MACFARLANE AUSLEY FERGUSON & MCMULLEN ORIGINAL FILE COPY

ATTORNEYS AND COUNSELORS AT LAW

111 MADISON STREET SUITE 2300
P.O. BOX 1531 (ZIP 33601)
TAMPA, FLORIDA 33602
(813) 273-4200 FAX (813) 273-4396

227 SOUTH CALHOUN STREET
P.O. BOX 391 (ZIP 32302)
TALLAHASSEE, FLORIDA 32301
(904) 224-9115 FAX (904) 222-7560

400 CLEVELAND STREET
P.O. BOX 1669 (ZIP 34617)
CLEARWATER, FLORIDA 34615
(813) 441-8966 FAX (813) 442-8470

May 7, 1996

HAND DELIVERY

IN REPLY REFER TO:

Tallahassee

Ms. Blanca S. Bayo, Director
Division of Records and Reporting
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Prudency Review to Determine Regulatory Treatment of Tampa Electric Company's Polk Unit; FPSC Docket No. 960409-EI

Dear Ms. Bayo:

Enclosed for filing in the above docket are the original and fifteen (15) copies of each of the following:

1. Prepared Direct Testimony of Girard F. Anderson. 05109-96
2. Prepared Direct Testimony of Thomas F. Bechtel. 05110-96
3. Prepared Direct Testimony and Exhibit of Charles R. Black. 05111-96
4. Prepared Direct Testimony and Exhibit of Thomas L. Hernandez. 05112-96
5. Prepared Direct Testimony and Exhibit of John R. Rowe, Jr. 05113-96
6. Prepared Direct Testimony and Exhibit of Hugh W. Smith. 05114-96
7. Prepared Direct Testimony and Exhibit of Elizabeth A. Townes. 05115-96

Please acknowledge receipt and filing of the above by stamping the duplicate copy of this letter and returning same to this writer.

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Thank you for your assistance in connection with this matter.

Sincerely,

Lee L. Willis

LLW/pp
Enclosures

cc: All Parties of Record (w/encls.)

158p.

ORIGINAL FILE COPY

TAMPA ELECTRIC COMPANY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 960409-EI

TESTIMONY
AND EXHIBIT OF

JOHN R. ROWE, JR.

158 p.

TAMPA ELECTRIC COMPANY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 960409-EI

TESTIMONY

AND EXHIBIT OF

JOHN R. ROWE, JR.

BEFORE THE PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

JOHN R. ROWE, JR.

Q. Please state your name, occupation and business address.

A. My name is John R. Rowe, Jr. I am Vice President - Staff, Regulatory and Business Strategy for Tampa Electric Company. My business address is 702 North Franklin Street, Tampa, Florida 33602.

Q. Please describe your educational background and business experience.

A. I graduated from the Georgia Institute of Technology in Atlanta, Georgia in 1962 with a bachelor of science degree in Industrial Management. In 1971, I graduated from the University of South Florida in Tampa with a master of Business Administration degree. I am a Certified Public Accountant licensed in Florida. I am a member and past president of the Florida Institute of CPAs and a member of the American Institute of CPAs.

In July, 1962, I was employed by Tampa Electric Company as a management trainee. I held various positions in the management development, customer service, business systems and accounting departments until 1974, when I was elected Assistant Controller. I was subsequently elected Controller in 1981, Assistant Vice President in 1984, and Vice President in 1990. I assumed my present duties in December of 1994. In my current position, I am responsible for the study of and for making policy recommendations on various complex regulatory and business issues.

Q. Have you prepared an exhibit in support of your testimony?

A. Yes. Exhibit No. __ (JRR-1) consisting of eight documents has been prepared under my direction and supervision.

Q. Have you previously testified before this Commission?

A. Yes. A listing of dockets in which I have testified is provided in Document No. 1 of my attached Exhibit.

Q. What is the purpose of your testimony?

A. My testimony proposes the appropriate regulatory treatment for the costs of Polk Unit One and for the Port Manatee plant site. I also explain how Tampa Electric developed, negotiated and obtained agreement and approval for a unique, innovative and effective plan to reduce its costs, to accumulate the savings derived to offset the costs of Polk Unit One and to provide the company with incentives to maximize its cost savings, all of which is relevant to the deliberations of this proceeding.

Q. Mr. Rowe, will you please describe the broad regulatory policy issues that may be involved in this docket and provide the fundamental considerations that the Commission should take into account as it sets about the task of reviewing the Polk Power Station project?

A. Yes, I will. If the Commission determines it is necessary to review certain aspects of Polk Unit One prudency, a fundamentally important consideration in this docket should be the Commission's standard of review in evaluating the prudence of utility decision making. A determination of prudence or imprudence calls for an inquiry into whether there was a rational basis for the decisions made by management. This standard is essentially the same as the competent substantial evidence standard the Supreme Court of Florida applies when reviewing decisions made by this Commission.

In applying this standard when reviewing the Commission's orders, the Court recognizes that reasonable people can come to different conclusions after reviewing the same facts. The exact same standard applies in the Commission's review of management decisions. The Commission should not determine prudence by reference to what it might have done if it had been exercising the power of management. The question is whether there is any rational basis for the decision that was made, and not whether another reasonable person confronted with the same facts would have made a different decision.

In appraising whether there is a rational basis for the utility's actions, the Commission's role is to review a utility's decisions solely in light of the facts known or which should have been known at the time the decision was made. Stated differently, the Commission may not apply the twenty-twenty vision of hindsight when determining whether a utility acted prudently under any given set of circumstances.

Q. Given these standards, what implications for Polk Power Station prudency are important to understand?

A. It follows, logically, that in reviewing a project like the

Polk Power Station which, over a significant time line has a number of decision points, each decision to proceed with construction must be evaluated based on information that utility management knew or should have known at the time the decision was made. Consequently, each decision to proceed forward with the project must be based not only on prospective alternatives and their consequences, but on a recognition of the amount of sunk costs which have already been expended and the costs to adapt to some new plan as well as the cancellation costs that would be incurred if construction commitments were materially changed or terminated. In the case of Polk Unit One, these potential cancellation costs include the cost of abandoned equipment, damages on outstanding contracts, and the potential loss of U.S. Department of Energy funding.

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. The benefit of any doubt of whether to continue construction of a unit, the need for which has been certified, should be to continue with the construction of the unit in order to assure the public that reliable service will be available to them as expected.

Q. How is a determination of prudence affected by changes in the real world which occur over time?

A. The Commission should expect that assumptions, forecasts, and plans for any large project may change over time. Even a consensus forecast of the future is no guarantee that the future will turn out to be as expected. Nevertheless, plans and commitments based on reasonable forecasts must be made, or long-lived construction projects will not come to fruition. Tampa Electric recognizes that it has a responsibility to review its plans after implementation has begun and to construct its facilities in a cost-effective way.

Finally, I would like to point out that the purpose of this hearing is not to retry the Certification of Need proceeding. After an exhaustive effort by all parties, the Commission reached its decision on the need for Polk Unit One and certified that the company could proceed with building an integrated coal gasification plant at the Polk County site. If the Commission determines that this hearing should address prudency, this hearing should focus on whether Tampa Electric's management acted prudently <u>after</u> the certification order.

Through the evidence presented in this docket, I believe the Commission will see that Tampa Electric regularly reviewed the changes in assumptions, forecasts, and plans subsequent to the need certification process, that it re-evaluated and determined the most cost-effective options taking into account the funds expended, committed, and necessary to change options, and that the actions to construct the plant and put it into commercial operation were and are being done competently. The company will continue to monitor all these factors as it proceeds on with the plant's construction, which is expected to be completed on time and ready for commercial operation in October, 1996.

Q. How does Tampa Electric propose to treat the costs of the Polk Power Station for all regulatory purposes?

A. Tampa Electric believes that the actual costs of the Polk Power Station, net of any Department of Energy (DOE) funding provided, should be recognized and approved as part of Tampa Electric's rate base and operating expenses for all regulatory purposes.

The specific dollar amounts that should be considered for inclusion in the company's rate base and operating expenses are described in the testimony of Ms. Elizabeth Townes. I believe the Commission will be well served in this proceeding by reviewing the projected annual costs of Polk Unit One as being representative of the potential financial impact of the unit on customers. As I will explain later in my testimony, that financial impact has been deferred through 1998 and Tampa Electric is continuing its efforts to mitigate that impact beyond 1998.

Q. How do you propose to treat for regulatory purposes the Polk Unit One funding that is provided pursuant to Tampa Electric's cooperative agreement with the DOE?

A. The DOE funding should be treated as a direct offset or reduction to the costs of Polk Unit One. Capital cost funding should be credited against actual capital costs and the net figure should be included in actual rate base. Operation and Maintenance (O&M) funding should be credited against actual O&M expenditures, the net of which should be recognized as actual O&M for the period.

Q. Why do you believe the actual net costs of Polk Unit One should be allowed in rate base and operating expenses for all regulatory purposes?

A. The Commission has already determined the prudence of proceeding with the construction of the plant in its Order No. 92-002 regarding the Determination of Need. I believe that the Commission will find as a result of the evidence presented in this Docket that Tampa Electric acted prudently after the need for the plant was approved. If the Commission agrees, I then believe that the appropriate costs to be included are one hundred percent of the actual costs incurred.

Q. Why is it necessary to address the regulatory treatment related to the Polk Power Station at this time?

A. Pursuant to the stipulation between the Office of Public Counsel (OPC), the Florida Industrial Power Users Group (FIPUG) and the company approved April 30, 1996, the calculation of actual earned return on equity at December 31, 1996, 1997 and 1998 requires a determination of the regulatory treatment of the Polk Power Station costs. A copy of this stipulation is provided in Document No. 3 of my Exhibit. In addition to being necessary to implement the stipulation agreement, it is also important to assure investors that the Commission has approved the regulatory treatment of this significant addition to the company's investment.

Q. Is approval of the regulatory treatment of Polk Unit One in this docket similar to approvals granted previously by the Commission to other utilities who have added generating capacity to their systems?

A. Yes. Approval of the regulatory treatment of Polk Unit One is similar to the requests by other utilities to include capacity investments in rate base and to allow capacity operating expenses in net operating income. Since 1980, the first year following the passage of the Florida Electrical Power Plant Siting Act (PPSA), Gulf Power Company, Florida Power Corporation, Florida Power and Light Company and Tampa Electric have all made such requests to the Commission, and the Commission has acted on each such request in light of the facts and circumstance presented in evidence in each proceeding. In most instances, these requests were made in full base rate revenue proceedings, in which the utility sought additional base revenue to support the new costs of the capacity it owned.

However, in 1990, Florida Power and Light Company petitioned the Commission to include its purchase of some 76% of Scherer Unit No. 4 in rate base as it was acquired from Georgia Power Company in installments over the 1991-1995 period without petitioning for an increase in its base rates. In the FPL-Scherer case (Docket No. 900796-EI), the Commission addressed three main issues: (1) whether FPL had demonstrated the need for the Scherer generation, (2) whether the purchase of Scherer was reasonable and prudent, and (3) whether the acquisition adjustment should be given base rate treatment. The Commission found in its Order No. 24165 that FPL's purchase of 76% of Scherer Unit Four appeared to be the most cost-effective alternative available to FPL to meet its forecasted load, that FPL's forecasted investment in Scherer Unit Four was a reasonable and prudent investment, and that FPL should be allowed to include its investment in Scherer in rate base as a prudent investment. A copy of Order No. 24165 is provided as Document No. 4 of my Exhibit. The issues in this docket (No. 960409) are similar to those in the FPL Scherer docket in that in neither case was an increase in rates sought in connection with the docket. In this docket, however, the need determination of Polk Unit One has already been made and there is no acquisition adjustment issue.

In 1994, FPL completed the construction of its Martin Plant Units Three and Four. The need for these units had been previously certified by the Commission in 1990 in Docket No. 890974-EI. A copy of Order No. 23080 in Docket No. 890974-EI is provided in Document No. 5 of my Exhibit. When the projects were completed, FPL reflected the cost of the projects in its rate base and the operating expenses of the new capacity in its operating income without petitioning the Commission for additional base rates. No request by FPL was made nor was a finding made by the Commission as to the prudence of either the Martin project or of the Lauderdale repowering project. The estimated cost of the Martin project at the time of the need determination in 1989 was in excess of $600 million.

The issues in this docket (960409-EI) are similar to those in the Martin-Lauderdale docket for FPL in that a need hearing had previously certified the need for the capacity and no increase in rates was sought at the completion of the project(s). However, the Commission did not initiate a docket to determine the prudency of the Martin or Lauderdale projects.

Q. In your opinion, what is the proper scope of this proceeding?

A. In my opinion, the Commission should first examine the implications of any precedents in its treatment of FPL's Scherer and Martin-Lauderdale additions. If the Commission then determines that an examination of prudency for Polk

Unit One is appropriate for Tampa Electric, this proceeding should focus on the prudency of Tampa Electric's actions regarding Polk Unit One between the approval and Certification of Need for Polk Unit One and the present as further input to determining the overall prudency of Polk Unit One. 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. The Commission should rely on its earlier decisions and utilize this proceeding to examine the prudence of the company's implementation of the construction of plant. The Commission should take Tampa Electric's innovative ratemaking treatment for 1995-1998 approved on April 30, 1996 into consideration as it makes its determinations.

Q. What is your understanding of the intended purpose of the Florida Electrical Power Plant Siting Act (PPSA or "The Act")?

A. The PPSA was intended to assure the public that the only power plants to be built in Florida after the passage of the PPSA were those which were certified to be needed and to be cost-effective and those which met the State's environmental standards. The PPSA also intended to prevent unnecessary disputes that might arise between utilities and the Commission regarding the propriety of proceeding to build a certified power plant which the utility's customers later had to support. The Act also assured utilities that once the need and cost-effectiveness of proposed capacity had been certified by the Commission, they could proceed with construction and reasonably expect to recover the costs of the new capacity.

Q. How has this Commission carried out its responsibilities to review the generation capacity needed in Florida?

A. The Commission has instituted a number of regulatory processes in connection with its responsibilities to review generation capacity needs. Among these processes are the following:

1. Periodic hearings on load forecasts.
2. Ten Year Site Plan reviews.
3. Conservation program load growth analyses.
4. Plant-specific need determination hearings.
5. Audits of construction work in progress.
6. Examinations of capacity costs pursuant to full rate cases.

7. Examinations of capacity needs and costs in the Purchased Power Clause hearings.

These processes have kept the Commission advised of the capacity needs in Florida and of the various means by which utilities are meeting the needs. A number of states which have higher electric costs than Florida are only today seeing the wisdom of PPSA legislation and the processes which implemented it, and they are now following Florida's leadership some 15 years later.

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 92-002") dated March 2, 1992, in Docket No. 91083-E1, the Commission certified the need for Polk Unit One. This order is included in Document No. 6 of my Exhibit. On page 4 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."

Q. Did the Commission also approve the type of generation represented by Polk Unit One as being the most cost-effective of the projections among all the feasible alternatives?

A. Yes. The Commission, on page 9 of Order No. 92-002, specifically found that Tampa Electric had demonstrated that the proposed integrated gasification combined cycle unit is the most cost-effective alternative to provide the additional needed capacity for Tampa Electric and peninsular Florida. This conclusion was supported by the Commission's further finding that Tampa Electric had adequately explored the construction of alternative generating technologies, including the initial evaluation of 46 different technologies and a detailed economic optimization analysis of seven different technologies that survived the initial screening. (See Order No. 92-002, page 12.)

Q. How has Tampa Electric continued to review its generating capacity plans after the issuance of Order No. 92-002 in order to verify that the development of Polk One remains cost-effective?

A. As Mr. Hernandez explains in his testimony, Tampa Electric has regularly re-examined its assumptions and plans regarding Polk Unit One and found the construction of this unit to be in the best interests of its customers. The costs of the capacity and the need to meet customer reliability have been reassessed as updated assumptions, facts and conditions evolved.

Q. Did Tampa Electric use its effective cost control system to prudently manage the costs of constructing Polk Unit One?

A. Yes. An effective project management organization was set up early in the development of Polk Unit One to insure that the plans were implemented in a cost-effective manner. Mr. Charles R. Black discusses in detail the processes used to prudently manage the costs of Polk Unit One in his testimony. As an example, despite the fact that Polk Unit One is a coal gasification plant and the first such plant of its size to be built, the net construction costs of Polk Unit One (omitting AFUDC and land/site development costs to make comparisons comparable) are projected to be less than 5% from the pre-engineering estimate made in Tampa Electric's Need Certification hearing as explained by Mr. Black. Polk Unit One is expected to begin to supply customers' needs full time in October of 1996, on time and very close to budget.

Q. Have you prepared a document which provides specific information about the "Port Manatee" site?

A. Yes. A map showing the location of the Port Manatee site and specific information regarding the site's size, current book value and use is provided in Document No. 7 of my Exhibit.

Q. What is the anticipated use of the "Port Manatee" site by Tampa Electric?

A. The Port Manatee site is still being held as a potential site for a future power plant. Although a Citizens' Siting Task Force recommended the present Polk Power Station site as being the preferred site for this plant by the community, they recognized the advantages of the Port Manatee site to future electric customers. Viable and cost-effective sites for power plants in Florida are a scarce and valuable commodity. If Florida's utilities are to have viable options for plant locations in the future, they must plan for those options now. Retention of the Port Manatee site at its relatively low book value together with the availability of expansion room at the Polk Power Station site provide important assurance to Tampa Electric's customers that needed generation can be sited in the future. Tampa Electric would notify the Commission promptly if other uses were to be made of the Port Manatee site.

Q. What is the appropriate regulatory treatment for the Port Manatee site?

A. Because the site has always been used as a future power plant site since its acquisition, the actual book value of the Port Manatee site should continue to be classified in "Property Held for Future Use" and be included in the rate base of Tampa Electric. The Commission found this to be the case in Tampa Electric's 1992 rate case in Docket No. 920324-EI. Relevant excerpts from Order No. 93-0165 in Docket No. 920324-EI are provided in Document No. 8 of my Exhibit.

Q. What is the appropriate regulatory treatment of the coal, oil and/or pet coke feedstock to be used in the operation of Polk Unit One?

A. While the specific dollar amounts to be approved should be a subject to be addressed in the Commission's semi-annual fuel hearings, the regulatory treatment of Polk Unit One feedstocks should be to allow the recovery of the actual feedstock costs of coal, oil and/or pet coke incurred in operating Polk Unit One. This will be accomplished through the normal estimation and true-up process administered in the Commission's fuel clause docket.

Q. What is the appropriate regulatory treatment of the seven-year tax life proposed for use in calculating Polk Unit One depreciation?

A. Tampa Electric believes Polk Unit One will qualify for a seven-year life under the Internal Revenue Service (IRS) code. This is an assumption and practice which benefits our customers because it results in lower revenue requirements than a longer tax life would. Our customers will enjoy lower revenue requirements as a result. We propose to utilize a seven-year life for this reason. Ultimately, the IRS will audit and rule on the use of a seven-year life. Tampa Electric asks the Commission to support this treatment in order to minimize costs to customers.

Q. Does Tampa Electric now seek increased base revenues from its customers to recover the annual revenue requirement effects of the Polk Power Station?

A. No. Tampa Electric does not seek an increase in its base rates at this time. Tampa Electric will not file a petition to change its base rates before July 1, 1998, in accordance with the terms and conditions of the stipulation approved in Docket No. 950379-EI. Under the terms of the stipulation among the Office of Public Counsel (OPC), the Florida Industrial Power Users Group (FIPUG), and the company, no interim or permanent increase in base rates is permitted before January 1, 1999. As mentioned earlier in my testimony, a copy of the approved stipulation is included in Document No. 3 of my Exhibit.

Traditionally, Tampa Electric has sought increased base revenues when new capacity has been added, but because of this Commission's approval of the proposed 1995 revenue deferral plan reflected in Order No. PSC-95-FOF-81 in Docket No. 950379-EI and its more recent approval of the provisions of the stipulation on April 30, 1996, no increase in base revenues for the Polk Power Station is necessary at this time. The effects of adding the Polk Power Station to the company's investment in capacity was the principal reason the April 30th stipulation was negotiated and approved, and the interaction of Polk Power Station accounting with Tampa Electric's regulatory status before this Commission were integral to the negotiated stipulation.

The company is doing everything reasonably possible to control and reduce its costs so that it will not have to seek an increase in its base rates in the future. Tampa Electric believes that it should and would be allowed to put the entire actual cost of the Polk Power Station in rate base even if no extraordinary efforts had been taken to change our way of doing business and to accumulate deferred revenues. The company also believes that the extraordinary work it has done in mitigating the impact of this new plant on its overall revenue requirements should be recognized by this Commission and that it should provide an important additional reason that the entire Polk Power Station investment should be placed in rate base.

Q. How will Tampa Electric be able to add the Polk Power Station investment to its rate base without increasing prices to its customers?

A. In anticipation of Polk Unit One coming into commercial service in late 1996, Tampa Electric's officers determined in mid-1994 that it should undertake extraordinary efforts to mitigate the revenue effects of the new unit on its customers. Tampa Electric, in effect, designed and initiated its own "alternative regulation plan" to reduce and mitigate the effect on the prices our customers pay for electric service of Polk Unit One being placed in-service. As part of a unique initiative, plans were made to undertake an extraordinary effort to remove significantly large amounts of cost from the business by doing business in new ways. By so doing, when Polk Unit One did come into service, the reduced costs of doing business would offset the increased costs needed to support the new capacity and avoid the service's effects of an increase in rates on our customers. We further determined that if these extraordinary efforts could become effective well before Polk Unit One went into service, that the accumulated savings in the interim could be used to offset the Polk Project costs after the Polk Power Station entered service as well.

The savings that would ensue from these efforts would be captured above some reasonable level of return and later used to offset the revenue effects of the plant when it was ready to enter service, thereby reducing the need for higher prices. It is important to recognize that, except for the beneficial revenue effect of unanticipated abnormal weather, no deferred revenues would have occurred had it not been for the extraordinary cost cutting efforts initiated and implemented by the company itself.

These cost control efforts coupled with this Commission's approval of the innovative plans for the earnings of Tampa Electric from 1995 through 1998 have enabled Tampa Electric to add Polk Unit One to its rate base without increasing its base rates.

The development, negotiation and implementation of those innovative plans to mitigate the revenue effects of Polk Unit One are clear evidence that at Tampa Electric, it has not been "business as usual." The results to date benefit both our customers and our investors, and we are proud of them.

Q. Have you considered any alternative ratemaking treatment for Tampa Electric's Polk Unit One investment and expenses?

A. Yes, we have. However, the stipulation approved by the Commission on April 30, 1996, is itself an innovative alternative ratemaking treatment of Polk Unit One which effectively deals with the potential revenue effects of the plant through December 31, 1998. Under the plan approved by the Commission, Tampa Electric has guaranteed that it will not increase its base rates before January 1, 1999, and that the Company will make a substantial refund beginning in October, 1996. This alternative ratemaking treatment provides a very beneficial result to Tampa Electric's Customers. As described earlier in my testimony, Tampa Electric is continuing its cost control efforts so that the effects of this settlement have an opportunity to extend into the future.

Q. Please summarize your direct testimony.

A. My testimony proposes the regulatory treatment of the Polk Power Station costs for all regulatory purposes, including how specific dollar amounts should be considered to help the Commission conclude that the actual costs of the Polk Power Station should be included in rate base and operating expenses. I propose that, if the Commission finds that Tampa Electric was prudent in carrying out its responsibilities after the need for Polk Unit One was approved, one hundred percent of actual Polk Power Station costs be included. I describe the appropriate regulatory treatment for the funding of Polk Unit One provided to Tampa Electric pursuant to its Cooperative Agreement with the DOE, saying that the funds received should be directly credited to the category of expenditures they are intended to subsidize and that the Commission should recognize the net costs in rate base and operating expenses for regulatory purposes.

In my testimony, I describe the relevance of the Florida Electrical Power Plant Siting Act and the company's Determination of Need proceeding to the regulatory treatment to be afforded Polk Unit One. I provide a brief description of the Commission's treatment of owned capacity additions to rate base by Florida utilities since 1980. I also speak to the appropriate regulatory treatment of the Port Manatee site in my testimony. Finally, I describe in my testimony how Tampa Electric's innovative planning and extraordinary cost control have resulted in an approved alternative ratemaking treatment for the Polk Power Station which defers the need for additional base rates from our customers until 1999 or beyond.

Q. Does this conclude your direct testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 960409-EI
SUBMITTED FOR FILING 5/7/96

EXHIBIT NO. ____ (JRR-1)

OF

JOHN R. ROWE, JR.

TABLE OF CONTENTS

TAMPA ELECTRIC COMPANY
DOCKET NO. 960409-EI
SUBMITTED FOR FILING 5/7/96
EXHIBIT NO. ___ (JRR-1)
DOCUMENT NO. 1

FPSC DOCKETS IN WHICH JOHN R. ROWE, JR. HAS TESTIFIED.

Docket No.	Subject
820001-CI	Impact of Deep Mine Closure On Price of Gatliff Coal To Tampa Electric
820007-EU	Supplemental Testimony - Tampa Electric Rate Case
820007-EU	Operations & Maintenance Expenses - Tampa Electric Rate Case
830001-EU	Rebuttal Testimony re: Disallowance of Gatliff Deep Mine Costs
850050-EI	Operations & Maintenance Expenses - Tampa Electric Rate Case
860001-EI	Gatliff Deep Mining Resumption and Justification of Labor Litigation Expenses
860001-EI-D	Confidentiality of Fuel Cost Information
870001-EI-A	Rebuttal To Stuart re: Propriety of Dual transportation System For Coal, Benefits To Customers From Affiliated Transactions, Pricing Methods
870001-EI-A	Rebuttal Testimony re: Propriety of Marginal Costs of Coal From Gatliff and Transportation Charges From Affiliates
881499-EI	Tampa Electric's Proposed Supplemental Service Rider Tariff
890646-EI	Territorial Dispute Between Tampa Electric and Florida Power Corporation Regarding Agrico Chemical Company Facilities
890750-EI	Territorial Dispute Between Tampa Electric and Florida Power Corporation regarding IMC Fertilizer Facilities
890833-EU	Cost Effectiveness of Underground Transmission & Distribution Conversions
900001-EI	Confidential Treatment of Form 423 Information For Tampa Electric
921288-EI	Proposed Rate re: Bidding of Generating Facilities
940204-EU	Rates For Home Based Businesses

TAMPA ELECTRIC COMPANY
DOCKET NO. 960409-EI
SUBMITTED FOR FILING 5/7/96
EXHIBIT NO. ___ (JRR-1)
DOCUMENT NO. 2

<u>INTERROGATORIES FILED IN DOCKET NO. 960409-EI</u>
<u>SPONSORED BY JOHN R. ROWE, JR.</u>

*SPONSORED TOGETHER WITH ANOTHER WITNESS

PREFACE

Several important points need to be underscored at the outset as a preface to Tampa Electric's answers to each of Staff's Interrogatories Nos. 1 - 14 in Docket No. 950379-EI.

First, readers of these responses should bear in mind that the construction of the Polk One unit marks a new era in power plant construction in Florida. In meeting its statutory obligation to serve its customers, a utility in Florida can no longer plan or implement the construction of a power plant without the consent and cooperation of the communities it serves and the communities in which the facilities are located. For the first time in Florida, a Citizen's Advisory Group reviewed the facts, recommended that the plant was needed, and that an inland site in Polk County should be used rather than an already-acquired less costly site on Tampa Bay. They did so, recognizing that although the project may cost more, it was of the type and location acceptable to them. Without the advice and consent of the community, years of costly litigation would have ensued. In adopting the Polk site, Tampa Electric Company acquired a site that is intended to be used for the next several generating units that may be required, and a site with which its customers are satisfied.

