MACFARLANE AUSLEY FERGUSON & MCMULLEN

ORIGINAL FILE COPY

ATTORNEYS AND COUNSELORS AT LAW

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

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

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

May 7, 1996

IN REPLY REFER TO:

HAND DELIVERY

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.)

~~223 p~~ 201 p.

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TAMPA ELECTRIC COMPANY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 960409-EI

TESTIMONY

AND EXHIBIT OF

THOMAS L. HERNANDEZ

201

TAMPA ELECTRIC COMPANY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 960409-EI

TESTIMONY

AND EXHIBIT OF

THOMAS L. HERNANDEZ

BEFORE THE PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

THOMAS L. HERNANDEZ

Q. Please state your name, address and occupation.

A. My name is Thomas L. Hernandez. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am the Director of Resource Planning at Tampa Electric Company.

Q. What is your educational background and business experience?

A. I graduated from Louisiana State University in August 1982 with a Bachelor of Science degree in Chemical Engineering. I have been employed by Tampa Electric in various engineering positions since August 1982. My current position is that of Director of Resource Planning, responsible for system reliability studies, energy resource planning studies, business development studies and regulatory support. I represent Tampa Electric as the Chairman of the Generation Task Force (GTF) of the Florida Electric Power Coordinating Group, Inc. (FCG). I also represent Tampa Electric on the EEI Transmission Subject

Area Committee (SAC), the EEI Generation SAC, and the Southeastern Electric Reliability Council (SERC) Engineering Committee.

Q. Mr. Hernandez, have you previously testified before this Commission?

A. Yes. I testified before this Commission in the last annual planning hearing, Docket No. 910004-EU. I also submitted testimony on Tampa Electric's Integrated Resource Planning (IRP) process in Docket No. 930551-EI, which dealt with the numeric conservation goals for Tampa Electric.

Q. Have you previously presented summaries of Tampa Electric's Ten Year Site Plans before this Commission?

A. Yes. I presented a summary of Tampa Electric's Ten Year Site Plan at the FPSC Staff Workshop to Review Ten Year Site Plans on August 7, 1992. I also provided a description of Tampa Electric's planning process at the FPSC Staff workshop on March 3, 1994. As Chairman of the Generation Task Force, I also prepared summaries of the FCG Peninsular Florida Ten Year Plan for presentation at the FPSC Staff Workshop to review Ten Year Site Plans held on August 19, 1994 and August 16, 1995.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain the analytical basis underlying Tampa Electric's conclusion that Polk Unit One is a reasonable and prudent addition to Tampa Electric's generating system and remains the most cost-effective alternative for meeting Tampa Electric's need for capacity. The need for the Polk One IGCC unit was originally determined and has been verified since using Tampa Electric's Integrated Resource Planning process. My testimony explains the Tampa Electric IRP process methodology and the associated forecasts, base assumptions, system reliability analyses, and economic analyses of generation and energy management alternatives used to develop Tampa Electric's energy resource plans. My testimony also explains the ongoing review of key planning assumptions and forecasts, and the results of several cost-effectiveness studies completed during construction of the Polk IGCC unit since issuance of the Commission's Order No. PSC-92-0002-FOF-EI approving the need.

Q. What exhibits are you sponsoring as part of your testimony in this proceeding?

A. My Exhibit No.__(TLH-1), consisting of eight documents, was prepared under my direction and supervision. It consists of: a detailed description of Tampa Electric's IRP process; a summary of Tampa Electric's Ten Year Site Plans (1992-1996); a summary of the Polk Unit One construction cost estimates; comparisons of key planning assumptions and forecasts; a summary of the Polk Unit One cost-effectiveness studies, and interrogatory responses prepared under my direction and supervision.

POLK UNIT ONE NEED

Q. Why is Polk Unit One needed?

A. Tampa Electric is required by law to provide reasonably sufficient, adequate and efficient service to each person who applies for service in the company's service area. In order to meet this obligation, Tampa Electric must construct and maintain an adequate and reliable production, transmission and distribution system. The company is dedicated to the efficient use of energy and has an aggressive conservation program that has been effective to date and which will continue to reduce future capital expenditures from what they would have been without such a program. Nevertheless, from time to time the continued growth in the number of customers on our system requires the construction of new generating capacity.

Polk Unit One is a state-of-the-art 250 megawatt integrated gasification combined cycle (IGCC) unit which the company is constructing in order to enable itself to cost-effectively meet the additional capacity needs on its system while maintaining an adequate reserve margin and the company's reliability criteria of 0.1 days/year loss of load probability.

Q. Has the need for Polk Unit One been addressed by the Commission?

A. Yes it has. After extensive review in Docket No. 910883-EI the Commission found that Tampa Electric had provided sufficient information on the need for additional capacity, the site, design, and engineering characteristics of Polk Unit One to enable the Commission to conclude that Polk Unit One was the most cost-effective generation alternative available to Tampa Electric. The Commission subsequently approved the need in Order No. PSC-92-0002-FOF-EI issued in Docket No. 910883-EI, <u>In re: Petition for Determination of Need for a Proposed Electrical Power Plant and Related Facilities in Polk County by Tampa Electric Company.</u>

Q. Was the Commission's determination of need specific to an IGCC unit?

A. Yes. The Commission conditioned its approval of Polk Unit One on Tampa Electric receiving $120 million in funding from the Department of Energy which is only available for construction of an IGCC unit. It is this funding, along with the low operating cost of the unit, that makes the IGCC unit the lowest cost unit addition for our ratepayers.

Integrated Resource Planning Process Overview

Q. Please describe the process used to identify the need for Polk Unit One and to determine the cost-effectiveness of the project on an ongoing basis.

A. We used our IRP methodology, as described in Document No. 1 of my Exhibit, to evaluate the cost-effectiveness of the Polk Unit One project. The objective of our IRP process is to evaluate, on a fair and consistent basis, numerous combinations of demand side and supply side resources in order to determine how to satisfy future energy requirements in a cost-effective and reliable manner.

REVIEW OF PLAN AND IGCC COST-EFFECTIVENESS

Continued Need for Polk Unit One

Q. In the years subsequent to the Commission's determination that Polk Unit One should be built, has Tampa Electric periodically reviewed the continuing need for this unit to meet the company's energy resource requirements?

A. Yes. The need for the Polk One IGCC unit was identified in 1991 to maintain our electric system reliability and integrity at a reasonable cost. The plant is still needed in 1996. Under my direction and supervision, Tampa Electric annually reviews key planning assumptions and forecasts as standard business practice. In addition, numerous economic evaluations of the IGCC project have been completed during the construction of Polk Unit One. As part of this process, all reasonable conservation measures that might delay the timing of need for Polk Unit One were included in each evaluation. The large amount of additional DSM resources that would have to be developed and implemented in order to have any effect on the Polk Unit One timing was not reasonable. In addition, the Commission in Docket No. 910883-EI specifically found that: "it appears that further timely and cost-effective conservation measures can not reliably defer the need for the IGCC unit." (Docket No. 910883-EI, Order No. PSC-92-0002-FOF-EI, at page 17.) The Florida Supreme Court later affirmed that decision. In each evaluation, the IGCC technology selected for Polk Unit One has been shown to be the most cost-effective alternative available.

Q. When does Tampa Electric plan to place Polk Unit One into commercial operation?

A. Polk Unit One will be placed in service on or about October 15, 1996. However, at the time of the need hearings for Polk Unit One, the most cost-effective plan was to construct the unit as a phased construction IGCC plant with a commercial operation date of July 1, 1995 for the General Electric 7F advanced combustion turbine and commercial operation as an IGCC unit by July 1, 1996. As a part of our ongoing economic and system reliability analyses, we determined during August 1993 that the advanced combustion turbine could be deferred from July 1995 to July 1996 while cost-effectively maintaining system reliability. Thus, we deferred the combustion turbine as was shown in our 1994 Ten Year Site Plan. That deferral postponed revenue requirements that would have otherwise occurred beginning July 1995. A summary of the recommended expansion plans for each of our Ten Year Site Plans from 1992 through 1996 is provided in Document No. 2 of my Exhibit.

Q. What accounts for the change in the projected commercial operation date from the originally forecasted July 1996 to the current date of October 15, 1996?

A. The change in the commercial operation date from July 1996 to October 1996 was reported in our 1995 Ten Year Site Plan as shown in Document No. 2 of my Exhibit. The primary reason was a delay in obtaining the necessary federal permit required to commence construction at the Polk Power Station site. The actual field construction start date was May 1994 but was originally anticipated to be January 1994, as shown in Tampa Electric's 1992 and 1993 Ten Year Site Plans. This four month delay in construction resulted in a three month delay in the commercial operation date.

Q. Should the commercial operation date of Polk Unit One be deferred beyond October 1996?

A. No. There were significant costs associated with deferring the Polk Unit One in-service date beyond October 1996. Deferring the project beyond October 1996 would result in additional fuel and purchased power costs to our retail Customers since Polk Unit One will be the first unit dispatched on our system on an incremental cost basis, and one of the lowest cost units to operate in Peninsular Florida. Another consideration is the level of construction expenses that have been devoted to the project. By year end 1994, we had spent approximately $200 million net of DOE reimbursements, or almost 40% of the total construction costs. By year-end 1995, our total expenditure was approximately $410 million net of DOE reimbursements, over 80% of the total construction costs. Therefore, from a practical and economic perspective, the avoidance or further deferral of Polk Unit One was not a prudent, viable alternative.

Q. How did you verify the continued cost-effectiveness of Polk Unit One?

A. Several economic evaluations of Tampa Electric's generation expansion plan have been completed since the Determination of Need proceedings in December 1991. In each review, the continued cost-effectiveness of Polk Unit One was examined in light of more current data and assumptions. The evaluations supported the development of the company's annual planning efforts as well as the annual Ten Year Site Plan filing and afforded Tampa Electric an opportunity to re-examine its expansion plan in light of revised assumptions. Each Ten Year Site Plan submitted by Tampa Electric from 1992 through 1996 provided updates to the Commission on both the cost of Polk Unit One as well as changes to the timing and type of future generating plant additions. A summary of the plan and Polk Unit One costs for each year 1992 through 1996 is shown in Document No. 4 of my Exhibit.

Q. What were the results of your cost-effectiveness evaluations?

A. Document No. 4 of my Exhibit summarizes the five cost-effectiveness evaluations of the Polk IGCC project that were completed based on various stages of construction between 1992 and 1996. The format and methodology of the original studies were revised to more accurately reflect all of the factors considered by management. In developing the costs associated with the combined cycle unit, the costs incurred up to the time of the study for the development and construction of the IGCC unit were included as sunk costs. For example, the 1994 cost-effectiveness study includes all actual project expenses and commitments through April 1994 for both the IGCC unit and combined cycle unit alternatives. The remaining estimated costs to complete the IGCC unit or combined cycle unit are then included separately for each plan.

This analysis methodology of using costs incurred up to the time of the study to determine sunk costs is conservative in that contractual commitments and associated contract cancellation penalties are excluded. Given the fact that our sunk cost estimate significantly understates the actual sunk costs that we would incur, consideration of offsetting revenues attributed to the sale of equipment, deferral of contracts, or the value of salvage would not result in a lower sunk cost estimate. A more detailed engineering analysis would likely result in an increase in sunk cost estimates. These additional costs would be assignable to the combined cycle plan as sunk costs if Tampa Electric had not continued with the construction of the IGCC plant. In addition, the DOE funding received on a cash-call basis was not assumed to be refundable from Tampa Electric to DOE. The sunk costs for the combined cycle plan would, therefore, increase if DOE requested any refund or if the cost of removal were to exceed gross salvage costs. Our assumptions regarding such costs in each of our annual cost-benefit analyses were reasonable.

Q. What was the significance of the 1994 conservation goals proceedings with regard to Polk Unit One?

A. In the course of this proceeding, the Commission reviewed and approved Tampa Electric's resource planning process which was the same process used to determine the need for

Polk Unit One. In effect, the Commission reviewed and approved the continued need for Polk Unit One in the course of identifying the next avoidable unit on Tampa Electric's system. Tampa Electric's avoided unit was a 1999 Combustion Turbine for establishing the conservation goals in Docket No. 930551-EG. This unit was the first deferrable or avoidable unit after Polk Unit One identified in Tampa Electric's resource plan. By recognizing that Polk Unit One could not be avoided in Tampa Electric's conservation plan, this Commission affirmed the need for the unit.

Q. Have you continued to monitor the cost-effectiveness of burning natural gas as a fuel option for Polk Unit One after the need determination order was issued?

A. Yes, we have. The use of natural gas as a primary fuel source was carefully considered in the need determination proceeding. Tampa Electric compared a wide variety of alternative technologies including combustion turbines and combined cycle units fueled primarily with natural gas. After considering the detailed evidence presented, the Commission concluded that the company had demonstrated that the proposed IGCC unit was the most cost-effective alternative to provide additional needed capacity for Tampa

Electric and peninsular Florida. One of the major reasons for that decision was the Department of Energy funding for construction of a gasified coal demonstration project. The Commission approved the plant's construction on the condition that the company receive the $120 million in Department of Energy funding. In order to qualify for the funding the plant had to be constructed to use gasified coal as its primary fuel source. Nevertheless, Tampa Electric continued to monitor the natural gas market as a potential secondary fuel as decribed in Mr. Hugh Smith's testimony. We also continued to review alternatives using natural gas in the ongoing cost-effectiveness studies which compared IGCC technology to combined cycle technology.

Review of Forecasts and Key Assumptions

Q. What key assumptions and forecasts were used in the Determination of Need proceedings and the IRP analysis used to support the cost-effectiveness of the Polk Unit One project?

A. Our key assumptions and forecasts pertained to the operations of existing and future Tampa Electric generating resources and include: unit cost estimates; unit operating parameters; fuel price forecasts; demand and energy forecasts; economic and financial assumptions (including escalation rates, cost of capital, capital structure, AFUDC rates, taxes, book and tax life, and the discount rate). The treatment of these key assumptions and forecasts and their roles in our planning process are described in more detail in Document No. 1 of my Exhibit.

Q. What was the Polk Unit One cost estimate used in the need determination proceeding?

A. An estimate of $413 million was the basis for the $195 million savings identified in the need hearing order. However, there were three estimates of the Polk Unit One costs shown in the record for Tampa Electric's Determination of Need proceedings. In Document No. 3 of my Exhibit, Table 1-1 shows the basis and origin of these estimates and the estimated cash flow streams. The original estimate of $291.9 million in 1991 dollars (or $372.6 million in 1996 dollars) was the basis for the $62 million savings referenced on page 4 of the Prepared Direct Testimony of John B. Ramil submitted on September 5, 1991. An intermediate estimate of $305.0 million (or $389.5 million in 1996 dollars) was provided in the December 4, 1991 Deposition of John B. Ramil conducted by the FPSC Staff. This estimate was apparently the basis for the $389 million cost later referenced in Commission Order No. PSC-

92-0002-FOF-EI on March 2, 1992.

This Order also references the estimate of $319.9 million in 1991 dollars (or $413 million in as-spent dollars through 1996) submitted on December 9, 1991 in the revisions to the Prepared Rebuttal Testimony of John B. Ramil originally filed on November 20, 1991. This estimate was the basis for the $195 million system savings referred to on page 9 of the Order for constructing an IGCC unit compared to constructing a combined cycle unit and also shown in Document No. 1 of the Rebuttal Exhibit of John B. Ramil titled "Comparison of Unit Parameters and Customer Savings." The $413 million installed cost estimate including AFUDC was also provided in the 1992 Tampa Electric Ten Year Site Plan (Table 10-1, Form 8A) filed April 1, 1992.

Q. In the need determination proceeding in Docket No. 910883-EI was the cost of land, land improvements and environmental mitigation included in the cost-effectiveness evaluation of alternative generation technologies?

A. No they were not. Since all seven of the alternative technologies were technically suitable for the selected Polk County site, and the selection of any one of the technologies would not affect the location or amount of land purchased or the associated site development and land improvement costs, including environmental mitigation, these combined costs were considered the same for all resource plan alternatives. Therefore, the net differential cumulative present worth of system revenue requirements would be the same with or without the inclusion of the site acquisition and development costs. We did include a nominal generic cost per acre in 1991 dollars. The source of this generic cost was the 1989 EPRI Technical Assessment Guide. The Polk site would be the site of choice for each of the seven technologies that passed the initial economic screening and were included in the detailed system revenue requirement analysis.

The $195 million system savings that was referenced by the Commission in the Order was based on the $413 million estimate which accounted for the DOE funding and AFUDC but did <u>not</u> include the land and site development expense as part of the unit installed cost.

Q. How has the original construction cost estimate of $413 million changed since the Need proceeding?

A. Document No. 3 of my Exhibit summarizes the various total project cost estimates from the need hearing forward to our most recent estimate in the fall of 1995. As shown in this document, using a consistent comparison which excludes the estimated land acquisition, site development and AFUDC expense, the comparative cost of Polk Unit One has remained relatively unchanged (4.3% above the December 9, 1991 need hearing estimate). The need hearing estimate was completed before any project specific engineering or design work had been completed, as was the case with all the estimates examined as alternatives. At the time of the need hearing, only one IGCC unit had been built in the United States, and no unit exactly like the Polk unit has been built to date. Mr. Charles R. Black further explains the evolution of the construction cost estimates in his direct testimony.

Q. As the project moved forward, did you continue to monitor Tampa Electric's annual demand and energy forecast?

A. Yes. Document No. 5 of my Exhibit summarizes the demand and energy forecast used in the Polk Unit One Need proceedings compared to subsequent forecasts used in Tampa Electric's annual planning process. The tables in Document No. 5 show the annual variance and cumulative variance for the projected winter peak on a total system and firm system basis, as well as the annual system net energy for load

(NEL) requirements.

Also included in Document No. 5 are Tampa Electric's actual total system and firm system peaks for the winter and system NEL requirements for the period 1993 through 1996. The actual 1996 winter peak of 3,445 MW was 19 MW higher, or 0.6% higher, than the total peak of 3,426 MW originally forecasted for 1996 at the time of the 1991 need hearing. On a firm peak basis, the actual 1996 winter peak was 26 MW higher, or 0.9% higher, than the forecast for 1996 at the time of the need hearing.

Q. Were the actual winter peaks that Tampa Electric experienced in 1995 and 1996 higher than forecasted?

A. Yes. This was primarily due to colder than normal weather which resulted in higher than expected heating-degree days for the winter period and also accounted for higher than expected system peaks.

Q. How is extreme weather considered in Tampa Electric's demand and energy forecasts?

A. We do not assume extreme weather conditions in developing the annual demand and energy forecast. However, colder than expected weather can have a significant impact on our winter peak. The normalized winter temperature of 31°F is assumed for planning purposes to forecast our winter peak. The actual temperature at the time of our peak experienced in 1996 was 26°F. The lower temperature by five degrees resulted in a 274 MW (8%) increase in the total system peak.

Q. What is Tampa Electric's reserve margin using the actual winter peak experienced in 1996?

A. Substituting the projected system firm winter peak of 2,856 MW as shown in our 1996 Ten Year Site Plan with the actual firm peak of 3,025 MW would result in a 1996 firm reserve margin of 20.9%. On a total system peak basis, a similar calculation would result in a reserve margin of 6.1%. Without the additional generating capacity, the reserve margin will continue to decline as we experience continued growth in our system peak and energy requirements.

Q. How did you ensure the reasonableness of your demand and energy forecasts in each of the annual Polk Unit One IGCC cost-effectiveness evaluations?

A. An internal review is based on trend analyses of past projections compared to actual experience. We also relied on external reviews of our demand and energy forecast methods and results by the Commission and the Department of Community Affairs (DCA). In Order No. PSC-93-0165-FOF-EI, Docket No. 920324-EI, the Commission reviewed Tampa Electric's demand and energy forecast models and found they were "... capable of and have produced reliable projections and that the input assumptions are reasonable." (Reference page 12.) In each annual review of Tampa Electric's Ten Year Site Plans for the years 1992 through 1995, DCA found that our forecasting methods were reasonable and the accuracy of the forecasts was one of the best in the state. In the FPSC Review of 1995 Ten Year Site Plans (December 1995), the Commission found that Tampa Electric's demand and energy forecast methodology is reasonable for planning purposes. The average forecast error for Tampa Electric was less than the average error for the state's eleven largest utilities. In addition, the Commission found that "forecast errors reveal no evidence of either systematic over-forecasting or under-forecasting by TECO." (Reference page 65.)

Q. Why is it important to track the fuel price forecast and projected operating characteristics of Polk Unit One?

A. The projected fuel prices and unit operating characteristics are key parameters for production cost projections used in the cost-effectiveness studies. Understanding the relative changes from one forecast to the next is helpful in understanding the result of subsequent cost-effectiveness studies. Document No. 6 of my Exhibit compares the fuel price forecasts as explained by Mr. Hugh W. Smith that were used in the cost-effectiveness studies. Document No. 7 of my Exhibit compares the key operating characteristics of the IGCC and CC unit.

Q. What assumptions did you make in your analyses concerning the cost of fuel?

A. The fuel assumptions for the IGCC unit varied in each study to reflect the most cost-effective and viable primary fuel source at the time of the study. The 1992 cost-effectiveness study assumed coal as the primary fuel throughout the study. In 1993, Tampa Electric realized the significant savings to our ratepayers which could be achieved by taking advantage of the wide range of fuels that can be gasified in the IGCC unit. One such fuel is petroleum coke and in the 1993 study, we assumed a blend of petroleum coke with coal. The 1994 and 1995 cost-effectiveness studies utilized coal with Section 29 tax credits due to the increased savings relative to a blend of petroleum coke with coal. However, the petroleum coke/coal blend also resulted in significant cost savings when compared to other generation alternatives. The 1996 cost-effectiveness study assumed a blend of petroleum coke with coal based on the status of Tampa Electric's efforts to realize the Section 29 benefits. The fuel assumptions for the combined cycle unit were based on as-available natural gas in the spring (March, April, May) and the fall (October, November) and distillate oil in the remaining months.

Q. What assumptions did you make regarding tax credits in your 1994 and 1995 Polk IGCC cost-effectiveness studies?

A. The 1994 and 1995 cost-effectiveness studies included additional savings related to tax credits under Section 29 of the Internal Revenue Code of 1986, amended for producing synthetic gas which effectively lowered the overall cost to construct and operate the IGCC unit. These credits were assumed applicable for the first eleven and twelve years of IGCC operation respectively with an approximate present worth value of $98 million in the 1994 study and $87 million in the 1995 study.

Q. If you had continued to assume a blend of petroleum coke and coal in the 1994 and 1995 studies and excluded any savings for the credits under Section 29 of the Internal Tax Code, what would be the result?

A. If the 1994 and 1995 studies included a petroleum coke/coal blend for the same period (excluding the two year demonstration period), the IGCC technology still provides significant savings although slightly lower than Section 29 tax credits using unblended coal. Consequently, using a petroleum coke and coal blend results in continued cost-effectiveness of the project.

Q. On what did you base your assumption that the Section 29 tax credit would be available?

A. In order to realize the Section 29 tax credit benefits, Tampa Electric proceeded aggressively beginning in late 1993 to attempt to meet the federal requirements necessary to qualify for the credit, including the extension of the qualifying "window" by one year to December 1, 1996. One of the qualifications was to have the qualifying plant commercially operable by December 31, 1995. The credit for alternative fuels was first enacted in the Windfall Profits Tax Act in 1980, and received very little use initially because of the limitations on the use of the credit. These limitations were eased in the late 1980s. When initially enacted, the credit was limited to assets placed in service prior to January 1, 1990. This date was subsequently extended to January 1, 1991 and then to January 1, 1993. In the Energy Policy Act of 1992, the credit was partially extended for alternative fuels produced from biomass or coal to assets placed in service prior to December 1, 1996. At that time, Tampa Electric was attempting to have the third party sale rule amended and we believed that the prospects for success were very good. Tampa Electric's efforts to amend this section continued through 1995 when the prospects of success decreased. Although we were unsuccessful, our efforts continue to date. The 1994 and 1995 cost-effectiveness studies included the tax credits, and the 1996 study excluded the tax credits in light of the decreased prospects for success and the primary fuel for the IGCC unit is now assumed to be a petroleum coke/coal blend after the two-year demonstration period.

Q. Is the continued construction of Polk Unit One cost-effective today?

A. Yes, most definitely. There is no question that based on the facts and circumstances we know today the continued construction of Polk Unit One is the most cost-effective alternative available. This option provides a savings to Tampa Electric's ratepayers of $201 million over the life of the unit compared to Tampa Electric's next best option.

Q. Please summarize your testimony.

A. My testimony describes the Polk Unit One project including the determination of need for the project and our continuous monitoring of the cost-effectiveness of constructing this facility using our proven IRP methodology. The Tampa Electric IRP process is a comprehensive economic, engineering and strategic analysis of the Tampa Electric system to determine the most cost-effective mix of energy resources to reliably meet our system requirements. This dynamic process allows the flexibility to incorporate changes in key assumptions, new regulatory or legislative requirements and unexpected business developments. The net output of the process is an integrated resource plan that defines the appropriate mix of existing and new supply and demand side resources. The same IRP process was used in the Polk One Need Hearing.

The subsequent cost-effectiveness reviews used the same analytical tools and methods, and review of key assumptions and forecasts. Based on these reviews, the comparative cost of Polk Unit One has remained relatively unchanged from that utilized in the Polk Unit One need determination proceeding. The five studies described in my testimony compared the cost-effectiveness of the IGCC unit to a combined cycle unit as the next generating plant addition to our system. In Document No. 4 of my Exhibit, Table 3-1 summarizes the IGCC plan savings compared to a plan that replaces the IGCC unit with a combined cycle unit. This table shows the continued cost-effectiveness of the IGCC project each time it was reviewed during the construction of the unit. The savings ranged from $101 million to the current projection of $201 million. This shows the reasonableness and prudence of the company's continued construction of the unit.

Q. Does this conclude your testimony?

A. Yes it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 960409-EI
WITNESS: HERNANDEZ
EXHIBIT NO. ____ (TLH-1)

TAMPA ELECTRIC COMPANY

INDEX

DOCUMENT NO. 1
(22 PAGES)

EXCERPTS FROM EXHIBIT TLH-1 IN DOCKET NO. 930551-EG

TAMPA ELECTRIC COMPANY
DOCKET NO. 930551-EG
WITNESS: HERNANDEZ
EXHIBIT NO. _____ (TLH-1)

INDEX

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 930551-EG

TAMPA ELECTRIC COMPANY

INTEGRATED RESOURCE PLANNING METHODOLOGY

FEBRUARY 24, 1994

TAMPA ELECTRIC COMPANY

INTEGRATED RESOURCE PLAN METHODOLOGY

1. Overview
2. Assumptions
3. Reliability Analysis
4. Alternative Technology Study
5. Economic Analysis
6. DSM Analysis
7. Strategic Issues
8. Summary

INTEGRATED RESOURCE PLANNING METHODOLOGY

1. Overview

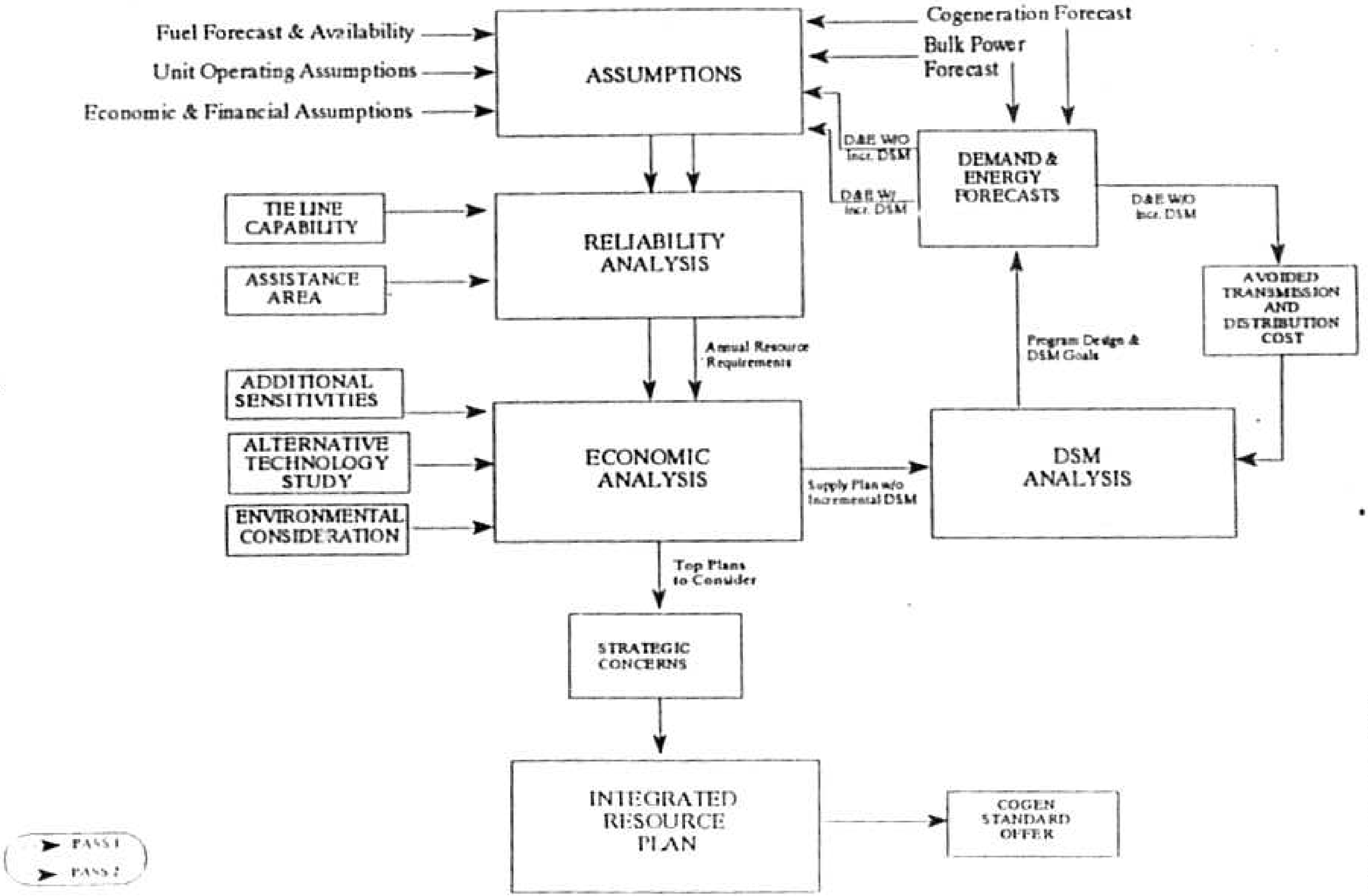
Integrated Resource Planning is a utility resource planning process in which combinations of demand side and supply side resources are evaluated on a fair and consistent basis to satisfy future energy requirements in a cost effective and reliable manner, while considering the interests of utility Customers and shareholders. This document is a description of Tampa Electric's Integrated Resource Planning Methodology which was used in Docket No. 930551-EG "Adoption of Numeric Conservation Goals and Consideration of National Energy Policy Act Standards (Section 111)." A flow diagram of the overall process is shown in Table 1.

The initial pass of the process incorporates a reliability analysis to determine timing of future resources, an alternative technology screening analysis to select supply side options to meet future needs and an economic analysis to determine what resource alternatives best meet future system demand and energy requirements. This pass freezes DSM activities at 1994 levels by excluding the future incremental utility sponsored DSM programs in the demand and energy forecast. This demand and energy forecast is also used to develop the avoided transmission and distribution costs. This forecast does include code related conservation requirements.

The supply plan and avoided transmission and distribution costs developed in the initial pass are used to analyze the cost effectiveness of incremental DSM programs and to develop the DSM goals. The demand and energy forecast is then revised to include both the existing and any additional cost effective DSM programs that are applicable to Tampa Electric's DSM goals. The initial pass is then repeated to incorporate both the supply and demand options.

Several resource plans are developed from the second pass. These plans incorporate both supply and demand side options. A sensitivity/strategic issues analysis is added to insure that an economically sound expansion plan, which has the flexibility to respond to future technological and economical changes, is selected.

TABLE 1
TAMPA ELECTRIC COMPANY
INTEGRATED RESOURCE PLAN METHODOLOGY



2. Assumptions

Various data assumptions are needed to develop the Integrated Resource Plan as shown in Table 2. Several departments throughout Tampa Electric are responsible for providing these assumptions.

Existing unit operating assumptions such as heat rates, capacity and availability are provided by the Production department for existing generating units. Projected existing unit availabilities are based on expected planned outages and historical unplanned outages. Unit heat rate equations are updated regularly by the Production department. The primary source for future unit operating assumptions and cost estimates is the EPRI Technical Assessment Guide.

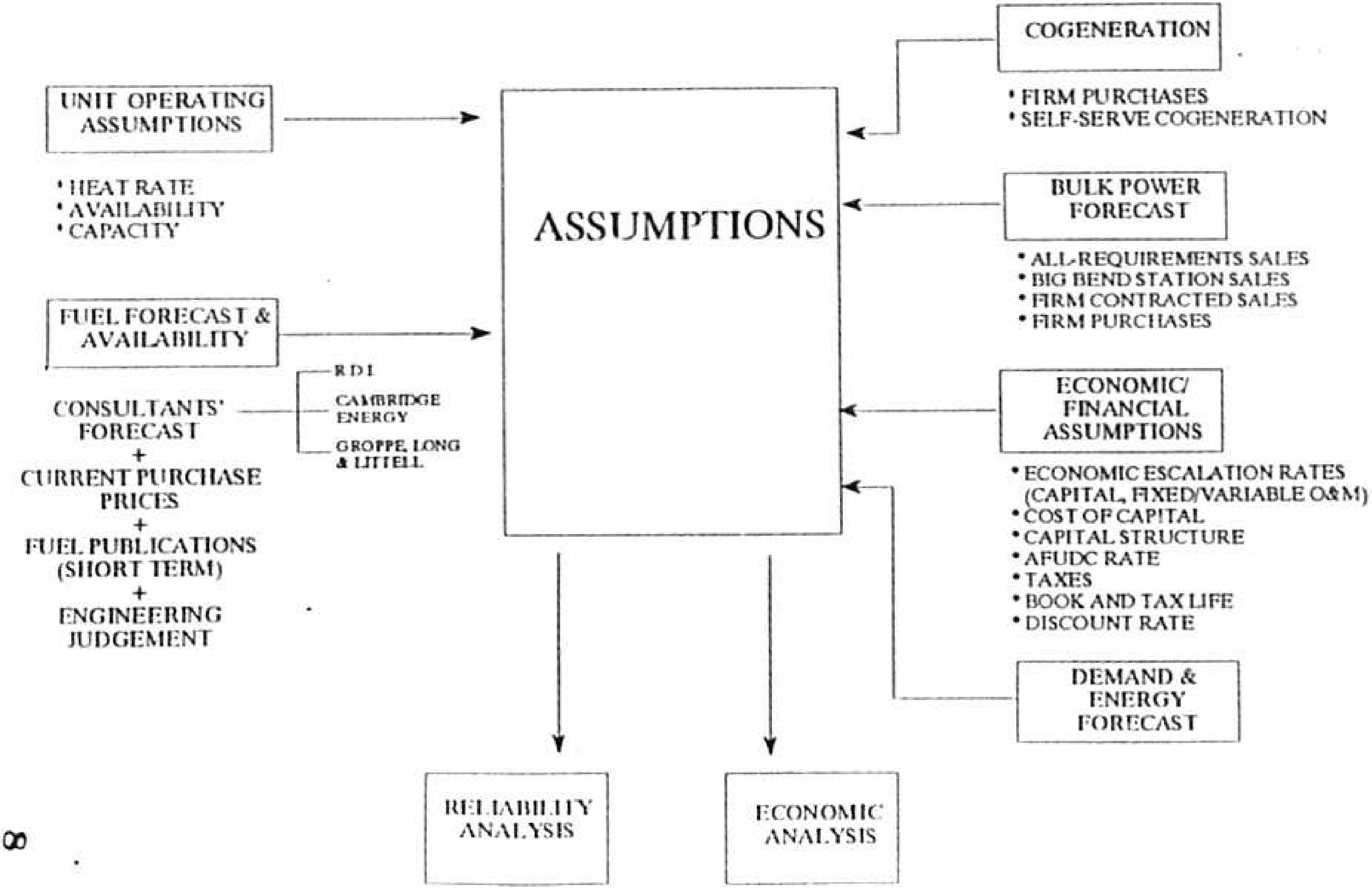
The fuel price forecast is provided by the Fuels department. The forecast is developed using consultants' forecasts, current purchase prices, fuel publications and engineering judgement. Included in the forecast is an estimate of projected fuel availabilities and fuel quality.

Tampa Electric Company has three generating units, Big Bend 1-3, which are affected in Phase I (1995-1999) under Title IV of the Clean Air Act Amendments. In order to comply with proposed sulfur dioxide emissions levels under Title IV, Tampa Electric plans to fuel blend lower sulfur coals with existing coal sources on Big Bend 1-3. In Phase II (2000-beyond), all of Tampa Electric's units are affected under Title IV except existing combustion turbines, Phillips Station and Dinner Lake. Tampa Electric's assumptions are to retrofit a Flue Gas Desulfurization system on Big Bend 3 and continue fuel blending on Big Bend 1-2.

The Cogeneration department forecasts firm cogeneration purchases and self-serve cogeneration. Self-serve cogeneration is used to develop the demand and energy forecast. Firm purchases are included as a resource to meet future demand and energy requirements.

The demand and energy forecast is the foundation from which the integrated resource plan is developed. Because of its critical importance, Tampa Electric Company has employed state-of-the-art methodologies for developing this forecast. The primary objective in the procedure is to blend proven statistical techniques with practical forecasting experience to provide a projection which represents the highest probability of occurrence.

TABLE 2
TEC INTEGRATED RESOURCE PLAN METHODOLOGY
ASSUMPTIONS



DOCKET 960409-EI, TLH EXHIBIT NO. 1,
TAMPA ELECTRIC COMPANY
PAGE 6 OF 20

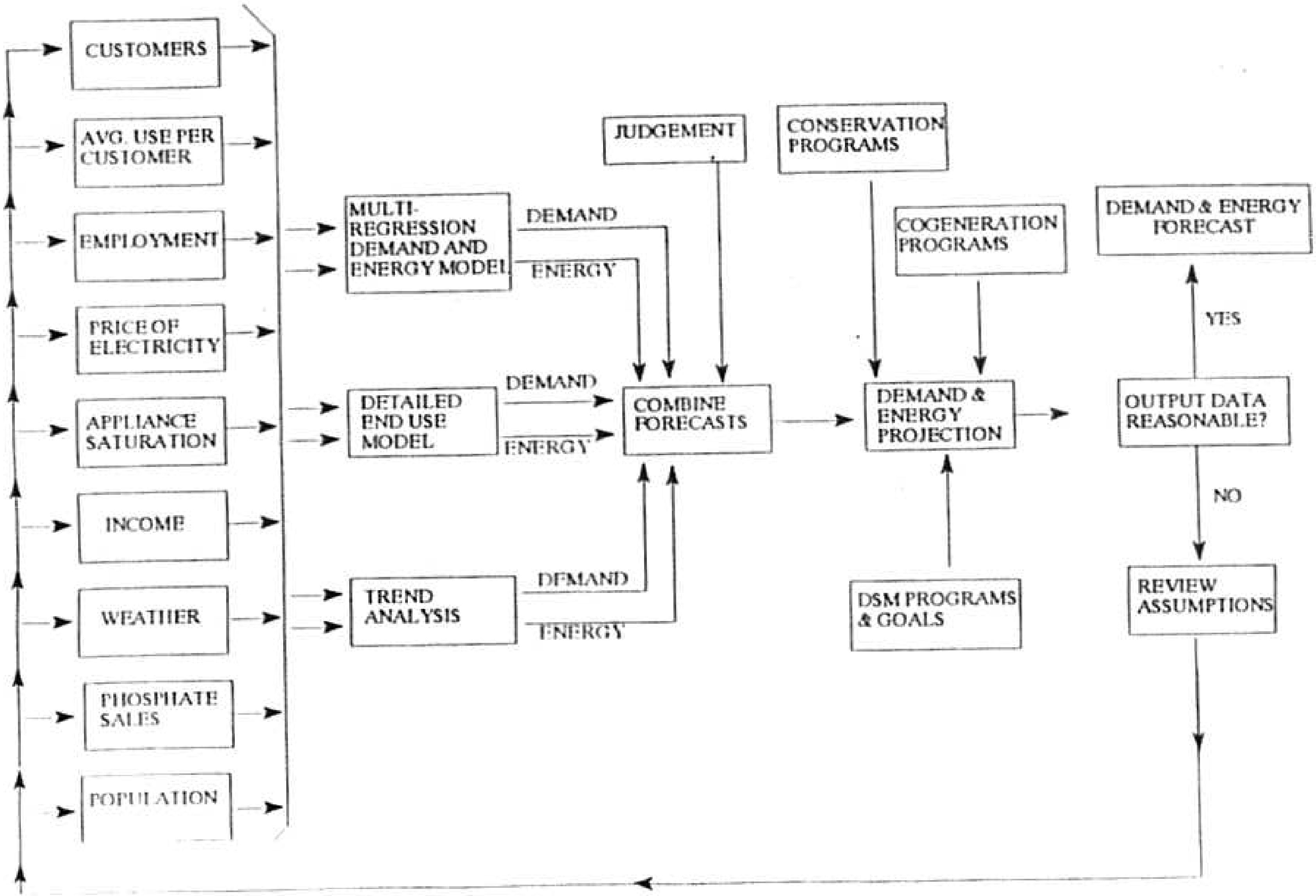
The Tampa Electric Company retail demand and energy forecast is the result of five separate forecasting methods: 1) Detailed End-Use Model; 2) Multiregression Model; 3) Trend Analysis; 4) Phosphate Method; and 5) existing utility sponsored Conservation Programs and Building Code requirements. The first three techniques are blended together to develop a demand and energy projection, excluding phosphate load (Table 3). Phosphate demand and energy is forecasted separately and then combined in the final forecast. The effect of the conservation programs and cogeneration forecast is incorporated into the process by subtracting the expected reduction in demand and energy from the forecast. The demand and energy forecast used in the first pass includes existing DSM programs at 1994 levels, but excludes incremental DSM programs. In the final pass, the cost effective DSM programs are incorporated into the forecast.

The wholesale forecast includes all requirement sales and firm contracted sales. A multiple regression approach similar to forecasting retail load is utilized for projecting all requirements load. Firm contracted sales are based on specific terms in the contract. Firm purchase contracts are also provided.

The economic and financial assumptions are used to determine the present worth revenue requirements associated with the resource plans and costs associated with the avoided unit. These include economic escalation rates, cost of capital, capital structure, AFUDC rates, taxes, book and tax life and the discount rate.

TABLE 3

TEC INTEGRATED RESOURCE PLAN METHODOLOGY
DEMAND & ENERGY FORECAST PROCESS



3. Reliability Analysis

A reliability analysis determines the adequacy of the existing and future generating resources required to reliably satisfy the current and projected demand and energy requirements of the Tampa Electric system.

The two reliability criteria used to assess system reliability is assisted loss of load probability (LOLP) and firm reserve margin. The assisted loss of load probability incorporates both the isolated system reliability and the availability of other resources via interconnections with other generating systems. A specific criteria is established from an analysis of historical system performance data, a review of acceptable utility industry standards for comparable regions and applying engineering judgement regarding operating conditions specific to the Tampa Electric system. The firm reserve margin is an isolated criteria and is based on a combination of the loss of Tampa Electric's largest unit and firm demand variance contingency. The current reliability criteria for our system is an assisted LOLP of 0.1 loss of load days per year and a minimum 20% firm reserve margin at the time of winter peak.

Tampa Electric uses TIGER, a computer program developed by Florida Power Corporation for analyzing system reliability, to analyze the primary or isolated system and potential resources available from our assistance areas. TIGER is a dual area loss of load probability program which calculates system operating reserve, isolated and net assisted LOLP, loss of load hours and expected unserved energy.

Tampa Electric's primary area consists of existing generating units, firm purchases and firm wholesale sales. The demand and energy forecast used in the initial pass includes conservation, interruptible load and existing DSM programs at 1994 levels but excludes future incremental DSM programs. The demand and energy forecast used in the second pass incorporates existing and any additional cost effective DSM programs. Tampa Electric's assistance area is comprised of all the electric utilities in Peninsular Florida and Southern Company. Each individual utility is analyzed according to the currently available Ten Year Site Plans.

