Sutherland
▪ Asbill & ▪
Brennan LLP
ATTORNEYS AT LAW

1275 Pennsylvania Avenue, NW
Washington, DC 20004-2415
202.383.0100
fax 202.637.3593
www.sablaw.com

ORIGINAL

JAMES M. BUSHEE
DIRECT LINE: 202-383-0643
Internet: james.bushee@sablaw.com

July 13, 2005

VIA HAND DELIVERY

Ms. Blanca Bayó
Director, Division of Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399

Re: In re: Petition for rate increase by Progress Energy Florida, Inc.
Docket No. 050078-EI

Dear Ms. Bayó:

Pursuant to the Florida Administrative Code and May 4, 2005 "Order Establishing Procedure" in the above referenced docket, Order No. PSC-05-0487-PCO-EI, White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate – White Springs hereby files the enclosed original and twenty-five (25) copies of the Direct Testimony and Exhibits of White Springs witnesses Maurice E. Brubaker, Alan R. Chalfant, Michael Gorman, and Thomas J. Regan. The enclosed documents have been furnished to the parties on the attached certificate of service by e-mail and either hand delivery or U.S Mail.

Please acknowledge receipt and filing of the above by stamping the enclosed extra copies of the testimony and attached exhibits and returning them to me.

Thank you for your assistance in connection with this matter.

Sincerely,

James M. Bushee

Attachments

CMP ____
COM 5
CTR orig
ECR ____ BRUBAKER - DN 06638-05
GCL 2 CHALFANT - DN 06639-05
OPC ____ GORMAN Vol 1 - DN 06640-05
MMS ____ GORMAN Vol 2 - DN 06641-05
RCA 1 REGAN - DN 06642-05
SCR ____
SEC 1
OTH ____

Certificate of Service

I hereby certify that a true and correct copy of the attached testimony and exhibits has been furnished by electronic mail and either hand delivery or U.S. Mail this 13th day of July, 2005, to the following:

Via electronic mail and hand delivery
Mike B. Twomey
AARP
8903 Crawfordville Road
Tallahassee, FL 32305

Via electronic mail and U.S. Mail
Richard A. Zambo
Richard A. Zambo, P.A
2336 S.E. Ocean Boulevard, #309
Stuart, FL 34996

Via electronic mail and U.S. Mail
John W. McWhirter, Jr.
Florida Industrial Power Users Group
400 North Tampa Street, Suite 2450
Tampa, FL 33601-3350

Via electronic mail and hand delivery
Jennifer Brubaker
Office of the General Counsel, Florida PSC
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

Via electronic mail and hand delivery
Timothy J. Perry
McWhirter Law Firm
117 South Gadsden Street
Tallahassee, FL 32301

Via electronic mail and hand delivery
Harold McLean/Joseph McGlothlin
Office of Public Counsel c/o FL Legislature
111 W. Madison Street, Room 812
Tallahassee, FL 32301

Via electronic mail and U.S. Mail
Karin S. Torain
PSC Administration (USA), Inc.
Skokie Boulevard, Suite 400
Northbrook, IL 60062

Via electronic mail and hand delivery
Scheffel Wright/John LaVia
Landers and Parsons, P.A.
310 West College Avenue
Tallahassee, FL 32301

Via electronic mail and hand delivery
Paul Lewis, Jr.
Progress Energy Florida, Inc.
106 East College Avenue, Suite 800
Tallahassee, FL 32301-7740

Via electronic mail and U.S. Mail
G. Sasso/J. Walls/J. Burnett/D. Triplett
Carlton Fields, P.A.
4221 West Boy Scout Boulevard
Tampa, FL 33607

Via electronic mail and U.S. Mail
James A. McGee/R. Alexander Glenn
Progress Energy Service Co., L.L.C.
100 Central Avenue, Suite 1D
Saint Petersburg, FL 33701

Soleta M. Faglie

Soleta M. Faglie

Before the

Public Utility Commission of Florida

In Re: Petition for Rate Increase by Progress Energy Florida, Inc.	Docket No. 050078-EI

Direct Testimony and Exhibits of

Maurice Brubaker

On behalf of

White Springs Agricultural Chemicals, Inc.
d/b/a PCS Phosphate – White Springs

July 13, 2005
Project 8383

BAI
BRUBAKER & ASSOCIATES, INC.
ST. LOUIS, MO 63141-2000

Before the

Public Utility Commission of Florida

In Re: Petition for Rate Increase by Progress Energy Florida, Inc.	**Docket No. 050078-EI**

Direct Testimony of Maurice Brubaker

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

A Maurice Brubaker. My business address is 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141-2000.

Q **WHAT IS YOUR OCCUPATION?**

A I am a consultant in the field of public utility regulation and president of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

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

A I have been involved in the regulation of electric utilities, competitive issues and related matters over the last three decades. Additional information is provided in Appendix A, attached to this testimony.

INTRODUCTION AND SUMMARY

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate – White Springs (White Springs). White Springs is a manufacturer of fertilizer products with plants and operations located within Progress Energy Florida, Inc.'s (PEF) service territory at White Springs, and receives service under rate schedules IS-1, IST-1 and SS-2.

Q WHAT IS WHITE SPRINGS' INTEREST IN THIS PROCEEDING?

A White Springs is one of PEF's largest customers consuming more than $20 million of power per year. In contrast to the average increase in base rates of 14% which PEF is seeking, the changes in rate design combined with the overall proposed increase for interruptible customers would cause White Springs' base rates to increase by more than 80%.

Q WHAT IS ADDRESSED IN YOUR TESTIMONY?

A My testimony addresses class cost of service and rate design issues, with particular attention given to the interruptible service schedules. I provide a comparison of PEF's rates with rates of other utilities in the southeastern part of the United States and show that PEF's rates are among the highest. I also show that as compared to its near average position in the early 1990s, PEF's rates are now significantly above the average rates charged by the comparison group of utilities. These high rates are a clear indication that PEF has not "performed" well for its customers and should not be entitled to any kind of "reward."

Q ARE ANY OF YOUR COLLEAGUES ALSO SUBMITTING TESTIMONY ON BEHALF OF WHITE SPRINGS?

A Yes. Mr. Michael Gorman testifies concerning PEF's capital structure, cost of capital and selected other revenue requirement issues. He recommends a return on equity of 9.8%. He also proposes several other adjustments to PEF's claims. Overall, his revenue requirement recommendation is for a decrease of at least $57 million from present rates.

Mr. Alan Chalfant testifies concerning the "performance" reward which PEF has sought for its stockholders. Mr. Chalfant's testimony, which responds to Dr. Cicchetti, explains why this reward is inappropriate.

Additionally, Mr. Thomas J. Regan, President of the PCS Phosphate Division, testifies concerning the impact of PEF's rate proposal on White Springs.

Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A My findings and recommendations may be summarized as follows:

1. PEF's rates, for all classes of customers, are among the highest charged by investor-owned utilities in the southeastern part of the United States.

2. Since 1990, the rates for my comparison group of investor-owned electric utilities have increased by approximately 15%, while PEF's rates have increased by more than 50%, making their large industrial rates more than 2.0¢/kWh, or about 45% higher than the group average. Any rate increase would just make the situation worse.

3. PEF has significantly increased its reliance on natural gas-fired resources, which has contributed to the significant escalation in rates. PEF's projections indicate that at least through 2014, it will acquire nothing but gas-fired resources, further increasing its reliance on natural gas.

4. PEF has been slow to seriously consider adding coal-fired resources. In fact, it has already replaced the Southern Company UPS coal-based contracts (expiring in 2010) with resources from Southern that are largely gas-fired.

5. PEF has done little in the way of preliminary work toward developing new coal-fired resources. Although it has indicated that coal-fired capacity could be in place by 2013, its current plans do not show any coal-fired capacity prior to 2015.

6. The class cost of service methodology proposed by PEF is inappropriate. Both of the studies presented include a weighting of energy along with 12 coincident peaks. This has the effect of skewing the allocation of generation capacity costs toward high load factor customers, without giving them a commensurate share of the lower cost of fuel from base load resources.

7. On the PEF system the winter and summer peak demands are the most prominent, and the most important in determining the amount of capacity that must be in place to provide reliable service.

8. My recommendation is to use the summer/winter coincident peak allocation study for cost allocation. If the Commission chooses not to do so, but instead wants to use some measure of energy in the allocation, then I would recommend using the 12 coincident peak study with a 1/13th weighting to energy.

9. PEF has proposed significant changes to its interruptible tariffs. Customers on IS-1, IST-1 and SS-2 will receive very large increases because of the change in the application of the credits and the change in the level of the credits themselves.

10. Customers on IS-1, IST-1 and SS-2 would receive increases on their base rates of over 75%, significantly higher than the 21% which PEF advertises on MFR Schedule E-13c. The reason for the difference is that PEF's MFR schedules consider neither the interruptible credit that customers receive currently, nor the drastic change in the level of the credits that would result if its proposals were adopted.

11. PEF has not supported the drastic changes that it proposes for these schedules.

12. My cost of service analysis shows that interruptible rates should be increased less than the system average increase that PEF has proposed (if there is an increase), and be decreased more than the average decrease. Based on the revenue decrease recommended by White Springs, the interruptible schedules should be decreased by at least 14%.

13. The existing credits in IS-1 and IST-1 should not be changed and the method of applying the credits also should not be changed. In addition, the interruptible credits for SS-2 should be designed to maintain the same relationship to the firm standby charges as exists between the demand charge and the interruptible credit in the IS-1 and IST-1 rates.

PEF'S PERFORMANCE

Q ON A GENERAL LEVEL, HOW DOES PEF'S RATE LEVEL COMPARE TO OTHER UTILITIES IN THE SOUTHEASTERN UNITED STATES?

A As I demonstrate below, PEF's rates are among the highest. At the same time that PEF is seeking a bonus for its stockholders, PEF's ratepayers are saddled with unreasonably high rates.

Q HAVE YOU HAD OCCASION TO COMPARE THE LEVEL OF PEF'S RATES WITH THE RATES CHARGED BY OTHER UTILITIES?

A Yes, I have. Exhibit MEB-1 ( ), page 1, shows the comparative cost of power for a large, high load factor firm industrial load under the rates of PEF and 37 other utilities serving generally in the southeastern part of the United States. Significantly, PEF's rates are second highest.

Page 2 of Exhibit MEB-1 ( ) shows a similar comparison with respect to interruptible power. To determine the costs on this exhibit, the maximum amount of allowable interruptible power under each utility's tariff was determined and priced. Since service taken under PEF's interruptible schedules is entirely interruptible, this calculation for PEF reflects 100% interruptible power. For some of the other utilities a portion of the service must be taken as firm, with the balance taken as interruptible. To that extent, this exhibit is conservative (i.e., favorable to PEF) in that it compares fully interruptible power from PEF to a mixture of firm and interruptible power from other utilities.

Q **WHAT IS SHOWN ON EXHIBIT MEB-2 ( )?**

A This exhibit is a graphical presentation which compares PEF's firm rates with the rates of the comparison group of utilities over the period 1990 through the present. Note that in the early 1990s, PEF's rates were at or near the average, but that now they are approximately 45% above the average.

Q **WHAT IS THE SOURCE OF THE DATA SHOWN ON EXHIBITS MEB-1 ( ) AND MEB-2 ( )?**

A The costs were calculated from individual utility tariffs and adjustment factors in effect at the times indicated, seasonally weighted to develop the annual cost.

Q **THESE TWO EXHIBITS ADDRESS RATES FOR LARGE INDUSTRIAL LOADS. HAVE YOU MADE SIMILAR COMPARISONS FOR OTHER CUSTOMERS?**

A Yes. This is included in Exhibit MEB-3 ( ). Data on this exhibit was taken from the Edison Electric Institute's (EEI) semi-annual "Typical Bills and Average Rates Report." The utilities in this exhibit are all of those that are included on Exhibit MEB-1 ( ) for which data is reported in the EEI bulletin. The costs reflected are the weighted average for the summer of 2004 and winter of 2005 in order to reflect annual costs. Page 1 of the exhibit ranks the utilities based on the cost to a residential customer using 750 kWh per month. In this instance, PEF is the fifth highest out of the group of 35. Page 2 is similar, with the ranking based on residential usage of 1,000 kWh per month. Again, PEF ranks fifth highest.

Page 3 is a ranking for a 500 kW, 100,000 kWh per month commercial customer. Here, PEF ranks second highest. Page 4 is a ranking for a 500 kW commercial customer using 180,000 kWh per month. PEF still ranks second highest.

Page 5 is the ranking based on a 1,000 kW industrial customer using 400,000 kWh per month. Again, PEF ranks second. Page 6 is a ranking for a 1,000 kW industrial customer using 650,000 kWh per month. PEF is fourth highest in this ranking.

Q WHAT IMPLICATIONS DO THESE RATE LEVELS HAVE WITH RESPECT TO DETERMINING WHETHER PEF SHOULD BE ENTITLED TO SOME KIND OF A "REWARD" FOR ITS "PERFORMANCE?"

A There are several implications. First, this is not the kind of "performance" that should be rewarded with an ROE bonus. If anything, PEF's ROE should be set at the low end of the range. Second, the Commission should look very closely at PEF's operations to determine why its rates are so high. One obvious reason, which I discuss below, is PEF's significant reliance on natural gas fueled generation. Third, absent prompt and decisive Commission action, PEF's customers will continue to pay excessive rates, thereby harming the Florida economy generally and the competitiveness of Florida's industry, in particular.

PEF'S RESOURCE MIX

Q ARE YOU FAMILIAR WITH THE MIX OF RESOURCES UTILIZED BY PEF TO SERVE THE ENERGY NEEDS OF ITS CUSTOMERS?

A Yes, I am. PEF relies heavily on natural gas to fuel its generation resources.

Q **WHAT ARE THE IMPLICATIONS OF THIS HEAVY RELIANCE ON GAS?**

A The result is that PEF's customers must pay high fuel costs.

Q **HAVE YOU REVIEWED PEF'S RECENT TEN-YEAR SITE PLANS?**

A Yes. I have reviewed PEF's Ten-Year Site Plans filed from 2001 through 2005.

Q **TO WHAT EXTENT WERE COAL-BASED OPTIONS ADDRESSED IN THESE FILINGS?**

A For the more recent plans, there is some discussion of coal-fired alternatives, but the only analysis presented is rather simplistic "screening curves" which examine the theoretical crossover points that show where one technology becomes more economical than another. The resource selections from those plans, which show additions through 2014, were exclusively gas-fired combined cycle units (and combustion turbine units). In none of these plans did coal apparently receive a serious analysis by PEF.

Q **CAN YOU PROVIDE AN EXAMPLE OF PEF'S RELIANCE UPON NATURAL GAS-FIRED GENERATION?**

A Yes, a good example of PEF's failure to even consider coal-fired generation is provided by its recent execution of unit power sales agreements with Southern Company. Although PEF's existing contract with Southern for 414 MW of coal-fired capacity does not expire until 2010, PEF gave no consideration to whether other coal-fired resources were available, either through purchased power or self-build options (Docket No. 041393-EI, Southern Company UPS Agreements).

Q SHOULD PEF HAVE CONSIDERED ADDING COAL CAPACITY?

A Yes. I believe it was particularly important that PEF undertake these considerations after the gas price spikes that occurred beginning in 2000. That event, coupled with subsequent spikes and escalating price levels, and the continued construction of gas-fired electric generation capacity (by merchants and others) certainly gave rise to concerns that natural gas prices would be both high and volatile. I believe PEF should have devoted more attention to analyzing the comparative risks and economics of natural gas and coal-fired generation.

Q IN ADDITION TO THIS FACTOR, ARE THERE OTHER REASONS WHY PEF SHOULD HAVE BEEN ACTIVELY CONSIDERING ACQUIRING COAL-FIRED POWER?

A Yes. From a resource diversity standpoint, PEF's current projections indicate a significantly increasing dependency on natural gas. For example, its Ten-Year Site Plans show an increase in the percentage of energy from oil and gas-fired resources from 28% in the year 2000, to a projected 34% in 2005, 42% in 2010, and 54% in 2014. This factor should have led PEF to more actively consider adding coal-fired generation to the system to meet part of the load growth requirements and maintain closer to an historic fuel diversity. Exhibit MEB-4 (   ) shows this pattern.

Q HAS THE FLORIDA PSC STAFF COMMENTED ON THIS TREND IN DEPENDENCY ON NATURAL GAS?

A Yes. The Commission's Division of Economic Regulation issued a report in December of 2004 entitled "A Review of Florida Electric Utility 2004 Ten-Year

Site Plans." At Page 6 of that report, in a section entitled "**AREAS OF CONCERN** – *IMPACT OF PLANS ON FUEL DIVERSITY*," the Staff commented as follows:

> "Over the past several years, utilities across the nation and within Florida have selected natural gas-fired generation as the predominant source of new capacity. If this trend continues, natural gas usage will approach the levels of oil usage that Florida was experiencing just prior to the oil embargoes of the 1970's. Recent past experience has shown that natural gas prices can be volatile. Further, Florida's utilities project a wide range of prices for natural gas. These facts, coupled with the Florida utilities' historic under-forecasting of natural gas price and consumption, could further strain Florida's economy. In the 1970's, the Commission took action to encourage the utilities to diversify their fuel mix in an effort to mitigate volatile fuel prices. Based on current fuel mix and fuel price projections, Florida's utilities should explore the feasibility of adding solid fuel generation as part of future capacity additions."