Second, readers should be reminded that fuel diversity is of strategic importance to the state of Florida. In a time when oil and nuclear fueled capacity can not be built, Florida's primary choices left are between coal and natural gas. Coal is a fuel with a plentiful domestic supply, but its use must meet ever-tightening environmental standards. The adequacy of domestic proven natural gas supplies are not certain, and there is substantial debate as to the level of prices for natural gas in the future as demand increases and the viability of gas transmission facilities is considered. There are clear and vital reasons to assure fuel diversity in the state. Development of technologies which produce power from coal in a cost effective and environmentally acceptable way is very important to Florida's security. The development of these technologies has been recognized as an important part of the national agenda for several years; so important that the U. S. Department of Energy has committed over $130 million in funding for the project. The Polk One plant is among the first of a generation of coal gasification power plants that meet these criteria. The technologies employed in this new plant are still developmental, but as a matter of strategic direction, it is vitally important to make these technologies work.

Third, the company's decision to construct Polk One was made with great care and with detailed consideration of a wide variety of alternatives. The determination of need proceeding before this Commission was an exhaustive effort by Tampa Electric, the Commission, the Staff and the various intervenors. This process ultimately resulted in the Commission's determination that Polk One is the most cost-effective alternative to enable Tampa Electric to reliably meet the needs of its customers. That determination of need proceeding created a statutory presumption of public need and necessity for the unit. The commission's decision was later confirmed by the Supreme Court of Florida.

The statutory process that resulted in approval of the Polk One Project not only assured the public that new generating capacity was needed and that the type of capacity was cost effective, but it provided assurance to the company, its suppliers and investors that construction could proceed without the undue regulatory risk that the large investment would not be fully recoverable. Tampa Electric proceeded with its financial commitments based on the findings of the need certification process.

The construction of a major power plant is clearly an extremely complex, dynamic and time consuming undertaking. The process requires years of planning, engineering, and construction. Such a project also involves numerous contractual commitments that must be made early in the project. These commitments generate costs if the project is curtailed or significantly modified, and these costs must receive constant consideration as the project plans develop. By their very nature, contractual commitments constrain the flexibility of the contract parties.

Another fundamentally important consideration in examining any change of plans involves the Commission's standard of review in evaluating the prudence of utility decision making. A determination of prudence or imprudence calls for an inquiry into whether there was a rational basis for the decisions made by management. This standard is essentially the same as the competent substantial evidence standard the Supreme Court of Florida applies when reviewing decisions made by this Commission. In applying this standard when reviewing the Commission's orders, the Court recognizes that reasonable people can come to different conclusions after reviewing the same facts. The exact same standard applies in the Commission's review of management decisions. It is not for a Commission to determine prudence by reference to what it might have done if it had been exercising the power of management. The question is whether there is any rational basis for the decision that was made and not whether another reasonable person confronted with the same facts would have made a different decision.

In appraising whether there is a rational basis for the utility's actions, the Commission's role is to review a utility's decisions solely in light of the facts known or which should have been known at the time the decision was made. Stated differently, the Commission may not apply the twenty-twenty vision of hindsight when determining whether a utility acted prudently under any given set of circumstances.

It follows, logically, that in reviewing a project which, over a significant time line has a number of decision points, each decision to proceed with construction must be evaluated based on information that utility management knew or should have known at the time the decision was made. Consequently, each decision to proceed forward with the project must be based on a recognition of the amount of sunk costs which have already been expended and the costs to adapt to some new plan as well as the cancellation costs that would be incurred if construction commitments were materially changed or terminated. In the case of Polk Unit One, these cancellation costs include the cost of abandoned equipment, damages on outstanding contracts, and the potential loss of U. S. Department of Energy funding.

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. The benefit of any doubt of whether to continue construction of a unit, the need for which has been certified, should be to continue with the construction of the unit, in order to assure the public that reliable service will be available to them as expected.

Finally, the reader should expect that assumptions, forecasts, and plans for any large project may change over time. Even a consensus forecast of the future is no guarantee that the future will be as expected. Nevertheless, plans and commitments based on reasonable forecasts must be made or long-lived construction projects will not come to fruition. Tampa Electric recognizes that it has a responsibility to review its plans after implementation has begun and to meet its obligations in the most cost-effective way. As the responses to the Staff's questions are reviewed, the reader will see that Tampa Electric regularly reviewed the changes in assumptions, forecasts, and plans subsequent to the need certification process, and that it re-evaluated and determined the most cost effective option taking into account the funds expended, committed, and necessary to change options. The Company will continue to monitor such information as it proceeds on with the plant's construction, which is expected to be completed on time and ready for commercial operation in October, 1996.

21. What is the current market value of the Cockroach Bay site and what does TECO plan to do with this property in the future?

A. Tampa Electric Company does not have a current market value appraisal of the Port Manatee (Cockroach Bay) site. The book value recorded in Account 105, Property Held For Future Use, as of December 31, 1995, is $4,874,999.75.

Tampa Electric Company purchased the Port Manatee site as a future power plant site. While the Siting Task Force favored a plant site in Polk County, the Port Manatee site was still considered a viable site for the future. Tampa Electric Company believes that technological advances in both the design and operation of new electric generating plants, as well as the evolution of environmental concerns (water use, etc.), may result in the designation of the Port Manatee site as the next power plant site of choice.

In Docket No. 920324-EI, Order No. PSC-93-0165-FOF-EI, the Commission Stated that: "By allowing the Port Manatee site to remain in the rate base, Tampa Electric will already have a viable generating site for future power plants. The Power Plant Siting Task Force recognized that the Port Manatee location was a viable generating site, although the task force ultimately recommended the Polk County location for Tampa Electric's next plant."

TAMPA ELECTRIC COMPANY
DOCKET NO. 960409-EI
SUBMITTED FOR FILING 5/7/96
EXHIBIT NO. __ (JRR-1)
DOCUMENT NO. 3

STIPULATION BETWEEN OFFICE OF PUBLIC COUNSEL, FLORIDA INDUSTRIAL POWER USERS GROUP AND TAMPA ELECTRIC COMPANY APPROVED APRIL 30, 1996.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Investigation into earnings for 1995 and 1996 of Tampa Electric Company

DOCKET NO. 950379-EI

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STIPULATION

The Office of Public Counsel ("OPC"), Florida Industrial Power Users Group ("FIPUG") and Tampa Electric Company ("Tampa Electric" or "the Company"), (collectively referred to as the "Parties"), enter into this Stipulation which represents their agreement to a comprehensive rate settlement covering Tampa Electric's base rates and rate of return for the period January 1, 1996 through December 31, 1998. Accordingly, as described in more detail below, the Parties have agreed as follows:

1) Tampa Electric's existing base rates will be frozen at current levels through December 31, 1998;

2) Any base rate increase, including any base rate increase associated with the commercial operation of Tampa Electric's Polk Power Unit One plant addition, is avoided at least through December 31, 1998;

3) The Commission will be requested to immediately set a procedural schedule for hearing and decision on the Polk Power Station by October 31, 1996. In an effort to avoid the need for such a hearing, the Parties will negotiate, in good faith, a joint recommendation specifying the regulatory treatment for the Polk Power Station for Commission approval.

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BUREAU OF RECORDS

4) Tampa Electric will refund $25 million plus interest to its Customers over a period of one year, commencing on October 1, 1996, with the possibility of additional refunds in 1999;

5) Tampa Electric will have a reasonable opportunity to earn a fair rate of return.

This Stipulation, as proposed, reflects the Commission's policy of encouraging parties to negotiate an amicable resolution of potentially contentious issues. As is the case with most fair and reasonable settlements, this Stipulation represents a very fine balance of benefits and burdens for all concerned. Therefore, the Parties respectfully request that the Commission approve and adopt this Stipulation in its entirety, without change or modification, at the earliest possible time.

<u>Refunds</u>

1. The Parties agree that Tampa Electric shall refund $25 million to Customers plus interest. The refund will be composed of $15 million derived from Tampa Electric's 1996 revenues and $10 million derived from those Tampa Electric revenues deferred in accordance with Order No. PSC-95-0580-FOF-EI ("Order 95-0580") issued May 10, 1995. The $25 million refund plus interest will be reflected as a credit on customer bills starting with the effective date of the new fuel adjustment charge beginning the first billing cycle for October, 1996.

Any portion of the $25 million refund not refunded shall accrue interest beginning October 1, 1996 at the thirty day commercial paper rate as specified in Rule 25-6.109, Florida Administrative Code. The refund credit will be reflected as a credit on Customer's bills calculated by multiplying a levelized factor adjusted for line losses times the actual KWH usage during the period of the credit. The total credit shall be spread over a 12-month period. However, in the event judicial review is sought by any person not a party to the stipulation of the Commission Order approving this stipulation or the continuing validity thereof, Tampa Electric shall not be required to commence or continue any refunds until the matter is finally resolved. Any over or under collection associated with the credit will be handled as a true-up component in the normal course of Tampa Electric's fuel cost recovery proceedings.

Rate Freeze

2. The Parties agree that Tampa Electric's current base rate level shall be frozen during the period January 1, 1996 through December 31, 1998. OPC and FIPUG agree that they will neither seek nor support any reduction in Tampa Electric's base rates between January 1, 1996 and December 31, 1998 unless such reduction is sought by Tampa Electric. The Parties further agree that Tampa Electric will not use the various recovery clauses which shall continue to be available to it in 1996, 1997 and 1998, to recover through such clauses capital items that normally would be recovered

through base rates. However, the Parties agree, for example, that Tampa Electric may recover its prudent expenditures associated with compliance with environmental laws and regulations through the environmental cost recovery clause. However, during the term of this stipulation, the environmental cost recovery clause will not be used to recover any of the costs incurred relative to Polk Power Station, except costs attributable to changes in environmental laws or regulations or any change in the application or enforcement thereof occurring after October 15, 1996. Tampa Electric will not seek to make any base rate increase effective on or before December 31, 1998, including any increase to reflect the major plant addition resulting from commercial operation of Tampa Electric's new Polk Power Unit One which is scheduled to commence service in October 1996. Provided further Tampa Electric shall not file before July 1, 1998 a petition and rate schedules initiating a base rate increase proceeding for rates to be effective after December 31, 1998.

Treatment of Base Revenues: 1996-1998

3. As part of this agreement, the Parties have settled on a disposition of certain deferred Tampa Electric revenues which accrued in 1995 and pursuant to this Stipulation will continue to accrue through 1998. In Order 95-0580, the Commission approved the deferral of certain of Tampa Electric's 1995 revenues to periods beginning January 1, 1997. As part of its order, the Commission required Tampa Electric to either file for a rate increase or

petition for the disposition of the 1995 deferred revenue by December 1, 1996. In addition, on January 3, 1996, the Commission approved Tampa Electric's proposal to hold certain 1996 revenues subject to the Commission's jurisdiction. This order accepting Tampa Electric's proposal was protested by OPC and FIPUG, the signatories to this Stipulation and settlement.[1] The Parties have now agreed on the treatment of Tampa Electric's base revenues and accumulated deferred revenues for 1996, 1997 and 1998 as set forth below.

<u>1996</u>

4. After accounting for the $15 million refund contemplated in paragraph 1 hereof, any actual Tampa Electric net revenue contributing to a ROE in excess of 11.75% on an FPSC adjusted basis, as specified in Tampa Electric's December earnings surveillance report for calendar year 1996, will be split 60%/40%. 60% of such revenues shall be deferred to periods beginning in 1997. The remaining 40% of such revenues shall be retained as earnings of the Company in 1996.

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[1]The Commission's January 3, 1996 decisions were incorporated into Order PSC-96-0122-FOF-EI ("Order 96-0122") issued January 23, 1996. The Commission on February 26, 1996 entered procedural Order No. PSC-96-0272-PCO-EI ("Order 96-0272") establishing a schedule for a hearing on various issues raised by OPC and FIPUG in protests of the Commission's Order 96-0122.

In order to give the Parties time to negotiate, the Commission's consideration of this matter was deferred from the Commission's March 5, 1996 Agenda. The Parties have now agreed on the treatment of Tampa Electric's base revenues and accumulated deferred revenues for 1996, 1997 and 1998 as set forth below.

1997

5. Tampa Electric shall have the discretion to reverse and add to the Company's revenues in 1997 all or any portion of the balance (remaining after the refunds required under paragraph 1 of this agreement) of the 1995 revenues deferred to periods beginning 1997 under the terms of Order 95-0580 and the 1996 deferred revenues described in paragraph 4 above.

6. The actual 1997 Tampa Electric net revenues which contribute to a ROE in excess of 11.75%, up to a net ROE of 12.75% for calendar year 1997, will be split 60%/40%. Sixty percent of such revenues shall be deferred and added to the revenues of the Company in 1998. The remaining 40% of such revenues shall be included in the earnings of the Company in 1997. The actual revenues contributing to a net ROE in excess of 12.75% for calendar year 1997 shall be deferred to calendar year 1998 and added to the revenues of the Company in 1998.

1998

7. The balance of all accumulated deferred revenues which were not reversed in 1997 will be deferred to calendar year 1998 and added to the revenues of the Company in 1998.

8. The actual 1998 Tampa Electric net revenues which contribute to a ROE in excess of 11.75%, up to a net ROE of 12.75% for calendar year 1998, will be split 60%/40%. 40% of the actual net revenues resulting in a ROE in excess of 11.75%, up to a net 12.75% ROE, shall be retained as earnings of the Company in 1998. The remaining 60% of the actual net revenues resulting in a ROE in

excess of 11.75%, up to a net 12.75% ROE for calendar year 1998 and all of the actual 1998 revenues resulting in a net ROE in excess of 12.75% shall be refunded to Customers. All of the monies held subject to refund after 1998 under this paragraph shall be refunded through a credit on Customer's bills calculated by multiplying a levelized factor adjusted for line losses times the actual KWH usage during the period of the credit. The credit shall include interest on the unamortized amount of the refund calculated in accordance with paragraph 9 herein. The refund period shall begin concurrently with the first fuel adjustment period following a final determination of the amount to be refunded, if any, and shall extend over a 12-month period. However, no refunds contemplated under this paragraph will be commenced until a final, non-appealable order (by the Commission or a court as the case may be) has been issued resolving all issues with respect to the calculation of earned ROE during the periods covered by this agreement, including the appropriate regulatory treatment of the Polk Power Station, all as set forth in paragraph 17 below. Any over or under collection associated with the proposed refund credit will be handled as a true-up component in the normal course of the fuel cost recovery proceedings.

<u>General Provisions</u>

9. The revenues held subject to refund and the deferred revenues provided for herein shall accrue interest at the thirty day commercial paper rate as specified in Rule 25-6.109, Florida

Administrative Code. These revenues shall be treated as if collected evenly throughout the year.

10. The Company plans to take a position regarding the tax life of its Polk Power Station intended to minimize its revenue requirements and to provide maximum benefits to its Customers. The Parties agree that any interest expense that might be incurred as the result of a Polk Power Station related tax deficiency assessment will be considered a prudent expense for ratemaking purposes and will support this position in any proceeding before the FPSC.

11. The calculations of the actual ROE for each calendar year will be on an "FPSC Adjusted Basis" using the appropriate adjustments approved in Tampa Electric's full revenue requirements proceeding. All reasonable and prudent expenses and investment will be allowed in the computation and no annualization or proforma adjustments shall be made.

12. This agreement does not preclude the review of the investment in and expenses of the Polk Power Station and the Port Manatee site. However, the Parties agree to negotiate in good faith a joint recommendation specifying the regulatory treatment of the Polk Power Station and Port Manatee site investment and expenses.

A. The Parties further agree to use their best efforts to obtain approval by the Commission of their joint recommendation or, in the absence of a joint recommendation, to seek a final resolution of the Polk Power Station and Port Manatee site regulatory treatment.

B. The timing of the resolution of the ratemaking treatment of the Polk Power Station and Port Manatee site investment is important to the Parties. The Parties request that the Commission immediately set a procedural schedule for hearing and decision on the Polk Power Station and Port Manatee site by October 31, 1996. The need for a hearing will be obviated if the Parties negotiate a resolution of the regulatory treatment of the Polk Power Station and Port Manatee site which is approved by the Commission.

13. The calendar years 1996, 1997, and 1998 surveillance reports on which the refunds and the revenue deferrals provided herein will be based are subject to audit by the FPSC staff and true-up.

14. The Parties agree that this Stipulation is intended to and shall settle the disposition of the Company's 1995 revenues deferred by Order 95-0580 and shall obviate the need for the hearings scheduled by Order 96-0272.

15. The provisions of this stipulation also resolve issues related to Tampa Electric's existing base rate levels, allowed return on equity, the procedures for the determination of Tampa Electric's earnings and the disposition of revenues earned above certain levels specified herein for the period 1996-1998.

16. The Parties agree that this docket shall remain open solely for the purpose of: resolving any issues pertaining to the calculation of earned ROE for the periods covered by this agreement; implementing the refunds provided herein; and

determining Tampa Electric's earnings for purposes of revenue deferral and sharing as set forth herein.

17. The Parties agree that any dispute relating to this Stipulation shall be addressed by the FPSC in the first instance. Except as provided in paragraph 19 hereof, each Party reserves any rights it may have to seek judicial review of any ruling concerning this Stipulation made by the FPSC. In the event judicial review is sought by any party hereto or any third party, in connection with this Stipulation, the Commission's approval thereof, the joint recommendation of the Parties concerning the Polk Power Station contemplated herein, or any action of the Commission or any party hereto under this Stipulation, whether relating to the calculation of earned ROE or otherwise, the Company shall not be required to commence or continue any refunds under paragraph 8 of this Stipulation until the matter is finally resolved.

18. This Stipulation shall be effective upon Commission approval. The Parties agree that if the FPSC does not adopt this Stipulation in its entirety, without modification, this Stipulation shall become null and void and of no effect.

19. The Parties agree to actively support the approval of this Stipulation by the Commission at the earliest possible time in order to avoid the time and expense of litigation. The Parties agree not to protest, seek reconsideration or judicial review of the Commission's approval of this Stipulation or to seek modification of this settlement and Stipulation subsequent to final Commission approval, except by mutual agreement.

20. The Parties acknowledge this Stipulation is being entered into for purposes of settlement only and that the Parties are entering into this Stipulation to avoid the expense and length of further legal proceedings and the uncertainty and risk inherent in any litigation. Neither this Stipulation nor any action to reach, effectuate or further this Stipulation may be construed as, or may be used as an admission by or against any party. Entering or carrying out this Stipulation or any negotiations related thereto shall not in any event be construed as, or deemed to be evidence of, an admission or concession by any of the Parties as a waiver of any applicable claim or defense, otherwise available.

21. The Parties participated jointly in the drafting of this Stipulation and, therefore, the terms of this Stipulation are not intended to be construed against any Party by virtue of draftsmanship.

22. This Stipulation may be executed in several counterparts, each of which shall constitute an original and all of which together constitute as one and the same instrument.

IN WITNESS WHEREOF, this Stipulation has been executed on the

25th day of March, 1996 by the undersigned counsel of record for the Parties hereto and/or by the Parties themselves in counter parts each of which shall be deemed an original.

The Office of Public Counsel

By Jack Shreve
Jack Shreve, Public Counsel

Tampa Electric Company

By [signature]
Gordon L. Gillette
Vice President, Regulatory and Business Strategy

Florida Industrial Power Users Group

By [signature]
John W. McWhirter, Jr.
Joseph A. McGlothlin
Vicki Gordon Kaufman
Attorneys for Florida Industrial Power Users Group

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy of the foregoing Stipulation has been furnished by U. S. Mail or hand delivery (*) on this 15th day of March, 1996 to the following:

Mr. Robert V. Elias*
Staff Counsel
Division of Legal Services
Florida Public Service
  Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Mr. Jack Shreve
Mr. John Roger Howe
Office of Public Counsel
c/o The Florida Legislature
111 West Madison Street - #812
Tallahassee, FL 32399-1400

Mr. Joseph A. McGlothlin
Ms. Vicki Gordon Kaufman
McWhirter, Reeves, McGlothlin,
  Davidson, Rief & Bakas
117 S. Gadsden Street
Tallahassee, FL 32301

Mr. John W. McWhirter, Jr.
McWhirter, Reeves, McGlothlin,
  Davidson, Rief & Bakas
100 North Tampa Street
Suite 2800
Tampa, FL 33602

ATTORNEY

llw\tec\950379-1.stpTallah

TAMPA ELECTRIC COMPANY
DOCKET NO. 960409-EI
SUBMITTED FOR FILING 5/7/96
EXHIBIT NO. __ (JRR-1)
DOCUMENT NO. 4

EXCERPTS FROM FPSC ORDER NO. 24165, FPL SCHERER PURCHASE (Pages 1-13)

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Regulatory Control

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition of Florida Power & Light Company for inclusion of the Scherer Unit No. 4 purchase in rate base, including an acquisition adjustment.	DOCKET NO. 900796-EI ORDER NO. 24165 ISSUED: 1-26-91

JRR
JBR
LLC
ASA
RC

The following Commissioners participated in the disposition of this matter:

CHAIRMAN, THOMAS M. BEARD
MICHAEL McK. WILSON
BETTY EASLEY
FRANK S. MESSERSMITH

Pursuant to notice, the Florida Public Service Commission held hearing in Tallahassee, Florida on December 12, 13, and 14, 1990.

APPEARANCES:

MATTHEW M. CHILDS, ESQUIRE, JOHN T. BUTLER, ESQUIRE, and GREGORY N. ANDERSON, ESQUIRE, Steel, Hector and Davis, 215 South Monroe Street, Suite 601, Tallahassee, Florida 32301-1804
On behalf of Florida Power & Light Company

JACK SHREVE ESQUIRE and JOHN ROGER HOWE, ESQUIRE, Office of Public Counsel, 111 West Madison Street, Room 812, Tallahassee, Florida 32399
On behalf of Office of Public Counsel

JOSEPH A. McGLOTHLIN, ESQUIRE and VICKI GORDON KAUFMAN, ESQUIRE, Lawson, McWhirter, Grandoff and Reeves, 522 East Park Avenue, Suite 200, Tallahassee, Florida 32301
On behalf of Nassau Power Corporation

FREDERICK J. MURRELL, ESQUIRE, Schroder & Murrell, The Barnett Center, Suite 375, 1001 Third Avenue West, Bradenton, Florida 34205
On behalf of Coalition of Local Governments

FREDERICK M. BRYANT, ESQUIRE, Moore, Williams, Bryant, Peebles and Gautier, 101 East College Avenue, Post Office Box 1169, Tallahassee, Florida 32302
On behalf of Florida Municipal Power Agency

DOCUMENT NUMBER-DATE
01391 FEB 26 1991
FPSC-RECORDS/REPORTING

M. ROBERT CHRIST, ESQUIRE and EDWARD A. TELLECHEA, ESQUIRE, Florida Public Service Commission, 101 East Gaines Street, Tallahassee, Florida 32399-0863
On behalf of the Commission Staff

PRENTICE PRUITT, ESQUIRE, Florida Public Service Commission, Office of the General Counsel, 101 East Gaines Street, Tallahassee, Florida 32399-0863
Counsel to the Commissioners

ORDER GRANTING FLORIDA POWER & LIGHT COMPANY'S PETITION TO INCLUDE THE SCHERER UNIT NO. 4 PURCHASE IN RATE BASE, INCLUDING ACQUISITION ADJUSTMENT

BY THE COMMISSION:

BACKGROUND

This docket was initiated by Florida Power and Light Company (FPL) on September 28, 1990, when it filed a Petition of Florida Power & Light Company For Inclusion of the Scherer Unit No. 4 Purchase in Rate Base, Including an Acquisition Adjustment. FPL proposed to purchase 76.36% (646 MW) of Unit No. 4 of the Robert Scherer Generating Plant (Scherer), a coal-fired generating unit located in Monroe County, Georgia. The total purchase price, as reflected in a letter of intent, is estimated to be $615,504,000, which exceeds the depreciated book cost for the portion of the unit to be purchased by FPL by an estimated $111,362,307.

The purpose of FPL's petition is to obtain the Florida Public Service Commission's (the Commission) prior approval to phase in FPL's share of the actual purchase price of the unit in rate base as FPL makes four installment payments. The installment payments are scheduled for January 1, 1991; June 1, 1993; June 1, 1994; and June 1, 1995. FPL did not, however, petition the Commission for any change in rates or charges to its customers.

When the Petition was filed, FPL was in the process of negotiating the purchase, and thus, there was no final purchase contract with Georgia Power Corporation (GPC) and the Southern Companies (Southern). Contract negotiations continued during and after the hearing. There was, however, a non-binding letter of intent entered into by GPC, Southern, and FPL which provided an estimated purchase price. The letter of intent was relied upon by FPL throughout the proceedings in this docket.

The following parties filed notices of intervention or petitions for leave to intervene: the Office of Public Counsel (OPC), Nassau Power Corporation (Nassau), Coalition of Local Governments (CLG), and the Florida Municipal Power Agency (FMPA). All parties were granted permission to intervene in this docket. OPC, Nassau, and CLG opposed the inclusion of Scherer in rate base for various reasons.

The hearing was held on December 12, 13 and 14, 1990. All the parties participated and some presented evidence. All the parties, excluding FMPA, filed briefs and post-hearing statements of issues and positions.

In order to dispose of this Petition, we find it necessary to address three primary issues. The three issues are as follows:

1. Has FPL demonstrated that there is a need for the additional generation capacity that will be provided by Scherer?

2. Is the purchase of Scherer a reasonable and prudent investment?

3. Should the Acquisition Adjustment be given rate base treatment.

This docket also involves sub-issues that are subsumed by the abovementioned primary issues. All other issues raised in this proceeding and not specifically addressed herein are deemed unnecessary for the resolution of this case or have been considered and been found to be without merit. The following provides an analysis of both the primary and sub-issues.

NEED

By necessity, the Commission must make a determination of need for the additional capacity that will be provided by Scherer before a determination of prudence is made. While this is not a traditional need determination proceeding under section 403.519, Florida Statutes, the same type of elements that are taken into account in the more traditional proceedings were considered in this docket. We have analyzed those elements and the evidence demonstrates that FPL, as an individual utility interconnected with the statewide grid, has shown a need for the additional capacity that will be provided by Scherer.

Reliability and Integrity

FPL asserts that its objective in its planning process was to provide adequate resources to reliably meet its customers' future demand for electric power in a cost-effective manner. To deal with unforeseen changes in conditions that might affect these objectives, FPL uses diversity and flexibility in its planning process. FPL uses two reliability criteria commonly accepted in the utility industry to determine the quantity of resources to maintain system reliability: (1) summer peak reserve margin of 15%, and (2) a maximum loss-of-load probability (LOLP) of 0.1 days per year. FPL maintains that it needs approximately 5,400 MW of resources to satisfy these criteria and to meet it's projected demand through 1997. The following table reveals how FPL plans to satisfy it's projected demand:

Demand Side Management Programs	1,137 MW
Repower Lauderdale/Martin No. 3 and 4	1,342 MW
Southern Company UPS	911 MW
QF approved/to be signed	590 MW
QF additional projected	600 MW
IGCC Martin No. 5 and 6	768 MW
Total	5,286 MW

The Petition requests a phased in approval of the 646 MW Scherer purchase in the following manner:

Phase in Date	MWs	Projected Reserve Margin
6-1-91	150	16.3%
6-1-93	266	22.1%
6-1-94	140	23.0%
6-1-95	90	23.2%
Total	646 MWs	

The result of the Scherer purchase will be to defer the first Martin No. 5 IGCC unit (this, in effect, will remove the Martin IGCC Unit out of the 1991-97 time frame) and subsequent facilities. That would result in avoiding the construction of one 646 MW IGCC.