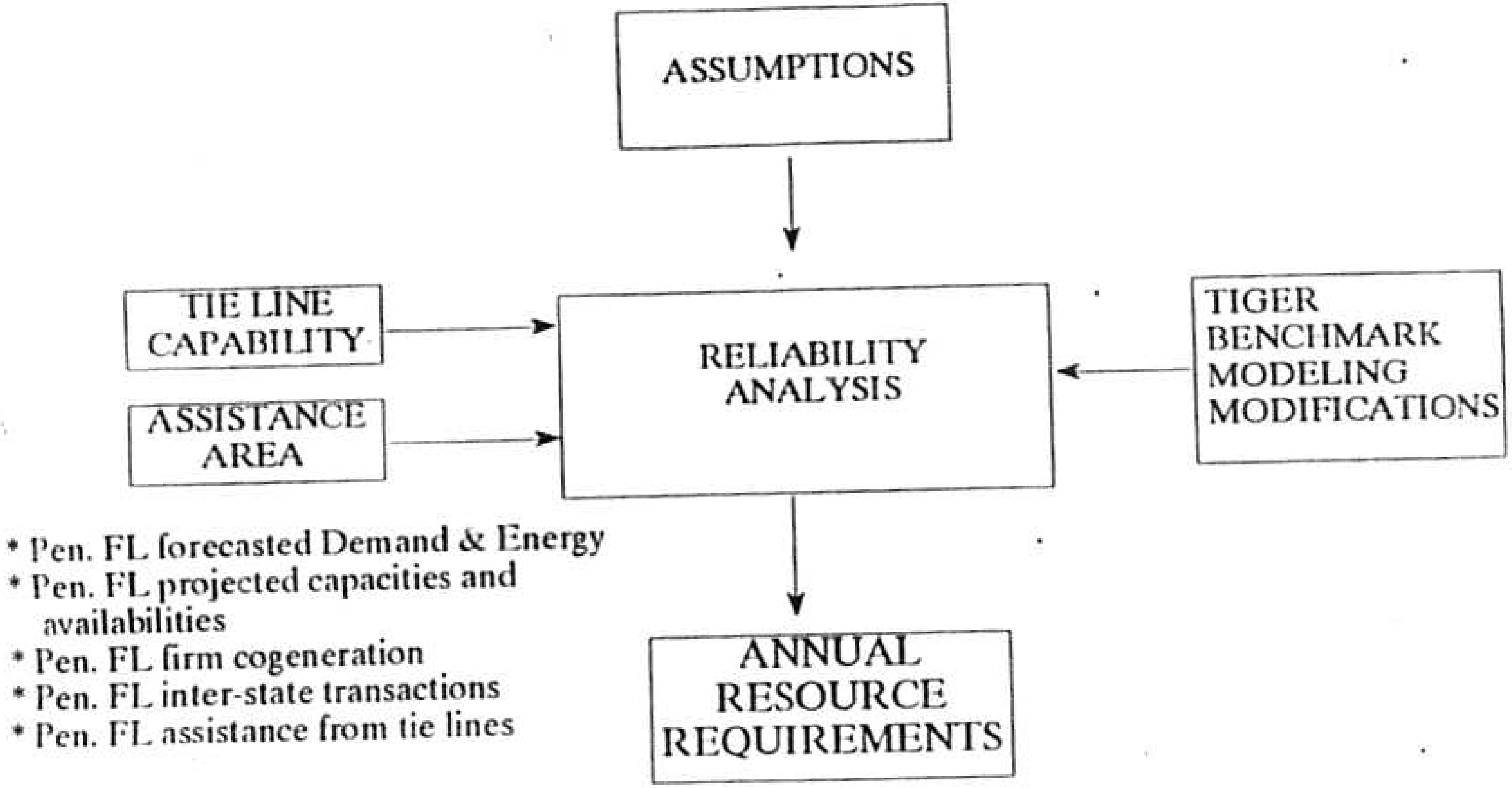
Available reserves in Tampa Electric's assistance area are accessed via Peninsular Florida's transmission grid and Tampa Electric's transmission interconnects. The ability to import capacity is limited by one or more of the following parameters: 1) transmission line capacities; 2) interconnect capacities; 3) other Peninsular Florida tie line constraints; 4) dispatch of Peninsular Florida generating units; and 5) available assistance area reserves.

These parameters are analyzed based on historical and projected data for Peninsular Florida.

The TIGER model is benchmarked to historical data to determine if any modeling modifications are needed to improve the models projection capabilities. Any modeling modifications found during the benchmark process are implemented in the reliability analysis.

The result of the reliability analysis is the timing and amount of the annual resource requirements needed to maintain system reliability based on the winter reserve margin and LOLP criteria. These requirements are 100% available capacity additions needed to maintain the stated reliability criteria. An overview of the reliability analysis is shown in Table 4.

TABLE 4
TEC INTEGRATED RESOURCE PLAN METHODOLOGY
RELIABILITY ANALYSIS



RELIABILITY CRITERIA

- 20% WINTER RESERVE MARGIN
- LOLP = 0.1 LOSS OF LOAD DAYS PER YEAR

4. Alternative Technology Study

An alternative technology screening is developed to determine the economic viability of a wide range of generating technologies for the Tampa Electric Company service area. These technologies include, but are not limited to, coal gasification, fluidized bed, combined cycle, combustion turbines, nuclear, renewables and distributive generation. Types of renewable technologies include solar photovoltaic, wind turbine and geothermal. Examples of distributive generation include fuel cells and batteries. Geographic viability, weather conditions, public acceptance, economics, lead-time, environmental acceptability, safety and proven demonstration and commercialization are used as criteria to screen the number of generating technologies to a manageable number. The remaining technologies are used in scenarios during the economic evaluation process.

The screening analysis is separated into two parts. In part one a preliminary screening analysis of forty-six technologies is used to eliminate any technology that is not technically viable for our region or system. Each technology is summarized based on plant size, plant cost ($/kw), average annual heat rate, commercial availability and technology development. Technologies are eliminated if regional geography/weather is not suitable for the technology (i.e. pumped hydro energy storage), if high technology costs exist when compared to similar type alternatives (i.e. atmospheric fluidized bed), if proven demonstration of technology has not been performed (i.e. non-integrated gasification combined cycle), if strong public opposition to technology or technology safety is questionable.

In part two of the screening analysis, the economics of the technologies which pass the preliminary screening are compared against each other. The comparisons are made by duty cycle class with all base load technologies compared against each other as are all the peaking and intermediate technologies. This part of the analysis utilizes screening curves to eliminate technologies. These curves are a graph of the levelized annual/lifecycle cost of various technologies at different capacity factors. The base load, intermediate and peaking technologies are evaluated from 50 to 100%, 15 to 50% and 0 to 15% capacity factor, respectively. Remaining technologies are then passed to the economic analysis.

5. Economic Analysis

A supply side analysis examines various supply side alternatives for meeting future capacity requirements. These include modifying existing units by repowering or over pressure operation and delayed retirements. Other resources such as constructing new unit additions, firm power purchases from other generating entities, joint ownership of generating capacity and modifications of the transmission system to increase import capability are included in the analysis. Some of these options can be evaluated based on feasibility and expected cost and are included as a sensitivity instead of being included in the optimization.

Tampa Electric uses the PROVIEW module of PROSCREEN, a computer model developed by Energy Management Associates, to evaluate the supply side resources. PROVIEW uses a dynamic programming approach to develop an estimate of the time and type of capacity additions which would most economically meet the system demand and energy requirements. Dynamic programming compares all possible combinations of generating unit additions which satisfy the specified reliability criteria and determine the schedule of additions which have the lowest revenue requirements. The model uses production costing analysis and incremental capital/O&M expenses to project the revenue requirements used to rank each plan that is analyzed.

The top plans developed by PROVIEW, which are based on lowest cumulative present worth revenue requirements, are first modeled in TIGER to verify that the plan meets our system reliability requirements. A detailed cost analysis for each resource plan is performed using the Capital Expenditure and Recovery module and the Generation and Fuel module of PROSCREEN. The capital expenditures associated with each capacity addition are obtained based on the type of generating unit, fuel type, capital spending curve and in-service year. The fixed charges resulting from the capital expenditures are expressed in "present worth" dollars for comparison. The fuel and the operating and maintenance costs associated with each scenario are projected based on estimated unit dispatch. The projections, which are expressed in "present worth" dollars, are combined with the fixed charges to obtain the total present worth of revenue requirements for each alternative plan.

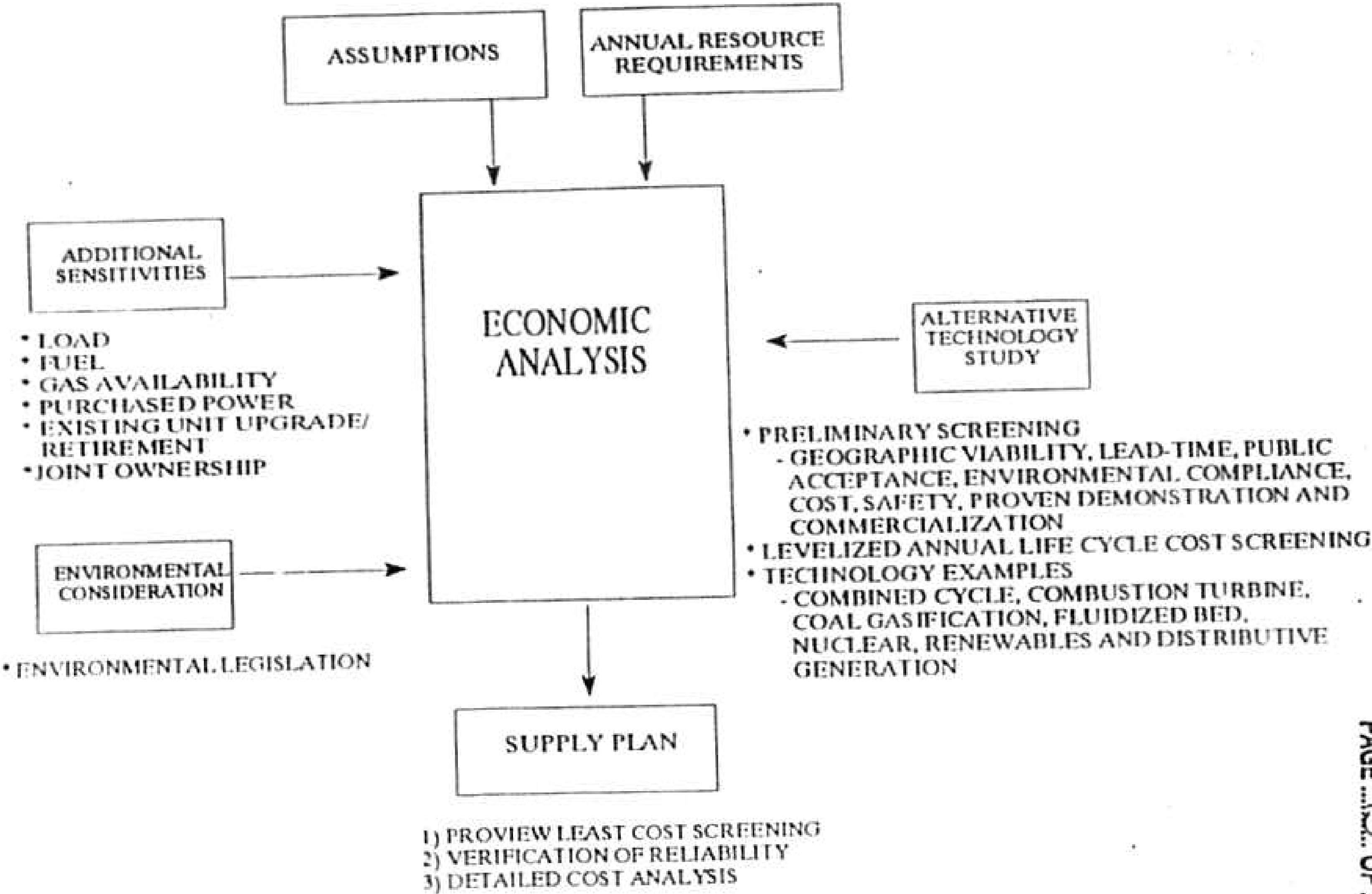
Sensitivities are then analyzed on the top plans to determine the potential impact of assumptions that can vary from the base case assumptions. These sensitivities involve parameters which are greatly influenced by the action and decisions of organizations other than Tampa Electric. These sensitivities can include load, fuel prices and supply side options.

From this economic analysis, various resource scenarios are developed which satisfy the established reliability criteria and environmental regulations. Table 5 is an overview of the economic analysis.

Initially, incremental DSM programs are not included in the demand and energy forecast. The supply plan developed in the initial pass is used to evaluate cost effective DSM programs and goals. These programs are incorporated in the demand and energy forecast and the initial pass is repeated. The results of the second pass are several resource plans. Each plan has revenue requirements associated with the base assumptions and the sensitivities. This information is then used in the strategic analysis.

TABLE 5

TEC INTEGRATED RESOURCE PLAN METHODOLOGY ECONOMIC ANALYSIS



6. DSM Analysis

In Tampa Electric's IRP process, the DSM analysis section identifies which DSM measures are cost-effective based on the following standard commission tests: the Rate Impact Measure (RIM), the Total Resource Cost (TRC) and the Participants Test. Using the Commission's standard cost-effectiveness methodology, each measure is evaluated based on different marketing and incentive assumptions. Utility plant avoidance assumptions for generation, transmission and distribution were derived earlier in the IRP process. A flow diagram of the DSM analysis is shown in Table 6.

Pass one of the IRP process established the supply plan requirements based on no incremental utility sponsored DSM programs. For this goal setting docket, all incremental DSM, except code related requirements, are frozen at 1994 levels. The first eligible unit for avoidance in the supply plan is used to analyze the cost effectiveness of the DSM programs. Avoided Unit capital cost and O&M as well as incremental fuel cost are used in the analysis. The avoided unit capital and O&M are developed using PROSCREEN. The incremental fuel cost is developed using PROMOD, a production costing computer model developed by Energy Management Associates.

In addition to avoiding generation cost, the DSM measures have the potential of avoiding transmission and distribution costs. An estimate of these costs is developed on both a demand and energy basis and is incorporated into the analysis.

The assumptions for the DSM measures were developed by Synergic Resources Corporation (SRC) from the Florida Energy Office (FEO) original study. Market penetration assumptions are derived from marketing and incentive scenario levels and provide the estimated number of adopters.

Tampa Electric evaluates DSM measures using a model called DSM-TECO, a derivative of the DSM-FIRE (Florida Integrated Resource Evaluation) model. These models emulate the Commission's prescribed cost-effectiveness methodology. Also, they are static in nature and evaluate DSM measures one at a time against static supply side assumptions.

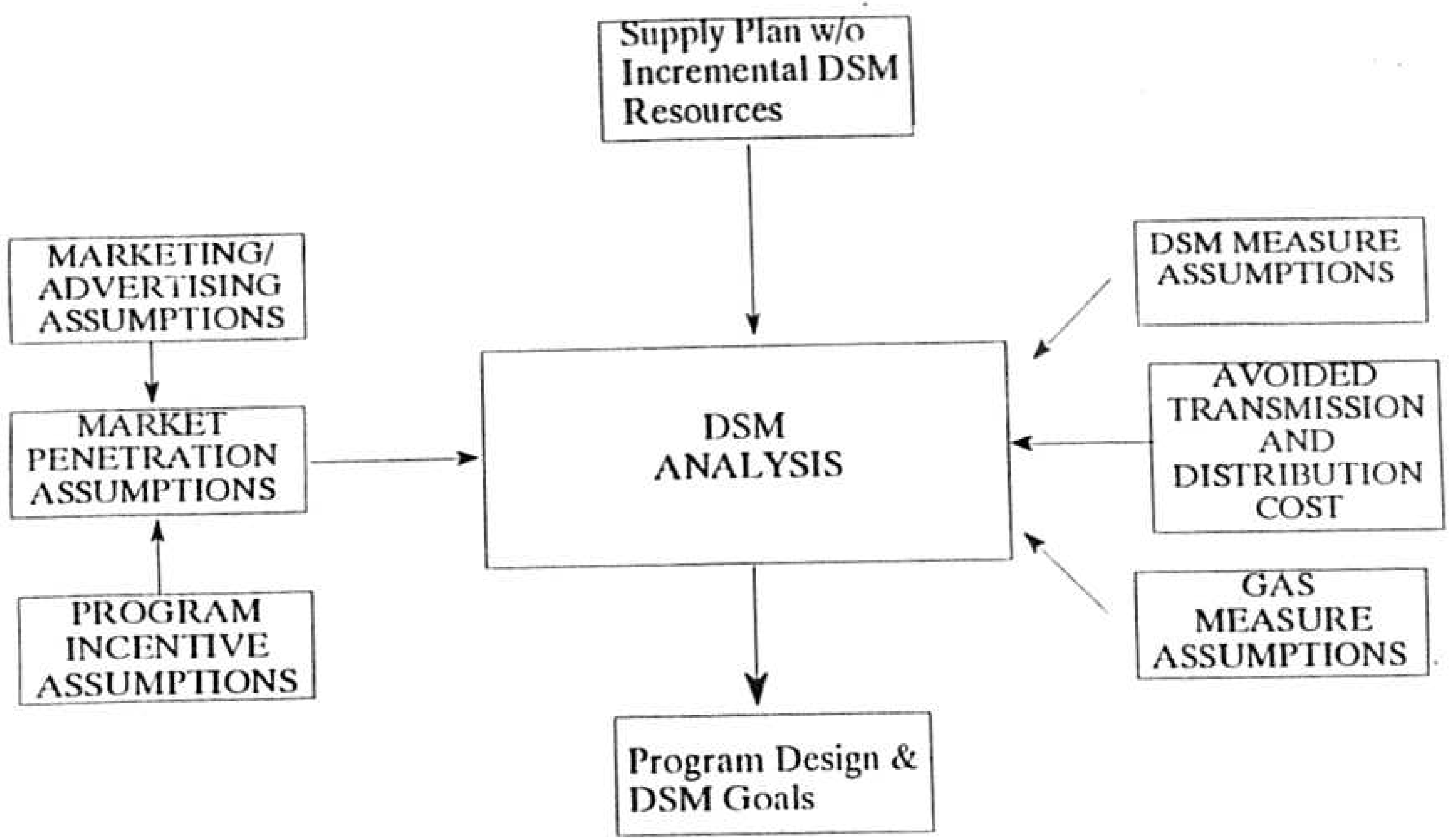
Natural gas measures may be required by the Commission for electric utility evaluation. The natural gas assumptions are primarily supplied through the gas industry.

The DSM market analysis is split between the residential and commercial sectors. After all the measures are screened for potential building code adoption, the remaining measures are then evaluated for potential utility sponsored programs. Where applicable, each residential measure is evaluated for both new and existing residences across three housing types: single family, multi-family and mobile homes. In the commercial sector, the evaluation process is the same, namely new and existing where applicable; however, due to the wide disparity in building envelopes, ten different building types are evaluated which include: office, restaurant, retail, grocery, warehouse, school, college, hospital, lodging and miscellaneous.

All measures that pass the RIM test in the DSM analysis are eligible for utility program adoption. Each adopted measure is quantified into annual kw/kwh savings and is reflected in the demand and energy forecast. Measures with the highest RIM values are generally adopted first. With a completed demand and energy forecast which includes the composite DSM programs in each year, pass 2 of the resource plan begins.

TABLE 6

TEC INTEGRATED RESOURCE PLAN METHODOLOGY
DSM COST EFFECTIVENESS SCREENING



7. Strategic Issues

After the second pass through the reliability and economic analysis, several resource plans are determined. Each plan has revenue requirements associated with the base assumptions and the sensitivities. These costs are evaluated with the strategic issues to determine Tampa Electric's integrated resource plan.

Strategic issues which affect the type, capacity, and/or timing of future generation resource requirements are analyzed in the study. These issues such as adaptability, environmental legislation, fresh water, Clean Air Act and plan acceptance are not easily quantified. Therefore, a strategic analysis is conducted to compare the overall performance of each alternative resource plan under each issue. The strategic issues and economic analysis are combined to ensure that an economically sound expansion plan is selected which has the flexibility to respond to future technological and economical changes.

The tool used to combine the strategic issued and economic analysis is the decision matrix. A decision matrix is used to compare and select the cost effective plan. Each alternative resource plan is analyzed on both a quantitative and qualitative basis. The quantitative analysis is based on comparing the cumulative present worth of revenue requirements for each alternative for both the base and sensitivity assumptions. The qualitative analysis considers these previously mentioned strategic issues. Each alternative is ranked based on pre-determined criteria with assigned weighting factors. A composite score or index is calculated for each alternative by multiplying the assigned ranking by the appropriate weighting factor for the criteria and summing the values for each category. The combined scores indicate the relative strength of each alternative on both a quantitative and qualitative basis.

8. Summary

The Tampa Electric integrated resource planning process is a comprehensive economic, engineering and strategic analysis of the Tampa Electric system to determine the cost effective mix of energy resources to reliably meet our system requirements. This dynamic process allows the flexibility to incorporate changes in key assumptions, new regulatory or legislative requirements and unexpected business development. The net output of the process is an integrated resource plan that defines the appropriate mix of existing and new supply and demand side resources.

DOCUMENT NO. 2
(2 PAGES)

SUMMARY OF TAMPA ELECTRIC'S TEN YEAR SITE PLANS
(1992-1996)

TAMPA ELECTRIC COMPANY
TEN YEAR SITE PLAN FILINGS

From Table III-1, Form 6

	1992 TYSP	1993 TYSP	1994 TYSP	1995 TYSP	1996 TYSP
1995	CT (7/95)	CT (7/95)			
1996	CG/HRSG (7/96)	CG/HRSG (7/96)	IGCC (7/96)	IGCC (10/96)	IGCC (10/96)
1997					
1998					
1999		CT			
2000	CT	CT			
2001	CT	CT	CT	CT	
2002	N/A	CT	CT	CT	CT
2003	N/A	N/A		CT	CT
2004	N/A	N/A	N/A	CT	CT
2005	N/A	N/A	N/A	N/A	CT

From Table IV-1, Form 8A

1991$	$319,882,000	$319,882,000	N/A	N/A	N/A
1996$	$413,038,000[1] (inc. AFUDC)	$413,038,000[1] (inc. AFUDC)	$485,560,000 (inc. AFUDC)	$503,317,000 (inc. AFUDC)	$506,165,000 (inc. AFUDC)

NOTE: [1] The $413 million estimate excludes land and site development costs.

DOCUMENT NO. 3
(6 PAGES)

POLK UNIT ONE CONSTRUCTION COST ESTIMATES

TABLE 1-1

POLK UNIT ONE INSTALLED COST ESTIMATES
PROVIDED DURING THE DETERMINATION OF NEED HEARING

		(1)	(2)	(3)
Unit Capacity (MW)		220	230	258.5
1991 $ ($000)		$291,940	$305,012	$319,882
1991 $ ($/kW)		1,327	1,327	1,237
1996 $ ($000)		372,598	389,534	408,259
1996 $ ($/kW)		1,693	1,693	1,579
As Spent 96 $ (000)	1991	0	0	0
	1992	4,026	4,209	4,524
	1993	51,964	54,326	56,147
	1994	209,418	218,937	228,206
	1995	74,008	77,372	83,186
	1996	0	0	0
	Sub-Total	339,416	355,844	372,062
	AFUDC	37,004	38,686	40,976
	TOTAL	$376,420	$393,530	$413,038

(1) John B. Ramil Prepared Direct Testimony filed September 5, 1991
(2) Deposition of John B. Ramil by FPSC Staff filed December 4, 1991
(3) John B. Ramil Rebuttal Testimony Exhibit JBR-2 filed November 20, 1991 and Revised Rebuttal Testimony filed December 9, 1991.

NOTE: The cost of land and site development was excluded from these installed cost estimates.

TABLE 1-2
POLK PROJECT COST ESTIMATE
DETERMINATION OF NEED HEARING
DECEMBER 1991

YEAR	**NET PROJECT COSTS[1] ($000)**	**DOE FUNDING ($000)**
1992	$4,705	($1,216)
1993	58,939	(15,091)
1994	243,381	(61,335)
1995	106,014	(22,358)
1996	0	0
TOTAL	$413,038[2]	($100,000)

[1] Project costs shown include AFUDC and are net of the DOE funding shown in Column 3. The cost for land and site development is excluded in this estimate.

[2] December 9, 1991 Fluor Daniel estimate provided in Table 1-1, page 4 of 8, of Interrogatory No. 1 response.

TABLE 1-3
POLK PROJECT COST ESTIMATE
BECHTEL ENGINEERING PRELIMINARY ESTIMATE
FALL 1993

YEAR	**NET PROJECT COSTS[1] ($000)**	**DOE FUNDING ($000)**
1992	$15,295	($3,741)
1993	73,068	(15,110)
1994	108,630	(25,332)
1995	233,188	(55,656)
1996	59,605	(11,307)
TOTAL	$489,786	($111,146)

1 Project costs shown include AFUDC and are net of the DOE funding. The cost for land and site development is <u>included</u> in this estimate.

TABLE 1-4
POLK PROJECT COST ESTIMATE
BECHTEL ENGINEERING DEFINITIVE ESTIMATE
FALL 1994

YEAR	NET PROJECT COSTS[1] ($000)	DOE FUNDING ($000)
1992	$15,295	($3,741)
1993	75,527	(11,809)
1994	98,994	(26,824)
1995	223,911	(54,329)
1996	89,590	(13,550)
TOTAL	$503,317	($110,253)

[1] Project costs shown include AFUDC and are net of the DOE funding. The cost for land and site development is included in this estimate.

TABLE 1-5
POLK PROJECT COST ESTIMATE
REVISED BECHTEL ENGINEERING ESTIMATE
FALL 1995

YEAR	NET PROJECT COSTS[1] ($000)	NET DOE FUNDING ($000)
1992	$15,295	($3,741)
1993	75,527	(11,809)
1994	102,273	(27,628)
1995	215,380	(52,485)
1996	97,690	(19,732)
TOTAL	$506,165	($115,395)

[1] Project costs shown include AFUDC and are net of the DOE funding. The cost for land and site development is included in this estimate.

DOCUMENT NO. 4
(12 PAGES)

SUMMARY OF POLK IGCC COST EFFECTIVENESS STUDIES
(1992-1996)

TABLE 3-1
POLK IGCC COST EFFECTIVENESS STUDIES SUMMARY
IGCC PLAN RELATIVE TO CC PLAN
DIFFERENTIAL SYSTEM CPWRR ($ x 10^6)

Year of Study	Capital	O&M	Fuel	Net System
1992	124	93	(372)	(155)
1993	260	64	(432)	(108)
1994	176	81	(358)	(101)
1995	122	75	(345)	(148)
1996	23	86	(310)	(201)

NOTE: The negative differential net system CPWRR shows the IGCC plan savings relative to the CC plan.

1992 POLK 1 IGCC COST EFFECTIVENESS STUDY

The 1992 Polk unit analysis compared system revenue requirements, in 1992 dollars, for the IGCC using the October 1992 cost estimate with the system revenue requirements of a phased combined cycle unit.

The capital costs for the IGCC and combined cycle are shown on the assumptions table attached. The capital costs for both the IGCC and combined cycle plans include the common costs for land acquisition, site development, and other common costs. The combined cycle cost also includes the sunk costs associated with the IGCC gasifier and related components through year-end 1992. It is also assumed that the expected DOE funding is included in the IGCC plan, but only DOE funding received at the time of the analysis for the combined cycle plan.

The fuel plan for the IGCC and combined cycle unit was developed from the 1992 Price Change forecast. Savings shown represent the IGCC burning a coal similar to Illinois No. 6. The combined cycle unit primary fuel was assumed to be natural gas and distillate oil as the secondary fuel throughout the study.

Total differential system revenue requirements including DOE and EPRI funding showed a system present worth savings of $155 million for the IGCC plan.

TAMPA ELECTRIC COMPANY
1992 POLK UNIT ANALYSIS

Resource Plans

Year	Polk IGCC	Polk CC
1995	7F CT	7F CT
1996	HRSG/CG	
1997	-	CT
1998	CT	HRSG
1999	CT	CT
2000	CT	CT
2001	CT	HRSG
2002	-	CT
2003	CC	2 CT's
2004	-	-
2005	HRSG	HRSG
2006	CT	CT
2007	CT	CT
2008	CT	HRSG
2009	-	CT
2010	HRSG	CT
2011	CT	CT

IGCC Plan Savings - 30 Year CPWRR (92$ x 1000)	
Capital	($124,067)
O&M	($93,228)
Fuel	$372,258
Tax Credit	$0
IGCC Plan Savings	$154,964

1993 POLK 1 IGCC COST EFFECTIVENESS STUDY

The 1993 Polk Unit One analysis compared system revenue requirements, in 1993 dollars, for the IGCC using the 1993 cost estimate with the system revenue requirements of a combined cycle unit. An economic and system reliability analysis showed that the 7F advanced combustion turbine could be deferred from a July 1995 commercial operation date to July 1996 while cost effectively maintaining system reliability.

The capital costs for the IGCC and combined cycle are shown on the assumptions table attached. The capital costs for both the IGCC and combined cycle plan include the common costs for land acquisition, site development, and other costs common to both plans. The combined cycle capital cost also includes the sunk costs associated with the IGCC gasifier and related components up to the time of the study. Both plans also include DOE funding received at the time of the study and expected additional DOE funding for the IGCC plan only.

The fuel plan for the IGCC unit and combined cycle was developed from the 1993 summer forecast. Savings shown represent the IGCC burning demonstration coals from 1996 to 1998, and a 80%/20% petroleum coke/Galatia coal blend from 1999 through the end of the study. The combined cycle unit primary fuel was assumed to be natural gas and distillate oil as the secondary fuel throughout the study.

Total differential system revenue requirements including DOE and EPRI funding showed a system present worth savings of $108 million for the IGCC plan.

TAMPA ELECTRIC COMPANY
1993 POLK UNIT ANALYSIS

Resource Plans

Year	Polk IGCC	Polk CC
1995		
1996	IGCC	CC
1997		
1998		
1999	CT	CT
2000	CT	CT
2001	HRSG	CT/HRSG
2002	CT	CT
2003	CT	CT
2004	HRSG	
2005	CT	HRSG
2006	CT	CT
2007	CT	CT
2008		CT
2009	HRSG	HRSG
2010	CT	
2011	CT	CT

IGCC Plan Savings - 30 Year CPWRR (93$ x 1000)	
Capital	($260,305)
O&M	($63,724)
Fuel	$431,624
Tax Credit	$0
IGCC Plan Savings	$107,595

1994 POLK 1 IGCC COST EFFECTIVENESS STUDY

The 1994 Polk 1 study compares the IGCC plan revenue requirements to the construction of a 215 MW combined cycle at the same site.

The capital costs for the IGCC and combined cycle are shown on the assumptions table attached. The capital costs for both the IGCC and combined cycle plan include the common costs for land acquisition, site development, and other costs common to both plans. The combined cycle capital cost also includes the sunk costs associated with the IGCC gasifier and related components up to the time of the study. Both plans also include DOE funding received at the time of the study and expected additional DOE funding for the IGCC plan only.

The fuel plans are from the 1994 spring forecast identified in the response to Interrogatory No. 5. Revenue requirement savings shown represent the IGCC Pitt #8 coal from 1996 to 1998, Illinois #6 coal from 1999 through the end of the study. Section 29 tax credits of $98 million were included for the first eleven years of operation (1996 - 2006). The combined cycle unit burns as-available natural gas in the spring and fall and distillate oil in the winter and summer throughout the study.

Total differential system revenue requirements including DOE and EPRI funding showed a system present worth savings of $101 million for the IGCC plan.

TAMPA ELECTRIC COMPANY
1994 POLK UNIT ANALYSIS

Resource Plans

YEAR	Polk IGCC	Polk CC
1994	-	-
1995	-	-
1996	IGCC	CC
1997	-	-
1998	-	-
1999	-	-
2000	CT	CT
2001	CT	CT
2002	CT	CT
2003	-	-
2004	CT	CT
2005	-	-
2006	CT	CT
2007	CT	CT
2008	CT	CT
2009	CT	CT
2010	CT	CT
2011	-	-
2012	-	CT
2013	CT	-

IGCC Plan Savings - 30 Year CPWRR (94$ x 1000)	
Capital	(176,047)
O&M	(80,512)
Fuel	259,235
Tax Credit	98,356
IGCC Plan Savings	101,032

1995 POLK 1 IGCC COST EFFECTIVENESS STUDY

The 1995 Polk 1 cost effectiveness study compared system revenue requirements between the base (IGCC) resource plan and a plan that substituted a combined cycle for the IGCC unit.

The capital costs for the IGCC and combined cycle are shown on the assumptions table attached. The capital costs for both the IGCC and combined cycle plan include the common costs for land acquisition, site development, and other costs common to both plans. The combined cycle capital cost also includes the sunk costs associated with the IGCC gasifier and related components up to the time of the study. Both plans also include DOE funding received at the time of the study and expected additional DOE funding for the IGCC plan only.

Fuel plans are from the 1994 fall fuel forecast. Several fuel plans were developed for the IGCC unit, however the revenue requirement savings shown represent the IGCC burning Pitt #8 coal from 1996 to 1998, Illinois #6 coal from 1999 to 2007, and a 65/35% pet coke/Powder River Basin coal blend from 2008 through the end of the study. Section 29 tax credits of $87 million were included for the first twelve years of operation (1996 - 2007) for the IGCC unit. The combined cycle unit burns as-available natural gas in the spring and fall months and distillate oil in the winter and summer months throughout the study.

Total differential system revenue requirements including DOE and EPRI funding showed a system present worth savings of $148 million for the IGCC plan.

TAMPA ELECTRIC COMPANY
1995 POLK UNIT ANALYSIS

Resource Plans

YEAR	Polk IGCC	Polk CC
1995	-	-
1996	IGCC	CC
1997	-	-
1998	-	-
1999	-	-
2000	-	-
2001	CT	CT
2002	CT	CT
2003	CT	CT
2004	CT	CT
2005	CT	CT
2006	-	-
2007	CT	CT
2008	CT	CT
2009	CT	CT
2010	-	-
2011	-	-
2012	CT	CT
2013	-	-
2014	CT	CT

IGCC Plan Savings - 30 Year CPWRR (95$ x 1000)	
Capital	(122,180)
O&M	(74,951)
Fuel	257,963
Tax Credit	87,335
IGCC Plan Savings	148,167

1996 POLK 1 IGCC COST EFFECTIVENESS STUDY

The 1996 Polk IGCC cost effectiveness study compared system revenue requirements of the IGCC base resource plan with a combined cycle plan that replaces the IGCC and adjusts for combined cycle unit capacity and availability.

The capital costs for the IGCC and combined cycle are shown on the assumptions table attached. The capital costs for both the IGCC and combined cycle plan include the common costs for land acquisition, site development, and other costs common to both plans. The combined cycle capital cost also includes the sunk costs associated with the IGCC gasifier and related components up to the time of the study. Both plans also include DOE funding received at the time of the study and expected additional DOE funding for the IGCC plan only.

Fuels were from the fall 1995 fuel forecast. The IGCC plan assumes Pitt #8 coal used from 1996-1998 (DOE demonstration period) and a 75/25% pet coke/Powder River Basin coal blend from 1999-2025. Section 29 tax credits are excluded in this study. The combined cycle uses as-available natural gas in the spring and fall months and distillate oil in the winter and summer months throughout the study.

Total differential system revenue requirements including DOE funding showed a system present worth savings of $201 million for the IGCC plan.

TAMPA ELECTRIC COMPANY
1996 POLK UNIT ANALYSIS

Resource Plans

Year	Polk IGCC	Polk CC
1996	IGCC	CC
1997	-	-
1998	-	-
1999	-	-
2000	-	-
2001	-	-
2002	CT	CT
2003	CT	CT
2004	CT	CT
2005	CT	CT
2006	CT	CT
2007	CT	CT
2008	-	-
2009	CT	2 CTs
2010	2 CTs	CT
2011	-	-
2012	-	-
2013	CT	CT
2014	-	CT
2015	CT	CT

IGCC Plan Savings - 30 Year CPWRR (96$ x 1000)	
Capital	(22,806)
O&M	(86,219)
Fuel	310,232
Tax Credit	0
IGCC Plan Savings	201,206

DOCUMENT NO. 5
(4 PAGES)

COMPARISON OF TAMPA ELECTRIC'S DEMAND AND ENERGY FORECASTS AND HISTORY

COMPARISON OF WINTER TOTAL SYSTEM PEAK DEMAND FORECAST
CHANGE IN PEAK DEMAND FORECAST FROM PREVIOUS YEAR'S FORECAST AND TOTAL CHANGE FROM NEED FORECAST (MW)

YEAR	FALL 90 NEED FORECAST	1992 SUMMER	TOTAL CHANGE	1992 FALL	TOTAL CHANGE	1993 FALL	TOTAL CHANGE	1994 FALL	TOTAL CHANGE	1995 FALL	TOTAL CHANGE	ACTUAL WINTER PEAK	WEATHER ADJUSTED ACTUAL
1993	3,190	(85)	(85)	77	(8)							2,886	3,143
1994	3,268	(85)	(85)	98	13	(106)	(93)					2,737	3,001
1995	3,348	(83)	(83)	88	5	(94)	(89)	(26)	(115)			3,244	3,153
1996	3,426	(80)	(80)	87	7	(91)	(84)	(23)	(107)	(16)	(123)	3,445	3,209
1997	3,508	(81)	(81)	38	(43)	(34)	(77)	(34)	(111)	12	(99)		
1998	3,587	(79)	(79)	38	(41)	(39)	(80)	(29)	(109)	13	(96)		
1999	3,667	(74)	(74)	39	(35)	(36)	(71)	(30)	(101)	18	(83)		
2000	3,745	(68)	(68)	39	(29)	(44)	(73)	(38)	(111)	21	(90)		
2001	3,817	(58)	(58)	40	(18)	(54)	(72)	(35)	(107)	34	(73)		

DOCKET NO. 960409-EI
TLH EXHIBIT NO. 1
DOCUMENT NO. 5
PAGE 2 OF 4

COMPARISON OF WINTER FIRM PEAK DEMAND FORECAST
CHANGE IN PEAK DEMAND FORECAST FROM PREVIOUS YEAR'S FORECAST AND TOTAL CHANGE FROM NEED FORECAST (MW)

YEAR	FALL 90 NEED FORECAST	1992 SUMMER	TOTAL CHANGE	1992 FALL	TOTAL CHANGE	1993 FALL	TOTAL CHANGE	1994 FALL	TOTAL CHANGE	1995 FALL	TOTAL CHANGE	ACTUAL WINTER PEAK	WEATHER ADJUSTED ACTUAL
1993	2,768	(63)	(63)	57	(6)							2,433	2,690
1994	2,843	(69)	(69)	78	9	(109)	(100)					2,372	2,636
1995	2,922	(77)	(77)	68	(9)	(103)	(112)	(14)	(126)			2,769	2,678
1996	2,999	(81)	(81)	67	(14)	(110)	(124)	(12)	(136)	(7)	(143)	3,025	2,789
1997	3,077	(87)	(87)	18	(69)	(61)	(130)	(14)	(144)	1	(143)		
1998	3,155	(92)	(92)	18	(74)	(63)	(137)	(14)	(151)	(3)	(154)		
1999	3,233	(93)	(93)	19	(74)	(61)	(135)	(12)	(147)	(8)	(155)		
2000	3,311	(97)	(97)	19	(78)	(68)	(146)	(13)	(159)	(11)	(170)		
2001	3,376	(87)	(87)	20	(67)	(78)	(145)	(13)	(158)	(3)	(161)		

DOCKET NO. 960409-EI
TLH EXHIBIT NO. 1
DOCUMENT NO. 5
PAGE 3 OF 4

COMPARISON OF NET ENERGY FOR LOAD FORECAST
CHANGE IN ENERGY FORECAST FROM PREVIOUS YEAR'S FORECAST AND TOTAL CHANGE
FROM NEED FORECAST (GWH)

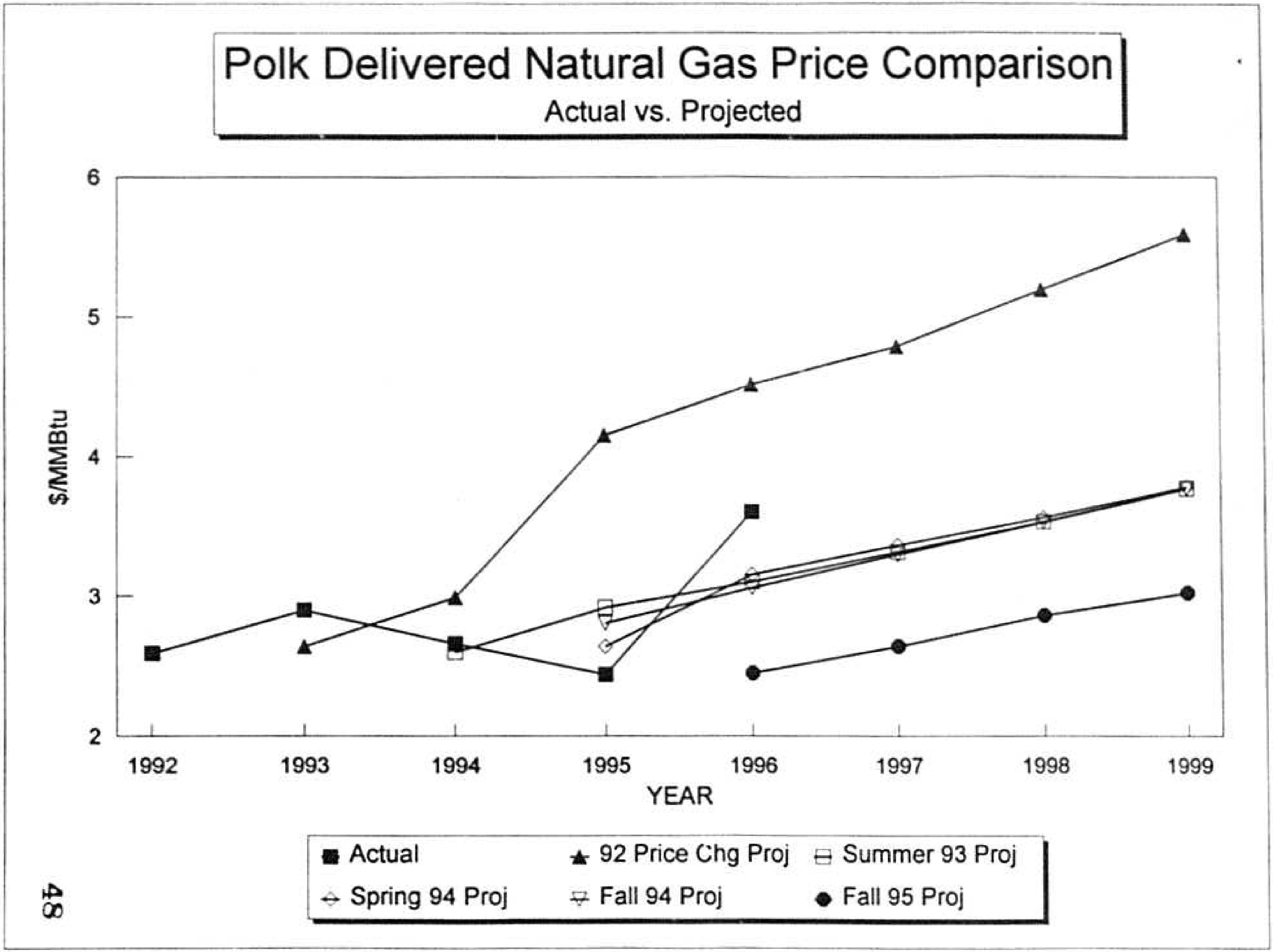
YEAR	FALL 90 NEED FORECAST	1992 SUMMER	TOTAL CHANGE	1992 FALL	TOTAL CHANGE	1993 FALL	TOTAL CHANGE	1994 FALL	TOTAL CHANGE	1995 FALL	TOTAL CHANGE
1993	15,172	(656)	(656)	598	(58)						
1994	15,615	(738)	(738)	632	(106)	(977)	(1,083)				
1995	16,023	(709)	(709)	613	(96)	(1,014)	(1,110)	355	(755)		
1996	16,431	(716)	(716)	567	(149)	(935)	(1,084)	468	(616)	(63)	(679)
1997	16,858	(726)	(726)	213	(513)	(525)	(1,038)	374	(664)	88	(576)
1998	17,284	(735)	(735)	215	(520)	(583)	(1,103)	308	(795)	159	(636)
1999	17,719	(746)	(746)	217	(529)	(613)	(1,142)	264	(878)	125	(753)
2000	18,153	(721)	(721)	219	(502)	(688)	(1,190)	153	(1,037)	133	(904)