Later in the report, at Page 21, in a section entitled "**GENERATING UNIT SELECTION**" Staff commented as follows:

> "According to the utilities' *Ten-Year Site Plans*, natural gas is forecasted to play an even more dominant role in electric power generation in Florida over the next ten years. To minimize price and supply volatility, electric power generation must rely on multiple fuel sources. As a result, Florida's utilities should evaluate potential sites for coal capability. To lessen the capital cost impact of building coal-fired units, utilities should look at the possibility of joint ownership of future coal units. Florida's municipal utilities have a successful history of sharing investment costs associated with coal units. Finally, utilities should investigate the possibility of receiving financial assistance through the DOE's CCT Program. As emerging research and development in coal-fired generation reduces high capital costs, emissions, permitting lead times, and investment risk, coal could again play a critical role in electric power generation in Florida."

I believe Staff's comments are right on point, and merit serious consideration.

Q **IS THERE ANY RECENT EVIDENCE THAT PEF IS NOW LOOKING MORE CLOSELY AT INSTALLING COAL-FIRED UNITS?**

A Yes. PEF revealed in the hearings on the Southern Company UPS agreements in Docket No. 041393-EI that its plans now contain mostly coal units beginning in the year 2015. Also, in 2004 we begin to see more serious studies, including some conducted by outside parties, of the comparative economics of various types of solid fuel units. These studies indicate the increasing attractiveness of these types of units in light of changes in fuel markets.

In response to White Springs' Interrogatory No. 15 in the UPS case, PEF claimed that it would take at least eight years to do the necessary development and construction for a coal-fired generating station, and if one accepts that claim, 2013 would be the earliest feasible in-service date.

In light of these circumstances and other factors noted above, PEF should have intensified its efforts in regard to the analysis and development of coal-fired resources, and their expeditious construction if such analysis continues to reveal them as appropriate choices. So far, it appears that PEF has only performed a preliminary site survey. In contrast, a number of coal-fired plants with 2010-2015 projected in-service dates are already in the planning stages by other Florida utilities.

Q **SHOULD PEF'S SLOW PACE IN EXPLORING COAL OPTIONS BE TAKEN INTO ACCOUNT IN SETTING PEF'S RETURN ON EQUITY?**

A Yes. Even if a single gas-fired resource decision is considered reasonable, PEF has significant capacity needs and could have pursued coal-based options more aggressively than it has. Had it done so, relief from the impact of escalated natural gas prices could become available to PEF's customers at an earlier time. I would urge the Commission to keep this fact in mind as it evaluates PEF's requests.

COST OF SERVICE METHODOLOGY

Q ARE YOU FAMILIAR WITH THE METHODOLOGY WHICH PEF HAS PROPOSED TO USE FOR DETERMINING THE COST OF SERVING ITS VARIOUS CLASSES OF CUSTOMERS?

A Yes, I am. The cost of service studies are sponsored by PEF witness William Slusser.

Q HOW IS THIS SECTION OF YOUR TESTIMONY ORGANIZED?

A In this section I will first discuss the proposed energy weightings, then I will address the appropriate number of peaks to utilize in the cost allocation process. Finally, I will address the results of the cost of service studies as I have modified them.

Energy Weighting

Q WHAT WEIGHTING OF ENERGY HAS PEF PROPOSED IN ITS CLASS COST ALLOCATIONS?

A PEF has presented two class cost of service studies. The first study uses 12 monthly coincident peaks with a $1/13^{th}$ weighting of energy as is required to be submitted in the MFRs. An alternative study, which PEF prefers, uses 12 monthly coincident peaks but has a 25% weighting to energy.

Q **WHAT ARGUMENT DOES PEF ADVANCE TO SUPPORT ITS PROPOSED ENERGY WEIGHTING?**

A It his testimony, PEF witness Slusser indicates (at page 17) that he supports a significant energy weighting in the allocation of production plant capital costs because "...PEF has made a considerable investment in production plant for reasons other than simply meeting peak demand." Essentially, he is arguing that it is necessary to allocate a significant portion of capital costs to classes based on their energy usage because high load factor classes purportedly receive more benefit from the lower energy cost associated with base load units than do lower load factor customers.

To determine his percentage, he estimates what PEF's generation fleet would have required in the way of investment if it were entirely peakers, divides the result by actual investment to obtain a factor of 50%, and then divides that by 2 to derive his recommended 25% weighting which he claims is a "middle ground."

Q **DO YOU AGREE WITH MR. SLUSSER'S APPROACH?**

A No, I do not. The fact that different technologies have different capital costs and different fuel costs does not provide justification for Mr. Slusser's energy weighting.

Q **PLEASE EXPLAIN.**

A It is true that utilities select the mix of generation facilities that they expect will be able to serve the total load at the lowest overall cost, taking into account the combination of fixed costs and variable costs, i.e., to minimize total costs.

Having made that decision, the amount of fixed costs on the system is set, and does not vary with kilowatthour output or the number of hours that a facility is operated. These are truly fixed costs, which traditional allocation methods treat as demand-related costs and allocate to customer classes based on a method such as average and excess demands or coincident peak demands, using one or more peaks.

The type of fuel is determined by the specific technology employed, but the total fuel cost varies as a function of total kilowatthour output – and thus is treated as a variable cost. Typically, the variable costs are allocated on the basis of the total annual kilowatthours required by the various customer classes.

Q DOES MR. SLUSSER'S METHODOLOGY APPROPRIATELY REFLECT THE CAPITAL COSTS/FUEL COST TRADEOFFS?

A No, it does not. He only addresses the capital side, and completely ignores the fuel side.

Q PLEASE EXPLAIN.

A Recognizing that the different technologies have different combinations of fixed and variable costs, any analysis that would attempt to more precisely articulate costs by customer class would require a determination of the technology or technologies that would be installed if a utility served each customer class independently, at its lowest cost. The result would be that for high load factor customer classes relatively more base load plant would be installed, and relatively less peaking plant would be installed. The converse would be true for lower load factor classes.

High load factor classes would have more fixed costs, but they also would have lower fuel costs; while the low load factor classes would be allocated less capital costs but more fuel costs. This type of analysis is necessary in order to reflect both sides of the capital costs/fuel cost tradeoff. The simplistic approach taken by Mr. Slusser simply does not recognize the fuel cost side of the equation, and as a result overcharges high load factor customer classes.

Q IF A SYMMETRICAL APPROACH WERE TO BE FOLLOWED, HOW WOULD IT BE USED TO ALLOCATE THE ACTUAL COSTS THAT A UTILITY HAS INCURRED?

A If this type of analysis were done for each class on a stand-alone basis, then the results of this analysis would have to be analyzed to determine how to apply them to the actual fixed and variable costs which the utility has incurred in pursuit of its goal of selecting that combination of technologies which serves its total load at the lowest total (fixed plus variable) cost.

Q HAVE YOU PERFORMED THIS TYPE OF ANALYSIS?

A No, and neither has Mr. Slusser – but it would be necessary to do so in order to explicitly recognize the impacts of the issues Mr. Slusser has raised.

Q HOW DO TRADITIONAL COST ALLOCATION STUDIES RECOGNIZE THIS MIX OF TECHNOLOGIES?

A Traditional cost allocation studies recognize that the mix or combination of plants is built to serve the overall or combined load characteristics of all customer classes – and not for the load characteristics of any particular customer class.

Therefore, energy costs are allocated across all customer classes on an equal cents per kilowatthour basis, and fixed costs are allocated across all customer classes on an equal dollars per kilowatt of demand basis. This approach is reasonable, and avoids a lot of complexity and assumptions that would be required if one were to attempt to more precisely identify the specific mix of plants and the resulting separately determined capital and fuel costs.

Q **ARE THERE OTHER REASONS WHY IT IS INAPPROPRIATE TO INCLUDE CAPITAL COSTS IN ALL HOURS OF THE YEAR BY USING AN ENERGY ALLOCATION?**

A Yes. In considering the different types of technologies available, the trade-off between variable costs and capital costs that determine which technology is more economical occurs at some specific number of hours of operation. Beyond the hours of operation where there is a "break-even" between the total cost of two different technologies, operating the capital intensive plant more hours does not change the decision of what type of technology to install. Thus, it is only hours up to that point which could even arguably make a difference in technology choices.

Q **CAN YOU ILLUSTRATE?**

A Yes. Assume Technology A has a capital cost of $500 per kilowatt, a heat rate of 7,000 Btu per kilowatthour, O&M expense of 0.3¢ per kilowatthour, and that it is fired with natural gas at a delivered cost of $7.00 per MMBtu. The total of fuel and O&M expenses would be 5.2¢ per kilowatthour.

Assume that a second technology has a capital cost of $300 per kilowatt, a heat rate of 12,000 Btu per kilowatthour and O&M expenses of 0.3¢ per kilowatthour. With the same fuel price, the total variable cost of this unit would be 8.7¢ per kilowatthour.

The difference in variable cost is, therefore, 3.5¢ per kilowatthour (8.7¢ - 5.2¢). Assuming a carrying charge rate of 15%, the difference in capital cost is $30 per kW (the $200 per kW difference in capital cost times 15%). The break-even point (the hours of operation required for the lower fuel cost to outweigh the higher capital cost) is 860 hours ($30 ÷ $0.035).

This illustrates that only about 10% of the hours in the year (860 out of 8,760) are arguably important in the technology choice question. Since the additional hours are not relevant in this decision – it is wrong to include loads in those additional hours in the cost allocation process – because those loads had nothing to do with the incurrence of the capital cost. The cost allocation methodology used by Mr. Slusser suffers heavily from this problem because he allocates a significant proportion of capital costs on energy.

Q **HOW MUCH CAPITAL COST PER KW DID MR. SLUSSER ASSIGN TO EACH CUSTOMER CLASS IN HIS 12CP WITH 25% ENERGY WEIGHTING COST OF SERVICE STUDY?**

A This is shown on Exhibit MEB-5 ( ). The values are obtained by dividing the net plant investment allocated to customer classes by the average of the 12 monthly coincident peak demands used in the cost allocation. As expected, classes with an above average load factor are allocated an above average capital cost per kW of demand.

Q DO THE DIFFERENT TECHNOLOGY TYPES HAVE THE SAME FUEL COST?

A No. As noted above, fuel costs vary quite significantly among base load, intermediate and peaking facilities.

Q DOES MR. SLUSSER RECOGNIZE THIS IN HIS ALLOCATION?

A No. As noted above, he allocates the same base rate energy-related cost per kWh to all classes. Furthermore, fuel cost is recovered through the separate fuel adjustment clause, and that also is on an average basis with no distinction made with respect to class load pattern, load factor or how much base load plant and how much production plant investment Mr. Slusser assigns in his cost of service study.

Q ARE THERE SIGNIFICANT VARIATIONS?

A Yes. Exhibit MEB-6 (   ) shows the costs by resource group, as reflected in the workpapers for Mr. Slusser's jurisdictional separation study. The costs range from 2.8¢ per kWh for base load facilities to 9.4¢ per kWh for peaking facilities. If an energy weighting is included in the allocation of capacity costs, then there must be some symmetrical consideration given to the assignment of fuel and variable purchase power costs. The variations in fuel and purchased power costs are quite significant, and it is inconsistent to reflect differential costs on the capital side, as Mr. Slusser has done, and not reflect similar considerations that offset these differences on the energy side.

Q IN PERFORMING THE COST ALLOCATIONS TO THE "STRATIFIED" CUSTOMER GROUP IN THE WHOLESALE JURISDICTION, DOES MR. SLUSSER RECOGNIZE THE RELATIONSHIP BETWEEN THE ENERGY COSTS AND THE CAPITAL COSTS ASSIGNED TO THESE CUSTOMERS?

A Yes, he does. Since he obviously recognizes both sides of the equation in his wholesale allocation, it is not clear why he has not done so in his retail allocation.

Q IN DETERMINING FUEL EXPENSE FOR PURPOSES OF RECOVERY FROM RETAIL CUSTOMERS IN THE FUEL ADJUSTMENT MECHANISM, DOES PEF RECOGNIZE THESE ALLOCATIONS OF FUEL COSTS TO THE "STRATIFIED" WHOLESALE CUSTOMERS?

A Yes. Mr. Slusser indicates on page 9 of his testimony that this is done.

Peaks to Use in Cost Allocation

Q HAVE YOU REVIEWED PEF'S ANNUAL LOAD PATTERN?

A Yes, I have. Exhibit MEB-7 ( ) presents PEF's load characteristics for the historical period 1996 through 2004. Page 1 summarizes key statistics and the balance of the pages in this exhibit show the monthly peak demands in graphical format.

Q WHAT DOES PAGE 1 OF EXHIBIT MEB-7 ( ) SHOW?

A In addition to the system peak, it shows the ratio of the peak demand in the maximum month to the peak demand in the minimum month (column 2) and the ratio of the maximum demand to the average of the monthly peaks (column 3).

Column 2 indicates the extent of spread between the highest monthly (or annual) peak demand and the highest demand in the month which had the lowest maximum demand. The larger this number, the more seasonal the utility system. As can be seen, the PEF load pattern remains very seasonal.

Column 3 is a measure of the extent to which the maximum monthly (or annual) demand exceeds the average of the maximum demands in the other months. Again, the larger the number, the more seasonal the load pattern. Column 3 also indicates a highly seasonal load pattern.

Q **THE COLUMN 3 RATIO FOR 2004 SEEMS TO BE MUCH LOWER THAN FOR MOST OTHER YEARS. WHAT IS THE REASON FOR THAT?**

A In 2004, as is clearly shown in column 1 on page 1, the system peak was significantly lower than the peak experienced in the preceding several years. Because of a mild weather peak day, the annual peak occurred in the summer, which is not PEF's normal load pattern. The weather pattern in 2004 caused the maximum demand to be lower than expected, and thus the ratio in column 3 is lower than normal.

Q **WHAT IS SHOWN ON THE ADDITIONAL PAGES IN EXHIBIT MEB-7 (   )?**

A They show, for each year, a bar chart presentation of the monthly peak demands. The annual system peak demand is in orange. A review of this material confirms what is shown on the first page – mainly, that the PEF load pattern continues to be very seasonal.

Q WHAT IS SHOWN ON EXHIBIT MEB-8 ( )?

A Exhibit MEB-8 ( ) is similar to Exhibit MEB-7 ( ) except that it shows PEF's projected data for the year 2005 and the 2006 test year. The seasonal pattern here is similar to what the historic data reveals – namely, a strong winter peak.

Q BASED ON THIS INFORMATION, WHAT METHODOLOGY DO YOU RECOMMEND FOR ALLOCATING FIXED PRODUCTION COSTS TO CUSTOMER CLASSES?

A This analysis indicates that PEF's load is seasonal, with a strong winter peak, and a somewhat weaker secondary peak occurring during the summer.

In order to provide reliable service, PEF must build capacity or acquire resources under contract to meet its anticipated firm annual system peak demand, plus a 20% reserve margin. Since it is these peaks that drive the capacity additions, it is reasonable to use the average of the winter and summer peak demands for purposes of allocating costs to customer classes.

Cost of Service Results

Q HAVE YOU PREPARED SUMMARIES OF THE RESULTS OF ALTERNATIVE COST OF SERVICE STUDIES?

A Yes. Exhibit MEB-9 ( ), page 1, is a summary of the results of the class cost of service study using my recommended summer/winter coincident peak demand allocation methodology. This is similar in format to PEF's summary tables. Lines 1-14 develop the total cost of service. Lines 15-17 show the revenues at current rates, line 18 shows the required revenue change to make class revenues equal to cost of service, and line 19 shows the percentage change.

Q **BY UTILIZING A COST OF SERVICE STUDY BASED ON THE FULL AMOUNT OF PEF'S PROPOSED RATE INCREASE, ARE YOU INTENDING TO ENDORSE THAT AMOUNT OF RATE INCREASE?**

A Absolutely not. The best way to compare the results of different cost allocation methodologies is to use the same overall revenue requirement. This permits differences due to allocation issues to be isolated from differences due to changes in the level of total revenue requirements.

Q **FOCUSING ON THE INTERRUPTIBLE CLASS, HOW DOES THE 7.5% INCREASE YOU HAVE CALCULATED IN THE CONTEXT OF PEF'S INCREASE PROPOSAL COMPARE TO THE RESULTS OF PEF'S COST OF SERVICE STUDIES?**

A Under the 12CP and 25% energy weighting study, PEF calculated a required increase for this class of approximately 25%. Under its 12CP and $1/13^{th}$ average study, it calculated an increase of approximately 22%.

Q **WHAT ELSE IS SHOWN ON EXHIBIT MEB-9 ( )?**

A The remaining lines on Exhibit MEB-9 ( ) show the unit costs for each class.

Q **WHAT IS SHOWN ON PAGE 2 OF EXHIBIT MEB-9 ( )?**

A Page 2 of Exhibit MEB-9 ( ) shows the cost of service results if the winter coincident peak demand were used for cost allocation.