This generation expansion plan was initially introduced in Docket Nos. 890974-EI and 890973-EI. In Order No. 23080, the prehearing officer ruled that no factual findings would be made in the above referenced docket regarding Martin Units 5 and 6 until FPL's request for power supply proposals (RFP) process was completed.

The RFP process began in June, 1989 and FPL received 34 proposals totalling 10,793 MWs. The RFP process was eventually completed with the selection of the Scherer UPS option. However, upon comparing the Scherer purchase option with the Scherer UPS purchase, the discounted and full standard offer contracts, and the Martin IGCC units, the analysis demonstrates that the Scherer purchase is the most cost-effective alternative when taking into account emission credits and other non-quantifiable benefits. According to FPL, the phased purchase of Scherer will give it access to additional capacity to meet the need created in 1991 by the outage at Turkey Point Nuclear Station, and allow for flexibility in responding to changes in load conditions and/or construction requirements resulting from changes in conservation and qualifying facility forecasts that have occurred since FPL presented its expansion plan in Docket Nos. 890973-EI and 890974-EI. In summary, the evidence shows that the purchase of Scherer will allow FPL to maintain adequate system reliability and integrity.

QF Capacity

FPL's generation expansion planning process used in evaluating the Scherer purchase considered three sources of supply-side resources: qualifying facilities, purchased power, and new generating units. After demand-side activities have been incorporated, FPL's base expansion plan included 538 MW of qualifying facilities (QFs) that have signed contracts with FPL and have received Commission approval or for which they anticipate Commission approval. FPL's forecast document projects an additional 590 MW of QF capacity by 1997, which reflects FPL's best estimate of the number and total capacity of QFs that will be able to provide cost-effective power to FPL. FPL did not, however, include Nassau's 435 MW standard-offer contract in its generation expansion planning, while including the Indiantown Cogeneration project. The approval of the proposed Scherer purchase to meet a portion of FPL's 1996 need may possibly not accommodate Nassau's project, and consequently, Nassau argues that its project should be included in FPL's identification of QF facilities which will be available in 1996. We find, however, that questions concerning whether Nassau's project should be included in FPL's identification of QF facilities for 1996 are more appropriately reserved for a specific determination of need proceeding.

Demand Side Options

FPL has also demonstrated that a wide range of conservation or other demand-side alternatives, that would mitigate the need for the capacity represented by the purchase of Scherer, were adequately taken into consideration in its power supply plan. As part of FPL's capacity planning process, FPL includes cost-effective demand side programs. These programs are the first type of resources included in their capacity expansion plan and are considered well before any other type of resources are inserted into the plan.

Some of the intervenors expressed their concerns over FPL's treatment of demand side alternatives and their concerns were heightened by the passage of the 1990 Clean Air Act Amendments. However, prior to the opening of this docket, FPL prepared and submitted to the Commission an extensive demand side management plan comprising of 21 programs which were approved in Order Nos. 23560 and 23667, Docket No. 900091-EG. For example, in Appendix A, Order No. 23560, FPL reveals that it has implemented a Commercial/Industrial thermal storage program and are actively pursuing research and development projects for residential thermal storage systems and commercial or industrial stored water heating.

The impact of FPL's conservation programs, interruptible rates and residential load control has been forecasted at approximately 1317 MW through 1997. We find that this demonstrates that FPL's capacity expansion plan took into account conservation and other demand side alternatives.

Fuel Diversity

The addition of 646 MW of coal fired power to FPL's capacity will also serve to enhance fuel diversity among its generation units, according to FPL. The purchase of the Scherer coal-fired unit will only constitute approximately 6% of FPL's total power mix but it will start reducing FPL's dependence on oil-fired units beginning in 1991.

Cost Effective Alternatives

A comparison of the cumulative present values of different cost component for the different purchase options for Scherer power was presented by OPC during the hearing. Cost comparisons of Scherer purchase option and the standard offer options (with a 20% risk and without a risk) were also offered by FPL. [Note: In the discussion that follows, all numbers will be in thousands of dollars.] The comparisons revealed the following cumulative present value revenue requirements (CPVRR):

Scherer UPS (RFP) option: $42,794,175
Scherer purchase option: $42,813,923
Standard Offer option (with 20% risk): $43,021,755
Standard Offer option (without 20% risk): $43, 232,952

A comparison of these numbers reveals that the Scherer UPS option is the most cost-effective option in that it offers a savings of $19,748 over the next best option: the Scherer purchase option.

The CPVRR comparison offered by OPC, however, was not complete in that it did not take into consideration Scherer's SO_2 emission allowances. As previously mentioned, under the 1990 Amendments to the Clean Air Act, FPL will be entitled to Unit 4's share of emission allowances that are designated to the entire Scherer facility. FPL asserts that under the Scherer purchase option, it will be responsible for $18,213 in SO_2 emission allowance costs. Under the Scherer UPS option, it will be responsible for $131,067 in SO_2 emission allowance costs. When these elements are considered in the cost comparison, the CPVRR for the Scherer purchase option is $93,106 less than the CPVRR for the UPS option. Therefore, we find that the Scherer purchase is the most cost-effective alternative when taking into account SO_2 emission credits.

Strategic Concerns

Scherer's SO_2 emission allowances is just one of the strategic concerns that we were asked to consider when making this need determination. Other strategic concerns or benefits not specifically quantified in the record were also considered. Some of the additional benefits claimed by FPL were:

(1) that the joint participation by JEA in the purchase of Scherer Unit 4 paved the way for additional transmission interface capability from JEA. This is important since JEA owns the remaining transmission capacity currently available on the Southern/Florida interface.

(2) facilitation of the expansion of the Southern/Florida transmission interface.

(3) assuming the unit life will extend beyond thirty years, FPL will not have to replace the capacity, as it would under the UPS arrangement.

While these elements may not be quantifiable, they appear to provide benefits to FPL, its ratepayers, and Florida's general body of ratepayers. Thus, they should be considered when determining whether there is a need for the Scherer Unit.

Associated Facilities

No additional transmission facilities or upgrades will be needed in order to receive energy and capacity subject to existing contracts or for the Scherer purchase. FPL asserts that there is sufficient interface capacity to transmit all Scherer power into Florida. OPC concurs with FPL's assertion.

Based on the foregoing analysis, we find that the capacity that will be provided by the purchase of Scherer is reasonably consistent with the needs of Peninsular Florida when taking into consideration timing, impacts on the reliability and integrity of the Peninsular Florida grid, cost, fuel diversity, and other relevant factors.

ACQUISITION ADJUSTMENT

FPL has requested that we approve as a part of the purchase price of $615,387,000 an acquisition adjustment in the amount of $111,362,000, which represents the difference between FPL's purchase price and the seller's net original cost of the unit. The Commission policy has been to deny such requests unless the utility could demonstrate extraordinary circumstances were present or prove the transaction results in a net benefit to the ratepayers. See, e.g., Re: Petition of Gulf Power Company for Approval of "Tax Savings" Refund for 1988, Docket No. 890324-EI, Order No. 23536 (FPSC, Sept. 27, 1990).

In general, the intervenors do not take issue with the inclusion of an acquisition adjustment in the purchase price but, object to the approval of the purchase. Our view is that the amount in question does not appear to be a ordinary acquisition adjustment. We find the amount in question should be evaluated based on whether the purchase of Scherer is necessary, reasonable, and the most cost-effective alternative. Because we have previously made those findings, we find the amount of $111,362,000 should be should be included in rate base on a pro rata basis consistent with the phased purchase of the unit.

PRUDENCE

A principal issue in this proceeding is whether the purchase by FPL of Scherer is reasonable and prudent. Intervenors would have the Commission reject any finding of prudence . They do not believe the record supports such a finding. According to the intervenors, absent a final contract a finding of prudence is not warranted.

In resolving this issue, we note that in an earlier portion of this order we found that the purchase of the unit appears to be the most cost-effective alternative available to FPL to meet its forecasted 1996 system load requirements. Accordingly, based on this finding and FPL's representation that the final contract to purchase the unit will not differ significantly from the letter of intent and other evidence presented by FPL concerning this transaction, we find that the purchase by FPL of Scherer is a reasonable and prudent investment necessary to enable FPL to meet is forecasted 1996 system load requirements. Absent a showing that the final contract and letter of intent vary to a significant degree, we do not intend to relitigate this issue in any future proceeding. Thus, the new plant will be placed in FPL's rate base and deemed to be a prudent investment, with rates allowed to recover the investment in the next applicable proceeding. Issues we are leaving open for future proceedings involving the Scherer purchase and its costs other than a significant variance from the purchase price are O & M expenses, cost of capital and rate design.

Competent and Substantial Evidence

Having reviewed the record in this proceeding, we find that there is competent and substantial evidence to support our findings.

In consideration of the foregoing, it is

ORDERED by the Florida Public Service Commission that Florida Power & Light Company's Petition For Inclusion of the Scherer Unit No. 4 Purchase in Rate Base, Including an Acquisition Adjustment is hereby approved.

By ORDER of the Florida Public Service Commission, this 26th day of FEBRUARY, 1991.

STEVE TRIBBLE, Director
Division of Records and Reporting

(S E A L)

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APPENDIX A

Rulings on Proposed Findings of Facts

A. The following constitutes the Commission's specific rulings pursuant to section 120.59(2), Florida Statutes (1989), and Rule 25-22.059(1) & (3), Florida Administrative Code, on the Proposed Findings of Fact submitted by the Office of Public Counsel.

1. FPL's petition referred to Section 366.076(1), Florida Statutes, which is a procedural statute permitting limited proceedings, but did not identify any substantive statutory authority for the Commission to give prior approval for the purchase of Scherer Unit No. 4.

This statement is clearly not a finding of fact but rather a conclusion of law. Nevertheless, we will address it. We concur in part and disagree in part with this conclusion. Section 366.076(1), Florida Statutes, is not solely procedural in nature. Section 366.076(1) is also substantive in that it also authorizes the Commission to act. We agree with OPC that FPL did not identify any substantive statutory authority for the Commission to give

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Regulatory Control

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition of Florida Power & Light Company for inclusion of the Scherer Unit No. 4 purchase in rate base, including an acquisition adjustment.	)	DOCKET NO. 900796-EI ORDER NO. 24165-A ISSUED: 3-1-91

JRR ASA
JBR RC
LLL

The following Commissioners participated in the disposition of this matter:

THOMAS M. BEARD, CHAIRMAN
BETTY EASLEY
FRANK S. MESSERSMITH
MICHAEL McK. WILSON

AMENDED ORDER GRANTING FLORIDA POWER & LIGHT COMPANY'S PETITION TO INCLUDE THE SCHERER UNIT NO. 4 PURCHASE IN RATE BASE, INCLUDING ACQUISITION ADJUSTMENT

BY THE COMMISSION:

On February 26, 1991 Order No. 24165, Order Granting Florida Power & Light Company's Petition to Include The Scherer Unit No. 4 Purchase in Rate Base, Including Acquisition Adjustment, was issued. To more accurately reflect the intent of the Florida Public Service Commission, the first chart following the first full paragraph on page 4 of Order No. 24165 should be deleted and replaced with the following chart:

Demand Side Management Programs	1,317 MW
Repower Lauderdale/Martin No. 3 and 4	1,342 MW
Southern Company UPS	911 MW
QF approved/to be signed	538 MW
QF additional projected	590 MW
IGCC Martin No. 5 and 6	768 MW
Total	5,466 MW

Furthermore, the second and third sentences in the second complete paragraph on page 5 of the same order should be deleted and replaced with the following sentences:

DOCUMENT NUMBER-DATE

02028 MAR -1 1991

After demand-side activities have been incorporated, FPL's base expansion plan included 538 MW of qualifying facilities (QFs) that have signed contracts with FPL and have received Commission approval. FPL's forecast document projects an additional 590 MW of QF capacity by 1997, of which FPL has signed negotiated contracts totalling 352 MW which have not yet received Commission approval. This reflects FPL's best estimate of the number and total capacity of QFs that will be able to provide cost-effective power to FPL.

In consideration of the foregoing, it is

ORDERED by the Florida Public Service Commission that the first chart following the first full paragraph on page 4 of Order No. 24165 should be deleted and replaced with the following chart:

Demand Side Management Programs	1,317 MW
Repower Lauderdale/Martin No. 3 and 4	1,342 MW
Southern Company UPS	911 MW
QF approved/to be signed	538 MW
QF additional projected	590 MW
IGCC Martin No. 5 and 6	768 MW
Total	5,466 MW

It is further

ORDERED that the second and third sentences in the second complete paragraph on page 5 of the same order should be deleted and replaced with the following sentences:

After demand-side activities have been incorporated, FPL's base expansion plan included 538 MW of qualifying facilities (QFs) that have signed contracts with FPL and have received Commission approval. FPL's forecast document projects an additional 590 MW of QF capacity by 1997, of which FPL has signed negotiated contracts totalling 352 MW which have not yet received Commission approval. This reflects FPL's best estimate of the number and total capacity of QFs that will be able to provide cost-effective power to FPL.

By ORDER of the Florida Public Service Commission, this 1st day of March, 1991.

Steve Tribble

STEVE TRIBBLE, Director
Division of Records and Reporting

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NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.59(4), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Director, Division of Records and Reporting within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water or sewer utility by filing a notice of appeal with the Director, Division of Records and Reporting and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900 (a), Florida Rules of Appellate Procedure.

TAMPA ELECTRIC COMPANY
DOCKET NO. 960409-EI
SUBMITTED FOR FILING 5/7/96
EXHIBIT NO. __ (JRR-1)
DOCUMENT NO. 5

FPSC Order No. 23080 In Docket No. 890974-EI

FPL Martin Expansion Project Need Approval

BEFORE THE FLORIDA PUBLIC SERVICE COMMISION

In re: Petition of Florida Power and Light Company to determine need for electrical power plant - Martin expansion project.	DOCKET NO. 890974-EI ORDER NO. 23080 ISSUED: 06/15/90

The following Commissioners participated in the disposition of this matter:

MICHAEL McK. WILSON, Chairman
THOMAS M. BEARD*
BETTY EASLEY
GERALD L. GUNTER

*Commissioner Beard did not participate in the disposition of the Motion for Reconsideration filed by Broward County or the Petition for Clarification and/or Reconsideration filed by Florida Power and Light Company.

ORDER APPROVING NEED DETERMINATION
and DENYING MOTIONS FOR RECONSIDERATION

BY THE COMMISSION:

On July 25, 1989, Florida Power and Light Company (FPL) filed its petition for a construction of Martin Units 3, 4, 5 and 6 simultaneous with the filing of a motion to consolidate this need determination petition with FPL's need determination petition for the repowering of its Lauderdale Units 4 and 5 (Docket No. 890973- EI). Order No. 22267, issued on December 5, 1989, partially denied FPL's request for consolidation of the two dockets and limited the factual findings in this proceeding to those associated with the Lauderdale repowering and Martin Units 3 and 4. Although evidence was presented on Martin Units 5 and 6, it was for informational purposes only, per Order No. 22267 at 3, 5.

Direct testimony was filed by FPL on December 8, 1989; by Hadson Development Corporation, Charles Bronson, and the Office of Public Counsel (OPC) on January 29, 1990; and by Broward County (Broward) on February 7, 1990. Prehearing statements were filed by Broward, OPC, Staff, Charles Bronson, Hadson Development Corporation and FPL on February 12, 1990. Rebuttal testimony was filed by FPL and Broward on February 16, 1990.

ORDER NO. 23080
DOCKET NO. 890974-EI
PAGE 2

At the prehearing conference in this docket held on February 23, 1990, Commissioner Easley granted joint intervention status to Hadson Development Corporation and Charles Bronson (Bronson-Hadson) until such time as their interests became noncompatible. The issues and positions enumerated in the draft prehearing order were also reviewed at the prehearing conference and additional issues were considered. Commissioner Easley ruled that certain of Broward's and Bronson-Hadson's issues would be excluded from consideration in this proceeding. At the prehearing conference, at the request of FPL and Bronson-Hadson, all parties agreed to an expedited schedule for the consideration by the full panel of the prehearing officer's ruling. This expedited schedule was approved by Chairman Wilson on Friday, February 23, 1990.

Pursuant to that schedule, Broward and Bronson-Hadson filed their written motions for reconsideration of the ruling on Monday, February 26, 1990; the response of FPL opposing reversal of the ruling was filed on Wednesday, February 28, 1990; and Staff's recommendation was filed on Friday, March 2, 1990. Simultaneous with the filing of the motions for reconsideration, Broward and Bronson-Hadson also filed requests for oral argument before the full panel. Pursuant to Commission procedure, Commissioner Easley denied that request on Thursday, March 2, 1990, in Order No. 22631. When Broward was notified of this ruling, counsel indicated that Broward wished to seek full panel review of this decision also.

At its March 6, 1990 agenda conference, the full Commission voted to affirm Commissioner's Easley's ruling denying oral argument and excluding certain issues from consideration in this docket. [Order No. 22826, issued On April 16, 1990.] The hearing in this docket was held on March 21-23, 1990 with testimony offered on behalf of FPL, Broward, Bronson-Hadson and OPC. Briefs were filed by the parties on April 6, 1990.

In addition to its nonconfidential brief filed on April 6, 1990, Broward also filed Appendix C to its brief. Appendix C contains references to material which was the subject of a pending request for confidentiality on April 6, 1990. Subsequent to the filing of Appendix C, Commissioner Easley, as prehearing officer, ruled that the materials referred to in Appendix C are not confidential. [Order No.

ORDER NO. 23080
DOCKET NO. 890974-EI
PAGE 3

22850, issued on April 23, 1990.] Likewise, Commissioner Easley ruled on the confidentiality of the other documents contained in Composite Exhibit 33 entered into the record in this proceeding. [Order No. 22851, issued on April 23, 1990.] All of the documents, with the exception of portions of the Strategic Energy Information, Tropicana Products, Inc., Florida Power and Light Study, dated June 6, 1988, were found by Commissioner Easley to be nonconfidential. [Order No. 22851 at 2- 5.]

The Commission voted on FPL's need determination applications in this docket and Docket No. 890974-EI at a properly noticed special agenda conference held on April 23, 1990. Pursuant to Commission rules, FPL and Broward filed timely motions for reconsideration/clarification on April 30, 1990. Responses to the motions for reconsideration were filed on May 2, 1990 by FPL, Broward and Bronson-Hadson. The Staff recommendation addressing the motions for reconsideration was filed on May 4, 1990 and the matter was considered by the full Commission at its regularly scheduled agenda conference on May 15, 1990. This order will reflect the Commission's initial vote on April 23, and its May 15 vote on the motions for reconsideration.

NEED

In its petition of July 25, 1989, FPL requested that it be allowed to construct two new 400 MW class units at its existing Martin site. These units will be 385 MW advanced combined cycle units fired primarily by natural gas, with distillate oil as an alternate fuel and the capability of future conversion to burn coal gas. These units have projected commercial operation dates of December 31, 1993 and December 31, 1994, respectively. After the completion of both units, the capacity on FPL's system will be increased by 770 MW.

Reliability and Integrity

FPL's 15% summer reserve margin and 0.1 day/year loss of load probability (LOLP) are satisfactory reliability criterion given their individual system configuration and interconnections with other utilities. LOLP is the criteria driving the need for power in the 1993 timeframe, and appropriately so, as it is calculated on peak loads for all twelve months. Thus, it reflects the adequacy of capacity to

ORDER NO. 23080
DOCKET NO. 890974-EI
PAGE 4

serve both summer and winter peak needs. That being the case, we find that the reliability criterion used by FPL to determine its need for 770 MW of capacity in 1994 and 1995 to be reasonable for planning purposes.

FPL's load forecast is based on historical demand and customer growth in their service territory. FPL's projections take into account the uncertainties of future economic conditions and population estimates through the use of high, low and mid-band forecasts of energy and demand. Thus, we find that the mid-band load forecast used by FPL to determine its need for Martin Units 3 and 4 is adequate for planning purposes.

FPL's Base Plan, set forth in this docket and the companion need determination docket, Docket 890973-EI, proposes 572 MW of capacity installation by 1993 (the Lauderdale repowering); 770 MW of new capacity construction (Martin Units 3 and 4); and over 3,000 MW of non-construction alternatives, including load management, interruptible load, purchases from QFs, Southern Company purchases, and additional conservation. No party to this docket disputes the fact that FPL has a need for capacity in the 1993 to 1995 timeframe. The only disagreement is how that need is most economically filled.

A one-year delay in the in-service date of Martin Unit 3 would cause FPL's 1994 LOLP to fall to be 0.19, a level significantly above an adequate reliability criteria of 0.1. A similar delay in Marin Unit 4 would cause system LOLP to deteriorate to 0.40, clearly an unaccepatable level of reliability risk to FPL's ratepayers. Thus, we find that FPL does exhibit a need for additional capacity in 1994 and 1995 and would suffer an unacceptable level of risk should Martin Units 3 and 4 not be approved.

Broward and Bronson-Hadson argue that FPL's choice of technology for filling its capacity needs in 1994 and 1995 is unproven and based on unreliable fuel supplies. The availability of natural gas to fire the proposed units and the type of technology chosen will be addressed later in this order. FPL states in its position on the issue of electric system reliability and integrity that "[w]hile Martin Unit No. 4 will contribute to meeting FPL's reliability need in 1995, the current forecast indicates that it will be necessary to accelerate the construction of the combined cycle portion of Martin Unit Nos. 5 and 6 in order to meet FPL's reliability

ORDER NO. 23080
DOCKET NO. 890974-EI
PAGE 5

criteria at the time of the 1995 summer peak." We note here that FPL will not receive a determination of need for Martin Units 5 and 6 in this or the companion proceeding, Docket No. 890973-EI, and that the results of the RFP may provide capacity in 1995 to offset this proposed construction.

Witness Gillette testified on behalf of the Florida Electric Power Coordinating Group (FCG) that Peninsular Florida has a need for approximately 3,015 MW of new generating capacity in the 1992-1995 timeframe, comprised of 2,640 MW of combined cycle capacity and 375 MW of combustion turbine capacity. FPL's 1994- 1995 need for Martin Units 3 and 4, two 385 MW combined cycle units, is thus consistent with Peninsular Florida generation needs. Based on the facts stated above, we find that the proposed Martin Units 3 and 4 will provide for electric system reliability and integrity to both FPL and Peninsular Florida.

<u>Adequate Electricity at Reasonable Cost</u>

FPL's Base Plan, which includes the Lauderdale repowering, Martin Units 3 and 4, Martin Units 5 and 6, and over 3,000 MW of non-construction alternatives, shows the best present value of revenue requirements of any plan examined using FPL's PROSCREEN analysis. FPL's Base Case is also the optimum plan when analyzed using methods similar to those used in the last annual planning hearing. That is, the Lauderdale repowering followed by Martin Units 3 and 4 remains the best combination of generating additions for 1993-1995, even if Martin Units 5 and 6 are removed from the Base Plan for purposes of analysis.

The estimated total installed cost of Martin Units 3 and 4 is $632 million, or $821/incremental KW. On and off-site transmission facilities are estimated at an additional $44 million. The total project cost is $676 million, or $878/KW including transmission.

Both Broward and Bronson-Hadson argue that the units' reliance on natural gas and oil causes them to be subject to fuel supply disruption. The record indicates that FPL has firm gas supply and transportation contracts in place to provide adequate fuel for the units. FPL also has the ability to buy interruptible gas from the pipeline. Thus, we find, based on the record before us, that there is no significant risk of fuel interruption.

Broward further argues that FPL should be required to immediately install coal gasification facilities at the proposed Martin units. There is no evidence in the record of the cost of Broward's proposal. FPL's Base Plan is modeled with gasification facilities being constructed in conjunction with the installation of Martin Units 5 and 6. When coal gasification is modeled in FPL's generation expansion plan at an earlier date, the results are not an optimal least-cost generation expansion plan for FPL or Peninsular Florida. For this reason, given current projections of fuel availability and price, we find that the proposed Martin Units 3 and 4 will provide adequate electricity to FPL and Peninsular Florida at a reasonable cost.

FPL's fuel forecasts are consistent with other contemporaneous fuel forecasts. The 30-year scenario analysis reflects the relationship among crude, distillate and residual oils, natural gas, and coal under assumed conditions in the energy markets. The most-likely fuel forecast used by FPL in its Present Value Revenue Requirement (PVRR) analysis shows the expected differential between coal prices and the price of natural gas and oil. It also accounts for the termination of FPL's firm gas supply contracts in 2002.

We note, however, that the best fuel forecasts are only that: educated estimates of future market conditions. And, we observe that the only thing which is absolutely predictable in this area is that no matter who does it or how carefully it is done, the forecast will be incorrect. It is with this caveat that we make the finding that FPL's fuel forecast is reasonably adequate for planning purposes based upon the record developed at the hearing in this docket.

FPL has entered into 15-year firm gas supply and transportation contracts with Citrus Trading Corporation and Florida Gas Transmission (FGT), respectively, to provide 327 million cubic feet (mcf)/day annually to FPL's system. This quantity of gas is sufficient to fuel the repowered Lauderdale units and Martin Units 3 and 4. After these contracts terminate, FPL anticipates that similar quantities of gas will be available on a firm or interruptible basis.

The repowered Lauderdale units and Martin Units 3 and 4 will burn 292 mcf/day at 100% capacity (net summer capability). Since the units will not run at 100% capacity factor, their actual burn will be somewhat less. Broward argues that these units will consume the bulk of FPL's natural gas supplies, causing existing units to rely on oil as their primary fuel. This is true. FPL will use the available supplies of natural gas in its most efficient units, including repowered Lauderdale and Martin 3 and 4. Other existing units, formerly run primarily on natural gas, will then burn oil.

Nonetheless, the projected oil burn on FPL's system in 1999 will remain less than 1980-81 levels and below FPL's share of the Florida Energy and Efficiency Act (FEECA) oil use reduction goals. These oil consumption levels assume the addition of coal-gas fired capacity after 1996; increased performance of Turkey Point nuclear units; and more efficient fuel use in the repowered Lauderdale and Martin 3 and 4 units.

Through the year 2000, FPL's gas usage is projected to remain constant; oil usage is expected to decline slightly; and with the addition of coal-gas fired capacity after 1996, coal usage will increase significantly. When purchases from Southern and JEA are included, over 50% of FPL's energy requirements will come from coal and nuclear generation, with the remainder from natural gas and oil. This configuration of fuel usage, assuming that fuel is available in the quantities FPL projects, provides adequate fuel diversity for FPL's system.

Broward argues that the Lauderdale repowering and Martin 3 and 4 rely on natural gas which is not stable as to price or availability. As discussed above, FPL has contracts in place for firm gas supply and transportation. Barring a breach of the FGT pipeline into the state or some Presidentially-declared emergency, availability and price are assured under such an arrangement. Further, FPL's planned addition of gasified coal units (IGCC's) to its system after 1996 allows the flexibility to retrofit repowered Lauderdale and Martin 3 and 4 to burn gasified coal. This ensures fuel availability for those units after the firm gas contracts terminate.

Based on the record, we conclude that FPL will have adequate supplies of natural gas to operate its units efficiently. That being the case, we find that with the addition of the proposed Martin Units 3 and 4 will give FPL adequate fuel diversity on its system. The record indicates that the mix of natural gas and coal- fired generation proposed by FPL with the addition of Martin Units 3 and 4 will not significantly affect the overall fuel mix of the Peninsula. Thus, we find that the proposed Martin Units 3 and 4 will also provide for adequate fuel diversity for Peninsular Florida.