ACTUAL N.E.L.	WEATHER ADJUSTED ACTUAL
14,500	14,656
14,731	14,748
15,682	15,455

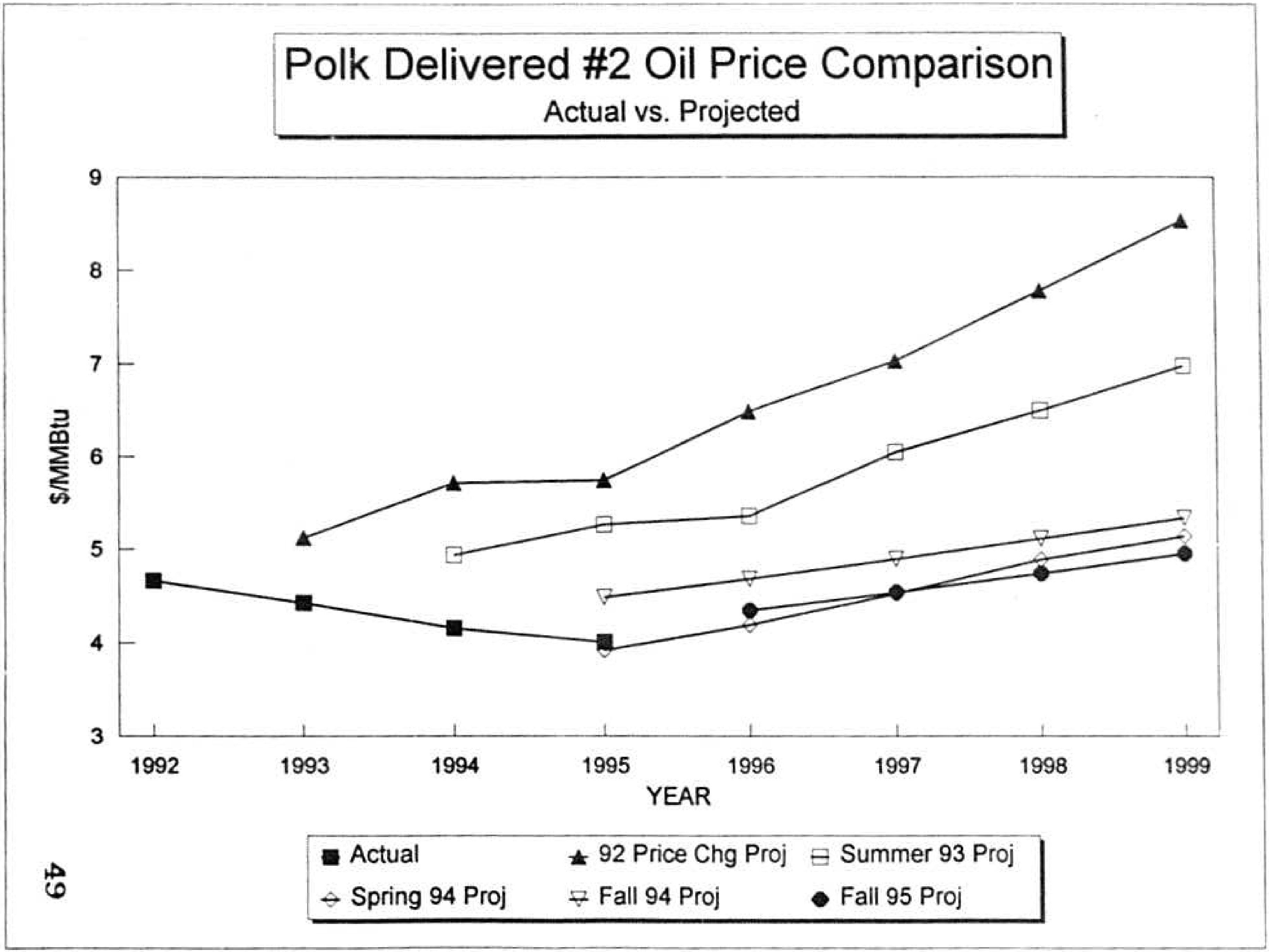
TAMPA ELECTRIC COMPANY
DOCKET NO. 960409-EI
WITNESS: HERNANDEZ
EXHIBIT NO. ____ (TLH-1)
DOCUMENT NO. 6
PAGE 1 OF 5

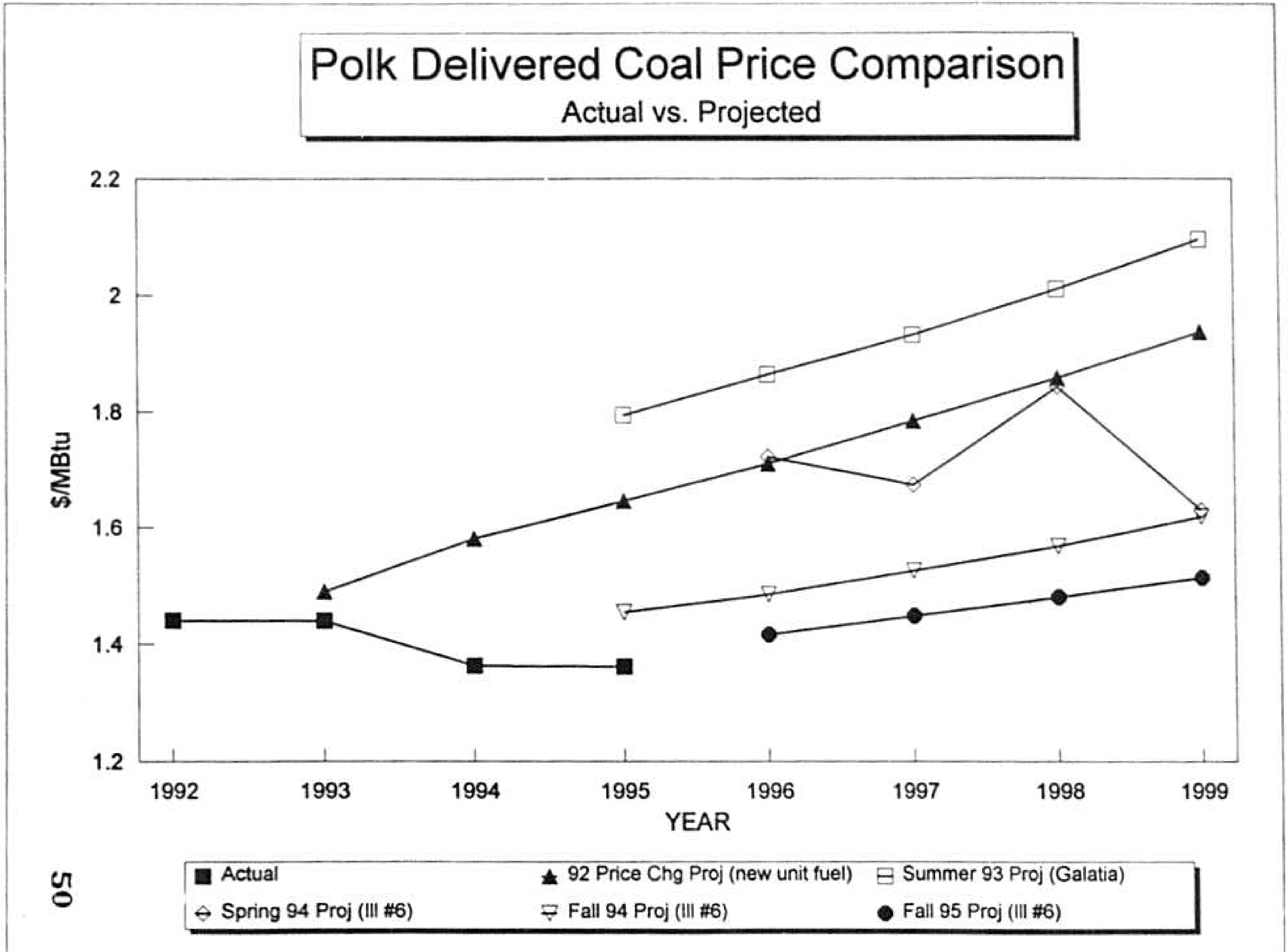
DOCUMENT NO. 6
(5 PAGES)

COMPARISON OF TAMPA ELECTRIC'S FUEL FORECAST HISTORY

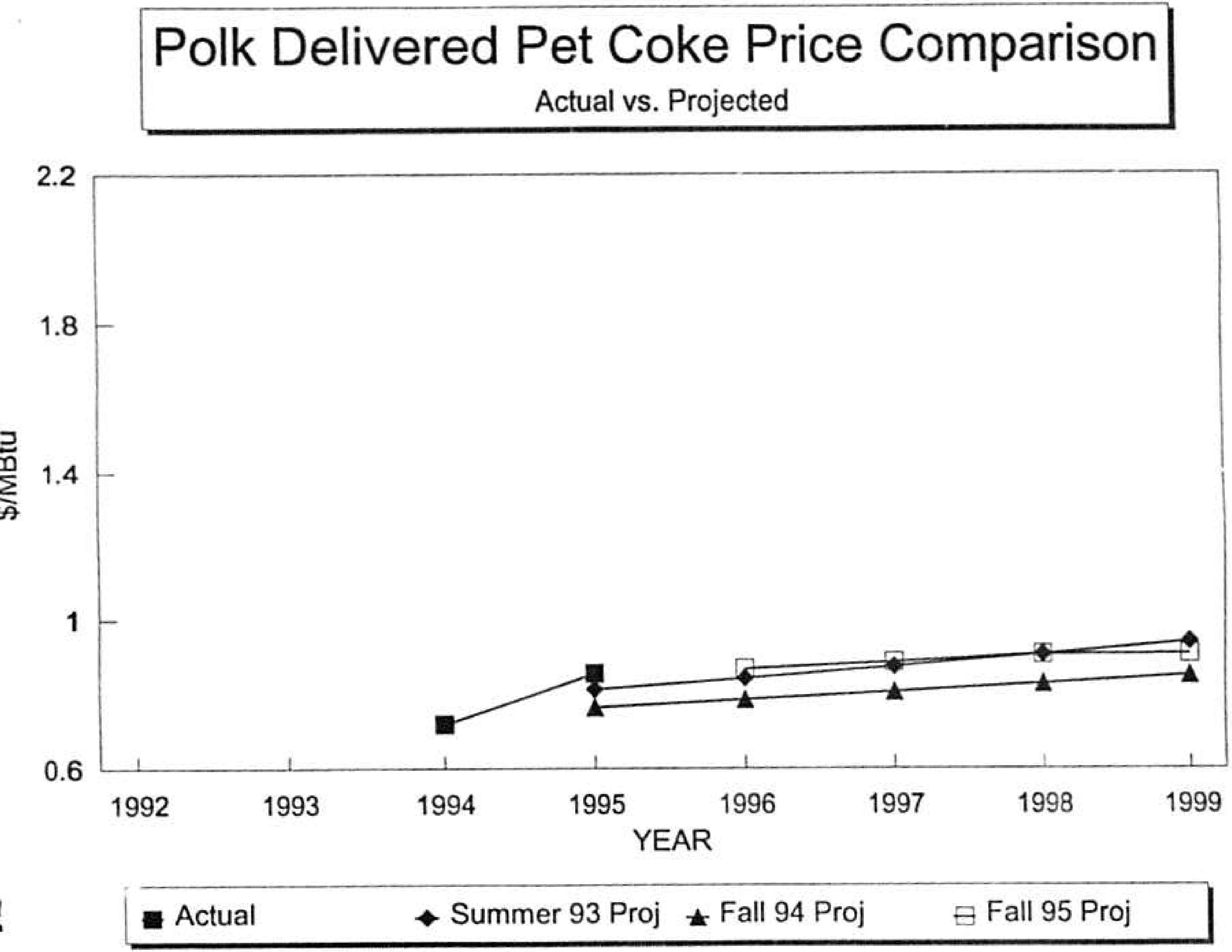


Polk Delivered Natural Gas Price Comparison
Actual vs. Projected
6
5
4
3
2
$/MMBtu
1992
1993
1994
1995
1996
1997
1998
1999
YEAR
Actual
92 Price Chg Proj
Summer 93 Proj
Spring 94 Proj
Fall 94 Proj
Fall 95 Proj


Polk Delivered #2 Oil Price Comparison
Actual vs. Projected
$/MMBtu
9
8
7
6
5
4
3
1992
1993
1994
1995
1996
1997
1998
1999
YEAR
Actual
92 Price Chg Proj
Summer 93 Proj
Spring 94 Proj
Fall 94 Proj
Fall 95 Proj



Polk Delivered Coal Price Comparison
Actual vs. Projected
$/MBtu
2.2
2
1.8
1.6
1.4
1.2
1992
1993
1994
1995
1996
1997
1998
1999
YEAR
Actual
92 Price Chg Proj (new unit fuel)
Summer 93 Proj (Galatia)
Spring 94 Proj (Ill #6)
Fall 94 Proj (Ill #6)
Fall 95 Proj (Ill #6)


Polk Delivered Pet Coke Price Comparison
Actual vs. Projected
2.2
1.8
1.4
1
0.6
$/MBtu
1992
1993
1994
1995
1996
1997
1998
1999
YEAR
Actual
Summer 93 Proj
Fall 94 Proj
Fall 95 Proj

DOCUMENT NO. 7
(5 PAGES)

IGCC OPERATING ASSUMPTIONS

TABLE 15-1
POLK IGCC NEED HEARING AVAILABILITY ESTIMATE

159 MW CT-Oil (1)

Operating Year	Equivalent Unplanned Outages (Hours)	Planned Outages (Hours)	Total Unavailability (Hours)	EAF (%)
1	295	370	664	92.4
2	N/A	N/A	N/A	N/A
3	N/A	N/A	N/A	N/A
Mature Plant	N/A	N/A	N/A	N/A

260 MW CC-Coal (2)

Operating Year	Equivalent Unplanned Outages (Hours)	Planned Outages (Hours)	Total Unavailability (Hours)	EAF (%)
1	N/A	N/A	N/A	N/A
2	1,012	740	1,752	80
3	1,012	740	1,752	80
Mature Plant	1,012	740	1,752	80

220 MW CC-Oil (2)

Operating Year	Equivalent Unplanned Outages (Hours)	Planned Outages (Hours)	Total Unavailability (Hours)	EAF (%)
1	N/A	N/A	N/A	N/A
2	461	370	831	90.5
3	461	370	831	90.5
Mature Plant	461	370	831	90.5

NOTES:

(1) The Polk IGCC unit was planned as phased construction at the time of the Need Hearing, with the advanced combustion turbine in-service date by July 1995 and the balance of plant by July 1996. Beyond the first year of operation, the combustion turbine will not be operated in a simple cycle mode.

(2) The combined cycle-coal availability is shown lower than the combined cycle-oil availability due to the expected higher maintenance requirements of the coal gasification system.

TABLE 15-2

POLK IGCC CURRENT AVAILABILITY ESTIMATE

159 MW CT-Oil (1)

Operating Year	Equivalent Unplanned Outages (Hours)	Planned Outages (Hours)	Total Unavailability (Hours)	EAF (%)
1	N/A	N/A	N/A	N/A
2	N/A	N/A	N/A	N/A
3	N/A	N/A	N/A	N/A
Mature Plant	N/A	N/A	N/A	N/A

250 MW CC-Coal (2)

Operating Year	Equivalent Unplanned Outages (Hours)	Planned Outages (Hours)	Total Unavailability (Hours)	EAF (%)
1	2,916	720	3,636	58.5
2	2,125	432	2,557	70.8
3	915	720	1,635	81.3
Mature Plant	854	720	1,574	82.0

210 MW CC-Oil (2)

Operating Year	Equivalent Unplanned Outages (Hours)	Planned Outages (Hours)	Total Unavailability (Hours)	EAF (%)
1	540	336	876	90.0
2	540	336	876	90.0
3	540	336	876	90.0
Mature Plant	540	336	876	90.0

NOTES:

(1) The current Polk IGCC unit construction plan deferred the advanced combustion turbine and balance of plant to a commercial operation date of October 1996. The combustion turbine will not be operated in a simple cycle mode.

(2) The combined cycle-coal availability is shown lower than the combined cycle-oil availability due to the expected higher maintenance requirements of the coal gasification system.

Polk Unit One
HEAT RATES

Study	HEAT RATES - 1997			
	IGCC	**Source**	**CC**	**Source**
Need	8,486	Fluor - Daniel	7,820	1989 TAG
1992	8,631	Fluor - Daniel	7,996	Hardee
1993	8,971	Texaco	7,841	UE&C
1994	8,935	Project Team	7,641	Project Team
1995	8,775	Project Team	7,900	Project Team
1996	8,775	Project Team	7,669	Project Team

'NOTES: UE&C = United Engineers & Constructors
Hardee = Based on Hardee Power Station I/O curves

Polk Unit One
O&M Costs

	IGCC - without DOE Funding			
	Fixed	Variable	Total	
Study	'97$ x 1000	$/MWH	$000/yr	Source
Need	9,885	3.64	16,258	BGL Estimate
1992	9,550	3.04	14,871	Fluor - Daniel
1993	6,416	2.70	11,146	Texaco
1994	13,522	NA	13,522	Proj. Team
1995	13,289	NA	13,289	Proj. Team
1996	11,974	NA	11,974	Proj. Team

A sulfur credit of $ 1,450 not shown for the 1993 study (97$x 1000).

For consistency, each study excludes the DOE credit of $20M over the 2 year demonstration period beginning on the commercial operation date.

DOCUMENT NO. 8
(145 PAGES)

INTERROGATORIES SPONSORED
BY THOMAS L. HERNANDEZ
IN DOCKETS 950379-EI AND 960409-EI

1. At the time of the Need Determination for the Polk IGCC Unit, Tampa Electric estimated an installed cost of approximately $389 million, net of the DOE grant. (See page 9 of Order No. PSC-92-0002-FOF-EI.) In response to a Staff data request in Docket 950379-EI, Tampa Electric now estimates an installed cost of approximately $503 million. (See Item 5 of November 15 response from Gordon Gillette to Tim Devlin.) ,

a. Please provide a time-based flow chart by major construction activity showing the projected expenditures for the Polk IGCC Unit based on the original cost estimate of approximately $389 million provided during the Need Determination proceedings. Please explain and show the effect of the DOE funding in this flow chart.

b. Please provide a time-based flow chart by major construction activity showing the actual and projected expenditures for the Polk IGCC Unit based on revised cost estimates at the time the decision was made to construct the unit as an integrated IGCC rather than as a separate advanced combustion turbine with a later addition of a heat recovery steam generator/coal gasifier. Please explain and show the effect of the DOE funding in this flow chart.

c. Please provide a time-based flow chart by major construction activity showing the actual and projected expenditures for the Polk IGCC Unit based on the current cost estimate of approximately $503 million. Please explain and show the effect of the DOE funding in this flow chart.

A. a. Three estimates of the Polk Unit 1 IGCC costs are shown in the record for Tampa Electric's Determination of Need proceedings. The attached Table 1-1 (on page 4 of this response) shows the basis and origin of these estimates and the estimated cash flow streams. The original estimate of $291.9 million in 1991 dollars (or $372.6 million in 1996 dollars) was the basis for the $62 million savings referenced on page 4 of the Prepared Direct Testimony of John B. Ramil submitted on September 5, 1991. An intermediate estimate of $305.0 million (or $389.5 million in 1996 dollars) was provided in the December 4, 1991 Deposition of John B. Ramil by the FPSC Staff. This estimate was apparently the basis for the $389 million cost later referenced in Commission Order No. PSC-92-0002-FOF-EI on March 2, 1992.

This Order also references the estimate of $319.9 million in 1991 dollars (or $413 million in as-spent dollars through 1996) submitted on December 9, 1991 in the revisions to the Prepared Rebuttal Testimony of John B. Ramil originally filed on November 20, 1991. This estimate was the basis for the $195 million system savings referred to on page 9 of Order No. PSC-92-0002-FOF-EI for constructing an IGCC unit compared to constructing a combined cycle unit and also shown in Document No. 1 of the Rebuttal Exhibit of John B. Ramil titled "Comparison of Unit Parameters and Customer Savings." The $413 million installed cost estimate including AFUDC was also provided in the 1992 Tampa Electric Ten Year Site Plan (Table 10-1, Form 8A) filed April 1, 1992.

At the time of the Need Hearings (December 1991), detailed cash flow projections for the project had not been generated by major construction activity and the DOE Cooperative Agreement had not been signed. Therefore, a cash flow projection was not provided related to the $413 million estimate. However, in response to this Interrogatory, the cash flow methodology inherent in John Ramil's Supplemental Testimony and Deposition Late Filed Exhibit No.4 has been used to provide a cash flow distribution shown in Table 1-2 for the December 9, 1991 Need Hearing estimates.

The $195 million system savings referenced by the Commission in the Order and was based on the $413 million estimate which contained the DOE funding and AFUDC but did not include the land and site development expense as part of the unit installed cost. For purposes of comparison, land and site development costs were considered approximately the same between alternative technologies that would be constructed at the same site and would not impact the economic analyses on a differential cumulative present worth revenue requirement (CPWRR) basis.

b. At the time of the Need Hearings (December 1991), the most cost effective plan was to construct the unit as a phased construction Integrated Coal Gasification Combined Cycle (IGCC) plant with a commercial operation date of July 1, 1995 for the 7F advanced combustion turbine and the balance of the IGCC plant with commercial operation by July 1, 1996. This decision was the subject of John Ramil's Prepared Rebuttal Testimony in the Need Hearings.

In August 1993, an economic and system reliability analysis showed that the 7F advanced combustion turbine could be deferred from a commercial operation date of July 1995 to July 1996 while cost effectively maintaining system reliability. The deferral of the combustion turbine is shown in the 1994 Tampa Electric Ten Year Site Plan (Table III-1, Form 6) filed April 1, 1994. The deferral postponed revenue requirements that would have occurred in July 1995 as the first phase of the plant was placed in service. The revised cash flow and total project estimates are shown on Table 1-3.

c. The installed cost estimate of approximately $503 million was prepared by Bechtel in the fall of 1994 and based on a detailed engineering analysis. This estimate was based on contractual commitments to date, planning studies, plot plans, electric single line diagrams, instrument index, equipment indexes, and civil engineering design sketches issued up to July 1994. The $503 million estimate was net of DOE and EPRI funding and included all known work associated with the project including land acquisition, site development, and AFUDC costs. At the time of this estimate, the DOE cooperative agreement had been signed and the cash call guidelines and procedures had been set. The approved DOE capital cost funding available at the time of this estimate was approximately $110 million based on cost sharing formulas in the cooperative agreement and an additional $20 million in funding for operating and maintenance expenses during the two-year demonstration period. The estimate has been allocated by year in accordance with the estimate detail provided by Bechtel and is shown in Table 1-4. Adjusting the $503 million estimate to remove AFUDC and land acquisition and site development costs results in a $385 million estimate for direct plant costs and puts this estimate on a comparable basis to the December 1991 Need Hearing estimate of $372 million. This $13 million increase represents a 3.5% variance to the December 1991 Need Hearing estimate as shown in Table 2-1, page 3 of 3 response to Interrogatory No. 2.

The most current estimate of approximately $506 million reflects the decision by EPRI in 1995 to withdraw funding of $3 million for the development of the IGCC simulator used for modeling of the IGCC process and for operations training of plant personnel. The time-based flow chart for the $506 million estimate is shown in Table 1-5 (page 8) of this response. Adjusting the $506 million estimate to remove AFUDC, land acquisition and site development costs, as discussed above, results in a current estimate of $388 million. This $16 million variance to the 1991 Need Hearing represents a 4.3% increase as shown in Table 2-1.

TABLE 1-1

POLK UNIT ONE INSTALLED COST ESTIMATES PROVIDED DURING THE DETERMINATION OF NEED HEARING

		(1)	(2)	(3)
Unit Capacity (MW)		220	230	258.5
1991 $ ($000)		$291,940	$305,012	$319,882
1991 $ ($/kW)		1,327	1,327	1,237
1996 $ ($000)		372,598	389,034	408,259
1996 $ ($/kW)		1,693	1,693	1,579
As Spent 96 $ (000)	1991	0	0	0
	1992	4,026	4,209	4,524
	1993	51,964	54,326	56,147
	1994	209,418	218,937	228,206
	1995	74,008	77,372	83,186
	1996	0	0	0
	Sub-Total	339,416	355,844	372,062
	AFUDC	37,004	38,686	40,976
	TOTAL	$376,420	$393,530	$413,038

(1) John B. Ramil Prepared Direct Testimony filed September 5, 1991
(2) Deposition of John B. Ramil by FPSC Staff filed December 4, 1991
(3) John B. Ramil Rebuttal Testimony Exhibit JBR-2 filed November 20, 1991 and Revised Rebuttal Testimony filed December 9, 1991.

NOTE: The cost of land and site development was excluded from these installed cost estimates.

TABLE 1-2

POLK PROJECT COST ESTIMATE
DETERMINATION OF NEED HEARING
DECEMBER 1991

YEAR	NET PROJECT COSTS[1] ($000)	DOE FUNDING ($000)	MAJOR CONSTRUCTION ACTIVITY
1992	$4,705	($1,216)	
1993	58,939	(15,091)	Due to the nature of this estimate and the methodology used to develop it, yearly activities were not yet identified. Generic, historical construction curves were utilized to provide expected yearly expenditures for this estimate.
1994	243,381	(61,335)	
1995	106,014	(22,358)	
1996	0	0	
TOTAL	$413,038[2]	($100,000)	

[1] Project costs shown include AFUDC and are net of the DOE funding shown in Column 3. The cost for land and site development is excluded in this estimate.
[2] December 9, 1991 Fluor Daniel estimate provided in Table 1-1, page 4 of 8, of Interrogatory No. 1 response.

TABLE 1-3
POLK PROJECT COST ESTIMATE
BECHTEL ENGINEERING PRELIMINARY ESTIMATE
FALL 1993

YEAR	NET PROJECT COSTS[1] ($000)	DOE FUNDING ($000)	MAJOR CONSTRUCTION ACTIVITY
1992	$15,295	($3,741)	- Continued Polk Project permitting & certification activities. - Amended DOE Cooperative Agreement. - Selected A/E and completed Preliminary Engineering Package (PEP). - Developed business agreements for detailed engineering, consulting, and construction management services. - Developed RFPs for Air Separation unit (ASU), Syngas Cooler, and other major equipment. - Order issued for FPSC Need for Polk Power Station Unit No. 1.
1993	73,068	(15,110)	- Continue Polk Project permitting & certification activities. - Complete land acquisition activities. - Award contracts: detailed engineering & consulting services; Air Separation unit engineer, procure and construct; radiant & convective cooler purchases; Hot Gas Clean-up (HGCU) system design package; other long-lead plant equipment purchases. - Prepare bid packages for site reclamation and plant equipment. - Continue detailed engineering, procurement, and project management activities.
1994	108,630	(25,332)	- Complete Polk Power site certification. - Complete Environmental Impact Statements (EIS) for Environmental Protection Agency (EPA). - Complete U.S. Army Corps of Engineers 404 permit. - Award contracts: site development east of SR 37; sulfuric acid plant; brine concentration system equipment; coal handling system equipment; structural steel, piping, and other bulk materials; control, maintenance, and warehouse buildings; coal silos; miscellaneous plant equipment; railroad, site wells, and field erected tanks; underground piping and plant foundations. - Continue detailed engineering, procurement, and project management activities. - Bid balance of major construction contracts. - Begin delivery of bulk material and major equipment.
1995	233,188	(55,656)	- Ongoing construction contracts: railroad, site wells, coal silos, and field erected tanks; underground piping, plant foundations, and structural steel; site development and buildings. - Contractor mobilizations: sulfuric acid plant and ASU; power block contractor; gasification process contractor; HGCU and balance of plant contractors. - Delivery of balance of bulk materials and major equipment. - Continue detailed engineering, procurement, and project management activities. - Plant staff hiring and training.
1996	59,605	(11,307)	- Complete construction contracts. - Contract for final paving and landscaping. - Plant staff training. - Start-up of plant equipment, systems, and processes. - Initiate DOE demonstration period.
TOTAL	$489,786	($111,146)	

[1] Project costs shown include AFUDC and are net of the DOE funding. The cost for land and site development is included in this estimate.

TABLE 1-4

POLK PROJECT COST ESTIMATE
BECHTEL ENGINEERING DEFINITIVE ESTIMATE
FALL 1994

YEAR	NET PROJECT COSTS[1] ($000)	DOE FUNDING ($000)	MAJOR CONSTRUCTION ACTIVITY
1992	$15,295	($3,741)	- Continued Polk Project permitting & certification activities. - Amended DOE Cooperative Agreement. - Selected A/E and completed Preliminary Engineering Package (PEP). - Developed business agreements for detailed engineering, consulting, and construction management services. - Developed RFPs for Air Separation unit (ASU), Syngas Cooler, and other major equipment. - Order issued for FPSC Need for Polk Power Station Unit No. 1.
1993	75,527	(11,809)	- Continued Polk Project permitting & certification activities. - Completed land acquisition activities. - Awarded contracts: detailed engineering & consulting services; Air Separation unit engineer, procure and construct; radiant & convective cooler purchases; Hot Gas Clean-up (HGCU) system design package; other long-lead plant equipment purchases. - Prepared bid packages for site reclamation and plant equipment. - Continued detailed engineering, procurement, and project management activities.
1994	98,994	(26,824)	- Complete Polk Power site certification. - Complete Environmental Impact Statements (EIS) for Environmental Protection Agency (EPA). - Complete U.S. Army Corps of Engineers 404 permit. - Award contracts: site development east of SR 37; sulfuric acid plant; brine concentration system equipment; coal handling system equipment; structural steel, piping, and other bulk materials; control, maintenance, and warehouse buildings; coal silos; miscellaneous plant equipment; railroad, site wells, and field erected tanks; underground piping and plant foundations. - Continue detailed engineering, procurement, and project management activities. - Bid balance of major construction contracts. - Begin delivery of bulk material and major equipment.
1995	223,911	(54,329)	- Ongoing construction contracts: railroad, site wells, coal silos, and field erected tanks; underground piping, plant foundations, and structural steel; site development and buildings. - Contractor mobilizations: sulfuric acid plant and ASU; power block contractor; gasification process contractor; HGCU and balance of plant contractors. - Delivery of balance of bulk materials and major equipment. - Continue detailed engineering, procurement, and project management activities. - Plant staff hiring and training.
1996	89,590	(13,550)	- Completion of construction contracts. - Contract for final paving and landscaping. - Plant staff training. - Start-up of plant equipment, systems, and processes. - Initiate DOE demonstration period.
TOTAL	$503,317	($110,253)	

[1] Project costs shown include AFUDC and are net of the DOE funding. The cost for land and site development is included in this estimate.

TABLE 1-5

POLK PROJECT COST ESTIMATE
REVISED BECHTEL ENGINEERING ESTIMATE
FALL 1995

YEAR	NET PROJECT COSTS[1] ($000)	DOE FUNDING ($000)	MAJOR CONSTRUCTION ACTIVITY
1992	$15,295	($3,741)	- Continued Polk Project permitting & certification activities. - Amended DOE Cooperative Agreement. - Selected A/E and completed Preliminary Engineering Package (PEP). - Developed of business agreements for detailed engineering, consulting, and construction management services. - Developed RFPs for Air Separation unit (ASU), Syngas Cooler, and other major equipment. - Order issued for FPSC Need for Polk Power Station Unit No. 1.
1993	75,527	(11,809)	- Continued Polk Project permitting & certification activities. - Completed land acquisition activities. - Award contracts: detailed engineering & consulting services; Air Separation unit engineer, procure and construct; radiant & convective cooler purchases; Hot Gas Clean-up (HGCU) system design package; other long-lead plant equipment purchases. - Prepared bid packages for site reclamation and plant equipment. - Continued detailed engineering, procurement, and project management activities.
1994	102,273	(27,628)	- Completed Polk Power site certification. - Completed Environmental Impact Statements (EIS) for Environmental Protection Agency (EPA). - Completed U.S. Army Corps of Engineers 404 permit. - Awarded contracts: site development east of SR 37; sulfuric acid plant; brine concentration system equipment; coal handling system equipment; structural steel, piping, and other bulk materials; control, maintenance, and warehouse buildings; coal silos; miscellaneous plant equipment; railroad, site wells, and field erected tanks; underground piping and plant foundations. - Continued detailed engineering, procurement, and project management activities. - Bid balance of major construction contracts. - Began delivery of bulk material and major equipment.
1995	215,380	(52,485)	- Ongoing construction contracts: railroad, site wells, coal silos, and field erected tanks; underground piping, plant foundations, and structural steel; site development and buildings. - Contractor mobilizations: sulfuric acid plant and ASU; power block contractor; gasification process contractor; HGCU and balance of plant contractors. - Delivery of balance of bulk materials and major equipment. - Continue detailed engineering, procurement, and project management activities. - Plant staff hiring and training.
1996	97,690	(19,732)	- Completion of construction contracts. - Contract for final paving and landscaping. - Plant staff training. - Start-up of plant equipment, systems, and processes. - Initiate DOE demonstration period.
TOTAL	$506,165	($115,395)	

[1] Project costs shown include AFUDC and are net of the DOE funding. The cost for land and site development is included in this estimate.

65

2. Please provide a full and complete reconciliation and justification of the differences between the magnitude and timing of costs shown in response to Interrogatory No. 1.a. through 1.c. above.

A. As depicted on the attached Table 2-1, based on a consistent comparison which excludes the estimated land acquisition and site development and AFUDC expense, the comparative costs of Polk Unit No. 1 have remained relatively unchanged (4.3% above the December 9, 1991 Need Hearing estimate). The Need Hearing estimate was completed before any project specific engineering or design work had been completed, as was the case with all the estimates examined as alternatives. It should also be noted that the design of this unit combines the innovative integration of proven technologies with a developmental hot gas clean-up process (HGCU) that offers potentially lower unit heat rates and therefore lower operating costs. At the time of the Need Hearing, only one IGCC unit had been built in the United States, and no unit exactly like the Polk unit has ever been built. The advancement of the integration and technology of the unit is the reason DOE had provided funding for the project, and the relative newness of the design makes the projection of costs more difficult.

The initial estimate of $413 million (Table 1-2, Interrogatory No. 1) was developed using, primarily, capacity-factored and equipment-factored estimating techniques. Capacity-factored estimating is based on multiplying the cost of a similar unit for which the direct construction costs are known by the ratio of the new unit's capacity to that of the similar unit. Capacity ratios are adjusted by an exponent chosen on the basis of the unit type. Equipment-factored estimating is based on the cost and specifications of each major equipment item (vessels, compressors, turbines, exchangers, etc.). Costs for bulk materials and field labor man-hour requirements are factored, based on appropriate equipment parameters (duty, size, weight, metallurgy, temperature, pressure, etc.), to determine the total direct construction cost. Such estimates have obvious limitations, but they are often used to produce relative "Order of Magnitude" accuracy comparisons. Expected accuracy ranges of total project cost estimates tend to narrow as more information becomes available throughout the life of any project.

The fall 1993 preliminary estimate (Table 1-3, Interrogatory No. 1) concentrated on the scope and pricing of major equipment. Budget quotes were obtained from prospective bidders to establish equipment costs. Bulk materials and construction labor costs were factored as a percentage of major equipment dollars based on historical data. These more design-specific estimating processes typically result in improved levels of accuracy.

The fall 1994 (Table 1-4, Interrogatory No. 1) estimate was much more detailed than previous estimates and was based on planning studies, piping and instrumentation diagrams, plot plans, electrical single line diagrams, instrument index, equipment index, and civil design drawings and sketches. Equipment pricing was based on commitments and budget quotes. Large bore piping, electrical, instrumentation, concrete, structural steel, buildings, and earthwork estimates were based on quantity take-offs and historical pricing data. Construction labor man-hours were generated from take-off quantities and priced out using 1994 labor rates and historical production rates.

The fall 1995 estimate (Table 1-5, Interrogatory No. 1) was more detailed and relied heavily on actual contract commitment data and an engineering estimate of work not yet under contract. At the time of this update, the project was approximately 86% committed. The acceptable industry standard of this type of reforecast would be +10% and -5%.

A primary objective of the Polk project management team has always been to manage capital costs to their lowest possible levels. Many scope modifications have taken place as the project has evolved. A few of the significant changes implemented to achieve a more cost effective project since the early stages of this project include, but are not limited to the following:

- reduction of on-site coal storage capabilities by utilizing existing facilities;
- replacement of original sulfur recovery and tail gas treating systems with a more cost effective sulfuric acid plant;
- deletion of piling requirements for all major structures; and
- reduction of overall site plot plans to reduce bulk material requirements.

The capital costs have essentially remained level from the pre-design stage through construction when comparable costs are examined. The 4.3% variance from 1991 Need Hearing estimates to the 1995 definitive project reforecast is a significant achievement for the first-time design and installation of a new technology such as an IGCC power plant. If the start-up and check-out phase of the project does not identify any new technological or operational problems, the project management team expects the comparable capital costs to remain within 5% of the December 9, 1991 Need Hearing estimates.

TABLE 2-1

POLK PROJECT COST ESTIMATE COMPARISONS

($000)

INTERROGATORY REFERENCE:	(1a)	(1b)	(1c)	(1c)
Plant Components	Need Hearing 12/91 Estimate	Fall 1993 Estimate	Fall 1994 Estimate	Fall 1995 Estimate
Plant	$472,062	$488,016	$495,523	$503,331
DOE Funding	(100,000)	(111,146)	(110,253)	(115,395)
Subtotal without AFUDC & Land	372,062	376,870	385,270	387,936
% Variance from 12/91 Estimate		1.3%	3.5%	4.3%
Land Acquisition & Site Development	0	56,353	64,535	65,835
AFUDC	40,976	56,563	53,513	52,394
TOTAL PROJECT ESTIMATE:	$413,038	$489,786	$503,318	$506,165

Key Estimate Clarifications

1. The 12/91 Need Hearing estimate (Column 1a) excluded Land Acquisition & Site Development costs in installed cost.
2. The Fall 1993, Fall 1994, and Fall 1995 estimates included Land Acquisition & Site Development costs.
3. Through time, as estimates were developed with more engineering data, component costs were captured more accurately and consistently utilizing the project work break-down structure developed during the preliminary engineering stage of the project in 1992.
4. The Fall 1994 and Fall 1995 estimates (Columns 1c) were prepared as a budget estimates using flow sheets, layout, and equipment details.

3. Please provide a full and complete description of any analyses done during the construction of the Polk IGCC Unit to evaluate the effect of cost and timing changes on the continued cost effectiveness of the unit. Please provide a summary of all assumptions used in the analysis.

A. Annual economic evaluations of Tampa Electric's generation expansion plan have been completed since the Determination of Need proceedings in December 1991 and the subsequent Commission order on March 2, 1992 approving the construction of the Polk IGCC unit. In each annual review, the continued cost effectiveness of Polk 1 was examined in light of more current data and assumptions. The annual evaluations supported the development of the company's annual planning efforts as well as the annual Ten-Year Site Plan filing and afforded Tampa Electric an opportunity to re-examine its expansion plan in light of revised assumptions. Each Ten Year Site Plan submitted by Tampa Electric from 1992 through 1995 provided updates to the Commission on both the cost of the Polk 1 project as well as changes to the timing and type of future generating plant additions.

Table 3-1 is a summary of five cost effectiveness evaluations of the Polk IGCC project that were completed between 1992 and 1996. The format and methodology of the original studies were revised to maintain consistency in how actual and balance of project cash flow streams in each calendar year were handled for both the IGCC and combined cycle plans. In developing the combined cycle plan, costs incurred up to the time of the study for the development and construction of the IGCC unit were included as sunk costs in the combined cycle plan. For example, the 1994 cost effectiveness study includes all actual project expenses and commitments through April 1994 for both the IGCC plan and combined cycle plan. The remaining estimated costs to complete the IGCC unit or combined cycle unit are included for each plan.

This analysis methodology of using costs incurred up to the time of the study to determine sunk costs rather than on an accrual basis is conservative in that contractual commitments and associated contract cancellation penalties are excluded. These additional costs would be assignable to the combined cycle plan as sunk costs if Tampa Electric had not continued with the construction of the IGCC plant. In addition, the DOE funding received on a cash-call basis was not assumed to be refundable from Tampa Electric to DOE. The sunk costs for the combined cycle plan would therefore increase if DOE requested any refund.

The fuel assumptions for the IGCC unit varied in each study to reflect the most cost effective and viable primary fuel source at the time of the study. The 1992 cost effectiveness study assumed coal as the primary fuel throughout the study. The 1993 and 1996 studies assumed a blend of petroleum coke with coal. The 1994 and 1995 cost effectiveness studies included additional savings related to Section 29 tax credits for producing synthetic natural gas and/or alternative lower cost fuels used for the IGCC unit. These credits were assumed applicable for the first eleven and twelve years, respectively, of IGCC operation, and a blend of petroleum coke with coal for the balance of the study. The tax credits had an approximate value of $98 million in the 1994 study and $87 million in the 1995 study. The fuel assumptions for the combined cycle unit were based on as-available natural gas in the spring (March, April, May) and the fall (October, November) and distillate oil in the remaining months.

The five studies summarized in the response to this interrogatory study compare the cost effectiveness of the IGCC unit to a combined cycle unit as the next generating plant addition to our system. The balance of the expansion plan was included in the total system revenue requirements break-out of the capital, O&M, and fuel requirements on a cumulative present worth basis. Table 3-1 (page 4 of this response) summarizes the IGCC plan savings compared to a plan that replaces the IGCC unit with a combined cycle. The savings are based on differential system cumulative present worth revenue requirements (CPWRR) shown in the current year dollars for each study. This table shows the continued cost effectiveness of the IGCC project each time it was reviewed during the construction of the unit.

Another fundamentally important consideration in examining any change of construction 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.

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 terminated. In the case of Polk Unit One, these cancellation costs include damages on outstanding contracts and the potential loss of U. S. Department of Energy funding.

TABLE 3-1
POLK IGCC COST EFFECTIVENESS STUDIES SUMMARY
IGCC PLAN RELATIVE TO CC PLAN
DIFFERENTIAL SYSTEM CPWRR ($ x 10^6)

Year of Study	Capital	O&M	Fuel	Net System
1992	124	93	(372)	(155)
1993	260	64	(432)	(108)
1994	176	81	(358)	(101)
1995	122	75	(345)	(148)
1996	23	86	(310)	(201)

NOTE: The negative differential net system CPWRR shows the IGCC plan savings relative to the CC plan.

1992 POLK 1 IGCC COST EFFECTIVENESS STUDY

The 1992 Polk unit analysis compared system revenue requirements, in 1992 dollars, for the IGCC using the October 1992 cost estimate with the system revenue requirements of a phased combined cycle unit.

The capital costs for the IGCC and combined cycle are shown on the assumptions table attached. The capital costs for both the IGCC and combined cycle plans include the common costs for land acquisition, site development, and other common costs. The combined cycle cost also includes the sunk costs associated with the IGCC gasifier and related components through year-end 1992. It is also assumed that the expected DOE funding is included in the IGCC plan, but only DOE funding received at the time of the analysis for the combined cycle plan.

The fuel plan for the IGCC and combined cycle unit was developed from the 1992 Price Change forecast. Savings shown represent the IGCC burning a coal similar to Illinois No. 6. The combined cycle unit primary fuel was assumed to be natural gas and distillate oil as the secondary fuel throughout the study.

Total differential system revenue requirements including DOE and EPRI funding showed a system present worth savings of $155 million for the IGCC plan.

TAMPA ELECTRIC COMPANY
1992 POLK UNIT ANALYSIS

Resource Plans

Year	Polk IGCC	Polk CC
1995	7F CT	7F CT
1996	HRSG/CG	
1997	-	CT
1998	CT	HRSG
1999	CT	CT
2000	CT	CT
2001	CT	HRSG
2002	-	CT
2003	CC	2 CT's
2004	-	-
2005	HRSG	HRSG
2006	CT	CT
2007	CT	CT
2008	CT	HRSG
2009	-	CT
2010	HRSG	CT
2011	CT	CT

IGCC Plan Savings - 30 Year CPWRR (92$ x 1000)	
Capital	($124,067)
O&M	($93,228)
Fuel	$372,258
Tax Credit	$0
IGCC Plan Savings	$154,964

TAMPA ELECTRIC COMPANY
1992 POLK UNIT ANALYSIS

Assumptions

	Polk IGCC	Polk CC
As Spent Capital ($ x 1000)		
Plant	381,739	145,025
Gasifier related "Sunk"	Included in plant	4,792
Land and Site Development	52,656	52,656
Common	88,505	78,274
DOE credit	(100,629)	(2,856)
Total	422,271	277,891
Total w/AFUDC	457,643	309,601
Tax Life	20 Years	15 Years (CT) 20 Years (HRSG)
O&M		
Fixed (97$000)	9,550	1,147
Variable ($/MWh)	3.04	5.19
Escalation		
Capital (1992)	4.00%	4.00%
Capital (1993)	4.10%	4.10%
Capital (1994)	4.40%	4.40%
Capital (1995 - beyond)	4.80%	4.80%
O&M	4.50%	4.50%
AFUDC	7.93%	7.93%
Discount Rate	10.06%	10.06%
Capacity (MW)	263.3	217
Heat Rate (Btu/kWh)	8631	7996
Fuel Forecast	See 1992 Price Change forecast (Intr #5) Coal	See 1992 Price Change forecast (Intr #5) Natural Gas/Distillate Oil
D&E Forecast	See 1992 Price Change forecast (Intr #7)	See 1992 Price Change forecast (Intr #7)

1. IGCC O&M excludes DOE O&M credit ($20M over 1996, 1997, 1998).

1993 POLK 1 IGCC COST EFFECTIVENESS STUDY

The 1993 Polk Unit One analysis compared system revenue requirements, in 1993 dollars, for the IGCC using the 1993 cost estimate with the system revenue requirements of a combined cycle unit. An economic and system reliability analysis showed that the 7F advanced combustion turbine could be deferred from a July 1995 commercial operation date to July 1996 while cost effectively maintaining system reliability.