Q **AS COMPARED TO THE SUMMER/WINTER COST ALLOCATION METHODOLOGY, WHAT ARE THE RESULTS OF THE WINTER COINCIDENT PEAK ALLOCATION METHODOLOGY?**

A The winter coincident peak allocation methodology indicates a 4% revenue increase would be required for the interruptible customers, assuming PEF were to get the entire 14% average increase that it has requested. Under this methodology, the increase is approximately one-half of the increase indicated under the summer/winter coincident peak methodology which I have proposed.

Q **IN THE COST OF SERVICE STUDIES IN YOUR EXHIBIT MEB-9 ( ) AND IN PEF'S COST OF SERVICE STUDIES, HOW ARE THE LOADS OF THE INTERRUPTIBLE CLASS TREATED?**

A For purposes of this cost of service methodology, interruptible loads are treated the same as firm loads – that is, they are included in the peaks used for cost allocation. As an offset, the credits which interruptible customers receive for being interruptible are not subtracted in determining the revenues used in the study. This approach implicitly assumes that the credits which customers receive are appropriate.

Q **IS THERE ANOTHER WAY TO VIEW THE COST OF SERVING INTERRUPTIBLE CUSTOMERS?**

A Yes. The other way is to exclude interruptible loads from the capacity cost allocation since the utility does not install capacity to serve interruptible load. When this approach is taken, it is necessary to utilize the revenue of the interruptible class after subtracting the interruptible credits that are received by the customers. This approach is a more direct measurement of the cost to serve interruptible load because it compares costs actually incurred to revenues actually received.

Q **HAVE YOU PREPARED SUCH AN ANALYSIS?**

A Yes. Exhibit MEB-10 ( ) presents this analysis for the interruptible class.

Q **VIEWED IN THIS MANNER, WHAT IS THE RESULT FOR THE INTERRUPTIBLE CLASS?**

A As determined in this manner, the increase to the interruptible class is less than the increase indicated by the summer/winter coincident peak allocation study which treated the loads as firm. The increase is about 4.5% on the base revenues as PEF presents them (7.4% on the revenues actually paid by these customers). Accordingly, any revenue change for the class should be about 10 percentage points more negative than the average. For example, if the overall revenue change is a 5% reduction, the interruptible class should see a reduction of 15%. I discuss this in more detail in the next section of my testimony.

INTERRUPTIBLE RATES

Q **WHAT CHANGES HAS PEF PROPOSED IN ITS INTERRUPTIBLE RATES?**

A PEF has proposed massive changes. First, it proposes to eliminate the IS-1 and IST-1 rate schedules and transfer customers to the IS-2 and IST-2 schedules. The proposed increase in base rates, combined with the change in how the interruptible credit is applied, cause substantial increases to these customers.

PEF also proposes to significantly decrease the interruptible credits in the SS-2 standby rate.

Q ON MFR SCHEDULE E-13C, PAGE 1, PEF INDICATES THAT THE BASE RATE PERCENTAGE INCREASE FOR THE IS CLASS IS APPROXIMATELY 21%. IS THIS AN ACCURATE ASSESSMENT OF THE BASE RATE IMPACT?

A No. It is important to recognize that in the MFR schedules the "base rate" revenue for the IS class is prior to the subtraction of the interruptible credits. It also does not show the large proposed reduction in the level of credits. Thus, what PEF calls "base rates" does not truly reflect base rates because the credits are omitted. The credits decrease considerably under PEF's proposal to eliminate the IS-1 and IST-1 rates and move these customers to IS-2 and IST-2. For White Springs, the change in size and application of the interruptible credit causes a real base rate increase of over 80%, or four times what is indicated in the MFR schedule referenced above.

Q ARE YOU ABLE TO ESTIMATE THE OVERALL IMPACT ON THE IS CLASS?

A Yes. It appears that the credits under present rates are approximately $17 million. Thus, the current revenues net of the credits would be approximately $24 million ($41 million - $17 million). At proposed rates, I estimate that the credits would be only about $8 million, so the net base rates after reflecting PEF's proposed increase in rates and decrease in credits would be approximately $42 million ($50 million - $8 million). Thus, the overall increase proposed by PEF for the IS class is approximately 75%, generally consistent with what I calculated for White Springs.

Q WHAT ROLE DOES INTERRUPTIBLE POWER PLAY IN A UTILITY SYSTEM?

A PEF, and other utilities, have utilized interruptible tariffs for many years as a means of reducing the amount of generation capacity that must be installed, consequently reducing the cost of generation resources. Essentially, interruptible customers are offered the use of power when the capacity is not needed to serve the load of firm customers. In the particular instance of PEF, interruptible customers can be called upon (with or without notice and without limitation as to the frequency and duration of interruption) to stop taking service when the capacity that otherwise would serve interruptible load is needed by firm customers anywhere in the state.

In addition, in the event of an identified potential generation resource deficiency, Phase 1 of PEF's operating plan is to notify interruptible (and curtailable) customers of the anticipated need for interruptions. The second phase of the program is to initiate emergency purchases for these customers (who have requested that such purchases be made) and to charge these customers for such purchases. In the event that system conditions become worse, then these customers are required to cease taking service.

Interruptible loads also are equipped with under-frequency relays which are designed to trip the load off of the system before any firm load is shed in the event of the occurrence of an unanticipated system disturbance that creates a generation resource deficiency.

These features of interruptible service are not reflected in class cost of service studies, but clearly bring significant value to the system and to the firm customers.

Q IS PEF CONTINUING TO EXPERIENCE GROWTH IN ITS FIRM LOAD?

A Yes. Both PEF and Florida as a whole continue to experience significant growth, and PEF alone has identified the need to add over 3800 MW of new resources by 2014 in order to provide reliable service. If the dramatic changes which PEF has proposed are adopted and result in discouraging the continued use of this viable resource, then one of two results will occur. If customers decide that interruptible power is not priced far enough below firm power to justify its use, and loads move to firm service, more capacity would have to be added to maintain reliable service. If the higher prices cause customers to reduce or terminate operations, then there will be harm to the economy of the service area.

Q HAS PEF PROVIDED ANY JUSTIFICATION FOR THE MATERIAL CHANGES IN THE IS RATES?

A No. Mr. Slusser simply announces that it is time to eliminate these tariffs and argues that the credits are not appropriate – but offers no evidence.

Q DID WHITE SPRINGS REQUEST ANY SUPPORTING MATERIAL FROM PEF?

A Yes. White Springs requested (White Springs POD No. 26) PEF to provide its most current calculation of the appropriate interruptible credit. In response, PEF provided an outdated (February 2002) conservation cost-effectiveness test calculation. The material provided consists of some summary sheets and one page which lists some assumptions that potentially were used in the calculations. However, the details of the calculations themselves are not provided.

Q PUTTING ASIDE THE SPECIFIC DETAILS OF THE CALCULATIONS, DO YOU BELIEVE THAT THE APPROACH WHICH PEF HAS USED IN THIS EVALUATION IS APPROPRIATE FOR INTERRUPTIBLE RATES?

A No, I do not.

Q PLEASE EXPLAIN.

A The genesis of the methodology was for the evaluation of energy efficiency programs. These programs provide customers with the same firm service, functionality and comfort, but enable them to utilize less energy. A major component of such programs is a reduction in the use of kilowatthours. Accordingly, it was important to evaluate the energy reducing impact of these programs over a number of years.

Interruptible power, on the other hand, has a totally different quality to it than the alternative of firm service. Interruptible service is inferior in that the utility can, under the agreed conditions, withdraw the power from the interruptible customer entirely. The benefit of continuing to serve the load as interruptible is not in reducing energy use, but in the fact that it permits the utility to avoid contracting for purchased peaking power, or constructing peaking units to provide the reliability function that is provided by interruptible customers.

Because of these differences, I believe that the methodology which PEF has applied is not appropriate.

Q **HAVE YOU INDEPENDENTLY EVALUATED THE LEVEL OF THE INTERRUPTIBLE CREDIT?**

A Yes. Exhibit MEB-11 ( ) shows the revenue requirement associated with a combustion turbine, which is a proxy for avoided capacity cost and can be used as a measure of interruptible credit adequacy.

Q **PLEASE EXPLAIN THIS EXHIBIT.**

A It shows the fixed cost revenue requirement of a newly-installed combustion turbine. The calculation uses capital and operating cost data taken from the Energy Information Administration's Annual Energy Outlook, 2005. The revenue requirement was calculated using EIA's capital cost and operating cost data, along with PEF's claimed cost of equity and capital structure. Since PEF maintains a 20% planning reserve margin, the revenue requirement per kilowatt of capacity is increased by 20% to establish the revenue requirement per kilowatt of load served.

Line 3 shows the monthly credit that would be appropriate based on these calculations. Using the first year revenue requirement for the CT would produce a monthly credit of $9 per kW while a levelized revenue requirement calculation would suggest a monthly credit in the vicinity of $7 per kW. Both of these credits are significantly higher than the current credit that applies to the IS-1 and IST-1 rate schedules.

This also clearly demonstrates that the existing credits are significantly below what can be justified, and establishes that PEF's proposal to significantly reduce credits paid to customers should be rejected.

Q UNDER PEF'S PROPOSAL, WOULD THE METHOD OF APPLYING THE INTERRUPTIBLE CREDIT THAT IS CURRENTLY USED IN IS-1 AND IST-1, BE CHANGED?

A Yes. Under PEF's proposal the demand credit would be reduced in proportion to the customer's load factor, as calculated on the customer's billing demand. Currently, a customer receives a credit based on its maximum demand. For example, a customer with a calculated billing load factor for the month of 75% would experience a reduction of 25% in the level of the credit. PEF doesn't explain the reason for this adjustment, or why it is appropriate.

Q DO YOU AGREE WITH THIS APPROACH?

A No. Reducing the credit based on billing load factor assumes that there is a direct relationship between billing load factor and a customer's demand at the time PEF would interrupt. Since the customer has to pay for the maximum demand experienced for the month, and must reduce the demand to zero whenever PEF decides that it needs the capacity, it is appropriate for the customer to receive a credit based on that same maximum demand. PEF's approach greatly understates the value of interruptible power and further adds to the increases that interruptible customers would experience.

Q ARE THERE OTHER SIGNIFICANT CHANGES PROPOSED TO INTERRUPTIBLE TARIFFS?

A Yes. PEF has proposed dramatically to reduce the credits for interruptible demand on the standby schedule, SS-2.

Q **DO YOU AGREE WITH THE PROPOSED CREDITS?**

A No.

Q **PLEASE EXPLAIN.**

A To explain the problem with Mr. Slusser's calculation, it is necessary first to consider how the standby charges for firm service were determined. These calculations are set forth on Schedule D to MFR Schedule E-14 Supplement. As shown on page 2, the monthly reservation charge is equal to the production capacity component plus the transmission component, times 10% as an anticipated forced outage factor for cogenerators. The peak day utilization charge is simply the same production and transmission cost divided by 21 on-peak days in a typical month. The standby customer pays the larger of the standby charge or the application of the daily prices to the actual use of standby service. Although this particular 10% factor would tend to overcharge a customer with a more reliable generating facility, the general approach to determining the charges for firm standby service is reasonable.

Q **DID MR. SLUSSER USE THE SAME APPROACH TO DETERMINE THE CHARGES FOR INTERRUPTIBLE STANDBY SERVICE?**

A No. He started from a completely different place. To calculate the credit for interruptible standby service, he began with his proposed interruptible capacity credit in the IS-2 rate, and multiplied it by 10%. To obtain the daily credit he began with the same IS capacity credit and divided it by 21.

Q WHAT IS WRONG WITH HIS CALCULATION?

A First, the credit that Mr. Slusser starts with (putting aside the issue on whether or not the IS-1 rate should remain in place) is a credit that is applied to the demand charge in the interruptible tariff, it is not a credit that is applied to the unit cost of generation and transmission. Thus, there is a mismatch to begin with. Second, the 10% unavailability factor applies to generation capacity. It is not clear what relationship, if any, it might have to the standby credit. Third, and for much the same reason, simply dividing the credit by 21 days per month has no relationship to the unit cost of generation and transmission to which the credit is applied.

Q HOW SHOULD THESE CREDITS BE CALCULATED?

A I believe the logical way to calculate these credits is to determine the relationship between the credit in the interruptible tariff and the demand charge in the interruptible tariff and use that percentage to apply to the firm standby charges to develop the interruptible credit.

Assuming little or no change in the IS-1 rates, the current relationship of approximately 72% ($3.37/kW credit ÷ $4.70/kW demand charge) should be applied to the calculated firm rate standby charges to determine the credit applicable to customers taking interruptible standby service.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Qualifications of Maurice Brubaker

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

A Maurice Brubaker. My business address is 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141.

Q **PLEASE STATE YOUR OCCUPATION.**

A I am a consultant in the field of public utility regulation and President of the firm of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

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

A I was graduated from the University of Missouri in 1965, with a Bachelor's Degree in Electrical Engineering. Subsequent to graduation I was employed by the Utilities Section of the Engineering and Technology Division of Esso Research and Engineering Corporation of Morristown, New Jersey, a subsidiary of Standard Oil of New Jersey.

In the Fall of 1965, I enrolled in the Graduate School of Business at Washington University in St. Louis, Missouri. I was graduated in June of 1967 with the Degree of Master of Business Administration. My major field was finance.

From March of 1966 until March of 1970, I was employed by Emerson Electric Company in St. Louis. During this time I pursued the Degree of Master of Science in Engineering at Washington University, which I received in June, 1970.

In March of 1970, I joined the firm of Drazen Associates, Inc., of St. Louis, Missouri. Since that time I have been engaged in the preparation of numerous studies relating to electric, gas, and water utilities. These studies have included analyses of the cost to serve various types of customers, the design of rates for utility services, cost forecasts, cogeneration rates and determinations of rate base and operating income. I have also addressed utility resource planning principles and plans, reviewed capacity additions to determine whether or not they were used and useful, addressed demand-side management issues independently and as part of least cost planning, and have reviewed utility determinations of the need for capacity additions and/or purchased power to determine the consistency of such plans with least cost planning principles. I have also testified about the prudency of the actions undertaken by utilities to meet the needs of their customers in the wholesale power markets and have recommended disallowances of costs where such actions were deemed imprudent.

I have testified before the Federal Energy Regulatory Commission (FERC), various courts and legislatures, and the state regulatory commissions of Alabama, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Georgia, Guam, Hawaii, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Missouri, Nevada, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, South Dakota, Texas, Utah, Virginia, West Virginia, Wisconsin and Wyoming.

The firm of Drazen-Brubaker & Associates, Inc. was incorporated in 1972 and assumed the utility rate and economic consulting activities of Drazen Associates, Inc., founded in 1937. In April, 1995 the firm of Brubaker & Associates, Inc. was formed. It includes most of the former DBA principals and staff. Our staff includes consultants with backgrounds in accounting, engineering, economics, mathematics, computer science and business.

During the past ten years, Brubaker & Associates, Inc. and its predecessor firm has participated in over 700 major utility rate and other cases and statewide generic investigations before utility regulatory commissions in 40 states, involving electric, gas, water, and steam rates and other issues. Cases in which the firm has been involved have included more than 80 of the 100 largest electric utilities and over 30 gas distribution companies and pipelines.

An increasing portion of the firm's activities is concentrated in the areas of competitive procurement. While the firm has always assisted its clients in negotiating contracts for utility services in the regulated environment, increasingly there are opportunities for certain customers to acquire power on a competitive basis from a supplier other than its traditional electric utility. The firm assists clients in identifying and evaluating purchased power options, conducts RFPs and negotiates with suppliers for the acquisition and delivery of supplies. We have prepared option studies and/or conducted RFPs for competitive acquisition of power supply for industrial and other end-use customers throughout the Unites States and in Canada, involving total needs in excess of 3,000 megawatts. The firm is also an associate member of the Electric Reliability Council of Texas and a licensed electricity aggregator in the State of Texas.

In addition to our main office in St. Louis, the firm has branch offices in Phoenix, Arizona; Chicago, Illinois; Corpus Christi, Texas; and Plano, Texas.

\\Snap4100\Docs\TSK\8383\Testimony\69121.doc

BRUBAKER & ASSOCIATES, INC.

