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June 3, 1996

HAND-DELIVERED

Blanca S. Bayo, Director
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Gunter Building
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0870

Re: Prudence review to determine regulatory treatment of Tampa Electric Company's Polk Unit - Docket No. 960409-EI

Dear Ms. Bayo:

Enclosed for filing and distribution are the original and sixteen copies of the Direct Testimony and Exhibits of Randall J. Falkenberg in the above docket.

Please acknowledge receipt of the above on the extra copy enclosed herein and return it to me. Thank you for your assistance.

Yours truly,

Joe A. McGlothlin

Joseph A. McGlothlin

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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

TAMPA ELECTRIC COMPANY

DOCKET NO. 960409-EI

TESTIMONY CONFORMED TO
FLORIDA ADMINISTRATIVE CODE NO. 25-22.048 (4)(a)

DIRECT TESTIMONY

AND EXHIBITS

OF

RANDALL J. FALKENBERG

ON BEHALF OF THE

FLORIDA INDUSTRIAL POWER USERS GROUP

KENNEDY AND ASSOCIATES
ATLANTA, GEORGIA

JUNE 1996

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 960409-EI

DIRECT TESTIMONY OF RANDALL J. FALKENBERG

Q. Please state your name and business address.

A. Randall J. Falkenberg, Suite 475, 35 Glenlake Parkway, Atlanta, Georgia 30328.

Q. What is your occupation and by whom are you employed?

A. I am a utility rate and planning consultant holding the position of Vice President and Principal with the firm of J. Kennedy and Associates, Inc. ("Kennedy and Associates").

Q. Please describe briefly the nature of the consulting services provided by Kennedy and Associates.

A. Kennedy and Associates provides consulting services in the electric, gas, and telephone utility industries. The firm provides expertise in system planning, load forecasting, financial analysis, cost of service, utility accounting, revenue requirements, and rate design. Our clients have included the Georgia, Louisiana, and Oklahoma Public Service Commissions, the Attorneys General of Kentucky and New Mexico, the Office of Public Utility Counsel of Texas, the Consumers' Utility Counsel of Georgia, industrial consumer groups in over a dozen states, a number of publicly-owned utilities, a major Federal

Public Power Authority, and the New Orleans Business Council.

I. QUALIFICATIONS

Q. Please describe your education and professional experience.

A. Exhibit No. ___ (RJF-1) describes my education and experience within the utility industry. I have nineteen years of experience in the utility industry and have worked for utilities, both as an employee and as a consultant, and as a consultant to major corporations, state and federal government agencies, and public service commissions. I have been directly involved in a number of cases related to the Bath County, Beaver Valley, Brandon Shores, Grand Gulf, Millstone, Palo Verde, Perry, River Bend, Trimble County, Vogtle, and Wilson power plants concerning the topics of rate recognition, prudence, power system reliability, and economics.

During my employment with EBASCO Services I developed probabilistic production cost and reliability models used in studies for numerous utility industry clients. I personally directed a number of marginal and avoided cost studies performed for compliance with the Public Utility Regulatory Policies Act of 1978 ("PURPA"). At EBASCO, I also participated in a wide variety of consulting projects in the rate, planning, and forecasting areas.

In 1982 I accepted the position of Senior Consultant with Energy Management Associates ("EMA"). At EMA I trained and consulted with planners and financial analysts at several utilities in applications of the PROMOD III and PROSCREEN II planning models. In particular, I assisted planners in the application of these models to the preparation of studies of revenue requirements and the financial impact of alternative expansion plans. I also assisted in EMA's educational seminars and trained utility personnel in revenue requirements analysis, production cost modeling, reliability analysis, and other techniques of generation planning.

Since joining Kennedy and Associates in 1984, I have been responsible for the firm's work in the areas of generation planning, reliability analysis, and the rate treatment of new capacity additions. I have presented expert testimony on these and other matters in over seventy-five cases before regulatory commissions and courts in Arkansas, Connecticut, Florida, Georgia, Kentucky, Louisiana, Maryland, Michigan, Minnesota, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Texas, and West Virginia. Included in Exhibit No. ___ (RJF-1) is a list of my appearances.

Q. **Have you previously presented testimony before the Florida Public Service Commission?**

A. Yes. In 1984 I appeared before the Florida Public Service Commission ("FPSC") in Florida Power Company ("FPC") Docket No. 830470-EI and addressed issues related to the Crystal River 5 generating unit. In 1987 I filed testimony in FPC Docket No. 870220-EI related to cost allocation and rate design and the performance of the Crystal River 3 nuclear plant. In 1992 I filed testimony in FPC Docket No. 910890-EI related to cost allocation and a variety of revenue requirements issues. Docket Nos. 870220-EI and 91890-EI were settled prior to my appearance. In 1992 I filed testimony in TECO's last general rate case (Docket No. 920324-EI) addressing issues related to cost allocation, jurisdictional separations and interruptible rates. That case was also settled prior to my appearance. I have also presented testimony in a number of smaller proceedings addressing issues related to interruptible load, off-system sales and DSM.

Q. Please discuss how your qualifications relate to the issues you are addressing in this case.

A. The primary subject matter of this testimony concerns the rate treatment of a new power plant and cost allocation. I have already pointed out my experience in cases related to the rate treatment of new power plants. In addition, as can be seen from Exhibit No. ____ (RJF-1) I began my work in the utility industry in the cost of service and rate design area nineteen years ago. I have been involved in cost of service and rate design analysis during most of my career.

Because it is purported that the selection of a cost allocation technique is intended to reflect the decision process underlying plant construction, I believe my experience in the planning area and prudence audits enables me to bring the perspective of the planner to this issue. In my previous work I have extensively reviewed a great number of utility planning documents that have led to the construction of new capacity over the period from the 1960s to the present, and have also been involved in a great number of planning cases concerned with major plant additions. As a result, although I will be addressing cost of service related issues, I will be approaching them from the perspective of a system planing expert.

II. INTRODUCTION AND SUMMARY

Q. On whose behalf are you appearing and what is the purpose of your testimony?

A. I am appearing on behalf of the Florida Industrial Power Users Group ("FIPUG"). These industrial customers are among the largest power consumers on the Tampa Electric Company ("TECO") system and have a direct interest in the regulatory treatment of the Polk County power plant which will be addressed in this case. FIPUG has asked Kennedy and Associates to review TECO's filing and comment on the Company's proposed regulatory treatment of the Polk County Unit and to address the issues raised in the Prehearing Order relative to the cost allocation methodology appropriate for the project and certain other issues.

Q. Do you have a summary of your testimony in this case?

A. Yes. I have concluded the following:

1. I do not dispute TECO's need for the added capacity available from the Polk County project and do not question the prudence, used and usefulness or cost effectiveness of the combined cycle portion of the plant. However, the Commission must decide whether the gasifier portion of the project is prudent, used and useful or cost effective.

2. My analysis of the cost effectiveness of the gasifier indicates that the current and near term fuel cost savings are minimal compared to the high initial capital costs of this project. If the Commission approves the prudence of the total investment, I recommend that the Commission utilize a phase-in approach to mitigate these high initial costs.

3. My analysis of TECO's planning process reveals that the need to add capacity in order to be able to meet peak demands was the driving force behind the decision to build the Polk County project. For this reason I recommend that the investment in the unit be allocated to classes receiving firm service on the basis of the firm classes' relative contributions to the peak demand on the system. TECO does not plan or build capacity to serve its Interruptible customers. Accordingly, they do not cause these costs to be incurred, and they should receive no allocation of production costs. Based on TECO's system characteristics, I recommend a ten summer/winter peak method for

allocation of the Polk County Unit.

4. I urge the Commission to reject any form of energy allocation (such as the equivalent peaker methodology) because such methods are based on a flawed understanding of the system planning process. Moreover, the rationale (incorrectly) offered by some analysts as justifying a departure from a peak responsibility approach to allocation of production cost is premised on the presence of fuel savings which are now insignificant, in the case of TECO's Polk County Unit, and are expected to remain so for more than two decades.

5. I urge the Commission to reject any notion that TECO will have a stranded cost recovery problem for two reasons. First, TECO's embedded cost of capacity and energy (including Polk County Unit) is lower than the cost of new combined cycle generation. In a competitive market, it is likely TECO would earn higher rates of return on its assets. Second, TECO's investors knew full well that competition was a possibility during the period of the Polk County's Unit construction. Thus, they accepted the risks of any stranded costs for the plant.

6. The FERC Mega-NOPR heralds a new era of wholesale power competition. Owing to this major shift in the regulatory paradigm, the

Commission should carefully assess the jurisdictional allocation of the Polk County Unit (and all plants) between the retail and wholesale market. The Commission should make an assignment of any capacity resources not needed to serve retail loads to the wholesale jurisdiction and impute long term wholesale sales at whatever cost it allows for the Polk County Unit.

III. RATE TREATMENT OF THE POLK COUNTY UNIT

Q. Due to the stipulation TECO's rates are frozen until January 1, 1999. Why is rate treatment of the Polk County Unit an issue?

A. The stipulation addresses the crucial issue of TECO's base rate levels by freezing rates. TECO, FIPUG and the OPC are all satisfied with this result. It also determines the treatment of any excess earnings via a deferral mechanism. However, the remaining issue to be addressed is the question of how one measures excess earnings in the surveillance reports. If TECO includes the full cost of the Polk County Unit in its regulatory rate base, then, all other things being equal, earnings will be depressed. In that case, earnings may not exceed the 11.75% level and revenues previously deferred will be "used up." If, on the other hand, TECO is not allowed the full cost of the Polk County Unit in rate base, then earnings will be increased. Because the Company is allowed to retain 40% of the excess earnings between 11.75% and 12.75%, this "softens the blow" of any disallowances imposed.

Q. Recognizing that the stipulation has already been approved by the Commission, please comment on its advantages.

A. The stipulation is part of an innovative solution to the sometimes contentious problem of reflecting a new plant in rates. In this particular case, a major advantage is that it utilizes some of the over earnings that the Company has been experiencing in order to mitigate the high initial cost of the Polk County Unit. The 60/40 sharing mechanism rewards TECO for sales growth and cost cutting efforts, and also (potentially) allows ratepayers to share in these benefits. In addition, the sharing also makes the Company somewhat less sensitive to disallowances, as noted above. This is useful because it gives the Company more flexibility to manage costs. However, the most significant fact is that present circumstances allow TECO to pursue this plan without a base rate increase and the ratepayers' advocates and the utility consider this an equitable solution.