The capital costs for the IGCC and combined cycle are shown on the assumptions table attached. The capital costs for both the IGCC and combined cycle plan include the common costs for land acquisition, site development, and other costs common to both plans. The combined cycle capital cost also includes the sunk costs associated with the IGCC gasifier and related components up to the time of the study. Both plans also include DOE funding received at the time of the study and expected additional DOE funding for the IGCC plan only.

The fuel plan for the IGCC unit and combined cycle was developed from the 1993 summer forecast. Savings shown represent the IGCC burning demonstration coals from 1996 to 1998, and a 80%/20% petroleum coke/Galatia coal blend from 1999 through the end of the study. The combined cycle unit primary fuel was assumed to be natural gas and distillate oil as the secondary fuel throughout the study.

Total differential system revenue requirements including DOE and EPRI funding showed a system present worth savings of $108 million for the IGCC plan.

TAMPA ELECTRIC COMPANY
1993 POLK UNIT ANALYSIS

Resource Plans

Year	Polk IGCC	Polk CC
1995		
1996	IGCC	CC
1997		
1998		
1999	CT	CT
2000	CT	CT
2001	HRSG	CT/HRSG
2002	CT	CT
2003	CT	CT
2004	HRSG	
2005	CT	HRSG
2006	CT	CT
2007	CT	CT
2008		CT
2009	HRSG	HRSG
2010	CT	
2011	CT	CT

IGCC Plan Savings - 30 Year CPWRR (93$ x 1000)	
Capital	($260,305)
O&M	($63,724)
Fuel	$431,624
Tax Credit	$0
IGCC Plan Savings	$10[illegible]595

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TAMPA ELECTRIC COMPANY
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TAMPA ELECTRIC COMPANY
1993 POLK UNIT ANALYSIS

Assumptions

	Polk IGCC	Polk CC
As Spent Capital ($ x 1000)		
Plant	$392,275	$142,431
Gasifier related "Sunk"	Included in Plant	$17,347
Land and Site Development	$57,040	$57,040
Common	$95,052	$54,744
DOE credit	($111,146)	($18,851)
Total	$433,221	$252,711
Total w/AFUDC	$489,784	$279,125
Tax Life	20 Years	20 Years
O&M		
Fixed (97$000)	6,416	1,095
Variable ($/MWh)	2.70	5.19
Escalation		
Capital (1993)	3.50%	3.50%
Capital (1994)	3.80%	3.80%
Capital (1995 - beyond)	4.00%	4.00%
O&M	4.50%	4.50%
AFUDC	7.70%	7.70%
Discount Rate	9.17%	9.17%
Capacity (MW)	251.2	211
Heat Rate (Btu/kWh)	8971	7841
Fuel Forecast	See 1993 Summer forecast (Intr #5) Pet Coke/ Galatia Coal	See 1993 Summer forecast (Intr #5) Natural Gas/Distillate Oil
D&E Forecast	See 1992 Fall forecast (Intr #7)	See 1992 Fall forecast (Intr #7)

1. IGCC O&M excludes DOE O&M credit ($20M over 1996, 1997, 1998). Variable O&M excludes a $1.45M sulfur credit

1994 POLK 1 IGCC COST EFFECTIVENESS STUDY

The 1994 Polk 1 study compares the IGCC plan revenue requirements to the construction of a 215 MW combined cycle at the same site.

The capital costs for the IGCC and combined cycle are shown on the assumptions table attached. The capital costs for both the IGCC and combined cycle plan include the common costs for land acquisition, site development, and other costs common to both plans. The combined cycle capital cost also includes the sunk costs associated with the IGCC gasifier and related components up to the time of the study. Both plans also include DOE funding received at the time of the study and expected additional DOE funding for the IGCC plan only.

The fuel plans are from the 1994 spring forecast identified in the response to Interrogatory No. 5. Revenue requirement savings shown represent the IGCC Pitt #8 coal from 1996 to 1998, Illinois #6 coal from 1999 through the end of the study. Section 29 tax credits of $98 million were included for the first eleven years of operation (1996 - 2006). The combined cycle unit burns as-available natural gas in the spring and fall and distillate oil in the winter and summer throughout the study.

Total differential system revenue requirements including DOE and EPRI funding showed a system present worth savings of $101 million for the IGCC plan.

TAMPA ELECTRIC COMPANY
1994 POLK UNIT ANALYSIS

Resource Plans

YEAR	Polk IGCC	Polk CC
1994	-	-
1995	-	-
1996	IGCC	CC
1997	-	-
1998	-	-
1999	-	-
2000	CT	CT
2001	CT	CT
2002	CT	CT
2003	-	-
2004	CT	CT
2005	-	-
2006	CT	CT
2007	CT	CT
2008	CT	CT
2009	CT	CT
2010	CT	CT
2011	-	-
2012	-	CT
2013	CT	-

IGCC Plan Savings - 30 Year CPWRR (94$ x 1000)	
Capital	(176,047)
O&M	(80,512)
Fuel	259,235
Tax Credit	98,356
IGCC Plan Savings	101,032

TAMPA ELECTRIC COMPANY
1994 POLK UNIT ANALYSIS

Assumptions

	Polk IGCC	Polk CC
As Spent Capital ($ x 1000):		
Plant	395,475	146,635
Gasifier Related "Sunk"	included in plant	34,847
Land and Site Development	61,223	61,223
Common	94,141	54,399
DOE Credit	(110,253)	(22,863)
Total	440,586	274,241
Total w/ AFUDC	495,946	305,688
Tax Life	10 Years (Gasifer) 20 Years (Other)	20 Years
O&M: :		
Fixed(97 $000)	13,522	5,648
Variable ($/MWH)	NA	0.40
Escalation:		
Capital	4.00%	4.00%
O&M	3.70%	3.70%
AFUDC Rate	7.70%	7.70%
Discount Rate	8.47%	8.47%
Capacity (MW)	253	215
Heat Rate (BTU/KWH)	8,935	7,641
Fuel Forecast	See 1994 Spring Forecast (Intr. #5)	See 1994 Spring Forecast (Intr. #5)
(1996 - 1998)	Pitt #8	Natural Gas/ Distillate Oil
(1999 - 2023)	Illinois #6	Natural Gas/ Distillate Oil
D&E Forecast	See 1993 Fall Forecast (Intr. # 7)	See 1993 Fall Forecast (Intr. # 7)

Note:
IGCC fixed O&M includes variable costs and excludes DOE credit. (Total DOE O&M credit is approx. $20 M over years 1996, 1997, and 1998)

1995 POLK 1 IGCC COST EFFECTIVENESS STUDY

The 1995 Polk 1 cost effectiveness study compared system revenue requirements between the base (IGCC) resource plan and a plan that substituted a combined cycle for the IGCC unit.

The capital costs for the IGCC and combined cycle are shown on the assumptions table attached. The capital costs for both the IGCC and combined cycle plan include the common costs for land acquisition, site development, and other costs common to both plans. The combined cycle capital cost also includes the sunk costs associated with the IGCC gasifier and related components up to the time of the study. Both plans also include DOE funding received at the time of the study and expected additional DOE funding for the IGCC plan only.

Fuel plans are from the 1994 fall fuel forecast. Several fuel plans were developed for the IGCC unit, however the revenue requirement savings shown represent the IGCC burning Pitt #8 coal from 1996 to 1998, Illinois #6 coal from 1999 to 2007, and a 65/35% pet coke/Powder River Basin coal blend from 2008 through the end of the study. Section 29 tax credits of $87 million were included for the first twelve years of operation (1996 - 2007) for the IGCC unit. The combined cycle unit burns as-available natural gas in the spring and fall months and distillate oil in the winter and summer months throughout the study.

Total differential system revenue requirements including DOE and EPRI funding showed a system present worth savings of $148 million for the IGCC plan.

TAMPA ELECTRIC COMPANY
1995 POLK UNIT ANALYSIS

Resource Plans

YEAR	Polk IGCC	Polk CC
1995	-	-
1996	IGCC	CC
1997	-	-
1998	-	-
1999	-	-
2000	-	-
2001	CT	CT
2002	CT	CT
2003	CT	CT
2004	CT	CT
2005	CT	CT
2006	-	-
2007	CT	CT
2008	CT	CT
2009	CT	CT
2010	-	-
2011	-	-
2012	CT	CT
2013	-	-
2014	CT	CT

IGCC Plan Savings - 30 Year CPWRR (95$ x 1000)	
Capital	(122,180)
O&M	(74,951)
Fuel	257,963
Tax Credit	87,335
IGCC Plan Savings	148,167

TAMPA ELECTRIC COMPANY
1995 POLK UNIT ANALYSIS

Assumptions

	Polk IGCC	Polk CC
As Spent Capital ($ x1000):		
Plant	387,645	144,576
Gasifier Related "Sunk"	included in plant	170,417
Land and Site Development,	64,538	64,538
Common	107,874	62,676
DOE Credit	(110,253)	(67,452)
Total	449,804	374,755
Total w/ AFUDC	503,317	409,434
Tax Life	10 Years (Gasifier) 20 Years (Other)	20 Year
O&M:		
Fixed (97 $000)	13,289	5,648
Variable ($/MWH)	NA	0.40
Escalation:		
Capital		
1995	3.30%	3.30%
1996	3.80%	3.80%
1997	4.00%	4.00%
O&M		
1995	3.00%	3.00%
1996	3.50%	3.50%
1997	3.70%	3.70%
AFUDC	7.28%	7.28%
Discount Rate	9.51	9.51
Capacity (Nominal)	249.1 (1996 - 1997) 250.3 (1998 - 2024)	244
Heat Rate (Btu/kWh)		
@ Minimum (25%)	11,040	11,380
@ Maximum(100%)	8,775 (1996 - 1998) 9,140 (1999 - 2007) 8,869 (2008 - 2024)	7900
Fuel Forecast	See1994 Fall Forecast (Intr. #5)	See1994 Fall Forecast (Intr. #5)
(1996 - 1998)	Pitt #8	Natural Gas/Distillate Oil
(1999 - 2007)	Illinois #6	Natural Gas/Distillate Oil
(2008 - 2024)	PetCoke/PRB (65/35%)	Natural Gas/Distillate Oil
D&E Forecast	See1994 Fall Forecast (Intr. #7)	See1994 Fall Forecast (Intr. #7)

Notes:

1. IGCC O&M cost includes variable costs and excludes DOE credit. (Total DOE O&M credit is approx. $20 M over years 1996, 1997, and 1998.)

1996 POLK 1 IGCC COST EFFECTIVENESS STUDY

The 1996 Polk IGCC cost effectiveness study compared system revenue requirements of the IGCC base resource plan with a combined cycle plan that replaces the IGCC and adjusts for combined cycle unit capacity and availability.

The capital costs for the IGCC and combined cycle are shown on the assumptions table attached. The capital costs for both the IGCC and combined cycle plan include the common costs for land acquisition, site development, and other costs common to both plans. The combined cycle capital cost also includes the sunk costs associated with the IGCC gasifier and related components up to the time of the study. Both plans also include DOE funding received at the time of the study and expected additional DOE funding for the IGCC plan only.

Fuels were from the fall 1995 fuel forecast. The IGCC plan assumes Pitt #8 coal used from 1996-1998 (DOE demonstration period) and a 75/25% pet coke/Powder River Basin coal blend from 1999-2025. Section 29 tax credits are excluded in this study. The combined cycle uses as-available natural gas in the spring and fall months and distillate oil in the winter and summer months throughout the study.

Total differential system revenue requirements including DOE funding showed a system present worth savings of $201 million for the IGCC plan.

TAMPA ELECTRIC COMPANY
1996 POLK UNIT ANALYSIS

Resource Plans

Year	Polk IGCC	Polk CC
1996	IGCC	CC
1997	-	-
1998	-	-
1999	-	-
2000	-	-
2001	-	-
2002	CT	CT
2003	CT	CT
2004	CT	CT
2005	CT	CT
2006	CT	CT
2007	CT	CT
2008	-	-
2009	CT	2 CTs
2010	2 CTs	CT
2011	-	-
2012	-	-
2013	CT	CT
2014	-	CT
2015	CT	CT

IGCC Plan Savings - 30 Year CPWRR (96$ x 1000)	
Capital	(22,806)
O&M	(86,219)
Fuel	310,232
Tax Credit	0
IGCC Plan Savings	201,206

TAMPA ELECTRIC COMPANY
1996 POLK UNIT ANALYSIS

Assumptions

	IGCC	CC
As Spent Capital ($ x 1000):		
Plant	384,870	142,168
Gasifier Related "Sunk"	included in plant	244,942
Land and Site Development	65,835	65,835
Common	118,461	67,014
DOE Credit	(115,395)	(96,338)
Total	453,771	423,621
Total w/ AFUDC	506,165	463,085
Tax Life	7 Years (All Components)	20 Years
O&M		
Fixed (97$000)	11,974	3,551
Variable ($/MWh)	NA	1.46
Escalation		
Capital (1996)	3.4%	3.4%
Capital (1997 - beyond)	3.5%	3.5%
O&M (1996)	3.1%	3.1%
Capital (1997 - beyond)	3.2%	3.2%
AFUDC	7.79%	7.79%
Discount Rate	9.26%	9.26%
Capacity (MW)		
Winter	250	233
Summer	250	212
Heat Rate (Btu/kWh)		
@max (1996-1998)	8775	7669
@max (1999-2025)	8869	7669
Fuel Forecast	See 1995 Fall Forecast (Intr. #5)	See 1995 Fall Forecast (Intr. #5)
(1996 - 1998)	Pitt #8	Natural Gas/Distillate Oil
(1999 - 2025)	Pet Coke /PRB	Natural Gas/Distillate Oil
D&E Forecast	See 1995 Fall Forecast (Intr. #7)	See 1995 Fall Forecast (Intr. #7)

Note:
1. IGCC fixed O&M includes variable costs and excludes DOE credit. (Total DOE O&M credit is $20 M over years 1996, 1997, and 1998.)

5. Attachment 1 is Tampa Electric's base case natural gas and coal price forecast that was submitted as Late Filed Exhibit No. 35 in Docket 910883-EI. Please verify that this was Tampa Electric's base case scenario and provide this same information for each subsequent fuel price forecast that was generated up to and including Tampa Electric's most recent forecasts. These forecasts should be separately identified and labeled.

A. The aforementioned natural gas and coal price forecast that was submitted as Late Filed Exhibit No. 35 was Tampa Electric's base case fuel forecast for the annual planning process. Tables 5-1 and 5-2 contain subsequent coal and petroleum coke (pet coke) fuel price forecasts including the most recent forecast developed in the fall 1995 planning process. Tables 5-3, 5-3L, and 5-3H contain the corresponding natural gas price forecasts for the base, high, and low forecast scenarios, respectively. Table 5-4 contains the distillate oil price forecast.

TABLE 5-1
(Revised)

IGCC - FUEL FORECASTS ($/MBTU)

COALS

	1991/92 Winter Forecast	1992 Price Change	1993 Summer Forecast	1993 Fall Forecast	1994 * Spring Forecast	1994 Fall Forecast			1995 Fall Forecast		
			(Galatia)	(ILL #6)	(ILL #6)	(PITT 8)	(ILL #6)	(PRB)	(PITT 8)	(ILL #6)	(PRB)
1996	1.71	1.71	1.86	1.56	1.72	1.65	1.49	1.67	1.63	1.42	1.87
1997	1.78	1.78	1.93	1.89	1.67	1.69	1.53	1.74	1.67	1.45	1.92
1998	1.86	1.86	2.01	1.66	1.64	1.74	1.57	1.83	1.71	1.48	1.99
1999	1.94	1.94	2.10	1.71	1.63	1.80	1.62	1.89	1.81	1.51	2.05
2000	2.03	2.03	2.19	1.77	1.68	1.86	1.67	1.95	1.80	1.55	2.07
2001	2.13	2.13	2.30	1.83	1.74	1.92	1.73	2.01	1.85	1.59	2.12
2002	2.24	2.24	2.44	1.90	1.80	1.99	1.79	2.08	1.90	1.63	2.17
2003	2.36	2.36	2.57	1.97	1.87	2.06	1.86	2.16	1.95	1.67	2.22
2004	2.49	2.49	2.70	2.05	1.94	2.13	1.92	2.23	2.01	1.71	2.27
2005	2.63	2.63	2.84	2.13	2.01	2.21	1.99	2.32	2.06	1.75	2.32
2006	2.77	2.77	3.00	2.22	2.08	2.29	2.07	2.40	2.12	1.79	2.37
2007	2.93	2.93	3.16	2.32	2.16	2.38	2.14	2.48	2.18	1.83	2.43
2008	3.10	3.10	3.34	2.42	2.24	2.47	2.22	2.57	2.24	1.88	2.48
2009	3.28	3.28	3.52	2.53	2.32	2.56	2.30	2.67	2.30	1.92	2.54
2010	3.47	3.47	3.72	2.65	2.41	2.65	2.39	2.76	2.37	1.97	2.59
2011	3.67	3.67	3.92	2.78	2.49	2.75	2.47	2.86	2.43	2.02	2.65
2012	3.90	3.90	4.14	2.92	2.58	2.85	2.56	2.97	2.50	2.06	2.72
2013	4.14	4.14	4.38	3.06	2.68	2.93	2.65	3.07	2.57	2.11	2.78
2014	4.40	4.40	4.64	3.22	2.78	3.06	2.75	3.19	2.64	2.16	2.84
2015	4.72	4.72	4.94	3.36	2.88	3.17	2.85	3.31	2.71	2.21	2.91
2016	5.07	5.07	5.28	3.51	2.98	3.29	2.96	3.43	2.79	2.27	2.98
2017	5.44	5.44	5.64	3.68	3.10	3.41	3.07	3.56	2.87	2.32	3.05
2018	5.85	5.85	6.04	3.86	3.23	3.55	3.20	3.71	2.95	2.38	3.13
2019	6.31	6.31	6.47	4.05	3.36	3.70	3.33	3.87	3.03	2.44	3.20
2020	6.80	6.80	6.93	4.26	3.51	3.86	3.48	4.04	3.12	2.50	3.29
AAGR%	5.92%	5.92%	5.63%	4.27%	3.01%	3.60%	3.60%	3.75%	2.74%	2.38%	2.38%

A:\FUELFCS3.WK4

* The 1994 Spring Forecast was revised. The original values provided were from the 1993 Fall Forecast.

TABLE 5-2

	IGCC - FUEL FORECASTS ($/MBTU)		
	PET COKE		
	1993 Summer Forecast	1994 Fall Forecast	1995 Fall Forecast
1996	0.84	0.79	0.87
1997	0.87	0.81	0.89
1998	0.91	0.83	0.91
1999	0.94	0.85	0.91
2000	0.98	0.87	0.95
2001	1.02	0.90	0.97
2002	1.07	0.93	0.99
2003	1.12	0.95	1.02
2004	1.17	0.98	1.04
2005	1.23	1.01	1.07
2006	1.29	1.04	1.10
2007	1.35	1.07	1.12
2008	1.42	1.10	1.15
2009	1.49	1.14	1.18
2010	1.56	1.17	1.21
2011	1.64	1.21	1.24
2012	1.72	1.24	1.27
2013	1.80	1.28	1.30
2014	1.90	1.32	1.33
2015	2.00	1.36	1.36
2016	2.12	1.40	1.40
2017	2.25	1.44	1.43
2018	2.38	1.49	1.47
2019	2.53	1.54	1.50
2020	2.69	1.59	1.54
	4.97%	2.96%	2.41%

TABLE 5-3
(Revised)

NATURAL GAS
BASE FORECAST
($/MBTU)

	1992* Price Change	1993 Summer Forecast	1993 Fall Forecast	1994 Spring Forecast	1994 Fall Forecast	1995 Fall Forecast
1996	4.51	3.10	3.34	3.15	3.06	2.45
1997	4.78	3.31	3.51	3.36	3.29	2.64
1998	5.19	3.53	3.69	3.56	3.53	2.86
1999	5.59	3.77	3.90	3.78	3.77	3.03
2000	6.04	4.03	4.11	4.02	4.01	3.21
2001	6.54	4.31	4.35	4.28	4.28	3.40
2002	7.06	4.59	4.60	4.57	4.56	3.59
2003	7.63	4.89	4.88	4.89	4.88	3.80
2004	8.26	5.21	5.19	5.23	5.22	4.02
2005	8.95	5.55	5.52	5.61	5.60	4.27
2006	9.67	5.92	5.87	6.01	6.00	4.53
2007	10.46	6.31	6.25	6.46	6.45	4.81
2008	11.28	6.73	6.66	6.94	6.92	5.11
2009	12.17	7.18	7.10	7.46	7.45	5.43
2010	13.08	7.67	7.57	8.03	8.01	5.78
2011	14.06	8.18	8.08	8.49	8.48	6.15
2012	15.05	8.73	8.62	8.99	8.97	6.44
2013	16.13	9.31	9.20	9.51	9.49	6.75
2014	17.31	9.92	9.83	10.08	10.06	7.08
2015	18.56	10.58	10.50	10.68	10.66	7.43
2016	20.02	11.27	11.23	11.32	11.30	7.79
2017	21.59	12.02	12.01	12.01	11.98	8.18
2018	23.22	12.81	12.91	12.79	12.77	8.58
2019	25.00	13.66	13.88	13.63	13.60	9.01
2020	26.81	14.56	14.92	14.53	14.50	9.46
AAGR%	7.71%	6.66%	6.43%	6.58%	6.70%	5.79%

* The 1992 Price Change forecast was revised to match the natural gas being used by the combined cycle in the 1992 Polk cost effectiveness study.

TABLE 5-3L

	NATURAL GAS LOW FORECAST ($/MBTU)				
	1992 Price Change	1993 Fall Forecast	1994 Spring Forecast	1994 Fall Forecast	1995 Fall Forecast
1996	2.71	3.09	2.95	2.83	2.28
1997	2.87	3.24	3.03	3.04	2.45
1998	3.03	3.40	3.12	3.25	2.66
1999	3.21	3.59	3.22	3.42	2.80
2000	3.41	3.78	3.33	3.58	2.93
2001	3.69	3.99	3.44	3.74	3.04
2002	3.94	4.22	3.56	3.92	3.16
2003	4.19	4.47	3.69	4.11	3.28
2004	4.47	4.75	3.82	4.30	3.41
2005	4.77	5.04	3.96	4.51	3.55
2006	5.09	5.36	4.10	4.73	3.68
2007	5.43	5.70	4.25	4.97	3.83
2008	5.80	6.07	4.41	5.21	3.98
2009	6.20	6.47	4.57	5.47	4.13
2010	6.62	6.89	4.73	5.73	4.29
2011	7.07	7.35	4.91	5.91	4.46
2012	7.56	7.84	5.08	6.09	4.56
2013	8.09	8.36	5.26	6.28	4.66
2014	8.66	8.92	5.45	6.47	4.76
2015	9.33	9.53	5.65	6.66	4.86
2016	10.05	10.19	5.86	6.85	4.95
2017	10.82	10.89	6.07	7.04	5.05
2018	11.66	11.70	6.33	7.26	5.14
2019	12.56	12.57	6.60	7.48	5.23
2020	13.54	13.51	6.88	7.71	5.32
AAGR%	6.94%	6.34%	3.59%	4.26%	3.59%

TABLE 5-3H

NATURAL GAS
HIGH FORECAST
($/MBTU)

	1992 * Price Change	1993 Fall Forecast	1994 Spring Forecast	1994 Fall Forecast	1995 Fall Forecast
1996	5.13	3.60	3.35	3.28	2.67
1997	5.73	3.78	3.69	3.54	2.88
1998	6.35	3.98	3.99	3.80	3.07
1999	7.05	4.21	4.33	4.07	3.25
2000	7.85	4.44	4.71	4.33	3.46
2001	8.69	4.70	5.13	4.62	3.66
2002	9.57	4.98	5.58	4.94	3.87
2003	10.53	5.29	6.09	5.29	4.10
2004	11.54	5.63	6.64	5.67	4.35
2005	12.65	5.99	7.25	6.07	4.61
2006	13.74	6.38	7.92	6.52	4.90
2007	14.93	6.79	8.66	7.01	5.21
2008	16.08	7.24	9.47	7.54	5.54
2009	17.32	7.73	10.35	8.11	5.89
2010	18.64	8.25	11.32	8.73	6.27
2011	20.06	8.81	12.08	9.25	6.68
2012	21.61	9.40	12.89	9.79	7.01
2013	23.30	10.03	13.76	10.36	7.35
2014	25.15	10.73	14.70	10.98	7.71
2015	27.31	11.47	15.71	11.65	8.09
2016	29.62	12.27	16.79	12.35	8.49
2017	32.13	13.13	17.94	13.10	8.91
2018	34.89	14.12	19.25	13.96	9.36
2019	37.89	15.19	20.66	14.88	9.83
2020	41.15	16.34	22.18	15.87	10.33
AAGR%	9.06%	6.51%	8.19%	6.79%	5.80%

REVISED 05/02/96
TAMPA ELECTRIC COMPANY
DOCKET NO. 950379-EI
STAFF'S FIRST SET
INTERROGATORY NO. 5
SPONSOR: HERNANDEZ

TABLE 5-4
(Revised)

	#2 OIL BASE FORECAST ($/MBTU)					
	1992 * Price Change	1993 Summer Forecast	1993 Fall Forecast	1994 Spring Forecast	1994 Fall Forecast	1995 Fall Forecast
1996	6.48	5.36	5.39	4.19	4.68	4.34
1997	7.02	6.04	5.90	4.52	4.89	4.53
1998	7.78	6.49	6.16	4.89	5.12	4.74
1999	8.53	6.97	6.42	5.14	5.33	4.95
2000	9.37	7.49	6.67	5.41	5.61	5.14
2001	10.31	8.04	6.94	5.70	5.90	5.38
2002	11.27	8.64	7.22	6.01	6.22	5.63
2003	12.34	9.28	7.50	6.34	6.56	5.89
2004	13.51	9.97	7.81	6.70	6.92	6.16
2005	14.79	10.71	8.12	7.07	7.30	6.45
2006	16.13	11.50	8.44	7.41	7.65	6.75
2007	17.60	12.36	8.77	7.77	8.02	7.00
2008	19.10	13.28	9.12	8.15	8.41	7.27
2009	20.76	14.27	9.47	8.55	8.81	7.55
2010	22.45	15.33	9.85	8.96	9.24	7.84
2011	24.25	16.47	10.24	9.40	9.68	8.14
2012	26.08	17.70	10.63	9.85	10.14	8.46
2013	28.07	19.01	11.15	10.32	10.62	8.78
2014	30.23	20.42	11.71	10.83	11.14	9.12
2015	32.54	21.93	12.29	11.36	11.68	9.47
2016	35.22	23.55	12.96	11.92	12.25	9.84
2017	38.08	25.29	13.66	12.55	12.90	10.23
2018	41.06	27.16	14.47	13.29	13.65	10.66
2019	44.32	29.17	15.26	14.08	14.45	11.12
2020	47.60	31.33	16.09	14.92	15.31	11.60
AAGR%	8.66%	7.63%	4.66%	5.44%	5.06%	4.18%

* The 1992 Price Change forecast was revised to match the No. 2 oil being used by the combined cycle in the 1992 Polk cost effectiveness study.

6. Please identify which of the fuel forecasts described in Interrogatory No. 5 were used to evaluate the continued cost effectiveness of the Polk IGCC Unit described in Interrogatory No. 3.

A. The following table identifies the fuel price forecasts described in Interrogatory No. 5 that were used in the Polk IGCC cost effectiveness studies as described in the response to Interrogatory No. 3.

TABLE 6-1

POLK IGCC COST EFFECTIVENESS STUDIES FUEL FORECASTS

Year of Study	IGCC - Coal	IGCC - Pet Coke	CC - Natural Gas
1992	1992 Price Change	N/A	1992 Price Change
1993	1993 Summer Forecast	1993 Summer Forecast	1993 Summer Forecast
1994	1994 Spring Forecast	1994 Spring Forecast	1994 Spring Forecast
1995	1994 Fall Forecast	1994 Fall Forecast	1994 Fall Forecast
1996	1995 Fall Forecast	1995 Fall Forecast	1995 Fall Forecast

7. Please provide the base case demand and energy forecast used in Docket No. 910883-EI and each subsequent demand and energy forecast that was generated up to and including Tampa Electric's most recent forecasts. These forecasts should include annual values for seasonal firm peak demand and annual net energy for load and should be separately identified and labeled.

A. The firm total system demand forecast used in Docket 910883-EI and each subsequent demand forecast up to and including Tampa Electric's most recent forecast are shown in Table 7-1. The base energy forecast and subsequent energy forecast are provided in Table 7-2.

TABLE 7-1

WINTER FIRM SYSTEM DEMAND BASE FORECAST (MW)						
	1991 Need Hearing	1992 Price Change	1992 Fall Forecast	1993 Fall Forecast	1994 Fall Forecast	1995 Fall Forecast *
1991	2,561					
1992	2,700	2,651				
1993	2,768	2,705	2,705			
1994	2,843	2,774	2,774	2,743		
1995	2,922	2,845	2,845	2,810	2,796	
1996	2,999	2,918	2,918	2,875	2,863	2,845
1997	3,077	2,990	2,990	2,947	2,933	2,904
1998	3,155	3,063	3,063	3,018	3,004	2,991
1999	3,233	3,140	3,140	3,098	3,086	3,064
2000	3,311	3,214	3,214	3,165	3,152	3,142
2001	3,376	3,289	3,289	3,231	3,218	3,214

* Current Forecast

SUMMER FIRM SYSTEM DEMAND BASE FORECAST (MW)						
	1991 Need Hearing	1992 Price Change	1992 Fall Forecast	1993 Fall Forecast	1994 Fall Forecast	1995 Fall Forecast *
1991	2,397					
1992	2,469	2,417				
1993	2,533	2,475	2,475			
1994	2,603	2,542	2,542	2,523		
1995	2,678	2,614	2,614	2,590	2,589	
1996	2,750	2,685	2,685	2,659	2,656	2,640
1997	2,824	2,760	2,760	2,733	2,728	2,708
1998	2,897	2,834	2,834	2,807	2,799	2,794
1999	2,972	2,907	2,907	2,891	2,882	2,866
2000	3,045	2,983	2,983	2,962	2,949	2,942

* Current Forecast

TABLE 7-2

	ENERGY BASE FORECAST (GWH)					
	1991 Need Hearing	1992 Price Change	1992 Fall Forecast	1993 Fall Forecast	1994 Fall Forecast	1995 Fall Forecast *
1991	14529					
1992	14806	14591				
1993	15172	14513	14524			
1994	15615	14874	14874	14526		
1995	16023	15311	15311	14909	15264	
1996	16431	15712	15712	15345	15807	15742
1997	16858	16129	16129	15816	16194	16273
1998	17284	16546	16546	16177	16481	16637
1999	17719	16970	16970	16573	16832	16957
2000	18153	17428	17428	16958	17107	17239

* Current Forecast

8. Please identify which of the demand and energy forecasts described in Interrogatory No. 7 were used to evaluate the continuing cost effectiveness of the Polk IGCC Unit described in Interrogatory No. 3.

A. The following table indicates the demand and energy forecasts described in Interrogatory No. 7 that were used in the Polk IGCC cost effectiveness studies as described in the response to Interrogatory No. 3.

TABLE 8-1

POLK IGCC COST EFFECTIVENESS STUDIES DEMAND & ENERGY FORECASTS

Year of Study	Base Case Forecasts
1992	1992 Price Change
1993	1992 Fall Forecast
1994	1993 Fall Forecast
1995	1994 Fall Forecast
1996	1995 Fall Forecast

9. As part of the discovery process in Docket No. 910883-EI, the FPSC Staff requested Tampa Electric to perform a sensitivity on Tampa Electric's proposed generation expansion plan that utilized a constant differential price between coal and natural gas. The results of that sensitivity were filed as Late Filed Exhibit No. 16. Based on page 14 of 17 from that exhibit (see Attachment 2), Plan 5 had the lowest present value of total expenditures. Plan 5 consisted of the addition of combustion turbine and combined cycle units and did not include the Polk IGCC Unit, which was contained in Plan 7. Please verify these results.

A. The natural gas price sensitivity referenced in Late Filed Exhibit No. 16 was requested by the FPSC Staff during the Determination of Need proceedings to compare the economics of the top seven energy resource plans on a system revenue requirement basis under a fuel price sensitivity in which escalation on gas was the same as coal. The fuel price sensitivity was considered unlikely compared to other natural gas price forecasts at the time of the Determination of Need proceedings as discussed on page 4 of 17 from Late Filed Exhibit No. 16. In this analysis, Plan 5 had lower system present worth revenue requirements compared to Plan 7.

However, under this low natural gas forecast sensitivity, Plan 7 did show savings of $263 million compared to Plan 3 but not as much savings as Plan 5. The higher savings shown in Plan 5 were due to the lower operating costs of the three combined cycle units and the seven combustion turbine units. This plan benefited from the lower natural gas costs compared to Plan 7 which did not benefit from this sensitivity since the IGCC unit was based on coal as the primary fuel at the time of the Need Hearing.

The results of the Late Filed Exhibit No. 16 sensitivity have now been further discounted in subsequent analyses by Tampa Electric because (1) the basis of the Staff's natural gas forecast had been considered unlikely at the time of the Need Hearing, and (2) other fuel options for the IGCC unit such as petroleum coke were not considered. If an IGCC fuel sensitivity using petroleum coke had been included, Plan 7 would have resulted in significantly lower operating costs (and therefore savings) when compared to all of the plans.

It should be noted that a similar economic analysis was provided in Late Filed Deposition Exhibit 4 of the Staff deposition of John Ramil. This analysis utilized what Tampa Electric considered to be more realistic fuel forecasts. Late Filed Deposition Exhibit 4 supports \$195 million in savings on a cumulative present worth revenue requirement (CPWRR) basis associated with Plan 7 (which was based on the phased construction of the Polk 1 IGCC unit and subsequent 20-year generation expansion) relative to Plan 3 (which was based on phased combined cycle additions as shown in Docket 910004-EU). In Late Filed Deposition Exhibit 4, Plan 5 was not cost effective compared to Plan 7 (\$313 million higher CPWRR) or Plan 3 (\$110 million higher CPWRR). This Late Filed Deposition Exhibit 4 analysis was based on Tampa Electric assumptions, forecasts, and methodologies as submitted at that time.

12. Please provide the current estimate of the cost of the Polk IGCC Unit showing annual revenue requirements broken down, at a minimum, to show total capital, O&M, and fuel costs expressed in nominal dollars, cumulative present worth dollars, and cents per kilowatt hour. Please document all assumptions including Tampa Electric's fuel forecast by year.

A. The current estimate of $506 million for the Polk IGCC unit that was identified in the response to Interrogatory No. 1 was used as the basis for the unit revenue requirement analysis provided in Table 12-1. Key economic assumptions are shown in Table 12-2.

REVISED 05/02/96
TAMPA ELECTRIC COMPANY
DOCKET NO. 950379-EI
STAFF'S FIRST SET
INTERROGATORY NO. 12
SPONSOR: HERNANDEZ

TABLE 12-1

POLK IGCC

IGCC WITH REVISED PROJECTIONS AND DOE CREDIT
NOMINAL COST PROJECTION

YEAR	IGCC							
	O&M		FUEL		CAPITAL		TOTAL	
	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh
1996	265	0.060	6,313	1.430	19,521	4.421	26,099	5.910
1997	2,669	0.152	25,654	1.464	96,710	5.520	125,033	7.137
1998	4,242	0.242	26,280	1.500	89,418	5.104	119,940	6.846
1999	12,997	0.742	17,182	0.981	84,685	4.834	114,864	6.556
2000	13,413	0.763	17,782	1.012	80,358	4.574	111,553	6.350
2001	13,842	0.790	18,161	1.037	76,555	4.370	108,558	6.196
2002	14,285	0.815	18,600	1.062	72,769	4.153	105,654	6.030
2003	14,742	0.841	19,050	1.087	69,648	3.975	103,441	5.904
2004	15,214	0.866	19,566	1.114	69,610	3.962	104,390	5.942
2005	15,701	0.896	19,986	1.141	68,286	3.898	103,973	5.935
2006	16,203	0.925	20,473	1.169	66,980	3.823	103,657	5.916
2007	16,722	0.954	20,960	1.196	65,702	3.750	103,384	5.901
2008	17,257	0.982	21,519	1.225	64,442	3.668	103,218	5.875
2009	17,809	1.016	21,972	1.254	63,194	3.607	102,975	5.878
2010	18,379	1.049	22,499	1.284	61,960	3.537	102,838	5.870
2011	18,967	1.083	23,039	1.315	60,739	3.467	102,745	5.864
2012	19,574	1.114	23,658	1.347	59,532	3.389	102,764	5.850
2013	20,200	1.153	24,163	1.379	58,337	3.330	102,701	5.862
2014	20,847	1.190	24,748	1.413	57,159	3.263	102,753	5.865
2015	21,514	1.228	25,348	1.447	55,995	3.196	102,856	5.871
2016	22,202	1.264	26,035	1.482	54,846	3.122	103,083	5.868
2017	22,913	1.308	26,597	1.518	53,713	3.066	103,223	5.892
2018	23,646	1.350	27,254	1.556	52,596	3.002	103,496	5.907
2019	24,403	1.393	27,928	1.594	51,497	2.939	103,828	5.926
2020	25,184	1.433	28,700	1.634	50,414	2.870	104,297	5.937
2021	25,989	1.483	29,333	1.674	49,350	2.817	104,673	5.974
2022	26,821	1.531	30,064	1.716	48,304	2.757	105,190	6.004
2023	27,679	1.580	30,815	1.759	47,276	2.698	105,770	6.037
2024	28,565	1.626	31,673	1.803	46,269	2.634	106,508	6.063
2025	29,479	1.683	32,380	1.848	45,282	2.585	107,141	6.115
2026	30,423	1.736	33,192	1.895	34,558	1.972	98,173	5.603
CPW (96$)	149,565		229,157		739,058		1,117,779	

NOTES:

1. Assumes an in-service date of October 1, 1996.

TABLE 12-2

TAMPA ELECTRIC COMPANY
Polk IGCC Unit

Assumptions

	IGCC
As Spent Capital ($ x 1000):	
Plant	384,870
Gasifier Related "Sunk" Costs	included in plant
Land and Site Development	65,835
Common	118,461
DOE Credit	(115,395)
Total	453,771
Total w/ AFUDC	506,165
Tax Life (yrs)	7
O&M	
Fixed (97$000)	11,947
Variable ($/MWh)	NA
Escalation	
Capital	3.5%
O&M	3.2%
AFUDC Rate	7.79%
Discount Rate	9.26%
Capacity (MW)	
Winter	250
Summer	250
Capacity Factor	80%
Heat Rate (Btu/kWh)	
(1996 - 1998)	8775 (2)
(1999 - 2026)	8869 (2)
Fuel	
(1996 - 1998)	Pitt # 8
(1999 - 2026)	Pet Coke/PRB
	(See 1995 Fall Forecast - Intr. #5)

Notes:

(1) O&M shown excludes DOE credit ($20 M over 1996, 1997, and 1998). Variable costs included in fixed O&M number.

(2) Heat rate at full load.

13. Please provide a current estimate of the cost of constructing a hypothetical natural gas fired combined cycle unit at the Polk site in lieu of the Polk IGCC Unit. Please document all assumptions including Tampa Electric's fuel forecast by year. Please provide:

   a. The total capital cost associated with a hypothetical Polk Combined Cycle Unit that would be included in rate base.

   b. The total annual revenue requirements broken down, at a minimum, to show total capital, O&M, and fuel costs expressed in nominal dollars, cumulative present worth dollars, and cents per kilowatt hour.

A. a. The total capital cost, including AFUDC, to construct a natural gas-fired combined cycle unit at the Polk site in lieu of the IGCC unit is provided in Table 13-1. As discussed in the response to Interrogatory No. 3, any common costs (including, but not limited to land and site development) and sunk costs associated with the gasification process were included in the combined cycle costs.

   b. The combined cycle unit revenue requirement analysis is provided in Table 13-2.

TABLE 13-1

TAMPA ELECTRIC COMPANY
Hypothetical Polk CC Unit

Assumptions

	Polk CC
As Spent Capital ($ x 1000):	
Plant	142,128
Gasifier Related "Sunk" Costs	244,942
Land and Site Development	65,875
Common	67,014
DOE Credit	(96,338)
Total	423,621
Total w/ AFUDC	463,085
Tax Life (yrs)	20
O&M	
Fixed (97$000)	3,551
Variable ($/MWh)	1.46
Escalation	
Capital	3.5%
O&M	3.2%
AFUDC Rate	7.79%
Discount Rate	9.26%
Capacity (MW)	
Winter	233
Summer	212
Capacity Factor	80%
Heat Rate (Btu/kWh)	7,669 (1)
Fuel	Natural Gas (See 1995 Fall Forecast - Intr. #5)

Note:

(1) Represents CC annual heat rate at full load.

TABLE 13-2

COMBINED CYCLE

POLK CC BASE CASE WITH REVISED PROJECTIONS
NOMINAL COST PROJECTION

YEAR	COMBINED CYCLE UNIT							
	O&M		FUEL		CAPITAL		TOTAL	
	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh
1996	1,444	0.351	7,736	1.879	17,839	4.333	27,019	6.562
1997	5,798	0.377	31,116	2.025	90,129	5.866	127,043	8.268
1998	5,984	0.389	33,721	2.195	86,228	5.612	125,933	8.196
1999	6,175	0.402	35,652	2.320	87,758	5.386	124,585	8.108
2000	6,380	0.414	37,992	2.465	79,513	5.160	123,884	8.039
2001	6,577	0.428	40,015	2.604	76,353	4.969	122,945	8.001
2002	6,787	0.442	42,310	2.753	73,269	4.768	122,366	7.963
2003	7,004	0.456	44,775	2.914	70,557	4.592	122,336	7.962
2004	7,237	0.470	47,564	3.086	68,921	4.472	123,722	8.028
2005	7,460	0.485	50,277	3.272	67,121	4.368	124,858	8.126
2006	7,698	0.501	53,340	3.471	65,330	4.252	126,368	8.224
2007	7,945	0.517	56,633	3.686	63,550	4.136	128,128	8.338
2008	8,208	0.533	60,350	3.916	61,783	4.009	130,341	8.458
2009	8,461	0.551	63,981	4.164	60,025	3.906	132,467	8.621
2010	8,732	0.568	68,072	4.430	58,278	3.793	135,082	8.791
2011	9,012	0.586	72,470	4.716	56,545	3.680	138,027	8.983
2012	9,311	0.604	76,158	4.942	54,826	3.558	140,294	9.104
2013	9,598	0.625	79,596	5.180	53,117	3.457	142,310	9.261
2014	9,905	0.645	83,454	5.431	51,424	3.347	144,783	9.422
2015	10,222	0.665	87,526	5.696	49,743	3.237	147,491	9.599
2016	10,561	0.685	92,089	5.976	48,426	3.142	151,076	9.803
2017	10,886	0.708	96,353	6.271	47,651	3.101	154,890	10.080
2018	11,235	0.731	101,134	6.582	46,713	3.040	159,081	10.353
2019	11,594	0.755	106,178	6.910	45,788	2.980	163,561	10.644
2020	11,979	0.777	111,824	7.256	44,879	2.912	168,681	10.946
2021	12,348	0.804	117,113	7.622	43,987	2.863	173,448	11.288
2022	12,743	0.829	123,035	8.007	43,111	2.806	178,890	11.642
2023	13,151	0.856	128,149	8.340	42,252	2.750	183,552	11.945
2024	13,587	0.882	133,879	8.687	41,411	2.687	188,877	12.256
2025	14,006	0.912	139,074	9.051	40,590	2.642	193,670	12.604
2026	14,454	0.941	144,890	9.429	31,079	2.023	190,424	12.393
CPW ('96$)	79,869		573,055		709,326		1,362,250	

NOTES:

1. Assumes an in-service date of October 1, 1996.

14. Please provide the information requested in Interrogatory No.13 but based on a constant cost differential between coal and natural gas. Please assume the 1995 price for delivered coal is $2.129 per million Btu. For natural gas, assume a 1995 price of $2.154 per million Btu and apply FGT's FTS2 rates of $0.0479 per million Btu usage charge and $0.756 per million Btu reservation charge. Assume Tampa Electric's current Base Case coal price escalation rates to escalate the delivered prices of natural gas.

