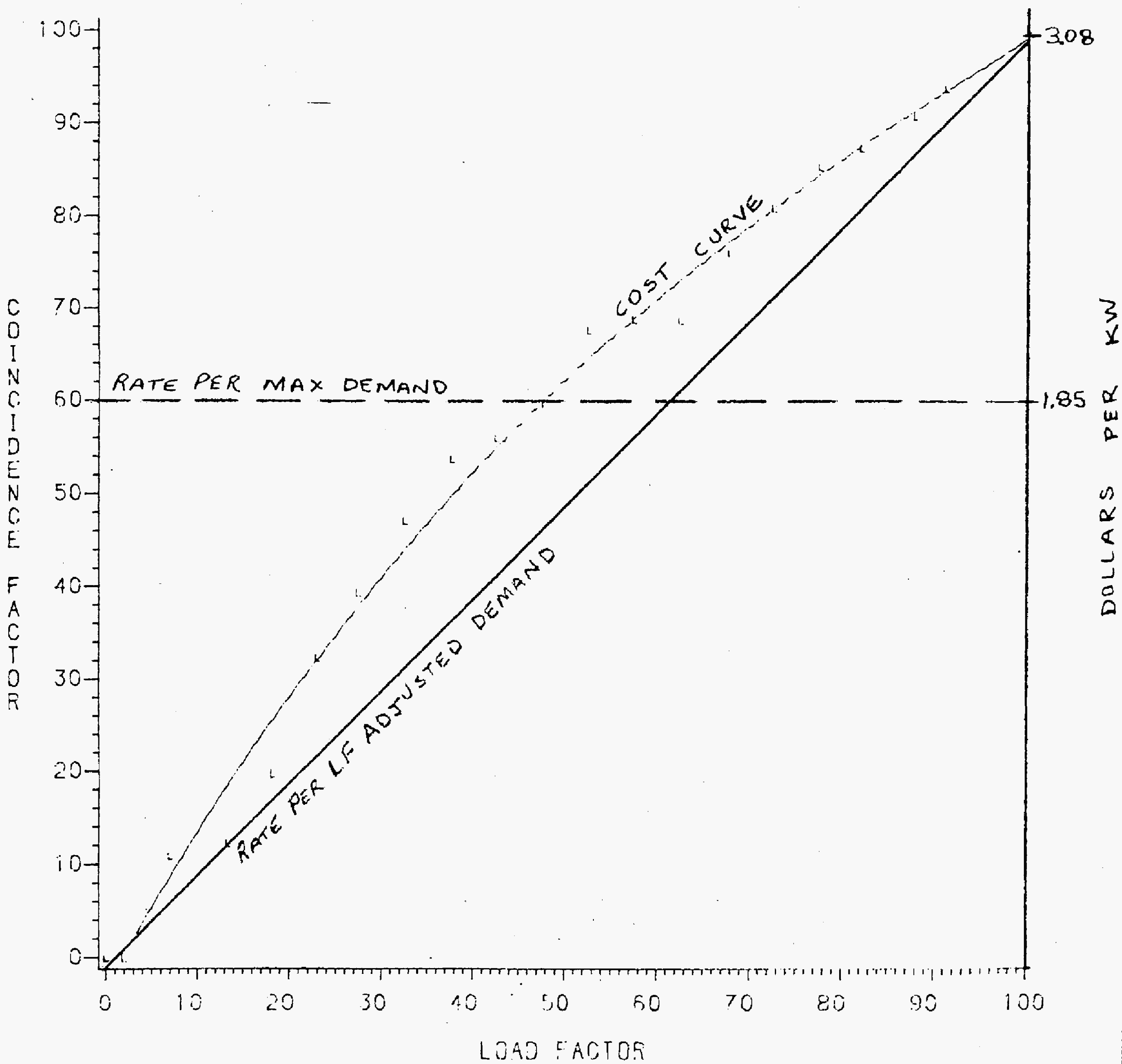
| Line | Description | (1) TOTAL RETAIL | (2) RESIDENTIAL (RS) | (3) GEN SERV NON DEM (GS-1) | (4) GEN SERV 100% LF (GS-2) | (5) GEN SERV DEMAND (GSD, SS-1) | (6) CURTAIL-ABLE (CS, SS-3) | (7) INTERRUPT-IBLE (IS, SS-2) | (8) LIGHTING (LS) |
|---|---|---|---|---|---|---|---|---|---|
| | Production Plant (000's): | | | | | | | | |
| 1 | Plant in Service | $ 3,756,577 | $ 2,067,320 | $ 129,227 | $ 5,786 | $ 1,342,150 | $ 20,623 | $ 180,805 | $ 10,668 |
| 2 | Depreciation Reserves | (2,188,398) | (1,204,320) | (75,282) | (3,371) | (781,871) | (12,014) | (105,329) | (6,214) |
| 3 | Net Production Plant | 1,568,179 | 863,000 | 53,945 | 2,415 | 560,279 | 8,609 | 75,476 | 4,454 |
| 4 | 12 - Mo Avg CP kW at Generator | 8,063,900 | 4,578,500 | 279,200 | 10,800 | 2,798,500 | 41,800 | 346,300 | 8,800 |
| 5 | Cost per kW of Net Production Plant | 194.47 | 188.49 | 193.21 | 223.61 | 200.21 | 205.96 | 217.95 | 506.14 |
| 6 | Index | 100 | 97 | 99 | 115 | 103 | 106 | 112 | 260 |
| 7 | mWh Requirements at Generator | 44,139,862 | 21,979,116 | 1,489,353 | 94,542 | 17,126,546 | 282,108 | 2,811,057 | 357,142 |
| 8 | Cost per mWh of Net Production Plant | 35.53 | 39.26 | 36.22 | 25.54 | 32.71 | 30.52 | 26.85 | 12.47 |
| 9 | Index | 100 | 111 | 102 | 72 | 92 | 86 | 76 | 35 |

# FLORIDA POWER CORPORATION

** RATE DEPT **

1983-84 LOAD FACTOR/COINCIDENCE FACTOR CURVE

** LARGE DEMAND **



DOCKET NO. 050078-EI
PROGRESS ENERGY FLORIDA
EXHIBIT NO. ____ (WCS-10)

DUE TO VOLUME THIS EXHIBIT HAS BEEN

FILED SEPARATELY IDENTIFIED AS:

EXHIBIT NO. ____ (WCS-10)
MINIMUM FILING REQUIREMENTS
SECTION E- RATE SCHEDULES
JURISDICTION SEPARATION STUDY

REFLECTS REVISED SALES FORECASE
AND
WINTER PARK TREATED AS WHOLESALE

PROJECTED TEST YEAR 2006

REVISED AUGUST 5, 2005