<u>Cost-Effective Alternative</u>

As discussed above, FPL's Base Plan includes 572 MW of capacity installation by 1993 (the Lauderdale repowering); 770 MW of new capacity construction (Martin Units 3 and 4); and over 3,000 MW of non-construction alternatives, including load management, interruptible load, purchases from QFs, Southern Company purchases, and additional conservation. This plan is designed to meet FPL's projected load growth of approximately 350 MW per year in the 1990's.

The ongoing Request for Proposals (RFP) process seeks 800 MW of capacity to be supplied in the 1994 to 1997 time period, preferably in 1996. If this is successful, the most likely effect on FPL's Base Plan will be to delay the proposed Martin Units 5 and 6 in-service date (1996) for approximately two years.

The analysis of the Base Plan shows that, over 25- and 30-year planning horizons, the Base Plan has the best economics of any expansion plan studied. FPL's choice of combined cycle technology also allows some scheduling flexibility should load growth be faster or slower than forecast. For example, the in-service date of Martin 4 and/or the combined cycle portion of Martin 5 and 6 can be accelerated by one year as required to meet changing assumptions regarding load or non-construction alternatives. Likewise, the units can be delayed as required. The Base Plan also has the flexibility to support substitution of coal gas for natural gas as changes in fuel prices warrant.

Broward argues that "increased emissions from FPL's planned units, <u>if not adequately controlled</u>..." (emphasis added) may affect the construction of additional generating capacity in FPL's load center. We expect that the Florida Department of Environmental Regulation (DER) will determine adequate levels of emission control and require FPL to meet these emission control requirements for both new and existing units. Nonetheless, FPL's Base Plan analysis takes such considerations into account. The proposed IGCC units, for example, have lower levels of pollutant emissions and use less water than pulverized coal units.

The first use of advanced combined cycle technology should present no undue technical risks. Advanced combined cycles incorporate advanced combustion turbine units (CTs). These CTs differ from conventional CTs principally in their higher firing temperatures and improved heat rates. Witness Fries testified that recently-completed full load tests of these units show no unusual problems. In addition, the advanced CT manufacturer is providing performance guarantees backed by substantial liquidated damages provisions.

In light of the uncertainties, environmental, economic, and demographic, facing FPL and the electric industry in general, we find that the record supports the finding that Martin Units 3 and 4 are the appropriate generating alternatives for supplying capacity to FPL in 1994 and 1995. We further find that, as discussed above, the proposed units are reasonably consistent with the capacity needs of Peninsular Florida.

FPL has identified the technical characteristics Martin Units 3 and 4 and provided a detailed cost estimate for the project. The Martin site was chosen for the new combined cycle units after a detailed site evaluation study showed: the site lacked significant environmental constraints; contained a cooling pond sized for additional capacity; was located within the southeast Florida load center; required minimal transportation system upgrades; was of sufficient size; and had competitive modes of fuel delivery available. The record also demonstrates that FPL has the financial capability to finance construciton of the proposed units under any reasonable set of economic assumptions.

Broward argues that FPL has failed to apprise the Commission of the full cost of environmental controls for the project and costs associated with the new technology of advanced combined cycle units. Having reviewed the record before us, we find that FPL has provided sufficient information on the site, design and engineering characteristics of Martin Units 3 and 4 to enable us to evaluate its proposal.

FPL's Base Plan includes 911 MW of purchased power from the Southern Company on its existing Unit Power Sales (UPS) contracts and 374 MW of purchases from JEA's share of the St. John's River Power Park unit. In addition, FPL presented testimony that it contacted every major utility with which it was interconnected to inquire about the availability of power in the amount and at the times needed. Testimony was given at the hearing that the Southern Company was among those so contacted in 1988. We note that on January 5, 1990 the Southern Company responded to FPL's RFP with an offer to provide 848 MW of capacity from its existing Scherer Unit 4 coal plant subject to the rights of first refusal of other existing UPS contract customers starting January 1, 1994. [Exhibit No. 45 at page 9.] With that fact in mind, we qualify our finding that FPL has adequately pursued the purchase of existing capacity from other utilities to fill its capacity needs as of 1988.

In addition to pursuing the purchase of existing capacity from other utilities to meet its needs, FPL is also required to explore and evaluate the availability of capacity from qualifying facilities (QFs) and non-utility generators (independent power producers). We conclude, based on this record, that FPL has failed to adequately encourage cogeneration and small power production and thus to adequately pursue this option to meet its present capacity needs.

Based upon the record developed in this proceeding, it appears that FPL's policies treat QF power as a last-choice option, despite its duty under Rule 25-17.001(3)(d), Florida Administrative Code, to "aggressively" seek to integrate QF capacity into its system where cost-effective.

FPL's approach as outlined in its Strategic Energy Business Study is to: to promote energy sales [Exhibit 30 at 24-55], "facilitate" solid waste generation, and "compete" with self-generation [Exhibit 30 at 13]. Self-generation is described as a major "threat" to FPL [Exhibit 31 at 4, 13, 15]. The only mention of deferring generation is through expansion of load management. [Exhibit 31 at 27] Noticeably absent is any concept that conservation of energy is a desirable goal or that QF capacity in any form should be encouraged so as to defer generating capacity.

Exhibit 42 indicates that FPL requested bids for approximately 800 MW of capacity in the timeframe 1994-1996; it received bids for 34 projects with a total of 10,793 MW over that same time period. As the response to FPL's recent RFP demonstrates, substantial amounts of viable non-utility capacity are available to a receptive utility.

Of concern also is the testimony of Broward's Witness Henderson that FPL made negotiations so difficult that Broward was forced to accept the current standard offer in order to sell the capacity from its solid waste facilities. And, even after tendering the standard offer, Broward had to petition the Commission to enforce FPL's acceptance of that standard offer. [T. 608] The conclusion which we draw from this record is that FPL has placed itself in the position of having to build capacity which it may have been able to avoid had it more aggressively pursued QF capacity on its system.

Broward has argued that, in light of the facts brought out during this proceeding, we should require FPL to file a cogeneration development plan in its conservation/cogeneration docket, Docket 900091-EG, within 90 days of the date of the final order in this docket. Having reviewed Order No. 22176, issued in Docket No. 890737-PU, we find this to be unnecessary. Order No. 22176 states, in part:

> Each utility shall submit a program for attracting qualifying facilities, including its yearly estimates of nontraditional generation over a ten-year planning horizon.

Order No. 22176 at 5.

Should FPL or any other utility subject to FEECA not provide such a program, the Commission has the jurisdiction to propose a program for them. However, the utility must be given an opportunity to do so first. For these reasons, we find that Docket No. 900091-EG is the appropriate docket to address this issue and we reject Broward's request.

This is not to say, however, that we do not consider FPL's treatment of cogenerators to be an area of much concern. We will be looking in greater detail at FPL's treatment of cogeneration and cogenerators not only in Docket No. 900091-EG as discussed above, but also in FPL's rate case docket, Docket No. 900038-EI, and in our review of cogeneration pricing, Docket No. 891049-EU.

As discussed in this order, based on the record before us, we have found that FPL has not aggressively pursued the acquisition of power from qualifying facilities or promoted conservation in its service territory. These activities might have delayed the in-service dates of the proposed Lauderdale repowering and Martin Units 3 and 4. The fact is, however, that FPL now has an undisputed need for power in 1993, 1994, and 1995. While the ongoing RFP process may provide capacity as early as 1995, that process will not effect the need for the units at issue here. Under these circumstances and for the reasons discussed above, we find that Martin Units 3 and 4 are FPL's and Peninsular Florida's most cost-effective alternative to provide power to its customers in 1994 and 1995.

Conservation

FPL's demand-side activities have reduced summer peak demand by 636.8 MW through 1989. It is interesting to note that of the 636.8 MW of conservation-induced demand reduction achieved by FPL, 355.2 MW was achieved by the year 1985. (Exhibit 54) It is also interesting to note that the additional impact of FPL's conservation programs has steadily decreased from 1985 to 1989 such that for 1989 only 35.9 MW of summer peak demand was reduced by FPL's conservation efforts. (Exhibit 54) Exhibit 55 also indicates that even if the "revenue losses" associated with conservation were excluded from FPL's Base Plan, there would be no change in that plan. Thus, the revenue losses attributable to conservation as projected by FPL are necessarily negligible. Put another way, the amount of peak load actually being reduced by FPL's conservation programs is quite small when compared to FPL's total load.

It should be noted, however, that during this time period the real price of electricity declined. We cannot ignore the effect that this declining real price had on demand during this same time period. Declining real prices may have caused an increase in demand and a concomitant lessening of conservation efforts by customers. This phenomenon may have had an impact on FPL's conservation efforts.

Based on this record, we conclude that FPL did not pursue all of the conservation and demand-side reduction programs which it could have. Consequently, FPL might have been able to either completely or partially defer its need for one or both of the Martin Units. It is clear that FPL does not have sufficient conservation and other non-generating alternatives reasonably available to it a this time to defer the proposed units. And it is also clear that, given these conditions, Martin Units 3 and 4 constitute the most cost-effective alternative available to FPL and to Peninsular Florida to supply its capacity needs in 1994 and 1995.

Associated Facilities

The integration of Martin Units 3 and 4 will require expansion of an exisitng 230 KV substation at the site and the addition of off-site transmission in existing rights-of-way. In particular, a second 230 KV circuit with a normal rating of at least 750 MVA will need to be constructed between the Martin Plant and the Indiantown Substation, a total distance of approximately 12 miles. Following addition of that circuit, the exisitng Martin- Indiantown 230 KV circuit will have to reconductored to upgrade it to a normal rating of at least 750 MVA.

A new 30 inch diameter natural gas lateral will be constructed from the FGT mainline to the plant site. FPL and FGT are jointly performing studies to determine the optimum route for this lateral. The preliminary length estimate for this lateral is 18 to 23 miles. The length of the lateral is subject to change once the final routing is determined.

Should the Martin Unit Nos. 3 and 4 be retofit to burn gasified coal, the Martin Plant site is currently served by a six mile rail spur from the main line of the Florida East Coast Railway. In order to provide the flexibility of having two alternative means of coal delivery (and the resulting competitive coal transportation costs), a rail spur approximately one mile in length would need to be constructed from the existing CSX Railroad main line, which runs adjacent to the plant site.

Environmental compliance

FPL has included the capital and operating costs of meeting all presumed local, state and federal environmental regulations in the project costs used as the basis for FPL's economic analysis of the proposed units. These costs are reflected in the Site Certification Application filed with DER.

It is DER which will ultimately determine the Best Available Control Technology (BACT) for the Lauderdale repowering and Martin Units 3 and 4, taking into account technical, environmental, and economic impacts. It is that agency which exercises jurisdiction over environmental compliance of utility operating units. Should DER find that selective catalytic reduction (SCR) technology is required for emissions control, as both Broward and OPC have argued, then the record indicates that the effect of SCR would be to increase the overall PVRR of the expansion plan, but the Base Plan would remain the most cost-effective for meeting FPL's capacity needs. Thus, we find that FPL has taken into account the reasonably anticipated costs of environmental compliance in the unit selection process.

Future generation siting

As discussed in more detail below, it is our opinion that making findings of fact involving the environmental impacts on *present or future* generating capacities is the responsibility of the Hearing Officer at the DER Certification Hearing, and ultimately the Governor and Cabinet, sitting as the Power Plant Siting Board. Based upon that decision, we find this factual issue to be moot.

Costs related to natural resources

FPL did not attempt to quantify societal costs associated with use of natural resources, such as water, or impacts on air quality or other environmental resources. These impacts were considered in a qualitative manner through the application of strategic considerations in the generation planning process. While these strategic considerations did not cause any change to FPL's Base Plan, FPL's witnesses testified that in situations in which the economics of the alternative plans were closer, these types of factors might tip the balance.

No testimony was presented nor record developed by any party, including intervenor Bronson/Madson who raised this issue, which would enable the Commission to quantify the dollar costs associated with such societal impacts. However, as is discussed below we are of the opinion that the Commission cannot and should not consider these types of environmental and natural resource costs in making need determinations pursuant to the Power Plant Siting Act. As such, we find that this factual issue is moot.

Authority to place conditions

Pursuant to Section 403.519, Florida Statutes, the Commission has the inherent authority to place conditions on need determinations supported by the record developed in the proceeding. Such conditions are similar in effect to those placed on the applicants by the Department of Environmental Regulation (DER) or any of the other statutory parties to proceedings under the Power Plant Siting Act (Sections 403.501-.517, Florida Statutes). A violation of any of the conditions placed upon a need determination would result in appropriate action being taken by this agency. Such action could include a hearing and the subsequent modification, revocation or suspension of the need certification if the evidence developed so indicates.

The imposition of conditions on a need determination issued by this body should not be construed as resulting in the automatic invalidation of a need determination should those conditions not be met. Rather, conditions imposed on a need determination are a tool by which this agency can meet its statutory requirements to assure that any additional generating capacity to be constructed in this state is indeed the most cost-effective means of meeting the state's energy needs. This is consistent with this body's recent decision in the Seminole Electric Cooperative docket, Docket No. 880309-EC, Order No. 22590, issued on February 21, 1990.

Bidding

Section 403.519, Florida Statutes, requires that the Commission "shall take into account . . . whether the proposed plant is the most cost-effective alternative available." Rule 25-22.081, Florida Adminstrative Code, requires a discussion of the major available generating alternatives including purchases, and "an evaluation of each alternative in terms of economics, reliability, long term flexibility and usefulness..." Clearly, a Request for Proposals (RFP) to construct specified capacity for any public utility represents an "available generating alternative" to the construction of capacity by that utility and should be completed prior to the Commission's consideration of the cost-effectiveness of utility-constructed units.

ORDER NO. 23080
DOCKET NO. 890974-EI
PAGE 16

FPL has taken the position that this issue should not be decided in this docket since the Commission has ruled that no factual findings will be made regarding Martin Units 5 and 6 until the results of the RFP process are presented to the Commission in future hearings. We agree with FPL that the denial of FPL's motion for consolidation in this docket has limited the factual findings in this proceeding to Martin Units 3 and 4. As noted in Order No. 22267, the primary rationale for declining to consider factual findings on Martin Units 5 and 6 was the fact that the current RFP process could not be completed by the decision date in this proceeding. However, in order to give some guidance to other need determination applicants, we are of the opinion that we should rule on the issue in this proceeding.

Therefore, consistent with this Commission's ruling in Order No. 19468, we find that all bidding processes should be complete before the Commission reaches the merits of any need application. In re: Petition of Seminole Electric Cooperative, Inc., Tampa Electric Company and TECO Power Services to determine need for electrical power plant, Order No. 19468, issued on June 8, 1988 at pages 3-6. We also find that this issue should be considered further in a rulemaking proceeding and order our Staff to institute same.

Indispensable party

Section 403.519, Florida Statutes, lists specific items which "shall" be considered by the Commission in deciding the question of power plant need: "need for electric system reliability and integrity"; "need for adequate electricity at a reasonable cost"; "whether the proposed plant is the most cost-effective alternative available"; "conservation measures . . . which might mitigate the need for the proposed power plant" and "other matters within the jurisdiction which it deems relevant."

This language was intended to "flesh-out" the general language of Section 403.507(1)(b), Florida Statutes, which states, in part: "The Public Service Commission shall prepare a report as to the present and future need for the electrical generating capacity to be supplied by the proposed electrical power plant. The report may include the comments of the commission with respect to any matters within its jurisdiction." It is clear from the language of Sections

403.507 and .519 that this Commission is free to consider other issues within its jurisdiction in reaching its decision on power plant need, but must consider the four issues specifically raised. The information required in Rule 25-22.081, Florida Administrative Code, is designed to enable this Commission to satisfy the statutory mandates of Sections 403.507 and .519.

The information required by Rule 25-22.081 can be divided into roughly two areas: information regarding the need of the petitioner for the proposed generating capacity [Rules 25-22.081(3) and (6)] and information regarding the most cost-effective means of providing that need [Rules 25-22.081(2), (4) and (5)] In addition, the rule requests information on the impact of the proposed generating capacity on the electric utilities and other qualifying facilities connected to the statewide electric transmission and distribution grid. [Rule 25-22.081(1)]. When a utility awards a contract to a bidder for the supply of all or part of that utility's capacity needs, the utility must be an indispensable party to the need determination proceeding in order for the Commission to adequately evaluate the need application. The reason is simple: the need for the capacity remains that of the utility. The winning bidder has no independent need of his own. In order for the specific mandates of the statute to be meaningful, they must be answered from the utility's perspective. The award of a bid to a third party does not suddenly cut the utility out of the picture. The utility is in the same posture it would be in had it pursued the other options mentioned in the statute: purchased power, cogeneration, conservation, load management: a utility with a need for new capacity.

Further, the cost-effectiveness of the bid must be evaluated not only from the perspective of the other bidders, i.e., did the utility pick the lowest cost viable candidate, but also in terms of the utility's other options for the supply of that capacity: purchased power, demand-side reduction programs, cogeneration, and utility construction. Unless the utility which awards the bid is an indispensable party, it is virtually impossible to develop the record in these areas. This is the type of information which is exclusively in the hands of the utility. Likewise, the basic question of need for capacity can only be adequately proven by the entity needing the power: the utility. Independent power producers, under any moniker, do not have the ability to produce accurate load forecasts because they don't have the data base on which such an analysis is built.

This Commision has previously voted to no longer "rubber stamp" need determinations filed by qualifying facilties where such facilities have entered into a standard offer or negotiated contract for the sale of their cogenerated power to an investor-owned electric utility. Order No. 22341 at 26.

In taking that position, we found:

> In so doing we take the position that to the extent that a proposed electric power plant constructed as a QF is selling its capacity to an electric utility pursuant to a standard offer or negotiated contract, that capacity is meeting the needs of the purchasing utility. As such, that capacity must be evaluated from the purchasing utility's perspective in the need determination proceeding, i.e., a finding must be made that the proposed capacity is the most cost-effective means of meeting purchasing utility X's capacity needs in lieu of other demand and supply side alternatives.
>
> . . . .
>
> Fourth, as discussed above, we adopt the position that "need" for the purposes of the Siting Act (Sections 403.501-.517, Florida Statutes), is the need of the entity ultimately consuming the power, the electric utility purchasing the power. Cogeneration is another alternative to that purchasing utility's construction of capacity or purchase of wholesale power from another source.

Order No. 22341 at 26-27.

The rationale which supported that decision supports this one. Therefore, we find that an electric utility should be an

ORDER NO. 23080
DOCKET NO. 890974-EI
PAGE 19

indispensable party to any winning bidder's need determination proceeding before this body regardless of any contractual agreements that the bidder will be solely responsible for obtaining certification for the bid capacity.

Compliance with FEECA

Broward has argued that this Commission can not certify as needed a plant which is fueled by natural gas or oil since such plants are contrary to FEECA. This is but another rehash of Issue No. 37 in the Planning Hearing docket, Docket No. 890004-EU: Should the Commission accept as reasonable generation expansion plans which would increase Florida utilities' consumption of and reliance on natural gas and oil? In answering that question affirmatively, the Commission stated as follows:

> The initial language of Sections 366.81 and 366.82 [FEECA] could have been read as an expression of the Legislature's intent that no increase in the consumption of natural gas or oil be allowed in the state. We did so interpret it in Order No. 17480, issued on April 30, 1987, in the last planning hearing docket. Order No. 17480 at 10. Historically, cogeneration facilities which are not refuse burners have been fueled in whole or in part by natural gas. Their inclusion in the list of activities to be encouraged by this Commission indicates that the Legislature is interested in the most economic use of natural gas and oil, not in an absolute ban on increased gas and oil usage no matter what.
>
> Likewise, the addition of language which indicates that the growth rate of both peak demand and electric consumption should be reduced and controlled indicates that an absolute prohibition against increased use of petroleum fuels is not what is intended. Peaker units are fueled exclusively by natural gas and oil.

> Based on these changes to both the Fuel Use Act and FEECA, we are now of the opinion that the mandate of this Commission given by both the Congress and Legislature is to encourage the most economic use of natural gas and oil, *not to prohibit its use completely*.

Order No. 22341 at 16-17 [Emphasis added.]

The key to the development of a least-cost generation expansion plan is to select the units which are the most cost-effective while maintaining a reasonable reliability factor. Based on the record before us, it appears that a plan which begins with the addition of natural gas-fired combined cycle units is more cost-effective than one which begins with the addition of any coal-based alternative. Even with the inclusion of the repowered Lauderdale units, the construction of Martin Units 3 and 4 result in FPL's projected oil burn remaining below FPL's share of the FEECA goal of 58,734,000 barrels per year throughout the study period.

FPL correctly points out that Section 403.519 was enacted as part of FEECA and directs the Commission to consider whether the proposed plant is the most cost-effective alternative available and whether there are conservation measures that might mitigate the need for the proposed plant. Nowhere does any section of FEECA prohibit the certification of a proposed unit which burns natural gas or petroleum fuels, provided that the unit is the most cost-effective generating alternative.

For these reasons, we find that FPL's proposed Martin Units 3 and 4 comply with the provisions of FEECA.

Environmental impacts

The Siting Act sets forth a comprehensive licensing scheme for new and expanded steam-fired generating capacity. Under the Siting Act there are several divisions of responsibility. The final decision on certification is made by the Governor and Cabinet sitting as the Power Plant Siting Board. Section 403.509, *Florida Statutes*. The Governor and Cabinet are charged with the responsibility of:

> [effecting] a reasonable balance between the need for the facility and the environmental impact resulting from construction and opera- tion of the facility, including air and water quality, fish and wildlife, and the water resources of the state.

Section 403.502(2), Florida Statutes.

The decision of the Governor and Cabinet is made based upon the record developed at the final certification hearing conducted by a designated hearing officer from the Division of Administrative Hearings (DOAH). It is this hearing officer who is charged with the responsibility of preparing a recommended order based on all of the evidence of record presented at the certification hearing. Section 403.508, Florida Statutes. The Commission is a statutory party to the final certification hearing and a positive determination of need pursuant to Sections 403.507 and 403.519, Florida Statutes, is a prerequisite to the conduct of the final certification hearing.

The Commission's role in the power plant siting process is found in three sections of the Siting Act. Section 403.507(1)(b) requires the Commission to prepare a report as to the present and future need for the proposed electrical generating capacity which is the subject of the application. The report "may include the comments of the commission with respect to any matters within its jurisdiction." As discussed previously, Section 403.519 indicates in more detail the issues to be considered by the Commission in making a need determination. This list also includes "other matters within its [Commission's] jurisdiction which it deems relevant." Last, Section 403.508 makes the Commission a statutory party to the final certification hearing.

The Commission does not have statutory jurisdiction over the environment or natural resources in the State of Florida. The responsibility for those areas is divided among numerous state and local agencies: DER, the Department of Natural Resources, local Water Management Districts, the Game and Fresh Water Fish Commission, local zoning boards to name but a few. These are the agencies which are charged with the evaluation of the environmental impacts of this or any future proposed plants. These matters are simply not within the jurisdiction of this body and therefore, not properly considered in the need determination at issue here.

The environmental impacts of these proposed units are properly litigated before the hearing officer in the final certification hearing. And, under Section 403.507(2), Florida Statutes, DER is charged with the responsibility and authority to conduct or contract for studies in the following areas:

> (e) Impact on suitable present and projected water supplies for this and other competing land uses.
> (f) Impact on surrounding land uses.
> (h) Environmental impacts.

The intervenors have raised several environmental issues: the depletion of potable water by the proposed power plants; the ability of cogenerators, municipalities or FPL itself to site plants in the same area in subsequent years as the need arises for additional generation; and levels of NOx and SOx emissions which would require the installation of Selective Catalytic Reduction to the facility. These are within the areas covered by Section 403.507(2) quoted above and can be raised in the final certification hearing before the hearing officer. These are matters within the specific technical expertise of the environmental agencies mentioned above.

The forum in which the Legislature intended the record to be developed on the environmental impacts of proposed power plants is the forum in which the agencies charged with environmental matters have the greatest input: the final certification hearing. Given the existence of this forum and the lack of jurisdiction over the subject matter, the Commission should not seek to expand its need determination proceedings to cover environmental and natural resource issues.

This does not mean that the Commission should not consider the cost of equipment reasonably believed to be required to actually operate the proposed plants. These costs were developed in the record of this proceeding and are discussed in Issue 23. Externalities which involve a balancing of public good versus need for new generation are the matters which are properly excluded from consideration by this body and best left to the environmental agencies and ultimately the

Governor and Cabinet. Therefore, we find that the Commission can not and should not consider the cost to the state and its citizens of the environmental and natural resource impacts of the proposed Martin Units 3 and 4.

<u>Grant of need determination</u> .

Broward County has suggested that the Commission grant FPL's petition for need for the Lauderdale repowering subject to certain conditions. First, Broward would require that the combined cycle units be converted to coal gasificiation as soon as feasible. We reject this condition of need certification for several reasons. First, as discussed above, it appears from this record that generating capacity which burns natural gas and petroleum fuels, where cost-effective, does not violate FEECA or federal conservation mandates. The record developed in this proceeding indicates that combined cycle units burning natural gas are the most cost-effective generating alternative available to FPL. Thus, we will not impose this condition on FPL's Martin Units 3 and 4 need determination.

Second, Broward has requested that FPL be required to take whatever steps are necessary so as to minimize the environmental impact of the proposed units, e.g., install SCR and burn low-sulfur oil as a back-up fuel. We find that this condition involves environmental matters which are not within our jurisdiction but within the jurisdiction and expertise of the environmental agencies identified in the Siting Act.

Finally, Broward County has suggested that FPL be required to make a "proactive effort" to encourage QF capacity. While we are of the opinion that FPL may not have done all that it might have to develop either cogeneration or conservation in its service territory, and, while we agree that FPL should be required to develop a comprehensive plan for the cost-effective integration of cogeneration on its system, this plan should be developed in FPL's conservation docket, Docket No. 900091-EG; it should not be made a condition of this need determination.

That being the case, we find that no conditions should be imposed on this need determination. We further find that based upon the resolution of the factual and legal issues raised in this proceeding, FPL's petition for determination of need for the proposed Martin Units 3 and 4 should be granted.

MOTIONS FOR RECONSIDERATION

Broward

Broward has essentially raised two issues in its motion for reconsideration: 1) that there is not enough gas to run FPL's system with the Lauderdale repowering and Martin Units 3 and 4 (Issues 10, 5-8, 18 and 19) and 2) that the Commission should require FPL to submit a cogeneration development plan in Docket No. 900091-EQ based upon FPL's demonstrated anti-cogeneration conduct over the last eight years (Issue 17).

Issue 10:

In its motion Broward points out that Staff has compared annual average firm gas commitments with the summer peak demand of the Lauderdale Repowering and Martin Units 3 and 4 to erroneously reach the conclusion that natural gas will be available to economically dispatch the proposed units in the manner assumed by FPL in its PROMOD runs. Broward correctly states that FPL's average commitment for firm gas is 327 mcf/day [T. 708] while its consumption of natural gas for the Lauderdale Repowering and Martin Units 3 and 4 is 292 mcf/day at summer peak [T. 693] and 320-350 mcf/day at winter peak [T. 694]. Since FPL's available firm gas capacity is 280 mcf/day during winter peak periods [T. 694], Broward argues that FPL will be "short" on gas during winter peak periods by roughly 40-70 mcf/day. Motion at 2-3.

Having reviewed again the testimony of FPL Witness Silva and Exhibits 71 and 72, we are still of the opinion, that notwithstanding these facts, there will be enough gas to fuel the Lauderdale and Martin Units 3 and 4 as predicted. The 40-70 mcf/day of gas which will be short will be supplied by interruptible gas. [Exhibit 72] This seems a reasonable assumption given the past availability of natural gas to FPL.

