DEPARTMENT OF THE NAVY
NAVAL FACILITIES ENGINEERING COMMAND
LITIGATION OFFICE
720 KENNON STREET SE ROOM 136
WASHINGTON NAVY YARD DC 20374-5051

IN REPLY REFER TO

August 7, 2009

Office of Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Dear Sir or Madam:

Enclosed please find the original and seven copies of the Federal Executive Agencies' Testimony and Exhibits of James Selecky in the above-referenced Docket.

Sincerely,

AUDREY VAN DYKE
Counsel for the
Secretary of the Navy

Cc:
Service List as listed on FPSC website

COM 5
ECR CO
GCL 1
OPC
RCP
SSC
SGA
ADM
CLK I

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In Re: Petition for Rate Increase by Progress Energy Florida, Inc.	))))	**Docket No. 090079-EI**

Direct Testimony and Exhibits of

James T. Selecky

On behalf of

Department of the Navy

Project 9143
August 10, 2009

BRUBAKER & ASSOCIATES, INC.
CHESTERFIELD, MO 63017

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In Re: Petition for Rate Increase by Progress Energy Florida, Inc.	**Docket No. 090079-EI**

Direct Testimony of James T. Selecky

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A James T. Selecky. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

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

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to my testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am presenting testimony on behalf of the Department of the Navy (DoN). DoN purchases electricity from Progress Energy Florida, Inc. (PEF or the Company).

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A The purpose of my testimony is to address PEF's "Allocated Class Cost of Service and Rate Return Study" (CCOSS). Specifically, I will discuss PEF's proposed allocation of production capacity costs. The fact that an issue is not addressed in my testimony should not be construed as an endorsement of PEF's position.

Q PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A The summary of my conclusions and recommendations is listed below:

1. The retail class cost of service study methodology proposed by PEF is inappropriate because it allocates 50% of the production fixed cost on an energy basis.
2. Allocating 50% of the fixed production cost on an energy basis has the effect of skewing allocation of generation capacity costs toward high-load factor customers without providing a proper share of the lower cost of fuel from the base load resources.
3. If the Commission is going to allocate a significant portion of the fixed production costs on energy basis, it should also allocate the energy symmetrically. That is high load factor customers who receive an above average allocation of base load production costs should receive the benefit of lower fuel costs produced by this generation resource.
4. PEF's system winter and summer peak demands are the most prominent and therefore the most important in determining PEF's capacity needs. Therefore, summer/winter coincident peaks should be used to allocate fixed production costs.
5. If the Commission elects not to utilize a summer/winter peak coincident peak allocation, I recommend using the 12 coincident peak study with a 1/13 weighting to energy as contained in the Minimum Filing Requirements.

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

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

Q HAS PEF FILED MULTIPLE CCOSS IN THIS CASE?

A Yes. As indicated in the direct testimony of PEF witness William Slusser, PEF has filed three CCOSS(s). The first CCOSS is required under the Commission's Minimum Filing Requirements (MFR). This CCOSS allocates production fixed costs using the average of the 12 monthly coincident peaks and 1/13 weighted average demand (12CP and 1/13 AD method). This method allocates 12/13 or approximately 92% of a production capacity cost on the basis of class multi-coincident peaks and 1/13 or approximately 8% of the production capacity on the basis of class average hourly demands or energy.

In addition, PEF has prepared and presented the results of two additional CCOSS(s). These CCOSS(s) weight energy responsibility by 25% and 50% respectively. These studies are referred to the 12CP and 25% AD study and 12CP and 50% AD study.

Q WHAT IS PEF'S POSITION IN THIS PROCEEDING REGARDING THE ALLOCATION OF FIXED PRODUCTION COSTS.

A PEF is supporting the allocation of fixed production costs on a basis of 50% demand and 50% energy. To develop its proposed revenue increases by rate class, PEF utilized the results of the CCOSS 12CP and 50% AD method.

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

A In the testimony of PEF witness Slusser, he states that a significant energy weighting in the allocation of production plant capital costs is needed because the higher up-front capital costs are incurred to achieve lower energy or fuel costs. The lower cost of fuel is allocated to the rate classes on an energy basis. Therefore, Mr. Slusser argues that a significant portion of its production capacity costs should be apportioned in the same manner as customers realized the benefits i.e., on an energy basis.[1]

Q HOW DID PEF DETERMINE HOW MUCH OF THE FIXED PRODUCTION COST SHOULD BE ALLOCATED ON AN ENERGY BASIS?