Comparative Study of the Cost of Power to an Industrial Customer as of April, 2005 50,000 kW Load, 90% Load Factor and 90% Power Factor at Transmission Level

50,000 kW Firm Power

Line	Utility Company	Total Cost (1)	Cents per kWh (2)
1	Tampa Electric Company	$ 2,150,120	6.545
2	**Progress Energy Florida**	**2,126,524**	**6.473**
3	El Paso Electric Company, TX	2,058,841	6.267
4	Entergy Louisiana, Inc.	2,057,687	6.264
5	Entergy Gulf States, Inc., LA	1,990,283	6.059
6	Entergy Mississippi, Inc.	1,987,138	6.049
7	Dominion North Carolina Power	1,916,209	5.833
8	Florida Power & Light Company	1,906,933	5.805
9	Central Louisiana Electric Company, Inc.	1,887,259	5.745
10	Entergy Gulf States, Inc., TX	1,878,428	5.718
11	Entergy New Orleans, Inc.	1,813,782	5.521
12	Progress Energy Carolinas, NC	1,716,435	5.225
13	Savannah Electric & Power Company	1,700,743	5.177
14	Mississippi Power Company	1,660,831	5.056
15	Empire District Electric Company, OK	1,645,978	5.011
16	Southwestern Public Service Company, OK	1,564,667	4.763
17	Gulf Power Company	1,551,581	4.723
18	Progress Energy Carolinas, SC	1,515,114	4.612
19	Georgia Power Company	1,492,747	4.544
20	Public Service Company of Oklahoma	1,486,479	4.525
21	South Carolina Electric & Gas Company	1,398,829	4.258
22	Nantahala Power & Light Company	1,332,080	4.055
23	Duke Power Company, NC	1,325,938	4.036
24	Alabama Power Company	1,322,394	4.026
25	Oklahoma Gas & Electric Company, OK	1,302,518	3.965
26	Empire District Electric Company, AR	1,271,366	3.870
27	Entergy Arkansas, Inc.	1,270,405	3.867
28	Southwestern Electric Power Company, AR	1,245,627	3.792
29	Oklahoma Gas & Electric Company, AR	1,227,401	3.736
30	Southwestern Public Service Company, TX	1,203,482	3.664
31	Tennessee Valley Authority	1,202,178	3.660
32	Southwestern Electric Power Company, TX	1,193,033	3.632
33	Kentucky Utilities Company	1,146,987	3.492
34	Louisville Gas and Electric Company	1,105,130	3.364
35	Duke Power Company, SC	1,095,570	3.335
36	Kingsport Power Company	1,042,900	3.175
37	Southwestern Electric Power Company, LA	1,024,341	3.118
38	Kentucky Power Company	1,024,158	3.118

Utilities in Previous Study that have been removed because of Texas Customer Choice:
Central Power and Light Company
Reliant Energy - HL&P
TXU
West Texas Utilities

BRUBAKER & ASSOCIATES, INC.

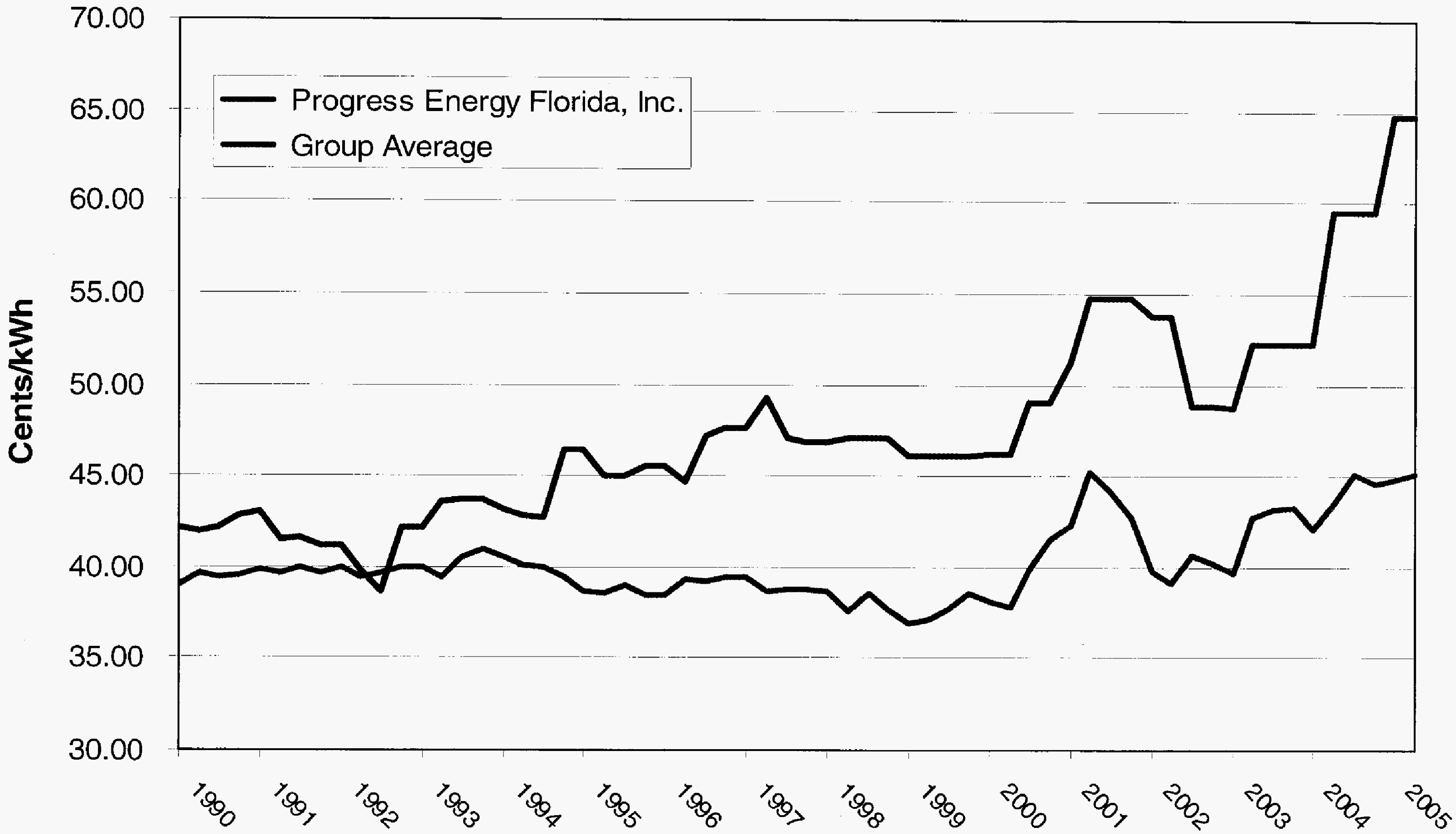
Comparative Study of the Cost of Power to an Industrial Customer as of April, 2005 50,000 kW Load, 90% Load Factor and 90% Power Factor at Transmission Level

Maximum Allowable Amount of Interruptible Power

Line	Utility Company	Total Cost (1)	Cents per kWh (2)
1	Entergy Louisiana, Inc.	$ 1,866,130	5.681
2	Entergy Gulf States, Inc., LA	1,862,979	5.671
3	Florida Power & Light Company	1,827,122	5.562
4	Entergy Gulf States, Inc., TX	1,771,214	5.392
5	**Progress Energy Florida**	**1,767,303**	**5.380**
6	Tampa Electric Company	1,757,731	5.351
7	Dominion North Carolina Power	1,671,812	5.089
8	Savannah Electric & Power Company	1,626,836	4.952
9	Empire District Electric Company, OK	1,554,712	4.733
10	Progress Energy Carolinas, NC	1,496,985	4.557
11	Entergy New Orleans, Inc.	1,393,206	4.241
12	Public Service Company of Oklahoma	1,365,450	4.157
13	Georgia Power Company	1,282,260	3.903
14	Progress Energy Carolinas, SC	1,265,114	3.851
15	Empire District Electric Company, AR	1,196,646	3.643
16	Alabama Power Company	1,193,886	3.634
17	South Carolina Electric & Gas Company	1,173,829	3.573
18	Oklahoma Gas & Electric Company, OK	1,170,326	3.563
19	Duke Power Company, NC	1,143,089	3.480
20	El Paso Electric Company, TX	1,141,426	3.475
21	Southwestern Public Service Company, TX	1,123,237	3.419
22	Tennessee Valley Authority	1,108,763	3.375
23	Southwestern Electric Power Company, TX	1,103,335	3.359
24	Southwestern Electric Power Company, AR	1,101,882	3.354
25	Kentucky Utilities Company	932,671	2.839
26	Duke Power Company, SC	920,595	2.802
27	Louisville Gas and Electric Company	901,737	2.745
28	Entergy Arkansas, Inc.	850,484	2.589
29	Kentucky Power Company	n/a	
30	Kingsport Power Company	n/a	
31	Central Louisiana Electric Company, Inc.	n/a	
32	Entergy Mississippi, Inc.	n/a	
33	Gulf Power Company	n/a	
34	Mississippi Power Company	n/a	
35	Nantahala Power & Light Company	n/a	
36	Oklahoma Gas & Electric Company, AR	n/a	
37	Southwestern Electric Power Company, LA	n/a	
38	Southwestern Public Service Company, OK	n/a	

Utilities in Previous Study that have been removed because of Texas Customer Choice:
Central Power and Light Company
Reliant Energy - HL&P
TXU
West Texas Utilities

Average Quarterly Cost of Firm Power for an Industrial Customer
with a 50,000 kW Load, 90% Load Factor and 90% Power Factor and Transmission Service
Progress Energy Florida, Inc. vs. Group Average



Source: Quarterly data, January 1990 through April 2005

Docket No. 050078-EI
Witness: Maurice Brubaker
Exhibit No. MEB-2 ( )

EEI Typical Bill Cost for a Residential Customer with Monthly Usage of 750 kWh

Weighted Average Costs in ¢/kWh for Summer 2004 and Winter 2005

Line	Utility Company		Cost ¢/kWh
1	El Paso Electric Company, TX	TX	10.81
2	Tampa Electric Company	FL	10.13
3	Entergy Mississippi, Inc.	MS	10.02
4	Entergy Gulf States, Inc. TX	TX	9.67
5	**Progress Energy Florida**	**FL**	**9.54**
6	Mississippi Power Company	MS	9.50
7	Dominion North Carolina Power	NC	9.49
8	Entergy Gulf States, Inc.	LA	9.10
9	South Carolina Electric & Gas Company	SC	9.09
10	Entergy Louisiana, Inc.	LA	8.95
11	Entergy Arkansas, Inc.	AR	8.85
12	Progress Energy Carolinas, Inc.	NC	8.83
13	Florida Power & Light Company	FL	8.82
14	CLECO Power LLC	LA	8.78
15	Progress Energy Carolinas, Inc.	SC	8.77
16	Gulf Power Company	FL	8.69
17	Alabama Power Company	AL	8.34
18	Oklahoma Gas & Electric Company	OK	8.21
19	Duke Power Company	NC	8.20
20	Entergy New Orleans, Inc.	LA	8.08
21	Public Service Company of Oklahoma	OK	7.70
22	OG&E Electric Services	AR	7.65
23	Georgia Power Company	GA	7.38
24	Duke Power Company	SC	7.37
25	Empire District Electric Company	OK	7.33
26	Southwestern Public Service Company, OK	OK	7.30
27	Southwestern Public Service Company, TX	TX	7.17
28	Empire District Electric Company	AR	7.00
29	Southwestern Electric Power Company	AR	6.69
30	Louisville Gas & Electric Company	KY	6.67
31	Southwestern Electric Power Company	TX	6.37
32	AEP (Kentucky Power Rate Area)	KY	6.35
33	Southwestern Electric Power Company	LA	6.29
34	Kentucky Utilities Company	KY	5.39
35	AEP (Kingsport Power Rate Area)	TN	5.37

Source: Edison Electric Institute, "Typical Bills and Average Rates Report", Summer 2004 and Winter 2005

EEI Typical Bill Cost for a Residential Customer with Monthly Usage of 1,000 kWh

Weighted Average Costs in ¢/kWh for Summer 2004 and Winter 2005

Line	Utility Company		Cost ¢/kWh
1	El Paso Electric Company, TX	TX	10.66
2	Tampa Electric Company	FL	9.84
3	Entergy Gulf States, Inc. TX	TX	9.53
4	Entergy Mississippi, Inc.	MS	9.32
5	**Progress Energy Florida**	**FL**	**9.27**
6	Dominion North Carolina Power	NC	9.17
7	Entergy Gulf States, Inc.	LA	8.95
8	Florida Power & Light Company	FL	8.88
9	South Carolina Electric & Gas Company	SC	8.84
10	Entergy Louisiana, Inc.	LA	8.82
11	Mississippi Power Company	MS	8.79
12	Entergy Arkansas, Inc.	AR	8.62
13	Progress Energy Carolinas, Inc.	NC	8.61
14	Progress Energy Carolinas, Inc.	SC	8.42
15	CLECO Power LLC	LA	8.39
16	Gulf Power Company	FL	8.34
17	Duke Power Company	NC	8.02
18	Entergy New Orleans, Inc.	LA	7.93
19	Alabama Power Company	AL	7.85
20	Oklahoma Gas & Electric Company	OK	7.49
21	Public Service Company of Oklahoma	OK	7.38
22	OG&E Electric Services	AR	7.28
23	Georgia Power Company	GA	7.25
24	Duke Power Company	SC	7.17
25	Southwestern Public Service Company, OK	OK	6.90
26	Southwestern Public Service Company, TX	TX	6.80
27	Empire District Electric Company	OK	6.76
28	Empire District Electric Company	AR	6.52
29	Louisville Gas & Electric Company	KY	6.50
30	Southwestern Electric Power Company	AR	6.46
31	Southwestern Electric Power Company	LA	6.11
32	AEP (Kentucky Power Rate Area)	KY	6.07
33	Southwestern Electric Power Company	TX	5.95
34	Kentucky Utilities Company	KY	5.22
35	AEP (Kingsport Power Rate Area)	TN	5.13

Source: Edison Electric Institute, "Typical Bills and Average Rates Report", Summer 2004 and Winter 2005

EEI Typical Bill Cost for a Commercial Customer with Monthly Usage of 500 kW and 150,000 kWh

Weighted Average Costs in ¢/kWh for Summer 2004 and Winter 2005

Line	Utility Company		Cost ¢/kWh
1	El Paso Electric Company, TX	TX	11.04
2	**Progress Energy Florida**	**FL**	**9.52**
3	Tampa Electric Company	FL	8.30
4	Entergy Mississippi, Inc.	MS	8.07
5	Florida Power & Light Company	FL	8.02
6	Entergy Gulf States, Inc.	LA	7.95
7	Alabama Power Company	AL	7.93
8	Entergy Gulf States, Inc. TX	TX	7.87
9	South Carolina Electric & Gas Company	SC	7.82
10	Entergy Louisiana, Inc.	LA	7.80
11	Dominion North Carolina Power	NC	7.37
12	CLECO Power LLC	LA	7.34
13	Entergy New Orleans, Inc.	LA	7.05
14	Georgia Power Company	GA	7.01
15	Mississippi Power Company	MS	6.97
16	Gulf Power Company	FL	6.94
17	Southwestern Public Service Company, TX	TX	6.59
18	Louisville Gas & Electric Company	KY	6.50
19	Progress Energy Carolinas, Inc.	SC	6.45
20	Oklahoma Gas & Electric Company	OK	6.41
21	Progress Energy Carolinas, Inc.	NC	6.33
22	Duke Power Company	NC	6.27
23	Public Service Company of Oklahoma	OK	6.26
24	Southwestern Public Service Company, OK	OK	6.22
25	Duke Power Company	SC	5.89
26	AEP (Kentucky Power Rate Area)	KY	5.75
27	Empire District Electric Company	OK	5.75
28	Entergy Arkansas, Inc.	AR	5.73
29	Empire District Electric Company	AR	5.65
30	OG&E Electric Services	AR	5.42
31	AEP (Kingsport Power Rate Area)	TN	4.97
32	Southwestern Electric Power Company	LA	4.89
33	Kentucky Utilities Company	KY	4.84
34	Southwestern Electric Power Company	AR	4.43
35	Southwestern Electric Power Company	TX	4.40

Source: Edison Electric Institute, "Typical Bills and Average Rates Report", Summer 2004 and Winter 2005

EEI Typical Bill Cost for a Commercial Customer with Monthly Usage of 500 kW and 180,000 kWh

Weighted Average Costs in ¢/kWh for Summer 2004 and Winter 2005

Line	Utility Company		Cost ¢/kWh
1	El Paso Electric Company, TX	TX	10.18
2	**Progress Energy Florida**	**FL**	**9.32**
3	Tampa Electric Company	FL	7.88
4	Entergy Mississippi, Inc.	MS	7.81
5	Entergy Gulf States, Inc.	LA	7.70
6	Entergy Gulf States, Inc. TX	TX	7.65
7	Entergy Louisiana, Inc.	LA	7.56
8	Florida Power & Light Company	FL	7.55
9	Alabama Power Company	AL	7.40
10	South Carolina Electric & Gas Company	SC	6.96
11	Dominion North Carolina Power	NC	6.96
12	CLECO Power LLC	LA	6.92
13	Entergy New Orleans, Inc.	LA	6.68
14	Mississippi Power Company	MS	6.46
15	Gulf Power Company	FL	6.43
16	Georgia Power Company	GA	6.29
17	Southwestern Public Service Company, TX	TX	6.08
18	Duke Power Company	NC	6.07
19	Oklahoma Gas & Electric Company	OK	6.01
20	Progress Energy Carolinas, Inc.	SC	5.98
21	Public Service Company of Oklahoma	OK	5.92
22	Progress Energy Carolinas, Inc.	NC	5.86
23	Louisville Gas & Electric Company	KY	5.82
24	Southwestern Public Service Company, OK	OK	5.75
25	Duke Power Company	SC	5.65
26	AEP (Kentucky Power Rate Area)	KY	5.53
27	Empire District Electric Company	OK	5.39
28	Entergy Arkansas, Inc.	AR	5.29
29	Empire District Electric Company	AR	5.28
30	OG&E Electric Services	AR	5.10
31	AEP (Kingsport Power Rate Area)	TN	4.72
32	Southwestern Electric Power Company	LA	4.60
33	Kentucky Utilities Company	KY	4.43
34	Southwestern Electric Power Company	AR	4.17
35	Southwestern Electric Power Company	TX	4.11