In 1989, FPL had a contract for 19 mcf/day of firm gas. [Exhibit 1 at Appendix D, page 23] In January of that year FPL burned 317 mcf/day of natural gas. [Exhibit 71] Since only 19 mcf/day was provided pursuant to firm contracts, 298 mcf/day was supplied to FPL under interruptible contracts. This is an amount far in excess of the 40-70 mcf/day which is questioned by Broward County. It is an amount which can be delivered by the Phase I natural gas facilities which are currently in place. There is no reason to believe that that small quantity of gas will not be available in the future. We would also point out that this "shortage" will be reduced by another 20mcf/day if the Phase II expansion goes as planned. [Exhibit 72]. As currently proposed to the FERC, the completion date for the Phase II expansion is July of 1991 or approximately two years prior to the in-service date of the first of the units certified in these dockets.

The record developed in these dockets does support the Commission's vote that adequate assurances have been provided regarding available fuel to service both the Lauderdale and Martin Units 3 and 4. That being the case, we will deny Broward's motion with regard to Issue 10.

Issues 5-8, 18 and 19

Next Broward urges us to reconsider its vote on Issues 5, 6, 7, 8, 18 and 19. These are the issues which address adequate electricity at a reasonable cost, system reliability and integrity, and most cost-effective alterative. Broward argues that since natural gas will not be available in sufficient quantities, there is some question whether the combined cycle units are the most cost-effective units available to meet FPL's need. This would be true, they contend, since the units will not be able to maintain 63-78% capacity factors modeled in the Proscreen analysis through the year 1999. Motion at 3. Having already concluded that the record does establish that adequate gas will be available to maintain these capacity factors, we find this argument to be unpersuasive.

Broward also contends that the higher than historic availabilities for FPL's Turkey Point nuclear units modeled in the generation expansion plans would also result in the cost-effectiveness of the combined cycle units being suspect. Motion at 4. However, as Exhibit 25 demonstrates, when a capacity factor of 65% (close to Turkey Point's historic capacity factor) is used for Turkey Point, the least-cost generation expansion plan for FPL remains the same until the year 1995 when 300 additional MW of power are needed. [T. 265]. Broward further argues that the inclusion of Martin Units 5 and 6 in the generation expansion plan skews the economic dispatch of Units 3 and 4. Motion at 4-5. We would refer Broward to Exhibit 27 which indicates that even if Martin Units 5 and 6 were removed completely from the generation expansion plan, the Lauderdale Repowering and Martin Units 3 and 4 would still offer FPL's ratepayers the most cost-effective option up until 1995. [T. 267-68].

We would finally take exception with Broward's statement that "certifying the Lauderdale units and Martin Units 3 and 4 may lead FPL to later argue that Units 5 and 6 have been tacitly certified." Motion at 4. Given the specific ruling by the prehearing officer in the order on consolidation that no factual findings would be made in either of the above dockets regarding Martin Units 5 and 6, as well as the reiteration of that ruling at the prehearing conference, we would be incredulous if anyone could, or would, make an argument that any legal or factual finding regarding Martin Units 5 and 6 was made in these dockets. [Order 22267 at 3, 5] As was stated repeatedly during the hearing, all factual findings on Martin Units 5 and 6 will be made at a later date when the RFP process is complete. For these reasons, we deny Broward's motion to reconsider our findings on Issues 5-8, 18 and 19.

Cogeneration development plan

Broward finally argues that the record developed in these dockets would support the imposition of the requirement on FPL that it file a cogeneration development plan in its conservation/cogeneration docket, Docket 900091-EG, within 90 days of the final order in this docket. As discussed above, we have determined that this would be redundant given our decision in Order No. 22176. That being the case, we will also deny Broward's motion on this point.

FPL

FPL's petition for reconsideration deals with only two issues: Issue 17, "Has the availability of purchased power from qualifying facilities and non-utility generators been adequately explored and evaluated?" and Issue 20, "Are there sufficient conservation or other non-generating alternatives reasonably available to FPL to mitigate the need for the proposed Lauderdale repowering [Martin Units 3 and 4]?" FPL takes issue with the Commission's findings that FPL has not adequately pursued either conservation or cogeneration as an alternative to the construction of the Lauderdale repowering or Martin Units 3 and 4.

FPL's arguments can be divided into four groups: 1) that the issues of conservation and cogeneration were "secondary" and of marginal relevance to the main issue of need determination addressed in the dockets; 2) that FPL was somehow denied due process by the "surprise" use of the materials contained in Exhibit 33 by Broward and Staff; 3) that if FPL did not vigorously encourage cogeneration it was the result of "mixed" signals given by the Commission and 4) that the record developed in this proceeding does not support the finding that FPL did not adequately seek to avoid construction of capacity through conservation measures or cogeneration.

Conservation and cogeneration

Contrary to the position taken by FPL, the use of conservation and cogeneration to mitigate the need for the construction of power plants is not a "secondary" issue in need determination dockets. Section 403.519, Florida Statutes, states as follows:

> The Commission shall also expressly consider the conservation measures taken by or reasonably available to the applicant or its members which might mitigate the need for the proposed plant . . .

[Emphasis added.]

In addition, Rule 25-22.081(4), Florida Administrative Code, states that a petition for a need determination shall contain:

> 4) A summary discussion of the major available generating alternatives which were examined and evaluated in arriving at the decision to pursue the proposed generating unit. The discussion shall include a general description of the generating unit alternatives, including purchases where appropriate; and an evaluation of each alternative in terms of economics, reliability, long term flexibility and usefulness and any other relevant factors.
>
> . . .

> (5) A discussion of viable nongenerating alternatives including an evaluation of the nature and extent of reductions in the growth rates of peak demand, KWH consumption and oil consumption resulting from the goals and programs adopted pursuant to the Florida Energy Efficiency and Conservation Act both historically and prospectively and the effects on the timing and size of the plant.

Clearly, the intent of the Legislature is for the Commission to explore other means of meeting the demonstrated need of the applicant. And where such means are available and are cost-effective, it is the express desire of the Legislature to require the applicant to avail itself of those nonconstruction alternatives. This is consistent with the overall purpose of the Power Plant Siting Act: to balance the need for reliable electric capacity with the environmental impacts of power plants. One can best avoid the detrimental environmental effects of building power plants by not constructing those plants in the first place.

We are not of the opinion, however, that the legislative mandate prohibits the construction of power plants. This is clearly illustrated by the legislative mandate to encourage the development of cogeneration facilties. Such facilities may minimize the environmental impacts because of their high efficiency.

Further, cogeneration is another form of purchased power which should be adequately explored before a utility can be certified to build its own capacity. See: Rule 25-22.081, Florida Administrative Code.

For these reasons, we are of the view that the issues of available cogeneration and conservation are not "secondary" to this proceeding but an integral part of the determination that FPL and this Commission have met their respective statutory obligations under the Power Plant Siting Act.

Denial of due process

FPL appears to be arguing against the admission of the materials contained in Exhibits 29, 30, 31, 32 and 33 after the fact essentially on the grounds that Staff and Broward used them to FPL's disadvantage. Petition at 4-5. The basic rule of law is that any objection not made to an exhibit at the time it is offered into evidence is waived. Our Staff properly identified and tendered the exhibits into evidence and FPL made no objection to them. [T. 270-74; 382-83; 1094-97] In fact, FPL conducted extensive voir dire (inquiry of the witness) on the exhibits, intended apparently to place the exhibits in the "perspective" which FPL now claims it was denied the opportunity to provide. Further, when asked by the Chairman specifically if FPL had an objection to the admission of Exhibits 29-32, FPL's counsel answered that FPL had no objection to their admission. [T. 383] With regard to Exhibit 33, FPL's counsel again specifically represented that he had no objection to the exhibit's admission into evidence. [T. 1096]

FPL has absolutely no basis for its statement that it was somehow prejudiced by the introduction of this evidence when it twice agreed to its admission. Whatever the infirmities of the materials contained in the exhibits, they existed at the time of their admission. We would also point out that no cross examination of these exhibits was conducted at hearing because a substantial number of the documents were the subject of a request for confidentiality made by FPL. Since this request, made the day before the hearing started, could not be disposed of until after the hearing, it would have been virtually impossible to cross examine on those documents even if there had been a witness produced who knew something about them.

Whatever the intentions of Broward, FPL could not have been surprised by any parties' reliance on these documents in regards to the issues dealing with conservation and cogeneration. Obviously our Staff believed them to be relevant since they specifically requested them by formal discovery, traveled to Miami to review them, identified the documents they considered germane, and identified them as exhibits at hearing. One does not go to all of that expense and effort not to use the materials entered into the record.

We are willing to let the documents speak for themselves. FPL's procedural and due process rights have been fully protected by this body. Thus, we are unpersuaded that this is a basis for reconsideration of our initial decision.

Mixed signals

FPL cites a long string of various Commission orders in which the Commission indicates that "lost revenues" to an electric utility are a concern of this body. Petition at 8-10. The appropriate forum to discuss this issue is in the cogeneration rules docket, planning hearing docket and conservation/cogeneration programs docket. These are the dockets in which it is appropriate for this body to discuss and resolve the often conflicting policy issues surrounding cogeneration. Thus, we are unpersuaded tht his is a basis for reconsideration.

Competent and substantial testimony

Having reviewed the record developed in this proceeding, we find that there is competent substantial testimony to support our findings. We have not found nor do we suggest that FPL has failed to carry its burden in establishing its need for the capacity it seeks to certify, but it appears from the record in this proceeding that FPL did not adequately pursue non-utility construction alternatives which might have mitigated that need. Thus, we will deny FPL's motion for reconsideration on this ground as well.

Therefore, it is

ORDERED By the Florida Public Service Commission that the petition of Florida Power & Light Company filed on July 25, 1989 for a determination of need for the construction of Martin Units 3 and 4 is hereby granted. It is further

ORDERED that the Motions for reconsideration/clarification filed by Broward County and Florida Power & Light Company are hereby denied as discussed above.

ORDERED that this order constitutes the final report required by Section 403.507(1)(b), Florida Statutes, the report concluding that a need exists, within the meaning of Section

403.519, Florida Statutes, for the construction of Martin Units 3 and 4 and the addition of 770 MW of capacity on Florida Power & Light Company's system. It is further

ORDERED that a copy of this order be furnished to the Department of Environmental Regulation, as required by Section 403.507(1)(b), Florida Statutes, on or before June 15, 1990.

BY ORDER of the Florida Public Service Commission this 15th day of JUNE, 1990.

Steve Tribble

STEVE TRIBBLE, Director
Division of Records and Reporting

Commissioner Beard dissents on Issues 13, 14, 18, 19, and 20 and would not grant certification to the proposed Martin Units 3 and 4.

(S E A L)

SBr

<u>FPSC ORDER NO. 92-002-FOF-EI</u>

<u>TAMPA ELECTRIC COMPANY</u>

<u>CERTIFICATION OF NEED POLK UNIT ONE</u>

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Petition for Determination of Need for a Proposed Electrical Power Plant and Related Facilities in Polk County by Tampa Electric Company.	DOCKET NO. 910883-EI ORDER NO. PSC-92-0002-FOF-EI ISSUED: 03/02/92

GFA MJH SMM CRB
WNC GJK HWS MDM
JRR JBR TWM DEP
RHK DMM TLH G.Nelson RC

The following Commissioners participated in the disposition of this matter:

SUSAN F. CLARK
BETTY EASLEY

ORDER DETERMINING THE NEED
FOR A PROPOSED ELECTRICAL POWER PLANT

BY THE COMMISSION:

Pursuant to Notice, a formal hearing was held in this docket on December 10-11, 1991 in Tallahassee, Florida. Having considered the record in this proceeding, the Commission now enters its Final Order.

BACKGROUND

Tampa Electric Company (TECO or Tampa Electric) filed a Petition for Determination of Need with the Commission on September 5, 1991. In that petition TECO requested that the Commission approve the construction of a 220 MW Integrated Coal Gasification Combined Cycle (IGCC) unit and related facilities at a site located in Polk County. The proposed IGCC project will consist of a 150 MW advanced combustion turbine (CT) unit to be placed in service in July, 1995, and a 70 MW heat recovery steam generator (HRSG) and coal gasifier to be placed in service in July, 1996. Transmission facilities associated with the construction of the plant include two circuits looping the Pebbledale-Hardee Power Station circuit and two circuits looping the Pebbledale-Mines circuit into a transmission switching station at Polk Unit One. Fuel transportation facilities associated with the construction of the plant include a natural gas lateral to the adjacent FGT pipeline for economy gas purchases, and an oil pipeline lateral to the GATX oil pipeline under construction next to the plant site.

The coal gasifier will employ a new technology that efficiently cleans coal gas at high temperatures. This technology will be a demonstration project for the U. S. Department of Energy (DOE). DOE has signed a cooperative agreement with TECO to provide a $120 million grant to offset some of the costs associated with the construction of the plant and the demonstration of the new technology.

In Docket No. 910004-EU, TECO's 220 MW phased combined cycle unit was designated as its avoided unit for pricing cogeneration. Upon learning of the availability of the $120 million grant from DOE to build the coal gasification plant, TECO estimated the cost of the IGCC unit and compared the project's impact on TECO's expansion plan with eight other expansion plans. When TECO determined that the IGCC unit, with the benefit of $120 million of DOE funding, cost less than the "avoided unit" proposed in Docket No. 910004-EU, TECO initiated this proceeding to determine the need for the IGCC unit.

Destec Energy (Destec), Ark Energy (Ark), Florida Industrial Cogeneration Association (FICA), and Floridians for Responsible Utility Growth (FRG) intervened in this proceeding. Prior to the pre-hearing conference, held on November 20, 1991, Destec and Ark withdrew from this proceeding. Prior to the hearing, held on December 10-11, 1991, FICA also withdrew from the case.

Post-hearing briefs were filed by Tampa Electric Company and Floridians for Responsible Utility Growth on January 3, 1992. FRG filed proposed findings of fact with its brief, and a ruling on each proposed finding is included in Appendix A attached to this order.

The basic issue we are called upon to decide in this proceeding is whether under the provisions of section 403.519, Florida Statutes, Tampa Electric Company has adequately demonstrated the need to construct its proposed plant. The Florida Public Service Commission is the sole forum to determine the need for the proposed power plant, and only issues relating to that need were considered in this proceeding. Separate public hearings will be held by the Department of Environmental Regulation before the Division of Administrative Hearings to consider environmental and other impacts of the proposed plant and its associated facilities.

Section 403.519 delineates five major topics for our consideration in making a determination of need:

1. the need for electric system reliability and integrity;

2. the need for adequate electricity at a reasonable cost;

3. whether the proposed plant is the most cost-effective alternative available;

4. conservation measures taken by or reasonably available to the applicant which might mitigate the need for the proposed power plant; and

5. other matters within the Commission's jurisdiction which it deems relevant.

We have considered all issues relevant to those topics and we hold, for the reasons set out below, that Tampa Electric has demonstrated the need for the proposed 220 MW IGCC plant. We approve the plant's construction on the condition that TECO does receive the $120 million dollar grant from the Department of Energy to help defray the costs of the project.

The Need for Electric System Reliability and Integrity.

TECO used a combination of criteria to determine its need for 220 MW of additional capacity in the 1995-1997 time frame, including a minimum 20% winter reserve margin and assisted Loss of Load Probability (LOLP) of 0.1 days per year. We find these criteria to be reasonably adequate for planning purposes. The 0.1 days per year LOLP criteria is consistent with the LOLP criteria used by the Florida Electric Power Coordinating Group (FCG), and the winter reserve margin is a reasonable one for a utility of Tampa Electric's size. The planning criteria are applied to TECO's load forecast to determine whether TECO will need additional capacity in 1995 and beyond.

In developing its load forecast, TECO first produces a single demand and energy forecast by combining end-use, multi-regression, and trend analysis techniques. A model of demand and energy use of phosphate customers is forecasted separately, as are the effects of TECO's conservation, load management, and cogeneration programs. The final forecast is a combination of all these methods. It includes projections of population, income, employment, appliance energy use, appliance saturations, appliance efficiency standards, price elasticity, weather (including temperature sensitivities), and residential, commercial and industrial consumption patterns. We believe that the forecasting methodology has produced a reasonably adequate prediction of TECO's future load. The forecast demonstrates that TECO does have a need for additional capacity beginning in 1995 to meet its reliability criteria.

To meet its reliability criteria, TECO shows a need for 65 MW of capacity in 1995, 66 MW in 1996, and 43 MW in 1997. TECO's proposed need for capacity is similar to the need demonstrated in TECO's expansion plan in Docket No. 910004-EU. That plan provided for 75 MW in 1995, 75 MW in 1996, and 70 MW in 1997. Since TECO's proposed unit consists of a 150 MW advanced combustion turbine and a 70 MW heat recovery steam generator, TECO will build a large portion (150 MW) of the needed 220 MWs of capacity at one time, somewhat earlier than needed. TECO had planned to phase in a 220 MW combined cycle unit by bringing a 75 MW combustion turbine (CT) on line in each of the years 1995 and 1996 with a 70 MW heat recovery steam generator being added in 1997. Given the participation of the DOE in the IGCC demonstration project, Tampa Electric will construct some portion of the needed 220 MW slightly sooner and some portion slightly later than under the old plan, but it will do so at a significantly lower cost. Since TECO does not anticipate any adverse effects on the reliability of its system by placing some of the capacity into service earlier than needed, and since early construction of part of the needed capacity is reasonable in order to obtain DOE funding for a substantial portion of the project and thus lower the cost, we believe early construction is justified.

It is clear from the record that if additional capacity is not placed into service by 1996, TECO's winter reserve margin is expected to fall below 20 percent and its LOLP is projected to rise above the 0.1 days per year maintained for system reliability. The first 150 MW of the IGCC unit is due to be put into service in just over three years, in mid-1995. Given the lead time necessary for utilities to construct new generating facilities, TECO's petition was filed at a reasonable time.

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.

TECO's reliability criteria of 0.1 days per year LOLP and minimum winter reserve margin of 20 percent would be violated with a delay in the in-service date of the proposed unit (Exhibit 1, p. 60). If no capacity is added to TECO's system in 1995, TECO's Loss of Load Probability (LOLP) is estimated to be 0.140 days per year and its winter reserve margin will be 19.1 percent. If no capacity is added in 1996, the net LOLP will deteriorate to 0.199 days per year and the winter reserve margin will drop to 16.2 percent. Thus, the addition of capacity from the proposed IGCC unit is needed for TECO to maintain acceptable reliability criteria.

TECO's proposed 220 MW IGCC unit is also needed to contribute to the reliability and integrity of the electric system of the State as a whole. Shahla Speck, of the Florida Electric Power Coordinating Group (FCG) testified in this proceeding that the phased-in capacity from Polk Unit One is consistent with the needs of Peninsular Florida, and will provide a portion of the additional generating capacity that is needed between 1995 and 1997 for the peninsula to maintain an adequate level of reliability.

Ms. Speck based her conclusion on an analysis of FCG's 1989 Planning Hearing document entitled "Generation Expansion Planning Studies", with consideration of all known changes which have occurred since that study was performed. Peninsular Florida's utilities plan to have 39,050 MW of total capacity, not including the proposed Polk Unit One, in the winter of 1996/1997 to meet a projected firm winter peak demand of 34,310 MW. The reserve margin is expected to be 4,740 MW. With the addition of TECO's proposed IGCC, the reserve margin will increase to 4,960 MW (14.5%), and with the projected capacity increase from 220 MW to 260 MW in the IGCC unit, Peninsular Florida's reserve margin will be 5000 MW (14.6%) in the winter of 1996/1997. We believe the addition of the proposed IGCC plant will contribute to the reliability of the electric system of the State of Florida by providing capacity in the time frame in which it is needed.

The proposed IGCC unit, which will burn gas extracted from coal, will not contribute to the fuel diversity of TECO's system, which is already heavily reliant on coal as a fuel. We are not persuaded by TECO's argument that coal gas is a new fuel that will contribute to fuel diversity on TECO's system. Regardless of the fact that gas is the end product of a coal gasification process, the source fuel is still coal. Currently, about 99% of the energy generated by TECO's units comes from coal. The IGCC unit will only increase TECO's reliance on coal as a major fuel source.

Furthermore, the proposed unit will not contribute to the fuel diversity of peninsular Florida. Peninsular Florida has a wide variety of generating technologies that use a diverse range of fuels, including coal, natural gas, oil, and nuclear. TECO's proposed IGCC unit will not significantly affect the fuel mix of Peninsular Florida's generating units, and therefore will not contribute to fuel diversity.

Nevertheless, in this proceeding the determinative issue is whether it is cost-effective for TECO and TECO's ratepayers to incur the higher capital cost of an IGCC unit to enable use of lower cost coal fuel. That appears to be the case here, because the DOE grant significantly lowers the total capital cost of the project. As we will explain in detail below, the IGCC unit is the most cost-effective alternative to meet TECO's capacity needs. That fact drives our decision to grant TECO's petition.

The Need for Adequate Electricity at a Reasonable Cost

Fuel forecasts and Fuel Costs

With certain reservations we find that TECO's fuel price forecast is reasonably adequate for planning purposes. TECO Witness Mr. Smith stated that coal prices are expected to remain relatively stable through the year 2000, while natural gas and oil prices are projected to increase rapidly. TECO's forecasting methodology includes reliance on data from government sources and industry association forecasts, trends, and two independent outside consultants. Forecasted transportation prices are added to obtain total delivered prices.

It appears that different fuel price forecasts have little impact on the proposed IGCC project's cost effectiveness. We are concerned, though, that TECO's forecast favors the use of coal over oil or natural gas over the long term for projects with similar costs. An extremely low natural gas price forecast favors an expansion plan which contains just combustion turbine and combined cycles. A low natural gas price forecast does not favor an expansion plan that includes the DOE IGCC project.

The type of new generating unit chosen is not necessarily driven by fuel cost per se; rather, it is the difference in cost among competing fuels. TECO's fuel forecast projects a widening cost differential between coal and natural gas or oil, when in fact for many years the cost differential between the cost of coal and the cost of natural gas and oil has remained relatively constant. In the future, TECO should pay close attention to this differential, and must be ready to substantiate continued reliance upon fuel price forecasts that have not accurately predicted the relationship between the price of coal and the price of natural gas and oil.

TECO provided sufficient assurance in this case that primary and secondary fuel will be available for the proposed plant on a long and short term basis at a reasonable cost. Fuel purchases will be made at market prices. TECO proposes to use the following fuels at its IGCC facility:

- Natural Gas

  TECO is proposing to use natural gas on an interruptible basis tc the extent available from Florida Gas Transmission. Dependence on interruptible gas means interruptions during peak demand or when the gas is most needed, and it is therefore practical to have on-site storage of No. 2 oil.

- No. 2 Oil

  TECO proposes to use No. 2 oil as the primary fuel in the first year and a backup or secondary fuel in all subsequent years. The Tampa Bay area is one of the key distribution areas for No. 2 oil. Delivery of No. 2 oil will be by truck from Port Manatee or by the GATX oil pipeline adjacent to the project site.

- Coal

  Coal will be the primary fuel for the IGCC unit. The coal to be used will be similar in sulfur content and price to that burned at TECO Big Bend Unit 4, and is the cheapest of all fuels. Delivery of coal to the plant will be by rail. Partial water borne delivery may be possible depending on the total delivered cost. Tests done using Eastern United States coals during the first two years will aid selecting the more cost-effective sources.

In conjunction with our semi-annual fuel cost recovery proceedings, we will of course evaluate all fuel related expenses to determine that the costs are reasonable and justified. We are satisfied here, though, that TECO has provided adequate assurances on the availability of primary and secondary fuel to the proposed facility on a long and short term basis at a reasonable cost.

Costs of Clean Air Act Compliance

The record in this case demonstrates that TECO adequately took into account the costs of environmental compliance associated with the Clean Air Act when it evaluated its future generation needs. TECO plans to comply with the Clean Air Act by one or more of the following: fuel switching; installing scrubbers; alternative technologies; and, purchasing allowances. Phase I compliance with the Clean Air Act will not be affected by the proposed IGCC plant, but the plant will be an asset to TECO in Phase II compliance. The Company estimates savings in the range of $50 to $100 million over the life of the proposed IGCC unit, compared to fuel switching or other Clean Air Act compliance strategies.

Site, Design, and Engineering Characteristics

TECO provided sufficient information on the site, design and engineering characteristics of its 220 MW IGCC unit to enable us to adequately evaluate its proposal. A Power Plant Site Selection Task Force, consisting of private citizens from environmental groups, businesses and universities, provided guidance and recommendations to TECO throughout the site selection process. The task force recommended the Polk County site, consisting of 3572 acres of mined out phosphate land. The site is located near the FGT/Hardee Power Station natural gas lateral and close to rail transportation for coal delivery. Distillate (No. 2) oil can be made available to the site by truck or pipeline.

Originally, TECO's proposed unit was to be a 220 MW IGCC with an estimated heat rate of 9060 BTU/kWh. Results from the FLUOR Engineering Study, received after TECO's need petition was filed on September 5, 1991, showed that the projected capacity of the unit increased to 260 MW and the heat rate dropped to 8486 BTU/kWh. These improvements result largely from two factors: TECO's decision to use a more efficient General Electric 7F turbine instead of a 7EA turbine, and TECO's determination that the heating value of natural gas is greater than that of coal gas.

TECO's proposed IGCC unit will present a demonstration of hot gas clean-up on a large scale. Hot gas clean-up technology has been successfully demonstrated on a 2 MW scale, but not on the scale TECO will attempt to demonstrate. No evidence was presented by any party that a scale-up in size was not viable. Rather, DOE Witness Bechtel's rebuttal testimony stated that "Tampa Electric has this capability as well as the presence in the industry to showcase effectively the project's results, thereby resulting in the successful commercialization of this technology".

The project will have redundant (hot and cold) gas clean-up capabilities to offset the risk that the hot gas clean-up technology will not perform as expected. No evidence was presented that showed that the back-up cold gas clean-up technology is not a reliable procedure. Although no utility currently has in its rate base a plant the size of TECO's proposed IGCC using cold gas clean-up, TECO presented evidence that cold gas clean-up has been successfully demonstrated in the United States with a number of projects, including:

- The 120 MW Cool Water Facility, located in California. Based on the Texaco gasification process and a General Electric combustion turbine unit, this plant operated for over 26,000 hours and achieved a capacity factor of 87%

in its final quarter of operation. This plant will be expanded and returned to commercial operation in a few years.

- The 160 MW facility owned by Dow Chemical in Louisiana. Consisting of a Dow gasifier and a combustion turbine that originally burned natural gas prior to being modified to burn gasified coal, this plant achieved a success similar to that experienced at the Cool Water Facility.

We therefore believe that TECO's proposed project is commercially viable. The record in this proceeding shows that TECO will be able to demonstrate the technical and economic viability of oxygen-blown, entrained-bed IGCC with hot gas clean-up, and generate clean, efficient, coal based power for the increasing demands of the region.

Most Cost-Effective Alternative

TECO has demonstrated that the proposed IGCC unit is the most cost-effective alternative to provide the additional needed capacity for TECO and peninsular Florida. Using TECO's most recent financial estimates, the proposed IGCC unit is estimated to save TECO's ratepayers $195 million over the life of the unit compared to TECO's next best option. These savings are primarily attributable to fuel savings (resulting from the use of coal) and the $120 million DOE contribution. The unit is projected to have an installed cost of $389 million dollars (1996), including the DOE funding. This estimate does not include the economic effects of potential EPRI funding for the project, which would result in even more savings. Clearly the $120 million in DOE funding and the potential for some additional assistance from EPRI have favorably affected the cost-effectiveness of the IGCC project.

