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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Petition of Gulf Power Company for an increase in its rates and charges.	))))	Docket No. 891345-EI Filed: April 27, 1990

DIRECT TESTIMONY OF RICHARD A. ROSEN

ACK ____
AFA 1
APP ____
CAF ____
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CTR 1 w/note
EAG ____
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OTH ____

Respectfully submitted,

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Attorneys for the Citizens
of the State of Florida

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Richard A. Rosen. My business address is Tellus Institute, Inc., 89 Broad Street, Boston, MA 02110.

Q. PLEASE DESCRIBE YOUR POSITION AT TELLUS INSTITUTE.

A. I am a senior research scientist at Tellus Institute, Inc., as well as executive vice-president of the firm. I am also the director of the firm's Energy Systems Research Group.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Florida Office of the Public Counsel.

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF THE TELLUS INSTITUTE.

A. The Tellus Institute is a non-profit organization specializing in energy and environmental research. Within the Tellus Institute, the Energy Systems Research Group (ESRG) focuses on utility research areas which include demand forecasting, conservation program analysis, electric utility dispatch and reliability modeling, least cost utility planning, avoided cost analysis, financial analysis, cost of service and rate design, non-utility generation issues, and cost of capital analysis.

Q. PLEASE ELABORATE ON ESRG'S EXPERIENCE WITH ELECTRIC UTILITY SYSTEM PLANNING.

A. ESRG has had wide experience assessing utility system supply options on both a service area and a regional basis. These assessments have encompassed generation plant, transmission plant, purchases of capacity and energy, central station and decentralized cogeneration plants, and alternative sources of energy such as wind, biomass, and solar energy connected to electricity grids. These assessments have dealt with the technical, economic, environmental, regulatory, and financial aspects of supply planning, including the relationships between supply planning, load forecasting, rate design, and revenue requirements. ESRG also has reviewed the prudence of past planning decisions by utilities.

Q. PLEASE REVIEW YOUR EXPERIENCE IN THE AREA OF GENERATION PLANNING.

A. Power supply system modeling and economic analysis has been a major focus of my activities for the past nine years. My research and testimony in this area began in 1980, and I have testified in numerous cases involving generation planning. For example, I submitted extensive generation planning testimony in the 1980 CAPCO Investigation in Pennsylvania in Case No. I-79070315, and in the 1981 Limerick Investigation as well (Case No. I-80100341). In early 1982, I prepared a major report for the Alabama Attorney General's Office entitled "Long-Range Capacity Expansion Analysis for Alabama Power Company and the Southern Company System", and I filed testimony in Docket No. 18337 before the Alabama Public Service Commission. In addition, I testified on the excess capacity issue regarding Susquehanna unit 1 in the 1983 Pennsylvania Power and Light Co. Rate Case (No. R-822169). In 1987, I testified before the Federal Energy Regulatory Commission on NEPOOL's Performance Incentive Program on behalf of the Maine Public Utilities Commission in Docket No. ER-86-694-001. In 1989 I testified before the Pennsylvania Public Utility Commission on excess capacity and ratemaking treatment regarding Philadelphia Electric Co.'s Limerick 2 nuclear unit. This work was performed on behalf of the Pennsylvania Office of Consumer Advocate in Docket No. R-891364. I also filed testimony regarding Gulf Power's 1989 rate filing (Docket No. 881167-EI), but this case was withdrawn by the Company. Finally, in 1990 I testified on behalf of the Michigan Community Action Agency Association regarding excess capacity and ratemaking treatment of Indiana Michigan Power Company's Rockport 2 coal-fired unit.

A partial summary of my additional generation planning experience follows: In 1983, I completed a generation planning analysis which involved modeling four separate utilities in Kentucky for the

Public Service Commission to assess current capacity expansion plans and the potential benefits of power pooling. In 1984, I testified before the Missouri Public Service Commission (Case No. ER-84-168) on excess capacity and ratemaking treatment for Union Electric Company's Callaway nuclear plant. In 1985, I testified before the Massachusetts D.P.U. with regard to the economics of Seabrook Unit 1 in Dockets 1656/1657, 84-49, 84-50, 1626, and 140. I also testified in the Wolf Creek hearing held before the Kansas Corporation Commission in Docket Nos. 120, 924-U, 142,098-U, 142-099-U, and 142,100-U on the issue of excess capacity on behalf of the Commission Staff, as well as before the Missouri Public Service Commission in Docket ER-85-128, concerning Kansas City Power and Light Company's investment in the Wolf Creek project. In 1988 I was chosen to serve a three-year term on the Research Advisory Committee of the National Regulatory Research Institute, an appointment made by the public utility commissioners serving on the NRRI Board of Directors. The remainder of my experience is summarized in my resume, which is attached as Exhibit ___(RAR-1).

II. SUMMARY AND CONCLUSIONS

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is twofold. The first issue I will address is the rate base treatment of Gulf Power's 63-MW ownership share of the Scherer 3 generating unit. This capacity is now available to serve territorial load but is not yet in the Gulf Power rate base. The question is whether this capacity should be included in Gulf Power's rate base during 1990, the test year of this case.

The second issue is whether or not the Company's sales forecast for the 1990 test year is reasonable as a basis for determining retail rates for that year.

Q. WOULD YOU PLEASE SUMMARIZE THE RESULTS OF YOUR ANALYSIS?

A. With respect to the issue of how much capacity from the Scherer 3 generating unit should be included in Gulf Power's rate base, I have reached the following conclusions:

1. The Southern Company, and therefore Gulf Power Company, has systematically and persistently pursued a system-wide generation expansion strategy during the 1980s

which has led to the presence of excess baseload capacity on the Gulf Power and Southern systems.

2. The appropriate required reserve margin for the Southern Company system, and thus for Gulf Power, is about 15 percent, given the relatively high reliability of the generating units in the system. The Southern system currently plans to build new generating capacity based on a reserve margin of approximately 16 percent. Even allowing some leeway for load uncertainty and for other planning uncertainties, an 18 percent planning reserve margin would be the maximum reasonable for the 1990 test year. At a minimum, this planning reserve level of 18 percent should be the baseline from which excess capacity on the Gulf Power system is measured. Based on this reserve level, Gulf Power has at least 131 MW of excess capacity on its system during 1990.

3. At the very least, the 63 MW of capacity from the Scherer 3 unit owned by Gulf Power, which consists of the 44 MW portion from which Unit Power Sales had been made to GSU prior to July 1988 and the 19 MW portion that had not yet been put into rate base, is excess capacity. The

basis for this conclusion is that Gulf Power does not need this capacity to maintain system reliability as noted in point #2 above. Furthermore, this capacity is not economical during the test year for the purpose of serving Gulf Power's retail customers.

4. Because the Scherer 3 capacity is both uneconomical and represents excess capacity on the Gulf system, I recommend that none of the investment the Company has made in this capacity be included in rate base in the test year. In addition, all other costs associated with this capacity should be removed from rates, including O&M costs and working capital. However, if the Scherer 3 capacity is not included in Gulf's rate base, the Company should be allowed to keep all revenues from selling this capacity to other members of the Southern Company (or other companies). If, in the interim years before the Scherer 3 capacity is again sold off-system (under new Unit Power Sales contracts entered into in 1988), some or all of this capacity becomes cost-effective to Gulf's ratepayers, the Company should file a new rate case to request

inclusion in the rate base of that portion which is economic.

5. My recommendation is supported by other considerations. The 44 MW portion of Scherer 3 capacity was freed up by the collapse of a sale to Gulf States Utilities (GSU). The availability of this capacity to serve Gulf Power retail customers during the test year, then, is simply the result of a calculated business decision on the part of Gulf Power and the Southern Company which failed. For this reason, the stockholders of Gulf Power, not the ratepayers, must be responsible for any economic losses resulting from such a business strategy. Currently, the Southern companies are suing GSU in court. Since the Company may be able to collect its losses from these UPS sales to GSU through its court action, the Florida Public Service Commission should not pass through the costs of this capacity to Gulf Power's ratepayers. Any award from the court action, up to the amount of the total losses, due to Commission action, should accrue to Gulf Power, given the business risk the Company took.

6. In the event that the Commission allows Gulf Power to include the 63 MW of Scherer 3 capacity in its rate base in 1990, the Company should, at the very least, be required to pledge itself to filing a rate case in 1992. At this time, the Company should be required to submit plans to remove Scherer 3 capacity from its rate base as portions of this capacity become unavailable to serve territorial load, due to the new Unit Power Sales that will be made from the unit beginning in 1993.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS WITH RESPECT TO THE COMPANY'S SALES FORECAST FOR THE TEST YEAR.