A To determine the percentage of base load generation that is energy related, Mr. Slusser estimates what PEF's generation fleet would have cost if the investment were entirely in peakers. Dividing the hypothetical peaker investment by the actual production generation investment produces a factor of 50.9%. As a result of this analysis, 50% of the fixed production cost was allocated on an energy basis.

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

A No. 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 Utilities generally 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. 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

[1] PEF's witness Slusser testimony, page 19.

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

Q DO UTILITY PLANNERS CONSTRUCT MORE CAPITAL-INTENSIVE CAPACITY FOR THE SOLE PURPOSE OF REDUCING FUEL COSTS?

A No. This belief is based on an oversimplification of the planning process. In reality, planners are faced with the decision of providing reliable service and minimizing total costs.

Cost minimization is a requirement so that the utility provides services at the lowest overall cost. The utility strives to install a mix of generating capacity that, along with its existing generation, yields the lowest total cost. In other words, the economic choice between a base load plant and a peaking plant must consider both capital costs and operating costs.

The utility's investment decisions are affected by many factors, among them; the existing generation mix, the availability of a suitable site for the plant, environmental restrictions, and fuel diversification.

Q WHAT FACTORS INFLUENCE THE UTILITY'S CHOICE OF GENERATING TECHNOLOGY?

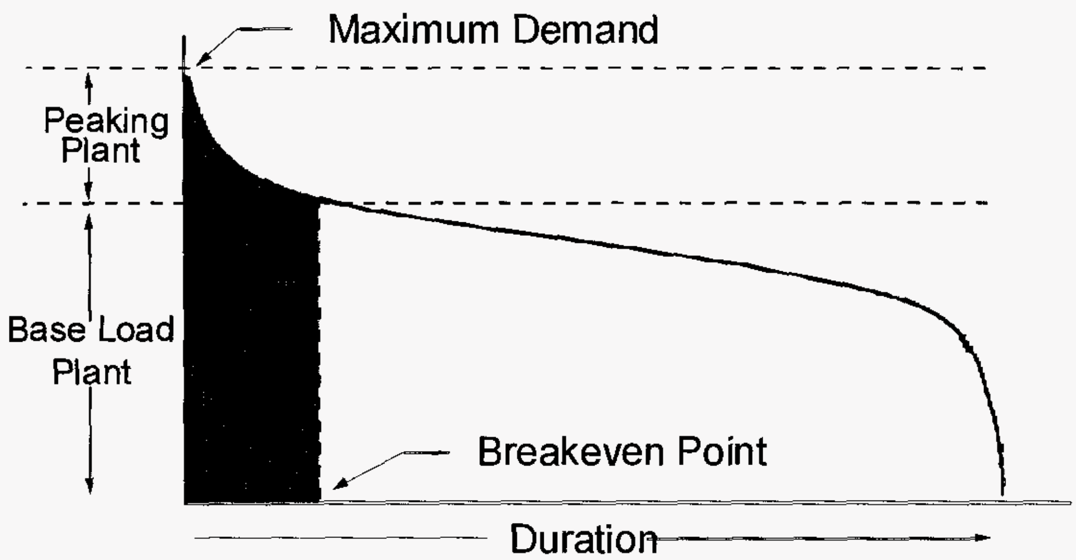
A The planning decision is dictated by engineering and economics. The utility seeks to minimize its total costs. Once a utility decides to install additional capacity, it must examine the economics of the situation. If the new capacity is expected to run only a limited number of hours, total costs are minimized by the choice of a peaking unit. On the other hand, if it were projected that the unit will run for a sufficient number of hours, then a baseload unit would be the more economical choice.

Q DOES THIS MEAN THAT THE UTILITY SPENDS MORE ON CAPITAL IN ORDER TO SAVE FUEL?

A No. In practice, the utility seeks to minimize its total costs – capital plus fuel. Thus, one could say that the utility spends more on fuel by using a peaker in order to save capital. In truth, such a statement does not give the complete picture.

Q COULD YOU PLEASE ILLUSTRATE THE DECISION-MAKING PROCESS?

A The basic idea is that utilities spend additional capital to save fuel costs–but only if the fuel savings are expected to outweigh the additional capital cost. If the baseload unit runs enough hours, the additional capital cost will be more than offset by the lower fuel cost. The point at which the fuel savings of the baseload plant just begin to offset the additional capital cost commonly is referred to as the "break-even" point. Of course, baseload plants normally run well beyond their break-even points. Hence, if things work out as planned, the total cost of baseload generation, per kWh, generally is much less than the total cost of peaking generation.



Q HAVE UTILITY REGULATORS RECOGNIZED THE RELEVANCE OF THE BREAK EVEN POINT?