The DOE Grant

Of the $120 million grant to be awarded to TECO by DOE, $100 million will go toward plant construction and $20 million will go toward the first two years of operation and maintenance of the proposed unit. TECO estimates that the hot gas clean-up equipment for its proposed unit will cost approximately $11.5 million ($1991). If the hot gas clean-up experiment fails and TECO is required to fully operate the cold gas clean-up system, TECO predicts a minimal reduction in plant efficiency that would result in a $3 million reduction in savings associated with the IGCC plant. This financial penalty is extremely low, considered in light of the $62 million savings ($195 million based on revised estimates) expected to result from choosing the IGCC plant.

DOE Witness Bechtel testified that the $120 million grant money is not refundable by TECO under any condition, and thus we believe TECO's ratepayers are adequately protected if the demonstration technology fails. If TECO profits from the sale of the plant to another party or utility, or if TECO profits from the commercialization of the technology by other utilities for future projects, TECO would typically be expected to pay 5% of future profits in royalties to DOE. We note that in the future if TECO does profit from the commercialization of the hot gas clean-up technology, we would expect TECO's ratepayers to share in the project's profits, just as they will have shared in the project's costs.

A final version of the DOE Cooperative Agreement was not available for our review in this proceeding. TECO is awaiting DOE approval of certain modifications to the agreement. These modifications include a change in the original site location to the Polk County site and use of the Texaco coal gasification technology. We were assured by the Department of Energy and TECO at the hearing that the final agreement will be forthcoming shortly and that it will issue in substantially the same form that it presently exists. We are confident that the grant will be available to TECO to defray a significant portion of the costs of the IGCC project, and therefore we approve the project. Because of the importance of the DOE grant to the cost-effectiveness of the project, however, we must condition our approval on TECO's receipt of the $120 million grant with no requirement that TECO repay any part of the $120 million grant.

Fuel forecast Comparisons

Due to concerns regarding the sensitivity of TECO's fuel forecasts, our staff asked TECO to perform an economic comparison of its proposed IGCC unit (using coal) and the phased combined cycle unit from Docket No. 910004-EU (using five different gas forecasts for the phased CC unit). The five fuel forecast scenarios used to compare TECO's proposed IGCC Unit and its phased combined cycle unit were:

1. TECO base fuel forecast;

2. FCG fuel forecast;
3. City of Tallahassee's latest (9/91) fuel forecast;

4. FPC base case and high case fuel forecast; and
5. Fuel forecast specified by staff. Because our staff believes that the price of natural gas will not escalate as rapidly as TECO estimated, TECO was asked to compare the economics of the IGCC unit and the phased combined cycle unit by using currently projected costs for coal and natural gas in 1995 and holding the 1995 cost differential between the two fuels constant over the life of the IGCC unit. Our staff considered this fuel forecast to be the "acid test", or "worst-case" forecast.

TECO also performed both a "break-even capacity factor" analysis and a "revenue requirements" analysis using the above mentioned fuel forecasts. In the "break-even capacity factor" analysis, the levelized in-service cost of the two plants (IGCC and CC) was determined at various capacity factors ranging from 30% to 100%. Throughout the capacity factor range in which TECO plans to operate its IGCC unit (around 80%), the IGCC plant was cost-effective under all fuel price scenarios.

In the "revenue requirements" analysis, the nominal costs of the two plants (IGCC and CC) were determined at a capacity factor of both 60% and 80% for each year of the life of the plant. The analysis concluded that TECO's proposed IGCC unit is cost-effective under all fuel price scenarios, including our staff's "acid test", at both the low capacity factor of 60% and the expected operating capacity factor of 80%.

TECO also performed a cost comparison between its proposed IGCC project and FPL's current avoided unit, a 1997 IGCC unit. Compared to FPL's avoided unit, TECO's proposed project is more cost-effective.

The cost savings testified to by TECO Witness Ramil do not include the estimated $50 to $100 million of savings (over the unit's life) which will derive from the fact that the IGCC unit will assist TECO in meeting the stringent requirements of Phase II of the Clean Air Act amendments. It is not possible at this time to determine a firm estimate of TECO's cost of complying with Phase II requirements. It is clear at this time, however, that the IGCC unit will enable TECO to back down on the dispatch of dirtier units on its system, and thus save TECO some costs of Phase II compliance.

Alternative Generating Technologies

TECO demonstrated in this proceeding that it adequately explored the construction of alternative generating technologies. TECO initially evaluated 46 different generating technologies to meet its future capacity needs. Each of these technologies were screened on the basis of geographic viability, construction lead time required, public acceptance, environmental compliance, cost, safety, and proven demonstration and commercialization. After performing a screening curve analysis, TECO selected the following seven technologies for an economic optimization analysis:

1. Conventional Pulverized Coal
2. Integrated Coal Gasification Combined Cycle (IGCC)
3. Combustion Turbine (CT)
4. Combined Cycle (CC)
5. Phosphoric Acid Fuel Cell
6. Solar Thermal
7. Photovoltaic Solar Cell

After evaluating the economics of expansion plans involving the technologies that passed the initial screening, TECO found that the expansion plan which included the IGCC unit - with the $120 million grant from the Department of Energy - was the most cost-effective plan. In other words, the IGCC unit had the lowest present worth revenue requirements (PWRR) of the other generating alternatives available.

Conservation

TECO projects that its 1996 winter peak demand will be reduced by 205 MW as a result of load management, and 277 MW as a result of its conservation programs. This 482 MW total represents 13% of TECO's projected 1996 winter peak demand (3703 MW). TECO currently spends 95% of its demand-side management dollars on programs targeted at residential customers. Between 1981 and 1990, 94% of the demand reductions TECO achieved through conservation were achieved through its residential programs, and it appears that TECO's residential conservation programs are doing a reasonable job of saturating the eligible market. The participation rates for some of TECO's commercial and industrial programs, however, appear to be low.

None of the parties in this proceeding presented quantitative evidence regarding the possibility of expanding participation in TECO's approved programs that are projected to have a participation rate of less than 10%. There is little evidence in the record to conclusively demonstrate either the feasibility or the difficulty of increasing participation rates in those programs. Furthermore, TECO's conservation programs appear to be deferring peaking units only, not baseload or intermediate load units.

We do believe TECO has adequately considered the conservation measures that would be reasonably available to avoid the need for this proposed plant. It does not appear that additional timely and cost effective conservation measures can reliably defer the need for capacity in 1995. System savings due to conservation programs are difficult to measure, and it is difficult to project the achievable penetration rate for each program. However, we also believe that TECO needs to demonstrate to us why it cannot be more aggressive in pursuing conservation, particularly for its commercial and industrial customers. We will therefore require TECO to resubmit its conservation plan no later than one year prior to filing its next need determination petition. This resubmission shall explain in a detailed and definitive manner why market penetration cannot be increased for each of TECO's approved conservation programs. We expect TECO to conduct market achievability studies, and to experiment with control and test groups. We will not accept conjecture about market penetration feasibility. In addition, TECO should consider expanding its conservation plan to include programs that would defer the need for baseload and intermediate load units.

Floridians for Responsible Utility Growth does not agree that TECO has adequately demonstrated that the proposed IGCC unit is the most cost-effective alternative to meet its future capacity needs. FRG urges us to deny TECO's petition because the company has failed to meet its statutory obligation to take available conservation measures and propose the most cost-effective resource alternative.

FRG argues that under section 403.519, the phrase "most cost-effective alternative" available means "least cost" option or combination of options available, and under that section utilities must demonstrate that proposed power plants are the least cost options available to meet system requirements. FRG states that because section 403.519 requires the Commission to take into account the need for adequate electricity "at a reasonable cost", as well as whether the proposed plant is "the most cost effective alternative," it follows that "cost-effective" must be given a meaning that is congruent with "reasonable cost" as well as with its common usage meanings. By common usage definition, FRG states, "cost-effective" means that an investment's benefits are equal to or greater than its costs and that the costs are less than those of other reasonable alternatives. In the context of resource options to meet electricity needs, then, the requirement to provide "reasonable cost electricity must be deemed to require electricity that can be provided at the lowest cost because it would not be "reasonable" to pay more than what is necessary for electric resources.

FRG acknowledges that there are other matters to consider besides cost in choosing a resource option, and FRG mentions that system reliability and integrity are two examples specifically mentioned in the statute. FRG concludes though that because TECO did not propose an alternative standard to assist us in determining what is "most cost-effective", and because "least cost" is the most logical standard in light of the provisions of section 403.519, we should adopt the interpretation that the terms "most cost-effective alternative" and "least cost option or combination of options" are synonymous.

We do not agree with FRG's interpretation of the phrase "most cost-effective alternative available". We believe that the Florida Legislature contemplated our consideration of a broad range of factors to determine the need for a proposed power plant, including electric system integrity and reliability and other strategic matters that might be relevant to a particular case. If the Legislature intended that the Commission use the more restrictive analysis contemplated by the term "least cost" in its determination of the need for a proposed power plant, the Legislature would have adopted that phrase. Rules of statutory construction require the inference that the phrase that the Legislature did use does not mean simply "least cost option". Our disagreement with FRG over the interpretation of section 403.519 may be more a matter of semantics than substance, because we believe that either interpretation attempts to reach the same result - the provision of adequate and reliable electric service at a reasonable cost.

FRG has asked us to determine what obligation TECO has under section 403.519 to demonstrate what measures have been taken or were reasonably available to TECO which might mitigate the need for TECO's proposed unit. FRG proposes that section 403.519 requires that utilities seeking a determination of need for new power plants must demonstrate that they have fully examined the energy efficiency and other DSM alternatives reasonably available to them, based on their own research and experience, the studies and experience of other Florida utilities, and the research and DSM programs of utilities nationwide. FRG contends that the statute also requires utilities to demonstrate that they have reasonably implemented (i.e., have undertaken well designed programs that are comprehensive in their coverage of customer market segments and electric end-uses) the cost-effective DSM measures available to mitigate the need for proposed plants.

It is our opinion that TECO, the petitioner in this case, has the burden to prove to the Commission by a preponderance of the evidence that it has a need to construct an IGCC unit in Polk County by 1996, taking into account all the factors set out in section 403.519, Florida Statutes. Specifically, TECO has the obligation to show the conservation measures it has taken to mitigate the need for the proposed unit, and it has the obligation to show that the measures taken were consistent with its conservation plans required by section 366.81, Florida Statutes, and approved by Commission order.

Section 403.519, Florida Statutes specifically directs the Commission to consider "the conservation measures taken by or reasonably available to the applicant . . . that might mitigate the need for the proposed plant. . . " This provision of section 403.519 should be construed in a manner that is consistent with and gives effect to the terms of FEECA, specifically sections 366.81 and 366.82(3) and (4). We are of the opinion that a consistent construction of the two statutes is achieved by requiring a utility in a need determination proceeding to show that it has reasonably implemented conservation measures included in its conservation plans, as directed by section 366.82(3) and as approved by Commission order, and that it has reasonably considered conservation measures that might mitigate the need for <u>this proposed plant</u>.

While the record in this proceeding shows that TECO can improve its conservation efforts, the record in this proceeding does not show that additional conservation can be implemented quickly enough to avoid construction of this particular power plant, and thus additional conservation cannot "mitigate the need" for the IGCC plant. FRG's proposal to expand our review and analysis of TECO's conservation efforts may have merit in another forum, but they exceed the scope of our review of those efforts here.

<u>Purchased Power Alternatives</u>

The record demonstrates that TECO adequately explored and evaluated the availability of purchased power from other electric utilities. TECO currently plans to purchase firm capacity from TECO Power Servicec (TPS) in 1993. At that time, TECO and SEC will share 295 MW of firm capacity generated at Hardee Power Station. The availability of this 295 MW is based on the projected backup energy requirements of SEC.

TECO also evaluated the possibility of importing capacity from the Southern Company via the 500 kV transmission line with a capacity of 3200 MW, 50% participation in an 800 MW coal unit, with a 1998 in-service date, and the possibility of purchasing 100 MW of firm capacity in both 1998 and 1999. These evaluations indicated that the proposed IGCC plan was still the most cost-effective alternative.

We note that all the cogenerators that intervened initially in this proceeding withdrew their intervention prior to the hearing. Thus the record does not show that any cogenerator offered to build capacity which would avoid the need for the IGCC project, or that cogeneration projects could fill TECO's capacity needs in a cost-effective manner. The $120 million DOE grant lowered the avoided cost of the project, thereby lowering the potential payments to cogenerators. It is, we suppose, theoretically possible that the DOE grant would be transferable to a cogenerator to demonstrate the new coal gasification technology, but practically speaking it is not likely that would happen. The transfer could not be made without DOE approval and it is clear from the record that DOE expects TECO to construct and demonstrate the project. Furthermore, a cogenerator, or any other party, would have difficulty securing a site, gaining permits and completing the construction of capacity in the short amount of time remaining to meet TECO's capacity needs.

TECO currently has a total of 289 MW of cogeneration on its system, with 41 MW from firm purchase contracts with three cogenerators and 248 MW from self service generation. TECO forecasts a total of 364 MW of cogeneration by 1996, with 68 MW of firm power purchases from cogenerators and 296 MW from phosphate mine self-service generation. A large percentage of the industrial load on TECO's system comes from phosphate mining operations.

We encourage TECO to actively pursue non-utility generation for its next needed capacity, particularly through negotiations for firm capacity purchases from qualifying facilities. Cogenerators who do not get satisfactory results by negotiating with TECO may intervene in TECO's next need determination proceeding. Here we will not require TECO to allow outside parties an opportunity to bid against its proposed IGCC unit. Currently, there is no Commission rule that requires bidding. Furthermore, TECO's IGCC unit with DOE funding is more cost effective than the combined cycle unit in Docket No. 910004-EU. It is unlikely that a bid lower than the cost of TECO's proposed IGCC could be obtained.

Conclusion

Based on our resolution of the factual and legal issues presented in this case, for the reasons explained above, and with the conditions explained above, we grant TECO's petition for determination of need for a 220 MW IGCC unit, with 150 MW on-line in 1995 and 70 MW on-line in 1996. We believe that TECO's petition satisfies the statutory requirements of section 403.519, Florida Statutes. The addition of 150 MW in 1996 and 70 MW in 1996 will serve TECO's capacity needs and contribute to meeting its reliability criteria of 0.1 days/year LOLP and 20% winter reserve margin. Phased-in capacity from Polk Unit One is consistent with the needs of Peninsular Florida, and will provide a portion of the additional generating capacity needed between 1995 and 1997 for the peninsula to maintain an adequate level of reliability. As a result of receiving $120 million in funding from DOE, TECO's proposed IGCC facility is the most cost-effective generation alternative. TECO estimates its proposed plant will save customers $195 million over the life of the unit, compared to the next best (most cost-effective) alternative. Operation of the IGCC will allow TECO to back down the dispatch of dirtier units, thereby assisting TECO with compliance with Phase II requirements of the Clean. It appears that further timely and cost effective conservation measures cannot reliably defer the need for the IGCC unit.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that, for the reasons, and with the conditions, set out in the body of this order, Tampa Electric Company's Petition for Determination of Need for a Proposed Electrical Power Plant and Related Facilities in Polk County is hereby granted. It is further

ORDERED that this Docket shall be closed.

By ORDER of the Florida Public Service Commission this 2nd day of MARCH, 1992.

STEVE TRIBBLE, Director
Division of Records and Reporting

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NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.59(4), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Director, Division of Records and Reporting within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water or sewer utility by filing a notice of appeal with the Director, Division of Records and Reporting and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900 (a), Florida Rules of Appellate Procedure.

APPENDIX

Responses to FRG's Proposed Findings of Fact

ISSUE 16 -- Conservation Measures Taken By & Available to TECO

A. EXAMINATION OF CONSERVATION OPTIONS:

1. TECO's reliance on the RIM test for economic screening of DSM leads to the rejection of economical savings opportunities. (Chernick, TR 344-345)

   We reject the above proposed finding of fact because this statement is a conclusion drawn by FRG, not a fact.

2. TECO uses the Rate Impact Measure (RIM) test as its primary cost-effectiveness screen for DSM. (Kordecki, TR 520)

   We accept the above proposed finding of fact.

3. TECO knows that the Commission has directed the utility to analyze DSM measures and programs with three tests: the RIM, the TRC test, and the "Participant" test, and that the Commission has not directed it eliminate measures that fail the RIM. (Kordecki, TR 522)

   We reject the above proposed finding of fact because the Commission has directed utilities to use these three tests to analyze only programs proposed for Commission approval, not all programs. The Commission has not directed utilities to screen DSM programs with these three tests.

4. Contrary to the Commission directive, TECO only used the RIM test to screen most DSM measures; and measures that failed the "revenue losses" part of the RIM were eliminated from further consideration. (Kordecki, TR 53C & 552)

   We reject the above proposed finding of fact because the Commission does not have a directive which states how a utility should screen DSM programs. The commission directs utilities on how to evaluate programs that they propose as part of the conservation plan.

5. The last "complete" DSM program examination by TECO was done prior to February 12, 1990 -- not as a part of the company's preparation for this need determination proceeding -- and only

22 potential new DSM programs were identified for further investigation and analysis. (Kordecki, TR 497)

We accept the above proposed finding of fact.

6. Five of the 22 potential new programs were eliminated for one reason or another, and two were dropped for reasons unrelated to cost-effectiveness: (1) the Energy Management Systems program, because it did not assure peak demand control -- even though the systems "functioned well for energy savings" -- and (2) residential lighting, because it failed the company's "ten-year life policy." (Kordecki, TR 498-499 & 540)

We accept the above proposed finding of fact.

7. Nine of the remaining 17 DSM measures were eliminated through TECO's application of a "revenue reduction" test (the "lost revenue" portion of the RIM test), excluding from further consideration measures whose cost saving benefits were lower than associated revenue reductions. (Kordecki, TR 499)

We accept the above proposed finding of fact.

8. TECO did not analyze any of these nine eliminated measures in combination with DSM measures that passed the RIM to determine whether the combination would permit greater energy savings and also pass the RIM test. (Kordecki, TR 541-542)

We accept the above proposed finding of fact.

9. Five of the final 8 DSM measures reviewed by TECO were then eliminated by application of the full RIM to determine whether the combination would permit greater energy savings and also pass the RIM test. (Kordecki, TR 499)

We reject the above proposed finding of fact because the statement is vague.

10. Although utility recovery of part or all of a DSM programs's costs from participants could lower the impact of that program on nonparticipants, TECO did not examine cost sharing or DSM financing approaches for measures that failed the RIM. By discarding upfront all DSM that failed the RIM, TECO never examined whether cost recovery or rate design changes could mitigate nonparticipant impacts. (Kordecki, TR 547-548 and

549-550)

We reject the above proposed finding of fact because the first sentence is an opinion, not a fact based on substantial competent evidence.

11. TECO directs its attention to "the most cost-effective" (emphasis added) DSM programs that provide "cost-effective" conservation for the utility ratepayers." (Kordecki, TR 501)

    We accept the above proposed finding of fact.

12. TECO's DSM focus is on residential customers because a focus on commercial & industrial customers would yield larger kWh savings; residential applications, by their very nature, "will not save large numbers of kilowatt-hours." (Kordecki, TR 512)

    We reject the above proposed finding of fact because this statement is an opinion drawn by FRG, not a fact.

13. TECO did not investigate the option of directly installing DSM measures in residences or facilities. (Kordecki, TR 571)

    We accept the above proposed finding of fact.

14. TECO did not examine appliance labeling programs for the residential sector in its last investigation of potential DSM measures (although it had done so in the early 1980's); nor did it examine motor efficiency measures or retail buy-down/deal rebate programs. (Kordecki, TR 572-573)

    We accept the above proposed finding of fact.

15. TECO did not consider the development of conservation programs that would reduce the need for baseload capacity or evaluate DSM measures against baseload units. (Kordecki, TR 245)

    We accept the above proposed finding of fact.

B. IMPLEMENTATION OF CONSERVATION MEASURES:

16. TECO has under-invested in economical energy efficiency resources. (Chernick, TR. 342)

    We reject the above proposed finding of fact because it is an opinion drawn by FRG, not a fact.

17. TECO's DSM planning weaknesses include the failure to target DSM market sectors comprehensively (leaving out customer sectors, end-uses and measures) and the failure to address market barriers adequately (keeping incentives too low, not doing direct installation, and using a fragmented approach). (Chernick, TR 345)

We reject the above proposed finding of fact because it is an opinion drawn by FRG, not a fact.

18. Although TECO is pursuing some "lost opportunity" resources, it is neglecting cost-effective lost opportunity options in all customer sectors -- programs that target appliance replacement, new construction in both the commercial and residential sectors, commercial remodeling and renovation, and C&I equipment replacement. (Chernick, TR 348-349)

We reject the above proposed finding of fact because it is an opinion drawn by FRG, not a fact.

19. TECO does not offer efficiency measures for many end-uses in the residential and C&I sectors -- e.g., for important household appliances and lighting in the residential sector and for HVAC and refrigeration in the C&I sector. (Chernick, TR 353-354)

We accept the above proposed finding of fact.

20. To be reasonably comprehensive, a utility DSM program should attempt to cover all customer segments and end-uses, and it should be comprehensive in terms of technologies treated, the technical and financial assistance offered, and the strategies for overcoming market barriers. (Chernick, TR 306)

We reject the above proposed finding of fact because it is an opinion, not a fact.

21. Many of TECO's current DSM programs are inadequate to overcome the market barriers to customers participation, and the major problems are insufficient incentives, the absence of direct delivery mechanisms, and a fragmented treatment of DSM market sectors. Chernick, TR 356-362)

We reject the above proposed finding of fact because the statement is a conclusion drawn by FRG, not a fact.

22. One of the 3 new DSM programs that survived TECO's RIM screen -- a duct efficiency program -- was not filed with the PSC in February 1990 "because the distribution delivery mechanism was not in place." (Kordecki, TR 500)

We accept the above proposed finding of fact as it is stated. However, Witness Kordecki testified that TECO will be filing the program soon. Furthermore, the finding is duplicative in substance to FRG proposed finding 24.

23. The duct efficiency program has significant potential for both peak and energy savings in TECO's service territory -- with at least 50% of the homes needing the service and with .9 kW of peak and 650 kWh of energy savings available per household (significantly lower than the Florida Solar Energy Center's estimates of 1.6 kW of peak reduction on average); and the cost would average only $150 to $250 per residence, depending on the severity of duct leakage. (Kordecki, TR 577-579)

We accept the above proposed finding of fact.

24. As of November 1991, nearly 3 years after the Solar Center study and 2 years after the duct service was examined by the company and passed the RIM test, TECO had not yet filed for PSC approval of the program. (Kordecki, TR 577)

We accept the above proposed finding of fact.

25. Among the reasons for the low customer penetration of certain TECO DSM programs, the company cited customer cost (in the case of the comprehensive C&I audit), tenant/owner differences or split incentives (with commercial indoor lighting), and performance bond requirements (with the conservation value program). (Kordecki, TR 573-574)

We accept the above proposed finding of fact.

26. TECO's HVAC program had an incentive for purchasers which was discontinued and then reinstated when customer participation fell dramatically. The reinstatement resulted in higher

customer participation, and a high incentive would tend to increase participation even more. (Kordecki, TR 575-577)

We reject the above proposed finding of fact because Witness Kordecki stated that, generally, an increased incentive would increase participation but that for this specific program it would not (Kordecki, TR 576).

27. TECO saved about 133 gigawatt hours of energy use during the 1980's, approximately 4% of the growth experienced over the 10 years, and expects to capture approximately 4% of the likely growth during the 1990's. (Kordecki, TR 240-241)

We reject the above proposed finding of fact because the record is unclear and confusing on this finding.

28. The low customer participation levels in TECO's commercial indoor lighting program for 1991 and 1996 are defended as reasonable on the basis of "the conditions of that program and what is involved in the program" -- not on the basis of other utility experience or industry standards. (Kordecki, TR 255-256)

We reject the above proposed finding of fact because Witness Kordecki does not state that the reasonableness of TECO's programs is not judged on the basis on other utility experience or industry standards. This is an assumption made by FRG.

29. The DSM program designs, savings results, and projected energy savings of other utilities clearly indicate that TECO could be implementing many additional conservation measures that could displace or postpone the Polk Unit. (Chernick, TR 321-341)

We reject the above proposed finding of fact because the projected savings from other utilities that Witness Chernick discussed are not yet proven savings and therefore cannot be considered to be completely reliable estimates of savings that might displace or postpone the Polk Unit.

ISSUE 21 -- Most Cost-Effective Alternative

C. EVALUATION OF DEMAND-SIDE AND SUPPLY-SIDE OPTIONS:

30. Conservation and other DSM measures that failed the rim test were excluded from further consideration by TECO, even if they passed the total resource cost (TRC) test. (Kordecki, TR 521)

We accept the above proposed finding of fact.

31. Although treated as a "cost" in the RIM evaluation, the "lost revenue" or "stranded investment" part of the RIM calculation does not represent an additional "cost" of DSM to the utility on its customers; rather, it is a transfer between customers within the utility system that does not affect utility revenue requirements or total system costs. (Kordecki, TR 526)

We accept the above proposed finding of fact.

32. TECO's goal in using the RIM to screen DSM is to assure that nonparticipants are not worse off with DSM than without DSM; that nonparticipants' electric bills will be no higher with DSM than without it; and that nonparticipants do not suffer inequity from participants' enjoyment of DSM benefits. (Kordecki, TR 527, 528)

We accept the above proposed finding of fact.

33. No nonparticipant analysis is made of supply options -- no examination of whether customers who did not need additional power are worse off with new supply than without it or suffer inequity from other customers' enjoyment of the new supply. (Ramil, TR 81-82)

We reject the above proposed finding of fact because Witness Ramil stated that he was unsure whether TECO noted every single criteria it used on pages 70 and 71 of the Need Study (TR 80). FRG did not ask specifically if this criteria was used. Instead, FRG concluded that TECO did not analyze supply-side options based on this criteria.

34. TECO does not eliminate supply options from further review solely on the basis that they would increase rates to some degree or raise revenue requirements. (Ramil, TR 81-82)

We accept the above proposed finding of fact.

35. In evaluating supply options TECO attempts to determine which option is "least cost" -- has the lowest present worth revenue

requirements -- and uses a model called PROVIEW that optimizes on the basis of lowest revenue requirements. (Ramil, TR 78-79)

We accept the above proposed finding of fact.

36. No DSM portfolio or individual conservation program was evaluated alongside the final supply options to determine whether DSM measures would have lower present worth revenue requirements and lower system costs to customers. (Ramil, Part 7, Exhibit 1, pages 66-73)

We reject the above proposed finding of fact because Witness Ramil did not make the above statement anywhere in the Need Study, particularly the pages referenced.

D. LEAST COST/MOST COST-EFFECTIVE ALTERNATIVE:

37. The goal of utility resource planning is to minimize the long-run costs of providing adequate and reliable energy services to customers, and cost minimization requires that utilities choose the resources with the lowest costs first, adding progressively more expensive options until demand is satisfied. (Chernick, TR 297-298)

We reject the above proposed finding of fact because it is a general statement of policy, not a fact.

38. Least cost utility planning requires utilities to pursue the most cost-effective resource plan. Such a plan would include all cost-effective DSM that is available for less than the cost of the supply it would avoid. Not pursuing all cost-effective DSM would obligate a utility to purchase more costly supply to make up for energy savings foregone. (Chernick, TR 299)

We reject the above proposed finding of fact because it is a statement of opinion or conclusion drawn by FRG.

39. TECO did not compare the total system costs and rate impacts of the DSM measures that passed the TRC but failed the RIM with the rate impacts and revenue requirements of the final group of supply options evaluated by the company. Nor did TECO determine whether the DSM Measures rejected for failing the RIM would have cost less or had lower revenue requirements

than the proposed new facility. (Kordecki, TR 550)

We reject the above proposed finding of fact because it is a conclusion drawn by FRG. Witness Kordecki stated that the programs that were rejected would increase rates. Therefore, FRG has derived an improper conclusion from Witness Kordecki's other statements.