A. Based on a review of the Company's short-term forecasting performance over the past several years and an analysis of its long-term forecast of retail sales in the early 1990s, Gulf's sales forecast for the test year is likely to be too low. In fact, although weather-adjusted sales have grown by an average of 318 GWH per year over the period 1986 through 1989, the Company is forecasting only a 124 GWH increase in retail sales for 1990--from 7575 GWH to 7699 GWH. I believe that the Company's own average forecast for sales growth for the years 1990 through 1993--approximately 204 GWH per year--is a more reasonable rate of growth to assume for the period 1989 to 1990. This represents an approximate

2.7 percent increase from 1989 actual retail sales to 7779 GWH. Based on this figure, average retail rates should be adjusted downward to reflect this estimated 1.0 percent increase in 1990 sales compared with the Company's projection.

Q. WHAT IMPACT DO THESE RESULTS HAVE ON THE RETAIL REVENUES BEING REQUESTED IN THIS CASE?

A. Excluding the investment in 63 MW of Scherer 3 capacity from the rate base of Gulf Power would reduce the rate base by $55.3 million[1], and by also excluding other Scherer 3 costs would reduce required revenues for retail customers by about $3.6 million during the test year 1990. This reduction represents approximately 13.7 percent of the requested rate increase of $26.3 million and translates into about a 1.45 percent reduction in overall retail rates. Increasing the sales forecast by 1.0 percent would reduce test year retail revenues by a similar percentage. Thus the total reduction in retail revenues that I am recommending to the Public Service Commission in this case is roughly 23.2 percent, or $6.1 million of the Company's proposed increase, based on just the two

[1] This figure includes a credit of $4.94 million to account for the system capacity sales to the rest of the Southern Company system lost (or additional system purchases made) as a result of the exclusion of 63 MW of Scherer 3 capacity from rate base in 1990. Thus if Scherer 3 is excluded from rate base, I propose that the Company be allowed to keep these revenues that have been credited to ratepayers in this filing.

issues on which I am testifying. The total reduction in retail rates would be 2.45 percent. Other Citizens' witnesses will have further rate adjustments to recommend.

III. HISTORICAL ANALYSIS OF SOUTHERN COMPANY EXPANSION PLANS AND UPS SALES

Q. WOULD YOU PLEASE DESCRIBE THE HISTORY OF THE SOUTHERN COMPANY'S PLAN FOR BUILDING NEW GENERATING UNITS DURING THE 1980s?

A. Yes. However, it is first important to understand that Gulf Power's expansion plans during the 1980s were not exactly the same as those of the other members of the Southern Company. Each Company owns different shares in different power plants. Typically, however, during the 1980s the main components of the expansion plans of all the Southern Company utilities were large baseload units, either coal or nuclear. As those plants were completed, the capacity mix of all the utilities within the Southern Company became more heavily weighted towards baseload units.

Q. DID THE EXPANSION PLANS FOR THE SOUTHERN COMPANY CHANGE MUCH DURING THE 1980s?

A. No, these plans did not change much during the 1980s, at least not with respect to the plans to build new baseload units. After the Southern Company formulated its December 17, 1981 expansion plan, the components of subsequent plans remained basically the same. The

Scherer, Miller, and Vogtle units that have already gone into commercial operation did so in a time frame quite close to that projected in late 1981. Since 1981, no major baseload additions proposed for the 1980s as early as 1981 were cancelled, or even significantly delayed.

However, two peaking units--the Rocky Mountain and Goat Rock pumped storage hydro facilities scheduled for commercial operation in 1987 and 1989, respectively--were subsequently delayed or cancelled. Because these plants were peaking units, it was the peaking portion of the 1981 and subsequent Southern Company expansion plans that was substantially altered, but not the baseload portion of those plans.

Q. WERE THESE EXPANSION PLANS, WITH THEIR DEPENDENCE ON NEW BASELOAD PLANTS, CONSISTENT WITH THE SOUTHERN COMPANY'S OWN PLANNING STUDIES DURING THE 1980s?

A. No, by basing its expansion plan during the entire 1980s primarily on new baseload units, the Southern Company was overlooking some clear signals from its own planning studies that this might not be the most economical strategy. As far back as July 1984, its "1984 System Generation Mix Study" indicated that the next set of new generating units in the 1990s, after completion of the currently planned baseload units, should be new peaking capacity. While this result does not prove conclusively that some or all of the new units planned for completion during the 1980s should have been peakers, it provides strong evidence that they should have been.

Unfortunately, the 1984 System Generation Mix Study did not explore the most economical mix of capacity types to build during the remainder of the 1980s. As stated on page 7 of the report, the computer model that the Southern Company used to compute the most economical mix of new capacity as distributed between new peaking and new baseload capacity "was only allowed to add generation to the system after 1990. Budgeted unit additions scheduled prior to the end of 1992 were considered to be installed on schedule". In other words, the study was constrained to leave the 1980s units unchanged and not consider any alternatives in that time frame. Similarly, the Southern Company's 1982 and 1986 generation mix studies focused on new units beginning in 1993 and thereafter.

Q. DID THE SOUTHERN COMPANY REVIEW ITS BASELOAD CAPACITY PLANS?

A. No, it did not. During the 1980s, the Southern Company's major generation planning studies focused solely on the capacity mix for new units in the 1990s, while ignoring the prudence of the baseload orientation of its scheduled construction program in the 1980s. This program culminated in the projected completed construction of Miller unit 4 by 1991.

This approach to planning appears to have been imprudent in that a proper economic analysis probably would have shown that the new coal baseload units planned for the late 1980s and early 1990s, such as Miller 3 and 4 and Scherer 4, should have been delayed or cancelled altogether. The addition of at least some new peaking capacity is indicated, interspersed between the completion dates of fewer or deferred baseload units.

Q. WHAT DID THE SOUTHERN COMPANY DETERMINE TO BE ITS ECONOMICALLY OPTIMAL CAPACITY MIX IN THE 1990S?

A. By 1984, the Company's own planning studies demonstrated that all new capacity after Miller 4 in the 1990s should be peaking capacity, as stated above. By 1986, the Company's economic analysis of its capacity mix showed just how far the system expansion plans had deviated from producing the optimal mix of capacity. Page 11 of the 1986 study, as filed in Florida Docket No. 860004-EU-A, showed that the projected Southern Company capacity mix for 1995 would deviate substantially from the long-term optimal mix of capacity (both new and old):

Capacity Type	Percent of Mix: Projected 1995	Percent of Mix: Optimal
Peaking	13	27
Intermediate	4	16
Base Load	83	57
Total	100	100

Thus the actual outcome of the Southern Company planning process resulted in a very significant deviation from the long run optimum. The Southern Company derived almost identical results in its most recent capacity expansion study dated September 1988.

Q. DO THESE RESULTS FOR THE SOUTHERN COMPANY AS A WHOLE IMPLY THAT THE CURRENT MIX OF CAPACITY ON THE GULF POWER SYSTEM IS ALSO FAR FROM THE LONG-RUN OPTIMUM, AS IT IS FOR THE SOUTHERN COMPANY AS A WHOLE?

A. Yes. In the September 1988 filing of the Gulf Power expansion plan in Docket No. 880004-EU-A, Gulf Power showed that its long-run optimal mix of capacity would be about 59 percent baseload, 12 percent intermediate, and 29 percent peaking capacity. Gulf Power's 1986 filing showed very similar results. Yet, Gulf Power's expansion plan throughout most of the 1980s was designed to produce a capacity mix of about 95 percent baseload coal capacity by 1994, with about 5 percent peaking capacity. Again, these results for Gulf Power itself show that the Company completely miscalculated what its expansion plan during the 1980s should have been. Indeed, the Company knew that it had done so by 1986, and perhaps even before 1984. Yet, neither Gulf Power nor the Southern Company altered its schedule for new baseload units to any significant degree after late 1981.

Q. DOES THIS DEVELOPING EXCESS OF BASELOAD CAPACITY ON BOTH THE SOUTHERN COMPANY AND THE GULF POWER SYSTEMS HELP EXPLAIN WHY AS EARLY AS 1982 THE SOUTHERN COMPANY BEGAN TO SIGN CONTRACTS TO SELL SOME OF THIS BASELOAD CAPACITY TO OTHER UTILITIES IN THE FORM OF "UNIT POWER SALES"?

A. Yes. I believe the Southern Company's developing perception by 1982 that it was planning to build vastly more baseload capacity on its system than would be necessary or economical to serve its own load, led it to sign several Unit Power Sales (UPS) contracts to "get rid of" of some of this excess coal capacity. Indeed, Mr. Parsons indicates in his pre-filed testimony in this case that the "UPS concept" evolved with the growing realization that construction of baseload capacity had outpaced demand during the 1970s and 1980s. According to Mr. Parsons, "Many utilities [presumably including the Southern Company] were well into the construction stage for a large number of generating units which would not be needed until significantly later in time" (Parsons, p. 5, l. 20-23). The Southern Company and Gulf Power Company response to this premature construction of baseload capacity was to continue with the construction program as planned and attempt to sell the excess capacity off-system until it was needed by the Company's territorial customers.