A. The projected unit costs for a natural gas-fired combined cycle unit located at the Polk site described in Interrogatory No. 13 were used in the unit revenue requirement analysis provided in Table 14-1. The FPSC staff gas forecast shown in Table 14-2 was created by adding a fixed differential between coal (starting @ $2.129/MBtu) and gas (starting @ $2.958/MBtu including usage and reservation charges) to the coal price which is escalating at Polk IGCC coal escalation rates.

TABLE 14-1

COMBINED CYCLE WITH FPSC E&G FUEL SENSITIVITY
NOMINAL COST PROJECTION

YEAR	COMBINED CYCLE UNIT							
	O&M		FUEL		CAPITAL		TOTAL	
	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh
1996	1,444	0.351	9,453	2.296	17,839	4.333	28,735	6.979
1997	5,798	0.377	35,845	2.333	90,129	5.866	131,772	8.576
1998	5,984	0.389	36,428	2.371	86,228	5.612	128,640	8.372
1999	6,175	0.402	36,960	2.405	82,758	5.386	125,893	8.193
2000	6,380	0.414	37,761	2.450	79,513	5.160	123,654	8.024
2001	6,577	0.428	38,335	2.495	76,353	4.969	121,265	7.892
2002	6,787	0.442	39,039	2.541	73,269	4.768	119,096	7.751
2003	7,004	0.456	39,758	2.587	70,557	4.592	117,319	7.635
2004	7,237	0.470	40,614	2.635	68,921	4.472	116,772	7.577
2005	7,460	0.485	41,251	2.685	67,121	4.368	115,832	7.538
2006	7,698	0.501	42,027	2.735	65,330	4.252	115,055	7.488
2007	7,945	0.517	42,794	2.785	63,550	4.136	114,289	7.438
2008	8,208	0.533	43,708	2.836	61,783	4.009	113,699	7.378
2009	8,461	0.551	44,384	2.888	60,025	3.906	112,871	7.346
2010	8,732	0.568	45,211	2.942	58,278	3.793	112,221	7.303
2011	9,012	0.586	46,055	2.997	56,545	3.680	111,612	7.264
2012	9,311	0.604	47,058	3.054	54,826	3.558	111,195	7.215
2013	9,598	0.625	47,809	3.111	53,117	3.457	110,524	7.193
2014	9,905	0.645	48,717	3.170	51,424	3.347	110,045	7.162
2015	10,222	0.665	49,648	3.231	49,743	3.237	109,612	7.133
2016	10,561	0.685	50,750	3.293	48,426	3.142	109,736	7.121
2017	10,886	0.708	51,578	3.357	47,651	3.101	110,116	7.166
2018	11,235	0.731	52,594	3.423	46,713	3.040	110,542	7.194
2019	11,594	0.755	53,633	3.490	45,788	2.980	111,015	7.225
2020	11,979	0.777	54,858	3.560	44,879	2.912	111,716	7.249
2021	12,348	0.804	55,792	3.631	43,987	2.863	112,127	7.297
2022	12,743	0.829	56,910	3.704	43,111	2.806	112,765	7.339
2023	13,151	0.856	58,057	3.778	42,252	2.750	113,460	7.384
2024	13,587	0.882	59,404	3.855	41,411	2.687	114,402	7.424
2025	14,006	0.912	60,434	3.933	40,590	2.642	115,031	7.486
2026	14,454	0.941	61,667	4.013	31,079	2.023	107,200	6.976
CPW (96$)	79,869		432,949		709,326		1,222,144	

NOTES:

1. Assumes an in-service date of October 1, 1996.

TABLE 14-2

FPSC Staff
Fixed Differential Methodology

YEAR	COAL $/MBTU	Esc. Rate %	Fixed Differential	GAS $/MBTU
1995	2.129	1.67%	0.8289	2.958
1996	2.165	2.23%	0.8289	2.994
1997	2.213	2.24%	0.8289	3.042
1998	2.262	1.99%	0.8289	3.091
1999	2.307	2.54%	0.8289	3.136
2000	2.366	2.45%	0.8289	3.195
2001	2.424	2.46%	0.8289	3.253
2002	2.484	2.45%	0.8289	3.313
2003	2.545	2.46%	0.8289	3.374
2004	2.608	2.46%	0.8289	3.437
2005	2.672	2.47%	0.8289	3.501
2006	2.738	2.38%	0.8289	3.566
2007	2.803	2.38%	0.8289	3.632
2008	2.869	2.38%	0.8289	3.698
2009	2.938	2.39%	0.8289	3.766
2010	3.008	2.38%	0.8289	3.837
2011	3.079	2.39%	0.8289	3.908
2012	3.153	2.39%	0.8289	3.982
2013	3.228	2.39%	0.8289	4.057
2014	3.305	2.39%	0.8289	4.134
2015	3.384	2.39%	0.8289	4.213
2016	3.465	2.39%	0.8289	4.294
2017	3.548	2.43%	0.8289	4.377
2018	3.634	2.43%	0.8289	4.463
2019	3.722	2.43%	0.8289	4.551
2020	3.813	2.43%	0.8289	4.642
2021	3.906	2.43%	0.8289	4.735
2022	4.001	2.43%	0.8289	4.829
2023	4.098	2.43%	0.8289	4.927
2024	4.197	2.43%	0.8289	5.026
2025	4.300	2.43%	0.8289	5.128
2026	4.404		0.8289	5.233

Notes: (1) 1995 coal price of $2.129/MBTU is escalated at Illinois #6 coal escalation rates.

(2) 1995 gas price is $2.154/MBTU plus a $0.0479/MBTU usage charge and a $0.756/MBTU reservation charge.

15. Please provide a calculation of the Polk Unit's currently projected equivalent availability factor. Is the current equivalent availability factor different from what was assumed in Docket No. 910883-EI? If so, please provide a detailed explanation of the differences. Also, please provide the currently projected individual equivalent availabilities for the air separation unit, the coal gasifier, the sulfuric acid plant, and the power block.

Please provide a detailed discussion as to how the use of a single slurry pump for the gasifier affects the Polk unit's equivalent availability factor.

A. <u>Comparison of Polk Unit 1 Availability</u>

The current expectation of the Polk IGCC unit availability is different than the availability assumptions used in the Determination of Need proceedings (Docket No. 910883-EI). The two primary reasons for the difference are in the change in the construction plan and the level of engineering design data at the time of the Need Hearing.

Initially, the IGCC construction plan was based on a commercial operation date of July 1995 for the advanced combustion turbine, and July 1996 for the balance of plant. This would have resulted in simple cycle operation of the combustion turbine on distillate oil as shown in Table 15-1 for approximately one year and the associated availability of only the combustion turbine. The current plan is based on a commercial operation date of October 1996 for the combined cycle using gasified coal as the primary fuel and distillate oil as the secondary fuel as shown in Table 15-2. The operation of the combustion turbine in a simple cycle mode is not a cost effective alternative. However, the operation of the combustion turbine in a combined cycle mode on distillate oil is cost effective at times when the coal gasification system is unavailable and the system needs the generation from the Polk 1 unit. Since the combined cycle power block can be operated when the gasification system is unavailable, the equivalent availability shown in Table 15-2 is higher than the availability of the combined cycle using only gasified coal.

The IGCC initial availability estimate was made by Texaco early in the preliminary design phase. The Polk details had not yet been developed at this stage, so this estimate reflected Texaco's expectations for a mature IGCC plant of their generic configuration and design. This estimate was sufficient for initial project planning purposes. However, as Polk's detailed design progressed, Tampa Electric Company found it necessary for planning purposes to develop an availability estimate which reflected some known factors such as lower availability during the two-year Department of Energy demonstration period.

Projected Individual Component Equivalent Availabilities

There was only one IGCC plant with sufficient operating experience and reliability data to serve as a basis for this estimate: Cool Water. Cool Water was a 100 MW IGCC power plant which operated for four and one-half years commencing in 1984. It consisted of a dedicated oxygen plant, an oxygen blown Texaco gasifier with full heat recovery, and a General Electric combined cycle; so it was very close to Polk's configuration. Cool Water's reliability and reliability growth have been well documented in public reports and in an extensive proprietary data base which carefully identifies durations and causes of each outage. This data was the basis for the most recent Polk projections.

The approach taken in making the Polk projections entailed considering every Cool Water outage by cause and duration, and adjusting them according to differences between Polk and Cool Water configurations, specific hardware, and experience level. This approach differs from mathematically combining availability statistics of the individual plant components or subsections. The methodology used for the Polk projections made it much easier to deal with the extensive "masking" (interactions between plant subsection or component outage data) that takes place in an IGCC plant and the heavy dependence of the predicted result on the highly variable and potentially long start-up times of two of the three major plant subsections (air separation and gasification). Consequently, individual subsection or component availabilities were not developed for the Polk availability estimate. Instead, an overall IGCC availability estimate was developed, as shown in the following table.

TABLE 15-1

POLK IGCC NEED HEARING AVAILABILITY ESTIMATE

159 MW CT-Oil (1)

Operating Year	Equivalent Unplanned Outages (Hours)	Planned Outages (Hours)	Total Unavailability (Hours)	EAF (%)
1	295	370	664	92.4
2	N/A	N/A	N/A	N/A
3	N/A	N/A	N/A	N/A
Mature Plant	N/A	N/A	N/A	N/A

260 MW CC-Coal (2)

Operating Year	Equivalent Unplanned Outages (Hours)	Planned Outages (Hours)	Total Unavailability (Hours)	EAF (%)
1	N/A	N/A	N/A	N/A
2	1,012	740	1,752	80
3	1,012	740	1,752	80
Mature Plant	1,012	740	1,752	80

220 MW CC-Oil (2)

Operating Year	Equivalent Unplanned Outages (Hours)	Planned Outages (Hours)	Total Unavailability (Hours)	EAF (%)
1	N/A	N/A	N/A	N/A
2	461	370	831	90.5
3	461	370	831	90.5
Mature Plant	461	370	831	90.5

NOTES:

(1) The Polk IGCC unit was planned as phased construction at the time of the Need Hearing, with the advanced combustion turbine in-service date by July 1995 and the balance of plant by July 1996. Beyond the first year of operation, the combustion turbine will not be operated in a simple cycle mode.

(2) The combined cycle-coal availability is shown lower than the combined cycle-oil availability due to the expected higher maintenance requirements of the coal gasification system.

TABLE 15-2

POLK IGCC CURRENT AVAILABILITY ESTIMATE

159 MW CT-Oil (1)

Operating Year	Equivalent Unplanned Outages (Hours)	Planned Outages (Hours)	Total Unavailability (Hours)	EAF (%)
1	N/A	N/A	N/A	N/A
2	N/A	N/A	N/A	N/A
3	N/A	N/A	N/A	N/A
Mature Plant	N/A	N/A	N/A	N/A

250 MW CC-Coal (2)

Operating Year	Equivalent Unplanned Outages (Hours)	Planned Outages (Hours)	Total Unavailability (Hours)	EAF (%)
1	2,916	720	3,636	58.5
2	2,125	432	2,557	70.8
3	915	720	1,635	81.3
Mature Plant	854	720	1,574	82.0

210 MW CC-Oil (2)

Operating Year	Equivalent Unplanned Outages (Hours)	Planned Outages (Hours)	Total Unavailability (Hours)	EAF (%)
1	540	336	876	90.0
2	540	336	876	90.0
3	540	336	876	90.0
Mature Plant	540	336	876	90.0

NOTES:

(1) The current Polk IGCC unit construction plan deferred the advanced combustion turbine and balance of plant to a commercial operation date of October 1996. The combustion turbine will not be operated in a simple cycle mode.

(2) The combined cycle-coal availability is shown lower than the combined cycle-oil availability due to the expected higher maintenance requirements of the coal gasification system.

Gasifier Slurry Pump

The basis for determining overall unit availability has primarily been comparison to the Cool Water gasification plant for similar equipment, and engineering judgment based on specific equipment history. Polk Unit 1 incorporates a single high quality diaphragm pump in slurry charge service. This pump, manufactured by GEHO, is considerably more reliable than the pumps in similar service at Cool Water (based on current industry experience). Consequently, mechanical pump failures will be significantly lower at Polk in the early years of operation.

While evaluating one vs. two-pump availability effects, many factors were considered: (1) specific GEHO operating characteristics, (2) experience at other Texaco licensed facilities, and (3) overall unit preventive maintenance and operating philosophy (i.e., effects of short duration trips, etc. on overall unit availability). Based on all of these factors, the increased availability offered by installing a second pump does not justify the additional cost.

While all of the data supports the decision to install a single slurry charge pump, the Polk design does allow for the addition of a second pump if actual operating conditions warrant it in the future. The availability and economic impacts of a single pump will be closely monitored to determine if there is a need for a second pump.

19. In Docket NO. 910883-EI, was the cost of land, land improvements, and environmental mitigation included in the cost effectiveness evaluation of alternative generation technologies?

a. If the answer to interrogatory number 19 is yes, please provide the acreage, land costs, and land improvement costs including environmental mitigation costs which were assumed for each type of generation alternative that was evaluated. How do these costs compare to current estimates?

b. If the answer to Interrogatory No. 19 is no, please justify why these costs were not considered in the evaluation.

A. No.

a. Not applicable.

b. Since all seven of the alternate technologies were technically suitable for the selected Polk County site, and the selection of any one of the technologies would not affect the location and amount of land purchased or the associated site development and land improvement costs, including environmental mitigation, these combined costs were considered the same for all resource plan alternatives. Therefore, the net differential cumulative present worth of system revenue requirements would be the same with or without the inclusion of the site acquisition and development costs.

However, a nominal generic cost for land of $1,200/acre in 1991 dollars (Source: 1989 EPRI Technical Assessment Guide) was used in the alternate technology comparison shown in the graphs on pages 72, 73, and 74 of the Polk Unit One Need Determination Study filed September 1991 (Docket No. 910883-EI). The Polk site, which is approximately 4,347 acres, would be the site of choice for each of the seven technologies that passed the initial economic screening and were included in the detailed system revenue requirement analysis.

24. Did TECO include the cost of a gas lateral in Docket No. 910883-EI when an evaluation of a natural gas fired combustion turbine or a combined cycle unit was performed?

a. If the answer to Interrogatory No. 24 is yes, please provide the assumed cost and interconnection point of the lateral.

b. If the answer to Interrogatory No. 24 is no, please justify why this cost was not included in the evaluation.

A. No. Tampa Electric did not include the cost of a gas lateral in an economic evaluation of a natural gas fired combustion turbine or combined cycle unit.

a. Not applicable.

b. All of the seven alternate technologies, including the combined cycle and combustion turbine technologies, used the appropriate fuel and associated Tampa Electric fuel price forecast on an as-delivered basis to the Polk site. While the use of natural gas at the site would require gas metering and gas transmission equipment, these additional costs were not included in the cost estimates of these technologies at the time of the Determination of Need proceedings. Since the IGCC technology was the most cost effective alternative, the inclusion of additional costs to implement other technologies would not have altered Tampa Electric's decision.

26. Please provide an estimate of the total annual revenue requirement, in 1996 dollars, based on current cost information and actual historic inflation and interest rates, for each technology type that was evaluated in Docket No. 910883-EI. The total annual revenue requirement must include the cost of required return on investment, operation and maintenance, and the cost of fuel. State all assumptions that were made to estimate the revenue requirement for each unit type. Separate the total annual revenue requirement for each unit type by capital, operation and maintenance, and fuel. An example format is shown on Attachment 1.

A. There were seven technologies that passed the initial economic screening on a levelized cost basis and all seven technologies were included in the detailed system revenue requirement analysis during the Determination of Need proceedings. The economic screening was used to eliminate higher cost technologies or technologies that were considered not yet commercially available. The detailed system revenue requirement analysis is the appropriate method to evaluate the cost effectiveness of multiple combinations of both supply and demand side energy resource alternatives. A unit revenue requirement analysis is only a more detailed screening tool and should not be used in place of a more detailed system economic analysis.

In response to this interrogatory, the annual revenue requirements and key assumptions are provided for the same seven technologies that were included in the detailed system revenue requirement analysis identified in the Need Hearing as shown below:

1. Pulverized Coal
2. Integrated Gasification Combined Cycle
3. Combined Cycle
4. Phosphoric Acid Fuel Cell
5. Photovoltaic Solar Cells
6. Solar Thermal
7. Combustion Turbine.

All seven of the alternate technologies are technically suitable for the selected Polk County site, and the selection of any one of the technologies would not affect the location and amount of land purchased by Tampa Electric or the associated site development and land improvement costs. Therefore, these combined costs are considered the same for all resource plan alternatives and are excluded from each of the unit revenue requirements shown in the following tables.

The capital and O&M costs in the 1993 EPRI Technical Assessment Guide (TAG) were used as the basis for all of the technologies except for the IGCC unit which is based on Tampa Electric current cost estimates and includes the DOE funding.

Fuel prices are from Tampa Electric's fall 1995 fuel forecast as provided in response to Staff's 1st Set, Interrogatory No. 5, Docket No. 950379-EI. The IGCC unit assumes Pitt #8 coal used in 1996 and 1997, and a 75/25% Pet Coke/Powder River Basin coal blend from 1998 to 2025. The combined cycle, combustion turbine, and fuel cell technologies use as-available natural gas in the spring and fall months, and distillate oil in the winter and summer months.

All technologies were evaluated at the same capacity (250 MW) and 80% capacity factor which may have required multiple units of a lower rated technology or a scale-down of a single unit with a higher capacity rating. However, the photovoltaic solar cell technology has an operating limitation of approximately 30-35% due to availability of useful sunlight over all hours in the year, and would not be available at an 80% capacity factor. All seven technologies were assumed to have a commercial operation date of January 1, 1996.

TABLE 26-1

PULVERIZED COAL

NOMINAL COST PROJECTION

YEAR	PULVERIZED COAL							
	O&M		FUEL		CAPITAL		TOTAL	
	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh
1996	13,725	0.781	24,462	1.392	54,523	3.104	*92,710	5.277
1997	14,143	0.807	24,939	1.423	68,574	3.914	107,657	6.145
1998	14,596	0.833	25,497	1.455	66,261	3.782	106,354	6.070
1999	15,063	0.860	26,860	1.533	64,061	3.656	105,984	6.049
2000	15,553	0.885	26,740	1.522	61,967	3.527	104,260	5.935
2001	16,042	0.916	27,321	1.559	59,971	3.423	103,335	5.898
2002	16,556	0.945	27,995	1.598	58,067	3.314	102,617	5.857
2003	17,085	0.975	28,682	1.637	56,249	3.211	102,016	5.823
2004	17,642	1.004	29,468	1.677	54,481	3.101	101,591	5.783
2005	18,196	1.039	30,110	1.719	52,728	3.010	101,034	5.767
2006	18,779	1.072	30,852	1.761	50,982	2.910	100,612	5.743
2007	19,380	1.106	31,585	1.803	49,245	2.811	100,210	5.720
2008	20,010	1.139	32,427	1.846	47,516	2.705	99,953	5.689
2009	20,640	1.178	33,106	1.890	45,795	2.614	99,541	5.682
2010	21,300	1.216	33,897	1.935	44,083	2.516	99,280	5.667
2011	21,982	1.255	34,704	1.981	42,381	2.419	99,067	5.655
2012	22,697	1.292	35,630	2.028	40,688	2.316	99,015	5.636
2013	23,411	1.336	36,382	2.077	39,004	2.226	98,797	5.639
2014	24,160	1.379	37,250	2.126	37,331	2.131	98,741	5.636
2015	24,933	1.423	38,140	2.177	35,668	2.036	98,742	5.636
2016	25,745	1.465	39,160	2.229	34,276	1.951	99,181	5.646
2017	26,555	1.516	39,986	2.282	33,382	1.905	99,923	5.703
2018	27,404	1.564	40,958	2.338	32,660	1.864	101,022	5.766
2019	28,281	1.614	41,951	2.394	31,949	1.824	102,182	5.832
2020	29,202	1.662	43,089	2.453	31,250	1.779	103,541	5.894
2021	30,120	1.719	44,016	2.512	30,563	1.744	104,700	5.976
2022	31,084	1.774	45,086	2.573	29,889	1.706	106,059	6.054
2023	32,079	1.831	46,183	2.636	29,229	1.668	107,491	6.135
2024	33,123	1.885	47,435	2.700	28,582	1.627	109,141	6.212
2025	34,165	1.950	48,456	2.766	27,949	1.595	110,570	6.311
CPW ('96$)	202,526		332,782		583,242		1,118,551	

NOTES

1. Assumes an in-service date of January 1, 1996.
2. Current unit assumptions based on 1993 EPRI TAG data escalated to January 1996.

170

TABLE 26-1A

TAMPA ELECTRIC COMPANY
Pulverized Coal

Assumptions

	Pulverized Coal
Plant Size (MW)	250
Number of Units	1
Plant Investment as of 1/1/96 ($000)	
Plant Investment	353,608
Accumulated Depreciation	0
Net Plant In-Service	353,608
Fuel Stock /Plant Material & Supplies	Included in Plant Investment
Total Net Plant Investment	353,608
Annual Revenue Requirement ($000)	See TABLE 26-1
Annual Capacity Factor	80%
Net Generation (MWH)	1,752,000
Revenue Requirement per KWH	See TABLE 26-1
Assumptions Used	
Installed Cost (1/1/96, $000)	353,608
Heat Rate (HHV, Btu/kWh)	9830
Fuel Cost per Million BTU	ILL#6, See TABLE 5-1
Fuel Cost per MWH	See TABLE 26-1
Fixed O&M ($000/year)	11,048
Capital Replacement ($000/year)	NA
Variable O&M ($/MWH)	1.52
Property Tax Rate (% of In-Service Cost)	1.81
Depreciation Rate	3.33%
Return on Investment	12.55%
Discount Rate	9.26%
Capital Escalation	
1993	3.00%
1994	2.30%
1995	3.20%
O&M Escalation	
1993	3.00%
1994	2.60%
1995	3.00%
1996	3.10%
1997 and Beyond	3.20%

TABLE 26-2

Polk IGCC Modified for Consistency with TAG

NOMINAL COST PROJECTION

YEAR	Polk IGCC Modified for Consistency with TAG							
	O&M		FUEL		CAPITAL		TOTAL	
	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh
1996	1,614	0.092	25,114	1.430	62,212	3.541	88,940	5.063
1997	1,974	0.113	25,654	1.464	77,098	4.401	104,726	5.978
1998	12,357	0.705	16,983	0.969	73,245	4.181	102,585	5.855
1999	12,753	0.728	17,182	0.981	69,265	3.953	99,200	5.662
2000	13,161	0.749	17,782	1.012	65,641	3.736	96,584	5.498
2001	13,582	0.775	18,161	1.037	62,081	3.543	93,824	5.355
2002	14,016	0.800	18,600	1.062	58,531	3.341	91,147	5.202
2003	14,465	0.826	19,050	1.087	54,990	3.139	88,505	5.052
2004	14,928	0.850	19,566	1.114	52,092	2.965	86,586	4.929
2005	15,406	0.879	19,986	1.141	51,169	2.921	86,561	4.941
2006	15,899	0.907	20,473	1.169	50,140	2.862	86,512	[illegible].938
2007	16,407	0.936	20,960	1.196	49,127	2.804	86,494	4.937
2008	16,932	0.964	21,519	1.225	48,123	2.739	86,574	4.928
2009	17,474	0.997	21,972	1.254	47,129	2.690	86,576	4.942
2010	18,033	1.029	22,499	1.284	46,146	2.634	86,678	4.947
2011	18,610	1.062	23,039	1.315	45,173	2.578	86,823	4.956
2012	19,206	1.093	23,658	1.347	44,212	2.517	87,076	4.957
2013	19,820	1.131	24,163	1.379	43,260	2.469	87,244	4.980
2014	20,455	1.168	24,748	1.413	42,321	2.416	87,523	4.996
2015	21,109	1.205	25,348	1.447	41,394	2.363	87,851	5.014
2016	21,785	1.240	26,035	1.482	40,479	2.304	88,299	5.029
2017	22,482	1.283	26,597	1.518	39,577	2.259	88,656	5.060
2018	23,201	1.324	27,254	1.556	38,687	2.208	89,142	5.085
2019	23,944	1.367	27,928	1.594	37,811	2.158	89,683	5.119
2020	24,710	1.407	28,700	1.634	36,950	2.103	90,360	5.143
2021	25,501	1.456	29,333	1.674	36,101	2.061	90,935	5.190
2022	26,317	1.502	30,064	1.716	35,268	2.013	91,649	5.231
2023	27,159	1.550	30,815	1.759	34,451	1.966	92,425	5.275
2024	28,028	1.595	31,673	1.803	33,649	1.915	93,350	5.314
2025	28,925	1.651	32,380	1.848	32,863	1.876	94,167	5.372
CPW (965)	152,286		237,841		622,422		1,012,549	

NOTES:

1. Assumes an in-service date of January 1, 1996.
2. TEC Polk IGCC Unit costs modified to be consistent with EPRI TAG. Includes DOE Funding
3. Capital costs include expenditure of approx. $4M in 1997 for plant modifications to burn pet coke blend

TABLE 26-2A

TAMPA ELECTRIC COMPANY
Polk IGCC Mod

Assumptions

	Polk IGCC Mod Includes DOE Credit
Plant Size (MW)	250
Number of Units	1
Plant Investment as of 1/1/96 ($000)	
Plant Investment	403,470
Accumulated Depreciation	0
Net Plant In-Service	403,470
Fuel Stock /Plant Material & Supplies	Included in Plant Investment
Total Net Plant Investment	403,470
Annual Revenue Requirement ($000)	See TABLE 26-2
Annual Capacity Factor	80%
Net Generation (MWH)	1,752,000
Revenue Requirement per KWH	See TABLE 26-2
Assumptions Used	
Installed Cost (1/1/96, $000)	403,470
Heat Rate (HHV, Btu/kWh) 1996-1998	
(1996 - 1997)	8,775
(1998 - beyond)	8,869
Fuel Cost per Million BTU	See TABLE 5-1
1996-1997	Pitt #8
1998 - 2025	Pet Coke/ PRB (75/25%)
Fuel Cost per MWH	See TABLE 26-2
Fixed O&M ($000/year)	
1996	1,614
1997	1,974
1998	12,357
Capital Replacements ($000/year)	NA
Variable O&M ($/MWH)	0.00
Property Tax Rate (% of In-Service Cost)	1.81
Depreciation Rate	3.33%
Return on Investment	12.55%
Discount Rate	9.26%
Capital Escalation	
1993	3.00%
1994	2.30%
1995	3.20%
O&M Escalation	
1993	3.00%
1994	2.60%
1995	3.00%
1996	3.10%
1997 and Beyond	3.20%

TABLE 26-3

COMBINED CYCLE

NOMINAL COST PROJECTION

YEAR	COMBINED CYCLE							
	O&M		FUEL		CAPITAL		TOTAL	
	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh
1996	6,939	0.395	46,957	2.673	21,042	1.198	74,939	4.266
1997	7,152	0.408	49,344	2.816	26,464	1.511	82,961	4.735
1998	7,381	0.421	52,133	2.976	25,572	1.460	85,087	4.857
1999	7,618	0.435	54,657	3.120	24,723	1.411	86,998	4.966
2000	7,863	0.448	57,297	3.261	23,915	1.361	89,075	5.070
2001	8,113	0.463	59,964	3.423	23,145	1.321	91,222	5.207
2002	8,372	0.478	62,950	3.593	22,410	1.279	93,733	5.350
2003	8,640	0.493	66,109	3.773	21,708	1.239	96,458	5.506
2004	8,919	0.508	69,641	3.964	21,026	1.197	99,587	5.669
2005	9,202	0.525	72,969	4.165	20,349	1.161	102,520	5.852
2006	9,497	0.542	76,707	4.378	19,675	1.123	105,879	6.043
2007	9,801	0.559	80,217	4.579	19,005	1.085	109,023	6.223
2008	10,117	0.576	84,166	4.791	18,338	1.044	112,621	6.411
2009	10,438	0.596	87,837	5.014	17,674	1.009	115,949	6.618
2010	10,772	0.615	91,970	5.249	17,013	0.971	119,755	6.835
2011	11,117	0.635	96,350	5.499	16,356	0.934	123,823	7.068
2012	11,475	0.653	100,640	5.729	15,703	0.894	127,818	7.276
2013	11,839	0.676	104,580	5.969	15,053	0.859	131,472	7.504
2014	12,218	0.697	108,984	6.221	14,407	0.822	135,609	7.740
2015	12,609	0.720	113,588	6.483	13,765	0.786	139,962	7.989
2016	13,016	0.741	118,746	6.759	13,228	0.753	144,990	8.253
2017	13,429	0.767	123,472	7.048	12,883	0.735	149,785	8.549
2018	13,859	0.791	129,057	7.366	12,604	0.719	155,520	8.877
2019	14,302	0.816	134,922	7.701	12,330	0.704	161,554	9.221
2020	14,764	0.840	141,465	8.052	12,060	0.686	168,289	9.579
2021	15,232	0.869	147,544	8.421	11,795	0.673	174,571	9.964
2022	15,720	0.897	154,306	8.807	11,535	0.658	181,561	10.363
2023	16,223	0.926	160,850	9.181	11,280	0.644	188,353	10.751
2024	16,746	0.953	168,181	9.573	11,031	0.628	195,959	11.154
2025	17,278	0.986	174,881	9.982	10,786	0.616	202,945	11.584
CPW (96$)	102,413		824,009		225,090		1,151,511	

NOTES:

1. Assumes an in-service date of January 1, 1996.
2. Current unit assumptions based on 1993 EPRI TAG data escalated to January 1996.

TABLE 26-3A

TAMPA ELECTRIC COMPANY
Combined Cycle

Assumptions

	Combined Cycle
Plant Size (MW)	250
Number of Units	1.11
Plant Investment as of 1/1/96 ($000)	
Plant Investment	136,467
Accumulated Depreciation	0
Net Plant In-Service	136,467
Fuel Stock /Plant Material & Supplies	Included in Plant Investment
Total Net Plant Investment	136,467
Annual Revenue Requirement ($000)	See TABLE 26-3
Annual Capacity Factor	80%
Net Generation (MWH)	1,752,000
Revenue Requirement per KWH	See TABLE 26-3
Assumptions Used	
Installed Cost (1/1/96, $000)	136,467
Heat Rate (HHV, Btu/kWh)	7520
Fuel Cost per Million BTU	NG and #2Oil, See TABLE 5-3&4
Fuel Cost per MWH	See TABLE 26-3
Fixed O&M ($000/year)	6,274
Capital Replacement ($000/year)	NA
Variable O&M ($/MWH)	0.38
Property Tax Rate (% of In-Service Cost)	1.81
Depreciation Rate	3.33%
Return on Investment (%)	12.55%
Discount Rate	9.26%
Capital Escalation	
1993	3.00%
1994	2.30%
1995	3.20%
O&M Escalation	
1993	3.00%
1994	2.60%
1995	3.00%
1996	3.10%
1997 and Beyond	3.20%

TABLE 26-4

PHOSPHORIC ACID FUEL CELL

NOMINAL COST PROJECTION

YEAR	PHOSPHORIC ACID FUEL CELL							
	O&M		FUEL		CAPITAL		TOTAL	
	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh
1996	9,715	0.553	53,383	3.039	46,017	2.619	109,115	6.211
1997	10,015	0.572	56,096	3.202	57,876	3.303	123,988	7.077
1998	10,336	0.590	59,267	3.383	55,924	3.192	125,527	7.165
1999	10,667	0.609	62,136	3.547	54,067	3.086	126,870	7.241
2000	11,009	0.627	65,137	3.708	52,300	2.977	128,446	7.311
2001	11,360	0.648	68,169	3.891	50,615	2.889	130,145	7.428
2002	11,724	0.669	71,564	4.085	49,008	2.797	132,296	7.551
2003	12,099	0.691	75,155	4.290	47,474	2.710	134,728	7.690
2004	12,487	0.711	79,171	4.507	45,982	2.617	137,640	7.835
2005	12,886	0.735	82,953	4.735	44,502	2.540	140,341	8.010
2006	13,298	0.759	87,203	4.977	43,029	2.456	143,530	8.192
2007	13,724	0.783	91,194	5.205	41,562	2.372	146,480	8.361
2008	14,164	0.806	95,683	5.446	40,103	2.283	149,950	8.535
2009	14,616	0.834	99,856	5.700	38,651	2.206	153,123	8.740
2010	15,084	0.861	104,555	5.968	37,206	2.124	156,845	8.952
2011	15,566	0.888	109,534	6.252	35,769	2.042	160,870	9.182
2012	16,066	0.914	114,411	6.512	34,340	1.955	164,817	9.382
2013	16,578	0.946	118,890	6.786	32,919	1.879	168,388	9.611
2014	17,109	0.977	123,897	7.072	31,507	1.798	172,513	9.847
2015	17,656	1.008	129,131	7.370	30,104	1.718	176,891	10.097
2016	18,223	1.037	134,994	7.684	28,929	1.647	182,146	10.368
2017	18,805	1.073	140,368	8.012	28,174	1.608	187,346	10.693
2018	19,406	1.108	146,717	8.374	27,565	1.573	193,688	11.055
2019	20,027	1.143	153,384	8.755	26,964	1.539	200,375	11.437
2020	20,670	1.177	160,823	9.154	26,375	1.501	207,868	11.832
2021	21,330	1.217	167,733	9.574	25,795	1.472	214,857	12.264
2022	22,012	1.256	175,421	10.013	25,227	1.440	222,660	12.709
2023	22,716	1.297	182,860	10.437	24,669	1.408	230,246	13.142
2024	23,446	1.335	191,195	10.883	24,123	1.373	238,763	13.591
2025	24,194	1.381	198,811	11.348	23,589	1.346	246,594	14.075
CPW (96$)	143,400		936,762		492,253		1,572,415	

NOTES:

1. Assumes an in-service date of January 1, 1996.
2. Current unit assumptions based on 1993 EPRI TAG data escalated to January 1996.

126

TABLE 26-4A

TAMPA ELECTRIC COMPANY
Fuel Cell

Assumptions

	Fuel Cell
Plant Size (MW)	250
Number of Units	2.50
Plant Investment as of 1/1/96 ($000)	
Plant Investment	298,443
Accumulated Depreciation	0
Net Plant In-Service	298,443
Fuel Stock /Plant Material & Supplies	Included in Plant Investment
Total Net Plant Investment	298,443
Annual Revenue Requirement ($000)	See TABLE 26-4
Annual Capacity Factor	80%
Net Generation (MWH)	1,752,000
Revenue Requirement per KWH	See TABLE 26-4
Assumptions Used	
Installed Cost (1/1/96, $000)	298,443
Heat Rate (HHV, Btu/kWh)	8549
Fuel Cost per Million BTU	NG and #2Oil, See TABLE 5-3&4
Fuel Cost per MWH	See TABLE 26-4
Fixed O&M ($000/year)	9,372
Capital Replacement ($000/year)	NA
Variable O&M ($/MWH)	0.20
Property Tax Rate (% of In-Service Cost)	1.81
Depreciation Rate	3.33%
Return on Investment (%)	12.55%
Discount Rate	9.26%
Capital Escalation	
1993	3.00%
1994	2.30%
1995	3.20%
O&M Escalation	
1993	3.00%
1994	2.60%
1995	3.00%
1996	3.10%
1997 and Beyond	3.20%

TABLE 26-5

PHOTOVOLTAIC SOLAR CELLS

NOMINAL COST PROJECTION

YEAR	PHOTOVOLTAIC SOLAR CELLS							
	O&M		FUEL		CAPITAL		TOTAL	
	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh
1996	1,714	0.098	0	0.000	102,111	5.812	103,825	5.910
1997	1,768	0.101	0	0.000	123,657	7.058	125,425	7.159
1998	1,824	0.104	0	0.000	112,149	6.401	113,973	6.505
1999	1,882	0.107	0	0.000	104,592	5.970	106,474	6.077
2000	1,943	0.111	0	0.000	98,526	5.608	100,469	5.719
2001	2,005	0.114	0	0.000	93,580	5.341	95,585	5.456
2002	2,069	0.118	0	0.000	93,618	5.343	95,687	5.462
2003	2,135	0.122	0	0.000	91,755	5.237	93,890	5.359
2004	2,204	0.125	0	0.000	89,906	5.118	92,110	5.243
2005	2,274	0.130	0	0.000	88,072	5.027	90,346	5.157
2006	2,347	0.134	0	0.000	86,252	4.923	88,599	5.057
2007	2,422	0.138	0	0.000	84,448	4.820	86,870	4.958
2008	2,499	0.142	0	0.000	82,658	4.705	85,157	4.847
2009	2,579	0.147	0	0.000	80,886	4.617	83,465	4.764
2010	2,662	0.152	0	0.000	79,129	4.516	81,791	4.668
2011	2,747	0.157	0	0.000	77,390	4.417	80,137	4.574
2012	2,835	0.161	0	0.000	75,669	4.307	78,504	4.469
2013	2,926	0.167	0	0.000	73,965	4.222	76,891	4.389
2014	3,019	0.172	0	0.000	72,281	4.126	75,300	4.298
2015	3,116	0.178	0	0.000	70,616	4.031	73,732	4.208
2016	3,216	0.183	0	0.000	68,971	3.926	72,187	4.109
2017	3,319	0.189	0	0.000	67,346	3.844	70,665	4.033
2018	3,425	0.195	0	0.000	65,742	3.752	69,167	3.948
2019	3,534	0.202	0	0.000	64,161	3.662	67,695	3.864
2020	3,647	0.208	0	0.000	62,602	3.563	66,249	3.771
2021	3,764	0.215	0	0.000	61,066	3.486	64,830	3.700
2022	3,885	0.222	0	0.000	59,554	3.399	63,439	3.621
2023	4,009	0.229	0	0.000	58,067	3.314	62,076	3.543
2024	4,137	0.235	0	0.000	56,606	3.222	60,743	3.458
2025	4,270	0.244	0	0.000	55,170	3.149	59,440	3.393
CPW (1965)	25,306		0		1,008,918		1,034,224	

NOTES:
1. Assumes an in-service date of January 1, 1996.
2. Current unit assumptions based on 1993 EPRI TAG data escalated to January 1996.

128

TABLE 26-5A

TAMPA ELECTRIC COMPANY
Photovoltaic

Assumptions

	Photovoltaic
Plant Size (MW)	250
Number of Units	50
Plant Investment as of 1/1/96 ($000)	
Plant Investment	662,232
Accumulated Depreciation	0
Net Plant In-Service	662,232
Fuel Stock /Plant Material & Supplies	Included in Plant Investment
Total Net Plant Investment	662,232
Annual Revenue Requirement ($000)	See TABLE 26-5
Annual Capacity Factor	80%
Net Generation (MWH)	1,752,000
Revenue Requirement per KWH	See TABLE 26-5
Assumptions Used	
Installed Cost (1/1/96, $000)	662,232
Heat Rate (HHV, Btu/kWh)	NA
Fuel Cost per Million BTU	Renewable
Fuel Cost per MWH	See TABLE 26-5
Fixed O&M ($000/year)	1,714
Capital Replacement ($000/year)	NA
Variable O&M ($/MWH)	0.00
Property Tax Rate (% of In-Service Cost)	1.81
Depreciation Rate	3.33%
Return on Investment (%)	12.55%
Discount Rate	9.26%
Capital Escalation	
1993	3.00%
1994	2.30%
1995	3.20%
O&M Escalation	
1993	3.00%
1994	2.60%
1995	3.00%
1996	3.10%
1997 and Beyond	3.20%

TAMPA ELECTRIC COMPANY
DOCKET NO. 950379-EI
STAFF'S SECOND SET
INTERROGATORY NO. 26
SPONSOR: HERNANDEZ

TABLE 26-6

SOLAR THERMAL

NOMINAL COST PROJECTION

YEAR	SOLAR THERMAL							
	O&M		FUEL		CAPITAL		TOTAL	
	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh
1996	13,588	0.773	0	0.000	108,849	6.196	122,437	6.969
1997	13,990	0.799	0	0.000	131,817	7.524	145,807	8.322
1998	14,438	0.824	0	0.000	119,550	6.824	133,988	7.648
1999	14,900	0.850	0	0.000	111,495	6.364	126,395	7.214
2000	15,398	0.876	0	0.000	105,028	5.978	120,426	6.855
2001	15,868	0.906	0	0.000	99,755	5.694	115,623	6.600
2002	16,376	0.935	0	0.000	99,796	5.696	116,172	6.631
2003	16,900	0.965	0	0.000	97,810	5.583	114,710	6.54
2004	17,465	0.994	0	0.000	95,840	5.455	113,305	6.450
2005	17,999	1.027	0	0.000	93,884	5.359	111,883	6.386
2006	18,575	1.060	0	0.000	91,944	5.248	110,519	6.308
2007	19,169	1.094	0	0.000	90,020	5.138	109,189	6.232
2008	19,810	1.128	0	0.000	88,113	5.016	107,923	6.143
2009	20,416	1.165	0	0.000	86,224	4.921	106,640	6.087
2010	21,069	1.203	0	0.000	84,351	4.815	105,420	6.017
2011	21,743	1.241	0	0.000	82,497	4.709	104,240	5.950
2012	22,470	1.279	0	0.000	80,662	4.591	103,132	5.870
2013	23,157	1.322	0	0.000	78,847	4.500	102,004	5.822
2014	23,898	1.364	0	0.000	77,051	4.398	100,949	5.762
2015	24,663	1.408	0	0.000	75,276	4.297	99,939	5.704
2016	25,488	1.451	0	0.000	73,522	4.185	99,010	5.636
2017	26,267	1.499	0	0.000	71,790	4.098	98,057	5.597
2018	27,107	1.547	0	0.000	70,081	4.000	97,188	5.547
2019	27,975	1.597	0	0.000	68,395	3.904	96,370	5.501
2020	28,910	1.646	0	0.000	66,733	3.799	95,643	5.444
2021	29,794	1.701	0	0.000	65,096	3.716	94,890	5.416
2022	30,747	1.755	0	0.000	63,485	3.624	94,232	5.379
2023	31,731	1.811	0	0.000	61,899	3.533	93,630	5.344
2024	32,792	1.867	0	0.000	60,341	3.435	93,133	5.301
2025	33,794	1.929	0	0.000	58,811	3.357	92,605	5.286
CPW (96$)	200,378		0		1,075,498		1,275,875	

NOTES:

1. Assumes an in-service date of January 1, 1996.
2. Current unit assumptions based on 1993 EPRI TAG data escalated to January 1996.