40. Since TECO did not examine whether measures failing the RIM would pass the TRC, the utility has no estimate of the amount of savings attainable through rejected measures and programs that would be cost-effective under the TRC -- measures which, by definition, would lower revenue requirements and reduce system costs. (Kordecki, TR 552-554)

We reject the above proposed finding of fact because although TECO did not evaluate in detail measures that failed the RIM test, FRG draws the conclusion that TECO has no estimates of the savings attainable from such programs.

<u>ISSUE 26 -- Factual Basis for Granting TECO's Petition</u>

E. RESULTS OF TECO'S USE OF THE "RIM" TO SCREEN DSM:

41. TECO's resource planning and DSM evaluation goal is "to cost effectively reduce revenue requirements, utility cost and lower future potential rates." (Kordecki, TR 239)

We accept the above proposed finding of fact.

42. Average customer costs and utility revenue requirements that result from DSM programs, as compared with new generation, can be lower even when customer rates to pay for the DSM are much higher, but such DSM programs would be rejected by TECO for failure to pass the RIM test. (Kordecki, TR 528-533)

We reject the above proposed finding of fact because even though the above hypothetical situation was proposed by FRG in its cross-examination of witness Kordecki, an actual program of this sort was never mentioned in the record.

43. DSM programs that fail the RIM are excluded by TECO without regard to the number of likely nonparticipants or the reasons

for non-participation. (Kordecki, TR 535)

We accept the above proposed finding of fact.

44. Contrary to the "WIN-WIN" characterization of TECO, rejection of DSM programs for failing the RIM test (i.e., for increasing the rates of nonparticipants) and building new generation instead can result in making only the customers that would not participate in DSM programs "winners" (by increasing their costs less than under a DSM resource approach) but making the customers who would participate "big losers" (by denying them the cost savings from the DSM programs and increasing their costs to pay for the new generation. (Kordecki, TR 535-536)

We reject the above proposed finding of fact because, although Witness Kordecki may have discussed the above subject, FRG incorrectly drew opinions or conclusions from the statement and, therefore, it is not a finding of fact.

45. DSM programs failing the RIM may have a smaller rate impact on nonparticipant customers in the early years of implementation than a proposed new power plant, and nonparticipants who leave the system prior to the break even point would "win" both in terms of rates and costs. (Kordecki, TR 546)

We accept the above proposed finding of fact because the second statement is an opinion FRG drew based on the first statement (which was said in the record).

46. Although greater flexibility in complying with acid rain legislation was described by the company as a key virtue of the proposed new power plant, TECO did not evaluate or model a portfolio of DSM measures to determine whether they would give the company more or less flexibility to meet clean air standards than Polk Unit One. (Ramil. TR 72-75)

We reject the above proposed finding of fact. On the pages cited above, Witness Ramil testified only that he did not perform the analysis described above. He noted only that Witness Kordecki might have.

47. Although company witnesses expressed concern about meeting clean air standards, TECO made no environmental impact comparisons between rejected DSM programs and the final group of supply options evaluated. (Ramil, TR 75-76)

We accept the above proposed finding of fact.

48. The RIM test has no role in the economic screening of DSM programs because it leads to the rejection of cost-effective conservation measures -- measures whose total benefits exceed their total costs. (Chernick, TR 300)

We reject the above proposed finding of fact because it is a conclusion drawn by FRG, not a fact.

F. CONSERVATION MEASURES TAKEN BY & AVAILABLE TO TECO:

49. Although Polk Unit One, if built, will be a baseload unit, TECO has focused its DSM efforts on programs that reduce peak demand and mitigate the need for peaking capacity, and the company plans to continue this focus on reducing peak demand in the years ahead. (Kordecki, TR 242-243)

We reject the above proposed finding of fact. Witness Kordecki did state that TECO has focused its DSM efforts on programs which reduce peak demand. However, the last part of the above statement is incorrect, as Witness Kordecki did not state that TECO plans to continue focusing on programs which only reduce peak demand.

50. If TECO had evaluated and developed DSM programs directed at reducing baseload capacity, which it chose not to do, those programs would have reduced its need for additional baseload capacity; and if it now were implementing energy saving DSM programs, they would assist in deferring the need for new baseload capacity. (Kordecki, TR 243-244)

We accept the above proposed finding of fact.

51. Research and utility experience shows that while homeowners finance cars and other things, they have little interest in financing energy efficiency measures. (Kordecki, TR 549)

We accept the above proposed finding of fact.

52. It would be possible for TECO to design a cost-effective residential new construction program that promotes efficiency installations which exceed code, and there is cost-effective potential in some construction market segments that would not

suggest code change. (Kordecki, TR 560-561)

We accept the above proposed finding of fact.

53. Because residential sales constitute about 41% of TECO retail sales and C&I about 52%, with both projected to grow over 2% a year during the next decade, there is likely to be as much potential for energy savings in the C&I sector as in the residential sector. (Kordecki, TR 567-568)

We accept the above proposed finding of fact.

54. TECO analyses show that DSM programs in the C&I sector have significant potential for energy savings but not for peak demand reductions. (Kordecki, TR 568)

We accept the above proposed finding of fact.

55. Most of the savings projected from the collaborative efforts cited by Mr. Chernick come from the C&I sector. (Kordecki, TR 568).

We accept the above proposed finding of fact.

56. There is nothing peculiar about the commercial sector in Florida, as compared with the commercial sector in other states, that would prevent TECO from getting greater energy savings. (Kordecki, TR 569)

We accept the above proposed finding of fact.

57. Although familiar with the federal government's list of some 200 energy conservation measures published under the Clean Air Act amendments, TECO has not investigated and analyzed most of the measure in a specific fashion. (Kordecki, TR 575)

We reject the above proposed finding of fact because it is misleading. Witness Kordecki testified that TECO investigated the measures in a general fashion, but that TECO probably had not analyzed every one of them in specific detail.

58. Although TECO's out-of-state witnesses demonstrated that there are many reasons why the estimated savings from FRG comparison utility programs may be overstated, neither testified that the savings estimates of FRG witness Chernick were too high by any

specific range of amounts (Perl, TR 638 & Kahn, TR 422-425); thus, on the basis of comparison utility projections and Mr. Chernick's conservative analysis of their implications for TECO, it is clear that TECO could have implemented better designed and more comprehensive efficiency programs that would capture significantly greater levels of energy savings during the 1990's. (Chernick, TR 367-376)

We reject the above proposed finding of fact because the second part of the statement is an opinion or conclusion drawn by FRG, not a fact.

59. On the basis of these facts and those listed in Parts A & B above, the Commission finds that TECO has neither adequately examined (investigated, analyzed and compared) not reasonably implemented (i.e., undertaken well designed programs that are comprehensive in their coverage of customer market segments and electric end-uses) many cost-effective energy conservation measures that are available to mitigate the need for the proposed new power plant. (Chernick, Kordecki & Perl)

We reject the above proposed finding of fact.

G. **MOST COST-EFFECTIVE ALTERNATIVE:**

60. On the basis of the company's testimony, and specifically the facts listed above in parts C & D, the Commission finds that TECO's approach to evaluating demand - and supply-side resource options is inconsistent and inequitable, and that it unfairly discriminates against energy efficiency options in favor of supply options that may be more costly and less equitable to its customers. (Kordecki & Ramil)

We reject the above proposed finding of fact.

61. On the basis of TECO's testimony and the facts highlighted above, the Commission finds that TECO's integrated planning process -- with its inconsistent evaluation of DSM and supply options -- is not capable of demonstrating that the proposed new plant is the most cost-effective alternative available; and the Commission further finds that the company has not shown by a preponderance of the evidence on this record that Polk Unit One is the most cost-effective option. (Chernick, Kordecki & Ramil)

We reject the above proposed finding of fact.

PROPOSED CONCLUSIONS OF LAW

ISSUE 27 -- Does "Most Cost-Effective" Mean "Least Cost"?

1. Reading and interpreting the plain language of Section 403.519 of the Florida Electrical Power Plant Siting Act as a whole, as well as considering it in the context of FEECA's direction to construe this section liberally to help control the growth rates of electric use and demand, and noting that the company analyzes and chooses its supply-side options on the basis of lowest cost, the Commission concludes as follows:

   a. that adequate electricity at "reasonable cost" means electricity that meets basic system requirements at the lowest possible cost, since it would be "unreasonable" to pay more than necessary for such electricity;

   b. that "cost-effective" alternative means that a resource option's benefits equal or exceed its costs; and

   c. that "most cost-effective" alternative means "lowest cost" or "least cost" resource option available to meet system needs.

2. The Commission also concludes that use of a practical standard such as "least cost" for evaluating the "most cost-effective alternative" is necessary in order to carry out is statutory obligation, and that "least cost" is the most logical standard in light of the specific provisions of Sec. 403.519.

We reject proposed conclusions of law 1 and 2 because the terms "most cost-effective alternative available" and "least cost option" are not synonymous. If the Legislature intended that the Commission use the more restrictive analysis contemplated by the term "least cost option" in its determination of the need for a proposed power plant, the Legislature would have adopted that specific term.

ISSUE 28 -- TECO's Obligation to Demonstrate DSM Measures Taken or

Reasonably Available to Mitigate the Need for the Polk Unit

3. The Commission concludes that Section 403.519 of the Siting Act requires that utilities seeking a determination of need for new power plants demonstrate the following:

   a. that they have fully examined (i.e., investigated, analyzed, and compared) the energy efficiency and other DSM alternatives reasonably available to them, based on their own research and experience, the studies and experience of other Florida utilities, and the research and DSM programs of utilities nationwide; and

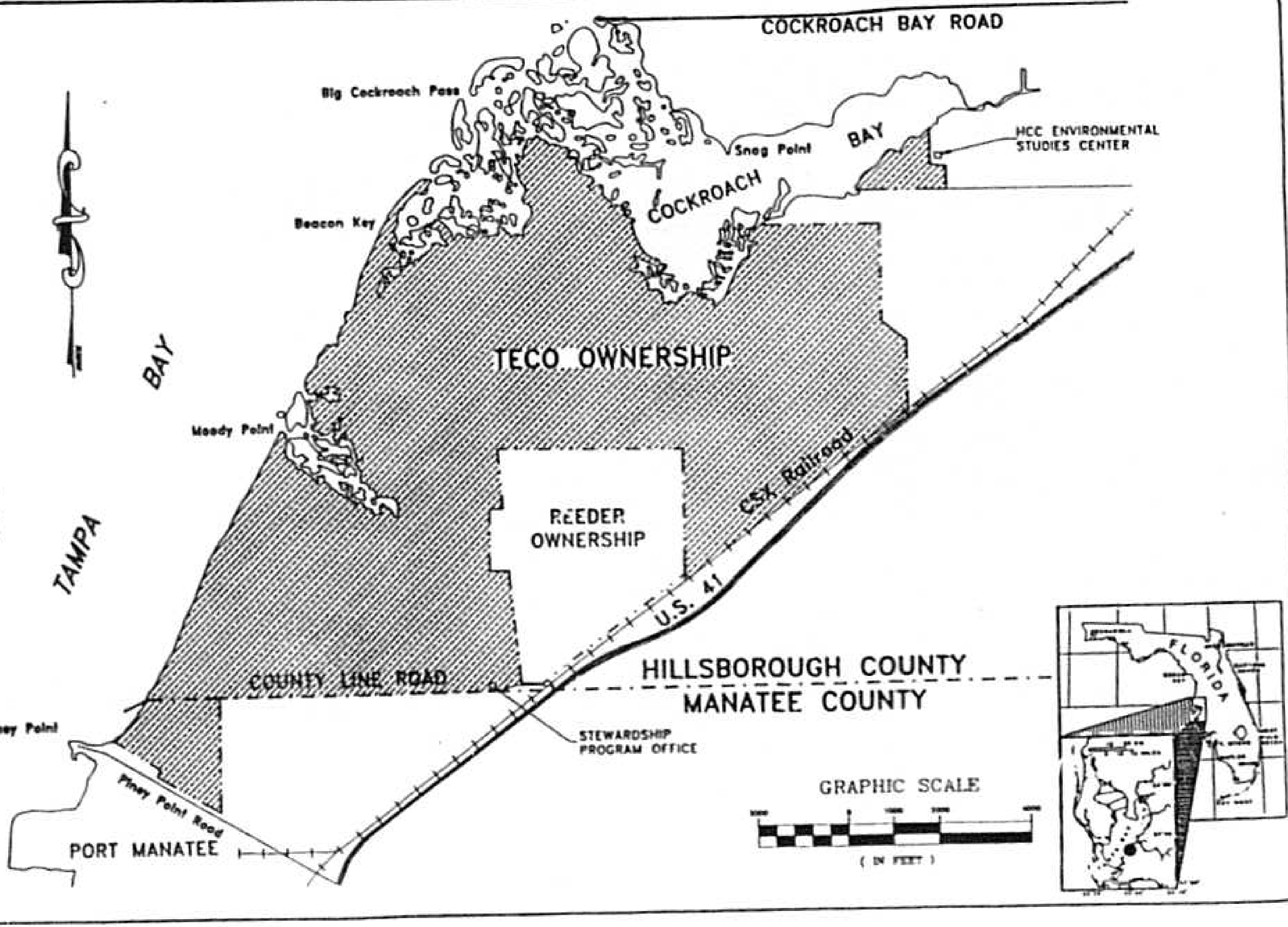
   b. that they have reasonably implemented (i.e., have undertaken well designed programs that are comprehensive in their coverage of customer market segments and electric end-uses) the cost-effective DSM measures available to mitigate the need for proposed plants.

4. The Commission concludes that TECO has not met its statutory obligations under Section 403.519, F.S., having failed to demonstrate by a preponderance of the evidence either that it has fully examined or reasonably implemented the DSM measures reasonably available to mitigate the need for Polk Unit One.

We reject proposed conclusions of law 3 and 4 because they expand the Commission's review and analysis of TECO's conservation efforts beyond the scope of what is required in this need determination proceeding. In this proceeding TECO has the obligation to show, and the Commission has the responsibility to consider, the conservation measures TECO has taken to mitigate the need for the proposed unit. The conservation measures to be considered by the Commission here are those measures that might mitigate the need for this proposed plant. While the record in this proceeding shows that TECO can improve its conservation efforts, the record in this proceeding does not show that additional conservation can be implemented quickly enough to avoid construction of this particular power plant, and thus additional conservation cannot "mitigate the need" for the IGCC plant.

TAMPA ELECTRIC COMPANY
DOCKET NO. 960409-EI
SUBMITTED FOR FILING 5/7/96
EXHIBIT NO. __ (JRR-1)
DOCUMENT NO. 7

<u>PORT MANATEE SITE MAP</u>
<u>AND STATISTICS</u>



PORT MANATEE
PLANNING AREA

FIGURE 1

PORT MANATEE SITE STATISTICS AT 4-30-96

A. Size: 665 Acres of Uplands
<u>1835 Acres of Wetlands</u>
2500 Acres M.O.L. Total

B. Book Value: $4,878,096.89

C. Expected use: Potential Power Plant Site

D. Regulatory Treatment: Book Value Recorded in Account 105 "Property Held For Future Use" And Included In Rate Base Per Docket No. 920324-EI, Tampa Electric's Last Base Rate Case (See p.33 of order)

TAMPA ELECTRIC COMPANY
DOCKET NO. 960409-EI
SUBMITTED FOR FILING 5/7/96
EXHIBIT NO. __ (JRR-1)
DOCUMENT NO. 8

EXCERPTS FROM FPSC DOCKET NO 920324-EI,
ORDER NO. PSC-93-0165-FOF-EI

TAMPA ELECTRIC COMPANY RATE CASE

FEB [illegible]

Regulatory [illegible]

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Application for a rate increase by Tampa Electric Company.	) DOCKET NO. 920324-EI) ORDER NO. PSC-93-0165-FOF-EI) ISSUED: 02/02/93

The following Commissioners participated in the disposition of this matter:

J. TERRY DEASON, Chairman
BETTY EASLEY
LUIS J. LAUREDO

Pursuant to duly given notice, the Florida Public Service Commission held public hearings in this docket on September 30, 1992, in Tallahassee, Florida; on October 7, 1992 in Tampa, Florida; and October 12 through 19, 1992 in Tallahassee, Florida. Having considered the record herein, the Commission now enters its final order.

APPEARANCES:

LEE L. WILLIS, Esquire, JAMES D. BEASLEY, Esquire, and KENNETH R. HART, Esquire, Ausley, McMullen, McGehee, Carothers and Proctor, 227 South Calhoun Street, Post Office Box 391, Tallahassee, Florida 32302.
On behalf of Tampa Electric Company.

JOHN ROGER HOWE, Esquire, Deputy Public Counsel, and H. Floyd Mann II, Esquire, Associate Public Counsel, Office of Public Counsel, c/o The Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400.
On behalf of the Citizens of the State of Florida.

JOHN W. McWHIRTER, JR., Esquire and LEWIS J. CONWELL, Esquire, McWhirter, Grandoff and Reeves, 201 East Kennedy Boulevard, Suite 800, Post Office Box 3350, Tampa, Florida 33601-3350; and VICKI GORDON KAUFMAN, Esquire and JOSEPH A. McGLOTHLIN, Esquire, McWhirter, Grandoff and Reeves, 315 South Calhoun Street, Suite 716, Tallahassee, Florida 32301.
On behalf of Florida Industrial Power Users Group.

DEBRA SWIM, Esquire and ROSS BURNAMAN, Esquire, 1115 North Gadsden Street, Tallahassee, Florida 32303-6237; and TERRY BLACK, Esquire, Pace University Energy Project, Center for Environmental Legal Studies, 78 North Broadway, White Plains, New York 10603.
On behalf of Legal Environmental Assistance Foundation/John Ryan.

DOCUMENT NUMBER-DATE

01243 FEB-2 93

FPSC-RECORDS/REPORTING

PAMELA K. AKIN, City Attorney and TYRON BROWN, Esquire, 315 East Kennedy Boulevard, 5th Floor, City Hall, Tampa Florida 33602.
On behalf of City of Tampa.

LT. COL. BRUCE J. BARNARD, and CAPT. TERRIE M. GENT, AFLSA/ULT, 139 Barnes Drive, Tyndall AFB, FL 32403-5319.
On behalf of the Department of Air Force.

PATRICK K. WIGGINS, Esquire, Wiggins and Villacorta, P.A., 501 East Tennessee Street, Tallahassee, Florida 32302
On behalf of District School Board of Pasco County, Florida.

ROBERT V. ELIAS, Esquire, DONNA L. CANZANO, Esquire, MICHAEL A. PALECKI, Esquire, and M. ROBERT CHRIST, Esquire, Florida Public Service Commission, 101 E. Gaines Street, Tallahassee, Florida 32399-0863
On behalf of the Commission Staff.

PRENTICE P. PRUITT, Esquire, Florida Public Service Commission, 101 E. Gaines Street, Tallahassee, Florida 32399-0862
On behalf of the Commissioners.

ORDER GRANTING CERTAIN INCREASES

CASE BACKGROUND

On May 22, 1992, Tampa Electric Company (TECO or Tampa Electric or the company or the utility) filed a Petition for an increase in its rates and charges and approval of a fair and reasonable rate of return. The petition seeks a permanent increase in TECO's rates and charges pursuant to Section 366.06, Florida Statutes. The petition cites the costs associated with building and maintaining an adequate and reliable production, transmission and distribution system; the cost of serving over 106,000 new customers expected to take service by 1993 as compared to 1984 (the test year in the company's last rate proceeding); and the effects of a 41% expected increase in inflation from the end of 1984 through 1993 as factors creating the need for higher rates.

The increases requested total 63.5 million dollars in 1993 and a step increase in 1994 of 34.4 million dollars. The company seeks a Commission determination that a 13.75% return on equity and a 9.22% overall rate of return is fair and reasonable for Tampa Electric Company. Tampa Electric Company filed new tariff schedules reflecting the proposed increases. The company did not seek an interim increase.

By Order No. PSC-92-0596-FOF-EI issued July 1, 1992, the Commission voted to suspend the permanent increase pending review. A prehearing conference was held on September 30, 1992 in Tallahassee, Florida. A customer service hearing was held on October 7, 1992 in Tampa, Florida. The final hearing was held on October 12-16, 1992 in Tallahassee, Florida.

TABLE OF CONTENTS

I. SUMMARY OF DECISION

We authorize an increase to Tampa Electric Company's annual revenues of $1,163,000 beginning February 4, 1993; an additional $17,412,000 increase beginning January, 1994; for a total increase of $18,575,000. The 1994 rate changes shall become effective with the first billing cycle of that month.

We have set the rate of return on common equity capital at 12%.

We establish an interim incentive to encourage Tampa Electric Company to maximize off-system sales of surplus capacity. We find that TECO should not be rewarded or penalized for its performance in the areas of residential rates, customer service and energy conservation.

II. TEST PERIOD

A. Test Year

The purpose of the test year is to represent the financial operations of a company during the period in which the new rates will be in effect. Based on the filing date of TECO's request for a rate increase, the first date that the new rates will be in effect is approximately February, 1993.

There are primarily two options for evaluating Tampa Electric Company's expected financial operations. The first option is to use a historical test year and make pro forma adjustments to it. The second is to use a projected test year. Both of these options have strengths and weaknesses.

implying that no obligation exists. Even under the pay-as-you-go method, estimates would be necessary for the use of projected test years. Further, FAS No. 106 requires companies to regularly review their calculations and make adjustments. The Commission could monitor such adjustments. Moreover, long-term estimates are routinely used in rate cases.

Regarding the amortization of the transition obligation and inter-generational inequity, TECO testified that, even with the amortization of the transition obligation, there is better matching and a more equitable allocation with FAS No. 106 than with the pay-as-you-go method. Also, amortizing the transition obligation is similar to catch-up methods for underrecovery of depreciation, for changing income tax treatments, and for pension accounting.

Regarding the possibility that funds collected through rates will not go to pay benefits, we note that funding of OPEBs would eliminate this possibility though it might not be the least cost method. We also note that FAS No. 106 requires a company to review the calculations of OPEB costs and make adjustments for material changes.

Accordingly, we find that FAS No. 106 shall be used by Tampa Electric for ratemaking purposes. We believe that the accrual accounting prescribed by FAS No. 106 is appropriate for ratemaking, because it matches the cost of OPEBs to the period when employees are working and earning the benefits. Continuing the pay-as-you-go method would result in a mismatch between the cost of an employee's service and the period when the employee provides that service. We acknowledge that FAS No. 106 costs are estimates but note that many costs recognized in rate cases are based on estimates. FAS No. 106 estimates are reviewed and can be monitored and corrected.

IV. RATE BASE

To establish TECO's overall revenue requirements, we must determine its rate base. The rate base represents that investment on which the company is entitled to earn a reasonable return. A utility's rate base is comprised of various components, including 1) plant-in-service, 2) depreciation reserve, 3) construction work in progress (CWIP) (where appropriate), 4) property held for future use, 5) fuel inventory, and 6) working capital.

TECO requested a rate base of $1,868,787,000 ($1,970,215,000 system) for the 1993 projected and $2,073,467,000 ($2,180,246,000 system) for the 1994 projected test year. Evidence developed during the course of the proceedings has led us to reduce the jurisdictional amounts to $1,749,355,000 for 1993 and $1,850,927,000 for 1994. We therefore approve the rate base summarized in the schedules attached to this Order as Appendix 1.

A. Methodology

We find that the use of a simple average methodology is not appropriate for computing the 1994 rate base.

In the company's original filing, a 13-month average was used to compute the rate base for the 1993 Projected Test Year. TECO requested that the Commission, after making staff adjustments to the 1993 data, use TECO's financial model to determine the appropriate additional revenue increase for the 1994 Subsequent Test Year. The company submitted very little additional information for 1994 based on its request to use its model to determine the 1994 revenue increase. TECO was asked to supply a number of stand-alone MFR schedules for the 1994 Subsequent Test Year. The schedules were prepared using a simple average rather than the standard 13-month average method. A comparison of the two methods shows that TECO's 1994 revenue requirement, before any staff adjustments, is $1,383,000 higher using the 13-month average. We believe that the 1994 data used to compute a revenue increase, if any, should be comparable to the data used to compute the 1993 revenue increase. Therefore, we find that a 13-month average shall be used to determine any revenue increase for the 1994 Subsequent Test Year. A comparison of the two methodologies is shown on the following tables (000's):

RATE BASE

	Simple ave.	13-month	Diff.
Plant in Service	$2,626,092	$2,625,595	($497)
Acc. Deprec.	(996,699)	(996,434)	265
Net P-I-S	1,629,393	1,629,161	(232)
CWIP	213,831	213,831	----
PHFU	62,036	62,036	----
Net Plant	1,905,260	1,905,028	(232)
Working Capital	168,207	166,926	(1281)
Total Rate Base	$2,073,467	$2,071,954	($1513)

NET OPERATING INCOME

Tot. Oper. Rev	$612,747	$612,747	----
Oper. Expenses:			
Operation-fuel	(7,561)	(7,561)	----
-other	(144,991)	(144,991)	----
Maintenance	(76,180)	(76,180)	----
Depre.& Amort.	(107,980)	(107,980)	----
Taxes-other	(41,960)	(41,960)	----
Curr. Inc. Taxes	(61,840)	(62,012)	172
Deferred Inc. Taxes	(2,820)	(2,821)	1
Charge/Eqiv ITC	4,214	4,214	----
Loss on Disposal	9	9	----
Total Oper. Expenses	(439,109)	(439,282)	173
Net Operating Income	$173,638	$173,465	($173)

B. Plant In Service

1. Hookers Point Generating Station

The Hookers Point units were removed from extended cold shutdown status and returned to service between October, 1990 and January, 1991. In its past expansion plans, Tampa Electric had planned to phase the five units into service between 1991 and 1993. Mr. Ramil testified that Tampa Electric accelerated the time frame for returning the units to service for three reasons: to enhance reliability of its electric system; to take advantage of an improved market for off-system sales; and to comply with the Commission's Order No. 22708, Docket No. 900071-EG, regarding the 1989 Christmas capacity shortfall. These arguments are discussed below.

a. Enhance reliability of its electric system

Mr. Ramil testified that the Hookers Point units were needed to provide enough peaking capacity to insure that the loss of load probability (LOLP) of Tampa Electric's system was not violated (Tr. 1981-7). Tampa Electric's reliability criterion, consisting of a minimum 20% reserve margin and a maximum 0.1 days/year LOLP, will be met with the inclusion of generation from the Hookers Point units. However, if such generation is not included, Tampa Electric's system LOLP will be well above 0.1 days/year between 1993 and 2000.

Mr. Stewart, Public Counsel's witness argued that Tampa Electric does not need the Hookers Point capacity. He correctly stated that the reserve margin will be reasonably adequate whether or not such capacity is included on Tampa Electric's system. However, Mr. Stewart did not discuss the possibility that such capacity was needed to meet the LOLP criteria, although he admitted that a utility should be reliable during the entire year and not just at peak times (Tr. 1273). It should be noted that, for the period from 1993 to 2000, Tampa Electric's summer reserve margin criteria is not violated, and the winter reserve margin is projected to be no lower than 16%, if Hookers Point was not returned to service.

Tampa Electric's system is over 3300 MW and the combined capacity of the five Hookers Point units is 210 MW. Tampa Electric's generating system is primarily baseloaded. Hookers Point capacity is used to meet peak and near peak loads, which occur many hours of the year thus greatly contributing to the reliability of the system. We agree that the Hookers Point units are needed for Tampa Electric to meet its reliability criteria.

b. To take advantage of an improved market for off-system sales

Exhibit 45 contains a "Summary for Appropriation Request" from June 1990 authorizing the return of the Hookers Point units to service. Tampa Electric's budget for 1990 did not include the start-up costs for all the units because it had not planned to return all five units to service at one time. Tampa Electric proposed selling 80 MW of capacity off-system between 1991 and 1994, which would generate more than enough revenue to offset the incremental cost of restarting all five units at once.