Q. DID GULF POWER ALSO EMPLOY THE "UPS CONCEPT" IN AN ATTEMPT TO ALLEVIATE THE EXCESS CAPACITY ON ITS SYSTEM?

A. Yes. As I discuss below, Gulf entered into UPS contracts for portions of its Daniel units 1 and 2 as well as Scherer 3, which came on-line in 1987. Although Gulf Power did not invest in any new baseload capacity after this date, its 25-percent share of Scherer 3 (212 MW) brought the Company's capacity mix far above the optimal level of baseload capacity.

Q. WOULD YOU PLEASE DESCRIBE THE UNIT POWER SALES THAT GULF POWER HAD ENTERED INTO IN THE EARLY 1980s?

Yes, I would. In Schedule 10 of Exhibit No.___(EBP-1) Mr. Parsons provides a tabular overview of all the UPS sales from members of the Southern Company. From that schedule we see that Gulf Power has made substantial UPS sales from the Daniel 1 and 2 units since January 1983. These UPS sales peaked at over 460 MW during 1988. Beginning in January 1987, Gulf Power also began to make significant UPS sales from the Scherer 3 unit as soon as it went into commercial operation. These UPS sales peaked at 193 MW in early 1988, just prior to the termination of power deliveries to the GSU system. This 193 MW of UPS sales from Scherer 3 represented all but 19 MW of Gulf Power's ownership share of capacity from Scherer 3, assuming a rating of 848 MW for Scherer 3. (According to Schedule 3 of Exhibit___(EBP-1), this is the capacity rating used by Mr. Parsons in developing his exhibits.) In total, from all three generating units, Gulf Power's UPS sales peaked at 660 MW in June 1988.

In contrast, after January 1989, Gulf Power made only 149 MW of UPS sales from its ownership share of Scherer 3, owing to the loss of the GSU sales and the completion of the Miller 3 and Scherer 4 units from which UPS sales are now made. This level of UPS sales from Gulf Power's ownership share of Scherer 3 persisted during 1989, with the exception of one month--February -- in which sales from this unit peaked at 163 MW. After January 1989, Georgia Power and Alabama Power, the owners of Miller 3 and Scherer 4, assumed a greater share of all Southern Company system UPS sales, while the total of such sales dropped by about 700 MW from earlier levels.

Thus, with the loss of the UPS sales to GSU, 44 MW of Scherer 3 capacity and 106 MW of Daniel capacity became available to serve Gulf's territorial load. In addition, 19 MW of Scherer 3 capacity owned by Gulf Power that never served the UPS customers and was never included in Gulf Power's rate base, is currently available to serve territorial load.

Q. WHY WASN'T GULF POWER'S NON-UPS SHARE OF SCHERER 3 CAPACITY EVER PUT INTO GULF'S RATE BASE?

A. The plant went into commercial operation in early 1987. Gulf Power did not file a rate case in that year, and the Company's request for a rate increase in 1988 was subsequently withdrawn.

Q. WAS IT WISE FOR THE SOUTHERN COMPANY IN GENERAL, AND GULF POWER SPECIFICALLY, TO ENTER INTO UNIT POWER SALES CONTRACTS?

A. Generally, it was wise for both the Southern Company and Gulf Power to temporarily sell off capacity in new baseload units to other utilities under Unit Power Sales agreements. This strategy was especially sound during the early years when expensive new capacity came on-line, since the UPS contracts covered most, if not all, of the full marginal costs of the new units.

Nevertheless, in completing construction of these new baseload units long before they were needed to serve the Southern Company's own load in an economical manner, and in signing UPS contracts to get rid of this uneconomical capacity, the member companies of the Southern Company were all taking a significant business risk. The risk was that one or more of these UPS contracts would fall through or somehow be abrogated, and the uneconomical baseload capacity would return to the use of its owner. Unfortunately, this risk became a reality in July 1988, when the Gulf States Utilities UPS contract completely collapsed, and the Southern Company members stopped delivering power to GSU. This contract currently is in litigation.

Q. WOULD YOU EXPLAIN IN MORE DETAIL WHAT YOU MEAN BY "BUSINESS RISK"?

A. Yes. Equity investors in any utility company take the risk that the utility's business itself might suffer some downturn or reduction in earnings. This is the "business risk" in investing. Because of the possibility of loss, or diminution of value, investors expect and usually receive a rate of return at a premium over that earned by investments that are risk free. In this case, Gulf Power and Southern Company investors were assuming business risks associated with transactions extending beyond their normal retail utility business.

Business risks typically include changes in demand for a product, cost overruns, errors of management, resource shortages and, more to the point here, breach of contract by sellers or purchasers. No investor in the equity securities of an ongoing business should reasonably expect to be insulated from all such risks.

In particular, if Gulf Power's ratepayers were required by the Public Service Commission to absorb such risks--and thereby insulate the stockholders of the Southern Company from them--these ratepayers would function, in effect, as insurers. In this case, they would be insuring against a collapse of the Gulf States UPS contract. This is not a proper role for ratepayers to assume, unless the allowed rate of return for Gulf Power <u>excluded</u> a business risk premium which, of course, it does not.

Q. IF IT WAS A SOUTHERN COMPANY MANAGEMENT DECISION TO BUILD EXPENSIVE NEW COAL UNITS PREMATURELY, WHO SHOULD NOW PAY FOR THIS UNNEEDED CAPACITY?

A. If a business risk such as that described above to overbuild the baseload generating system was taken by the management of the Southern Company, then its stockholders must bear all the consequences of taking such a risk. Thus, the stockholders of the Southern Company must bear all the cost consequences of the collapse of the GSU contract. If the

Company can recover damages from GSU in court, then it should be allowed to keep those damages for 1990 and beyond for its stockholders (up to the extent of any regulatory adjustment made by the Florida PSC in this docket). However, Gulf Power should not expect that the retail ratepayers should bail it out of a difficult financial situation which resulted directly from a clear business risk taken by management.

It is also important to remember that the stockholders have already benefitted substantially from all the UPS sales made since 1983, by having made greater profits than they would have made if the new baseload coal units involved in the UPS sales had never been built. Any losses that the stockholders now face must be considered in this context of past gains. This is especially true in light of the fact that the Southern Companies have recently succeeded in contracting for new Unit Power Sales to run from the year 1993 through 2010, during which time the stockholders will again earn profits from their investments in the plants from which the UPS sales are made.

Q. PLEASE DESCRIBE THESE NEW UPS SALES CONTRACTS SIGNED BY THE SOUTHERN COMPANY.

A. Certainly. These extremely important <u>new</u> UPS contracts were signed by the Southern Company operating utilities during the period from July 19, 1988 through August 17, 1988. These contracts are for up to 400 MW of power to be delivered to the Florida Power Corporation, 900 MW of power to be delivered to Florida Power and Light, and 200 MW of power to be delivered to the Jacksonville Electric Authority during the period from June 1, 1993 through May 31, 2010. Gulf Power's share of these purchases would involve a maximum of 212 MW of power from the Scherer 3 unit by June 1, 1995, with deliveries starting at up to 51 MW to JEA and FP&L on June 1, 1993.

Q. DOES THE EXISTENCE OF THESE NEW UPS CONTRACTS MEAN THAT GULF POWER WILL WITHIN JUST A FEW YEARS BE SELLING ITS SCHERER 3 CAPACITY TO OTHER UTILITIES FOR UP TO 17 YEARS JUST WHEN THAT CAPACITY MIGHT START TO BECOME COST EFFECTIVE TO SERVE GULF POWER'S TERRITORIAL LOAD?

A. Yes. Exhibit ___(RAR-2) shows the results of adding together Gulf Power's UPS commitments under its old UPS contracts with its commitments under the three new UPS contracts. All of these commitments come from the Scherer 3 unit, of which Gulf owns 212 MW (at the unit's highest likely rating). This exhibit shows that the 63 MW that is available during the test year 1990 from Scherer 3 to serve Gulf Power's own load will be reduced to only 11 MW by June 1992. In essence, then, the 63 MW portion of Scherer 3 that Gulf Power is proposing to put into its rate base in this case will not be available to serve its retail load between June 1995 and the year 2010.

If we take these new contracts as a given, then it is clear that there is no economic justification for Gulf Power to include any capacity from Scherer 3 in its rate base in 1990. Inclusion of this capacity in rate base during the period from January, 1990 through June 1993, when it will again begin to be phased out of serving retail load, is unlikely to be cost effective for ratepayers. (See Section IV for a more complete statement of this argument.) If it were cost effective to ratepayers for Scherer 3 capacity to be in rate base from 1990 to 1993, then it would be <u>more</u> cost-effective after 1993 (as the plant depreciates but other costs escalate) and it would suggest that the new UPS contracts which Gulf Power signed were imprudent!