130

TABLE 26-6A

TAMPA ELECTRIC COMPANY
Solar Thermal

Assumptions

	Solar Thermal
Plant Size (MW)	250
Number of Units	1.25
Plant Investment as of 1/1/96 ($000)	
Plant Investment	705,935
Accumulated Depreciation	0
Net Plant In-Service	705,935
Fuel Stock /Plant Material & Supplies	Included in Plant Investment
Total Net Plant Investment	705,935
Annual Revenue Requirement ($000)	See TABLE 26-6
Annual Capacity Factor	80%
Net Generation (MWH)	1,752,000
Revenue Requirement per KWH	See TABLE 26-6
Assumptions Used	
Installed Cost (1/1/96, $000)	705,935
Heat Rate (HHV, Btu/kWh)	NA
Fuel Cost per Million BTU	Renewable
Fuel Cost per MWH	See TABLE 26-6
Fixed O&M ($000/year)	6,716
Capital Replacement ($000/year)	NA
Variable O&M ($/MWH)	3.91
Property Tax Rate (% of In-Service Cost)	1.81
Depreciation Rate	3.33%
Return on Investment (%)	12.55%
Discount Rate	9.26%
Capital Escalation	
1993	3.00%
1994	2.30%
1995	3.20%
O&M Escalation	
1993	3.00%
1994	2.60%
1995	3.00%
1996	3.10%
1997 and Beyond	3.20%

TABLE 26-7

COMBUSTION TURBINE

NOMINAL COST PROJECTION

YEAR	COMBUSTION TURBINE							
	O&M		FUEL		CAPITAL		TOTAL	
	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh
1996	2,913	0.166	81,738	4.653	17,650	1.005	102,301	5.823
1997	3,002	0.171	85,893	4.903	22,123	1.263	111,018	6.337
1998	3,099	0.177	90,748	5.180	21,236	1.212	115,083	6.569
1999	3,198	0.183	95,142	5.430	20,411	1.165	118,750	6.778
2000	3,301	0.188	99,736	5.677	19,643	1.118	122,679	6.983
2001	3,406	0.194	104,379	5.958	18,925	1.080	126,710	7.232
2002	3,515	0.201	109,577	6.254	18,243	1.041	131,335	7.496
2003	3,627	0.207	115,076	6.568	17,574	1.003	136,277	7.778
2004	3,744	0.213	121,224	6.900	16,908	0.962	141,876	8.076
2005	3,863	0.220	127,016	7.250	16,245	0.927	147,124	8.397
2006	3,986	0.228	133,524	7.621	15,584	0.889	153,094	8.738
2007	4,114	0.235	139,634	7.970	14,925	0.852	158,673	9.057
2008	4,246	0.242	146,507	8.339	14,269	0.812	165,022	9.393
2009	4,382	0.250	152,898	8.727	13,616	0.777	170,895	9.754
2010	4,522	0.258	160,092	9.138	12,966	0.740	177,580	10.136
2011	4,666	0.266	167,716	9.573	12,427	0.709	184,809	10.548
2012	4,817	0.274	175,182	9.972	12,148	0.691	192,147	10.937
2013	4,970	0.284	182,041	10.390	11,892	0.679	198,903	11.353
2014	5,129	0.293	189,708	10.828	11,639	0.664	206,476	11.785
2015	5,293	0.302	197,722	11.285	11,389	0.650	214,404	12.238
2016	5,463	0.311	206,700	11.766	11,143	0.634	223,306	12.711
2017	5,637	0.322	214,927	12.268	10,901	0.622	231,466	13.212
2018	5,818	0.332	224,649	12.822	10,662	0.609	241,129	13.763
2019	6,004	0.343	234,858	13.405	10,427	0.595	251,288	14.343
2020	6,197	0.353	246,247	14.017	10,196	0.580	262,640	14.950
2021	6,394	0.365	256,828	14.659	9,969	0.569	273,191	15.593
2022	6,599	0.377	268,599	15.331	9,746	0.556	284,944	16.264
2023	6,810	0.389	279,991	15.981	9,527	0.544	296,328	16.914
2024	7,029	0.400	292,752	16.664	9,313	0.530	309,094	17.594
2025	7,253	0.414	304,414	17.375	9,103	0.520	320,770	18.309
CPW (96$)	42,989		1,434,345		183,609		1,660,943	

NOTES:

1. Assumes an in-service date of January 1, 1996.
2. Current unit assumptions based on 1993 EPRI TAG data escalated to January 1996.

132

TABLE 26-7A

TAMPA ELECTRIC COMPANY
Combustion Turbine

Assumptions

	Combustion Turbine
Plant Size (MW)	250
Number of Units	3.13
Plant Investment as of 1/1/96 ($000)	
Plant Investment	114,471
Accumulated Depreciation	0
Net Plant In-Service	114,471
Fuel Stock /Plant Material & Supplies	Included in Plant Investment
Total Net Plant Investment	114,471
Annual Revenue Requirement ($000)	See TABLE 26-7
Annual Capacity Factor	80%
Net Generation (MWH)	1,752,000
Revenue Requirement per KWH	See TABLE 26-7
Assumptions Used	
Installed Cost (1/1/96, $000)	114,471
Heat Rate (HHV, Btu/kWh)	13090
Fuel Cost per Million BTU	NG and #2OiL See TABLE 5-3&4
Fuel Cost per MWH	See TABLE 26-7
Fixed O&M ($000/year)	2,746
Capital Replacement ($000/year)	NA
Variable O&M ($/MWH)	0.09
Property Tax Rate (% of In-Service Cost)	1.81
Depreciation Rate	3.33%
Return on Investment (%)	12.55%
Discount Rate	9.26%
Capital Escalation	
1993	3.00%
1994	2.30%
1995	3.20%
O&M Escalation	
1993	3.00%
1994	2.60%
1995	3.00%
1996	3.10%
1997 and Beyond	3.20%

27. Please provide an estimate of the total annual revenue requirement, in 1996 dollars, based on the cost, inflation, and interest rate projections used by Tampa Electric Company in Docket No. 910883 -EI for each technology type that was evaluated in that docket. The total annual revenue requirement must include the cost of required return on investment, operation and maintenance, and the cost of fuel. State all assumptions that were made to estimate the revenue requirement for each unit type. Separate the total annual revenue requirement for each unit type by capital, operation and maintenance, and fuel. An example format is shown on Attachment I.

A. There were seven technologies that passed the initial economic screening on a levelized cost basis and all seven technologies were included in the detailed system revenue requirement analysis during the Determination of Need proceedings. The economic screening was used to eliminate higher cost technologies or technologies that were considered not yet commercially available. The detailed system revenue requirement analysis is the appropriate method to evaluate the cost effectiveness of multiple combinations of both supply and demand side energy resource alternatives. A unit revenue requirement analysis is only a more detailed screening tool and should not be used in place of a more detailed system economic analysis.

In response to this interrogatory, the annual revenue requirements and key assumptions are provided for the same seven technologies that were included in the detailed system revenue requirement analysis identified in the Need hearing as shown below:

1. Pulverized Coal
2. Integrated Gasification Combined Cycle
3. Combined Cycle
4. Phosphoric Acid Fuel Cell
5. Photovoltaic Solar Cells
6. Solar Thermal
7. Combustion Turbine.

All seven of the alternate technologies are technically suitable for the selected Polk County site, and the selection of any one of the technologies would not affect the location and amount of land purchased by Tampa Electric or the associated site development and land improvement costs. Therefore, these combined costs are considered the same for all resource plan alternatives and are excluded from each of the unit revenue requirements shown in the following tables.

The capital and O&M costs from the 1991 Polk Unit One Need Determination Study were used as the basis for all of the technologies. The IGCC capital cost is based on the $413 million estimate provided in the Need Hearing less the land and site development costs, and the revenue requirement analysis includes the DOE funding.

Fuel prices are from Tampa Electric's 1991 Need Hearing and are provided in Table 27-8. The IGCC unit assumes coal used in 1996 to 2025. The combined cycle, combustion turbine, and fuel cell technologies use as-available natural gas in the spring and fall months, and distillate oil in the winter and summer months.

All technologies were evaluated at the same capacity (250 MW) and 80% capacity factor which may have required multiple units of a lower rated technology or a scale-down of a single unit with a higher capacity rating. However, the photovoltaic solar cell technology has an operating limitation of approximately 30-35% due to availability of useful sunlight over all hours in the year, and would not be available at an 80% capacity factor. All seven technologies were assumed to have a commercial operation date of January 1, 1996.

TABLE 27-1

PULVERIZED COAL

NOMINAL COST PROJECTION

YEAR	PULVERIZED COAL							
	O&M		FUEL		CAPITAL		TOTAL	
	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh
1996	25,879	1.473	34,977	1.991	61,878	3.522	122,734	6.986
1997	26,642	1.521	36,849	2.103	77,824	4.442	141,315	8.066
1998	27,494	1.569	38,817	2.216	75,198	4.292	141,509	8.077
1999	28,374	1.620	40,963	2.338	72,702	4.150	142,040	8.107
2000	29,325	1.669	43,407	2.471	70,326	4.003	143,059	8.143
2001	30,219	1.725	46,151	2.634	68,061	3.885	144,431	8.244
2002	31,186	1.780	49,371	2.818	65,900	3.761	146,457	8.359
2003	32,184	1.837	52,948	3.022	63,836	3.644	148,968	8.503
2004	33,263	1.893	56,860	3.237	61,830	3.519	151,953	8.649
2005	34,277	1.956	60,461	3.451	59,840	3.416	154,578	8.823
2006	35,374	2.019	64,039	3.655	57,859	3.302	157,272	8.977
2007	36,506	2.084	67,616	3.859	55,887	3.190	160,009	9.133
2008	37,729	2.148	71,568	4.074	53,925	3.070	163,223	9.291
2009	38,879	2.219	75,308	4.298	51,972	2.966	166,160	9.484
2010	40,124	2.290	79,601	4.543	50,030	2.856	169,755	9.689
2011	41,408	2.363	84,252	4.809	48,098	2.745	173,758	9.918
2012	42,795	2.436	89,326	5.085	46,176	2.628	178,297	10.149
2013	44,100	2.517	94,806	5.411	44,266	2.527	183,172	10.455
2014	45,511	2.598	100,709	5.748	42,367	2.418	188,587	10.764
2015	46,968	2.681	108,401	6.187	40,479	2.310	195,847	11.179
2016	48,542	2.763	115,514	6.575	38,900	2.214	202,956	11.553
2017	50,022	2.855	122,353	6.984	37,885	2.162	210,260	12.001
2018	51,622	2.946	130,045	7.423	37,065	2.116	218,732	12.485
2019	53,274	3.041	138,095	7.882	36,258	2.070	227,627	12.992
2020	55,060	3.134	147,442	8.393	35,465	2.019	237,966	13.545
2021	56,738	3.238	156,424	8.928	34,686	1.980	247,849	14.147
2022	58,554	3.342	166,409	9.498	33,921	1.936	258,884	14.776
2023	60,428	3.449	177,031	10.104	33,172	1.893	270,630	15.447
2024	62,453	3.555	188,847	10.749	32,437	1.846	283,737	16.151
2025	64,357	3.673	200,352	11.436	31,719	1.810	296,428	16.919
CPW (96$)	381,602		708,579		661,916		1,752,096	

NOTES

1. Assumes an in-service date of January 1, 1996.
2. Unit assumptions based on Sept. 1991 Polk Unit One Need Determination Study data escalated to Jan. 1996

TABLE 27-1A

TAMPA ELECTRIC COMPANY
Pulverized Coal

Assumptions

	Pulverized Coal
Plant Size (MW)	250
Number of Units	1
Plant Investment as of 1/1/96 ($000)	
Plant Investment	401,306
Accumulated Depreciation	0
Net Plant In-Service	401,306
Fuel Stock /Plant Material & Supplies	Included in Plant Investment
Total Net Plant Investment	401,306
Annual Revenue Requirement ($000)	See TABLE 27-1
Annual Capacity Factor	80%
Net Generation (MWH)	1,752,000
Revenue Requirement per KWH	See TABLE 27-1
Assumptions Used	
Installed Cost (1/1/96, $000)	401,306
Heat Rate (HHV, Btu/kWh)	10210
Fuel Cost per Million BTU	Avg. Coal, See TABLE 27-8
Fuel Cost per MWH	See TABLE 27-1
Fixed O&M ($000/year)	11,969
Capital Replacement ($000/year)	NA
Variable O&M ($/MWH)	7.92
Property Tax Rate (% of In-Service Cost)	1.81
Depreciation Rate	3.33%
Return on Investment	12.55%
Discount Rate	9.26%
Capital Escalation	
1991	0.90%
1992	2.50%
1993	3.00%
1994	2.30%
1995	3.20%
O&M Escalation	
1991	4.20%
1992	3.00%
1993	3.00%
1994	2.60%
1995	3.00%
1996	3.10%
1997 and Beyond	3.20%

TABLE 27-2

INTEGRATED GASIFICATION COMBINED CYCLE

NOMINAL COST PROJECTION

YEAR	INTEGRATED GASIFICATION COMBINED CYCLE							
	O&M		FUEL		CAPITAL		TOTAL	
	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh
1996	24,566	1.398	31,928	1.817	61,136	3.480	117,630	6.696
1997	25,298	1.444	33,637	1.920	76,890	4.389	135,825	7.753
1998	26,108	1.490	35,433	2.022	74,297	4.241	135,838	7.753
1999	26,943	1.538	37,393	2.134	71,830	4.100	136,166	7.772
2000	27,838	1.585	39,624	2.255	69,482	3.955	136,944	7.795
2001	28,695	1.638	42,128	2.405	67,245	3.838	138,068	7.881
2002	29,614	1.690	45,067	2.572	65,110	3.716	139,791	7.979
2003	30,561	1.744	48,333	2.759	63,071	3.600	141,965	8.103
2004	31,576	1.797	51,904	2.954	61,089	3.477	144,569	8.229
2005	32,549	1.858	55,191	3.150	59,123	3.375	146,862	[illegible]
2006	33,590	1.917	58,457	3.337	57,166	3.263	149,213	8.517
2007	34,665	1.979	61,722	3.523	55,217	3.152	151,604	8.653
2008	35,816	2.039	65,330	3.719	53,278	3.033	154,424	8.790
2009	36,919	2.107	68,744	3.924	51,349	2.931	157,012	8.962
2010	38,100	2.175	72,662	4.147	49,430	2.821	160,193	9.143
2011	39,320	2.244	76,908	4.390	47,521	2.712	163,749	9.346
2012	40,625	2.312	81,539	4.641	45,622	2.597	167,786	9.551
2013	41,876	2.390	86,542	4.940	43,735	2.496	172,153	9.826
2014	43,216	2.467	91,930	5.247	41,859	2.389	177,006	10.103
2015	44,599	2.546	98,952	5.648	39,994	2.283	183,545	10.476
2016	46,080	2.623	105,445	6.002	38,433	2.188	189,958	10.813
2017	47,499	2.711	111,688	6.375	37,431	2.136	196,618	11.223
2018	49,019	2.798	118,709	6.776	36,621	2.090	204,350	11.664
2019	50,588	2.887	126,057	7.195	35,823	2.045	212,468	12.127
2020	52,268	2.975	134,589	7.661	35,040	1.995	221,897	12.631
2021	53,877	3.075	142,789	8.150	34,270	1.956	230,936	13.181
2022	55,602	3.174	151,903	8.670	33,514	1.913	241,019	13.757
2023	57,381	3.275	161,599	9.224	32,774	1.871	251,754	14.370
2024	59,286	3.375	172,385	9.812	32,048	1.824	263,719	15.011
2025	61,112	3.488	182,887	10.439	31,339	1.789	275,338	15.716
CPW (96$)	362,330		646,812		653,979		1,6[illegible]3,121	

NOTES.

1. Assumes an in-service date of January 1, 1996.
2. Unit assumptions based on Dec. 1991 Polk Unit One Need hearing proceedings data escalated to Jan. 1996. Capital cost were modified to be consistent with EPRI tag. Includes DOE funding.

TABLE 27-2A

TAMPA ELECTRIC COMPANY
IGCC

Assumptions

	IGCC
Plant Size (MW)	250
Number of Units	1
Plant Investment as of 1/1/96 ($000)	
Plant Investment	396,494
Accumulated Depreciation	0
Net Plant In-Service	396,494
Fuel Stock /Plant Material & Supplies	Included in Plant Investment
Total Net Plant Investment	396,494
Annual Revenue Requirement ($000)	See TABLE 27-2
Annual Capacity Factor	80%
Net Generation (MWH)	1,752,000
Revenue Requirement per KWH	See TABLE 27-2
Assumptions Used	
Installed Cost (1/1/96, $000)	396,494
Heat Rate (HHV, Btu/kWh)	9320
Fuel Cost per Million BTU	Avg. Coal, See TABLE 27-8
Fuel Cost per MWH	See TABLE 27-2
Fixed O&M ($000/year)	14,134
Capital Replacement ($000/year)	NA
Variable O&M ($/MWH)	5.94
Property Tax Rate (% of In-Service Cost)	1.81
Depreciation Rate	3.33%
Return on Investment (%)	12.55%
Discount Rate	9.26%
Capital Escalation	
1991	0.90%
1992	2.50%
1993	3.00%
1994	2.30%
1995	3.20%
O&M Escalation	
1991	4.20%
1992	3.00%
1993	3.00%
1994	2.60%
1995	3.00%
1996	3.10%
1997 and Beyond	3.20%

TABLE 27-3

COMBINED CYCLE

NOMINAL COST PROJECTION

YEAR	COMBINED CYCLE							
	O&M		FUEL		CAPITAL		TOTAL	
	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh
1996	9,434	0.537	103,867	5.912	24,212	1.378	137,513	7.827
1997	9,703	0.554	111,252	6.350	30,451	1.738	151,407	8.642
1998	10,014	0.572	122,749	7.006	29,424	1.679	162,186	9.257
1999	10,334	0.590	133,722	7.633	28,447	1.624	172,504	9.846
2000	10,690	0.609	139,785	7.957	27,517	1.566	177,992	10.132
2001	11,006	0.628	153,894	8.784	26,631	1.520	191,531	10.932
2002	11,358	0.648	171,019	9.761	25,786	1.472	208,163	11.881
2003	11,722	0.669	190,592	10.879	24,978	1.426	227,292	12.973
2004	12,126	0.690	219,103	12.472	24,193	1.377	255,422	14.539
2005	12,484	0.713	246,707	14.081	23,415	1.336	282,606	16.130
2006	12,884	0.735	278,318	15.886	22,639	1.292	313,840	17.913
2007	13,296	0.759	282,648	16.133	21,868	1.248	317,812	18.140
2008	13,754	0.783	286,224	16.292	21,100	1.201	321,078	18.276
2009	14,160	0.808	285,063	16.271	20,336	1.161	319,559	18.240
2010	14,614	0.834	292,502	16.695	19,576	1.117	326,692	18.647
2011	15,081	0.861	297,196	16.963	18,820	1.074	331,097	18.898
2012	15,601	0.888	305,383	17.383	18,068	1.028	339,052	19.299
2013	16,062	0.917	316,316	18.055	17,320	0.989	349,697	19.960
2014	16,576	0.946	319,849	18.256	16,577	0.946	353,002	20.149
2015	17,106	0.976	327,856	18.713	15,839	0.904	360,801	20.594
2016	17,696	1.007	362,200	20.617	15,221	0.866	395,117	22.491
2017	18,219	1.040	375,518	21.434	14,824	0.846	408,560	23.320
2018	18,801	1.073	396,397	22.625	14,503	0.828	429,702	24.526
2019	19,403	1.107	392,361	22.395	14,187	0.810	425,951	24.312
2020	20,072	1.143	386,484	21.999	13,877	0.790	420,433	23.932
2021	20,665	1.179	396,725	22.644	13,572	0.775	430,962	24.598
2022	21,326	1.217	408,353	23.308	13,273	0.758	442,952	25.283
2023	22,009	1.256	420,323	23.991	12,980	0.741	455,311	25.988
2024	22,767	1.296	433,829	24.694	12,692	0.722	469,288	26.713
2025	23,440	1.338	445,325	25.418	12,411	0.708	481,176	27.464
CPW (96$)	139,020		2,341,184		258,997		2,739,201	

NOTES:

1. Assumes an in-service date of January 1, 1996.
2. Unit assumptions based on Sept. 1991 Polk Unit One Need Determination Study data escalated to Jan. 1996.

TABLE 27-3A

TAMPA ELECTRIC COMPANY
Combined Cycle

Assumptions

	Combined Cycle
Plant Size (MW)	250
Number of Units	1.19
Plant Investment as of 1/1/96 ($000)	
Plant Investment	157,025
Accumulated Depreciation	0
Net Plant In-Service	157,025
Fuel Stock /Plant Material & Supplies	Included in Plant Investment
Total Net Plant Investment	157,025
Annual Revenue Requirement ($000)	See TABLE 27-3
Annual Capacity Factor	80%
Net Generation (MWH)	1,752,000
Revenue Requirement per KWH	See TABLE 27-3
Assumptions Used	
Installed Cost (1/1/96, $000)	157,025
Heat Rate (HHV, Btu/kWh)	7580
Fuel Cost per Million BTU	NG and #2Oil. See TABLE 27-8
Fuel Cost per MWH	See TABLE 27-3
Fixed O&M ($000/year)	1,175
Capital Replacement ($000/year)	NA
Variable O&M ($/MWH)	4.70
Property Tax Rate (% of In-Service Cost)	1.81
Depreciation Rate	3.33%
Return on Investment (%)	12.55%
Discount Rate	9.26%
Capital Escalation	
1991	0.90%
1992	2.50%
1993	3.00%
1994	2.30%
1995	3.20%
O&M Escalation	
1991	4.20%
1992	3.00%
1993	3.00%
1994	2.60%
1995	3.00%
1996	3.10%
1997 and Beyond	3.20%

TABLE 27-4

PHOSPHORIC ACID FUEL CELL

NOMINAL COST PROJECTION

YEAR	PHOSPHORIC ACID FUEL CELL							
	O&M		FUEL		CAPITAL		TOTAL	
	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh
1996	13,372	0.761	117,145	6.668	50,582	2.879	181,099	10.308
1997	13,756	0.785	125,474	7.162	63,616	3.631	202,846	11.578
1998	14,196	0.810	138,440	7.902	61,471	3.509	214,107	12.221
1999	14,650	0.836	150,817	8.608	59,430	3.392	224,897	12.837
2000	15,153	0.863	157,654	8.974	57,487	3.272	230,294	13.109
2001	15,603	0.891	173,567	9.907	55,636	3.176	244,806	13.973
2002	16,102	0.919	192,881	11.009	53,869	3.075	262,852	15.003
2003	16,618	0.948	214,957	12.269	52,182	2.978	283,757	16.196
2004	17,188	0.978	247,112	14.066	50,543	2.877	314,843	17.921
2005	17,698	1.010	278,245	15.882	48,916	2.792	344,859	19.684
2006	18,265	1.042	313,897	17.916	47,297	2.700	379,459	21.659
2007	18,849	1.076	318,781	18.195	45,685	2.608	383,315	21.879
2008	19,495	1.110	322,813	18.375	44,081	2.509	386,390	21.994
2009	20,075	1.146	321,504	18.351	42,484	2.425	384,063	21.921
2010	20,717	1.182	329,895	18.830	40,897	2.334	391,509	22.346
2011	21,380	1.220	335,188	19.132	39,317	2.244	395,885	22.596
2012	22,113	1.259	344,422	19.605	37,746	2.149	404,281	23.012
2013	22,770	1.300	356,752	20.363	36,185	2.065	415,708	23.728
2014	23,499	1.341	360,738	20.590	34,632	1.977	418,869	23.908
2015	24,251	1.384	369,768	21.105	33,089	1.889	427,108	24.378
2016	25,083	1.428	408,502	23.253	31,798	1.810	465,383	26.490
2017	25,828	1.474	423,522	24.174	30,969	1.768	480,319	27.415
2018	26,654	1.521	447,071	25.518	30,299	1.729	504,024	28.769
2019	27,507	1.570	442,519	25.258	29,639	1.692	499,665	28.520
2020	28,450	1.619	435,891	24.812	28,991	1.650	493,332	28.081
2021	29,296	1.672	447,441	25.539	28,354	1.618	505,090	28.829
2022	30,233	1.726	460,555	26.287	27,729	1.583	518,518	29.596
2023	31,201	1.781	474,055	27.058	27,116	1.548	532,372	30.387
2024	32,271	1.837	489,288	27.851	26,516	1.509	548,074	31.197
2025	33,229	1.897	502,254	28.667	25,929	1.480	561,413	32.044
CPW (96$)	197,074		2,640,472		541,079		3,378,625	

NOTES

1. Assumes an in-service date of January 1, 1996.
2. Unit assumptions based on Sept. 1991 Polk Unit One Need Determination Study data escalated to Jan. 1996

TABLE 27-4A

TAMPA ELECTRIC COMPANY
Fuel Cell

Assumptions

	Fuel Cell
Plant Size (MW)	250
Number of Units	10
Plant Investment as of 1/1/96 ($000)	
Plant Investment	328,045
Accumulated Depreciation	0
Net Plant In-Service	328,045
Fuel Stock /Plant Material & Supplies	Included in Plant Investment
Total Net Plant Investment	328,045
Annual Revenue Requirement ($000)	See TABLE 27-4
Annual Capacity Factor	80%
Net Generation (MWH)	1,752,000
Revenue Requirement per KWH	See TABLE 27-4
Assumptions Used	
Installed Cost (1/1/96, $000)	328,045
Heat Rate (HHV, Btu/kWh)	8549
Fuel Cost per Million BTU	NG and #2Oil, See TABLE 27-8
Fuel Cost per MWH	See TABLE 27-4
Fixed O&M ($000/year)	2,505
Capital Replacement ($000/year)	NA
Variable O&M ($/MWH)	6.19
Property Tax Rate (% of In-Service Cost)	1.81
Depreciation Rate	3.33%
Return on Investment (%)	12.55%
Discount Rate	9.26%
Capital Escalation	
1991	0.90%
1992	2.50%
1993	3.00%
1994	2.30%
1995	3.20%
O&M Escalation	
1991	4.20%
1992	3.00%
1993	3.00%
1994	2.60%
1995	3.00%
1996	3.10%
1997 and Beyond	3.20%

TABLE 27-5

PHOTOVOLTAIC SOLAR CELLS

NOMINAL COST PROJECTION

YEAR	PHOTOVOLTAIC SOLAR CELLS							
	O&M		FUEL		CAPITAL		TOTAL	
	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh
1996	8,717	0.496	0	0.000	113,507	6.461	122,224	6.957
1997	8,968	0.512	0	0.000	137,458	7.846	146,426	8.358
1998	9,255	0.528	0	0.000	124,665	7.116	133,920	7.644
1999	9,551	0.545	0	0.000	116,266	6.636	125,817	7.181
2000	9,878	0.562	0	0.000	109,522	6.234	119,400	6.796
2001	10,172	0.581	0	0.000	104,024	5.937	114,196	6.518
2002	10,498	0.599	0	0.000	104,066	5.940	114,564	6.539
2003	10,834	0.618	0	0.000	101,996	5.822	112,830	6.440
2004	11,204	0.638	0	0.000	99,941	5.689	111,145	6.327
2005	11,538	0.659	0	0.000	97,902	5.588	109,440	6.247
2006	11,907	0.680	0	0.000	95,879	5.473	107,786	6.152
2007	12,288	0.701	0	0.000	93,873	5.358	106,161	6.059
2008	12,709	0.723	0	0.000	91,884	5.230	104,593	5.954
2009	13,088	0.747	0	0.000	89,913	5.132	103,001	5.879
2010	13,506	0.771	0	0.000	87,961	5.021	101,467	5.792
2011	13,939	0.796	0	0.000	86,028	4.910	99,967	5.706
2012	14,415	0.821	0	0.000	84,114	4.788	98,529	5.608
2013	14,845	0.847	0	0.000	82,221	4.693	97,066	5.540
2014	15,320	0.874	0	0.000	80,348	4.586	95,668	5.460
2015	15,810	0.902	0	0.000	78,497	4.480	94,307	5.383
2016	16,351	0.931	0	0.000	76,668	4.364	93,019	5.295
2017	16,838	0.961	0	0.000	74,862	4.273	91,700	5.234
2018	17,377	0.992	0	0.000	73,080	4.171	90,457	5.163
2019	17,933	1.024	0	0.000	71,322	4.071	89,255	5.094
2020	18,546	1.056	0	0.000	69,589	3.961	88,135	5.017
2021	19,099	1.090	0	0.000	67,882	3.875	86,981	4.965
2022	19,710	1.125	0	0.000	66,201	3.779	85,911	4.904
2023	20,341	1.161	0	0.000	64,548	3.684	84,889	4.845
2024	21,036	1.197	0	0.000	62,923	3.582	83,959	4.779
2025	21,664	1.237	0	0.000	61,328	3.500	82,992	4.737
CPW (?965)	128,477		0		1,121,521		1,249,998	

NOTES

1. Assumes an in-service date of January 1, 1996.
2. Unit assumptions based on Sept. 1991 Polk Unit One Need Determination Study data escalated to Jan. 1996

TABLE 27-5A

TAMPA ELECTRIC COMPANY
Photovoltaic

Assumptions

	Photovoltaic
Plant Size (MW)	250
Number of Units	250
Plant Investment as of 1/1/96 ($000)	
Plant Investment	736,143
Accumulated Depreciation	0
Net Plant In-Service	736,143
Fuel Stock /Plant Material & Supplies	Included in Plant Investment
Total Net Plant Investment	736,143
Annual Revenue Requirement ($000)	See TABLE 27-5
Annual Capacity Factor	80%
Net Generation (MWH)	1,752,000
Revenue Requirement per KWH	See TABLE 27-5
Assumptions Used	
Installed Cost (1/1/96, $000)	736,143
Heat Rate (HHV, Btu/kWh)	NA
Fuel Cost per Million BTU	Renewable
Fuel Cost per MWH	See TABLE 27-5
Fixed O&M ($000/year)	1,979
Capital Replacement ($000/year)	NA
Variable O&M ($/MWH)	3.84
Property Tax Rate (% of In-Service Cost)	1.81
Depreciation Rate	3.33%
Return on Investment (%)	12.55%
Discount Rate	9.26%
Capital Escalation	
1991	0.90%
1992	2.50%
1993	3.00%
1994	2.30%
1995	3.20%
O&M Escalation	
1991	4.20%
1992	3.00%
1993	3.00%
1994	2.60%
1995	3.00%
1996	3.10%
1997 and Beyond	3.20%

TABLE 27-6

SOLAR THERMAL

NOMINAL COST PROJECTION

YEAR	SOLAR THERMAL							
	O&M		FUEL		CAPITAL		TOTAL	
	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh
1996	15,471	0.881	0	0.000	130,166	7.409	145,637	8.290
1997	15,945	0.910	0	0.000	157,632	8.997	173,577	9.907
1998	16,456	0.939	0	0.000	142,962	8.160	159,418	9.099
1999	16,982	0.969	0	0.000	133,330	7.610	150,312	8.579
2000	17,531	0.998	0	0.000	125,596	7.149	143,127	8.147
2001	18,087	1.032	0	0.000	119,291	6.809	137,378	7.841
2002	18,665	1.065	0	0.000	119,340	6.812	138,005	7.877
2003	19,263	1.099	0	0.000	116,966	6.676	136,229	7.776
2004	19,885	1.132	0	0.000	114,609	6.524	134,494	7.656
2005	20,515	1.171	0	0.000	112,270	6.408	132,785	7.[illegible]79
2006	21,172	1.208	0	0.000	109,951	6.276	131,123	7.484
2007	21,849	1.247	0	0.000	107,650	6.144	129,499	7.392
2008	22,555	1.284	0	0.000	105,369	5.998	127,924	7.282
2009	23,270	1.328	0	0.000	103,109	5.885	126,379	7.213
2010	24,014	1.371	0	0.000	100,871	5.757	124,885	7.128
2011	24,783	1.415	0	0.000	98,654	5.631	123,437	7.045
2012	25,584	1.456	0	0.000	96,459	5.491	122,043	6.947
2013	26,394	1.507	0	0.000	94,288	5.382	120,682	6.888
2014	27,239	1.555	0	0.000	92,141	5.259	119,380	6.814
2015	28,111	1.604	0	0.000	90,018	5.138	118,129	6.743
2016	29,019	1.652	0	0.000	87,921	5.005	116,940	6.656
2017	29,939	1.709	0	0.000	85,850	4.900	115,789	6.609
2018	30,897	1.764	0	0.000	83,806	4.783	114,703	6.547
2019	31,885	1.820	0	0.000	81,790	4.668	113,675	6.488
2020	32,916	1.874	0	0.000	79,802	4.542	112,718	6.416
2021	33,959	1.938	0	0.000	77,845	4.443	111,804	6.381
2022	35,045	2.000	0	0.000	75,917	4.333	110,962	6.333
2023	36,167	2.064	0	0.000	74,022	4.225	110,189	6.289
2024	37,335	2.125	0	0.000	72,159	4.107	109,494	6.233
2025	38,518	2.199	0	0.000	70,329	4.014	108,847	6.213
CPW (96$)	228,320		0		1,286,123		1,514,443	

NOTES
1. Assumes an in-service date of January 1, 1996.
2. Unit assumptions based on Sept. 1991 Polk Unit One Need Determination Study data escalated to Jan. 1996.

TABLE 27-6A

TAMPA ELECTRIC COMPANY
Solar Thermal

Assumptions

	Solar Thermal
Plant Size (MW)	250
Number of Units	3.13
Plant Investment as of 1/1/96 ($000)	
Plant Investment	844,185
Accumulated Depreciation	0
Net Plant In-Service	844,185
Fuel Stock /Plant Material & Supplies	Included in Plant Investment
Total Net Plant Investment	844,185
Annual Revenue Requirement ($000)	See TABLE 27-6
Annual Capacity Factor	80%
Net Generation (MWH)	1,752,000
Revenue Requirement per KWH	See TABLE 27-6
Assumptions Used	
Installed Cost (1/1/96, $000)	844,185
Heat Rate (HHV, Btu/kWh)	NA
Fuel Cost per Million BTU	Renewable
Fuel Cost per MWH	See TABLE 27-6
Fixed O&M ($000/year)	13,732
Capital Replacement ($000/year)	NA
Variable O&M ($/MWH)	0.99
Property Tax Rate (% of In-Service Cost)	1.81
Depreciation Rate	3.33%
Return on Investment (%)	12.55%
Discount Rate	9.26%
Capital Escalation	
1991	0.90%
1992	2.50%
1993	3.00%
1994	2.30%
1995	3.20%
O&M Escalation	
1991	4.20%
1992	3.00%
1993	3.00%
1994	2.60%
1995	3.00%
1996	3.10%
1997 and Beyond	3.20%

TABLE 27-7

COMBUSTION TURBINE

NOMINAL COST PROJECTION

YEAR	COMBUSTION TURBINE							
	O&M		FUEL		CAPITAL		TOTAL	
	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh
1996	17,200	0.979	192,113	10.935	18,688	1.064	228,000	12.978
1997	17,685	1.009	205,773	11.745	23,423	1.337	246,881	14.091
1998	18,251	1.042	227,036	12.959	22,484	1.283	267,771	15.284
1999	18,835	1.075	247,333	14.117	21,611	1.234	287,780	16.426
2000	19,490	1.109	258,547	14.717	20,797	1.184	298,834	17.010
2001	20,060	1.145	284,643	16.247	20,037	1.144	324,740	18.535
2002	20,702	1.182	316,317	18.055	19,315	1.102	356,333	20.339
2003	21,364	1.219	352,521	20.121	18,607	1.062	392,492	22.403
2004	22,107	1.258	405,253	23.068	17,902	1.019	445,263	25.345
2005	22,753	1.299	456,310	26.045	17,199	0.982	496,262	28.325
2006	23,482	1.340	514,778	29.382	16,499	0.942	554,758	31.664
2007	24,233	1.383	522,787	29.839	15,802	0.902	562,822	32.125
2008	25,076	1.427	529,400	30.134	15,108	0.860	569,584	32.422
2009	25,809	1.473	527,254	30.094	14,417	0.823	567,480	32.390
2010	26,635	1.520	541,013	30.880	13,728	0.784	581,376	33.184
2011	27,487	1.569	549,694	31.375	13,157	0.751	590,338	33.695
2012	28,443	1.619	564,837	32.151	12,862	0.732	606,142	34.503
2013	29,274	1.671	585,059	33.394	12,591	0.719	626,924	35.783
2014	30,211	1.724	591,595	33.767	12,323	0.703	634,129	36.195
2015	31,178	1.780	606,404	34.612	12,059	0.688	649,641	37.080
2016	32,262	1.836	669,927	38.133	11,798	0.672	713,987	40.641
2017	33,205	1.895	694,559	39.644	11,542	0.659	739,306	42.198
2018	34,268	1.956	733,178	41.848	11,289	0.644	778,735	44.448
2019	35,364	2.019	725,713	41.422	11,040	0.630	772,117	44.071
2020	36,594	2.083	714,842	40.690	10,795	0.614	762,231	43.387
2021	37,664	2.150	733,784	41.883	10,555	0.602	782,002	44.635
2022	38,869	2.219	755,292	43.110	10,318	0.589	804,479	45.918
2023	40,113	2.290	777,430	44.374	10,087	0.576	827,630	47.239
2024	41,508	2.363	802,411	45.675	9,860	0.561	853,779	48.599
2025	42,721	2.438	823,676	47.013	9,638	0.550	876,035	50.002
CPW ('96$)	253,399		4,330,263		194,400		4,778,063	

NOTES:

1. Assumes an in-service date of January 1, 1996.
2. Unit assumptions based on Sept. 1991 Polk Unit One Need Determination Study data escalated to Jan. 1996.

TABLE 27-7A

TAMPA ELECTRIC COMPANY
Combustion Turbine

Assumptions

	Combustion Turbine
Plant Size (MW)	250
Number of Units	3.13
Plant Investment as of 1/1/96 ($000)	
Plant Investment	121,198
Accumulated Depreciation	0
Net Plant In-Service	121,198
Fuel Stock /Plant Material & Supplies	Included in Plant Investment
Total Net Plant Investment	121,198
Annual Revenue Requirement ($000)	See TABLE 27-7
Annual Capacity Factor	80%
Net Generation (MWH)	1,752,000
Revenue Requirement per KWH	See TABLE 27-7
Assumptions Used	
Installed Cost (1/1/96, $000)	121,198
Heat Rate (HHV, Btu/kWh)	14020
Fuel Cost per Million BTU	NG and #2Oil, See TABLE 27-8
Fuel Cost per MWH	See TABLE 27-7
Fixed O&M ($000/year)	247
Capital Replacement ($000/year)	NA
Variable O&M ($/MWH)	9.65
Property Tax Rate (% of In-Service Cost)	1.81
Depreciation Rate	3.33%
Return on Investment (%)	12.55%
Discount Rate	9.26%
Capital Escalation	
1991	0.90%
1992	2.50%
1993	3.00%
1994	2.30%
1995	3.20%
O&M Escalation	
1991	4.20%
1992	3.00%
1993	3.00%
1994	2.60%
1995	3.00%
1996	3.10%
1997 and Beyond	3.20%

TABLE 27-8

TAMPA ELECTRIC COMPANY

1991 Need Determination
Fuel Forecast

Year	#2 Oil ($/MMBTU)	Average Coal ($/MMBTU)	Natural Gas ($/MMBTU)
1996	8.81	1.95	6.38
1997	9.40	2.06	6.94
1998	10.39	2.17	7.64
1999	11.33	2.29	8.31
2000	11.75	2.42	8.75
2001	12.79	2.53	9.91
2002	13.87	2.76	11.49
2003	15.71	2.96	12.45
2004	17.66	3.17	14.76
2005	19.73	3.38	16.97
2006	22.23	3.58	19.18
2007	22.59	3.78	19.46
2008	22.77	3.99	19.71
2009	22.71	4.21	19.72
2010	23.31	4.45	20.23
2011	23.92	4.71	20.22
2012	24.21	4.98	21.14
2013	25.08	5.30	22.05
2014	25.38	5.63	22.27
2015	26.04	6.06	22.80
2016	29.81	6.44	23.54
2017	30.82	6.84	24.72
2018	32.25	7.27	26.49
2019	31.73	7.72	26.49
2020	30.83	8.22	26.49
2021	31.71	8.74	27.30
2022	32.62	9.30	28.13
2023	33.55	9.90	28.99
2024	34.51	10.53	29.87
2025	35.50	11.20	30.78

Note: Fuel prices for 2021 through 2025 were calculated by escalating the values in 2020 using the average annual growth rates from the previous ten years for each fuel.

1. In response to Staff's Interrogatory No. 3 in Docket No. 950379-EI, the values for common costs and fixed and variable O&M for both the IGCC and CC units varied from year to year. Please justify the reasons for these changes and provide the sources relied upon for these estimated costs.

A. The fixed and variable O&M estimates for both the IGCC and CC units assuming a full year of operation in 1997 for each study are shown in Table 1. The IGCC O&M estimates are shown as reported in Staff's Interrogatory No. 3 in Docket No. 950379-EI and adjusted for comparison purposes. The adjusted cost estimates exclude DOE funding and sulfur credits. For consistency with the later studies, the 1992 and 1993 Study variable O&M dollars were calculated based on a 250 MW IGCC unit running at a 80% capacity factor.

The 1992 and 1993 IGCC O&M estimates were based on the best engineering estimates available at the time and contained both a fixed and variable component. The 1994, 1995, and 1996 IGCC O&M estimates combined the fixed and variable components and were developed by the Polk One Project Management Team based on more detailed Bechtel Engineering estimates.

The CC unit fixed and variable O&M estimates for all of the studies shown in Table 1 were based on EPRI TAG, except for the 1996 estimate which was based on TECO Power Services operation of the Hardee Power Station.

The O&M estimates for both the IGCC and CC units changed through time due to the data sources and the amount of engineering detail available at the time of each study.

All of the common costs identified in Table 1 were developed by the Tampa Electric Polk One Project Management Team.

Table 1
Polk Unit One

	Interrogatory #3			IGCC					
				Adjusted for Consistency (3)					
Study	Fixed '97$ x 1000	Variable $/MWH	Notes	Fixed '97$ x 1000	Variable $/MWH	Total $000/yr	O&M Source	Common Cost	Source
1992	3250	1.03	1	9,550	3.04	14,871	Fluor - Daniel	88,505	Proj. Team
1993	6416	1.92	2	6,416	2.70	11,146	Texaco	95,052	Proj. Team
1994	13522	NA		13,522	NA	13,522	Proj. Team	94,141	Proj. Team
1995	13289	NA		13,289	NA	13,289	Proj. Team	107,874	Proj. Team
1996	11974	NA		11,974	NA	11,974	Proj. Team	118,461	Proj. Team

Notes:
1. Included DOE funding.
2. Included a sulfur credit in the variable O&M.
3. Adjusted to exclude DOE funding and sulfur credit.

	CC					
Study	Fixed '97$ x 1000	Variable $/MWH	Total $000/yr	O&M Source	Common Cost	Source
1992	1,147	5.19	5,166	1989 TAG	78,274	Proj. Team
1993	1,095	5.19	4,932	1989 TAG	54,744	Proj. Team
1994	5,648	0.40	5,949	1993 TAG	54,399	Proj. Team
1995	5,648	0.40	5,949	1993 TAG	62,676	Proj. Team
1996	3,551	1.46	4,958	HPS	67,014	Proj. Team

Notes:
1. A 40% capacity factor for the CC was assumed.
2. The DOE O&M credit does not apply to the CC cases.

2. In response to Staff's Interrogatory No. 3 in Docket No. 950379-EI, starting with the 1994 study, TECO assumed "as-available natural gas" for the spring and fall months and distillate oil for summer and winter months as the fuel for the CC unit. What is meant by the term "as-available natural gas"?

A. The term "as available natural gas" as used in our response to Staff's Interrogatory No. 3 in Docket No. 950379-EI means natural gas delivered on an interruptible transportation basis. Transportation of natural gas can be acquired on both an interruptible and firm basis. Interruptible transportation purchases provide an advantage to the buyer in that the amount of transportation actually required can be very close to the transportation paid. The disadvantage for the buyer is the lack of assurances that the transportation required will be available.

4. In response to Staff's Interrogatory No. 3 in Docket No. 950379-EI, TECO provided five interim analyses comparing the Polk IGCC unit to a CC unit at the Polk Site. For each of the study results previously provided, please provide the following information:

1) the resulting annual capacity factors for the IGCC and CC units;

2) the annual amount of each type of fuel burned in the IGCC and CC units;

3) the annual reserve margin and LOLP values, with and without a unit addition at the Polk Site, for each year of the study period;

4) the annual nominal and cumulative present worth revenue requirement values; and

5) the source for the capital costs of the IGCC and CC units.

A. The unit operating data requested for the IGCC and CC unit and system reliability and system revenue requirements for each of the five cost effectiveness evaluations are provided in the attached tables and referenced below.

1) The resulting annual capacity factors for the IGCC and CC units for each study are shown in Table 4-1 of this response. The IGCC unit is expected to be the lowest cost unit on our system on an incremental cost basis and will be fully loaded except for periods when the gasification system is not operating. The capacity factors shown for the IGCC unit also include operation on distillate oil when the gasification system is unavailable. The CC unit dispatched on as-available natural gas and distillate oil would be expected to dispatch at a much lower capacity factor with higher usage over the summer months. The lower capacity factor for the IGCC unit in the first two years of operation reflects the DOE demonstration period which includes additional outage time between each fuel test burn to inspect and evaluate the gasification system and power block.

2) The resulting annual amount of each type of fuel for the IGCC and CC units corresponding to the annual capacity factors are shown in Table 4-2.

3) The annual firm reserve margin and assisted LOLP values are shown in Table 4-3 for each study with and without unit additions at the Polk site.

4) The differential annual system nominal and cumulative present worth revenue requirements are shown in Table 4-4 for each study for both the IGCC and CC unit resource plans.

5) The source for the capital cost estimates of the IGCC unit for planning purposes was the Tampa Electric Project Management Department. These estimates were based on the direct input of Fluor Daniel, Texaco, and Bechtel Engineering, and include the analyses and review of Tampa Electric and TECO Power Services engineers assigned to the project. The CC unit costs were developed by Project Management based on utilizing the IGCC power block and the appropriate supporting systems and common costs designed and constructed for the IGCC unit.