A Yes. The NARUC Cost Allocation Manual alludes to this fundamental concept:

> The choice of unit depends on the energy load to be served. A peak load of relatively brief duration, for example, less than 1,500 hours per year, may be served most economically by a CT unit. A peak load of intermediate duration, of 1,500 to 4,000 hours per year, may be served most economically by a CC unit. A peak load of long annual duration may be served most economically by a baseload unit (Page 53).

Q DID PEF REFLECT THE CONCEPT OF BREAK-EVEN ANALYSIS IN ITS ALLOCATION METHODS USED IN ITS CCOSS?

A No. The Company's CCOSS ignores this concept. In other words, if the break-even point between a baseload plant and a peaking plant is, for example, 1,500 hours, PEF's method erroneously presumes that energy consumed beyond the 1,500-hour mark contributes to the choice of the baseload plant when in fact it does not. Once the baseload plant is expected to run beyond the 1,500 hour mark, any additional usage is irrelevant to the choice of the baseload plant and thus plays no role whatsoever in the incurrence of fixed costs.

Q DOES PEF'S PROPOSED FIXED PRODUCTION COST ALLOCATION METHODOLOGY APPROPRIATELY REFLECT ANY CAPITAL COSTS/FUEL COST TRADEOFFS?

A No. PEF's proposed allocation method only addresses the capital side of the equation, and completely ignores the fuel side. PEF's proposed production cost allocation is not symmetrical regarding the allocation of fixed and variable cost.

Q HOW DOES THE PEF METHOD FAIL TO PROVIDE A SYMMETRICAL ALLOCATION OF BOTH CAPITAL AND OPERATING COSTS?

A The method proposed by PEF focuses on the allocation of fixed production costs. This result is claimed to be fair because high load factor customers require more base load capacity and because the capital cost of base load units tends to be higher than peaking plants. However, PEF's proposed allocation method makes no attempt to recognize the other side of the capital cost/operating cost trade-off. Base load plants may have above average capital costs, but they also have below average operating costs relative to peaking units. To ignore the fuel cost differential creates a mismatch between the theory and application. If system planning principles are to be applied in determining the allocation of production plant, then it is also logical and consistent to apply the same principles to the allocation of fuel expense.

Q IN WHAT WAY IS THE COMPANY'S COST OF SERVICE STUDY DEFICIENT IN THE ALLOCATION OF FIXED PRODUCTION COSTS?

A The Company's cost of service study understates the consequences of peaking behavior. The Company must build and design its system to accommodate its peak demand. Moreover, because generating units are dispatched in merit order, with the more expensive units coming on last, classes contributing to the peak loads are also responsible for higher fuel costs. PEF's proposed method masks or dilutes the consequences of peaking behavior.

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 Different types of generating plants have different combinations of fixed and variable costs. Therefore, any analysis that attempts to more precisely articulate costs by customer class requires a determination of the different types of generating plant 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 plants and less peaking plants would be installed. The converse would be true for lower load factor classes.

High load factor classes have more fixed costs, but they also have lower fuel costs; while the low load factor classes have 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 PEF does not recognize the fuel cost side of the equation, and as a result overcharges high load factor customer classes.

If this type of analysis were done for each class on a stand-alone basis, then the results 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. This type of analysis would be needed if fixed production costs were allocated on an energy basis, as recommended by Mr. Slusser to demonstrate the impacts of the issues he has raised.

Q HOW DO TRADITIONAL COST OF SERVICE STUDIES GENERALLY RECOGNIZE THIS MIX OF VARIOUS TYPES OF GENERATING STUDY?

A Traditional cost of service studies recognize that the mix or combination of generating plants is built to serve the overall or combined load characteristics of all customer classes – *not 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 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 ((7,000 Btu/kWh x $7/MMBtu) + 0.3¢/kWh)).

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 ($500 per kW - $300 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 50% ENERGY WEIGHTING COST OF SERVICE STUDY?

A This is shown on Exhibit No. JTS-1 ( ). The values are obtained by dividing the net plant investment allocated to each customer class 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 production plant investment Mr. Slusser assigns in his cost of service study.

Q ARE THERE SIGNIFICANT VARIATIONS?

A Yes. Exhibit No. JTS-2 ( ) shows the costs by resource group. PEF has classified its generation investments as base, intermediate and peaking. This data was taken from the 2008 FERC Form 1 for data. The fuel costs range from $45.92 per MWh for base load facilities to $151.72 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 HAVE YOU REVIEWED PEF'S ANNUAL DEMAND LOAD PATTERN?

A Yes, I have. Exhibit No. JTS-3 ( ) presents PEF's load characteristics for the historical period 1999 through 2008.