In fact, however, it is clear from the data in the Southern Company Intercompany Interchange Contract for 1990 that using the 63 MW of Scherer 3 capacity to serve Gulf Power territorial load in the 1990 test year is not cost effective. The degree to which the Scherer 3 capacity is not economical during the 1990 test year is the basis for my rate adjustment, as described above.

IV. REVIEW OF CURRENT GULF POWER SUPPLY PLANS

Q. WOULD YOU PLEASE DESCRIBE THE CURRENT RELATIONSHIP BETWEEN PEAK DEMAND AND THE GENERATING RESOURCES AVAILABLE TO MEET THAT DEMAND ON THE GULF POWER SYSTEM?

A. According to the response to Citizens' interrogatory #279, the Gulf Power Company is projecting a peak demand of 1750 MW for the summer of 1990. This peak demand is expected to occur in July. On the supply side, Gulf Power will have a system peak hour capability of about 2286 MW from its fossil fueled steam units, and another 36 MW from the Smith A combustion turbine unit. Combined with about 21 MW of power from the Southeastern Power Administration (SEPA), Gulf Power will thus have a total peak hour supply capability of 2343 MW. From this total capability we must then subtract the 149 MW of power from portion of the Scherer 3 unit owned by Gulf Power that will continue to serve the Unit Power Sales. This leaves a net capability for Gulf Power for meeting peak hour demand of 2194 MW.

Q. BASED ON THIS BALANCE BETWEEN SUPPLY AND DEMAND, WHAT RESERVE MARGIN WILL GULF POWER HAVE DURING THE PEAK PERIOD OF THE TEST YEAR 1990?

A. If the net peak hour supply capability of 2194 MW is divided by the projected July 1990 peak hour demand of 1750 MW, then, a reserve margin of 25.4 percent results. This figure compares with the 1990 figure of 25.5 percent in Mr. Parsons' Late Filed Exhibit No. 1.

Q. GULF POWER WAS PLANNING TO CONTINUE THE UPS SALES TO THE GSU SYSTEM UNTIL MAY 1992. WHAT WOULD THE COMPANY'S RESERVE MARGIN HAVE BEEN DURING THE TEST YEAR 1990 IF THESE UPS SALES HAD CONTINUED?

A. In order to determine what Gulf Power's reserve margin would have been had the GSU UPS sales continued, we simply need to subtract the 150 MW of capacity that served that UPS load from the total capacity of 2194 MW now available in 1990 to get 2044 MW. Dividing by the Company's peak load in July 1990 of 1750 MW, we obtain a reserve margin of 16.8 percent. Gulf Power presumably believes that it would have been prudent to have continued the UPS sales to the GSU system through 1990 (if GSU had not refused to pay for the power). Therefore it follows that Gulf Power would have found the resultant reserve margin calculated using Mr. Parsons' methodology of 16.8 percent acceptable for maintaining system reliability.

Q. WHAT RESERVE MARGINS IS THE COMPANY PLANNING TO HAVE BETWEEN NOW AND 1995, WHEN IT PLANS TO COMPLETE A NEW 126 MW COMBUSTION TURBINE?

A. According to the Company's Resource Expansion Plan 90A1 provided in response to Citizens' interrogatory #94 in this case (see Exhibit___(RAR-3)), Gulf's projected reserve margin decreases from 25.5 percent in 1990 to 15.3 percent in 1993, when sales of Gulf's portion of Scherer 3 will commence. This reserve margin drops even further--to 13.7 percent--in 1994. Even after the first new 126 MW combustion turbine peaking unit is put on-line in 1995, the projected reserve margin is only 16.4 percent. Note that these results for reserves follow the period from 1990 through 1992, during which time the Gulf Power Company is planning its generating system to have an average reserve margin of nearly 22 percent. Despite the additions of four additional 126 MW peaking units, one 129 MW intermediate-load unit, and "active demand side options", Gulf's planned reserve margin averages only about 14 percent over the period 1993 through 2010.

Q. WHAT WOULD BE AN ADEQUATE RESERVE MARGIN FOR THE GULF POWER SYSTEM FOR 1990, AND BEYOND?

A. Based upon my experience analyzing the system reliability of a wide range of electric power systems, and based on the high availability of the Southern Company's generating units, I believe that a 15 percent required reserve margin would be adequate for 1990 and beyond, for both the Southern Company system, and the Gulf Power system. (In its filing in Docket No. 880004-EU-A the Southern Company stated that its "effective forced outage rates (EFOR's) are significantly below industry averages" (p. 162). This fact resulted in average plant availability on the Southern system in recent years of about 89 percent, which indicates a very reliable system. Even if one allows some additional planning flexibility to meet the uncertainty in peak load due to the variability of the weather, and other planning uncertainties, a planning reserve margin of no more than 18 percent certainly would be adequate for 1990, and for the long run. This level of reserves is well above what Gulf Power is currently planning for through 1995.

Q. WHAT RESERVE MARGIN DOES THE GULF POWER COMPANY USE FOR PLANNING PURPOSES OVER THE LONG RUN?

A. According to the Company response to Citizens' interrogatory #94 in the current case, Gulf Power's resource expansion plan is based on a minimum 20 percent planning reserve margin guideline, while actual capital expenditures for capacity additions have been limited to a 16 percent planning reserve margin. As Gulf Power stated in response to Citizens' interrogatory #145 in Docket No. 88-004-EU-A, however, the Company does not plan on, or operate on, the basis of a separate reserve margin from the Southern Company system as a whole. In response to Citizens' interrogatory #146 in the same case, the Company states that the Southern system utilizes two planning guidelines. The first is a 20-25 percent reserve margin guideline, where "it should be emphasized that the 20% reserve margin is a <u>long term</u> guideline only [emphasis added]. It is not used by Southern as a mandatory point at which capacity additions will be added." The second guideline depends on a measure of generating system reliability, and is an expected unserved energy (EUE) guideline. This EUE criterion contrasts with the more common loss-of-load probability or LOLP criterion. Based on system reliability studies performed in the early to mid-1980s, Southern has decided that an EUE measure of less than 0.02 percent should be maintained.

Q. WHAT WOULD THE REQUIRED RESERVE MARGIN BE FOR THE SOUTHERN COMPANY SYSTEM IF IT WERE DESIGNED TO MAINTAIN AN EUE CRITERION OF 0.02 PERCENT?

A. This question can be answered approximately by referring to the "Southern Studies Form 2.2, page 3" which was filed in September 1988 in Docket No. 880004-EU-A. This form is reproduced here as Exhibit ___(RAR-4). On this table we can see how the annual EUE calculated for a given reserve margin compares to the Southern Company's 0.02 percent criterion. For example, in 1988 there was a reserve margin of 15.4 percent on the Southern system. This reserve margin yielded an EUE figure of 0.00025 percent, which is 80 times smaller than the EUE criterion. This result indicates that the required reserve margin could be considerably lower than 15.4 percent, and the 0.02 percent criterion would still be met.

Similarly, the EUE that Southern has calculated for future years when the reserve margin is expected to be about 20 percent, is never higher than 0.00144 percent, which is still almost 14 times lower than it needs to be according to the Company's reliability criterion. While I do not know, and the Company does not explain, why the EUE measure changes as much as it does from year to year, the general conclusion that one can reach from an examination of Exhibit ___(RAR-4) is that a 20 percent reserve margin is significantly higher than is required by the Southern Company's own reliability criterion. (This conclusion assumes, of course, that the EUE value is computed properly, an assumption which requires review in light of the significant year-to-year variability in the EUE results.) This conclusion is also consistent with my view that given the high equivalent availability of the Southern Company system, a 15 percent required reserve margin, and at most an 18 percent planning reserve margin, would be appropriate.

Q. IF AN 18 PERCENT PLANNING RESERVE MARGIN WOULD BE QUITE ADEQUATE FOR GULF POWER FOR 1990, DOES THIS IMPLY THAT THERE WILL BE EXCESS CAPACITY ON THE GULF POWER SYSTEM DURING THE TEST YEAR?

A. Yes. Based on an 18 percent reserve margin as being more than adequate for the Gulf Power system for the test year 1990, the Company would be planning to have 25.5 percent minus 18 percent, or 7.5 percent in excess reserves that cannot be justified on the basis of preserving adequate system reliability alone. This translates into excess capacity of at least 131 MW.

This amount of excess capacity consists of most of the extra 150 MW of the capacity from the GSU Unit Power Sales contract that reverted to Gulf Power for use to serve territorial customers in July 1988. Of course, prior to 1988 Gulf Power was planning to meet its load responsibility to the Southern Company system without the 150 MW of capacity assigned to GSU under contract.

If instead of an 18 percent reserve margin, the Company's long run planning reserve margin of 20 percent were used to determine the amount of excess capacity in 1990, there would still be about 110 MW of excess capacity.