Source: Edison Electric Institute, "Typical Bills and Average Rates Report", Summer 2004 and Winter 2005

EEI Typical Bill Cost for a Industrial Customer
with Monthly Usage of 1,000 kW and 400,000 kWh
Weighted Average Costs in ¢/kWh for Summer 2004 and Winter 2005

Line	Utility Company		Cost ¢/kWh
1	El Paso Electric Company, TX	TX	9.68
2	**Progress Energy Florida**	**FL**	**9.19**
3	Tampa Electric Company	FL	7.69
4	Entergy Gulf States, Inc.	LA	7.38
5	Florida Power & Light Company	FL	7.30
6	Entergy Mississippi, Inc.	MS	7.27
7	Entergy Gulf States, Inc. TX	TX	7.13
8	Entergy Louisiana, Inc.	LA	7.04
9	Progress Energy Carolinas, Inc.	NC	6.73
10	CLECO Power LLC	LA	6.70
11	Dominion North Carolina Power	NC	6.57
12	Georgia Power Company	GA	6.44
13	Entergy New Orleans, Inc.	LA	6.42
14	Progress Energy Carolinas, Inc.	SC	6.25
15	Gulf Power Company	FL	6.13
16	Mississippi Power Company	MS	5.98
17	Southwestern Public Service Company, TX	TX	5.73
18	Public Service Company of Oklahoma	OK	5.73
19	South Carolina Electric & Gas Company	SC	5.72
20	Oklahoma Gas & Electric Company	OK	5.59
21	Southwestern Public Service Company, OK	OK	5.49
22	Duke Power Company	NC	5.08
23	Entergy Arkansas, Inc.	AR	5.06
24	Empire District Electric Company	AR	5.05
25	Alabama Power Company	AL	5.05
26	Empire District Electric Company	OK	5.03
27	Louisville Gas & Electric Company	KY	4.71
28	Duke Power Company	SC	4.70
29	AEP (Kentucky Power Rate Area)	KY	4.50
30	Southwestern Electric Power Company	LA	4.45
31	OG&E Electric Services	AR	4.43
32	Kentucky Utilities Company	KY	4.11
33	AEP (Kingsport Power Rate Area)	TN	4.10
34	Southwestern Electric Power Company	AR	4.03
35	Southwestern Electric Power Company	TX	3.97

Source: Edison Electric Institute, "Typical Bills and Average Rates Report", Summer 2004 and Winter 2005

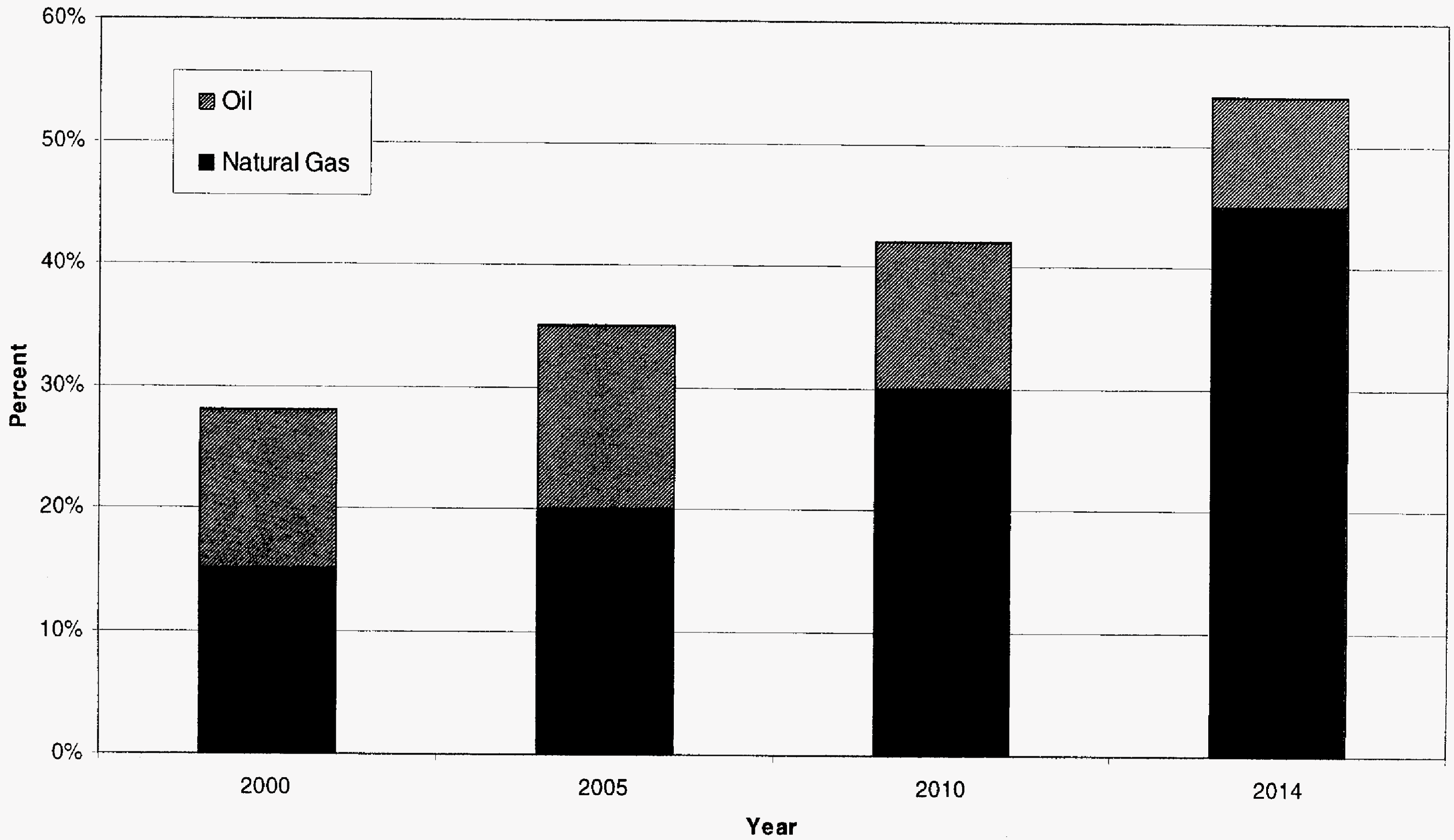
EEI Typical Bill Cost for a Industrial Customer
with Monthly Usage of 1,000 kW and 650,000 kWh
Weighted Average Costs in ¢/kWh for Summer 2004 and Winter 2005

Line	Utility Company		Cost ¢/kWh
1	El Paso Electric Company, TX	TX	7.14
2	Tampa Electric Company	FL	6.95
3	Entergy Gulf States, Inc.	LA	6.92
4	**Progress Energy Florida**	**FL**	**6.72**
5	Entergy Louisiana, Inc.	LA	6.61
6	Florida Power & Light Company	FL	6.49
7	Entergy Gulf States, Inc. TX	TX	6.43
8	Entergy Mississippi, Inc.	MS	6.43
9	CLECO Power LLC	LA	5.97
10	Entergy New Orleans, Inc.	LA	5.67
11	Dominion North Carolina Power	NC	5.52
12	Progress Energy Carolinas, Inc.	NC	5.41
13	Gulf Power Company	FL	5.25
14	Public Service Company of Oklahoma	OK	5.17
15	Progress Energy Carolinas, Inc.	SC	5.08
16	Mississippi Power Company	MS	5.07
17	Georgia Power Company	GA	4.95
18	Oklahoma Gas & Electric Company	OK	4.93
19	Southwestern Public Service Company, TX	TX	4.87
20	Southwestern Public Service Company, OK	OK	4.65
21	South Carolina Electric & Gas Company	SC	4.51
22	Empire District Electric Company	OK	4.47
23	Empire District Electric Company	AR	4.28
24	Duke Power Company	NC	4.20
25	Alabama Power Company	AL	4.20
26	OG&E Electric Services	AR	4.03
27	Southwestern Electric Power Company	LA	3.85
28	Entergy Arkansas, Inc.	AR	3.79
29	Duke Power Company	SC	3.74
30	Louisville Gas & Electric Company	KY	3.69
31	AEP (Kingsport Power Rate Area)	TN	3.68
32	Southwestern Electric Power Company	AR	3.58
33	AEP (Kentucky Power Rate Area)	KY	3.50
34	Southwestern Electric Power Company	TX	3.47
35	Kentucky Utilities Company	KY	2.93

Source: Edison Electric Institute, "Typical Bills and Average Rates Report", Summer 2004 and Winter 2005

PROGRESS ENERGY FLORIDA, INC.

Percent of Energy from Oil and Natural Gas



Source: 10 year PEF Site Plans for April 2001 and April 2005

Docket No. 050078-EI
Witness: Maurice Brubaker
Exhibit No. MEB-4 ( )

PROGRESS ENERGY FLORIDA, INC.

Cost per kW of Production Plant When Allocated Using
12 CP and 25% Energy
Projected Calendar Year 2006 Data, Fully Adjusted

Line	Description	Total Retail (1)	Residential RS (2)	Gen Serv NonDemand GS-1 (3)	Gen Serv 100% LF GS-2 (4)	Gen Serv Demand GSD, SS-1 (5)	Curtail-able CS, SS-3 (6)	Inter-ruptible IS, SS-2 (7)	Lighting LS (8)
	Production Plant (000):								
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

Docket No. 050078-EI
Witness: Maurice Brubaker
Exhibit No. MEB-5 (   )

PROGRESS ENERGY FLORIDA, INC.

Fuel and Purchased Power Energy Costs by Resource Category

Line	Resource Category	Total Cost (000) (1)	Net Generation MWh (2)	Fuel Cost Per Unit ¢/kWh (3)
1	Total Base	$1,186,735	41,860,583	2.835¢
2	Intermediate Total	$293,386	5,300,689	5.535¢
3	Peaking Total	$119,663	1,271,832	9.409¢
4	Total	$1,599,784	48,433,104	3.303¢

PROGRESS ENERGY FLORIDA, INC.

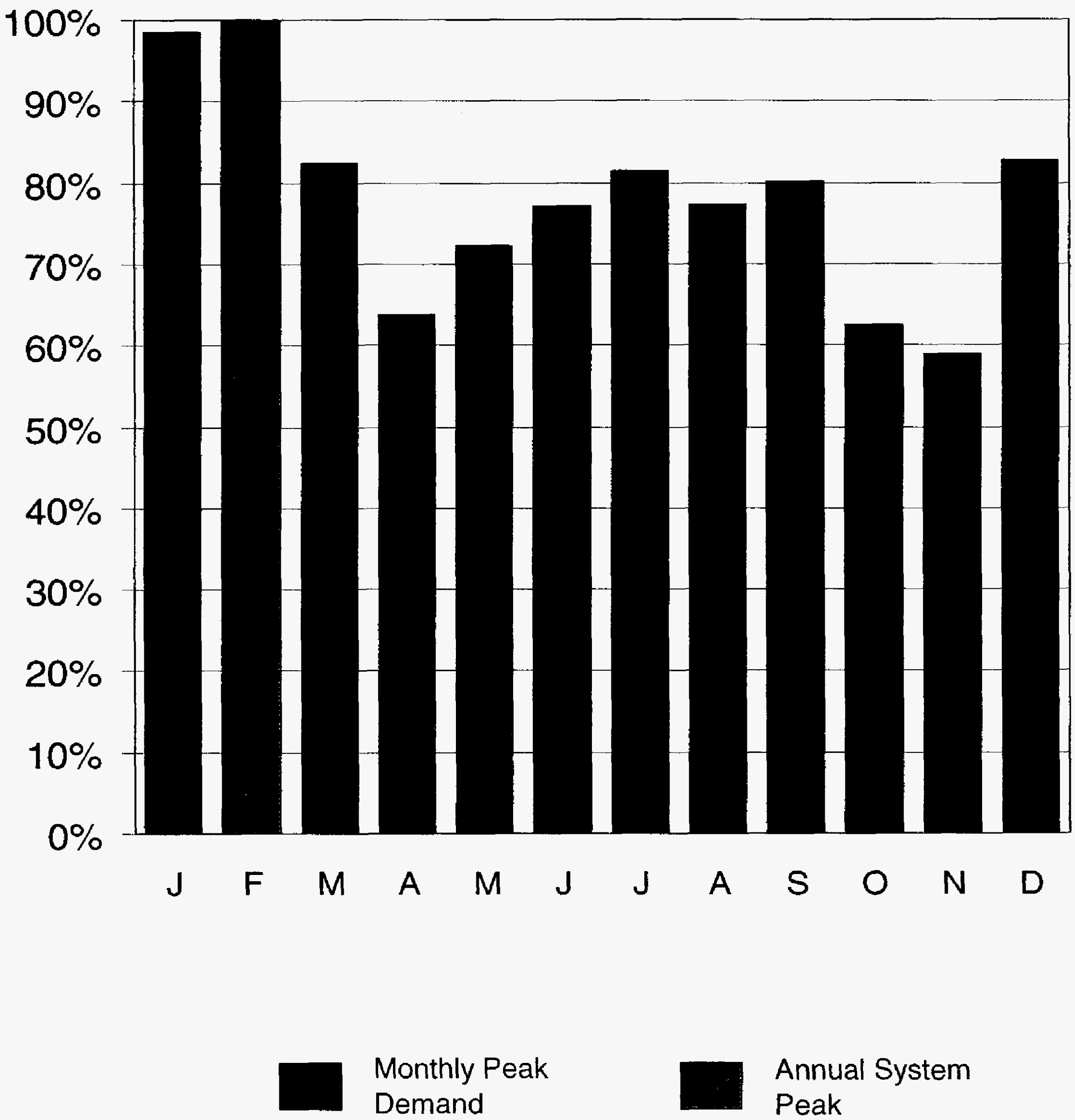
Summary of Load Characteristics
for Historical Years 1996 through 2004

Line	Year	System Peak (MW) (1)	Maximum-to-Minimum Monthly Peak (2)	Maximum-to-Average Monthly Peak (3)
1	1996	8,807	1.70	1.28
2	1997	8,066	1.60	1.25
3	1998	8,004	1.49	1.18
4	1999	8,318	1.58	1.22
5	2000	8,548	1.57	1.19
6	2001	9,839	1.83	1.31
7	2002	9,721	1.39	1.18
8	2003	10,507	1.61	1.33
9	2004	9,125	1.52	1.12

Source:
1996 through 2000: FERC Form No. 1, page 401.
2001 through 2004: MFR Schedule E-18, pages 1 and 2.

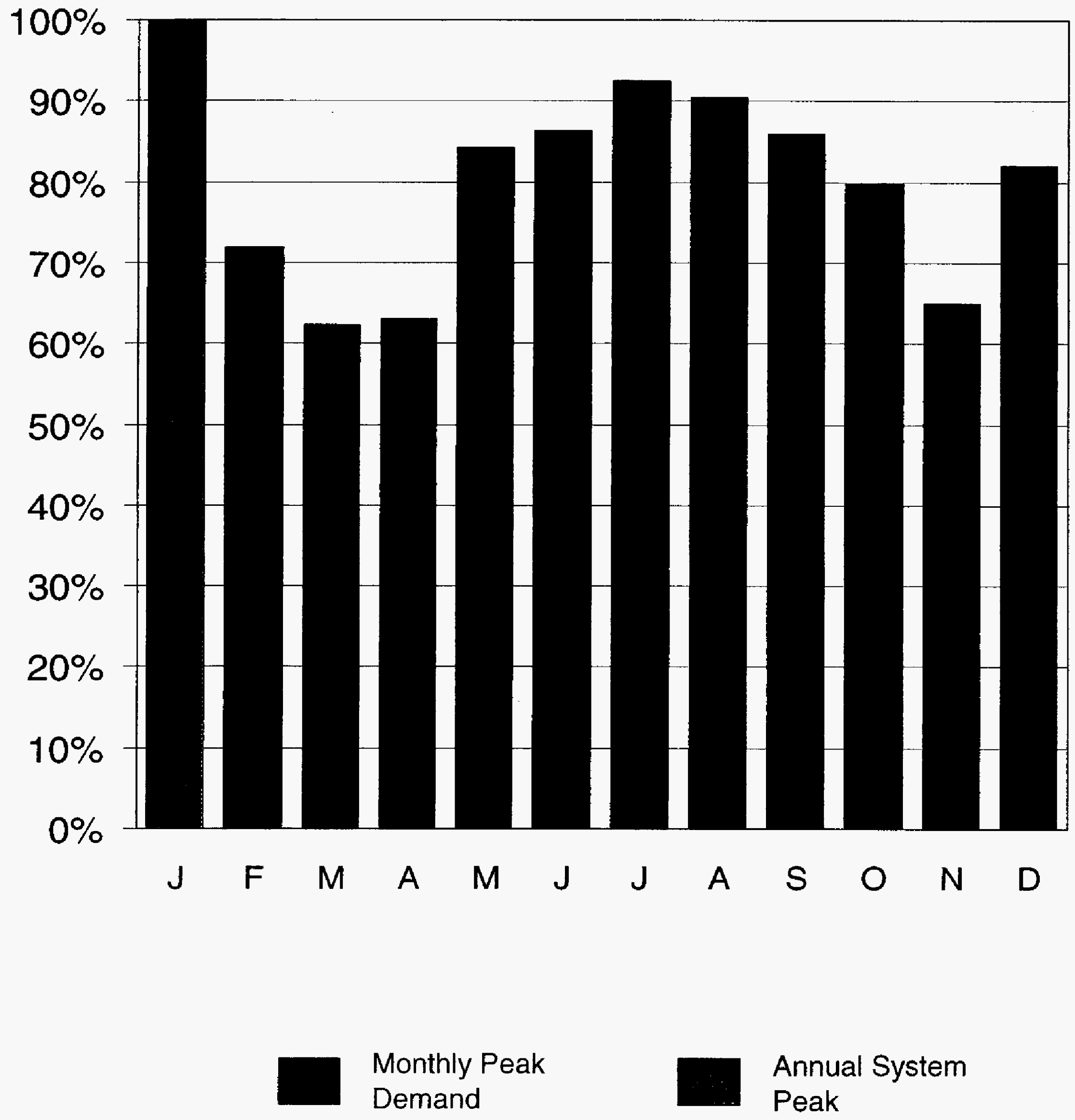
PROGRESS ENERGY FLORIDA, INC.