Q. Why do you believe that it is essential for TECO avoid rate increases?

A. TECO's rates are now among the highest in the state, and the Company has already lost substantial amounts of industrial load to self-generation. TECO's management has made rate stability a high priority, as evidenced by the stipulation and recent cost cutting efforts. With wholesale competition on the doorstep, and retail competition perhaps not far behind, the traditional solution of raising rates is becoming less and less attractive within the utility industry.

The last few years have seen substantial cost-cutting and downsizing efforts taking place in the utility industry and relative rate stability in most places. It appears that TECO has concluded its best future lies in cutting costs and using innovative regulatory approaches, rather than increasing rates, in order to increase shareholder value. I agree with this perception and support it.

Q. **With that as a background, please discuss the issue of the regulatory treatment of the Polk County Unit.**

A. The Commission must consider a number of factors in its determination of the rate treatment for the Polk County Unit. These include the traditional issues of prudence, used and useful and the cost-effectiveness of the resource. However, as discussed above, the stipulation itself also has a bearing on the impact of any cost disallowances which the Commission might impose. The Company has addressed the prudence issue in its testimony. For my part, I will note that prudence is not the only standard for ratemaking. Due to the presence of competition in wholesale markets, and the likely emergence of retail competition during the useful life of the Polk County Unit, the latter two standards will take on increasing importance. I will concentrate on the cost effectiveness of the resource relative to other options and make rate treatment recommendations which will mitigate its initial high cost.

Q. **Comment on the cost effectiveness of the Polk County Unit.**

A. Exhibit No. __ __ (RJF-2) is a cost-effectiveness analysis of the Polk County

Unit from the perspective of current ratepayers. The source data for this study comes directly from Mr. Hernandez's Exhibit No. ____ (TLH-1.) This analysis compares the current cost of the Polk County Unit to the costs of a gas-fired combined cycle unit at the site. The only modification I have made to Mr. Hernandez's study is to remove the Polk County gasifier sunk costs and the DOE grant from the analysis. This analysis, therefore, reflects the costs of the Polk County Unit as built compared to TECO simply building a combined cycle unit at the Polk County site.

Q. **Why is this a relevant standard of comparison, and how does your analysis differ from that of Mr. Hernandez?**

A. In TECO's original certification proceeding, a gas-fired combined cycle unit was one of the alternatives considered. Given that TECO demonstrated a need for new capacity, and the relative economic advantages of combined cycle generation, this would have been considered a reasonable capacity addition at that time, and it remains so today. TECO, however, decided to build a coal gasifier at the site and received the DOE grant for doing so. The Commission conditioned approval of the project upon the DOE grant. This analysis addresses the question of whether TECO's decision remains the most economic choice from the current perspective. Naturally, the Commission must also consider the question of prudence, i.e. whether the decision to build the gasifier was reasonably expected to be the least cost option in the first place.

Mr. Hernandez's study addresses the question of completion vs. cancellation of the project. By reflecting the gasifier-related sunk costs in his study, he focusses solely on the question of whether it made sense to complete or abandon the gasifier project. With so little left to be spent on the project, the answer is obviously yes, assuming that reasonable operating performance is possible from the gasifier.

Q. What are the results of your study?

A. My study shows that over its entire lifetime the Polk County Unit *may* be an economic resource compared to a conventional combined cycle plant built at the same site. However, the projected economic advantage is rather small ($27 million in NPV in 1996 dollars) and it will take until approximately the year 2021 before the high initial cost of the gasifier is overcome by the projected long term fuel cost benefits on a cumulative present value basis. Long term projections such as this are obviously quite uncertain. What is highly certain, however, is the fact that the initial costs of the gasifier dwarf any possible fuel cost benefits during the early years of operation of the plant. In the initial years of operation during TECO's rate freeze (1996 to 1998), the gasifier results in additional capital costs of $64 million (NPV) but produces less than $ 13 million in fuel cost savings.

Q. In your view, what is the primary consequence of the cost-effectiveness

test you have performed regarding the issue of rate treatment?

A. The analysis performed demonstrates two problems. First, there is some doubt as to the long-term economic advantages of the gasifier portion of the plant. However, irrespective of the question of long-term cost effectiveness, the high initial cost of the project relative to a "plain vanilla" combined cycle plant is the most pressing concern. I propose that the Commission seek to implement a rate treatment for the gasifier which will mitigate its high initial cost.

Q. Why is the high initial cost of the gasifier such a concern?

A. There are two reasons. First, there is the question of intergenerational equity. Today's ratepayers could well end up subsidizing future ratepayers by paying the highest costs of this asset when it produces minimal fuel savings. Second, with the likely prospect of both wholesale and retail competition in the years ahead, current ratepayers may find themselves of paying down much of the costs of the Polk County Unit under a regulated regime, while TECO reaps the benefits of the project's lower operating costs in the years ahead in a deregulated environment. TECO's current ratepayers may not retain the claim on the eventual benefits of the plant under competition, even after having suffered its high costs under regulation.

Q. Having identified this, please proceed now to the question of the rate treatment of the Polk County Unit.

A. In FIPUG's view, the high initial cost of the gasifier is not a major problem, so long as it does not give rise to a rate increase. We believe that it is possible to craft a solution to this problem.

Exhibit No. ____ (RJF-3) is a copy of a letter from Mr. Gordon Gillette, Vice President of Regulatory Affairs of TECO, to Mr. John Slemkewicz, Supervisor of Electric and Gas Accounting for the FPSC. The letter demonstrates that from 1994 to 1996, TECO would experience excess earnings, with a reduction in earnings in 1997, due to the inclusion of the Polk County Unit in rate base. However, the shortfall in 1997 was not as great as the over earnings in expected in the period 1994-1996. In addition, TECO's sales growth projections are not particularly large, averaging 3% or less. The interesting point is that for 1997 TECO's ROE was projected to be 9.28%, apparently without any base rate increases. While I do not intend to address the question of TECO's appropriate ROE, this indicates a shortfall of a magnitude which could potentially be eliminated via higher sales growth, cost cutting, etc.

Q. Are there any other factors which bear upon this question?

A. Yes. Under traditional utility regulatory accounting, the initial year of a new plant is the highest cost. Every subsequent year has a lower cost as the rate base is depreciated, and the deferred tax reserve decreases. In the present case, TECO hopes to be allowed a seven-year tax life for the project. This will greatly accelerate the reduction in cost during the initial years of operation. This suggests that if TECO could stave off the necessity for a rate increase in the first few years of the Polk County Unit, it will be easier to do so after that. Thus, the necessary ingredients are in place for recognition of the new plant in rates without a rate increase.

Q. **Would this be unusual?**

A. When viewed in the context of the period from the 1980s to 1990, this would have been unusual indeed. However, as Mr. Rowe points out in his direct testimony, FP&L has recently accomplished the inclusion of the costs of a number of new power plants into rate base without a base rate increase.

Q. **Please describe FIPUG's proposed rate treatment for the Polk County Unit.**

A. FIPUG proposes to allow TECO to initially include the cost of the combined cycle portion of the plant into rate base for purposes of surveillance reporting in conjunction with the rate freeze. This approach will be equitable to shareholders and will assure ratepayers that they are paying for a cost-effective resource.

Q. **Why do you recommend inclusion of the cost of the combined cycle portion of the plant in rate base as opposed to the total booked cost of the unit?**

A. A combined cycle plant represents a reasonable standard of comparison for a new utility plant. My review of planning studies in recent years indicates this has become the capacity addition of choice for most utilities. TECO contends that completion of the Polk County Unit as a coal gasification project was a lower total cost option than a combined cycle unit, based on its studies over the period 1992 to 1996. However, I seriously doubt that any one would have proposed a prudence disallowance had TECO decided that the added costs and technological risks of coal gasification did not warrant the investment and chose to build a conventional combined cycle plant instead. In addition, the higher than expected costs of the project and reduced fuel savings cast some doubt on its long-term benefits. Had the Commission expected these in the first case, I question if the plant would have ever been certified. Thus, under present economic circumstances, the combined portion of the cycle plant represents an option which would be both prudent and cost-effective. For this reason, I do not dispute inclusion of at least that amount of cost into rate base. Given the need for and cost-effectiveness of the combined cycle portion of the plant, the problems of intergenerational equity and the potential regulated ratepayer subsidization of TECO's competitive future discussed above are not concerns.

However, the gasifier portion of the plant cost represents an added investment which must pass the regulatory tests of prudence and used and usefulness, or cost-effectiveness, particularly in light of the issues of intergenerational equity and the prospect for electric utility competition.

Q. Assuming the Commission determines that the gasifier is a prudent expenditure, how do you propose that TECO treat the additional investment?

A. In that case, TECO should be allowed to recover all operating expenses and depreciation on the plant as a whole. However, in order to mitigate the high initial cost of the plant, I recommend that the Commission defer the return on the gasifier to effectuate a phase-in of its costs, so that the total rate impact of the project is as close to neutral as possible during its initial years of operation. Under the stipulation, TECO's investment and expenses for financial reporting purposes are largely independent of the rate treatment of the Polk County Unit during the rate freeze, because rate levels and expenses are independent of this.

Q. Do you have a specific schedule for this phase-in proposal?

A. Yes. I propose that in the first full year of operation, a deferred return be allowed on 100% of the gasifier investment ($191 million). Each year after that an additional 20% of the gasifier's initial rate base would be allowed a current return. At the end of five years, the full rate base would be allowed a current return. Deferrals would be amortized over years 10-30. This approach will mitigate any current rate impact of the plant, but will also provide a rapid and definite phase-in. At the end of the rate freeze, TECO could petition the Commission to accelerate the phase-in if it can demonstrate lower than currently expected costs or larger fuel savings benefits.

IV. COST OF SERVICE METHODOLOGY

<u>**Introduction to Cost of Service**</u>

Q. What is the purpose of this section of your testimony?

A. One of the issues raised in the Prehearing Order relates to the proper cost allocation method for the Polk County Unit. This issue is of vital importance to FIPUG and I will discuss it in detail.