Q. DO YOU HAVE ANY OTHER EVIDENCE WHICH LEADS YOU TO BELIEVE THAT THE 63 MW OF SCHERER 3 CAPACITY REPRESENTS EXCESS ON THE GULF SYSTEM IN 1990?

A. Yes. This evidence is based on the Company "Monthly Estimated Load-Capacity Comparison" forms provided in response to Citizens' interrogatory #280-J. These forms are part of the filing that the Southern Company makes to FERC each year based on a variety of projections that it makes for its system. On these forms, which are 1990 projections, Gulf Power plans to be selling other Southern Company members at least 100 MW of capacity under the pool's capacity equalization provisions during July 1990, when the Gulf Power system reaches it annual peak demand, and during August 1990, when the Southern Company system reaches it annual peak demand. These projections are consistent with my findings that in 1990 Gulf Power will have more than 100 MW of excess capacity.

Q. YOU HAVE SAID THAT GULF POWER COULD NOT JUSTIFY ITS EXCESS CAPACITY ON THE BASIS OF NEEDING TO PRESERVE ADEQUATE SYSTEM RELIABILITY. IS THERE ANY OTHER REASONABLE JUSTIFICATION FOR HAVING THIS

CAPACITY ON THE GULF POWER SYSTEM AND IN ITS RATE BASE DURING 1990?

A. No. The only other significant rationale that might possibly justify the use of the capacity freed up from the GSU contract on the Gulf Power system to serve retail load would be if it were economically favorable to the ratepayers of Gulf Power to do so. To be economically favorable means that it would have to be less expensive to ratepayers to have this capacity on the system in either the short or the long run, than not to have it on the system at all. In considering whether or not this is true for the 150 MW that reverted to the Gulf system from the GSU contract (and for the other 19 MW of Scherer 3 capacity owned by Gulf Power but never put in rate base), one must consider the two basic components of this capacity separately, the Daniel 1 and 2 capacity and the Scherer 3 capacity.

In 1990, the depreciated cost of Daniel capacity is less than both the Southern Company pool average and the cost of a new peaking unit. Because it is less costly to have the Daniel capacity in the Gulf Power rate base than to purchase pool capacity from other Southern Company members under the Intercompany Interchange Contract, it is clearly economical to utilize the Daniel capacity to serve Gulf's territorial ratepayers.

On the other hand, Scherer 3 capacity (at a depreciated cost of around $760 per kw) is more costly than that from the Southern Company pool in 1990. As a result, there is no possible economic justification for having any capacity from the Scherer 3 unit included in the retail rate base for the Gulf Power system during the test year. Indeed, this capacity is far too expensive to include in the Gulf Power rate base in the next few years.

Previously I have shown that none of the 63 MW of Scherer 3 is needed on the Gulf Power system to insure system reliability in 1990. Similarly, Exhibit___(RAR-5) shows that it is less costly in 1990 (and over the next few years) for Gulf Power to buy capacity from the rest of the pool under the IIC rates (in the event that Gulf needs any of this 63 MW) than to have any Scherer 3 capacity in the Gulf rate base.

Finally, as noted above, the Company is planning to make new Unit Power Sales from this unit in amounts up to its full ownership share (212 MW) by 1995. As a result, the Company would have to remove any Scherer 3 capacity from rate base by 1995. It is unlikely that any of the Company's investments in Scherer 3 would be in the retail rate base long enough to be of any economic benefit to Gulf Power retail ratepayers. Only as Scherer 3 becomes more fully depreciated and thus cheaper than other alternatives would inclusion in rate base be economical.

In summary, because the Scherer 3 capacity will not be economical for Gulf Power ratepayers prior to being sold off-system, ratepayers should not bear the higher up-front capacity costs of this relatively undepreciated capacity now. They would typically have this obligation for a new coal plant like Scherer 3 if the unit were to remain in service to ratepayers after the economic benefits in the long run compensated them for the high front-end costs in the early years. With Scherer 3, however, this compensation cannot occur until after the new UPS contracts terminate in the year 2010, if at all, which is too speculative a basis for including this capacity in the Gulf Power rate base now.

V. ANALYSIS OF COMPANY'S RATEBASING PROPOSAL FOR TEST YEAR

Q. HOW MUCH ADDITIONAL GENERATING CAPACITY HAS THE COMPANY PROPOSED TO INCLUDE IN ITS RATE BASE FOR THE TEST YEAR?

A. The Company has proposed to add 233 MW of Daniel 1, 234 MW of Daniel 2, and 63 MW of Scherer 3 capacity to its retail rate base in this case. As stated above, of the 63 MW of Scherer 3 capacity, 44 MW had been used to serve the GSU sale until July 1988. Since the unit came on-line in January 1987, Gulf Power did not choose to apply for recovery of its investment in the remaining 19 MW of Scherer 3.

Q. IN LIGHT OF YOUR ECONOMIC AND RELIABILITY ANALYSES PRESENTED IN SECTIONS III and IV ABOVE, HOW MUCH OF THIS ADDITIONAL GENERATING CAPACITY SHOULD BE INCLUDED IN GULF POWER'S RETAIL RATE BASE DURING THE TEST YEAR?

A. I recommend that none of the 63 MW of Scherer 3 capacity be included in Gulf Power's retail rate base in 1990. Even if this 63 MW of Scherer 3 capacity is excluded from the calculation of the Gulf Power reserve margin for the test year, that reserve margin will still be more than adequate at 21.8 percent, indicating that excess capacity beyond the 63 MW still exists on the system.

Q. ON THIS BASIS, HOW MUCH WOULD THESE RETAIL RATE BASE EXCLUSIONS BE, AND WHAT WOULD THE REDUCTION IN REQUIRED REVENUES BE, FOR THE TEST YEAR?

A. On this basis, the retail rate base exclusion related to the 63 MW of Scherer 3 capacity would be about $55.3 million, including working capital. Because of the nature of the Southern Company system capacity equalization methodology as approved by FERC, it is necessary to add a credit to the Company of $4.94 million, for sales to other Southern Company members from this capacity. (See Exhibit___(RAR-6) for a calculation of this credit.) If other expenses relating to the operation of Scherer 3 are also reduced on a pro-rata basis, then the reduction in required revenues for retail customers is about $3.6 million. These figures were provided to me by Mr. Larkin, another witness for the Office of the Public Counsel in this case.

Q. IN THE EVENT THAT THE COMMISSION APPROVES THE COMPANY'S APPLICATION FOR INCLUSION OF THE 63 MW OF SCHERER 3 CAPACITY IN RATE BASE, WHAT RATEMAKING TREATMENT SHOULD BE REQUIRED REGARDING REMOVAL OF THIS CAPACITY FROM RATE BASE ONCE IT NO LONGER

IS AVAILABLE TO SERVE TERRITORIAL LOAD BEGINNING IN 1993?

A. If the Florida Public Service Commission allows Gulf Power to include the 63 MW of Scherer 3 capacity in its rate base in 1990, I recommend that the Commission also require Gulf to file a rate case in 1992, prior to the commencement of the 17-year period in which up to 212 MW (Gulf's entire ownership portion) of Scherer 3 capacity will be sold off-system. This capacity should be removed from the Company's rate base as it becomes unavailable to serve territorial load, and not at some future date determined when Gulf Power decides to file another rate case.

VI. ANALYSIS OF COMPANY'S TEST YEAR SALES FORECAST

Q. PLEASE BEGIN THIS PORTION OF YOUR TESTIMONY BY EXPLAINING HOW YOUR DISCUSSION OF FORECASTING IS ORGANIZED.

A. My discussion of forecasting in this section focuses on the Company's forecast of retail sales for the test year 1990, as presented in the testimony and exhibits of Mr. Kilgore. My aim is to view the basis for and reasonableness of this forecast. To that end, I will first review the accuracy of the Company's previous forecasting results, and then I will discuss appropriate changes to the short-term forecast.

Q. HAS THE COMPANY'S SHORT-TERM FORECASTING PROVED ACCURATE IN THE PAST?

A. Although the accuracy of the Company's short-term forecasting has improved over the past several years, it has not proved consistently accurate through the 1980s. In Exhibit___(RAR-7) I have summarized data regarding the Company's short-term sales and customer forecasts for 1983 to 1989. This is the same type of information Mr. Kilgore relied upon in his discussion of forecasting accuracy. The data in the exhibit show the following:

1. The Company's forecasts have been fairly accurate in the past on an average basis although not on a year-to-year basis; and

2. Past forecasts of sales for one year into the future have exhibited a tendency to underestimate actual sales growth for the next year.