Analysis of Monthly Peak Demands
as a Percent of the Annual System Peak
for the Fiscal Year 1996



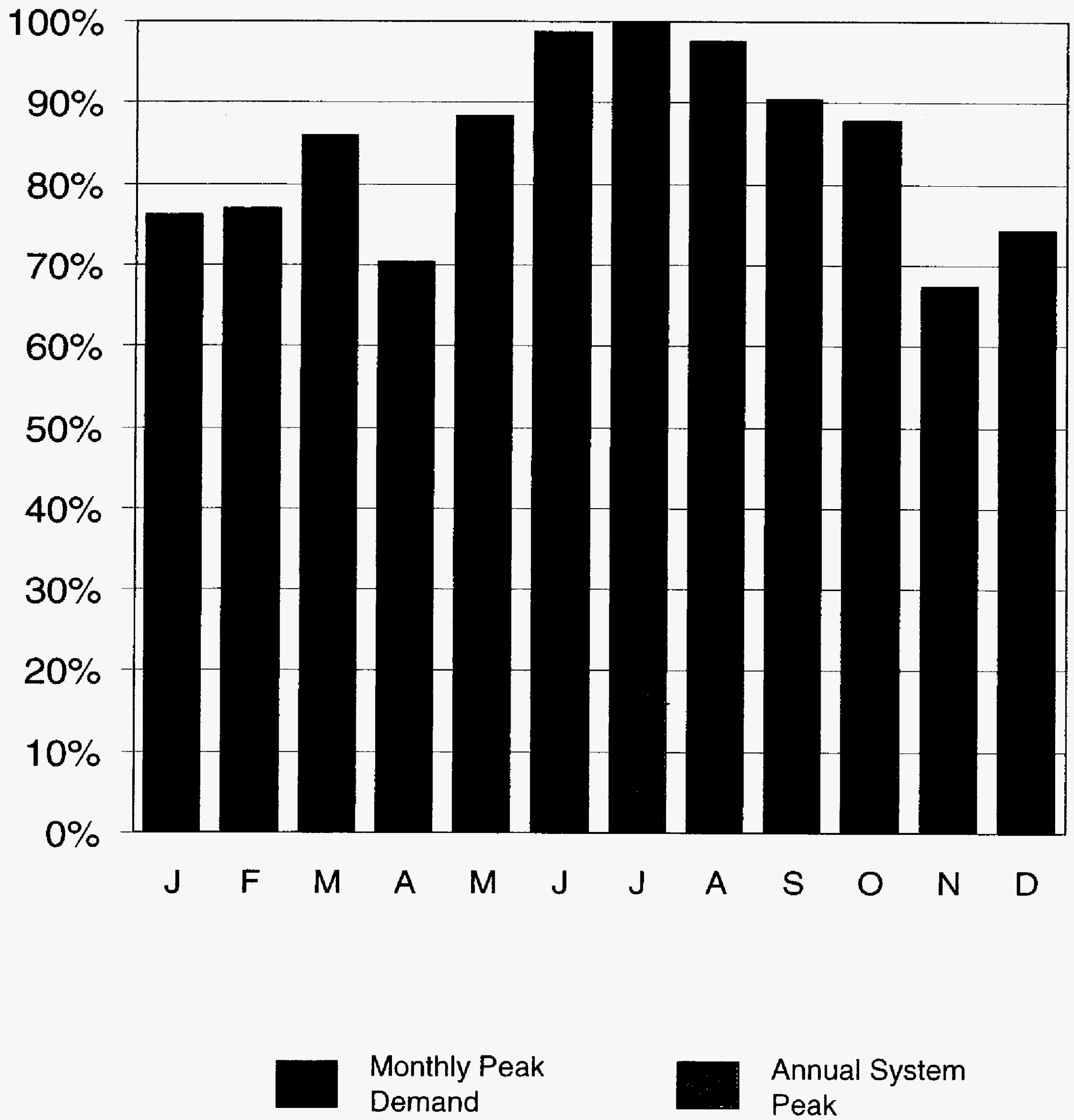
PROGRESS ENERGY FLORIDA, INC.

Analysis of Monthly Peak Demands
as a Percent of the Annual System Peak
for the Fiscal Year 1997



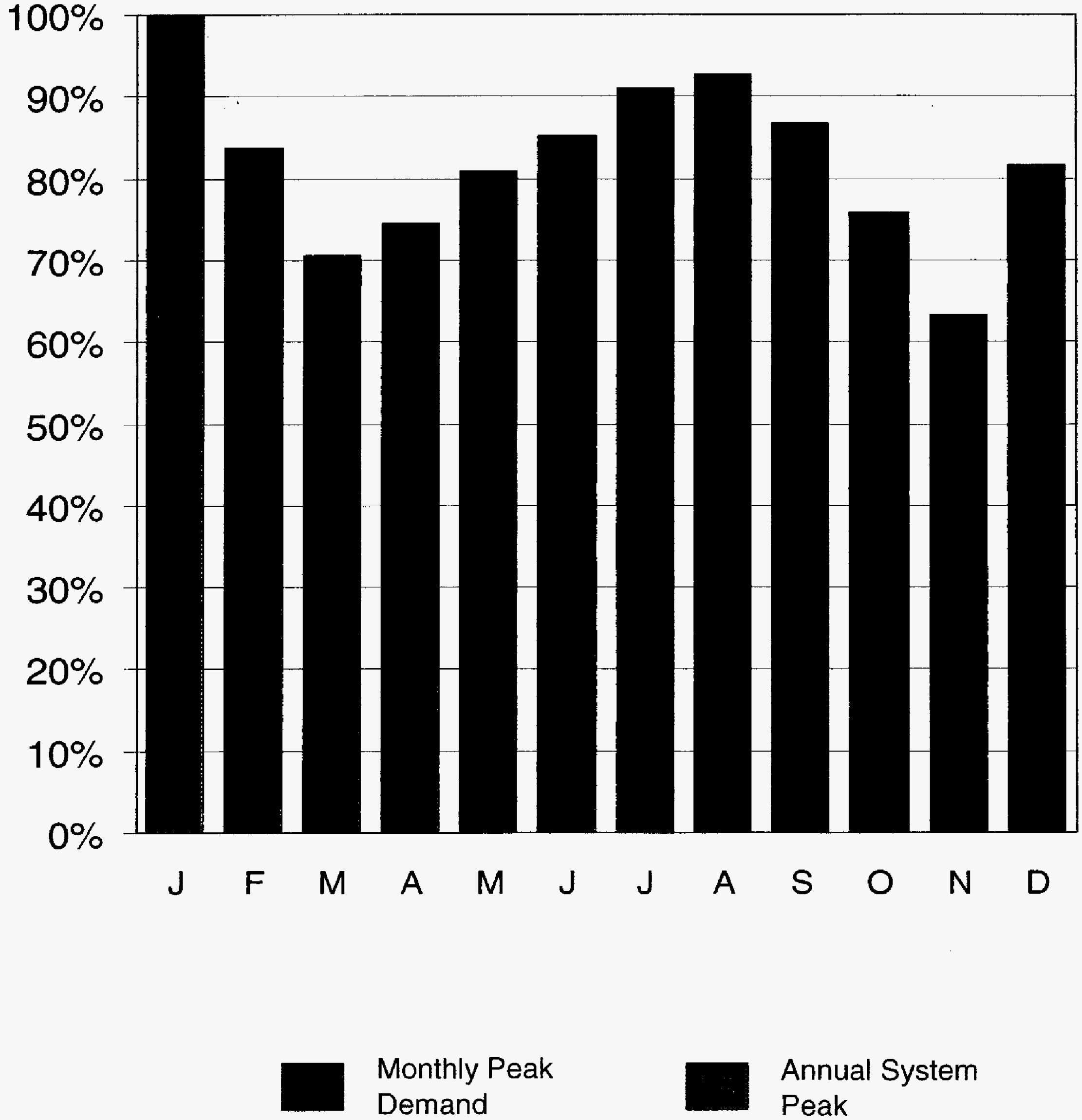
PROGRESS ENERGY FLORIDA, INC.

Analysis of Monthly Peak Demands
as a Percent of the Annual System Peak
for the Fiscal Year 1998



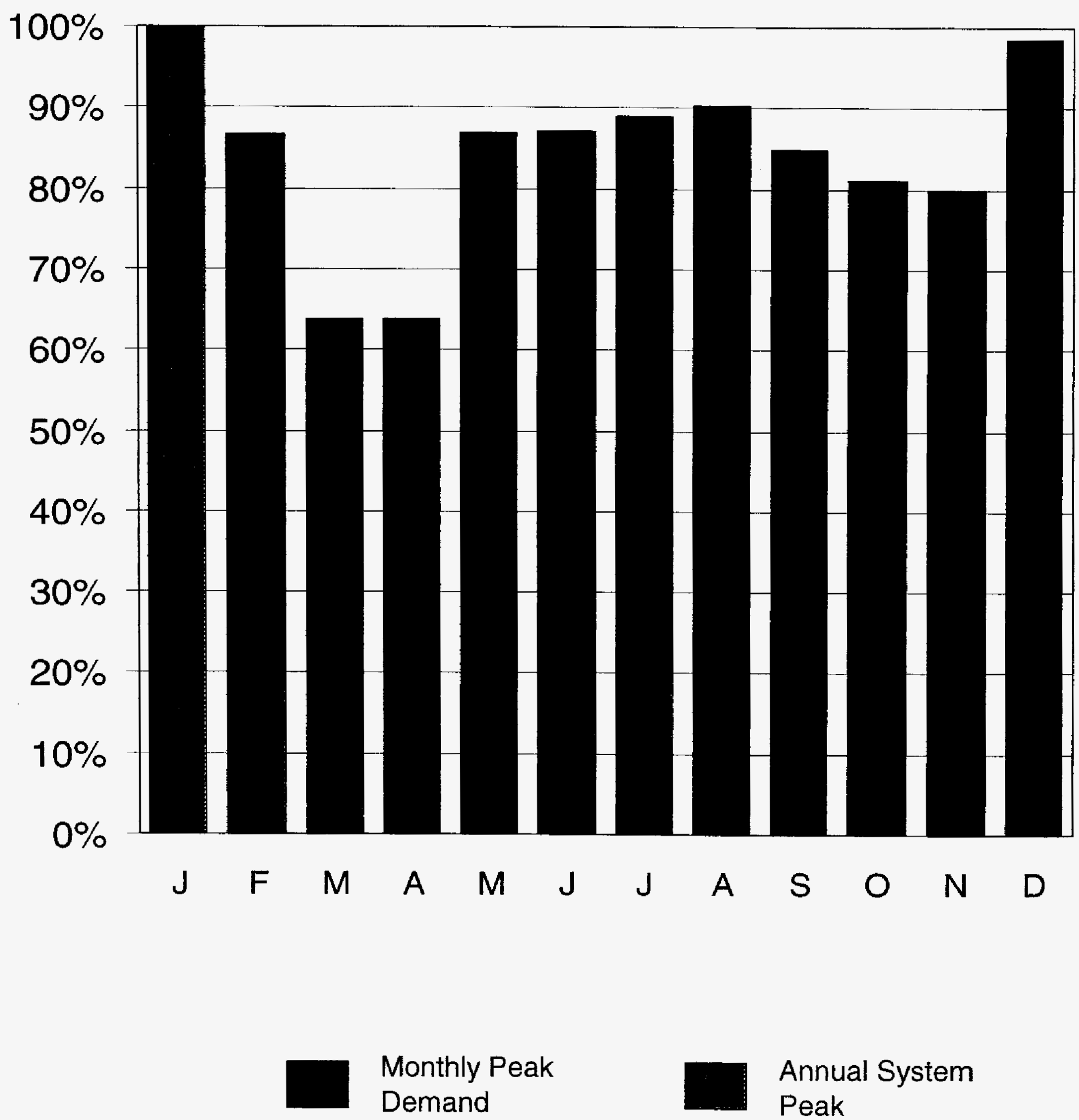
PROGRESS ENERGY FLORIDA, INC.

Analysis of Monthly Peak Demands
as a Percent of the Annual System Peak
for the Fiscal Year 1999



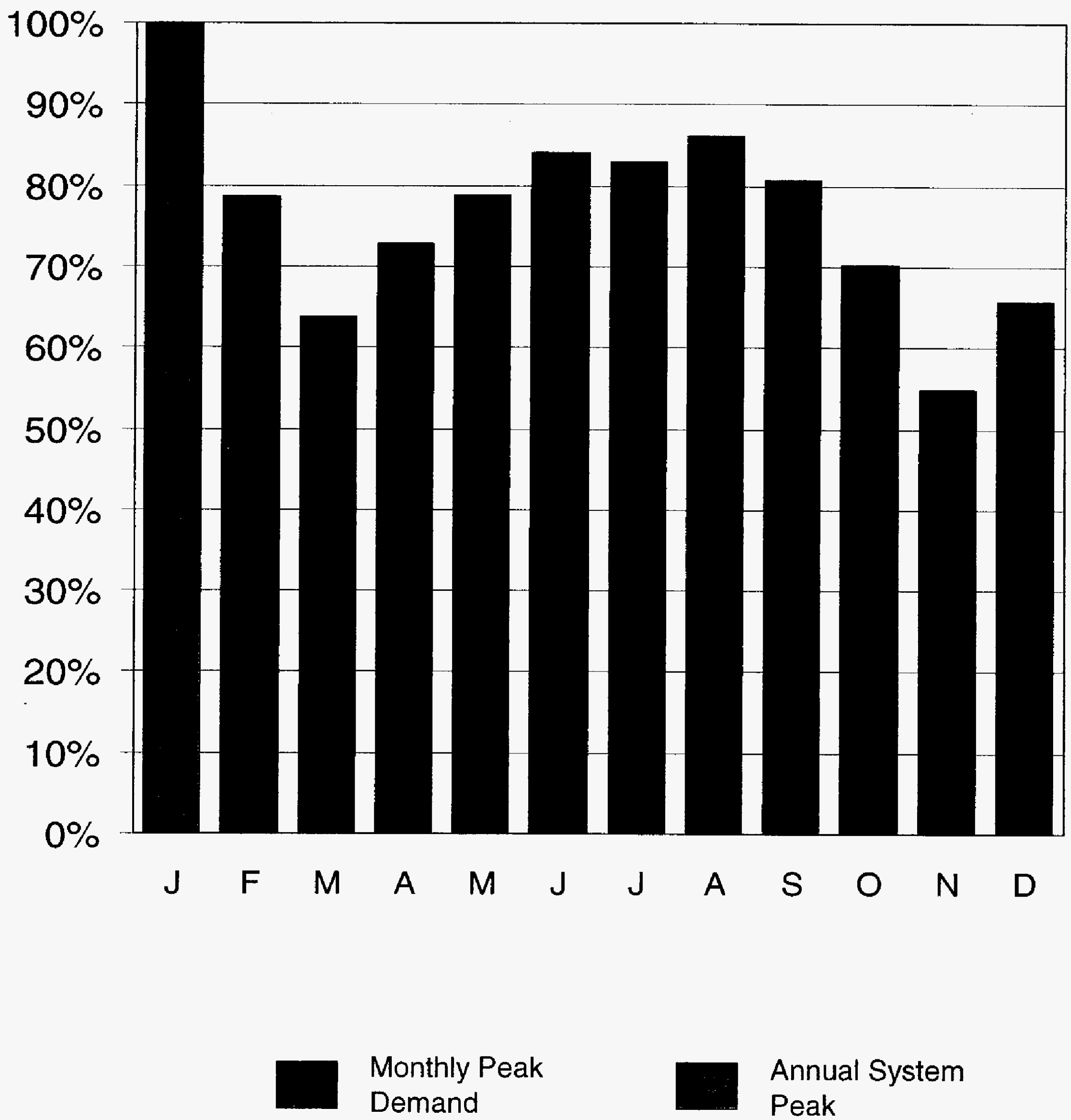
PROGRESS ENERGY FLORIDA, INC.