Q WHAT DOES PAGE 1 OF EXHIBIT NO. JTS-3 ( ) 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 for each year (column 3) and the ratio of the maximum demand to the annual average of the monthly peaks (column 4).

Column 3 indicates the extent of spread between the highest 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 4 is a measure of the extent of spread between the maximum annual demand and the average of the maximum demands in the other months of the year. Again, the larger the number, the more seasonal the load pattern. Column 4 also indicates a highly seasonal load pattern.

Q **WHAT IS SHOWN ON PAGE 2 OF EXHIBIT NO. JTS-3 ( )?**

A Page 2 shows, for each year, the monthly peak demands. The last column shows the average demands for the 10 year period from 1999 through 2008 and the percentage of each month's average demand to the 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 and summer peaks.

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 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.

However, if the Commission prefers to allocate a portion of the fixed production cost on an energy basis, the results of the 12 CP and 1/13 AD CCOSS contained in the MFD should be used to allocate any increase.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Qualifications of James T. Selecky

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A James T. Selecky. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

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

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EMPLOYMENT EXPERIENCE.

A I graduated from Oakland University in 1969 with a Bachelor of Science degree with a major in Engineering. In 1978, I received the degree of Master of Business Administration with a major in Finance from Wayne State University.

I was employed by The Detroit Edison Company (DECo) in April of 1969 in its Professional Development Program. My initial assignments were in the engineering and operations divisions where my responsibilities included evaluation of equipment for use on the distribution and transmission system; equipment performance testing under field and laboratory conditions; and troubleshooting and equipment testing at various power plants throughout the DECo system. I also worked on system design and planning for system expansion.

In May of 1975, I transferred to the Rate and Revenue Requirement area of DECo. From that time, and until my departure from DECo in June 1984, I held various positions which included economic analyst, senior financial analyst, supervisor of the Rate Research Division, supervisor of the Cost-of-Service Division and director of the Revenue Requirement Department. In these positions, I was responsible for overseeing and performing economic and financial studies and book depreciation studies; developing fixed charge rates and parameters and procedures used in economic studies; providing a financial analysis consulting service to all areas of DECo; developing and designing rate structure for electrical and steam service; analyzing profitability of various classes of service and recommending changes therein; determining fuel and purchased power adjustments; and all aspects of determining revenue requirements for ratemaking purposes.

In June of 1984, I joined the firm of Drazen-Brubaker & Associates, Inc. (DBA). In April 1995 the firm of Brubaker & Associates, Inc. (BAI) was formed. It includes most of the former DBA principals and staff. At DBA and BAI I have testified in electric, gas and water proceedings involving almost all aspects of regulation. I have also performed economic analyses for clients related to energy cost issues.

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

Q **HAVE YOU PREVIOUSLY APPEARED BEFORE A REGULATORY COMMISSION?**

A Yes. I have testified on behalf of DECo in its steam heating and main electric cases. In these cases I have testified to rate base, income statement adjustments, changes in book depreciation rates, rate design, and interim and final revenue deficiencies.

In addition, I have testified before the regulatory commissions of the States of Colorado, Connecticut, Georgia, Illinois, Indiana, Iowa, Kansas, Louisiana, Maryland, Massachusetts, Minnesota, Missouri, New Hampshire, New Jersey, North Carolina, Ohio, Oklahoma, Oregon, Tennessee, Texas, Utah, Washington, Wisconsin, and Wyoming, and the Provinces of Alberta, Nova Scotia and Saskatchewan. I also have testified before the Federal Energy Regulatory Commission. In addition, I have filed testimony in proceedings before the regulatory commissions in the States of Florida, Montana, New York and Pennsylvania and the Province of British Columbia. My testimony has addressed revenue requirement issues, cost of service, rate design, financial integrity, accounting-related issues, merger-related issues, and performance standards. The revenue requirement testimony has addressed book depreciation rates, decommissioning expense, O&M expense levels, and rate base adjustments for items such as plant held for future use, working capital, and post test year adjustments. In addition, I have testified on deregulation issues such as stranded cost estimates and rate design.

Q ARE YOU A REGISTERED PROFESSIONAL ENGINEER?

A Yes, I am a registered professional engineer in the State of Michigan.