Q. PLEASE DISCUSS THE RESULTS IN EXHIBIT___(RAR-7) IN MORE DETAIL.

A. The data on Sheet 1 of Exhibit___(RAR-7) are taken directly from Mr. Kilgore's Schedule 4 and its extensions, provided by the Company on discovery. Sheet 1 shows that there have been consistent divergences between the Company's forecasts of sales and the actual levels of these sales. This exhibit shows that the Company has underestimated actual sales in six of the last seven years. Nevertheless, the Company's average forecast of an annual increase of around 340 GWH for one year into the future has been approximately on-target. Note from Sheet 2 that since 1983 the smallest annual increase in actual sales has been 260 GWH.

Q. WHAT ABOUT THE COMPANY'S BASE RATE REVENUE FORECASTS?

A. In five out of the last seven years, the Company forecast of Base Rate Revenues has been less than actual Base Rate Revenues for the next year. Thus the Company has generally ended up better off than expected.

Q. DOES SHEET 1 PROVIDE THE ONLY USEFUL MEASURE OF THE ACCURACY OF THE COMPANY'S FORECAST?

A. No. In order to determine how accurate the Company's forecast of demand growth has been, one should also compare forecast growth with actual growth, as is done on Sheet 2. There I show the Company's forecasts of year-to-year growth and the actual year-to-year growth, for the period 1983 to 1989. This information was computed from data provided by Mr. Kilgore. As the exhibit shows, the Company's errors in forecasting growth have consistently been quite large from year to year.

Q. WHY IS IT APPROPRIATE TO FOCUS ON THE AMOUNT OF GROWTH WHEN ASSESSING THE ACCURACY OF THE COMPANY'S FORECASTING METHODS?

A. The reason is simple. Any forecast of sales or number of customers involves a small change in a large number. Actual growth will involve a small change in the same large number. Compared to the large number for the base year with which one begins, the difference between forecast growth and actual growth will <u>always</u> be fairly small, independent of the quality of the forecast. This is equally true whether the "large number" one begins with is the number of customers or the sales in a given year.

In order to assess the accuracy of a forecast of growth one must separate the magnitude of the starting point, which is very large, from the size of the growth forecasted and experienced, both of which are fairly small. That is what is done on Sheet 2.

Q. DO THE DATA IN EXHIBIT___(RAR-7) PROVIDE AN INDICATION OF THE SIZE OF THE COMPANY'S HISTORICAL TENDENCY TO UNDERESTIMATE FUTURE SALES GROWTH?

A. Yes, they do. This information is developed on Sheet 1 of the exhibit. There I show that, on average, the Company's sales estimates have been about 2.5 percent too low from 1983-1989. If one looks at the last three years, the average error is less, but it still averages about 1 percent too low. In setting up Sheet 1, I have followed Mr. Kilgore's terminology in his Schedule 4. In particular, in the portion of my exhibit dealing with sales, under the heading "% Deviation" I show the extent to which actual and weather adjusted sales have differed in the Company forecasts of sales for 1983 to 1989. The data on Sheet 1 show that, in most cases, actual and weather-adjusted sales have "deviated" above the Company's forecast.

Q. WHAT LEVEL OF RETAIL SALES GROWTH IS THE COMPANY FORECASTING FOR 1990?

A. As I have shown in sheet 3 of Exhibit___(RAR-7), Gulf projects total retail sales of 7699 GWH in 1990. This figure represents an increase of only 124 GWH (or 1.7 percent) over the 1989 sales level. In comparison, weather-adjusted retail sales actually grew at approximately 4.6 percent, or 318 GWH, per year between 1986 and 1989.

Q. WHAT LEVEL OF RETAIL SALES GROWTH IS THE COMPANY FORECASTING FOR THE MEDIUM TERM AFTER 1990?

A. The Company's medium term forecast, i.e. from 1990 through 1993, projects an annual rate of growth in retail sales of approximately 2.6 percent, or an approximate increase of 204 GWH per year. While this increase would be lower than actual growth in any year since 1983, it would be about 78 GWH above the forecast for 1990.

IN FORECASTING SALES GROWTH OF 124 GWH FOR 1990, DID MR. KILGORE ASSUME THE ACTUAL RATE INCREASES (NAMELY THE INTERIM RATES) APPROVED BY THE FLORIDA PSC FOR 1990, OR DID HE ASSUME THAT THE COMPANY'S ORIGINAL RATE REQUEST WOULD BE ADOPTED BY THE COMMISSION?

A. In calculating that Gulf Power retail sales would increase by 124 GWH during 1990 Mr. Gilgore assumed that the full rate increase originally requested by the Company would be implemented. However, the

Commission did not approve this full increase of $26.3 million for interim rates. Lower rates were approved. Since the Company's methodology for projecting sales growth for the residential and commercial customer classes utilize a short-run price elasticity effect, this means that sales will likely be higher during 1990, since the interim rate increase approved by the Commission was lower than Mr. Kilgore assumed in computing his test year sales forecast.

Q. HOW MUCH OF THIS 80-GWH DIFFERENCE BETWEEN MR. KILGORE'S 1990 RETAIL SALES FORECAST AND HIS MEDIUM TERM FORECAST AVERAGE MAY BE EXPLAINED BY SUCH PRICE ELASTICITY EFFECTS?

A. According to Mr. Kilgore's Late Filed Exhibit No. 1, an increase in sales of approximately 19 GWH may be justified on the basis of price elasticity effects during 1990 that are likely to occur. This exhibit compares Mr. Kilgore's original test year forecast to model results assuming actual Gulf Power prices through March 1990 and the interim rate increase in effect for the rest of the year. It shows that likely residential sales exceeded the test year forecast by approximately 14 GWH due simply to the earlier incorrect forecast for electricity prices for 1990. For commercial sales this figure was approximately 5 GWH, for a total of 19 GWH increase in the sales forecast.

Q. IN LIGHT OF YOUR ANALYSIS, HOW WOULD YOU RECOMMEND THAT THE COMPANY'S FORECAST BE TREATED BY THE COMMISSION?

A. I recommend that Gulf Power Company's forecast of retail sales for 1990 be adjusted to reflect the average medium-term rate of growth--204 GWH. The absolute sales level forecast in 1990, then, would be 7779 GWH rather than 7699 GWH. In percentage terms, this increase represents about a 1.0 percent adjustment to the 1990 sales forecast.

Q. WOULD YOU PLEASE SUMMARIZE WHY YOU FIND THIS ADJUSTMENT REASONABLE?

A. I find this adjustment to the Company's test year sales forecast to be reasonable for two reasons. First, as shown by the data on Sheet 1 of Exhibit___(RAR-7), the Company has tended to under-forecast year-to-year sales growth in the past. Second, consideration of the current forecast shows that some degree of underforecasting is quite likely to occur again for the test year, 1990, since that forecasted increase is unprecedented since 1983 in being so low. In addition, as discussed above, Mr. Kilgore stated during his deposition that he had assumed higher increases for the price of electricity in his econometric forecast equations than actually occurred for 1990. This would tend to have unreasonably depressed projected demand by about 19 GWH. Finally, I believe it is more appropriate to use the average sales growth forecast by the Company over the next few years for the 1989-1990 growth, as well, in case the Company does not file a new rate case again in the near future. Using the Company's own somewhat higher forecast for the medium term (1990-1993) will decrease the likelihood of overcollection after the test year is over if a new rate case is not filed.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

RICHARD A. ROSEN

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Education

Ph.D.:	Physics, Columbia University, 1974
M.A.:	Physics, Columbia University, 1969
B.S.:	Physics and Philosophy, M.I.T., 1966

Experience

1977-present: Energy Systems Research Group. Responsibility for a broad range of research on industrial energy conservation; electric generation planning issues; and modelling studies of long-range electric demand, utility system reliability, electric demand curtailment, and district heating systems.

1978-1980: Consultant to Brookhaven National Laboratory.

1979: Consultant to the National Academy of Sciences, Puerto Rico Energy Study Committee.

1976-1978: Assistant Physicist, Economic Analysis Division, National Center for the Analysis of Energy Systems, Brookhaven National Laboratory.

1974-1976: National Research Council - National Academy of Sciences Resident Research Fellow, Goddard Institute for Space Studies, New York.

1973: Instructor, Putney - Antioch Graduate School.