Q. Please explain the purpose and significance of a cost of service study.

A. In any general rate case, a cost of service study is a vital analysis which examines to what extent rates charged to various customer classes reflect the actual costs of providing each class the services that they use. We tend to think of a rate case as deciding two questions. First, we must determine the utility's overall revenue requirement. Once we know how much money in total the utility should be allowed to collect, the next step is to determine how that total revenue requirement is apportioned to each customer class. The simplest analogy is that the revenue requirements portion of the case determines the size of the pie, while the cost allocation portion determines how the pie is divided.

Using the information regarding each class' cost responsibility gained from a properly conducted cost of service study, it is possible to design cost-based rates. While the Commission is not designing rates in this case, any decision it makes on allocation methodology for the Polk County Unit will affect rates in the future. Cost-based rates are desirable, because they are equitable and because they provide the proper economic price signals to the customers who use the service. Further, by grouping costs among the appropriate categories, it is possible to design rates that provide precision in the recovery of revenue requirements.

Q. What are the basic elements of a cost of service study?

A. The first step in a cost of service study is called "functionalization." In this process one determines for any particular cost on the system whether it is related to the production, transmission or distribution of power or some other function. A generator is related to production, a transmission line is an example of a cost related to transmission, while a service drop would be related to distribution.

Once costs are functionalized they are then "classified" as being related to demand, energy or the number of customers. For example, the size of a generating unit is related to meeting demands on the system, while fuel costs are related to energy used. Meters are largely related to the number of customers on the utility.

These first two steps are not without some disagreement among experts; however, the final step in the process is generally the source of the least agreement. This step is known as allocation and in this process, the costs for each function and classification are distributed to customer classes based on their respective allocation factors. For some types of costs this part is rather easy. For example, meter costs can be assigned directly to each customer class. To the maximum extent possible, one would like to specifically assign costs to specific customers or classes.

The most frequently debated cost of service issue is the assignment of production-demand related costs. Unlike meters, whose use can be tracked to specific customers, when apportioning the cost of a generating plant that is used by all customers, such as the Polk County project, it is necessary to employ allocation factors because a specific assignment is not plausible. Consistent with the purpose of a cost of service study, the purpose of the allocation factor is to apportion costs in a manner that accurately reflects the factors that caused those costs to be incurred.

Q. What is the basic concept applied in determining the cost allocation for production plant?

A. Cost allocation is intended to reflect "cost causation." This concept means that one tries to allocate the costs of providing service to the customers who caused the cost to be incurred. For meters, the analysis is fairly simple. The cost of the meter at my house was caused by me because I want to use electricity and need a meter to be properly charged for it. With production-demand related costs, the analysis seems more complex, because all customers are constantly using these facilities at virtually all times. However, it is fairly easy to understand that the amount of capacity required on the system is related to the system peak demand. First and foremost, a utility's investment in generating capacity is a function of the total capacity it needs to meet the demands of its customers at the time of the system coincident peak demand. For this reason, traditionally analysts and Commissions have allocated the cost of a utility's investment in generating plant among firm customer classes based on their consumption at the time of the system peak demand. Interruptible customers agree to accept interruption whenever capacity is needed to serve firm customers. For that reason, TECO excludes them from consideration when quantifying the amount of capacity needed to serve the system. Historically, in recognition of the fact that they do not cause these costs to be incurred, their peak demands have accordingly been excluded from the development of production cost allocation factors. The Polk unit is no different in this regard.

Q. Is there evidence that such was the case with TECO's Polk County plant?

A. Yes. In fact, the Company's testimony is replete with statements which clearly emphasize the fact that the plant's primary purpose was to meet peak demand.

For example, the testimony of Mr. Anderson presents a recurring theme that the decision to build the plant was based upon a perception of need for new capacity to enable TECO to continue to provide reliable service. In fact, Mr. Anderson alludes to cold weather in 1989 as a catalyst for the decision to build a new plant:

> Q. Were there other events occurring during the Task Force's advisory participation that heightened your need to select a plant site?
>
> A. Yes. We experienced extreme cold weather over the Christmas Holidays of 1989. This event focused everyone's attention on the need for adequate and reliable generating capability for peninsular Florida. (Direct Testimony of Girard F. Anderson, page 10.)

Mr. Anderson also testifies that the Polk County Unit continues to be needed to meet TECO's obligation to serve its customers:

> In the final analysis, taking into consideration the changes discusses above, we believe the Polk power project remains in the best interest of all Tampa Electric Customers and represents the best means to meet its obligation to serve the future needs of its Customers. (ibid, page 21.)

Likewise the testimony of Mr. Rowe echoes the sentiment that the Polk County Unit is needed and establishes the concept that determination of need is the first step which was followed by a selection of resources based on cost-effectiveness considerations. For example, Mr. Rowe testifies as follows:

> The Certification of Need hearing has already determined that the capacity was needed and that an integrated gasification combined cycle unit located at the Polk Power Station site was the most cost-effective alternative available to meet that need. (Testimony of John R. Rowe, Jr. page 13.)

Q. Did the Commission specifically approve the need for the generating capacity represented by Polk Unit One?

A. Yes. In Order No. PSC-92-002-FOF-EI ("Order 92-00211) dated March 2, 1992, in Docket No. 91083-EI, the Commission certified the need for Polk Unit One. This order is included in Document No. 6 of my Exhibit. On page of the Order, the Commission found:

> TECO's reliability criteria will not be met unless the proposed IGCC unit is completed in the time frame requested. TECO would also risk losing the DOE

> funding it will receive for design, construction, and operation of the unit. Thus, any delays in the construction of the plant could ultimately cost TECO its most cost-effective alternative for meeting future capacity needs. (ibid, pg. 15)

Mr. Rowe further testifies that the continued decision to construct the plant as opposed to cancellation or abandonment was made in view of its continuing need:

> Any decision to delay or stop construction of a certified unit must also be made in view of the continuing need for the unit and the extreme consequences of failing to reliably serve the electric needs of the utility's customers. (ibid pg. 5.)

Finally, Mr. Hernandez testimony also presents examples of this theme:

> The need for the Polk one IGCC unit was originally determined and has been verified since using Tampa Electric's Integrated Resource Planning process. (Testimony of Thomas L. Hernandez, page 3.)
>
> Continued Need for Polk Unit One
>
> Q. In the years subsequent to the Commission's determination that Polk Unit One should be built, has Tampa Electric periodically reviewed

> the continuing need for this unit to meet the company's energy resource requirements?
>
> A. Yes. The need for the Polk One IGCC unit was identified in 1991 to maintain our electric system reliability and integrity at a reasonable cost. The plant is still needed in 1996.

Based on this testimony, it appears rather clear that TECO's decision to build the Polk County Unit was continuously driven by its obligation to serve, i.e. meet the peak demand.

Q. How does one measure the peak demand for allocation purposes?

A. There are numerous variations on the theme of fashioning coincident peak allocation factors. Many are attempts to tailor the methodology to the subject utility's system characteristics by identifying the particular months of the specific utility's operations which most influence the peak requirements. There is some debate about this point, because we generally do not know when the peak will actually occur. In general, we try to narrow it down to the fewest number of hours when the peak might occur. Many utilities use a single coincident peak method, which simply allocates production demand costs on the demands on the peak hour of the year. Others add certain monthly peaks, such as the three summer monthly peaks, or the six peaks in the summer and winter months. Some utilities reflect the 12 monthly peaks in the 12 CP method.

The Ten Summer/Winter Peak Methodology Is Recommended

Q. What method do you recommend for TECO?

A. As in the last TECO case, I recommend a ten summer/winter peak method. This approach reflects the highest demands in each season, irrespective of the month in which they occur. I believe this is a good approach because TECO has experienced peaks in both the summer and winter and peak demands are usually weather related. In any given year, the highest demands could all occur within a few days. Arbitrarily selecting the peak from the three summer or three winter months could miss some of the highest demand hours in any particular year. While the winter peaks are frequently higher than those in the summer, they tend to be of very short duration and can frequently can be met with interruptible loads. As a result, I believe that the summer peaks should also be included in the method selected for TECO.

Comparison of Cost of Service Methods

Q. Does the Company advocate any particular cost allocation methodology in its filing?

A. No. FIPUG is somewhat disappointed that TECO has not taken this opportunity to enunciate its position on the cost allocation methodologies relative to the Polk County Unit. This is a surprising development considering that the Commission specifically asked for comments on this issue, and because of its vital importance to FIPUG's members. From this I can only assume that the Company is satisfied with the cost allocation methods and results from its last rate case. In that case, the Company recommended the MFR method, and then later agreed to a modification to that method in settlement negotiations.

Q. **Are there methods other than the peak demand allocators you have discussed above?**

A. Yes. So far I have discussed examples of the "pure" peak responsibility methodology that has been the industry benchmark for decades. In the fairly recent past, some analysts have attempted to justify the introduction of a consideration of the classes' relative energy consumption as the basis for apportioning a portion of the costs of generation plant. In fact, the Commission's standard most frequently used methodology - which is prescribed as a component of rate case MFRs - uses allocation factors that reflect considerations of both twelve monthly peaks (12 CP) and "average demand", which is a measurement of energy consumption over time. In its MFR method, the Commission considers average demand as a "thirteenth" factor, added to the twelve coincident peak demands that would drive a "pure" 12 CP peak responsibility method and assigns a weight of 1/13 to that component. For several years now, the so called "equivalent peaker" method, which is a more extreme form of energy-based allocation than the

Commission's MFR methodology, has also been considered in most major rate cases. However, as I will develop further below, the Commission has used the method only once, 11 years ago. Since that single experiment, the Commission has specifically rejected it (for good reason) and has employed instead the 12 CP and 1/13 average demand methodology. The Company strongly recommended against the equivalent peaker method in its most recent case.

Q. In your view are the MFR and equivalent peaker methods appropriate?

A. No. For the reasons I have expressed already and those I will discuss shortly, the more one departs from a pure peak responsibility methodology, the more one strays from the objective of allocating costs on the basis of recognizing the factors that cause these production costs to be incurred.

Both the MFR and equivalent peaker methods incorporate examples of energy allocation concepts and for that reason I disagree with both, although I obviously find the MFR method far more acceptable. It is far closer to my recommended method and both the MFR and 10CP methods focus mainly on meeting peak demands.