TABLE 4 - 1

Capacity Factor (%)

Year	1992 Study		1993 Study		1994 Study		1995 Study		1996 Study	
	IGCC*	CC**	IGCC	CC	IGCC	CC	IGCC	CC	IGCC	CC
1992	-	-	-	-	-	-	-	-	-	-
1993	-	-	-	-	-	-	-	-	-	-
1994	-	-	-	-	-	-	-	-	-	-
1995	1.2%	1.2%	-	-	-	-	-	-	-	-
1996	39.3%	2.2%	39.3%	8.2%	15.0%	2.8%	15.9%	1.2%	10.9%	1.5%
1997	77.8%	2.7%	84.0%	14.1%	60.3%	10.0%	56.0%	7.4%	62.9%	10.7%
1998	77.6%	6.8%	84.1%	16.0%	69.3%	9.6%	66.2%	9.9%	73.1%	12.5%
1999	77.3%	8.1%	84.1%	17.7%	81.1%	12.0%	80.4%	10.7%	81.1%	10.5%
2000	77.4%	9.6%	84.3%	19.9%	81.2%	14.2%	80.5%	12.2%	81.3%	13.3%
2001	77.2%	11.5%	84.3%	20.5%	81.3%	16.5%	80.6%	13.4%	81.3%	13.6%
2002	77.2%	13.2%	84.4%	22.4%	81.4%	18.5%	80.8%	14.8%	81.4%	15.0%
2003	77.1%	9.9%	84.2%	17.8%	81.1%	19.3%	80.9%	13.3%	81.4%	11.9%
2004	77.2%	11.1%	84.0%	19.3%	81.1%	21.1%	81.1%	14.8%	81.4%	13.0%
2005	77.0%	12.6%	84.1%	20.2%	81.2%	23.6%	81.3%	16.5%	81.6%	19.5%
2006	77.0%	14.1%	84.2%	21.9%	81.3%	25.5%	81.4%	17.9%	81.7%	21.1%
2007	77.0%	15.7%	84.3%	23.6%	81.3%	26.6%	81.6%	19.3%	81.7%	22.0%
2008	77.2%	17.2%	84.3%	25.1%	81.1%	28.1%	79.8%	20.7%	81.8%	22.6%
2009	76.7%	19.2%	84.2%	26.3%	81.0%	30.5%	80.1%	22.6%	81.9%	24.8%
2010	76.6%	21.0%	84.3%	28.1%	81.0%	32.6%	80.3%	24.3%	81.4%	26.8%
2011	76.4%	22.9%	84.3%	29.8%	80.9%	33.3%	80.5%	24.3%	81.5%	28.1%
2012	76.7%	22.6%	84.3%	29.4%	80.9%	34.8%	80.7%	25.2%	81.6%	28.8%
2013	76.4%	22.9%	84.3%	29.1%	81.2%	37.5%	80.8%	34.1%	81.8%	30.5%
2014	76.4%	22.9%	84.3%	29.1%	81.2%	37.5%	81.1%	27.6%	81.0%	26.1%
2015	76.4%	22.9%	84.3%	29.1%	81.2%	37.5%	81.1%	35.8%	81.2%	33.7%
2016	76.7%	22.6%	84.3%	28.7%	81.1%	37.0%	81.1%	35.8%	81.2%	33.5%
2017	76.4%	22.9%	84.3%	29.1%	81.2%	37.5%	81.1%	35.8%	81.2%	34.0%
2018	76.4%	22.9%	84.3%	29.1%	81.2%	37.5%	81.1%	35.8%	81.2%	34.0%
2019	76.4%	22.9%	84.3%	29.1%	81.2%	37.5%	81.1%	35.8%	81.2%	34.0%
2020	76.7%	22.6%	84.3%	28.7%	81.1%	37.0%	81.1%	35.8%	81.2%	33.5%
2021	76.4%	22.9%	84.3%	29.1%	81.2%	37.5%	81.6%	35.8%	81.2%	34.0%
2022			84.3%	29.1%	81.2%	37.5%	81.4%	35.8%	81.2%	34.0%
2023					81.2%	37.5%	81.4%	35.8%	81.2%	34.0%
2024							81.4%	35.8%	81.2%	33.5%
2025									81.2%	34.0%

* 1995 and first half of 1996 capacity factor values represent advanced combustion turbine (ACT) of a phased IGCC unit

** 1995-1997 capacity factor values represent advanced combustion turbine (ACT) of a phased combined cycle unit (in service 1998)

7

156

TABLE 4 - 2A

Fuel Burn (Units x 1000)
1992 Study

Year	IGCC			CC	
	Coal	Pet Coke	Distillate Oil	Natural Gas	Distillate Oil
	TONS	TONS	BBL	MCF	BBL
1992	-	-	-	-	-
1993	-	-	-	-	-
1994	-	-	-	-	-
1995*	0	0	31	-	31
1996	357	0	22	-	60
1997	706	0	0	-	71
1998	706	0	0	525	94
1999	706	0	0	630	112
2000	710	0	0	747	133
2001	706	0	0	887	158
2002	706	0	0	1,012	181
2003	706	0	0	762	136
2004	710	0	0	855	153
2005	706	0	0	966	172
2006	706	0	0	1,082	193
2007	706	0	0	1,199	214
2008	710	0	0	1,316	235
2009	706	0	0	1,460	260
2010	706	0	0	1,594	284
2011	706	0	0	1,736	310
2012	710	0	0	1,722	307
2013	706	0	0	1,736	310
2014	706	0	0	1,736	310
2015	706	0	0	1,736	310
2016	710	0	0	1,722	307
2017	706	0	0	1,736	310
2018	706	0	0	1,736	310
2019	706	0	0	1,736	310
2020	710	0	0	1,722	307
2021	706	0	0	1,736	310

* 1995 values represent for advanced combution turbine in phased IGCC and CC

TABLE 4 - 2B

Fuel Burn (Units x 1000)
1993 Study

Year	IGCC			CC	
	Coal	Pet Coke	Distillate Oil	Natural Gas	Distillate Oil
	TONS	TONS	BBL	MCF	BBL
1993	-	-	-	-	-
1994	-	-	-	-	-
1995	-	-	-	-	-
1996	62	247	14	595	106
1997	123	490	22	1,022	182
1998	123	490	17	1,161	207
1999	123	490	17	1,284	229
2000	123	492	20	1,440	257
2001	123	490	21	1,479	264
2002	123	490	23	1,610	287
2003	123	490	18	1,284	229
2004	123	490	21	1,394	249
2005	122	490	23	1,450	259
2006	122	490	25	1,571	280
2007	122	490	28	1,696	303
2008	123	490	30	1,805	322
2009	122	488	34	1,883	336
2010	122	488	36	2,007	358
2011	122	488	38	2,131	380
2012	122	490	38	2,108	376
2013	122	488	37	2,081	371
2014	122	488	37	2,081	371
2015	122	488	37	2,081	371
2016	122	490	37	2,058	367
2017	122	488	37	2,081	371
2018	122	488	37	2,081	371
2019	122	488	37	2,081	371
2020	122	490	37	2,058	367
2021	122	488	37	2,081	371
2022	122	488	37	2,081	371

TABLE 4 - 2C

Fuel Burn (Units x 1000)
1994 Study

	IGCC			CC	
	Coal	Pet Coke	Distillate Oil	Natural Gas	Distillate Oil
Year	TONS	TONS	BBL	MCF	BBL
1994	-	-	-	-	-
1995	-	-	-	-	-
1996	119	0	0	415	0
1997	514	0	0	769	126
1998	568	0	0	881	97
1999	736	0	0	915	153
2000	739	0	0	1,087	179
2001	735	0	0	1,279	202
2002	736	0	0	1,472	226
2003	736	0	0	1,579	221
2004	738	0	0	1,720	243
2005	736	0	0	1,946	264
2006	736	0	0	2,110	283
2007	736	0	0	2,149	302
2008	736	0	0	2,267	322
2009	734	0	0	2,489	341
2010	734	0	0	2,670	360
2011	734	0	0	2,719	369
2012	736	0	0	2,837	389
2013	736	0	0	3,088	408
2014	736	0	0	3,088	408
2015	736	0	0	3,088	408
2016	738	0	0	3,033	408
2017	736	0	0	3,088	408
2018	736	0	0	3,088	408
2019	736	0	0	3,088	408
2020	738	0	0	3,033	408
2021	736	0	0	3,088	408
2022	736	0	0	3,088	408
2023	736	0	0	3,088	408

TABLE 4 - 2D

Fuel Burn (Units x 1000)
1995 Study

	IGCC			CC	
	Coal	Pet Coke	Distillate Oil	Natural Gas	Distillate Oil
Year	TONS	TONS	BBL	MCF	BBL
1995	-	-	-	-	-
1996	118	0	18	220	3
1997	414	0	92	509	163
1998	486	0	86	875	180
1999	719	0	31	1,035	181
2000	721	0	35	1,081	223
2001	719	0	40	1,227	235
2002	719	0	44	1,345	262
2003	719	0	45	1,377	206
2004	721	0	49	1,511	234
2005	719	0	54	1,656	261
2006	719	0	59	1,779	287
2007	719	0	63	1,907	312
2008	159	476	88	2,009	340
2009	158	475	96	2,182	373
2010	158	475	102	2,314	403
2011	158	475	105	2,419	384
2012	159	476	110	2,441	412
2013	158	474	116	2,600	677
2014	158	474	122	2,737	437
2015	158	474	122	2,737	710
2016	159	476	120	2,657	725
2017	158	474	122	2,737	710
2018	158	474	122	2,737	710
2019	158	474	122	2,737	710
2020	159	476	120	2,657	725
2021	159	478	114	2,737	710
2022	159	478	109	2,737	710
2023	159	478	109	2,737	710
2024	160	479	108	2,657	725

TABLE 4 - 2E

Fuel Burn (Units x 1000)
1996 Study

	IGCC			CC	
	Coal	Pet Coke	Distillate Oil	Natural Gas	Distillate Oil
Year	TONS	TONS	BBL	MCF	BBL
1996	81	-	0	199	3
1997	470	-	9	658	164
1998	544	-	15	799	185
1999	156	469	18	548	177
2000	157	470	23	1,017	168
2001	156	469	24	908	195
2002	156	469	26	981	216
2003	156	469	26	761	176
2004	157	470	28	741	210
2005	156	469	30	1,451	250
2006	156	469	33	1,561	272
2007	156	469	34	1,614	286
2008	157	470	36	1,647	297
2009	156	469	39	1,793	326
2010	155	465	49	1,918	356
2011	155	465	50	2,192	341
2012	156	467	53	2,010	391
2013	155	465	57	2,191	400
2014	153	459	74	1,493	412
2015	153	459	79	2,423	439
2016	154	461	79	2,386	445
2017	153	459	80	2,444	445
2018	153	459	80	2,444	445
2019	153	459	80	2,444	445
2020	154	461	79	2,386	445
2021	153	459	80	2,444	445
2022	153	459	80	2,444	445
2023	153	459	80	2,444	445
2024	154	461	79	2,386	445
2025	153	459	80	2,444	445

TABLE 4-3a

1992 Polk Study

	Reserve Margin %			Loss of Load Probability		
	IGCC Plan	CC Plan	No Expansion	IGCC Plan	CC Plan	No Expansion
1993	28%	28%	28%	0.0542	0.0542	0.0542
1994	26%	26%	26%	0.0906	0.0906	0.0906
1995	23%	23%	23%	0.0991	0.0991	0.1651
1996	27%	27%	21%	0.0667	0.0952	0.2415
1997	28%	28%	19%	0.0728	0.0759	0.3092
1998	28%	28%	16%	0.0690	0.0843	0.4702
1999	27%	27%	13%	0.0666	0.0814	0.7112
2000	27%	27%	11%	0.0654	0.0804	1.0755
2001	27%	27%	8%	0.0666	0.0981	1.6070
2002	25%	27%	6%	0.0859	0.0927	2.2825
2003	32%	32%	6%	0.0625	0.0844	4.5645
2004	30%	30%	4%	0.0787	0.1055	5.9706
2005	30%	30%	2%	0.0806	0.1080	7.7193
2006	30%	30%	0%	0.0770	0.1038	9.9074
2007	30%	30%	-1%	0.0725	0.0973	12.5021
2008	30%	30%	-3%	0.0687	0.0999	15.6258
2009	28%	30%	-5%	0.0855	0.0940	18.9272
2010	28%	30%	-6%	0.0872	0.0886	22.3625
2011	28%	30%	-8%	0.0816	0.0832	25.4890

TABLE 4-3b

1993 Polk Study

	Reserve Margin %			Loss of Load Probability		
	IGCC Plan	CC Plan	No Expansion	IGCC Plan	CC Plan	No Expansion
1994	26%	26%	26%	0.0574	0.0574	0.0574
1995	23%	23%	23%	0.1068	0.1068	0.1068
1996	19%	19%	19%	0.0825	0.0852	0.1630
1997	26%	25%	18%	0.0517	0.0606	0.2059
1998	23%	22%	15%	0.0843	0.0975	0.3177
1999	23%	21%	12%	0.0814	0.0948	0.4837
2000	22%	21%	10%	0.0810	0.0943	0.7296
2001	22%	23%	7%	0.0981	0.0715	1.1108
2002	22%	23%	5%	0.0948	0.0695	1.5626
2003	24%	25%	5%	0.0960	0.0705	2.5207
2004	23%	22%	3%	0.0943	0.0847	3.5498
2005	23%	22%	1%	0.0896	0.0842	5.1633
2006	23%	22%	-0%	0.0856	0.0806	7.9241
2007	23%	22%	-2%	0.0809	0.0763	12.2068
2008	21%	22%	-4%	0.0979	0.0723	19.9068
2009	21%	22%	-6%	0.0975	0.0721	31.1001
2010	21%	19%	-7%	0.0928	0.0870	50.4480

TABLE 4-3c

1994 Polk Study

	Reserve Margin %			Loss of Load Probability		
	IGCC Plan	CC Plan	No Expansion	IGCC Plan	CC Plan	No Expansion
1995	24%	24%	24%	0.0413	0.0413	0.0413
1996	21%	21%	21%	0.0292	0.0299	0.0366
1997	28%	27%	19%	0.0112	0.0115	0.0444
1998	25%	24%	17%	0.0186	0.0214	0.0785
1999	21%	20%	13%	0.0201	0.0234	0.0846
2000	22%	21%	11%	0.0263	0.0306	0.1625
2001	22%	21%	9%	0.0280	0.0329	0.2551
2002	22%	21%	6%	0.0363	0.0419	0.4101
2003	22%	21%	6%	0.0942	0.1084	0.7696
2004	22%	21%	4%	0.0869	0.0996	1.4904
2005	20%	19%	2%	0.1077	0.1234	3.5227
2006	20%	19%	0%	0.1068	0.1223	9.7713
2007	21%	20%	-1%	0.1048	0.1205	23.2382
2008	21%	20%	-3%	0.1045	0.1199	47.7029
2009	21%	20%	-5%	0.1037	0.1188	78.8034
2010	22%	21%	-6%	0.1018	0.1169	112.8294
2011	20%	19%	-8%	0.1073	0.1228	148.2043
2012	20%	21%	-8%	0.1281	0.1192	155.1028
2013	21%	20%	-9%	0.1254	0.1434	161.7374

TABLE 4-3d

1995 Polk Study

	Reserve Margin %			Loss of Load Probability		
	IGCC Plan	CC Plan	No Expansion	IGCC Plan	CC Plan	No Expansion
1996	27%	27%	27%	0.0286	0.0283	0.0396
1997	33%	33%	24%	0.0146	0.0159	0.0564
1998	29%	29%	21%	0.0245	0.0265	0.0978
1999	26%	26%	18%	0.0368	0.0404	0.1414
2000	23%	23%	16%	0.0727	0.0797	0.2616
2001	23%	23%	13%	0.0842	0.0918	0.4155
2002	23%	23%	10%	0.0733	0.0800	0.5563
2003	27%	27%	11%	0.0696	0.0762	0.8214
2004	27%	27%	9%	0.0732	0.0797	1.1897
2005	27%	27%	7%	0.0687	0.0749	1.6325
2006	25%	25%	6%	0.0949	0.1038	2.1283
2007	26%	26%	4%	0.0836	0.0922	2.7778
2008	27%	26%	3%	0.0739	0.0806	3.5821
2009	27%	27%	1%	0.0695	0.0759	4.7471
2010	25%	25%	-1%	0.0961	0.1050	5.6508
2011	23%	23%	-2%	0.0956	0.1047	5.8113
2012	25%	25%	-2%	0.0772	0.0846	6.5477
2013	24%	24%	-3%	0.0966	0.1067	7.1172
2014	24%	24%	-5%	0.0881	0.0965	8.0435

TABLE 4-3e

1996 Polk Study

	Reserve Margin %			Loss of Load Probability		
	IGCC Plan	CC Plan	No Expansion	IGCC Plan	CC Plan	No Expansion
1996	28%	28%	28%	0.0203	0.0204	0.0214
1997	34%	33%	25%	0.0118	0.0127	0.0377
1998	30%	30%	22%	0.0262	0.0297	0.0731
1999	27%	27%	19%	0.0186	0.0219	0.0725
2000	25%	24%	17%	0.0453	0.0427	0.1459
2001	22%	22%	14%	0.0706	0.0730	0.2436
2002	23%	22%	12%	0.0626	0.0672	0.3232
2003	26%	26%	14%	0.0759	0.0899	0.5498
2004	27%	26%	11%	0.0705	0.0840	0.7672
2005	27%	27%	10%	0.0876	0.0993	1.0822
2006	28%	27%	8%	0.0880	0.0988	1.4598
2007	29%	28%	6%	0.0678	0.0760	1.7713
2008	26%	25%	4%	0.0918	0.1062	2.3669
2009	26%	28%	2%	0.0968	0.0734	3.2519
2010	29%	28%	0%	0.0745	0.0822	4.5739
2011	26%	26%	-1%	0.0745	0.0826	4.6833
2012	26%	26%	-1%	0.0798	0.0927	5.7778
2013	27%	27%	-3%	0.0685	0.0928	7.2578
2014	25%	27%	-4%	0.0955	0.0866	9.2452
2015	25%	27%	-6%	0.0898	0.0806	11.7219

Table 4-4a

1992 POLK UNIT ANALYSIS

	NOMINAL DELTA REVENUE REQUIREMENTS ($000)					CUMULATIVE P.W. DELTA REVENUE REQUIREMENTS ($000)				
	CAPITAL	O&M	FUEL	TAX CREDIT	TOTAL	CAPITAL	O&M	FUEL	TAX CREDIT	TOTAL
1992	(258)	3	(670)	0	(925)	(258)	3	(670)	0	(925)
1993	(30)	0	0	0	(30)	(286)	3	(670)	0	(953)
1994	(30)	0	0	0	(30)	(310)	3	(670)	0	(977)
1995	(11,332)	0	0	0	(11,332)	(8,810)	3	(670)	0	(9,477)
1996	18,822	1,192	(10,103)	0	9,911	4,017	815	(7,555)	0	(2,723)
1997	34,153	4,221	(20,083)	0	18,292	25,166	3,429	(19,991)	0	8,604
1998	43,142	8,115	(19,959)	0	31,297	49,439	7,995	(31,221)	0	26,213
1999	28,534	13,969	(23,611)	0	18,892	64,026	15,136	(43,291)	0	35,870
2000	27,172	14,419	(27,275)	0	14,315	76,646	21,833	(55,960)	0	42,519
2001	12,014	13,373	(27,462)	0	(2,075)	81,716	27,477	(67,549)	0	41,644
2002	(1,026)	13,876	(30,596)	0	(17,746)	81,323	32,798	(79,281)	0	34,839
2003	27,426	15,737	(36,360)	0	6,802	90,878	38,280	(91,949)	0	37,209
2004	26,879	16,272	(41,662)	0	1,488	99,386	43,431	(105,137)	0	37,680
2005	25,522	16,736	(46,443)	0	(4,185)	106,727	48,245	(118,495)	0	36,477
2006	24,663	17,201	(53,029)	0	(11,165)	113,172	52,740	(132,353)	0	33,559
2007	23,769	17,562	(62,904)	0	(21,573)	118,816	56,910	(147,289)	0	28,436
2008	3,152	17,123	(65,216)	0	(44,941)	119,496	60,604	(161,359)	0	18,741
2009	(14,138)	17,052	(77,867)	0	(74,953)	116,725	63,947	(176,622)	0	4,049
2010	7,059	18,421	(96,259)	0	(70,780)	117,982	67,227	(193,766)	0	(8,557)
2011	6,664	18,649	(113,146)	0	(87,833)	119,060	70,245	(212,076)	0	(22,771)
2012	6,223	19,595	(121,010)	0	(95,191)	119,975	73,126	(229,868)	0	(36,767)
2013	5,706	20,365	(130,157)	0	(104,087)	120,737	75,847	(247,256)	0	(50,672)
2014	5,193	21,281	(139,795)	0	(113,321)	121,368	78,430	(264,224)	0	(64,427)
2015	4,678	22,240	(149,818)	0	(122,900)	121,884	80,883	(280,747)	0	(77,981)
2016	4,397	23,368	(161,189)	0	(133,423)	122,324	83,224	(296,899)	0	(91,351)
2017	4,587	24,285	(174,190)	0	(145,318)	122,742	85,435	(312,759)	0	(104,581)
2018	4,836	25,379	(187,081)	0	(156,866)	123,142	87,535	(328,235)	0	(117,558)
2019	4,776	26,519	(201,128)	0	(169,832)	123,501	89,528	(343,352)	0	(130,323)
2020	4,518	27,867	(214,398)	0	(182,013)	123,809	91,431	(357,994)	0	(142,753)
2021	4,136	28,960	(229,881)	0	(196,786)	124,006	93,228	(372,258)	0	(154,964)

Table 4-4b

1993 POLK UNIT ANALYSIS

	NOMINAL DELTA REVENUE REQUIREMENTS ($000)					CUMULATIVE P.W. DELTA REVENUE REQUIREMENTS ($000)				
	CAPITAL	O&M	FUEL	TAX CREDIT	TOTAL	CAPITAL	O&M	FUEL	TAX CREDIT	TOTAL
1993	0	0	0	0	0	0	0	0	0	0
1994	0	0	0	0	0	0	0	0	0	0
1995	0	0	0	0	0	0	0	0	0	0
1996	16,603	1,085	(11,699)	0	5,990	12,761	834	(8,991)	0	4,603
1997	44,677	7,917	(23,501)	0	29,093	44,214	6,408	(25,536)	0	25,086
1998	43,164	9,757	(25,939)	0	26,982	72,050	12,700	(42,264)	0	42,486
1999	41,708	7,515	(28,484)	0	20,739	96,688	17,139	(59,090)	0	54,737
2000	40,305	7,607	(32,116)	0	15,796	118,497	21,255	(76,468)	0	63,285
2001	26,740	6,540	(34,049)	0	(769)	131,751	24,497	(93,344)	0	62,904
2002	25,811	6,963	(37,637)	0	(4,863)	143,469	27,658	(110,431)	0	60,696
2003	24,975	7,349	(38,739)	0	(6,415)	153,856	30,714	(126,542)	0	58,028
2004	53,976	8,213	(48,594)	0	13,595	174,418	33,843	(145,054)	0	63,207
2005	35,271	8,162	(47,468)	0	(4,035)	186,726	36,691	(161,618)	0	61,799
2006	33,813	8,216	(52,330)	0	(10,300)	197,534	39,317	(178,344)	0	58,506
2007	32,444	8,238	(57,751)	0	(17,069)	207,033	41,729	(195,253)	0	53,509
2008	14,595	7,513	(62,170)	0	(40,062)	210,947	43,744	(211,927)	0	42,764
2009	13,860	7,346	(67,647)	0	(46,440)	214,352	45,549	(228,545)	0	31,356
2010	31,351	8,198	(76,450)	0	(36,901)	221,407	47,394	(245,749)	0	23,052
2011	30,042	8,154	(84,373)	0	(46,177)	227,600	49,074	(263,141)	0	13,533
2012	28,595	8,603	(90,056)	0	(52,858)	232,999	50,699	(280,145)	0	3,553
2013	27,144	9,076	(95,708)	0	(59,488)	237,694	52,268	(296,698)	0	(6,736)
2014	25,708	9,484	(102,458)	0	(67,266)	241,766	53,771	(312,930)	0	(17,393)
2015	24,302	9,912	(109,867)	0	(75,653)	245,293	55,209	(328,874)	0	(28,371)
2016	23,044	10,458	(118,241)	0	(84,739)	248,356	56,600	(344,592)	0	(39,636)
2017	22,039	10,824	(125,892)	0	(93,028)	251,040	57,918	(359,921)	0	(50,963)
2018	21,156	11,312	(134,813)	0	(102,345)	253,400	59,179	(374,958)	0	(62,378)
2019	20,273	11,821	(144,387)	0	(112,293)	255,471	60,387	(389,709)	0	(73,851)
2020	19,450	12,473	(153,778)	0	(121,856)	257,291	61,554	(404,101)	0	(85,255)
2021	18,709	12,908	(165,468)	0	(133,851)	258,895	62,661	(418,285)	0	(96,729)
2022	17,950	13,541	(169,864)	0	(138,373)	260,305	63,724	(431,624)	0	(107,595)

Table 4-4c

1994 POLK UNIT ANALYSIS

	NOMINAL DELTA REVENUE REQUIREMENTS ($000)					CUMULATIVE P.W. DELTA REVENUE REQUIREMENTS ($000)				
	CAPITAL	O&M	FUEL	TAX CREDIT	TOTAL	CAPITAL	O&M	FUEL	TAX CREDIT	TOTAL
1994	0	0	0	0	0	0	0	0	0	0
1995	0	0	0	0	0	0	0	0	0	0
1996	6,782	(1,529)	(1,388)	(2,922)	943	5,764	(1,300)	(1,180)	(2,483)	801
1997	31,207	(521)	(5,368)	(11,234)	14,083	30,217	(1,708)	(5,386)	(11,286)	11,836
1998	28,716	(1,703)	(4,134)	(15,431)	7,449	50,960	(2,938)	(8,372)	(22,433)	17,217
1999	26,701	8,370	(8,255)	(16,948)	9,869	68,742	2,636	(13,870)	(33,720)	23,789
2000	25,064	8,661	(15,447)	(17,507)	771	84,131	7,954	(23,354)	(44,468)	24,263
2001	23,730	8,962	(17,157)	(17,980)	(2,445)	97,562	13,027	(33,065)	(54,645)	22,879
2002	22,589	9,273	(19,108)	(18,519)	(5,765)	109,350	17,866	(43,036)	(64,309)	19,870
2003	21,495	9,611	(20,154)	(19,075)	(8,123)	119,690	22,490	(52,732)	(73,486)	15,962
2004	11,922	8,819	(26,190)	(19,704)	(25,153)	124,978	26,401	(64,347)	(82,224)	4,807
2005	19,923	10,292	(23,074)	(20,237)	(13,096)	133,124	30,609	(73,782)	(90,499)	(548)
2006	19,099	10,652	(26,297)	(20,843)	(17,389)	140,323	34,624	(83,694)	(98,356)	(7,103)
2007	18,703	11,034	(29,048)	0	690	146,823	38,459	(93,789)	(98,356)	(6,863)
2008	18,557	11,424	(32,106)	0	(2,125)	152,768	42,119	(104,075)	(98,356)	(7,544)
2009	18,418	11,819	(36,048)	0	(5,812)	158,208	45,610	(114,722)	(98,356)	(9,260)
2010	7,349	12,230	(40,853)	0	(21,274)	160,209	48,940	(125,847)	(98,356)	(15,053)
2011	7,560	12,674	(43,496)	0	(23,261)	162,107	52,122	(136,765)	(98,356)	(20,893)
2012	(4,089)	11,634	(48,424)	0	(40,879)	161,160	54,814	(147,972)	(98,356)	(30,353)
2013	8,952	13,571	(53,222)	0	(30,699)	163,070	57,710	(159,328)	(98,356)	(36,903)
2014	9,218	14,074	(56,207)	0	(32,916)	164,884	60,478	(170,384)	(98,356)	(43,378)
2015	9,377	14,594	(59,498)	0	(35,527)	166,584	63,125	(181,174)	(98,356)	(49,820)
2016	9,467	15,140	(62,266)	0	(37,659)	168,167	65,656	(191,583)	(98,356)	(56,116)
2017	9,437	15,694	(66,451)	0	(41,319)	169,621	68,075	(201,825)	(98,356)	(62,485)
2018	9,358	16,275	(70,772)	0	(45,139)	170,951	70,387	(211,881)	(98,356)	(68,899)
2019	9,258	16,877	(75,295)	0	(49,160)	172,164	72,598	(221,745)	(98,356)	(75,338)
2020	9,134	17,509	(79,442)	0	(52,799)	173,267	74,713	(231,339)	(98,356)	(81,715)
2021	9,051	18,149	(85,569)	0	(58,368)	174,275	76,733	(240,866)	(98,356)	(88,213)
2022	9,006	18,821	(90,548)	0	(62,721)	175,199	78,665	(250,160)	(98,356)	(94,651)
2023	8,965	19,517	(95,909)	0	(67,427)	176,047	80,512	(259,235)	(98,356)	(101,032)

Table 4-4d

1995 POLK UNIT ANALYSIS

	NOMINAL DELTA REVENUE REQUIREMENTS ($000)					CUMULATIVE P.W. DELTA REVENUE REQUIREMENTS ($000)				
	CAPITAL	O&M	FUEL	TAX CREDIT	TOTAL	CAPITAL	O&M	FUEL	TAX CREDIT	TOTAL
1995	1,611	0	0	0	1,611	1,611	0	0	0	1,611
1996	6,960	(1,585)	407	(2,545)	3,237	7,966	(1,447)	371	(2,545)	4,346
1997	18,430	(898)	30	(8,533)	9,029	23,335	(2,196)	396	(11,078)	10,457
1998	16,647	(2,124)	(3,901)	(9,265)	1,356	36,011	(3,814)	(2,574)	(20,343)	9,279
1999	15,257	7,923	(8,309)	(6,006)	8,865	46,619	1,695	(8,351)	(26,349)	13,614
2000	14,179	8,301	(11,156)	(9,363)	1,961	55,621	6,966	(15,434)	(35,712)	11,440
2001	13,492	8,605	(12,945)	(8,788)	364	63,444	11,955	(22,940)	(44,500)	7,959
2002	12,906	8,912	(14,576)	(8,266)	(1,024)	70,277	16,673	(30,657)	(52,766)	3,527
2003	12,370	9,269	(15,013)	(7,777)	(1,151)	76,258	21,155	(37,915)	(60,543)	(1,046)
2004	11,825	9,599	(17,734)	(7,339)	(3,649)	81,478	25,392	(45,745)	(67,882)	(6,756)
2005	11,280	9,938	(20,024)	(6,883)	(5,689)	86,025	29,399	(53,817)	(74,765)	(13,158)
2006	10,864	10,293	(22,729)	(6,478)	(8,050)	90,025	33,188	(62,185)	(81,242)	(20,214)
2007	10,704	10,660	(26,209)	(6,093)	(10,938)	93,623	36,771	(70,995)	(87,335)	(27,936)
2008	10,674	11,037	(39,368)	0	(17,657)	96,900	40,160	(83,080)	(87,335)	(33,356)
2009	10,646	11,427	(44,107)	0	(22,034)	99,884	43,363	(95,444)	(87,335)	(39,533)
2010	10,620	11,831	(49,264)	0	(26,812)	102,603	46,391	(108,054)	(87,335)	(46,396)
2011	10,597	12,277	(52,330)	0	(29,456)	105,079	49,261	(120,286)	(87,335)	(53,281)
2012	10,575	12,715	(57,011)	0	(33,721)	107,337	51,975	(132,455)	(87,335)	(60,479)
2013	10,555	13,035	(62,509)	0	(38,919)	109,394	54,516	(144,638)	(87,335)	(68,064)
2014	10,537	13,639	(67,222)	0	(43,046)	111,269	56,943	(156,603)	(87,335)	(75,726)
2015	10,523	13,989	(71,841)	0	(47,329)	112,980	59,217	(168,279)	(87,335)	(83,418)
2016	10,448	14,504	(75,606)	0	(50,654)	114,530	61,369	(179,500)	(87,335)	(90,936)
2017	10,251	15,044	(80,154)	0	(54,859)	115,919	63,408	(190,363)	(87,335)	(98,371)
2018	9,994	15,600	(85,240)	0	(59,646)	117,156	65,339	(200,911)	(87,335)	(105,752)
2019	9,739	16,177	(90,680)	0	(64,763)	118,257	67,167	(211,159)	(87,335)	(113,071)
2020	9,488	16,773	(96,163)	0	(69,902)	119,236	68,898	(221,082)	(87,335)	(120,284)
2021	9,240	17,396	(103,544)	0	(76,908)	120,107	70,537	(230,840)	(87,335)	(127,531)
2022	8,996	18,040	(109,805)	0	(82,769)	120,881	72,089	(240,288)	(87,335)	(134,654)
2023	8,754	18,707	(116,373)	0	(88,912)	121,569	73,559	(249,432)	(87,335)	(141,640)
2024	8,517	19,395	(118,886)	0	(90,974)	122,180	74,951	(257,963)	(87,335)	(148,168)

Table 4-4e

1996 POLK UNIT ANALYSIS

	NOMINAL DELTA REVENUE REQUIREMENTS ($000)					CUMULATIVE P.W. DELTA REVENUE REQUIREMENTS ($000)				
	CAPITAL	O&M	FUEL	TAX CREDIT	TOTAL	CAPITAL	O&M	FUEL	TAX CREDIT	TOTAL
1996	3,223	(1,772)	256	0	1,707	3,223	(1,772)	256	0	1,707
1997	7,071	(1,330)	(2,208)	0	3,533	9,695	(2,989)	(1,765)	0	4,941
1998	4,003	90	(4,177)	0	(84)	13,048	(2,914)	(5,264)	0	4,870
1999	2,961	8,717	(14,967)	0	(3,288)	15,319	3,770	(16,739)	0	2,350
2000	1,983	8,976	(17,944)	0	(6,986)	16,710	10,068	(29,330)	0	(2,552)
2001	1,404	9,260	(19,556)	0	(8,893)	17,612	16,015	(41,890)	0	(8,264)
2002	875	9,530	(21,664)	0	(11,259)	18,126	21,617	(54,624)	0	(14,882)
2003	496	9,934	(22,214)	0	(11,784)	18,393	26,961	(66,576)	0	(21,222)
2004	1,923	10,200	(25,252)	0	(13,130)	19,339	31,983	(79,010)	0	(27,687)
2005	2,330	10,299	(28,288)	0	(15,659)	20,390	36,625	(91,758)	0	(34,743)
2006	2,747	10,564	(31,441)	0	(18,130)	21,522	40,982	(104,726)	0	(42,221)
2007	3,179	10,864	(34,092)	0	(20,049)	22,723	45,083	(117,596)	0	(49,790)
2008	3,620	11,175	(36,335)	0	(21,540)	23,973	48,944	(130,150)	0	(57,232)
2009	(5,574)	10,484	(40,762)	0	(35,852)	22,211	52,250	(143,040)	0	(68,570)
2010	5,154	11,722	(44,413)	0	(27,537)	23,702	55,653	(155,895)	0	(76,540)
2011	5,636	12,042	(46,337)	0	(28,659)	25,195	58,843	(168,170)	0	(84,132)
2012	6,045	12,397	(50,455)	0	(32,013)	26,661	61,848	(180,402)	0	(91,893)
2013	6,459	12,709	(55,077)	0	(35,909)	28,094	64,668	(192,624)	0	(99,861)
2014	(4,644)	12,206	(57,230)	0	(49,668)	27,151	67,147	(204,247)	0	(109,949)
2015	(3,875)	12,219	(65,007)	0	(56,663)	26,430	69,419	(216,331)	0	(120,481)
2016	(3,369)	12,615	(67,748)	0	(58,502)	25,857	71,565	(227,856)	0	(130,434)
2017	(3,377)	12,991	(70,518)	0	(60,903)	25,332	73,588	(238,837)	0	(139,918)
2018	(3,242)	13,407	(73,476)	0	(63,310)	24,870	75,498	(249,308)	0	(148,940)
2019	(3,129)	13,836	(76,494)	0	(65,787)	24,461	77,303	(259,285)	0	(157,521)
2020	(3,033)	14,308	(79,483)	0	(68,207)	24,099	79,011	(268,774)	0	(165,664)
2021	(2,942)	14,736	(83,135)	0	(71,342)	23,778	80,621	(277,858)	0	(173,458)
2022	(2,852)	15,207	(86,518)	0	(74,162)	23,493	82,142	(286,510)	0	(180,875)
2023	(2,761)	15,694	(90,451)	0	(77,518)	23,240	83,578	(294,788)	0	(187,970)
2024	(2,711)	16,230	(94,106)	0	(80,587)	23,013	84,938	(302,671)	0	(194,721)
2025	(2,699)	16,714	(98,608)	0	(84,593)	22,806	86,219	(310,232)	0	(201,206)

8. When will the 145 MW sale from Big Bend 4 to the Hardee Power Station end? What is expected to happen to the resulting capacity returning to TECO?

A. The 145 MW Big Bend 4 sale to TECO Power Services for resale to Seminole Electric Cooperative will be in force through December 31, 2002. The additional capacity will contribute to Tampa Electric's installed and operating reserves as of January 1, 2003. This capacity has been consistently reported in this manner in Tampa Electric's Ten year Site Plans and consistently included in our annual integrated resource planning process and subsequent system cost studies.

9. On page 5 of 16, in response to Staff's Interrogatory No. 26 in Docket No. 950379-EI, Note 3 states "Capital costs include expenditure of approximately $4 million in 1997 for plant modifications to burn pet coke blend." Please provide a detailed description of the required plant modifications and costs. Was this expenditure included in the studies provided in response to Staff's Interrogatory No. 3 in Docket No. 950379-EI? If so, please provide the amount and timing of these expenditures assumed for each study.

A. The $4 million estimate was included in the 1996 study only for IGCC plant modifications in order to support a petroleum coke/coal blend beginning in 1999 and beyond. The potential plant modifications are in the areas of fuel handling and fluxing of the petroleum coke/coal blends, sulfur removal and recovery sections of the plant, and in the zero discharge wastewater treatment section of the plant. These potential modifications were identified in May, 1995 and therefore were not included in prior studies.

10. Please describe the relationship between the common and sunk costs assumed in response to Staff's Interrogatory No. 3 in Docket No. 950379-EI and the Net Project Costs identified in response to Staff's Interrogatory No. 1 in Docket No. 950379-EI.

A. The common and sunk costs assumed in Interrogatory No. 3 of Docket No. 950379-EI are defined as follows: common costs are non-area specific costs such as project management, construction management, state and federal environmental permitting, site engineering, buildings, field distributables, (e.g., temporary sensing, parking, etc.), operator training, administrative and general, Tampa Electric's costs prior to 6/92, and TECO Power Services costs to complete the assignment of the deal with DOE to Tampa Electric. Sunk costs are actual project-to-date expenditures up to the time of the respective cost effectiveness study.

Some overlap exists between sunk costs and common costs. The two categories are not mutually exclusive. In comparing the IGCC Unit to an alternative, the common costs associated with the gasification equipment up to the date of the study are considered sunk costs. The engineering costs, however, are common costs. All the items contained in either and/or both the common cost category and the sunk cost category are included in the IGCC net project cost estimate identified in Interrogatory No. 1 in Docket No. 950379-EI.

25. What would it cost to procure and establish firm natural gas supply to a 240 MW class unit at the Polk County Site fired at an 80 percent capacity factor going into service in 1996, based on FGT rates and any other options available in 1993? Please include in your response all engineering and economic assumptions.

A. By 1993, FGT's Phase III capacity was fully subscribed. Establishing a firm natural gas supply at that time would require Tampa Electric to acquire relinquished Phase III capacity, assuming it was available. Arrangements for selling the contracted gas starting in 1995 and continuing up to the in-service date of the unit (i.e., 1/1/96) would be required.

The cumulative present worth revenue requirements associated with the fixed and operating costs required to procure and establish a firm natural gas supply at an 80% capacity factor is approximately $744 million in 1993 dollars as shown in Table 25-1.

TABLE 25-1

Firm Gas Supply Analysis
Nominal Cost Projection

Unit In-service Date: 1/1/96

Year	Capital (Pipeline) ($000)	Natural Gas ($000)	Firm Gas Transportation ($000)	Total ($000)
1996	96	40,883	13,188	54,167
1997	93	43,652	13,188	56,933
1998	89	46,553	13,188	59,830
1999	85	49,719	13,188	62,991
2000	82	53,147	13,188	66,417
2001	78	56,840	13,188	70,106
2002	75	60,533	13,188	73,796
2003	72	64,489	13,188	77,749
2004	69	68,709	13,188	81,966
2005	66	73,193	13,188	86,447
2006	63	78,073	13,188	91,324
2007	60	83,216	13,188	96,464
2008	57	88,755	13,188	102,000
2009	53	94,689	13,188	107,930
2010	50	101,151	13,188	114,389
2011	48	107,877	13,188	121,113
2012	46	115,131	13,188	128,365
2013	44	122,780	13,188	136,012
2014	43	130,824	13,188	144,055
2015	41	139,528	13,188	152,757
2016	40	148,628	13,188	161,856
2017	38	158,519	13,188	171,745
2018	37	168,937	13,188	182,162
2019	35	180,147	13,188	193,370
2020	34	192,016	13,188	205,238
2021	32	204,677	13,188	217,897
2022	31	218,172	13,188	231,391
2023	29	232,557	13,188	245,774
CPW '93$	588	655,508	110,326	766,421

Note: Fuel reimbursement charge is not included in firm gas transportation values. (Estimate is 3% of fuel charge)

Table 25-2

Engineering and Economic Assumptions for Firm Gas Supply

1993 Assumptions	
Capacity (MW)	240
Capacity Factor (%) (Annual)	80
Heat Rate (BTU/KWH) (Heat Rate @ Maximum)	7,841
MBTU (x 1000) (Annual Contracted)	13,188
FTS-2 Rate ($/MBTU) (Projected Rate w/o Gas)	0.80
Gas ($/MBTU)	See 1993 Summer Forecast Table 5-3 of Intr. No. 5 (Docket 950379-EI)
Gas Pipeline Assumptions (1996$):	
6 Inch Diameter Pipe (1.3 miles)	280,675
Hot Tap	16,841
Meter Station	120,906
Total (1996$)	418,422
Capital Escalation (%)	
1993	3.5
1994	3.8
1995 and beyond	4.0
Pipeline Book Life (years)	30
Pipeline Tax Life (years)	15
1993 Discount Rate (%)	9.17

26. What would it cost to procure and establish firm natural gas supply to a 240 MW class unit at the Polk County site fired at an 80 percent capacity factor going into service in 1999, based on FGT rates and any other options available in 1993? Please include in your response all engineering and economic assumptions.

A. By 1993, FGT's Phase III capacity was fully subscribed. Establishing a firm natural gas supply at that time would require Tampa Electric to acquire relinquished Phase III capacity, assuming it was available. Arrangements for selling the contracted gas starting in 1995 and continuing up to the in-service date of the unit (i.e., 1/1/99) would be required.

The cumulative present worth revenue requirements associated with the fixed and operating costs required to procure and establish a firm natural gas supply at an 80% capacity factor is approximately $630 million in 1993 dollars as shown in Table 26-1. This value is lower than the response to Interrogatory No. 25 due to the three-year deferral of the fixed and operating costs since the commercial operation date was deferred three years. In addition, the operating period for this response was 27 years compared to 30 years in the response to Interrogatory No. 25.