Analysis of Monthly Peak Demands
as a Percent of the Annual System Peak
for the Fiscal Year 2000



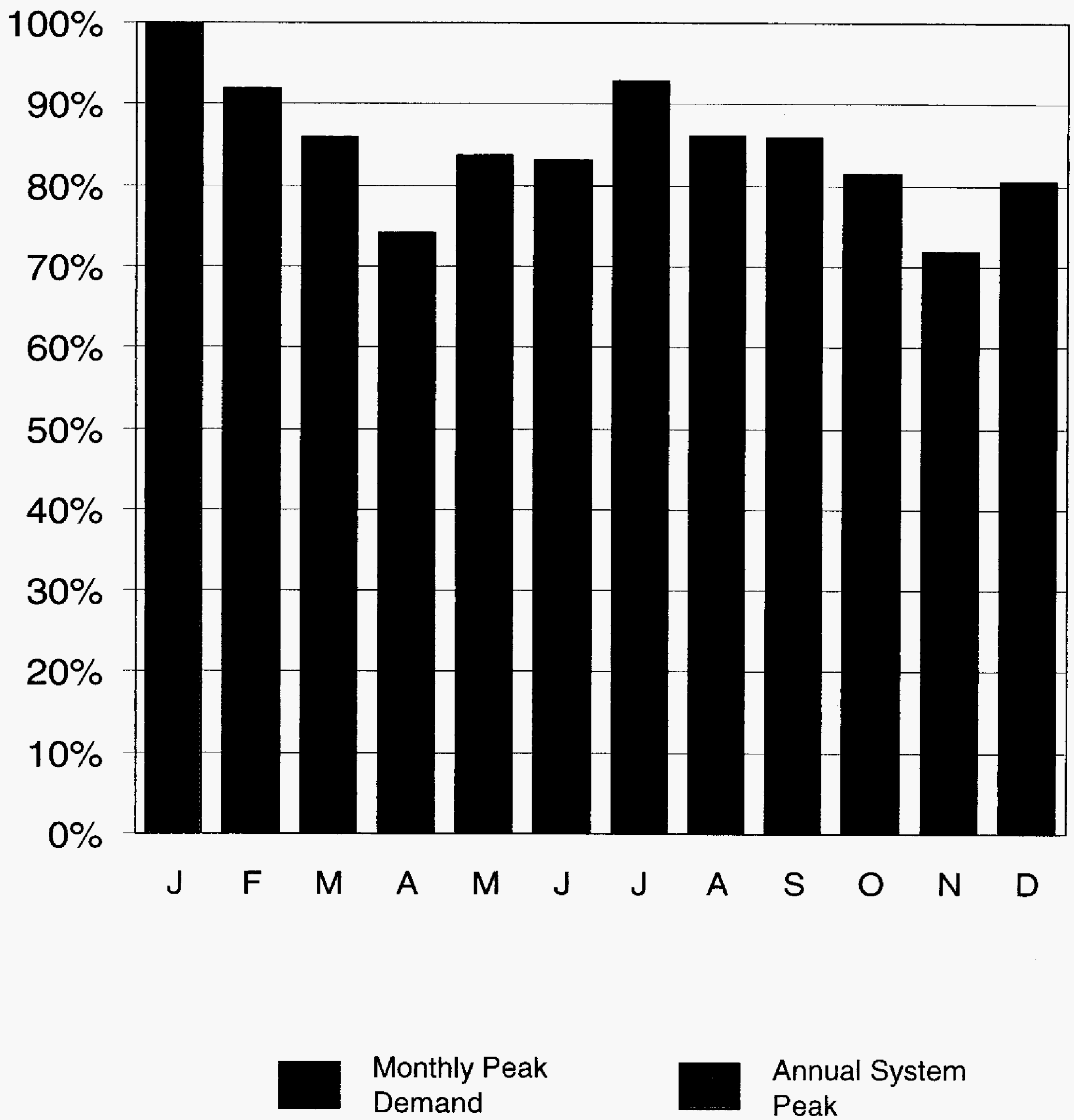
PROGRESS ENERGY FLORIDA, INC.

Analysis of Monthly Peak Demands
as a Percent of the Annual System Peak
for the Fiscal Year 2001



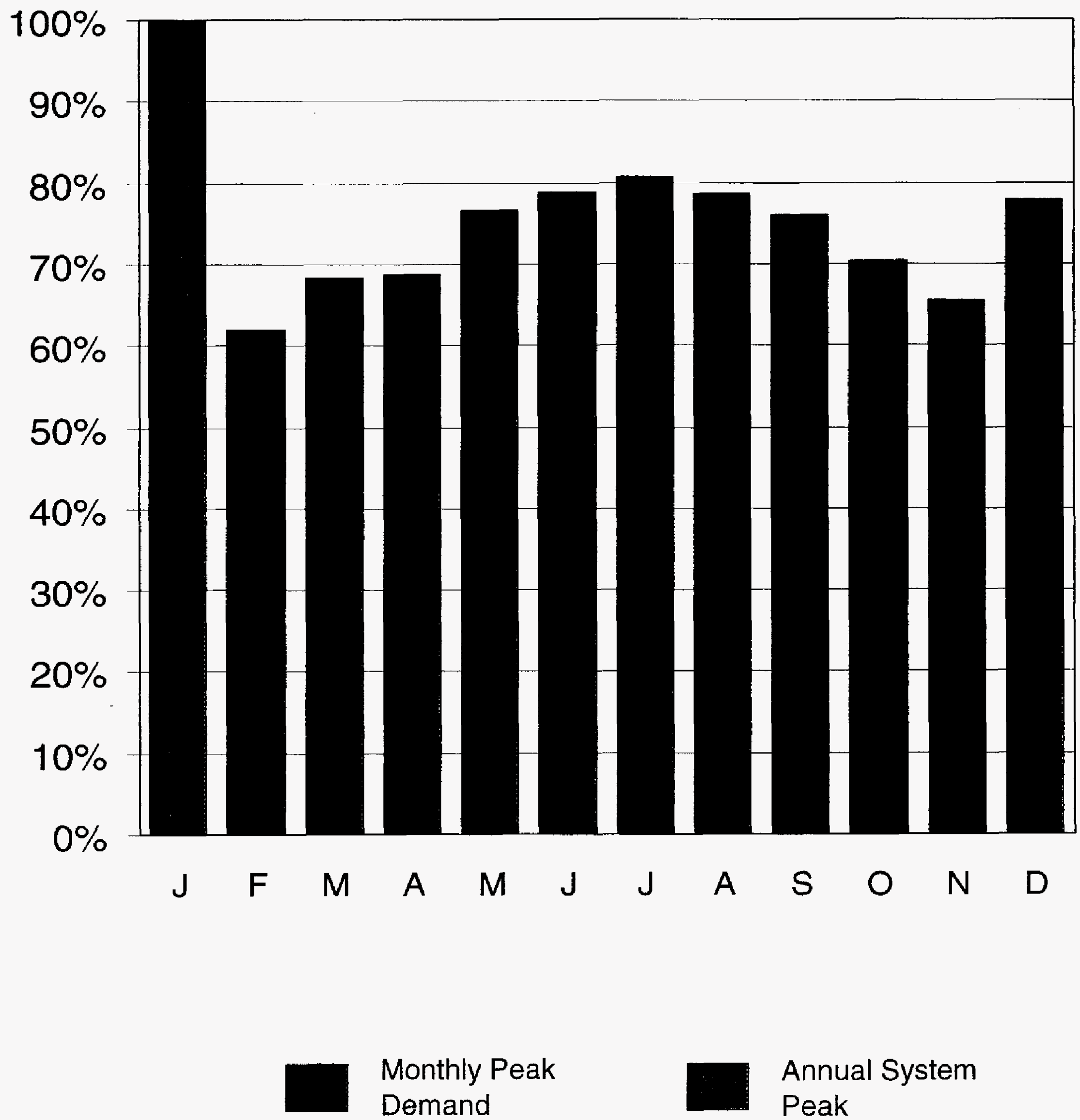
PROGRESS ENERGY FLORIDA, INC.

Analysis of Monthly Peak Demands
as a Percent of the Annual System Peak
for the Fiscal Year 2002



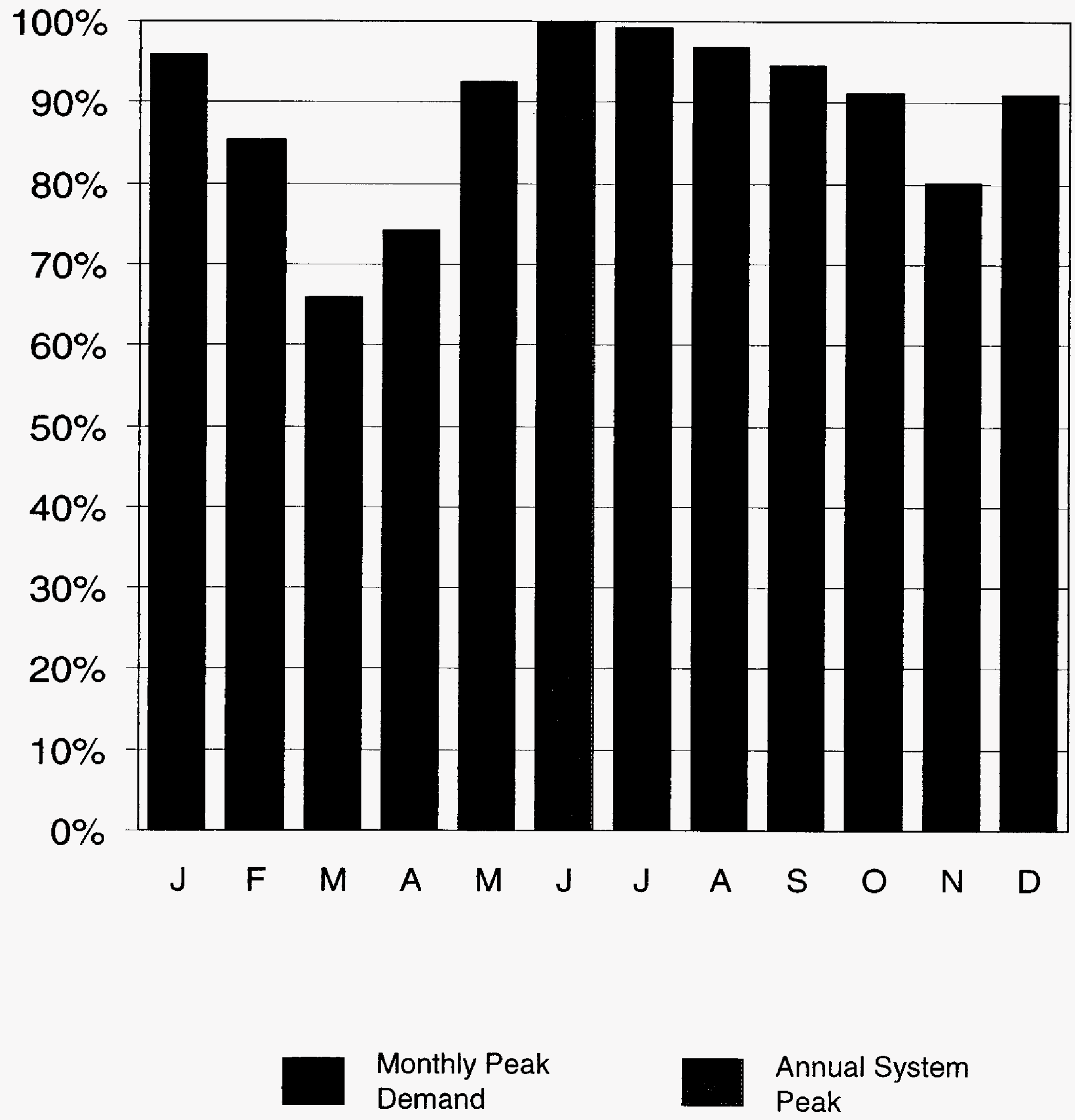
PROGRESS ENERGY FLORIDA, INC.

Analysis of Monthly Peak Demands
as a Percent of the Annual System Peak
for the Fiscal Year 2003



PROGRESS ENERGY FLORIDA, INC.

Analysis of Monthly Peak Demands
as a Percent of the Annual System Peak
for the Fiscal Year 2004



PROGRESS ENERGY FLORIDA, INC.

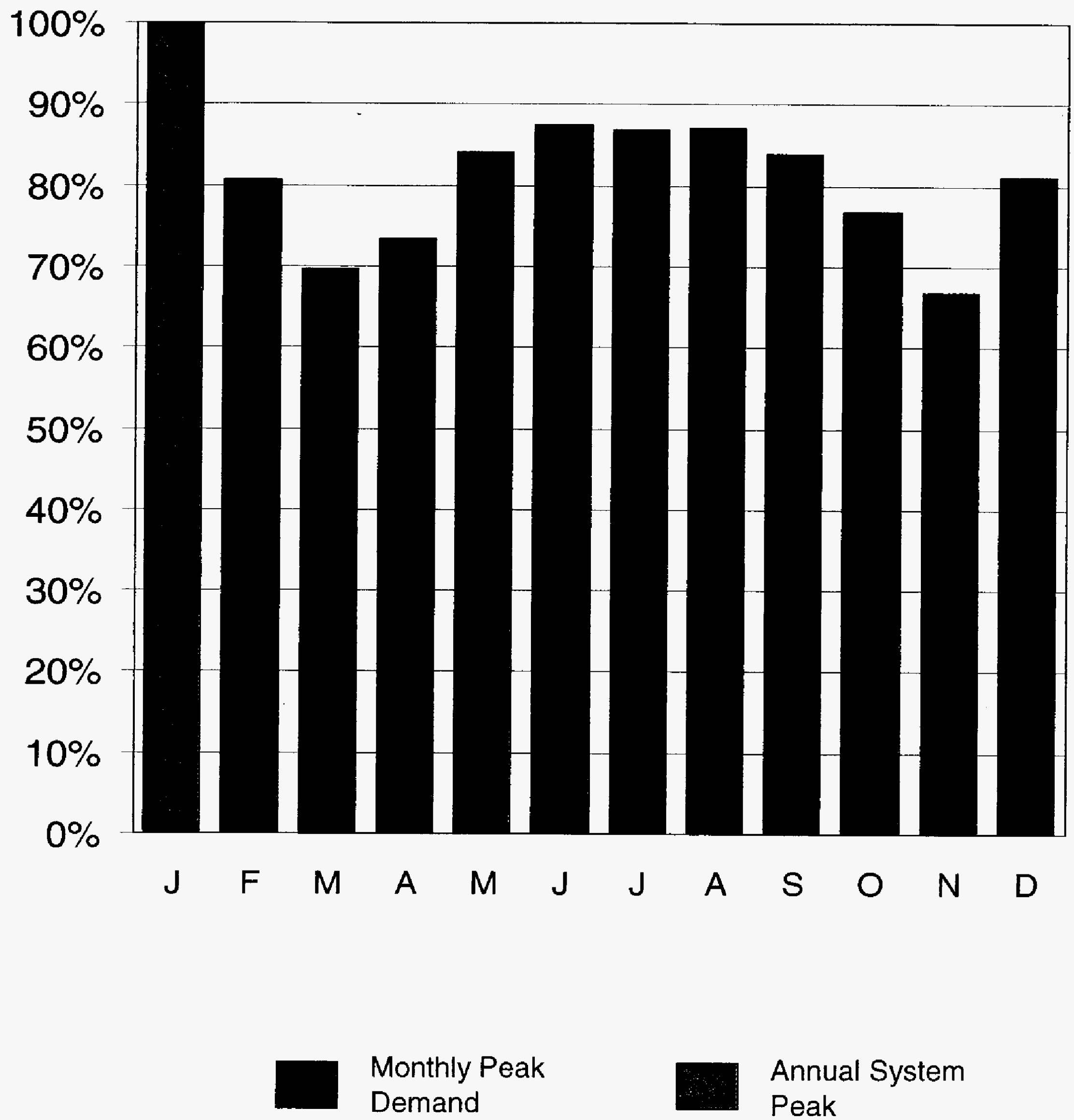
Summary of Load Characteristics for Projected Years 2005 and 2006

Line	Year	System Peak (MW) (1)	Maximum-to-Minimum Monthly Peak (2)	Maximum-to-Average Monthly Peak (3)
1	2005	10,502	1.50	1.23
2	2006	10,385	1.46	1.21

Source: Exhibit No. ____(JBC-2)