Q. Can you describe these competing methods mathematically?

A. Mathematically, the MFR method allocator can be written as follows:

$$\text{MFR Method} = \frac{\text{Sum of 12 Coincident Peak + Average Demand}}{13}$$

By contrast, my recommended ten summer/winter peak method assigns all production investment costs on the basis of the ten highest peak demands in the summer and winter months.

As to the more extreme equivalent peaker allocator, it is difficult to present a concise mathematical description because the method has changed over time. The original equivalent peaker method presented in TECO's 1985 rate case crudely assigned all costs of baseload plants in excess of the cost of peaking units on the basis of total energy consumption. When certain technical and conceptual flaws (which I shall not discuss in detail here) became apparent in the method, it was redefined by its advocates to base those allocations only on the classes' average demand in a quantified number of certain peak hours beyond which a base load unit is deemed to be more economical than a peaker. (These are the hours of operation above the so-called "break even point".) This well illustrates the fact that the equivalent peaker method -- indeed all CapSub based allocators -- are a "moving target", thus not easy to describe in concise terms.

Both the MFR and equivalent peaker methods incorporate examples of energy allocation concepts and foı that reason I disagree with both, although obviously the MFR method is far more acceptable. It is far closer to my recommended method and both methods focus mainly on meeting peak demands. The equivalent peaker method was rejected by the Commission in 1989 in Gulf

Power Docket No. 891345-EI.

Energy Allocation Methods Contrasted to Peak Demand Allocators

Q. What are the consequences of allocating the cost of generation plant on the basis of energy consumption?

A. The consequences are significant and adverse. First, an inordinate share of peak-related production costs are steered to high-load factor customers, including many industrial customers, leading to unjustifiably higher industrial rates. Industrial customers have demonstrated in many instances how they respond to high rates in a particular state, including Florida. These responses can include more self-generation, shifting of production to other states, scaling back production of marginally profitable product lines and even plant closings. Accordingly, an artificial shifting of demand costs -- costs caused by customers whose consumption characteristics create more of the peak requirement -- to high load factor customers (those whose consumption tends to be more or less constant regardless of the time of day or the season) is bad not only for the industrial customer, but for the utility and ultimately the other customers. Second, if fixed production costs are allocated based on energy, the utility may experience an over recovery or under recovery of fixed costs as consumption varies. If one carries the allocation process through to rate design, these fixed costs of production would be collected in the energy charge. Thus, changes in energy consumption due to weather, rapid economic growth or recessions will have a dramatic impact on the revenues collected by the utility.

These adverse consequences are present in all energy-based allocation methods. However, in the case of the Commission's twelve CP and 1/13 average demand methodology, one can at least say that the classes' contributions to the coincident system peak are the more predominant basis for allocating the fixed costs of generation capacity. I therefore regard it as more acceptable than more extreme examples of energy-based allocation formulas, even though the use of the "thirteenth factor" is arbitrary and, in my view, unsupportable.

Q. Do equivalent peaker advocates reflect peak demand in their analysis?

A. Yes. Even advocates of the equivalent peaker method reflect peak demands in their cost allocation methodology. However, they do not stop with peak demand alone. Rather, they also factor in the amount of energy used during the year as part of the allocation process. They justify this on the grounds of system planning economics, which as noted above, suggests that different types of capacity may be optimal for different utilities depending on load factor and (as is often conveniently forgotten) a whole host of other factors such as fuel costs, local fuel supply considerations, legal requirements, management philosophy, public policy concerns, and perhaps even political factors.

The equivalent peaker logic is typical of energy allocation proponents who have spawned a whole range of cost allocation theories, including those referred to as capital substitution ("CapSub"), of which the equivalent peaker method is an example. For the most part, these methods differ somewhat in actual application. However, they all stem from the same underlying premise - that system economics dictate whether baseload or peaking capacity is the most economical choice over time, and all share one conclusion derived from this premise - that, ergo, some portion of plant should be allocated on an energy basis in recognition of this planning process. Usually this energy allocation is justified on the basis that the baseload plants cost more than peakers and hence these higher costs are related to savings in energy costs. This is known as the capital substitution premise, i.e. that planners substitute capital for fuel in the decision to invest in baseload capacity. Initially, I must point out that while I agree with the premise that economics *should* dictate the type of capacity on the system, I do not concur with the conclusion that this is relevant to the proper allocation of production costs. In addition to fundamental theoretical and conceptual flaws, it would be particularly inapplicable in the case of TECO's Polk County unit.

While good executives are concerned with economics, in most cases it is the fundamental "obligation to serve" an aversion to risk that drivers the decision-making process. In my view, meeting the peak-demand has always been the ultimate driving force behind the decision to contstruct capacity. The quotations from TECO's testimony cited above provide ample evidence of this point and, I believe, argue strongly in favor of a peak-demand oriented allocation factor.

Later, I will demonstrate that in reality the selection of the type of capacity is driven by many factors such as management philosophy, risk aversion, diversity and security of fuel supply, unique oppotunities available to the utility and the existing capacity mix as well as relative economics. I will demonstrate this was certainly the case with the Polk County plant.

<u>The Equivalent Peaker Method is Based on an Unrealistic View of the Planning Process</u>

Q. Understanding your point that the inadequacy of fuel savings (relative to capital costs) for decades precludes the application of CapSub approach to the Polk County Unit in any event, why do you say the the rationale of such methods, such as the equivalent peaker approach, is misplaced?

A. The energy allocation theories <u>claim</u> to be based on the concept of cost causation. They claim to attempt to allocate costs to those customers who cause the costs to be incurred. However, they are either confusing or even refusing to make a proposed distinction between the nature of fixed and variable costs. They ignore the fact that different types of recovery mechanisms are appropriate for the different types of cost. They ignore the fact that there is virtually absolute certainly as regards the level of fixed costs on a utility's books but great uncertanty as to the future course of variable costs. Their assumption is that the great majority of costs were caused by energy rather than peak demand; because they confuse fixed and variable costs, they mix apples with oranges. According to this theory, the planner decides the amount of capacity to build based on meeting the peak demands. Theoretically, the type of capacity (baseload vs. peaking), is selected based on minimizing revenue requirements. Under this approach, the type of capacity built and the cost of that capacity is the result of an economic tradeoff made by the planner in response to the relative cost of fuels, generating technologies, and system load factor. Unfortunately for the planner, this idealized vision often does not reflect the reality of the planning process.

The planner may *recommend* which generating units should be built and will estimate what they will cost to build and to operate after they are completed, but the planner does not *decide* which plant will actually be built. The planner's recommendation is but one of many inputs upon which the directors and senior management rely in making construction decisions. Legal, financial, public policy concerns, and many other factors impact the decision-making process and may override the planners' recommendations. At best, the planner influences and facilitates the decision-making process by providing the decision makers with useful information on a timely basis concerning the relative economics (and perhaps the impact on system reliability and financial indicators) of various options.

While good executives are concerned with economics, in most cases it is the fundamental "obligation to serve" and aversion to risk that drives the decision-making process. In my view, meeting the peak-demand has always been the ultimate driving force behind the decision to construct capacity. The quotations from TECO's testimony cited above provide ample evidence of this point and, I believe, argue strongly in favor of a peak-demand oriented allocation factor.

Later, I will demonstrate that in reality the selection of the type of capacity is driven by many factors such as management philosophy, risk aversion, diversity and security of fuel supply, unique opportunities available to the utility and the existing capacity mix as well as relative economics. I will demonstrate this was certainly the case with the Polk County plant.

Q. **Isn't it true that the mix of generation and the choice of fuels are a function of economics?**

A. Economics appears to be among the least significant predictors of a utility's fuel mix. Based on my experience, the fuel mix has as much, if not far more, to do with other factors including management philosophy, political considerations, and even geography. Management philosophy (or even biases in favor of certain types of generation) seems to be a far stronger predictor of fuel mix than any other factor. For example, TECO and Florida Power & Light are both regulated by the Commission and operate within close geographic proximity. As a result, one would expect that both fuel and capital costs would be comparable between the two companies. In addition, both face a similar regulatory and political environment. The Florida Commission does not have a reputation for penalizing utilities who build new baseload plants. Thus, both utilities seemingly could expect reasonable cost recovery for baseload capacity, when it was an economic and justifiable choice. Despite these similarities, the two utilities have substantially different capacity mixes. Once the Polk County Unit is completed, TECO will have 87% coal-fired generation and 13% oil-fired peaking capacity and have never invested in nuclear power. FP&L, on the other hand, has about 18% nuclear capacity, only 5% coal-fired capacity, and 77% gas or oil-fired capacity. Given their close geographic proximity, it would appear that fuel and capital costs were about the same for both companies. Further, load factors were around 60% for both TECO and FP&L in 1994. If the equivalent peaker type of reasoning is correct, there is absolutely no way to explain the differences in the capacity mixes of FP&L and TECO.

To emphasize this point, I think it is useful to examine the load duration curves ("LDC") of TECO and FP&L. Exhibit No. ____ (RJF-4) shows both companies LDCs as a percent of peak demand. It is interesting to see how little difference there is between the two figures. From this, if the CapSub theory had any predictive capability, one would never expect the two companies to have such drastically different capacity mixes. Clearly, there is more going on than the CapSub advocates could ever possibly explain or care to admit.

Q. Does this mean that it is prudent for these two utilities to have such difference capacity mixes?

A. No. There may be many explanations of this including imprudent decision making.

Q. Above you mentioned the availability of "unique opportunities" to the utility as a driving force in selection of capacity resources. Does the comparison of TECO and FP&L also illustrate this point?