Testimony

Agency	**Case or Docket No.**	**Date**	**Topic**
Michigan Public Service Commission	U-9458 (ESRG 89-158)	Feb. 1990	Implications of excess capacity on the Indiana Michigan system for the costs that should be included in the Company's 1990 PSCR plan.
Vermont Public Service Board	5330 (ESRG 89-078)	Dec. 1989	Presentation of results of ESRG Study: *The Role of Hydro-Quebec Power in a Least-Cost Energy Resource Plan foı Vermont.*
		Feb. 1990	Further Testimony in above Docket
		Feb. 1990	Surrebuttal Testimony in above Docket
Pennsylvania Public Utility Commission	R-891364 (ESRG 89-90A)	Oct. 1989	Recommendations regarding the proper ratemaking treatment for PECo's Limerick 2 nuclear unit.
Florida Public Service Commission	881167-EI (ESRG 89-034)	May 1989	Ratebase Treatment of Gulf Power Scherer 3 Capacity
Federal Energy Regulatory Commission	ER88-630-000 (ESRG 88-153)	Apr. 1989	Pass Through of Performance Incentive Program Charges by New England Power Company
Public Service Commission of the District of Columbia	Formal Case No. 877 (ESRG 88-128D)	Feb. 1989	Evaluation of the Need and Justification for 210 MW CTs at Benning Road Site Proposed by PEPCO
	(ESRG 88-128E)	Mar. 1989	Rebuttal Testimony

Michigan Public Service Commission	U-8871 (ESRG 88-32)	Apr. 1988	Review of the Appropriate Avoided Costs for the CPCo System
	(ESRG 88-32A)	Aug. 1988	Rebuttal Testimony
Maine Public Utilities Commision	87-268 (ESRG 87-30A)	Apr. 1988	Review Related to the Staff's Evaluation of the Desirability of the Purchase of Power from Hydro Quebec Proposed by Central Maine Power
	87-268 (ESRG 87-30A1)	Aug. 1988	Supplemental Testimony
Pennsylvania Public Utility Commission	M-870111, G-870087 G-870088 (ESRG 88-01)	Feb. 1988	Review of Pennsylvania Power Company's Requested Recovery of Purchased Power Costs
Pennsylvania Public Utility Commission	R-870732 (ESRG 87-80)	Nov. 1987	Investigation into Pennsylvania Power Company's Share of Perry 1 Nuclear Unit and Assessment of Physical Excess Capacity. Direct and Rebuttal Testimony.
Michigan Public Service Commission	U-7830 (ESRG 85-35E)	Dec. 1987	Review of the Application of Consumers Power Company to Recover Its Midland Investment
Pennsylvania Public Utility Commission	R-870651 (ESRG 87-50D)	Oct. 1987	Investigation into Whether Perry 1 and Beaver Valley 2 Capacity Is Economically Used and Useful on the Duquesne System.
Federal Energy Regulatory Commission	ER-86-694-001	Sep. 1987	Analysis of NEPOOL's PIP Program on Behalf of Maine Public Utilities Commission

Maine Public Utilities Commission	86-242	June 1987	Investigation of Reasonableness of Rates
		Aug. 1987	Surrebuttal
Maryland Public Service Commission	7972	Feb. 1987	Investigation by the Commission of the Justness and Reasonableness of the Rates of Potomac Electric Power Company
Arizona Corporation Commission	U-1345-85-367	Feb. 1987	Concerning the Prudence of Palo Verde Investment
Michigan Public Service Commission	U-8578	Jan. 1987	Power Supply Cost Recovery Plan for Detroit Edison
Michigan Public Service Commission	U-8585	Jan. 1987	Power Supply Cost Recovery Plan for Upper Peninsula Power Company
Pennsylvania Public Utility Commission	R-860378	Sep. 1986	Economics of Duquesne Light Company's Share of Perry 1
		Nov. 1986	Surrebuttal
Pennsylvania Public Utility Commission	R-850267	Sep. 1986	Economics of Penn Power's Share of Perry 1
		Nov. 1986	Surrebuttal
		Mar. 1987	Supplemental
Michigan Public Service Commission	U-8348	July 1986	Palisades Performance Standards
Michigan Public Service Commission	U-8291	Apr. 1986	Power Supply Cost Recovery Plan for Detroit Edison
Michigan Public Service Commission	U-8286	Feb. 1986	Power Supply Cost Recovery Plan for Consumers Power

Michigan Public Service Commission	U-8297	Jan. 1986	Power Supply Cost Recovery Plan for Upper Peninsula Power Company
Michigan Public Service Commission	U-8285	Jan. 1986	Power Supply Cost Recovery Plan for Indiana & Michigan Company
Division of Public Utilities, Dept. of Business Regulation	85-2011-01 85-999-08	Jan. 1986	Construction of a Transmission Line and Transmission Facilities in Southwestern Utah
New York Public Service Commission	28252	Oct. 1985	Shoreham - Rate Moderation
		Jan. 1986	Surrebuttal
Missouri Public Service Commission	ER-85-128 EO-85-185 EO-85-224	June 1985	Wolf Creek Excess Capacity and the Prudency of Company Planning
Federal Energy Regulatory Commission	ER-84-560-000	Apr. 1985	Callaway Excess Capacity and a Review of Union Electric Planning
State Corporation Commission of the State of Kansas	120-924-U 142-098-U 142-099-U 142-100-U	Apr. 1985	General Investigation by the Commission of the Projected Costs and Related Matters of the Wolf Creek Nuclear Generation Facility at Burlington, Kansas
Michigan Public Service Commission	U-8042	Feb. 1985	Power Supply Cost Recovery Plan for Consumers Power Company
Michigan Public Service Commission	U-8020	Jan. 1985	Power Supply Cost Recovery Plan for Detroit Edison Company
Massachusetts Department of Public Utilities	84-49, 84-50, 84-140, 627, 1656 & 1957	Jan. 1985	Economics of Completing Seabrook 1 for Four Massachusetts Utilities
Michigan Public Service Commission	U-7830(M)	Dec. 1984	Future Capacity Requirements of Consumers Power Company

New Hampshire Public Utilities Commission	84-200	Nov. 1984	Investigation of Public Service Company of New Hampshire Financing Plan to Complete Construction of Seabrook 1
Michigan Public Service Commission	7830	Oct. 1984	In the Matter of the Application of Consumers Power Company for Authority to Increase its Rates Applicable to the Sale of Electricity
Maine Public Utilities Commission	84-113	Sep. 1984	Investigation of Seabrook Involvement by Maine Utilities
Missouri Public Service Commission	ER-84-168	Aug. 1984	In the Matter of Union Electric Company of St. Louis, Missouri for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company
Michigan Public Service Commission	U-7785	Apr. 1984	In the Matter of the Application of Consumers Power Company for Approval of a Power Supply Cost Recovery Plan and for Authorization of Monthly Power Supply Cost Recovery Factors for Calendar Year 1984
Ohio Power Siting Board	02-00022	Feb. 1984	In the Matter of the Cleveland Electric Illuminating Company/Ohio Edison Company Amended Application to Construct and Operate a Transmission Facility Identified as the Perry-Hanna 345 kV Transmission Line
Michigan Public Service Commission	U-7775	Feb. 1984	In the Matter of the Application of Application of Detroit Edison Company to Implement a Power Supply Recovery Plan in its 1984 Electrical Rates
Maine Public Utilities Commission	81-276	July 1983	As to the Avoided Costs for Cogeneration and Small Power Production Facilities on the Maine Public Service Company System

South Carolina Public Service Commission	82-352-E	June 1983	Review of A.S. Beck Analyses Regarding the Economics of the Catawba Nuclear Station
North Carolina Utilities Commission	E-2, Sub 461	June 1983	Application by Carolina Power and Light Company for Increase in Electric Rates
Michigan Public Service Commission	U-7550	May 1983	Application of Detroit Edison Company for Authority to Implement a Power Supply Recovery Plan in its 1983 Recovery Rates
Michigan Public Service Commission	U-7512	Apr. 1983	Application of Consumers Power Company for Authority to Implement a Power Supply Recovery Plan in its 1983 Recovery Rates
Pennsylvania Public Utilities Commission	R-822169	Mar. 1983	Excess Capacity for Pennsylvania Power & Light Company
North Carolina Utilities Commission	E-100, Sub 47	Feb. 1983	Power Plant Performance Standards and and Fuel Adjustment Clauses
Federal Energy Regulatory Commission	ER82-481	Dec. 1982	Overview of Conservation and Generation Options
Kentucky Public Service Commission	83-14	Dec. 1982	Review of the Kentucky-American Water Company Capacity Expansion Program
Maine Public Utilities Commission	81-276	Dec. 1982	As to the Avoided Costs for Cogeneration and Small Power Producers
Maine Public Utilities Commission	81-114	Nov. 1982	Maine Public Service Compnay Investigation of Power Supply Planning and Purchases
Maine Public Utilities Commission	82-174	Oct. 1982	Capital Costs of the Seabrook Nuclear Units
Indiana Public Service Commission	36818	Oct. 1982	An Economic Assessment of the Service Marble Hill Nuclear Station