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Progress Energy Florida

Cost per kW of Production Plant When Allocating Using
12 CP and 50% Energy
Forecasted 12 Mos Ending December 31, 2010

Line	Description	Total Electric	Residential	Gen Service Non-Demand	Gen Service 100% L.F.	Gen Service Demand	Gen Service Curt/Interrupt	Lighting Energy
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Production Plant (000)							
1	Plant in Service	$4,709,024	$2,603,384	$154,785	$8,571	$1,643,119	$275,243	$23,922
2	Depreciation Reserve	(2,256,845)	(1,247,696)	(74,183)	(4,108)	(787,480)	(131,913)	(11,465)
3	Net Plant	$2,452,179	$1,355,688	$80,602	$4,463	$855,639	$143,330	$12,457
4	12-Mo Avg CP kW @ Generator	7,214,900	4,330,700	236,300	10,400	2,279,900	348,800	8,800
5	Cost per kW of Net Production Plant	$340	$313	$341	$429	$375	$411	$1,416
6	Index	100	92	100	126	110	121	416

Source: PEF CCOSS 12 CP & 50% AD

Progress Energy Florida

Fuel Cost By Generation Category

Line	Generation Category	Fuel Cost (000)	Net Generation MWh	Average $/MWh
	(1)	(2)	(3)	(4)
	Base			
1	Crystal River Coal	$527,475	14,260,525	$36.99
2	Crystal River Nuclear	$32,073	6,424,712	$4.99
3	Bartow CC	$140,610	1,344,444	$104.59
4	Hines CC	$781,162	10,822,413	$72.18
5	Tiger Bay CC	$41,038	567,834	$72.27
6	Univ of Florida CT 1	$28,471	348,994	$81.58
7	Total	$1,550,827	33,768,922	**$45.92**
	Intermediate			
8	Anclote	$240,324	2,457,705	$97.78
9	Suwannee	$44,289	345,831	$128.07
10	Total	$284,614	2,803,536	**$101.52**
	Peaking			
11	Avon Park	$3,612	16,244	$222.33
12	Bartow	$4,411	37,055	$119.03
13	Bayboro	$3,589	18,969	$189.22
14	Debray	$20,640	141,374	$146.00
15	Higgins	$5,320	32,108	$165.70
16	Intercession City	$99,618	665,125	$149.77
17	Rio Pinar	$49	144	$338.95
18	Suwannee	$13,750	93,734	$146.69
19	Turner	$4,124	17,588	$234.47
20	Total	$155,113	1,022,341	**$151.72**

Source: 2008 FERC Form 1 Steam-Electric Generating Plant Statistics - Lines 12 & 20

Progress Energy Florida

Summarry of Load Characteristics
for Historical Years 1999 through 2008

Line	Year	System Peak (MW)	Maximum-to-Minimum Monthly Peak	Maximum-to-Average Monthly Peak
	(1)	(2)	(3)	(4)
1	1999	8,318	1.58	1.22
2	2000	8,548	1.57	1.15
3	2001	8,922	1.73	1.30
4	2002	9,045	1.43	1.18
5	2003	10,131	1.65	1.35
6	2004	9,125	1.52	1.12
7	2005	10,226	1.59	1.22
8	2006	10,094	1.57	1.22
9	2007	10,355	1.53	1.22
10	2008	10,153	1.49	1.16

Source: FERC Form 1

Progress Energy Florida

Monthly Peaks - Megawatts

Month	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999	Average	Percent of Maximum
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Jan	10,153	8,803	7,869	10,226	8,748	10,131	9,045	8,922	8,548	8,318	9,076	100%
Feb	8,223	9,097	10,094	7,399	7,791	6,142	8,295	6,942	7,409	6,964	7,836	86%
Mar	6,794	6,990	6,440	7,610	6,017	6,658	7,818	5,494	5,451	5,861	6,513	72%
Apr	7,619	7,473	7,835	7,012	6,760	6,690	6,712	6,291	8,421	6,197	7,101	78%
May	9,298	8,073	8,381	8,478	8,446	7,665	7,450	7,141	7,430	6,726	7,909	87%
Jun	9,898	9,348	9,348	8,927	9,125	7,914	7,700	7,628	7,442	7,079	8,441	93%
Jul	10,012	9,792	9,461	9,671	9,058	8,105	8,388	7,577	7,607	7,562	8,723	96%
Aug	10,036	10,355	9,689	9,686	8,842	7,882	8,109	7,790	7,717	7,715	8,782	97%
Sep	9,501	9,393	8,793	9,095	8,628	7,610	7,761	7,278	7,247	7,216	8,252	91%
Oct	8,059	8,568	8,285	8,301	8,324	7,021	7,243	6,122	6,926	6,302	7,515	83%
Nov	7,446	6,762	6,414	6,424	7,313	6,519	6,336	5,159	6,828	5,264	6,447	71%
Dec	8,064	7,110	6,792	7,772	8,303	7,801	7,337	6,239	8,421	6,791	7,463	82%

Source: FERC Form 1