A. Yes. For at least the last ten years, most economic studies have shown that gas or oil-fired combined cycle technology was the economic choice for new capacity addition. Yet FP&L and TECO have recently added new coal-fired resources to their generation portfolios. In both cases, unique circumstances drove the decisions. In TECO's case, the availability of the DOE grants in excess of a $100 million was obviously one of the critical factors in the Polk County Unit decision. In fact, the FPSC need determination made it clear that approval of the project was based on the project's qualification for the DOE grant. In the case of FP&L, it recently purchased a portion of Georgia Power

Company's Scherer 4 unit. This was a unique opportunity available to FP&L because GPC did not need the unit. GPC had originally sold the power from Scherer 4 to Gulf States Utilities, who later discovered it had no need for the plant. The Louisiana Public Service Commission denied cost recovery on the unit based specifically on its lack of need. Subsequently, GPC retained the capacity and requested rate recovery from the GPSC which was likewise denied. GPC's problem became FP&L's opportunity and the plant was sold. Scherer 4 was and remains a highly efficient, low cost, coal-fired plant. It costs little more than a combined cycle unit, yet two utilities sought to escape from the costs of the plant before FP&L determined it was needed. Clearly, the unique circumstances surrounding this plant and the Polk County unit were the primary drivers in capacity type decisions.

Nationally, one sees the same phenomenon. Fuel mix appears to have far more to do with geography than economics. For example, in coastal areas there is often a much greater reliance on oil-fired generation for <u>both</u> baseload and peaking generation. In midwestern and internal areas of the U.S., coal-fired generation is often predominant for <u>both</u> baseload and peaking generation. In general, the capacity that is in place now appears to be a function of the availability and access to fuels, the local acceptance of these fuels and the extent to which the fuel industry is established in the region. While this is admittedly a partial reflection of economics, other factors come into play. This is why utilities in Kentucky and Ohio (two states with substantial coal mining industries) primarily use coal, utilities in Florida and New York have historically used much more oil generation, and why utilities in Texas rely on natural gas. While it does not contradict economic theory that geographical variances in delivered prices would impact the capacity mix, it is difficult for the energy allocation advocates to explain why the choice of fuels for both baseload and peaking capacity is often the same.

Q. **Returning to the capital substitution premise, are there other major problems with the theory?**

A. Yes. A second major problem with these methods are they assume the planner will actually succeed in the assumed "substitution of capital for fuel." In fact, it is quite possible that the theory will fail to produce the least cost system even if it were rigorously applied and implemented. This model of planning ignores the dynamic and volatile nature of the planner's environment. The simple fact is that the planner will never succeed in building the optimal system for all future conditions of fuel prices, interest .ates, and capital costs. The reason is simple: the optimal system for the world of the late 1970s with low interest rates and projected $40/bbl oil, was quite suboptimal for the 1980s and 1990s environment with falling interest rates and oil prices. Under today's low interest rates and low fuel price environment, a much different mix would be optimal. If the optimal system were achieved, it would be suboptimal as soon as economic conditions changed.

Once again, the Polk County Unit illustrates these points painfully well. According to the figures contained in Mr. Hernandez's testimony, TECO expected substantial increases in natural gas and oil prices at the time when the plant was originally planned. For example, in the 1992 studies TECO projected that current (1996) prices for natural gas would be approximately $4.5/MMBTU, that oil would cost $6.5/MMBTU and that coal would cost $1.60 per MMBTU. The most recent actual years' prices (1995) are as follows: natural gas $2.50/MMBTU; oil $4.25/MMBTU and less than $1.40/MMBTU for coal. In all three cases, fuel prices have declined since 1992 rather than increased, as was originally expected! Such volatility in fuel prices is nothing new. For most of the past 20 years prices for coal, oil and natural gas have defied accurate prediction. This is a major problem with the capital substitution premise. It assumes fuel prices are relatively predictable, and that planners will succeed in determining the least cost fuel. The experience with the Polk County Unit (and virtually every other baseload plant built in the past two decades) calls this premise into question.

Q. Based on those high initial projections of fuel prices it would appear that TECO might have been able to justify building the Polk County Unit for the fuel savings alone even without an initial need for the capacity. Do

you agree with this observation and what inference do you draw from it?

A. It does appear from Mr. Hernandez's 1992 and 1993 projections that even without an immediate capacity need, TECO may have been able to project an economic benefit from building the Polk County Unit in 1996, compared to a new combined cycle plant five or ten years later. I think this is significant because it illustrates an important point about why the Polk County Unit was built in the first place. In my opinion, TECO would have never constructed this (or any other) plant unless it expected an immediate capacity need. While an economic comparison might have shown fuel cost benefits would outweigh the cost of the unit, given the above demonstrated volatility in fuel prices, in 1991 no prudent or rational utility executive would have ever undertaken the risk of building the plant absent a real anticipated need for its capacity. Projections of fuel cost savings have simply proven far too unreliable to undertake a massive capital investment such as a new power plant which was not expected to serve a capacity need.

Q. **TECO's estimated cost of building the Polk County Unit has also increased. Does this expose additional problems with the energy allocation premise?**

A. Yes. The final cost of the Polk County Unit will exceed the original estimates. The December 1991 estimate of $413 million plant cost estimate used in the need hearing will be exceeded based on the current $506 million total cost estimate. This provides another powerful example of the problems with the capital substitution premise, for it posity that all costs of a plant in excess of the cost of peaking capacity were incurred to save money on fuel. This means in the present case that all the cost increases were incurred on the basis of fuel savings. However, a major portion of the difference in plant costs were due to land costs not included in the original estimate. In reality, the cost increases (other than land) were not expected at the time the original decision to build the plant was made, and Mr. Hernandez has testified that all types of plants would require the same land costs. This is significant, for if the CapSub advocates are forthright about it, they would have to agree there is no basis for the allocation of cost overruns or land costs on an energy basis.

Q. **The equivalent peaker method assumes that the extra costs of baseload plants over those of peaking or intermediate units were incurred for fuel savings. How do the cost estimates of combustion turbines and combined cycle units used by TECO in the late 1991 compare to current expectations?**

A. In general, the actual costs of combined cycle and combustion turbine units have been less than earlier cost estimates, even those made as recently as 1991. Based on Mr. Hernandez's Exhibit TLH-1, page 141, in 1991 the Company expected a combined cycle unit would cost $628/kW and a new CT would cost $485/kW (pg. 149). TECO's current cost estimates are $546/kW (page 125) and $458/Kw (page 133) for combined cycle and CT's respectively (exclusive of land and common costs.) Thus, assuming that the current level of cost of the Polk County Unit over a combined cycle or combustion turbine plant represents the original expectations of the planner, would inappropriately shift millions in cost from demand to energy under the equivalent peaker premise. In this regard, the equivalent peaker method implies a particularly troubling form of hindsight, because it assumes that all increases in costs of the plant actually built are due to fuel savings, and that the same is true for decreases in the costs of alternative plants. TECO's high load factor consumers should not be penalized because the Polk County Unit cost more to build than was originally expected or because the cost of a gas-fired plant now costs less than expected. For this reason, I believe it is simply naive to assume that the cost of TECO's coal units in excess of gas or oil units of the cost of TECO's coal units were incurred because planners wanted to provide fuel savings.

Q. Please summarize the point of these examples.

A. The CapSub approach makes a number of unrealistic simplifying assumptions about the planning process. These examples show that while the CapSub advocate would assume that all unanticipated costs of the Polk County Unit were incurred to provide fuel cost savings, that was simply not the case. In fact, much of the extra cost of baseload units over CTs were unanticipated at the time and resulted because the project cost more than originally anticipated or because gas-fired generation now costs less than expected.

Q. Can you present any other examples which argue against the CapSub methods?

A. Yes. TECO's testimony points out that one of the problems it would have with building a gas-fired plant would be that it would operate with a rather low capacity factor, owing to the existing system capacity mix which is heavily dominated by coal. This would imply that gas pipeline demand charges would be spread over few units of consumption. This would raise the average cost of gas and, at a superficial level, seemingly support the notion of fuel savings. However, the real point is otherwise. This discussion demonstrates that the Polk County Unit did not simply avoid high energy costs: rather it avoided gas pipeline demand charges, which are essentially fixed costs of investments such as pipeline capacity. This illustrates that the existing capacity mix drives capacity expansion decisions, and in this case, the presence of large amounts of coal-fired capacity on the system had the effect of decreasing the attractiveness of gas fired generation.

Q. You seem to diminish the importance of the tradeoff between fuel and capital costs in the planning process. What does drive the process, if not economic considerations?

A. I believe that two forces have driven the process for at least the last twenty years, if not since the inception of the industry: the "obligation to serve" and the "aversion to risk." TECO's testimony in this case, as quoted previously, clearly establishes the Company's paramount concern over its obligation to serve. Aversion to risk, is a far more subtle concept, but I think it explains why utilities make differing fuel choice selections, in the face of similar fuel and capital cost inputs. For example, in the early 1970s, the oil and gas supply was considered insecure at times. For most utilities, the most risk averse plan to meet the obligation to serve (i.e. meet the peak) was to initiate and complete construction of nuclear or coal projects. In Florida, and nationwide, different utilities have shown differing responses to the recent trend of lower than expected gas and oil prices, coupled with diminishing concerns regarding fuel availability. Some utilities have simply taken far longer than others to decide that the gas and oil supply is secure enough to use these fuels in a new power plant. As noted above, TECO and the other utilities in the state face comparable fuel and capital costs. Yet, FPC built new peaking units in the early 1990's while TECO planned to build the Polk County plant at the same time. While both companies would undoubtably contend that they made the least cost choice, it would appear that differing assumptions regarding fuel prices and other factors were major drivers in the process. Ultimately, I believe that TECO was far more risk averse regarding the question of fuel availability, and less risk averse in regard to capital investments. For FPC, the reverse was true.

Q. **Are there other factors which might sway an executive's decision in favor of a particular fuel?**

A. Yes. TECO's coal mining interests would also be a factor which might sway an executive's decision process. Most utilities seem to have given up on the coal-fired option years ago, and there have been relatively few coal plant rate cases, particularly for plants started after 1990. I am only aware of two utilities who started a new coal-fired power plant after 1990 (the Polk County project and Neil Simpson No. 2 owned by Black Hills Power.) I find it rather interesting that in both cases these plants were built by utilities who also owned coal mining businesses.

The preceding discussion raises a serious question about the application of the equivalent peaker method. Economic comparisons often provide only an ambiguous suggestion concerning the most economic plant to build. Furthermore, the results can vary as quickly as fuel prices change. As a result, executives and regulators are likely to use their experience and judgment to decide the course of capacity expansion and select a risk averse plan which meets a broad range of policy goals. This was certainly true in the past and will continue to be true in the future. Systems have not historically been planned in accordance with the equivalent peaker method and the management was not absolutely bound to mechanical selection of the planners' projected, least-cost plan. One must then ask, why should rates be based on the assumption that the costs of the existing capacity mix is the <u>perfect and intended</u> result of this simplistic and highly idealized model of the decision-making process?