However, Public Counsel argued that the increased capacity from Hookers Point station would not be needed if Tampa Electric were not selling so much capacity off-system out of Big Bend 4. Public Counsel argued, in effect, that Tampa Electric is using more expensive generation out of Hookers Point to make cheaper generation from Big Bend 4 available to its wholesale customers, and that the retail ratepayers are subsidizing Tampa Electric's wholesale customers.

It should be noted here that the Commission imputed over $37 million of rate recovery for Big Bend 4 in Tampa Electric's last rate case in 1985, because the Commission determined that the utility did not need 145 MW of capacity from Big Bend 4 at that time. In doing so, the Commission provided an incentive for Tampa Electric to sell the excess capacity off-system.

c. To comply with the Commission's Order No. 22708, Docket No. 900071-EG, regarding the 1989 Christmas capacity shortfall

Mr. Ramil testified that Tampa Electric followed the Commission's recommendation that utilities return their long-term reserve standby units to service earlier (Tr. 1968-9, 1995-7). At page 9, section 9, of Order 22708, the Commission stated that

> Where practicable, cold standby units should be returned to service earlier, or their status should be enhanced from a state of "cold" standby to "hot" standby.

The Commission did not order Tampa Electric, or any other utility, to bring its plants back early, but only to consider doing so where practicable. Tampa Electric considered this advice and determined that it was prudent to accelerate plans to return the Hookers Point units to service. We agree with Tampa Electric's decision.

There was considerable evidence in this case concerning the prudence of returning the Hookers Point units to service. Some of the evidence, especially that concerning bringing the units back to bolster off-system sales, could imply that Hookers Point should be removed from retail rate base. However, the weight of the evidence surrounding Tampa Electric's need for the units to ensure system reliability and adequate LOLP leads us to conclude that the Hookers Point units are needed, and that their inclusion in rate base is appropriate. Accordingly, we find that the Hookers Point units shall be included as plant in service in the rate base of Tampa Electric Company.

2. <u>Over Accrual of AFUDC on Work Order K23</u>

Based on findings in the Staff Audit Report, Disclosure No. 8 (Exh.83,p.labeled 17), staff proposed that adjustments be made to reduce the 1993 Projected Test Year Rate Base by $95,275, to reduce Accumulated Depreciation by $16,952, and to reduce Depreciation Expense by $4,002. The report stated that the company continued to accrue AFUDC on a project for several months after all major work on the project had been completed. For the 1994 Subsequent Test Year, staff proposed to reduce Rate Base by $95,275, reduce Accumulated Depreciation by $20,954, and reduce Depreciation Expense by $4,002. The company reviewed this finding and in its response to the audit and agreed that the adjustments should be made. No other party took a position on the issue.

Therefore, we reduce the 1993 Projected Test Year Rate Base by $95,275, reduce Accumulated Depreciation by $16,952, and reduce Depreciation Expense by $4,002. For the 1994 Subsequent Test Year, we reduce Rate Base by $95,275, reduce Accumulated Depreciation by $20,954, and reduce Depreciation Expense by $4,002.

3. Compliance with Rule 25-6.0141(1)(e), Florida Administrative Code

In pertinent part, Rule 25-6.0141(1)(e), Florida Administrative Code states "Account 107, Construction Work in Progress shall be subdivided so as to segregate the cost of construction projects that are eligible for AFUDC from the cost of construction that are ineligible for AFUDC."

Audit Exception No. 1 of the Staff Audit Report states that TECO is in violation of Rule 25-6.0141(1)(e), F.A.C. The report states that the company is not subdividing Account 107 in the General Ledger and, therefore, is in violation of this section of the rule. The company responds that it has always complied with the rule that Account 107 be subdivided. TECO maintains that the rule does not specify the method of segregation.

The company prepares a monthly analysis of projects which are eligible as well as ineligible for AFUDC. These totals are included in two subsidiary ledgers (Exh.62-composite; Informal Data Request 24,p.1). Report FT003130 (p.7-10) lists all ineligible projects by project number. The general ledger contains total CWIP by month; and, the remainder, after subtracting the total of all ineligible projects, is the total of eligible projects.

The list of ineligible projects is at least four pages long. The inclusion of this level of detail in the general journal is not required. A general journal by definition need not contain a detailed breakdown of all accounts as long as there are sufficient other ledgers or subsidiary ledgers which are detailed and allow the search for, or confirmation of, specific accounting information. Part of the required audit work of TECO was an examination of projects eligible for AFUDC. There is no indication in the audit findings that suggest that the auditors had any difficulty in locating eligible or ineligible projects during their examination of construction projects. It appears that the auditor has taken the very conservative position that the rule requires that Account 107 be segregated in the general ledger itself.

The rule, however, does not say that; rather, the rule only states that Account 107 be segregated. TECO has segregated Account 107 in subsidiary ledgers rather than the general journal.

We believe that the level of detail contained in the subsidiary ledgers is adequate. Therefore, we find that TECO shall not be required to change its present method of recording and accounting for eligible and ineligible AFUDC projects in its subsidiary journals.

4. Adjustments Related to Dravo-Wellman Bucket Unloader Contract

Ms. Bouckaert, staff's witness, proposed through testimony (TR 1285) and Audit Disclosure Number 9 in the Staff Audit Report, adjustments to reduce Plant in Service \$46,028 (\$52,334 System) and reduce Accumulated Depreciation \$4,987 (\$5,670 System) for the 1993 projected test year. The recommended adjustments for 1994 are to reduce Plant in Service \$45,588 (\$52,334 System) and Accumulated Depreciation by \$6,086 (\$7,763 System) for the 1994 subsequent test year. (EX 84 Selected Audit Work Papers).

Audit Disclosure No. 9 states that TECO contracted with Dravo-Wellman to install a bucket coal unloader at the Gannon Station. The original contract price was \$2,841,750 and the original budget including overhead was \$3,172,000. Because of time delays and because the machine unloaded coal below the minimum unloading rate the parties entered into a settlement lowering the contract amount by \$1,525,000 from \$2,841,750 to \$1,316,750. As a result of the reduction in contract price, TECO overpaid Dravo-Wellman by \$775,000 since TECO had been making progress payments based on the original contract. The \$775,000 amount related to the refund had accrued AFUDC during the construction period, but upon refund of the overpayment, no AFUDC was removed from CWIP.

TECO believes the funds were properly expended, the company was without the use of the funds, and the accrued AFUDC should remain. Audit staff's position is that the \$775,000 was a refund of an overpayment and was not eligible for AFUDC.

Since the contractor agreed to accept less than one-half of the contract amount, it is clear that the contractor performed poorly on this contract. The actual cost to TECO includes the AFUDC on the overpayment. In summary, a contractor performed poorly and TECO sought and received such a large settlement that the contractor was required to make a refund.

Our rules do not specifically address AFUDC on amounts later refunded. It is preferable to address unusual events individually rather than through rule amendments. Since our rules do not address this situation we believe that it is within the discretion of the Commission to make adjustments to plant, accumulated depreciation and depreciation expense, for both the 1993 and 1994 test years. However, we make no adjustments, as TECO has taken the appropriate action to reasonably limit the cost of the unloader.

5. Adjustments Related to Planning and Pre-engineering Expenses Incurred at Big Bend 4

Concurrently with the staff financial audit, an engineering audit of expenses associated with Big Bend 4 (BB4) was also conducted. The recommendations of this Engineering Audit were contained in the Staff Audit Report. This issue was developed as a result of Audit Disclosure No. 2 in that report. Total architect\engineering costs from March, 1974 until March, 1978, when the final design of BB4 was authorized, amounted to $3,544,000. Of this total, $2,744,000 of these costs related to engineering design which had to be redone because of scope changes.

The audit opinion is that "Normally planning costs can be a part of project costs if they lead into an approved project in a reasonable span of time. In this project there were excessive delays from 1971 to 1978 due to adequate reserve capacities, and the costs do not reflect true project costs."

The report recommended that engineering costs of $2,744,000 should have been expensed rather than capitalized. Various design and scope changes caused rework which replaced $2,744,000 of original design work. The exact origin or cause of these changes cannot reasonably be determined at this time. The company in its response to the audit disclosure, points out that these changes were the proper response to variations in conditions such as economic and environmental changes which were outside the scope of their company operations. The company does not disagree that some additional costs may have been incurred; however, there is nothing in the record that suggests that these expenses might have been imprudent.

In spite of the luxury of hindsight, which does suggest that some of these expenses might properly have been expensed, we lack the detailed information to determine which expenses would appropriately be disallowed.

Overall, the record evidence in this proceeding does not support reversing Commission Order 15451, which allowed these charges in Rate Base. Therefore, we find that these charges shall remain as capitalized expenditures in TECO's Rate Base.

6. Adjustments Related to Architect/Engineering Expenses Incurred at Big Bend 4 Generating Station

Mr. Davis testified that the additional Architect/Engineering costs of $513,000 should have been expensed rather than capitalized in Audit Disclosure No.3. The circumstances involved in the construction of Big Bend 4 (BB4) were necessarily very complex. The record shows that numerous delays were encountered, but it is not currently reasonably possible to reconstruct the origin and circumstances of those delays. The company position states that costs for these drawings were part of the project cost accepted for capitalization in Order 15451 (TECO Brief, p.32), and there is no substantive evidence in the record to support reversal of that action.

Therefore, we find that the $513,000 expenditure for additional architect/engineering drawings related to Big Bend Unit 4 shall remain capitalized.

7. Inclusion of Sebring Utilities Generating System and Associated Transmission Facilities in Rate Base

In February, 1991, TECO purchased from the Sebring Utilities Commission (SUC) the generating units at the Phillips and Dinner Lake sites, associated transmission facilities, and agreed to provide full requirements service to Sebring's customers. We consider whether or not the purchase of the generating and transmission facilities is appropriate for inclusion in rate base.

Mr. Ramil, TECO's witness, stated that the SUC plants purchased "are economical sources of peaking and intermediate capacity and provide fuel savings to the Tampa Electric System." He further stated that the Phillips site is a desirable potential site for additional peaking and intermediate capacity.

TECO provided economic analyses of the SUC purchase in Late-filed Exhibits 128 and 129. Public Counsel correctly notes that in Late-filed Exhibit 128, the page entitled "Retail Jurisdictional Benefits from the Sebring Transaction" is on a system basis. The analysis shows the SUC purchase to have a positive cumulative present worth in each year for 1993-2002. However, TECO has included 1991 and 1992 fuel savings with 1993 fuel savings. This has the effect of making the transaction appear more cost-effective than it really is. A more accurate analysis would have included the costs (revenue requirements), and benefits (fuel savings and non-fuel revenues) for 1991 and 1992. Estimating these amounts shows the transaction to still be cost-effective, but with the cumulative present worth of the benefits not becoming positive until 1998.

Late-filed Exhibit 129 compares the effects on TECO's system with and without the SUC units. This analysis shows an increase in cost of approximately $28 million for the period 1993-2002 if the SUC units are excluded.

The addition of the SUC generating plants will only marginally improve TECO's reserve margin. TECO's 1992/93 winter reserve margin with the SUC units is forecasted to be 28%, but excluding the SUC units lowers the 92/93 reserve margin only to 27%. Throughout the forecasted period of 1992-2002, including the SUC units improves TECO's reserve margin by only one or two percentage points. TECO's system is primarily baseloaded, and the SUC units, which are peaking and intermediate in nature, will contribute to the reliability of the system.

We believe that the evidence in the record shows the addition of the SUC units are cost effective and will contribute to maintaining TECO's reserve margin. Also, the Phillips site provides TECO with an a site available for peaking and intermediate capacity to meet future needs. Therefore, we find that these units shall be included in rate base.

8. <u>Appropriate Rate Base Accounting Treatment for Sebring Utilities Commission Generating and Associated Transmission Facilities</u>

On February 28, 1991, TECO purchased some production and transmission plant assets from Sebring Utilities Commission at less than net book value, thereby creating a negative acquisition adjustment of $10,728,866.(MFR Schedule B-11, Composite EXH 3) The company paid $37,000,000 for assets having a net book value of $47,728,866. The initial entries TECO made to plant, Account 101, and reserve, Account 108, associated with this purchase were $67,367,000 and $18,461,000, respectively, with a credit of $10,728,866 to Account 114, Electric Plant Acquisition Adjustments.(Composite EXH 62, p. 19-24) Amortization of this acquisition adjustment was initiated based on a period of 23 years with a charge to Account 115, Accumulated Provision for

Amortization of Electric Plant Acquisition Adjustments and a credit to Account 406, Amortization of Electric Plant Acquisition Adjustments.(Schedule B-11, Composite EXH 3) The amortization period was based on the remaining life of facilities purchased.

In December 1991, the Federal Energy Regulatory Commission (FERC) directed TECO to treat the acquisition adjustment as a credit to the reserve, thereby restating the reserve of the purchased assets by the acquisition adjustment amount.(MFR Schedule B-11, Composite EXH 3) This may be predicated on an assumption that when plant is sold for less than book value, the market value is a better indicator than net book value. Whether net book value is reduced by an acquisition adjustment or by increasing accumulated depreciation, the result is to reduce the plant amounts to the total actually paid by TECO.

In accord with FERC's directive, TECO transferred the balances in Accounts 114 and 115 to the reserve, Account 108.(EXH 62) The acquisition adjustment is recorded and is being maintained as a separate subaccount in the reserve. (Schedule B-8b, p. 3-10, Composite EXH 3) In this respect, it has the same effect as if the amount were recorded in Account 114. We believe this treatment is satisfactory.

Accordingly, we find that the rate base accounting treatment for the Sebring Utilities Commission assets utilized by TECO in its filing for the 1993 and 1994 test years is appropriate.

9. Total Level of Plant In Service

We find that the appropriate jurisdictional Plant in Service is $2,437,233,000 for 1993 and $2,561,446,000 for 1994 based on the adjustments made concerning the overaccrual of AFUDC, the revised jurisdictional separation factors, the use of a thirteen month average for 1994, certain affiliated transactions and the over projection of plant in service discussed below.

Mr. Schultz, OPC's witness, testified in support of adjustments to plant in service and accumulated provision for depreciation based on a comparison between actual plant and accumulated depreciation for the months of December, 1991 through July, 1992. Schedule 5 of his prefiled testimony indicates that the actual plant balance for July 1992 was only $2,512,255,000 and the projected balance $2,528,129,000.

Exhibit 50, page 2 of 3, shows the projected plant in service for July 1992 (revised forecast) to be $2,529,311,000. Actual plant in service for July 1992 is only $2,512,255,000 which is $17,056,000 less. Since the revised forecast uses actual plant balances through January of 1992, this difference accumulated in only six months.

TECO did not provide any detailed explanation of the over projection of plant or any specifics showing when the growth rate of actual plant would accelerate to reduce or eliminate the over projection. Accordingly, we make adjustments to reduce plant in service, increase reserve for depreciation and amortization (adjustment to increase the reserve reduces the absolute dollar amount of the negative reserve), and reduce depreciation and amortization expense of the following:

1993 (000's)

	System	Jurisdictional
Plant	($17,056)	($15,910)
Reserve	$582	$543
Depreciation Expense	($635)	($592)

1994 (000's)

	System	Jurisdictional
Plant	($17,056)	($15,843)
Reserve	$1,217	$1,131
Depreciation Expense	($635)	($590)

These adjustments to plant, depreciation expense and the reserve are calculated based on the latest actual amounts. Actual system depreciation and amortization expense for the month of July 1992 of $7,796,000 was .3103% of the July plant balance of $2,512,255,000. That percentage applied to the $17,056,000 difference between actual plant and projected results in monthly adjustments to depreciation and amortization expense and the related reserve of $52,925.

C. Construction Work In Progress

1. Effect of Including CWIP in Rate Base on TECO's Financial Integrity

Tampa Electric proposes an amount of CWIP in rate base it believes is essential to maintain its financial integrity and credit rating. The calculations for the company are on a total company basis after adjustments for purchased power capacity and off-system sales.

Public Counsel believes the amount of CWIP proposed by the Company is inaccurate for several reasons. First, OPC believes Tampa Electric will be able to receive additional revenues if the Company asks for wholesale rate relief. OPC also points out that Tampa Electric did not include the cash flows from implementing FAS 106 when calculating the percent of funds generated internally. OPC further believes Tampa Electric has understated off-system sales for 1993, and has over projected the amount of construction it will incur during the test years. (TR 258, 598-600) In OPC's opinion, these misstatements understate the financial integrity of the company. Tampa Electric actually has more revenues available, and consequently, better financial integrity.

We based the financial integrity test on the regulated electric operations. Although Mr. Abrams testified on behalf of Tampa Electric that the rating agencies perform a credit analysis on a total company basis, the Commission can only be responsible for the regulated portion of Tampa Electric Company. The Commission considers the financial risks and strength of the regulated utility, while the wholesale operations are under the jurisdiction of the Federal Energy Regulatory Commission.

Mr. Abrams also states that only 6% of total company sales come from the wholesale business; therefore, any wholesale rate relief will have a marginal effect on the financial integrity. If we calculate Tampa Electric's financial integrity on a regulated rather than total company basis, it will alleviate OPC's concern that the financial integrity has been understated due to possible wholesale revenues.

Tampa Electric did not include the cash flows from implementing FAS 106 in its original financial integrity study. (TR 1870) The company did, however, calculate the effect of FAS 106 on financial integrity in a late-filed hearing exhibit No. 121. We considered the cash flows from FAS 106 when calculating the financial integrity for the regulated operations of Tampa Electric.

We agree with the OPC that the company may have overstated the amount of construction projected for 1993 and 1994. Overstating construction has the effect of overstating the amount of CWIP that should be included in rate base. We have adjusted the CWIP balance to reflect the over projected construction when considering the financial integrity of Tampa Electric.

OPC recommends that off-system sales be included in jurisdictional revenues, but not at the amount projected by Tampa Electric. OPC notes that the revenues collected through August 1992 are already higher than the 1993 full year forecast; therefore, the Company has understated off-system sales. If an incorrect amount of revenues is included in the regulated jurisdiction, it will affect Tampa Electric's financial integrity. As discussed at length beginning at page 82 of this Order, we have voted to remove off-system sales from jurisdictional revenues and included those revenues in the Fuel and Purchase Power Cost Recovery Clause. This eliminates the problems associated with under or over forecasting the level of off-system sales when setting base rates and when analyzing financial integrity.

Tampa Electric may not have correctly accounted for potential revenues from its wholesale business and FAS 106, or projected off-system sales precisely. In addition, we believe the proposed amount of CWIP in rate base is overstated.

Accordingly, we find that the company has not properly calculated the effects of including Construction Work in Progress in its rate base on its financial integrity.

2. Appropriate Level of Construction Work in Progress (CWIP) in Rate Base

We find that the Company has over projected its CWIP balance by \$11,972,000 (\$12,065,000 system) in 1993 and by \$11,959,000 (\$12,065,000 system) in 1994. In addition, after considering an acceptable level of financial integrity for Tampa Electric, we reduce the level of CWIP in rate base to \$18,793,000 for 1993 and \$48,017,000 for 1994.

A comparison of monthly CWIP amounts based on the original 1992 forecast contained in the MFRs and the revised monthly CWIP amounts for 1992 provided in Late-filed Exhibit 69 shows significant differences.

	ORIGINAL	REVISED	ACTUAL
December 1991	$13,032	$18,698	$18,698
January 1992	19,842	19,842	19,842
February 1992	26,326	20,121	23,180
March 1992	34,599	21,652	24,481
April 1992	38,868	28,024	27,541
May 1992	42,636	33,992	25,947
June 1992	44,185	36,035	21,110
July 1992	47,501	42,876	30,811
August 1992	50,567	46,725	
September 1992	56,700	54,230	
October 1992	58,771	58,121	
November 1992	65,649	67,701	
December 1992	56,194	52,818	

A review of the above figures indicates considerable variance between TECO's projections of CWIP and actual CWIP. The original 1992 was based on numbers through November, 1991. TECO's projection of CWIP for December, 1991 was $13,032,000. Actual CWIP was $18,698,000. In projecting CWIP just one month into the future, TECO had over projected the balance by $5,666,000. TECO used actual numbers through January, 1992 in projecting its revised budget for 1992. By July of 1992, the difference between TECO's second projection of CWIP for 1992 and actual CWIP was $12,065,000. Since projected plant in service for July exceeded actual plant in service by $17,056,000 the excess projected CWIP is not offset by an under projection of plant. Therefore, we reduce total projected CWIP for 1993 and 1994 by $11,972,000 ($12,065,000 system) and 11,959,000 ($12,065,000 system).

We have considered the amount of eligible CWIP needed in rate base to maintain Tampa Electric's financial integrity. The financial ratios considered include interest coverage and total debt to total capital. We note that two of the ratios calculated, funds flow interest coverage and funds from operations as a percentage of average total debt, are above the Standard & Poors standard for AA-rated companies even with no rate increase. Also, the level of net cash flow to capital expenditures set for AA-rated companies cannot be reached even after considering Tampa Electric's full rate request.

Interest coverage after AFUDC has been identified by the several witnesses as one of the most important indicators of financial integrity. We have calculated a jurisdictional interest coverage for Tampa Electric after all other Commission approved adjustments. The coverage is calculated on a jurisdictional basis rather than total company because the Commission can only be responsible for maintaining the integrity and strength of the regulated utility.

TECO's witness Mr. Abrams, who is employed by the Duff & Phelps rating agency, testifies that a 4.0 times interest coverage is appropriate for a AA-rated electric utility. Standard and Poor's, another rating agency, indicates that interest coverage for a AA-rated electric utility should be above 3.5 times. We believe the Company should be allowed enough CWIP in rate base to maintain an interest coverage of approximately 3.75 times. Therefore, in 1993, we allow only the $18,793,000 of CWIP ineligible for AFUDC in rate base. We have calculated, on a jurisdictional basis, that eliminating the remaining CWIP in 1993 will allow Tampa Electric a 4.16 times interest coverage.

In 1994, we allow $48,017,000 of CWIP in rate base. Disallowing the remaining CWIP in 1994 will jurisdictionally allow Tampa Electric a 3.75 times interest coverage. Mr. Abrams testifies that Tampa Electric will be in the peak year of its construction program in 1994. Based on this testimony, we believe that if Tampa Electric does not fall below the interest coverage standard for a AA-rated electric utility in the critical year of 1994, the financial pressure on the company caused by the construction program will begin to moderate.

Finally, a AA-rated company should maintain a debt ratio below 46%. These adjustments to the allowed level of CWIP do not affect Tampa Electric's requested debt ratios of 41% in 1993 and 42% in 1994. Therefore, Tampa Electric is within the debt ratio range needed to maintain a AA bond rating.

3. Plant Held for Future Use - Gannon Coal Yard

Tampa Electric purchased 11 acres of land in 1982 from Port Sutton, Inc. to support expansion of the Gannon Station coal yard when Gannon Station converted from oil to coal. A small part (0.66 acre) of this land, parcel B, cannot currently be used for coal storage because a large sulfur storage tank sits on the land. The sulfur tank will be used until 1999 pursuant to a pre-existing lease agreement between the tank user and Port Sutton. Tampa Electric testified that the entire land purchase was one transaction; Tampa Electric was not able to buy the land needed for Gannon's coal yard expansion without purchasing parcel B as well. Mr. Ramil testified that Tampa Electric was given a good deal on the land in exchange for allowing Port Sutton to continue receiving payments for the storage tank until expiration of the lease.

Staff's witness, Jack Hoyt, proposed in the Staff Audit Report and through testimony that $35,515 ($36,429 system) be transferred from Account 105 (Electric Plant Held for Future Use) to Account 121 (Non-Utility Plant). The Commission ordered Tampa Electric to put the dollar amount in question into Plant Held For Future Use in Order No. 17281, Docket No. 860001-EI. Mr. Ramil testified that parcel B "may indeed be useful for the plant site" once the lease on the tank expires. Therefore, we find that the level of Plant Held for Future Use for the Gannon Coal Yard is appropriate.

4. Plant Held for Future Use - Port Manatee Plant Site

Power plant sites in Florida are becoming increasingly more difficult to find, purchase, and permit. Tampa Electric has a potential power plant site at Port Manatee. Utilities purchase power plant sites in advance, because the value of the land will generally appreciate at a rate greater than the utility's overall rate of return. If the Commission found that the Port Manatee site was an imprudent investment and did not allow Tampa Electric to earn a rate of return on the property, Tampa Electric would be encouraged to sell the site now. Tampa Electric would then have to search for, and purchase, another site for a future power plant, at much greater cost.

Public Counsel argues that Tampa Electric has no current plans for the Port Manatee plant site. Staff agrees that, at the current time, the company has not identified a particular generating unit to be built at the site. However, as discussed before, it will be more difficult to find an alternate plant site in the future. By allowing the Port Manatee site to remain in rate base, Tampa Electric will already have a viable generating site for future power plants. The Power Plant Siting Task Force recognized that the Port Manatee location was a viable generating site, although the task force ultimately recommended the Polk County location for Tampa Electric's next plant. Accordingly, we find that the requested level of Plant Held for Future Use in the amount of $4,640,000 ($5,094,000 system) for 1993 and $4,692,000 ($5,172,000 system) for 1994 associated with the Port Manatee plant site is appropriate.

5. Reclassification of Substation Sites as Non-utility

The Staff Audit Report, Audit Disclosure No. 7, stated that three substation sites listed in the MFRs for the Projected Test Year ended December 31, 1993 had been transferred out of Account 105, Property Held for Future Use, to Account 121, Non-Utility

Property, in March of 1992. The Audit Report, which reported on the year ended December 31, 1991, recommended that an reduction of $86,000 be made to Account 105 to reflect this transfer which took place prior to the test year, but were still listed in the MFRs. Since the company had in fact effected the transfer in 1992, the 13-month average that was listed in the MFRs for the 1993 and 1994 Projected Test Years was $52,000. The company in its response to the audit agreed to the reduction. We accept and approve this reduction to Rate Base of $52,000. Since these sites contained no depreciable structures, there is no reduction for Accumulated Depreciation or Depreciation Expense.

6. Total Level of Plant Held for Future Use

Incorporating the adjustments made related to the reclassification of the three substation sites, the reclassification of the Jackson Road substation site and the revised jurisdictional separation, we find that the appropriate jurisdictional amounts of plant held for future use are $46,909,000 for the Projected Test Year 1993 and $60,382,000 for the Subsequent Test Year 1994.

In the past, Commission rate case decisions have reflected the importance of retaining certain properties held for future use in view of Florida's projected growth rate, the burden on the utilities to meet this growth rate, and the expense that might be incurred if the properties were sold and had to be replaced in the future at greater cost. One of the most important aspects of long range planning is the identification and acquisition of land for future system expansion requirements.

Public Counsel's witness, Mr. Schultz, applied a 10-year rule to plant held for future use, suggesting that property either owned by Tampa Electric for longer than ten years or whose projected in-service date is greater than ten years in the future should be removed from rate base. We disagree with this methodology because it arbitrarily disallows rate recovery for power plant, distribution substation, and transmission substation sites that Tampa Electric plans to use to meet future growth beyond a point in time ten years from now. It is well known that, in Florida, these sites are becoming increasingly more difficult to find, purchase, and permit. This is especially true for Tampa Electric Company, since a major part of its relatively small service territory is urban.

Another point to consider is that Tampa Electric's future system expansion plans must be coordinated with Hillsborough