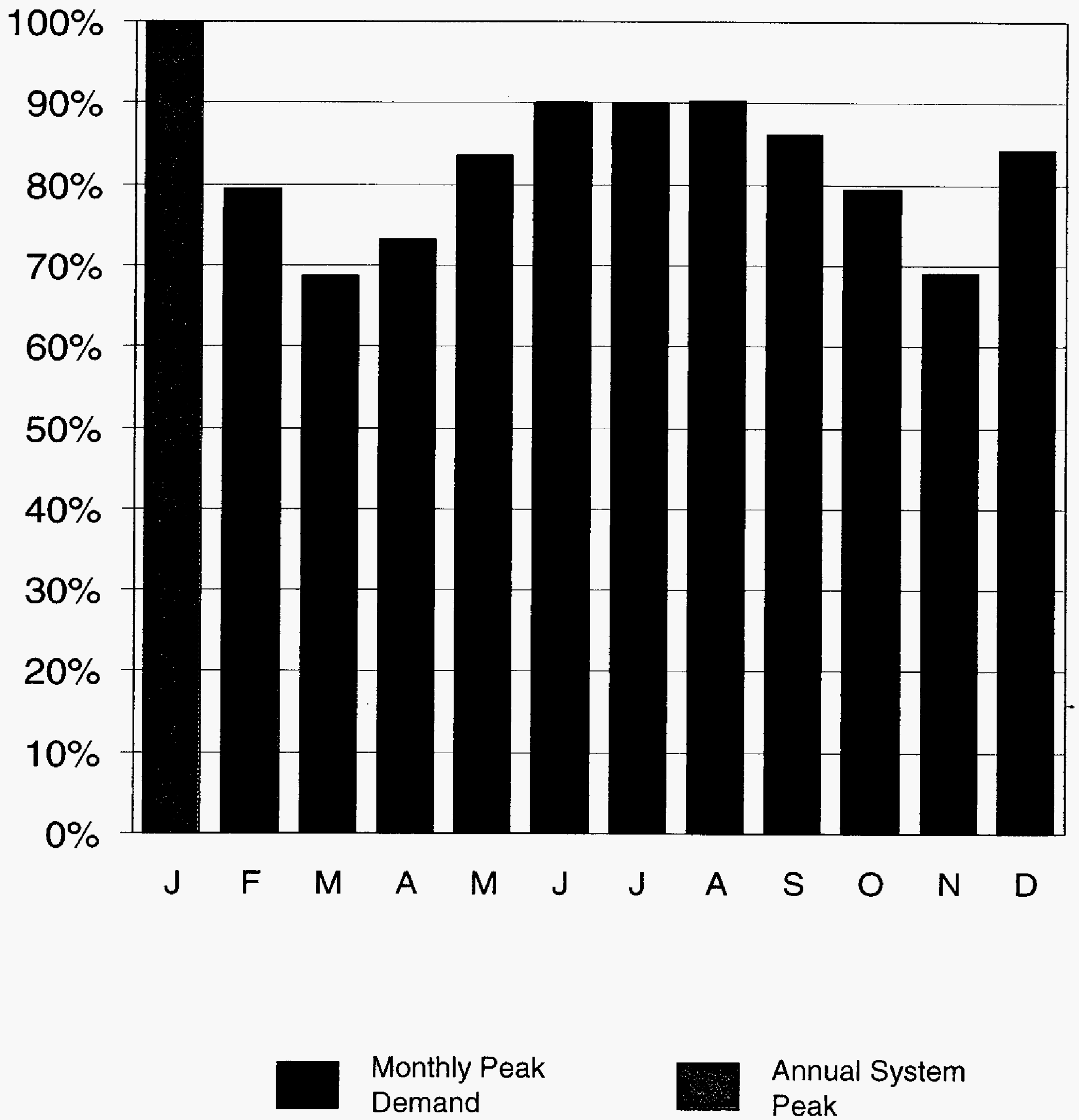
PROGRESS ENERGY FLORIDA, INC.

Analysis of Monthly Peak Demands
as a Percent of the Annual System Peak
for the Fiscal Year 2005



PROGRESS ENERGY FLORIDA, INC.

Analysis of Monthly Peak Demands
as a Percent of the Annual System Peak
for the Fiscal Year 2006



PROGRESS ENERGY FLORIDA, INC.

Revenue Requirement, Increases and Unit Costs
Summer/Winter CP Production Demand Allocation Method
Projected Calendar Year 2006 Data, Fully Adjusted

Line	Description	Total Retail	Residential RS	Gen Serv NonDemand GS-1	Gen Serv 100% LF GS-2	Gen Serv Demand GSD, SS-1	Curtail-able CS, SS-3	Inter-ruptible IS, SS-2	Lighting - LS Energy	Lighting - LS Facilities
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Cost of Service (000)									
	Production Capacity:									
1	Demand Component	$ 538,777	$ 337,194	$ 18,254	$ 634	$ 162,233	$ 2,049	$ 17,914	$ 499	$ -
2	Avg Demand Component	44,898	28,099	1,521	53	13,519	171	1,493	42	-
3	Total Prod Capacity	583,675	365,293	19,775	687	175,753	2,219	19,407	541	-
4	Production Energy	163,593	81,460	5,520	350	63,475	1,046	10,418	1,324	-
5	Transmission	142,896	80,366	4,938	200	50,037	759	6,363	236	-
6	Distribution Primary	297,282	172,116	11,000	301	97,461	2,168	11,839	2,394	-
7	Distribution Secondary	192,898	149,967	8,191	106	33,385	2	409	836	-
8	Distribution Services	82,444	73,067	5,978	591	2,794	-	2	16	-
9	Metering	51,681	43,230	4,180	308	3,656	17	281	11	-
10	Interruptible Equipment	431	-	-	-	-	-	431	-	-
11	Lighting Facilities	59,518	-	-	-	-	-	-	-	59,518
12	Customer Billing, Info, Etc	58,325	50,748	4,145	411	1,981	2	18	1,018	-
13	Rounding Adjustment	12	(3)	6	(2)	9	(6)	(2)	4	(3)
14	Total Cost to Serve	$ 1,632,755	$ 1,016,244	$ 63,733	$ 2,952	$ 428,551	$ 6,207	$ 49,166	$ 6,380	$ 59,515
	Revenue Requirements (000)									
	Revenues:									
15	Present Class Revenue	$ 1,427,197	$ 887,640	$ 65,410	$ 2,587	$ 369,178	$ 5,395	$ 45,709	$ 5,707	$ 45,572
16	Present Revenue Credits	55,025	40,348	2,908	204	9,913	147	1,002	168	335
17	Total Revenues	1,482,222	927,988	68,318	2,791	379,091	5,542	46,711	5,875	45,907
	Required Revenue Change:									
18	Amount	$ 205,558	$ 128,604	$ (1,677)	$ 365	$ 59,373	$ 812	$ 3,457	$ 673	$ 13,943
19	Percent	14.40%	14.49%	-2.56%	14.11%	16.08%	15.05%	7.56%	11.79%	30.60%
	Unit Costs									
	Customer Related Costs, per Bill:									
20	1. Metering		$2.55	$3.03	$2.58	$5.61	$140.50	$144.99	$2.75	
21	2. Customer Billing, Info, Etc		$3.00	$2.99	$3.00	$3.04	$16.53	$9.29	$1.29	
22	3. Secondary Service Tap		$4.32	$4.35	$4.31	$4.32		$3.20	$4.00	
23	4. Interruptible Equipment							$222.39		
	Energy Related Costs, per MWh:									
24	1. Production Energy		$3.95	$3.95	$3.95	$3.94	$3.87	$3.87	$3.95	
	Capacity Related Costs:									
	Based on MWh Sales, per MWh:									
25	1. Production Capacity		$16.37	$13.08	$7.15	$10.07	$7.58	$6.66	$1.49	
26	2. Production Capacity		$1.36	$1.09	$0.60	$0.84	$0.63	$0.56	$0.12	
27	3. Transmission		$3.90	$3.54	$2.26	$3.11	$2.81	$2.37	$0.71	
28	4. Distribution Primary		$8.36	$7.89	$3.40	$6.06	$8.02	$5.75	$7.15	
29	5. Distribution Secondary		$7.28	$5.92	$1.20	$2.50	$5.24	$2.59	$2.50	
	Based on Billing kW Demand, per KW									
30	1. Production Capacity					$3.93	$3.21	$2.75		
31	2. Production Capacity					$0.33	$0.27	$0.23		
32	3. Transmission					$1.21	$1.19	$0.98		
33	4. Distribution Primary					$2.37	$3.40	$2.29		
34	5. Distribution Secondary					$0.94	$1.79	$1.06		

PROGRESS ENERGY FLORIDA, INC.

Revenue Requirement, Increases and Unit Costs
Winter CP Production Demand Allocation Method
Projected Calendar Year 2006 Data, Fully Adjusted

Line	Description	Total Retail	Residential RS	Gen Serv NonDemand GS-1	Gen Serv 100% LF GS-2	Gen Serv Demand GSD, SS-1	Curtail-able CS, SS-3	Inter-ruptible IS, SS-2	Lighting - LS	
									Energy	Facilities
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Cost of Service (000)									
	Production Capacity:									
1	Demand Component	$ 538,777	$ 369,278	$ 15,995	$ 653	$ 133,948	$ 1,503	$ 16,397	$ 1,003	$ -
2	Avg Demand Component	44,898	30,773	1,333	54	11,162	125	1,366	84	-
3	Total Prod Capacity	583,675	400,051	17,327	707	145,110	1,629	17,764	1,087	-
4	Production Energy	163,593	81,460	5,520	350	63,475	1,046	10,418	1,324	-
5	Transmission	142,896	80,366	4,938	200	50,037	759	6,363	236	-
6	Distribution Primary	297,282	172,116	11,000	301	97,461	2,168	11,839	2,394	-
7	Distribution Secondary	192,898	149,967	8,191	106	33,385	2	409	836	-
8	Distribution Services	82,444	73,067	5,978	591	2,794	-	2	16	-
9	Metering	51,681	43,230	4,180	308	3,656	17	281	11	-
10	Interruptible Equipment	431	-	-	-	-	-	431	-	-
11	Lighting Facilities	59,518	-	-	-	-	-	-	-	59,518
12	Customer Billing, Info, Etc	58,325	50,748	4,145	411	1,981	2	18	1,018	-
13	Rounding Adjustment	12	(3)	6	(2)	9	(6)	(2)	4	(3)
14	Total Cost to Serve	$ 1,632,755	$ 1,051,002	$ 61,285	$ 2,973	$ 397,908	$ 5,616	$ 47,523	$ 6,926	$ 59,515
	Revenue Requirements (000)									
	Revenues:									
15	Present Class Revenue	$ 1,427,197	$ 887,640	$ 65,410	$ 2,587	$ 369,178	$ 5,395	$ 45,709	$ 5,707	$ 45,572
16	Present Revenue Credits	55,025	40,348	2,908	204	9,913	147	1,002	168	335
17	Total Revenues	1,482,222	927,988	68,318	2,791	379,091	5,542	46,711	5,875	45,907
	Required Revenue Change:									
18	Amount	$ 205,558	$ 163,362	$ (4,125)	$ 386	$ 28,730	$ 221	$ 1,814	$ 1,219	$ 13,943
19	Percent	14.40%	18.40%	-6.31%	14.91%	7.78%	4.10%	3.97%	21.35%	30.60%
	Unit Costs									
	Customer Related Costs, per Bill:									
20	1. Metering		$2.55	$3.03	$2.58	$5.61	$140.50	$144.99	$2.75	
21	2. Customer Billing, Info, Etc		$3.00	$2.99	$3.00	$3.04	$16.53	$9.29	$1.29	
22	3. Secondary Service Tap		$4.32	$4.35	$4.31	$4.32		$3.20	$4.00	
23	4. Interruptible Equipment							$222.39		
	Energy Related Costs, per MWh:									
24	1. Production Energy		$3.95	$3.95	$3.95	$3.94	$3.87	$3.87	$3.95	
	Capacity Related Costs:									
	Based on MWh Sales, per MWh:									
25	1. Production Capacity		$17.93	$11.46	$7.37	$8.31	$5.56	$6.10	$3.00	
26	2. Production Capacity		$1.49	$0.95	$0.61	$0.69	$0.46	$0.51	$0.25	
27	3. Transmission		$3.90	$3.54	$2.26	$3.11	$2.81	$2.37	$0.71	
28	4. Distribution Primary		$8.36	$7.89	$3.40	$6.06	$8.02	$5.75	$7.15	
29	5. Distribution Secondary		$7.28	$5.92	$1.20	$2.50	$5.24	$2.59	$2.50	
	Based on Billing kW Demand, per KW									
30	1. Production Capacity					$3.24	$2.36	$2.52		
31	2. Production Capacity					$0.27	$0.20	$0.21		
32	3. Transmission					$1.21	$1.19	$0.98		
33	4. Distribution Primary					$2.37	$3.40	$2.29		
34	5. Distribution Secondary					$0.94	$1.79	$1.06		

PROGRESS ENERGY FLORIDA, INC.

Revenue Requirement, Increase and Unit Costs
Summer/Winter CP Production Demand Allocation Method (Interruptible Demand Excluded)
Projected Calendar Year 2006 Data, Fully Adjusted

Line	Description	Total Retail (1)	Residential RS (2)	Gen Serv NonDemand GS-1 (3)	Gen Serv 100% LF GS-2 (4)	Gen Serv Demand GSD, SS-1 (5)	Curtail-able CS, SS-3 (6)	Inter-ruptible IS, SS-2 (7)	Lighting - LS Energy (8)	Lighting - LS Facilities (9)
	Cost of Service (000)									
	Production Capacity:									
1	Demand Component	$ 538,777	$ 348,791	$ 18,882	$ 656	$ 167,813	$ 2,119	$ -	$ 517	$ -
2	Avg Demand Component	44,898	29,066	1,573	55	13,984	177	-	43	-
3	Total Prod Capacity	583,675	377,857	20,455	710	181,797	2,296	-	560	-
4	Production Energy	163,593	81,460	5,520	350	63,475	1,046	10,418	1,324	-
5	Transmission	142,896	80,366	4,938	200	50,037	759	6,363	236	-
6	Distribution Primary	297,282	172,116	11,000	301	97,461	2,168	11,839	2,394	-
7	Distribution Secondary	192,898	149,967	8,191	106	33,385	2	409	836	-
8	Distribution Services	82,444	73,067	5,978	591	2,794	-	2	16	-
9	Metering	51,681	43,230	4,180	308	3,656	17	281	11	-
10	Interruptible Equipment	431	-	-	-	-	-	431	-	-
11	Lighting Facilities	59,518	-	-	-	-	-	-	-	59,518
12	Customer Billing, Info, Etc	58,325	50,748	4,145	411	1,981	2	18	1,018	-
13	Rounding Adjustment	12	(3)	6	(2)	9	(6)	(2)	4	(3)
14	Total Cost to Serve	$ 1,632,755	$ 1,028,807	$ 64,413	$ 2,976	$ 434,596	$ 6,283	$ 29,759	$ 6,398	$ 59,515
	Revenue Requirements (000)									
	Revenues:									
15	Present Class Revenue	$ 1,427,197	$ 887,640	$ 65,410	$ 2,587	$ 369,178	$ 5,395	$ 45,709	$ 5,707	$ 45,572
16	Interruptible Adjustment							(18,000)		
17	Present Revenue Credits	55,025	40,348	2,908	204	9,913	147	1,002	168	335
18	Total Revenues	1,482,222	927,988	68,318	2,791	379,091	5,542	28,711	5,875	45,907
	Required Revenue Change:									
19	Amount	$ 205,558	$ 141,167	$ (997)	$ 389	$ 65,418	$ 888	$ 2,050	$ 691	$ 13,943
20	Percent	14.40%	15.90%	-1.52%	15.02%	17.72%	16.47%	4.49%	12.11%	30.60%
	Unit Costs									
	Customer Related Costs, per Bill:									
21	1. Metering		$2.55	$3.03	$2.58	$5.61	$140.50	$144.99	$2.75	
22	2. Customer Billing, Info, Etc		$3.00	$2.99	$3.00	$3.04	$16.53	$9.29	$1.29	
23	3. Secondary Service Tap		$4.32	$4.35	$4.31	$4.32		$3.20	$4.00	
24	4. Interruptible Equipment							$222.39		
	Energy Related Costs, per MWh:									
25	1. Production Energy		$3.95	$3.95	$3.95	$3.94	$3.87	$3.87	$3.95	
	Capacity Related Costs:									
	Based on MWh Sales, per MWh:									
26	1. Production Capacity		$16.93	$13.53	$7.40	$10.42	$7.84		$1.54	
27	2. Production Capacity		$1.41	$1.13	$0.62	$0.87	$0.65		$0.13	
28	3. Transmission		$3.90	$3.54	$2.26	$3.11	$2.81	$2.37	$0.71	
29	4. Distribution Primary		$8.36	$7.89	$3.40	$6.06	$8.02	$5.75	$7.15	
30	5. Distribution Secondary		$7.28	$5.92	$1.20	$2.50	$5.24	$2.59	$2.50	
	Based on Billing kW Demand, per KW									
31	1. Production Capacity					$4.06	$3.32			
32	2. Production Capacity					$0.34	$0.28			
33	3. Transmission					$1.21	$1.19	$0.98		
34	4. Distribution Primary					$2.37	$3.40	$2.29		
35	5. Distribution Secondary					$0.94	$1.79	$1.06		

Docket No. 050078-EI
Witness: Maurice Brubaker
Exhibit No. MEB-10 (   )

Revenue Requirement of a Combustion Turbine
($/kW)

Line	Description	First Year Revenue Requirement (1)	Levelized Revenue Requirement (2)
1	Annual Cost	$92	$72
2	Annual Cost with 20% Reserve Margin	$110	$86
3	Monthly Credit	$9	$7

Note: Calculated using combustion turbine cost data from Energy Information Administration Annual Energy Outlook, 2005.