<u>**The Practice of the FPSC is to Reject Energy Based Allocations**</u>

Q. What has been the Commission's policy concerning the equivalent peaker method in particular, and energy allocation procedures in general?

A. Generally, the Commission has not accepted energy allocation procedures that used more than the 1/13 weighing. Outside of the 1985 TECO rate case, the equivalent peaker method has never been accepted by the Commission. From my own experience, I can point out that in the 1984 Florida Power Rate case, the FPSC rejected a cost allocation method that used only a <u>19%</u> energy weighing (or 50% of the cost of Crystal River 5.) This allocator proposed by the utility was premised on the assumption that due to fuel cost savings, 50% of the cost of Crystal River 5 should be allocated on an energy basis. However, in its order, the Commission rejected the fuel savings rationale for the allocation of Crystal River 5 costs (Order in Case No. 830470-EI, page 41). Even though a modified equivalent peaker method was proffered by FPC in Case No. 870220-EI in 1987, the Commission accepted a revenue distribution stipulation in that case which was completely contrary to the results indicated by the equivalent peaker method.

In the 1989 Gulf Power case the Commission explicitly and soundly rejected the equivalent peaker method:

> The equivalent peaker methodology implies a refined knowledge of costs, which is misleading, particularly as to the allocation of plant costs to hours past the break even point. [FPSC Order No. 23573, Docket No. 891345-EI, 120 P.U.R. 4th 1 (1990)]

This short statement by the Commission is an effective summary of the points I have developed in my testimony.

Finally, in TECO's last case, the Commission accepted the stipulation between the Company, FIPUG and the Staff which presented a modification to the peak-oriented MFR method, not an equivalent peaker method. Clearly, the Commission has seen through and rejected this discredited theory. It should continue to do so.

IV. OTHER ISSUES

Jurisdictional Separation Factors

Q. Are there any other issues you wish to address?

A. Yes. The Commission needs to carefully consider the issue of jurisdictional separation factors and the treatment of the Polk County Unit's costs in the wholesale jurisdiction. As a result of the FERC Orders 888 and 889 (stemming from the Mega-NOPR) TECO, and all utilities, will now be participating in a competitive wholesale market. While, in the past, the wholesale and retail jurisdictions were both regulated markets, now TECO will be involved in a regulated retail, but increasingly deregulated wholesale power business. Commissions have traditionally had strong concerns in instances where utilities operated in both regulated and competitive businesses and have frequently instituted special measures to protect regulated customers from subsidizing the deregulated or unregulated businesses. In the present case I urge the Commission to take special care that retail ratepayers do not subsidize wholesale ratepayers.

Q. **How can the Commission ensure this?**

A. The Commission should revisit the jurisdictional separation factors, particularly for generation resources and ensure that a reasonable portion of the costs of the Polk County Unit (and, in fact, all plants) is assigned to the wholesale jurisdiction. This can be done by allocating the wholesale jurisdiction all capacity not required to serve retail peak demands. In addition, the Commission should make it a rebuttable presumption that the allowed cost of the Polk County Unit is the cost of serving long term (greater than 5 years) wholesale loads. In other words, it should impute the costs of the Polk County Unit as the revenues derived from long term contracts in the wholesale market.

Q. **Explain why you believe that this should be done.**

A. TECO and all other utilities are now in a position to compete on a much broader scale for wholesale loads. A danger in this situation is that TECO could build unneeded capacity in an attempt to expand wholesale market share. To prevent retail customers from subsidizing TECO's unregulated wholesale efforts, the Commission should assign excess capacity to the wholesale jurisdiction and impute the allowed cost of the latest capacity addition to the wholesale market as the price of long term sales.

Stranded Costs and Price Indexing

Q. Do you believe that the Polk County Unit should be recognized in any future stranded cost recovery type of exit fee?

A. No. There is no evidence that TECO will have a stranded cost recovery problem. In fact, an excellent case can be made that TECO would earn higher returns on its resources under a competitive regime than would be the case with continued regulation.

Q. Please explain.

A. In considering stranded costs, it is important to recognize the entire generation mix of a utility, not just its highest cost, or most recently completed plant. In TECO's case, the Company's embedded cost of capacity (even with the Polk County Unit) is a less than $400/kW. This is lower than the current cost of a new combined cycle generator or combustion turbine. However, TECO's capacity mix is 87% coal-fired. Since coal fuel prices are now lower than natural gas or oil (and expected to remain so), it is clear that TECO's existing capacity mix will be lower in cost than either a new CT or combined cycle plant. Thus compared to the cost of new generation resources, TECO's existing resources would have a substantial competitive advantage. TECO can generate energy from its existing units at a lower cost than a new generation resource would require.

Q. Why is this significant?

A. In a competitive market, economic theory holds that price will equate to marginal cost. If excess capacity is present, then the price will equal short run marginal cost. However, in an equilibrium position, without excess capacity, price will equal the long run marginal cost of new generation. Currently, the load and capacity balance in the area is in balance. SERC, as a whole, has a reserve margin of 24% over the firm summer peak, while the Florida and Southern subregions have reserve margins of 23% and 20%, respectively. There is no longer a substantial amount of excess capacity in the region. Therefore, we can expect that under competition, the market price will equate rather quickly to the cost of new generation, and eventually settle in at a level higher than TECO's embedded cost of capacity. For this reason, TECO would expect to earn higher returns in a competitive market than under continued regulation. In light of this, it is clear that TECO's stranded costs are probably negative.

Q. Does the recent time frame for the Polk County Unit's construction have any bearing on this issue?

A. Yes. It is frequently suggested that investors would perceive it to be unfair if high cost nuclear plants were not included as part of a stranded cost recovery charge. While there is room to debate this point, at least one thing is clear. Unlike a nuclear plant, which was originally conceived in the early 1970s and perhaps completed in the 1980s, the Polk County Unit is a product of the last five years. While utility investors might claim to have had no idea that electricity competition would someday become a reality when nuclear plants were undertaken, the same cannot be said for TECO's current investors. The prospects for both retail and wholesale competition were well known in the early 1990s when TECO began its involvement in the project. In 1992, for example, the federal EPACT was passed which required the institution of wholesale competition. Thus, TECO's current investors made their choices with their eyes open as regards the possibility that the Polk County Unit might someday be an asset used in a competitive market. Thus, to this extent, investors should bear the risk (if any) of stranded costs for the Polk County Unit.

Q. Should the Commission establish a performance-based rate indexing as a method of cost recovery for TECO's Polk IGCC unit?

A. No. FIPUG has already proposed a ratemaking mechanism for the Polk

County Unit. Performance-based ratemaking is a frequently used term these days, and may mean different things to different people. I am assuming that in this instance, it means some form of rate indexing. Generally speaking, this has meant that utilities are allowed to automatically increase prices based on an index of inflation and fuel prices with, perhaps, a productivity offset. While there is no specific proposal on the table, this type of performance based ratemaking is unwarranted because it simply allows the utilities the opportunity to overearn. If such a system had been in place in Florida over the past decade, the current TECO refunds as well as the 1987 FPC rate reduction would have never taken place. Instead, steadily rising rates would have occurred, and substantial over collections would have resulted.

Further, formalistic ratemaking standards have been a one-way street. For example, the Commission has had an O&M benchmark methodology for years, but has been reluctant to apply it when it implied a large disallowance. For example, in the FP&L tax refund case, the Commission declined to reflect an O&M benchmark concept in determining the refund level. Unless the Commission is prepared to implement this type of approach, even if it spells serious problems for utilities at some future date, it should not allow it to be introduced now when "times are good."

The fundamental flaw with performance based ratemaking is that it tends to capture only increases to cost, such as due to inflation, without giving credit to sources of decreasing costs, such as sales growth, rate base depreciation, etc. For most electric utilities, very little of the actual cost of service is related to inflation, at least in the short run. Most electric utilities revenue requirements are dominated by the capital investment in production, transmission and distribution plant. In the absence of a new plant, these costs will decline over time. Labor related costs, such as O&M, may follow inflation to some extent, but are hardly driven by inflation. For example, utilities, such as TECO, have actually been able to freeze or even cut O&M expenses in some cases, even when overall inflation in the economy has been running at 3% or more. Finally, a utilities' fuel prices are driven by existing contracts, as well as prices in fuel markets. Simply because a neighboring utility has an increase in fuel costs does not mean TECO should be granted a fuel price increase.

The primary argument in favor of performance-based ratemaking is that it allows a utility to reap some of the rewards of its own cost cutting efforts and efficiency gains. However, FIPUG's proposal accomplishes that goal, while still allowing ratepayers to share in some of those benefits as a costly new power plant is worked into customer rates. I recommend that the Commission reject any form of rate indexing such as performance based ratemaking and adopt the FIPUG proposal instead.

Q. Does this conclude your testimony?

A. Yes.

QUALIFICATIONS OF RANDALL J. FALKENBERG, VICE PRESIDENT

EDUCATIONAL BACKGROUND

I received my Bachelor of Science degree with Honors in Physics and a minor in mathematics from Indiana University. I received a Master of Science degree in Physics from the University of Minnesota. My thesis research was in nuclear theory. At Minnesota I also did graduate work in engineering economics and econometrics. I have completed advanced study in power system reliability analysis.

PROFESSIONAL EXPERIENCE

After graduating from the University of Minnesota in 1977, I was employed by Minnesota Power as a Rate Engineer. I designed and coordinated the Company's first load research program. I also performed load studies used in cost-of-service studies and assisted in rate design activities.

In 1978, I accepted the position of Research Analyst in the Marketing and Rates department of Puget Sound Power and Light Company. In that position, I prepared the two-year sales and revenue forecasts used in the Company's budgeting activities and developed methods to perform both near- and long-term load forecasting studies.

In 1979, I accepted the position of Consultant in the Utility Rate Department of Ebasco Service Inc. In 1980, I was promoted to Senior Consultant in the Energy Management Services Department. At Ebasco I performed and assisted in numerous studies in the areas of cost of service, load research, and utility planning. In particular, I was involved in studies concerning analysis of excess capacity, evaluation of the planning activities of a major utility on behalf of its public service commission, development of a methodology for computing avoided costs and cogeneration rates, long-term electricity price forecasts, and cost allocation studies.