TABLE 26-1

Firm Gas Supply Analysis
Nominal Cost Projection

Unit In-service Date: 1/1/99

Year	Capital (Pipeline) ($000)	Natural Gas ($000)	Firm Gas Transportation ($000)	Total ($000)
1999	108	49,719	13,188	63,014
2000	105	53,147	13,188	66,440
2001	100	56,840	13,188	70,128
2002	96	60,533	13,188	73,817
2003	92	64,489	13,188	77,769
2004	88	68,709	13,188	81,985
2005	85	73,193	13,188	86,466
2006	81	78,073	13,188	91,342
2007	78	83,216	13,188	96,482
2008	74	88,755	13,188	102,017
2009	71	94,689	13,188	107,948
2010	67	101,151	13,188	114,406
2011	64	107,877	13,188	121,129
2012	60	115,131	13,188	128,379
2013	57	122,780	13,188	136,025
2014	54	130,824	13,188	144,066
2015	51	139,528	13,188	152,767
2016	50	148,628	13,188	161,866
2017	48	158,519	13,188	171,755
2018	46	168,937	13,188	182,171
2019	45	180,147	13,188	193,380
2020	43	192,016	13,188	205,247
2021	41	204,677	13,188	217,906
2022	40	218,172	13,188	231,400
2023	38	232,557	13,188	245,783
CPW '93$	502	563,332	82,401	646,235

Note: Fuel reimbursement charge is not included in firm gas transportation values. (Estimate is 3% of fuel charge)

Table 26-2

Engineering and Economic Assumptions for Firm Gas Supply

1993 Assumptions	
Capacity (MW)	240
Capacity Factor (%) (Annual)	80
Heat Rate (BTU/KWH) (Heat Rate @ Maximum)	7,841
MBTU (x 1000) (Annual for Fuel Reimbursement Charge)	13,188
FTS-2 Rate ($/MBTU) (Projected Rate w/o Gas)	0.80
Gas ($/MBTU)	See 1993 Summer Forecast Table 5-3 of Intr. No. 5 (Docket 950379-EI)
Gas Pipeline Capital (1999$):	
6 Inch Diameter Pipe (1.3 miles)	315,721
Hot Tap	18,943
Meter Station	136,003
Total (1999$)	470,668
Capital Escalation (%)	
1993	3.5
1994	3.8
1995 and beyond	4.0
Pipeline Book Life (years)	30
Pipeline Tax Life (years)	15
1993 Discount Rate (%)	9.17

27. Please provide the information requested in Docket 950379-EI in Staff's First Set of Interrogatories, No. 12 and No. 14, based on the Illinois coal base case forecasts of 1992, 1993, 1994, and 1995. For each of the sensitivities, assume Illinois coal is used in the IGCC. Also assume the CC is fired by gas priced according to an acid test method in which coal and natural gas prices are allowed to escalate according to base case assumptions for the first four years then the fourth year differential between the two fuels is held constant over the remaining study period.

A. Tampa Electric fails to see the relevance of this interrogatory given the fact that the Commission determined the need for IGCC rather than a combined cycle unit. Nevertheless, to respond to Staff's request, a summary of the results of the IGCC vs. CC unit comparison is shown below. This analysis is based on the assumptions and format used in Tampa Electric's response to Staff's First Set of Interrogatories, No. 12 and No. 14, and modified per this interrogatory. Also included for each analysis are key assumptions and the Illinois coal forecast for the IGCC sensitivities and the resulting natural gas forecast for the CC sensitivities based on FPSC Staff's acid test method.

Illinois Coal FORECAST YEAR	TABLE	IGCC CPWRR ($ x 10^6)	TABLE	CC CPWRR ($ x 10^6)
1992	27-1A	1,346	27-5A	1,578
1993	27-2A	1,290	27-6A	1,335
1994	27-3A	1,237	27-7A	1,307
1995	27-4A	1,178	27-8A	1,185

TABLE 27-1A

POLK IGCC

IGCC WITH REVISED PROJECTIONS, DOE CREDIT AND 1992 ILLINOIS #6 FORECAST

NOMINAL COST PROJECTION

YEAR	IGCC							
	O&M		FUEL		CAPITAL		TOTAL	
	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh
1996	265	0.060	6,510	1.474	19,521	4.421	26,296	5.955
1997	2,669	0.152	26,769	1.528	96,710	5.520	126,148	7.200
1998	4,242	0.242	28,021	1.599	89,418	5.104	121,681	6.945
1999	12,997	0.742	29,117	1.662	83,880	4.788	125,994	7.191
2000	13,413	0.763	30,295	1.724	79,599	4.531	123,307	7.019
2001	13,842	0.790	31,621	1.805	75,847	4.329	121,310	6.924
2002	14,285	0.815	33,187	1.894	72,104	4.116	119,576	6.825
2003	14,742	0.841	34,909	1.993	69,022	3.940	118,673	6.774
2004	15,214	0.866	36,731	2.091	69,023	3.929	120,968	6.886
2005	15,701	0.896	38,666	2.207	67,738	3.866	122,104	6.969
2006	16,203	0.925	40,701	2.323	66,464	3.794	123,368	7.042
2007	16,722	0.954	43,049	2.457	65,202	3.722	124,973	7.133
2008	17,257	0.982	45,521	2.591	63,951	3.640	126,729	7.214
2009	17,809	1.016	47,902	2.734	62,713	3.580	128,424	7.330
2010	18,379	1.049	50,719	2.895	61,488	3.510	130,586	7.454
2011	18,967	1.083	53,537	3.056	60,275	3.440	132,779	7.579
2012	19,574	1.114	56,823	3.234	59,077	3.363	135,474	7.711
2013	20,200	1.153	59,955	3.422	57,891	3.304	138,047	7.879
2014	20,847	1.190	63,556	3.628	56,721	3.238	141,124	8.055
2015	21,514	1.228	67,469	3.851	55,566	3.172	144,549	8.251
2016	22,202	1.264	72,363	4.119	54,425	3.098	148,991	8.481
2017	22,913	1.308	77,331	4.414	53,300	3.042	153,544	8.764
2018	23,646	1.350	82,967	4.736	52,191	2.979	158,804	9.064
2019	24,403	1.393	89,228	5.093	51,100	2.917	164,731	9.402
2020	25,184	1.433	96,223	5.477	50,025	2.848	171,431	9.758
2021	25,989	1.483	103,317	5.897	48,969	2.795	178,276	10.176
2022	26,821	1.531	111,239	6.349	47,930	2.736	185,990	10.616
2023	27,679	1.580	119,768	6.836	46,910	2.678	194,357	11.093
2024	28,565	1.626	129,304	7.360	45,910	2.613	203,779	11.599
2025	29,479	1.683	138,837	7.925	44,930	2.564	213,247	12.172
2026	30,423	1.736	149,482	8.532	34,213	1.953	214,118	12.221
CPW ('96$)	149,565		462,121		734,343		1,346,028	

NOTES:

1. Assumes an in-service date of October 1, 1996.
2. Capital cost excludes a $4M expense related to burning a pet coke blended fuel.

TABLE 27-1B

TAMPA ELECTRIC COMPANY
Polk IGCC Unit

Assumptions

	IGCC
As Spent Capital ($ x 1000):	
Plant	384,870
Gasifier Related "Sunk" Costs	included in plant
Land and Site Development	65,835
Common	118,461
DOE Credit	(115,395)
Total	453,771
Total w/ AFUDC	506,165
Tax Life (yrs)	7
O&M	
Fixed (97$000)	11,947
Variable ($/MWh)	NA
Escalation	
Capital	3.5%
O&M	3.2%
AFUDC Rate	7.79%
Discount Rate	9.26%
Capacity (MW)	
Winter	250
Summer	250
Capacity Factor	80%
Heat Rate (Btu/kWh)	
(1996 - 1998)	8775 (2)
(1999 - 2026)	8869 (2)
Fuel	
(1996 - 1998)	Pitt # 8
(1999 - 2026)	Illinois #6 (See Table 27-1C)

Notes:

(1) O&M shown excludes DOE credit ($20 M over 1996, 1997, and 1998). Variable costs included in fixed O&M number.

(2) Heat rate at full load.

TABLE 27-1C

TAMPA ELECTRIC COMPANY
Polk IGCC Unit

Illinois #6 Coal Forecast*

YEAR	$/MBTU
1996	1.65
1997	1.71
1998	1.79
1999	1.86
2000	1.93
2001	2.02
2002	2.12
2003	2.23
2004	2.34
2005	2.47
2006	2.60
2007	2.75
2008	2.90
2009	3.06
2010	3.24
2011	3.42
2012	3.62
2013	3.83
2014	4.06
2015	4.31
2016	4.61
2017	4.94
2018	5.30
2019	5.70
2020	6.13
2021	6.60
2022	7.11
2023	7.65
2024	8.24
2025	8.87
2026	9.55

* Based on 1992 Price Change Forecast

TABLE 27-2A

POLK IGCC

IGCC WITH REVISED PROJECTIONS, DOE CREDIT AND 1993 ILLINOIS #6 FORECAST

NOMINAL COST PROJECTION

YEAR	IGCC							
	O&M		FUEL		CAPITAL		TOTAL	
	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh
1996	265	0.060	9,339	2.115	19,521	4.421	29,125	6.595
1997	2,669	0.152	38,435	2.194	96,710	5.520	137,814	7.866
1998	4,242	0.242	40,126	2.290	89,418	5.104	133,786	7.636
1999	12,997	0.742	26,769	1.528	83,880	4.788	123,646	7.057
2000	13,413	0.763	27,784	1.581	79,599	4.531	120,796	6.876
2001	13,842	0.790	28,647	1.635	75,847	4.329	118,336	6.754
2002	14,285	0.815	29,743	1.698	72,104	4.116	116,132	6.629
2003	14,742	0.841	30,839	1.760	69,022	3.940	114,603	6.541
2004	15,214	0.866	32,179	1.832	69,023	3.929	116,416	6.627
2005	15,701	0.896	33,343	1.903	67,738	3.866	116,782	6.666
2006	16,203	0.925	34,752	1.984	66,464	3.794	117,419	6.702
2007	16,722	0.954	36,318	2.073	65,202	3.722	118,241	6.749
2008	17,257	0.982	37,987	2.162	63,951	3.640	119,195	6.785
2009	17,809	1.016	39,605	2.261	62,713	3.580	120,127	6.857
2010	18,379	1.049	41,483	2.368	61,488	3.510	121,350	6.926
2011	18,967	1.083	43,518	2.484	60,275	3.440	122,761	7.007
2012	19,574	1.114	45,835	2.609	59,077	3.363	124,486	7.086
2013	20,200	1.153	47,902	2.734	57,891	3.304	125,993	7.191
2014	20,847	1.190	50,406	2.877	56,721	3.238	127,974	7.304
2015	21,514	1.228	52,598	3.002	55,566	3.172	129,678	7.402
2016	22,202	1.264	55,096	3.136	54,425	3.098	131,724	7.498
2017	22,913	1.308	57,607	3.288	53,300	3.042	133,820	7.638
2018	23,646	1.350	60,425	3.449	52,191	2.979	136,262	7.778
2019	24,403	1.393	63,399	3.619	51,100	2.917	138,902	7.928
2020	25,184	1.433	66,869	3.806	50,025	2.848	142,078	8.087
2021	25,989	1.483	70,130	4.003	48,969	2.795	145,089	8.281
2022	26,821	1.531	73,887	4.217	47,930	2.736	148,639	8.484
2023	27,679	1.580	77,958	4.450	46,910	2.678	152,547	8.707
2024	28,565	1.626	82,477	4.695	45,910	2.613	156,952	8.934
2025	29,479	1.683	86,783	4.953	44,930	2.564	161,192	9.200
2026	30,423	1.736	91,563	5.226	34,213	1.953	156,199	8.915
CPW (96$)	149,565		405,856		734,343		1,289,764	

NOTES:

1. Assumes an in-service date of October 1, 1996.
2. Assumes IGCC fuel as Pitt #8 (1996 - 1998) and Illinois #6 coal (1999 - beyond) .

TABLE 27-2B

TAMPA ELECTRIC COMPANY
Polk IGCC Unit

Assumptions

	IGCC
As Spent Capital ($ x 1000):	
Plant	384,870
Gasifier Related "Sunk" Costs	included in plant
Land and Site Development	65,835
Common	118,461
DOE Credit	(115,395)
Total	453,771
Total w/ AFUDC	506,165
Tax Life (yrs)	7
O&M	
Fixed (97$000)	11,947
Variable ($/MWh)	NA
Escalation	
Capital	3.5%
O&M	3.2%
AFUDC Rate	7.79%
Discount Rate	9.26%
Capacity (MW)	
Winter	250
Summer	250
Capacity Factor	80%
Heat Rate (Btu/kWh)	
(1996 - 1998)	8775 (2)
(1999 - 2026)	8869 (2)
Fuel	
(1996 - 1998)	Pitt # 8
(1999 - 2026)	Illinois #6
	(See Table 27-2C)

Notes:

(1) O&M shown excludes DOE credit ($20 M over 1996, 1997, and 1998). Variable costs included in fixed O&M number.

(2) Heat rate at full load.

TABLE 27-2C

TAMPA ELECTRIC COMPANY
Polk IGCC Unit

Coal Forecast*

YEAR	Pitt #8 $/MBTU	Illinois #6 $/MBTU
1996	2.41	1.77
1997	2.50	1.86
1998	2.61	1.92
1999		2.00
2000		2.09
2001		2.19
2002		2.32
2003		2.44
2004		2.55
2005		2.69
2006		2.84
2007		2.99
2008		3.16
2009		3.34
2010		3.52
2011		3.72
2012		3.93
2013		4.16
2014		4.41
2015		4.69
2016		5.01
2017		5.32
2018		5.69
2019		6.10
2020		6.54
2021		7.02
2022		7.38
2023		7.76
2024		8.16
2025		8.59
2026		9.03

* Based on 1993 Fall Forecast

TABLE 27-3A

POLK IGCC

IGCC WITH REVISED PROJECTIONS, DOE CREDIT AND 1994 ILLINOIS #6 FORECAST

NOMINAL COST PROJECTION

YEAR	IGCC							
	O&M		FUEL		CAPITAL		TOTAL	
	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh
1996	265	0.060	6,394	1.448	19,521	4.421	26,180	5.928
1997	2,669	0.152	25,982	1.483	96,710	5.520	125,361	7.155
1998	4,242	0.242	26,750	1.527	89,418	5.104	120,410	6.873
1999	12,997	0.742	25,360	1.447	83,880	4.788	122,237	6.977
2000	13,413	0.763	26,214	1.492	79,599	4.531	119,226	6.787
2001	13,842	0.790	27,082	1.546	75,847	4.329	116,771	6.665
2002	14,285	0.815	28,021	1.599	72,104	4.116	114,410	6.530
2003	14,742	0.841	29,117	1.662	69,022	3.940	112,881	6.443
2004	15,214	0.866	30,138	1.716	69,023	3.929	114,375	6.510
2005	15,701	0.896	31,152	1.778	67,738	3.866	114,590	6.541
2006	16,203	0.925	32,404	1.850	66,464	3.794	115,071	6.568
2007	16,722	0.954	33,500	1.912	65,202	3.722	115,424	6.588
2008	17,257	0.982	34,847	1.984	63,951	3.640	116,055	6.606
2009	17,809	1.016	36,004	2.055	62,713	3.580	116,527	6.651
2010	18,379	1.049	37,413	2.135	61,488	3.510	117,280	6.694
2011	18,967	1.083	38,666	2.207	60,275	3.440	117,908	6.730
2012	19,574	1.114	40,184	2.287	59,077	3.363	118,835	6.764
2013	20,200	1.153	41,483	2.368	57,891	3.304	119,575	6.825
2014	20,847	1.190	43,049	2.457	56,721	3.238	120,617	6.885
2015	21,514	1.228	44,614	2.546	55,566	3.172	121,694	6.946
2016	22,202	1.264	46,463	2.645	54,425	3.098	123,090	7.007
2017	22,913	1.308	48,058	2.743	53,300	3.042	124,271	7.093
2018	23,646	1.350	50,093	2.859	52,191	2.979	125,930	7.188
2019	24,403	1.393	52,128	2.975	51,100	2.917	127,631	7.285
2020	25,184	1.433	54,626	3.109	50,025	2.848	129,834	7.390
2021	25,989	1.483	70,130	4.003	48,969	2.795	145,089	8.281
2022	26,821	1.531	74,044	4.226	47,930	2.736	148,795	8.493
2023	27,679	1.580	77,958	4.450	46,910	2.678	152,547	8.707
2024	28,565	1.626	82,303	4.685	45,910	2.613	156,778	8.924
2025	29,479	1.683	86,416	4.932	44,930	2.564	160,825	9.180
2026	30,423	1.736	90,983	5.193	34,213	1.953	155,619	8.882
CPW (96$)	149,565		353,273		734,343		1,237,180	

NOTES:

1. Assumes an in-service date of October 1, 1996.
2. Assumes IGCC fuel as Pitt #8 (1996 - 1998) and Illinois #6 coal (1999 - beyond) .

TABLE 27-3B

TAMPA ELECTRIC COMPANY
Polk IGCC Unit

Assumptions

	IGCC
As Spent Capital ($ x 1000):	
Plant	384,870
Gasifier Related "Sunk" Costs	included in plant
Land and Site Development	65,835
Common	118,461
DOE Credit	(115,395)
Total	453,771
Total w/ AFUDC	506,165
Tax Life (yrs)	7
O&M	
Fixed (97$000)	11,947
Variable ($/MWh)	NA
Escalation	
Capital	3.5%
O&M	3.2%
AFUDC Rate	7.79%
Discount Rate	9.26%
Capacity (MW)	
Winter	250
Summer	250
Capacity Factor	80%
Heat Rate (Btu/kWh)	
(1996 - 1998)	8775 (2)
(1999 - 2026)	8869 (2)
Fuel	
(1996 - 1998)	Pitt # 8
(1999 - 2026)	Pet Coke/PRB (See Table 27-3C)

Notes:

(1) O&M shown excludes DOE credit ($20 M over 1996, 1997, and 1998). Variable costs included in fixed O&M number.

(2) Heat rate at full load.

TABLE 27-3C

TAMPA ELECTRIC COMPANY
Polk IGCC Unit

Coal Forecast*

YEAR	Pitt #8 $/MBTU	Illinois #6 $/MBTU
1996	1.65	1.49
1997	1.69	[illegible]
1998	1.74	1.57
1999		1.62
2000		1.67
2001		1.73
2002		1.79
2003		1.86
2004		1.92
2005		1.99
2006		2.07
2007		2.14
2008		2.22
2009		2.30
2010		2.39
2011		2.47
2012		2.56
2013		2.65
2014		2.75
2015		2.85
2016		2.96
2017		3.07
2018		3.20
2019		3.33
2020		3.48
2021		4.48
2022		4.73
2023		4.98
2024		5.24
2025		5.52
2026		5.81

* Based on 1994 Fall Forecast

TABLE 27-4A

POLK IGCC

IGCC WITH REVISED PROJECTIONS, DOE CREDIT
AND 1995 ILLINOIS #6 FORECAST

NOMINAL COST PROJECTION

YEAR	IGCC							
	O&M		FUEL		CAPITAL		TOTAL	
	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh
1996	265	0.060	6,313	1.430	19,521	4.421	26,099	5.910
1997	2,669	0.152	25,654	1.464	96,710	5.520	125,033	7.137
1998	4,242	0.242	26,280	1.500	89,418	5.104	119,940	6.846
1999	12,997	0.742	23,638	1.349	83,880	4.788	120,515	6.879
2000	13,413	0.763	24,305	1.383	79,599	4.531	117,317	6.678
2001	13,842	0.790	24,834	1.417	75,847	4.329	114,523	6.537
2002	14,285	0.815	25,446	1.452	72,104	4.116	111,835	6.383
2003	14,742	0.841	26,070	1.488	69,022	3.940	109,835	6.269
2004	15,214	0.866	26,785	1.525	69,023	3.929	111,022	6.320
2005	15,701	0.896	27,368	1.562	67,738	3.866	110,807	6.325
2006	16,203	0.925	28,043	1.601	66,464	3.794	110,710	6.319
2007	16,722	0.954	28,710	1.639	65,202	3.722	110,633	6.315
2008	17,257	0.982	29,474	1.678	63,951	3.640	110,682	6.300
2009	17,809	1.016	30,092	1.718	62,713	3.580	110,614	6.314
2010	18,379	1.049	30,810	1.759	61,488	3.510	110,677	6.317
2011	18,967	1.083	31,545	1.800	60,275	3.440	110,787	6.323
2012	19,574	1.114	32,386	1.843	59,077	3.363	111,037	6.320
2013	20,200	1.153	33,069	1.888	57,891	3.304	111,161	6.345
2014	20,847	1.190	33,858	1.933	56,721	3.238	111,426	6.360
2015	21,514	1.228	34,668	1.979	55,566	3.172	111,747	6.378
2016	22,202	1.264	35,595	2.026	54,425	3.098	112,222	6.388
2017	22,913	1.308	36,346	2.075	53,303	3.042	112,559	6.425
2018	23,646	1.350	37,229	2.125	52,191	2.979	113,066	6.454
2019	24,403	1.393	38,132	2.176	51,100	2.917	113,635	6.486
2020	25,184	1.433	39,166	2.229	50,025	2.848	114,374	6.510
2021	25,989	1.483	40,009	2.284	48,969	2.795	114,967	6.562
2022	26,821	1.531	40,981	2.339	47,930	2.736	115,732	6.606
2023	27,679	1.580	41,978	2.396	46,910	2.678	116,567	6.653
2024	28,565	1.626	43,117	2.454	45,910	2.613	117,592	6.694
2025	29,479	1.683	44,044	2.514	44,930	2.564	118,454	6.761
2026	30,423	1.736	45,116	2.575	34,213	1.953	109,751	6.264
CPW (96$)	149,565		294,464		734,343		1,178,372	

NOTES:

1. Assumes an in-service date of October 1, 1996.
2. Assumes IGCC fuel as Pitt #8 (1996 - 1998) and Illinois #6 coal (1999 - beyond) .

TABLE 27-4B

TAMPA ELECTRIC COMPANY
Polk IGCC Unit

Assumptions

	IGCC
As Spent Capital ($ x 1000):	
Plant	384,870
Gasifier Related "Sunk" Costs	included in plant
Land and Site Development	65,835
Common	118,461
DOE Credit	(115,395)
Total	453,771
Total w/ AFUDC	506,165
Tax Life (yrs)	7
O&M	
Fixed (97$000)	11,947
Variable ($/MWh)	NA
Escalation	
Capital	3.5%
O&M	3.2%
AFUDC Rate	7.79%
Discount Rate	9.26%
Capacity (MW)	
Winter	250
Summer	250
Capacity Factor	80%
Heat Rate (Btu/kWh)	
(1996 - 1998)	8775 (2)
(1999 - 2026)	8869 (2)
Fuel	
(1996 - 1998)	Pitt # 8
(1999 - 2026)	Illinois #6
	(See Table 27-4C)

Notes:

(1) O&M shown excludes DOE credit ($20 M over 1996, 1997, and 1998). Variable costs included in fixed O&M number.

(2) Heat rate at full load.

TABLE 27-4C

TAMPA ELECTRIC COMPANY
Polk IGCC Unit

Coal Forecast*

YEAR	Pitt #8 $/MBTU	Illinois #6 $/MBTU
1996	1.63	1.42
1997	1.67	1.45
1998	1.71	1.48
1999		1.51
2000		1.55
2001		1.59
2002		1.63
2003		1.67
2004		1.71
2005		1.75
2006		1.79
2007		1.83
2008		1.88
2009		1.92
2010		1.97
2011		2.02
2012		2.06
2013		2.11
2014		2.16
2015		2.21
2016		2.27
2017		2.32
2018		2.38
2019		2.44
2020		2.50
2021		2.56
2022		2.62
2023		2.68
2024		2.75
2025		2.81
2026		2.88

* Based on 1995 Fall Forecast

TABLE 27-5A

**COMBINED CYCLE WITH FPSC E&G FUEL SENSITIVITY
NOMINAL COST PROJECTION**

YEAR	COMBINED CYCLE UNIT							
	O&M		FUEL		CAPITAL		TOTAL	
	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh
1996	1,444	0.351	14,241	3.459	17,839	4.333	33,524	8.142
1997	5,798	0.377	56,328	3.666	90,129	5.866	152,255	9.909
1998	5,984	0.389	61,160	3.980	86,228	5.612	153,371	9.981
1999	6,175	0.402	65,873	4.287	82,758	5.386	154,806	10.075
2000	6,380	0.414	66,892	4.341	79,513	5.160	152,785	9.914
2001	6,577	0.428	67,759	4.410	76,353	4.969	150,688	9.807
2002	6,787	0.442	68,937	4.486	73,269	4.768	148,993	9.696
2003	7,004	0.456	70,233	4.571	70,557	4.592	147,795	9.618
2004	7,237	0.470	71,738	4.655	68,921	4.472	147,895	9.597
2005	7,460	0.485	73,061	4.755	67,121	4.368	147,642	9.608
2006	7,698	0.501	74,593	4.854	65,330	4.252	147,622	9.607
2007	7,945	0.517	76,361	4.970	63,550	4.136	147,856	9.622
2008	8,208	0.533	78,356	5.085	61,783	4.009	148,348	9.626
2009	8,461	0.551	80,014	5.207	60,025	3.906	148,501	9.664
2010	8,732	0.568	82,135	5.345	58,278	3.793	149,145	9.706
2011	9,012	0.586	84,256	5.483	56,545	3.680	149,813	9.750
2012	9,311	0.604	86,865	5.637	54,826	3.558	151,002	9.799
2013	9,598	0.625	89,088	5.798	53,117	3.457	151,802	9.879
2014	9,905	0.645	91,798	5.974	51,424	3.347	153,127	9.965
2015	10,222	0.665	94,744	6.166	49,743	3.237	154,709	10.068
2016	10,561	0.685	98,566	6.396	48,426	3.142	157,552	10.224
2017	10,886	0.708	102,168	6.649	47,651	3.101	160,706	10.459
2018	11,235	0.731	106,410	6.925	46,713	3.040	164,358	10.696
2019	11,594	0.755	111,124	7.232	45,788	2.980	168,506	10.966
2020	11,979	0.777	116,530	7.562	44,879	2.912	173,387	11.251
2021	12,348	0.804	121,730	7.922	43,987	2.863	178,065	11.588
2022	12,743	0.829	127,693	8.310	43,111	2.806	183,547	11.945
2023	13,151	0.856	134,113	8.728	42,252	2.750	189,516	12.334
2024	13,587	0.882	141,437	9.178	41,411	2.687	196,435	12.747
2025	14,006	0.912	148,469	9.662	40,590	2.642	203,065	13.215
2026	14,454	0.941	156,482	10.184	31,079	2.023	202,015	13.147
CPW ('96$)	79,869		788,493		709,326		1,577,688	

NOTES:

1. Assumes an in-service date of October 1, 1996.
2. CC fuel is natural gas. Gas prices were calculated via FPSC staff's "acid test" methodology. (See Table 27-5C).

TABLE 27-5B

TAMPA ELECTRIC COMPANY
Hypothetical Polk CC Unit

Assumptions

	Polk CC
As Spent Capital ($ x 1000):	
Plant	142,128
Gasifier Related "Sunk" Costs	244,942
Land and Site Development	65,875
Common	67,014
DOE Credit	(96,338)
Total	423,621
Total w/ AFUDC	463,085
Tax Life (yrs)	20
O&M	
Fixed (97$000)	3,551
Variable ($/MWh)	1.46
Escalation	
Capital	3.5%
O&M	3.2%
AFUDC Rate	7.79%
Discount Rate	9.26%
Capacity (MW)	
Winter	233
Summer	212
Capacity Factor	80%
Heat Rate (Btu/kWh)	7,669 (1)
Fuel	Natural Gas (See Table 27-5C)

Note:

(1) Represents CC annual heat rate at full load.

TABLE 27-5C

FPSC Staff "Acid Test"
Fixed Differential Methodology

YEAR	Illinois #6 $/MBTU	Fixed Differential	GAS $/MBTU
1996	1.65		4.51
1997	1.71		4.78
1998	1.79		5.19
1999	1.86	3.73	5.59
2000	1.93	3.73	5.66
2001	2.02	3.73	5.75
2002	2.12	3.73	5.85
2003	2.23	3.73	5.96
2004	2.34	3.73	6.07
2005	2.47	3.73	6.20
2006	2.60	3.73	6.33
2007	2.75	3.73	6.48
2008	2.90	3.73	6.63
2009	3.06	3.73	6.79
2010	3.24	3.73	6.97
2011	3.42	3.73	7.15
2012	3.62	3.73	7.35
2013	3.83	3.73	7.56
2014	4.06	3.73	7.79
2015	4.31	3.73	8.04
2016	4.61	3.73	8.34
2017	4.94	3.73	8.67
2018	5.30	3.73	9.03
2019	5.70	3.73	9.43
2020	6.13	3.73	9.86
2021	6.60	3.73	10.33
2022	7.11	3.73	10.84
2023	7.65	3.73	11.38
2024	8.24	3.73	11.97
2025	8.87	3.73	12.60
2026	9.55	3.73	13.28

Note:
Starting coal (Illinois #6) and natural gas prices escalate according to 1992 Price Change Forecast base case assumptions for the first four years. The differential between coal and gas in the fourth year is held constant over the remaining study period.

TABLE 27-6A

COMBINED CYCLE WITH FPSC E&G FUEL SENSITIVITY
NOMINAL COST PROJECTION

YEAR	COMBINED CYCLE UNIT							
	O&M		FUEL		CAPITAL		TOTAL	
	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh
1996	1,444	0.351	10,547	2.561	17,839	4.333	29,829	7.245
1997	5,798	0.377	41,362	2.692	90,129	5.866	137,289	8.935
1998	5,984	0.389	43,483	2.830	86,228	5.612	135,695	8.831
1999	6,175	0.402	45,958	2.991	82,758	5.386	134,891	8.779
2000	6,380	0.414	46,801	3.037	79,513	5.160	132,694	8.611
2001	6,577	0.428	47,372	3.083	76,353	4.969	130,302	8.480
2002	6,787	0.442	48,197	3.137	73,269	4.768	128,253	8.347
2003	7,004	0.456	49,022	3.190	70,557	4.592	126,583	8.238
2004	7,237	0.470	50,110	3.252	68,921	4.472	126,268	8.194
2005	7,460	0.485	50,907	3.313	67,121	4.368	125,488	8.167
2006	7,698	0.501	51,968	3.382	65,330	4.252	124,996	8.135
2007	7,945	0.517	53,146	3.459	63,550	4.136	124,641	8.112
2008	8,208	0.533	54,483	3.535	61,783	4.009	124,474	8.077
2009	8,461	0.551	55,621	3.620	60,025	3.906	124,107	8.077
2010	8,732	0.568	57,035	3.712	58,278	3.793	124,045	8.073
2011	9,012	0.586	58,567	3.811	56,545	3.680	124,124	8.078
2012	9,311	0.604	60,392	3.919	54,826	3.558	124,529	8.081
2013	9,598	0.625	61,867	4.026	53,117	3.457	124,581	8.108
2014	9,905	0.645	63,752	4.149	51,424	3.347	125,081	8.140
2015	10,222	0.665	65,402	4.256	49,743	3.237	125,366	8.159
2016	10,561	0.685	67,365	4.371	48,426	3.142	126,352	8.199
2017	10,886	0.708	69,173	4.502	47,651	3.101	127,710	8.311
2018	11,235	0.731	71,294	4.640	46,713	3.040	129,242	8.411
2019	11,594	0.755	73,533	4.785	45,788	2.980	130,915	8.520
2020	11,979	0.777	76,229	4.947	44,879	2.912	133,087	8.636
2021	12,348	0.804	78,600	5.115	43,987	2.863	134,935	8.781
2022	12,743	0.829	81,428	5.299	43,111	2.806	137,282	8.934
2023	13,151	0.856	84,492	5.499	42,252	2.750	139,895	9.104
2024	13,587	0.882	87,980	5.709	41,411	2.687	142,978	9.278
2025	14,006	0.912	91,135	5.931	40,590	2.642	145,732	9.484
2026	14,454	0.941	94,734	6.165	31,079	2.023	140,267	9.128
CPW (96$)	79,869		545,609		709,326		1,334,804	

NOTES:

1. Assumes an in-service date of October 1, 1996.
2. CC fuel is natural gas. Gas prices were calculated via FPSC staff's "acid test" methodology. (See Table 27-6C).

TABLE 27-6B

TAMPA ELECTRIC COMPANY
Hypothetical Polk CC Unit

Assumptions

	Polk CC
As Spent Capital ($ x 1000):	
Plant	142,128
Gasifier Related "Sunk" Costs	244,942
Land and Site Development	65,875
Common	67,014
DOE Credit	(96,338)
Total	423,621
Total w/ AFUDC	463,085
Tax Life (yrs)	20
O&M	
Fixed (97$000)	3,551
Variable ($/MWh)	1.46
Escalation	
Capital	3.5%
O&M	3.2%
AFUDC Rate	7.79%
Discount Rate	9.26%
Capacity (MW)	
Winter	233
Summer	212
Capacity Factor	80%
Heat Rate (Btu/kWh)	7,669 (1)
Fuel	Natural Gas (See Table 27-6C)

Note:

(1) Represents CC annual heat rate at full load.

TABLE 27-6C

FPSC Staff "Acid Test"
Fixed Differential Methodology

YEAR	Illinois #6 $/MBTU	Fixed Differential	GAS $/MBTU
1996	1.56		3.34
1997	1.89		3.51
1998	1.66		3.69
1999	1.71	2.19	3.90
2000	1.77	2.19	3.96
2001	1.83	2.19	4.02
2002	1.90	2.19	4.09
2003	1.97	2.19	4.16
2004	2.05	2.19	4.24
2005	2.13	2.19	4.32
2006	2.22	2.19	4.41
2007	2.32	2.19	4.51
2008	2.42	2.19	4.61
2009	2.53	2.19	4.72
2010	2.65	2.19	4.84
2011	2.78	2.19	4.97
2012	2.92	2.19	5.11
2013	3.06	2.19	5.25
2014	3.22	2.19	5.41
2015	3.36	2.19	5.55
2016	3.51	2.19	5.70
2017	3.68	2.19	5.87
2018	3.86	2.19	6.05
2019	4.05	2.19	6.24
2020	4.26	2.19	6.45
2021	4.48	2.19	6.67
2022	4.72	2.19	6.91
2023	4.98	2.19	7.17
2024	5.25	2.19	7.44
2025	5.54	2.19	7.73
2026	5.85	2.19	8.04

Note:
Starting coal (Illinois #6) and natural gas prices escalate according to 1993 Fall Forecast base case assumptions for the first four years. The differential between coal and gas in the fourth year is held constant over the remaining study period.

TABLE 27-7A

COMBINED CYCLE WITH FPSC E&G FUEL SENSITIVITY
NOMINAL COST PROJECTION

YEAR	COMBINED CYCLE UNIT							
	O&M		FUEL		CAPITAL		TOTAL	
	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh
1996	1,444	0.351	9,663	2.347	17,839	4.333	28,945	7.030
1997	5,798	0.377	38,770	2.523	90,129	5.866	134,697	8.766
1998	5,984	0.389	41,598	2.707	86,228	5.612	133,810	8.708
1999	6,175	0.402	44,544	2.899	82,758	5.386	133,477	8.687
2000	6,380	0.414	45,265	2.937	79,513	5.160	131,158	8.511
2001	6,577	0.428	45,840	2.983	76,353	4.969	128,770	8.380
2002	6,787	0.442	46,547	3.029	73,269	4.768	126,603	8.239
2003	7,004	0.456	47,372	3.083	70,557	4.592	124,933	8.131
2004	7,237	0.470	48,219	3.129	68,921	4.472	124,377	8.071
2005	7,460	0.485	48,904	3.183	67,121	4.368	123,485	8.036
2006	7,698	0.501	49,847	3.244	65,330	4.252	122,875	7.997
2007	7,945	0.517	50,672	3.298	63,550	4.136	122,166	7.950
2008	8,208	0.533	51,765	3.359	61,783	4.009	121,756	7.901
2009	8,461	0.551	52,557	3.420	60,025	3.906	121,044	7.877
2010	8,732	0.568	53,618	3.489	58,278	3.793	120,628	7.850
2011	9,012	0.586	54,560	3.551	56,545	3.680	120,117	7.817
2012	9,311	0.604	55,783	3.620	54,826	3.558	119,919	7.782
2013	9,598	0.625	56,682	3.689	53,117	3.457	119,396	7.770
2014	9,905	0.645	57,860	3.765	51,424	3.347	119,189	7.757
2015	10,222	0.665	59,038	3.842	49,743	3.237	119,003	7.745
2016	10,561	0.685	60,510	3.927	48,426	3.142	119,497	7.754
2017	10,886	0.708	61,631	4.011	47,651	3.101	120,168	7.820
2018	11,235	0.731	63,163	4.111	46,713	3.040	121,111	7.882
2019	11,594	0.755	64,695	4.210	45,788	2.980	122,077	7.945
2020	11,979	0.777	66,656	4.325	44,879	2.912	123,514	8.015
2021	12,348	0.804	78,246	5.092	43,987	2.863	134,582	8.758
2022	12,743	0.829	81,192	5.284	43,111	2.806	137,047	8.919
2023	13,151	0.856	84,139	5.476	42,252	2.750	139,542	9.081
2024	13,587	0.882	87,494	5.678	41,411	2.687	142,493	9.246
2025	14,006	0.912	90,506	5.890	40,590	2.642	145,102	9.443
2026	14,454	0.941	93,944	6.114	31,079	2.023	139,478	9.077
CPW (96$)	79,869		517,486		709,326		1,306,682	

NOTES:

1. Assumes an in-service date of October 1, 1996.
2. CC fuel is natural gas. Gas prices were calculated via FPSC staff's "acid test" methodology. (See Table 27-7C).

TABLE 27-7B

TAMPA ELECTRIC COMPANY
Hypothetical Polk CC Unit

Assumptions

	Polk CC
As Spent Capital ($ x 1000):	
Plant	142,128
Gasifier Related "Sunk" Costs	244,942
Land and Site Development	65,875
Common	67,014
DOE Credit	(96,338)
Total	423,621
Total w/ AFUDC	463,085
Tax Life (yrs)	20
O&M	
Fixed (97$000)	3,551
Variable ($/MWh)	1.46
Escalation	
Capital	3.5%
O&M	3.2%
AFUDC Rate	7.79%
Discount Rate	9.26%
Capacity (MW)	
Winter	233
Summer	212
Capacity Factor	80%
Heat Rate (Btu/kWh)	7,669 (1)
Fuel	Natural Gas (See Table 27-7C)

Note:

(1) Represents CC annual heat rate at full load.

TABLE 27-7C

FPSC Staff "Acid Test"
Fixed Differential Methodology

YEAR	Illinois #6 $/MBTU	Fixed Differential	GAS $/MBTU
1996	1.49		3.06
1997	1.53		3.29
1998	1.57		3.53
1999	1.62	2.16	3.78
2000	1.67	2.16	3.83
2001	1.73	2.16	3.89
2002	1.79	2.16	3.95
2003	1.86	2.16	4.02
2004	1.92	2.16	4.08
2005	1.99	2.16	4.15
2006	2.07	2.16	4.23
2007	2.14	2.16	4.30
2008	2.22	2.16	4.38
2009	2.30	2.16	4.46
2010	2.39	2.16	4.55
2011	2.47	2.16	4.63
2012	2.56	2.16	4.72
2013	2.65	2.16	4.81
2014	2.75	2.16	4.91
2015	2.85	2.16	5.01
2016	2.96	2.16	5.12
2017	3.07	2.16	5.23
2018	3.20	2.16	5.36
2019	3.33	2.16	5.49
2020	3.48	2.16	5.64
2021	4.48	2.16	6.64
2022	4.73	2.16	6.89
2023	4.98	2.16	7.14
2024	5.24	2.16	7.40
2025	5.52	2.16	7.68
2026	5.81	2.16	7.97

Note:
Starting coal (Illinois #6) and natural gas prices escalate according to 1994 Fall Forecast base case assumptions for the first four years. The differential between coal and gas in the fourth year is held constant over the remaining study period.

TABLE 27-8A

COMBINED CYCLE WITH FPSC E&G FUEL SENSITIVITY*
NOMINAL COST PROJECTION

YEAR	COMBINED CYCLE UNIT							
	O&M		FUEL		CAPITAL		TOTAL	
	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh	$000	¢/kWh
1996	1,444	0.351	7,736	1.879	17,839	4.333	27,019	6.562
1997	5,798	0.377	31,110	2.025	90,129	5.866	127,037	8.267
1998	5,984	0.389	33,703	2.193	86,228	5.612	125,914	8.194
1999	6,175	0.402	35,706	2.324	82,758	5.386	124,639	8.111
2000	6,380	0.414	36,264	2.353	79,513	5.160	122,157	7.927
2001	6,577	0.428	36,606	2.382	76,353	4.969	119,536	7.779
2002	6,787	0.442	37,067	2.412	73,263	4.768	117,123	7.622
2003	7,004	0.456	37,537	2.443	70,557	4.592	115,098	7.491
2004	7,237	0.470	38,131	2.474	68,921	4.472	114,289	7.416
2005	7,460	0.485	38,514	2.506	67,121	4.368	113,095	7.360
2006	7,698	0.501	39,022	2.540	65,330	4.252	112,050	7.292
2007	7,945	0.517	39,524	2.572	63,550	4.136	111,019	7.225
2008	8,208	0.533	40,155	2.606	61,783	4.009	110,147	7.147
2009	8,461	0.551	40,564	2.640	60,025	3.906	109,051	7.097
2010	8,732	0.568	41,105	2.675	58,278	3.793	108,116	7.036
2011	9,012	0.586	41,658	2.711	56,545	3.680	107,215	6.977
2012	9,311	0.604	42,348	2.748	54,826	3.558	106,484	6.910
2013	9,598	0.625	42,806	2.786	53,117	3.457	105,520	6.867
2014	9,905	0.645	43,400	2.824	51,424	3.347	104,728	6.816
2015	10,222	0.665	44,009	2.864	49,743	3.237	103,974	6.767
2016	10,561	0.685	44,763	2.905	48,426	3.142	103,750	6.732
2017	10,886	0.708	45,272	2.946	47,651	3.101	103,810	6.756
2018	11,235	0.731	45,937	2.990	46,713	3.040	103,885	6.761
2019	11,594	0.755	46,617	3.034	45,788	2.980	103,999	6.768
2020	11,979	0.777	47,452	3.079	44,879	2.912	104,310	6.769
2021	12,348	0.804	48,030	3.126	43,987	2.863	104,365	6.792
2022	12,743	0.829	48,761	3.173	43,111	2.806	104,616	6.808
2023	13,151	0.856	49,512	3.222	42,252	2.750	104,915	6.828
2024	13,587	0.882	50,427	3.272	41,411	2.687	105,425	6.841
2025	14,006	0.912	51,068	3.323	40,590	2.642	105,664	6.877
2026	14,454	0.941	51,874	3.376	31,079	2.023	97,407	6.339
CPW (965)	79,869		395,690		709,326		1,184,886	

NOTES:

1. Assumes an in-service date of October 1, 1996.
2. CC fuel is natural gas. Gas prices were calculated via FPSC staff's "acid test" methodology. (See Table 27-8C).

TABLE 27-8B

TAMPA ELECTRIC COMPANY
Hypothetical Polk CC Unit

Assumptions

	Polk CC
As Spent Capital ($ x 1000):	
Plant	142,128
Gasifier Related "Sunk" Costs	244,942
Land and Site Development	65,875
Common	67,014
DOE Credit	(9C,338)
Total	423,621
Total w/ AFUDC	463,085
Tax Life (yrs)	20
O&M	
Fixed (97$000)	3,551
Variable ($/MWh)	1.46
Escalation	
Capital	3.5%
O&M	3.2%
AFUDC Rate	7.79%
Discount Rate	9.26%
Capacity (MW)	
Winter	233
Summer	212
Capacity Factor	80%
Heat Rate (Btu/kWh)	7,669 (1)
Fuel	Natural Gas (See Table 27-8C)

Note:

(1) Represents CC annual heat rate at full load.

TABLE 27-8C

FPSC Staff "Acid Test"
Fixed Differential Methodology

YEAR	Illinois #6 $/MBTU	Fixed Differential	GAS $/MBTU
1996	1.42		2.45
1997	1.45		2.64
1998	1.48		2.86
1999	1.51	1.52	3.03
2000	1.55	1.52	3.07
2001	1.59	1.52	3.11
2002	1.63	1.52	3.15
2003	1.67	1.52	3.19
2004	1.71	1.52	3.23
2005	1.75	1.52	3.27
2006	1.79	1.52	3.31
2007	1.83	1.52	3.35
2008	1.88	1.52	3.40
2009	1.92	1.52	3.44
2010	1.97	1.52	3.49
2011	2.02	1.52	3.54
2012	2.06	1.52	3.58
2013	2.11	1.52	3.63
2014	2.16	1.52	3.68
2015	2.21	1.52	3.73
2016	2.27	1.52	3.79
2017	2.32	1.52	3.84
2018	2.38	1.52	3.90
2019	2.44	1.52	3.96
2020	2.50	1.52	4.02
2021	2.56	1.52	4.08
2022	2.62	1.52	4.14
2023	2.68	1.52	4.20
2024	2.75	1.52	4.27
2025	2.81	1.52	4.33
2026	2.88	1.52	4.40

Note:
Starting coal (Illinois #6) and natural gas prices escalate according to 1995 Fall Forecast base case assumptions for the first four years. The differential between coal and gas in the fourth year is held constant over the remaining study period.