At Ebasco, I specialized in the development of computer models used to simulate utility production costs, system reliability, and load patterns. I was the principal author of production costing software used by eighteen utility clients and public service commissions for evaluation of marginal costs, avoided costs and production costing analysis. I assisted over a dozen utilities in the performance of marginal and avoided cost studies related to the PURPA of 1978. In this capacity, I worked with utility planners and rate specialists in quantifying the rate and cost impact of generation expansion alternatives. This activity included estimating carrying costs, O&M expenses, and capital cost estimates for future generation.

QUALIFICATIONS OF RANDALL J. FALKENBERG, VICE PRESIDENT

In 1982 I accepted the position of Senior Consultant with Energy Management Associates, Inc. and was promoted to Lead Consultant in June 1983. At EMA I trained and consulted with planners and financial analysts at several utilities in applications of the PROMOD and PROSCREEN planning models. I assisted planners in applications of these models to the preparation of studies evaluating the revenue requirements and financial impact of generation expansion alternatives, alternate load growth patterns and alternate regulatory treatments of new baseload generation. I also assisted in EMA's educational seminars where utility personnel were trained in aspects of production cost modeling and other modern techniques of generation planning.

I became a Principal in Kennedy and Associates in 1984. Since then I have performed numerous economic studies and analyses of the expansion plans of several utilities. I have testified on several occasions regarding plant cancellation, power system reliability, phase-in of new generating plants, and the proper rate treatment of new generating capacity.

PAPERS AND PRESENTATIONS

Mid-America Regulatory Commissioners Conference - June 1984: "Nuclear Plant Rate Shock - Is Phase-In the Answer"

Electric Consumers Resource Council - Annual Seminar, September 1986: "Rate Shock, Excess Capacity and Phase-in"

The Metallurgical Society - Annual Convention, February 1987: "The Impact of Electric Pricing Trends on the Aluminum Industry"

Public Utilities Fortnightly - "Future Electricity Supply Adequacy: The Sky Is Not Falling" What Others Think, January 5, 1989 Issue

Expert Testimony Appearances
of
Randall J. Falkenberg
As of April 1996

Date	Case	Jurisdict.	Party	Utility	Subject
3/84	8924	KY	Airco Carbide	Louisville Gas & Electric	CWIP in rate base.
5/84	830470-EI	FL	Florida Industrial Power Users Group	Florida Power Corp.	Phase-in of coal unit, fuel savings basis, cost allocation.
10/84	89-07-R	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power	Excess capacity.
11/84	R-842651	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Phase-in of nuclear unit.
2/85	I-840381	PA	Phila. Area Industrial Energy Users' Group	Philadelphia Electric Co.	Economics of cancellation of nuclear generating units.
3/85	Case No. 9243	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Economics of cancelling fossil generating units.
3/85	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Economics of pumped storage generating units, optimal reserve margin, excess capacity.
3/85	3498-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Cancellation of nuclear unit, load and energy forecasting, generation planning economics.
5/85	84-768-E-42T	WV	West Virginia Multiple Intervenors	Monongahela Power Co.	Economics of pumped storage generating units, optimal reserve margin, excess capacity.
7/85	E-7, SUB 391	NC	Carolina Industrial Group for Fair Utility Rates	Duke Power Co.	Nuclear unit economics, fuel cost projections.
7/85	9299	KY	Kentucky Industrial Utility Consumers	Union Light, Heat & Power Co.	Interruptible rate.
8/85	84-249-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Prudence review.
1/86	85-09-12	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Excess capacity, financial impact of phase-in of nuclear plant.
1/86	R-850152	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Phase-in and economics of nuclear plant.
2/86	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve margins, prudence, off-system sales guarantee plan.

Expert Testimony Appearances
of
Randall J. Falkenberg
As of April 1996

Date	Case	Jurisdict.	Party	Utility	Subject
5/86	86-081-E-GI	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Generation planning, economics prudence of a pumped storage hydro unit.
5/86	3554-U	GA	Attorney General Georgia Public Service Commission Staff	Georgia Power Co.	Cancellation of nuclear plant.
9/86	29327/28	NY	Occidental Chemical Corp.	Niagara Mohawk Power Co.	Avoided cost, production cost models.
9/86	E7-Sub 408	NC	NC Industrial Energy Committee	Duke Power Co.	Incentive fuel adjustment clause.
12/86	9437/613	KY	Attorney General of Kentucky	Big Rivers Electric Corp.	Power system reliability analysis, rate treatment of excess capacity.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power	Economics and rate treatment of Bath County pumped storage County Pumped Storage Plant.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend Nuclear Plant.
6/87	PUC-87-013-RD E002/E-015 -PA-86-722	MN	Eveleth Mines & USX Corp.	Minnesota Power/ Northern States Power	Economics of sale of generating unit and reliability requirements.
7/87	Docket 9885	KY	Attorney General of Kentucky	Big Rivers Electric Corp.	Financial workout plan for Big Rivers.
8/87	3673-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Nuclear plant prudence audit, Vogtle buyback expenses.
10/87	R-850220	PA	WPP Industrial Intervenors	West Penn Power Co.	Need for power and economics, County Pumped Storage Plant
10/87	870220-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Cost allocation, interruptible rate design.
10/87	870220-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Nuclear plant performance.
1/88	Case No. 9934	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Review of the current status of Trimble County Unit 1.

Expert Testimony Appearances
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As of April 1996

Date	Case	Jurisdict.	Party	Utility	Subject
3/88	870189-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Methodology for evaluating interruptible load.
5/88	Case No. 10217	KY	National Southwire Aluminum Co., ALCAN Alum Co.	Big Rivers Electric Corp.	Debt restructuring agreement.
7/88	Case No. 325224	LA 19th Div I Judicial District	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend Nuclear Plant.
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Weather normalization of gas sales and revenues.
10/88	3799-U	GA	Georgia Public Service Commission Staff	United Cities Gas Co.	Weather normalization of gas sales and revenues.
12/88	88-171-EL-AIR 88-170-EL-AIR	OH OH	Ohio Industrial Energy Consumers	Toledo Edison Co., Cleveland Electric Illuminating Co.	Power system reliability reserve margin.
1/89	I-880052	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Nuclear plant outage, replacement fuel cost recovery.
2/89	10300	KY	Green River Steel Co.	Kentucky Utilities	Contract dispute, interruptible rates.
3/89	P-870216 283/284/286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Reserve margin, avoided costs.
5/89	3741-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Prudence of fuel procurement.
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Need and economics of coal and nuclear capacity, power system planning.
10/89	2087	NM	Attorney General of New Mexico	Public Service Co. of New Mexico	Power system planning, economic and reliability analysis, nuclear planning, prudence.
10/89	89-128-U	AR	Arkansas Electric Energy Consumers	Arkansas Power Light Co.	Economic impact of asset transfer and stipulation and settlement agreement.

Expert Testimony Appearances of Randall J. Falkenberg As of April 1996

Date	Case	Jurisdict.	Party	Utility	Subject
11/89	R-891364	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Sale/leaseback of nuclear plant, excess capacity, phase-in construction delay imprudence.
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Sale/leaseback of nuclear power plant.
4/90	89-1001-EL-AIR	OH	Industrial Energy Consumers	Ohio Edison Co.	Power supply reliability, excess capacity adjustment.
4/90	N/A	N.O.	New Orleans Business Counsel	New Orleans Public Service Co.	Municipalization of investor-owned utility, generation planning, reliability analysis.
7/90	3723-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Weather normalization adjustment rider.
9/90	8278	MY	Maryland Industrial Group	Baltimore Gas & Electric Co.	Revenue requirements, gas and electric CWIP in rate base.
9/90	90-158	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Power system planning.
12/90	U-9346 Rebuttal	MI	Association of Businesses Advocating Tariff Equity (ABATE)	Consumers Power Co.	Demand-side management.
5/91	3979-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Demand-side management, load forecasting, and integrated resource planning.
7/91	9945	TX	Office of Public Utility Counsel	El Paso Electric Co.	Power plant planning, prudence, quantification of damages of imprudence, environmental costs of electricity.
8/91	4007-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Integrated resource planning, regulatory risk assessment.
11/91	10200	TX	Office of Public Utility Counsel	Texas-New Mexico Power Co.	Imprudence disallowance.
12/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Year-end sales and customer adjustment, jurisdictional allocation.
1/92	89-783-E-C	WVA	West Virginia Energy Users Group	Monongahela Power Co.	Avoided costs, reserve margin, power plant economics.
3/92	91-370	KY	Newport Steel Co.	Union Light, Heat & Power Co.	Interruptible rates, design, cost allocation.

Expert Testimony Appearances
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Randall J. Falkenberg
As of April 1996

Date	Case	Jurisdict.	Party	Utility	Subject
5/92	91890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Incentive regulation, jurisdictional separation, interruptible rate design.
6/92	4131-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Integrated resource planning, demand-side management.
9/92	920324-EI	FL	Florida Industrial Power Users Group	Tampa Electric Co.	Cost allocation, interruptible rates decoupling, DSM
10/92	4132-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Residential conservation program certification.
10/92	11000	TX	Office of Public Utility Counsel	Houston Lighting and Power Co.	Certification of utility cogeneration project.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Entergy/Gulf States Utilities (Direct)	Production cost savings from merger.
11/92	8469	MD	Westvaco Corp.	Potomac Edison Co.	Cost allocation, revenue distribution.
11/92	920606	FL	Florida Industrial Power Users Group	Statewide Rulemaking	Decoupling, demand-side management, conservation, performance incentive factor.
12/92	R-009 22378	PA	Armco Advanced Materials	West Penn Power Co.	Energy allocation of production costs.
1/93	8179	MD	Eastalco Aluminum/ Westvaco Corp.	Potomac Edison Co.	Economics of QF vs. combined cycle power plant.
2/93	92-E-0814 88-E-081	NY	Occidental Chemical Corp.	Niagara Mohawk Power Corp.	Special rates, wheeling.
3/93	U-19904	LA	Louisiana Public Service Commission Staff	Entergy/Gulf States Utilities (Surrebuttal)	Production cost savings from merger.
4/93	EC92 21000 ER92-806-000 (Rebuttal)	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	Merger.
6/93	930055-EU	FL	Florida Industrial Power Users' Group	Statewide Rulemaking	Investigation of proposed stockholder incentives for off-system sales of capacity and energy by investor-owned utilities.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers and Kentucky Attorney General	Big Rivers Electric Corp.	Prudence of fuel procurement decisions.

Expert Testimony Appearances
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Randall J. Falkenberg
As of April 1996

Date	Case	Jurisdict.	Party	Utility	Subject
9/93	4152-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Allocation of cost of pollution control equipment.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Analysis of revenue requirements and cost allocation issues.
4/94	93-465	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Review and critique proposed environmental surcharge.
4/94	4895-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co	Review of purchased power agreement and fuel adjustment clause.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Light Co.	Revenue requirements, incentive compensation.
7/94	94-0035-E-42T	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue annualization, ROE performance bonus, and cost allocation.
8/94	8652	MD	Westvaco Corp.	Potomac Edison Co.	Revenue requirements, ROE performance bonus, and revenue distribution.
1/95	94-332	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Company	Environmental surcharge.
1/95	94-996-EL-AIR	OH	Industrial Energy Users of Ohio	Ohio Power Company	Cost-of-service, rate design, demand allocation of power
3/95	E999-CI 93-583	MN	Large Power Intervenors	Minnesota Public Utilities Commission	Quantification of environmental costs.
4/95	95-060	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Company	Six month review of CAAA surcharge.
11/95	I-940032	PA	The Industrial Energy Consumers of Pennsylvania	Statewide - all utilities	Direct Access vs. Poolco, modeling Poolco, market power.
11/95	95-455	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Company	Clean Air Act Surcharge, Court Ordered Refund.

EXHIBIT NO.____(RJF-2)

Cost Effectiveness Test for Polk County IGCC
Cost Difference Between Polk IGCC and CC

	O&M	FUEL	CAPITAL	TOTAL	ACC NPV$
1996	-1179	-1423	7413	4811	4,811
1997	-3129	-5462	34974	26383	28,958
1998	-1742	-7441	29442	20259	45,929
1999	6822	-18470	26790	15142	57,537
2000	7033	-20210	24437	11260	65,439
2001	7265	-21854	22678	8089	70,633
2002	7498	-23710	20864	4652	73,368
2003	7738	-25725	19539	1552	74,203
2004	7977	-27998	21126	1105	74,747
2005	8241	-30291	21213	-837	74,370
2006	8505	-32867	21315	-3047	73,113
2007	8777	-35673	21441	-5455	71,053
2008	9049	-38831	21578	-8204	68,219
2009	9348	-42009	21722	-10939	64,760
2010	9647	-45573	21873	-14053	60,692
2011	9955	-49431	22026	-17450	56,070
2012	10263	-52501	22184	-20054	51,208
2013	10602	-55433	22347	-22484	46,219
2014	10942	-58706	22516	-25248	41,091
2015	11292	-62178	22691	-28195	35,850
2016	11641	-66054	22522	-31891	30,424
2017	12027	-69756	21831	-35898	24,835
2018	12411	-73880	21325	-40144	19,114
2019	12809	-78250	20828	-44613	13,295
2020	13205	-83124	20336	-49583	7,375
2021	13641	-87780	19852	-54287	1,444
2022	14078	-92971	19374	-59519	(4,508)
2023	14528	-97334	18904	-63902	(10,357)
2024	14978	-102206	18442	-68786	(16,119)
2025	15473	-106694	17999	-73222	(21,733)
2026	15969	-111698	13625	-82104	(27,494)
CPW (96$)	69,695	(343,900)	246,711	(27,494)	

TAMPA ELECTRIC
A TECO ENERGY COMPANY

EXHIBIT NO.____(RJF-3)

March 16, 1995

Mr. John Slemkewicz, Supervisor
Electric and Gas Accounting Section
Bureau of Revenue Requirements
Division of Auditing and Financial Analysis
Florida Public Service Commission
101 East Gaines Street, Room 352
Tallahassee, FL 32399-0850

Dear Mr. Slemkewicz:

Enclosed is the additional information requested by Tim Devlin that we discussed today related to our deferred revenue proposal. You will find a schedule indicating our projected jurisdictional adjusted rate of return analysis through 1997 and a schedule listing the major forecast assumptions included in that analysis. This information is our current best forecast without the effects of deferring revenues for these periods and, thus, is the beginning point for our revenue deferral discussions.

We are looking forward to meeting next week to further discuss our proposal.

Sincerely,

Gordon L. Gillette
Vice President - Regulatory Affairs

cc: Tim Devlin, Florida Public Service Commission
Roger Howe, Office of Public Counsel

bcc: A. D. Oak
L. L. Lefler
J. R. Rowe, Jr.
L. L. Willis, Esq.

enclosures

16-Mar-95

TAMPA ELECTRIC COMPANY
Jurisdictional Adjusted Rate of Return Analysis
1994 - 1997
(000's)

	1994	1994 (1)	1995	1996	1997
Revenues	$572,693	$572,693	$595,970	$612,223	$627,284
Expenses	437,189	424,106	431,633	441,989	470,521
Net Operating Income	$135,504	$148,587	$164,337	$170,234	$156,763
Rate Base	$1,748,663	$1,748,663	$1,742,486	$1,804,837	$2,154,891
Rate of Return	7.75%	8.50%	9.43%	9.43%	7.27%
Return on Equity	11.26%	12.87%	14.28%	13.81%	9.28%

(1) Excludes restructuring charge of $21.3 million.

16-Mar-95

TAMPA ELECTRIC COMPANY
1995 - 1997 MAJOR FORECAST ASSUMPTION

Customers:	1995	1996	1997
Residential	435,601	444,470	454,157
Commercial	54,432	55,459	56,586
Industrial	520	520	520
Other	4,187	4,273	4,362
Total	494,740	504,722	515,625

MWH Sales:			
Residential	6,162,000	6,308,000	6,467,000
Commercial	4,728,000	4,868,000	5,040,000
Industrial	2,289,000	2,359,000	2,300,000
Other	1,152,250	1,183,000	1,214,000
Total	14,331,250	14,718,000	15,021,000

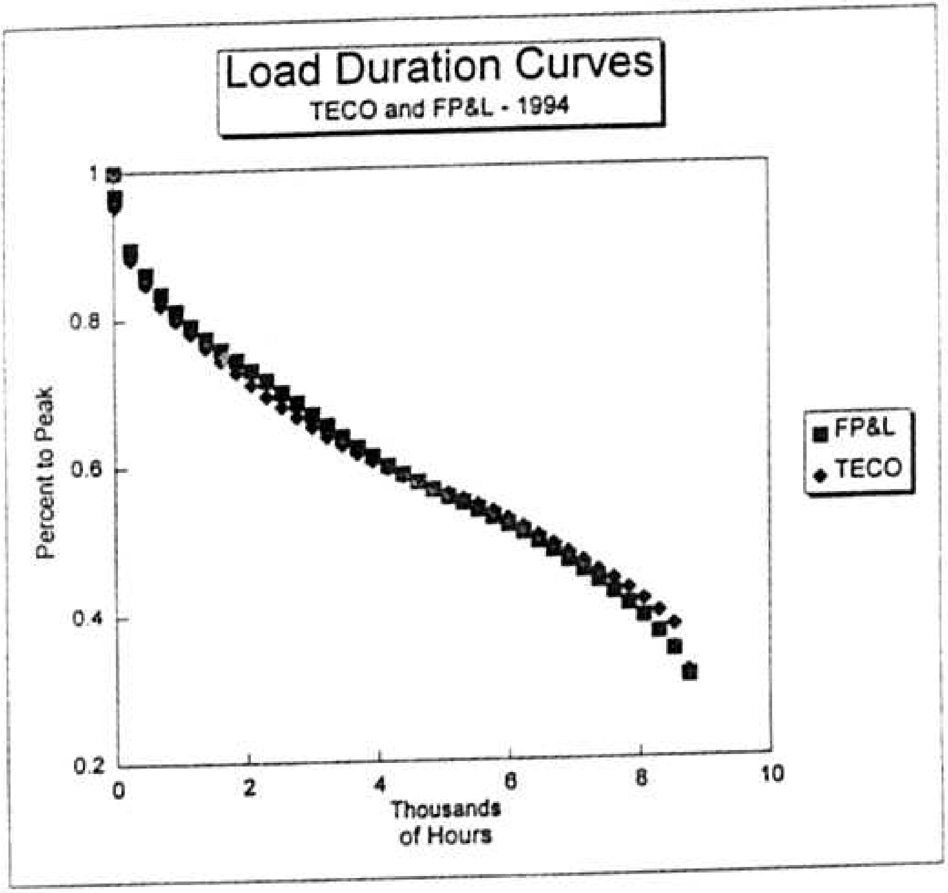
OTHER MAJOR FORECAST ASSUMPTIONS:

REVENUES:			
Retail Customer Growth	1.90%	2.00%	2.20%
Retail Sales Growth	3.00%	2.70%	2.10%
Sales for Resale	2,132,409 MWHs	2,417,866 MWHs	2,611,688 MWHs

OPERATION & MAINTENANCE EXPENSES:			
% Incr over Prior Year	-3.70%	0.00%	3.70%

CONSTRUCTION EXPENDITURES (excl AFUDC)	$319.9 Million	$177.3 Million	$119.2 Million

EXHIBIT NO.____(RJF-4)



CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the Direct Testimony and Exhibits of Randall J. Falkenberg has been furnished by hand delivery* or by U.S. Mail to the following parties of record, this 3rd day of June, 1996:

*Robert V. Elias
Staff Counsel
Public Service Commission
2540 Shumard Oak Boulevard
Gerald L. Gunter Building
Tallahassee, FL 32399-0850

*Office of Public Counsel
John Roger Howe, Esquire
Jack Sherve, Esquire
c/o The Florida Legislature
111 W. Madison Street
Tallahassee, FL 32399-1400

*Lee L. Willis
MacFarlane, Ausley, Ferguson
& McMullen
227 S. Calhoun
Tallahassee, FL 32301

Joseph A. McGlothlin

Joseph A. McGlothlin