New Hampshire Public Utilities Commission	DE81-312	Oct. 1982	Investigation Into Supply and Demand of Electricity for Public Service Company of New Hampshire
Michigan Public Service Commission	U-6923	May 1982	Consumers Power Company Electricity Case
Alabama Public Service Commission	18337	Jan. 1982	Long-Range Capacity Expansion Analysis
State of New York Energy Planning Board	SEMP II Hearings	Nov. 1981	Conservation and Generation Planning
Pennsylvania Public Utility Commission	80100341	Sep. 1981	Operating and Capital Costs: Limerick Nuclear Station; Surrebuttal
Maine Public Utilities Commission	MPUC 80-189	Apr. 1981	Electric Energy Costs: Seabrook Nuclear Power Plants; Surrebuttal
Pennsylvania Public Utility Commission	I-80100341	Feb. 1981	Operating and Capital Costs: Limerick Nuclear Generating Station
Ohio Public Utilities Commission	80-141 EL-AIR	Dec. 1980	CAPCO Construction Program; Generation Planning
Michigan Public Service Commission	U-6360	Sep. 1980	Generation Expansion Planning: Consumers Power Company
Pennsylvania Public Utility Commission	I-79070315	Aug. 1980	CAPCO Construction Schedule; Surrebuttal
Connecticut Power Facility Evaluation Council	F-80	June 1980	Renewable Resource Electric Generation in Connecticut
Pennsylvania Public Utility Commission	I-79070317	Mar. 1980	CAPCO: Generation Planning and Reliability
Michigan Public Service Commission	U-5979	June 1979	Forecast Critique and Adjustments: Consumers Power Company

Massachusetts Dept. of Public Utilities	19494	Aug. 1978	Long-range Electric Demand Forecast: Boston Edison Company
Pennsylvania Public Utility Commission	438	Mar. 1978	Long-range Forecast of Electric Energy Energy and Demand (Philadelphia Electric Company)

ESRG Research

Dec. 1989 *The Role of Hydro-Quebec Power in a Least-Cost Energy Resource Plan for Vermont*. A Report to the Vermont Public Service Board. ESRG No. 89-078. Principal investigator.

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Mar. 1989: *Update of 1985 Study on the Economics of Closing vs. Operating Shoreham.* ESRG Report No. 89-051. Principal investigator.

July 1988: *The Cost to Ratepayers of the Proposed LILCO Settlement.* A Report to Suffolk County. ESRG Report No. 88-23. Co-author.

Apr. 1988: *An Evaluation of Central Maine Power Company's Proposed Purchase of Power from Hydro Quebec*. A Report to the Maine Public Utilities Commission Staff. ESRG Report No. 87-30. Principal Investigator.

June 1987: *NEPOOL and New England's Electricity Future: Issues and Directions.* A Report to the New Hampshire Consumer Advocate. ESRG Study No. 86-83. Co-author.

May 1986: *Midland Options Study - A Response.* A report to the Michigan Department of the Attorney General. ESRG Study No. 85-35. Principal Investigator.

Sep. 1984: *The Economics of Seabrook 1 from the Perspective of the Three Maine Co-Owners.* ESRG Study No. 84-38. Principal Investigator.

May 1984: *Power Planning in Kentucky: Assessing Issues and Choices. Project Summary Report to the Public Service Commission.* ESRG Study No. 83-51. Project manager.

Apr. 1984: *Power Planning in Kentucky: Assessing Issues and Choices. Generation and Transmission System Planning.* ESRG Study No. 83-51/TR II. Project manager; Principal investigator.

Apr. 1984: *Power Planning in Kentucky: Assessing Issues and Choices. Utility Financial Forecasts: Two Case Studies.* ESRG Study No. 83-51/TR IV. Project manager.

Apr. 1984: *Draft Report: Electric Rate Consequences of Cancellation of the Midland Nuclear Power Plant.* ESRG Study No. 83-81. Principal investigator.

Jan. 1984: *Electric Rate Consequences of Retiring the Robinson 2 Nuclear Power Plant.* ESRG Study No. 83-10.

Jan. 1984: *Power Planning in Kentucky: Assessing Issues and Choices. Conservation as a Planning Option.* ESRG Study No. 83-51/TR III. Project manager.

Dec. 1983: *Power Planning in Kentucky: Assessing Issues and Choices. Long Range Forecasts for Kentucky and its Six Major Utilities.* ESRG Study No. 83-51/TR I. Project manager.

July 1983: *Long Island Without the Shoreham Power Plant: Electricity Cost and System Planning Consequences; Summary of Findings.* ESRG Study No. 83-14/S. Co-author.

Oct. 1982: *The Economics of Closing the Indian Point Nuclear Power Plants.* ESRG Study No. 82-40. Principal investigator.

Oct. 1982: Final Report of the Kentucky Public Service Commission. ESRG Study No. 82-45. Co-author.

Aug. 1982: *Nuclear Capacity Factors: The Effects of Aging and Salt Water Cooling.* A Report on Research in Progress. ESRG Study No. 82-81. Co-author.

Aug. 1982: *The Impacts of Early Retirement of Nuclear Power Plants: The Case of Maine Yankee.* ESRG Study No. 82-91. Co-author.

Apr. 1982: *A Power Supply and Financial Analysis of the Seabrook Nuclear Station as a Generation Option for the Maine Public Service Company.* ESRG Study No. 81-61. Principal investigator.

Jan. 1982: *Guidelines for Designing Rates for Sales to Qualifying Facilities Under Section 210 of the Public Utilities Regulatory Policies Act.* ESRG Study No. 81-32. Co-author.

July 1981: *Long-Range Capacity Expansion Analysis for Alabama Power Company and the Southern System.* ESRG Study No. 80-63. Co-author.

June 1981: *An Analysis of the Need for and Alternatives to the Proposed Coal Plant at Arthur Kill.* A Report to: Robert M. Herzog, Director, New York City Energy Office and Allen G. Schwartz, Corporation Counsel for the City of New York. ESRG Study No. 81-21. Co-author.

Oct. 1980: *The ESRG Electrical Systems Generation Model: Incorporating Social Costs in Generation Planning.* ESRG Study No. 80-12. A Report to the U.S. Department of Energy. Co-author.

Sep. 1980: *Reducing New England's Oil Dependence Through Conservation and Alternative Energy.*. ESRG Study No. 79-29. A Report to the U.S. General Accounting Office. Co-author.

July 1980: *Preliminary Economic and Need Analysis of the Proposed Brumley Gap Pumped Storage Facility for the AEP System.* ESRG Study No. 80-08/P. Principal investigator.

July 1980: *The Potential Impact of Conservation and Alternative Supply Sources on Connecticut's Electric Energy Balance.* ESRG Study No. 80-09. A Report to the Connecticut Power Facility Evaluation Council. Co-author.

Nov. 1979: *South Carolina Electric Demand Curtailment Planning.* A Report to the South Carolina Office of Energy Resources. Principal investigator.

May 1979: *Demand Curtailment Planning: Methodology.* ESRG Study No. 78-18. Chapter submitted to Brookhaven National Laboratory and the Department of Energy for the Electric Demand Curtailment Planning Study. Principal investigator.

May 1979: *Assessment of the New England Power Pool - Battelle Long Range Electric Demand Forecasting Model.* ESRG Study No. 79-06. A Report to the New England Conference of Public Utility Commissioners. Co-principal investigator.

Oct. 1978: *The Employment Creation Potential of Energy Conservation and Solar Technologies: The Implications of the Long Island Jobs Study for New England, 1978-1993.* ESRG Study No. 78-16. Co-author.

Nov. 1977: *Profile of Targets for the Energy Advisory Service to Industry.* ESRG Study No. 77-09. A Report to the New York State Energy Office. Co-Author.

Oct. 1977: *The Effect on Air and Water Emissions of Energy Conservation in Industry.* ESRG Study No. 77-04. Co-author.

July 1977: *The Effects on Air and Water Emissions of Energy Conservation in Industry.* ESRG Study No. 77-04. Co-author.

June 1977: *Toward an Energy Plan for New York.* ESRG Study No. 77-03. A Report to the Legislative Commission on Energy Systems. Co-author.

Apr. 1977: *Assessing Demand, Alternative Operating Strategies, and Utility Economics in the Service Territory of Orange and Rockland Utilities.* ESRG Report No. 77-01. Co-author.

Other Publications

Mar. 1978: *The Use of the Pulp and Paper Industry Process Model for R&D Decision Making.* Brookhaven National Laboratory Report No. BNL 24134. Co-author.

1976: "A Non-Linear Model for the Linewidth, Intensity, and Coherence of Astrophysical Masers," *Astrophysical Journal* vol. 190.

Papers

Sep. 1989: "Six Fallacies in Computing Avoided Costs," delivered at the NARUC Least Cost Planning Conference, Charleston, S.C.

Sep. 1987: "Electric Utility System Reliability and Reserves" (ESRG Paper). Co-author.

Sep. 1986: "Risk Sharing and the 'Used and Useful' Criterion in Utility Ratemaking" (ESRG Paper). Co-author.

Sep. 1986: *Risk Sharing, Excess Capacity, and the "Used and Useful" Criterion*, presented to the Fifth Biennial Regulatory Information Conference sponsored by the National Regulatory Research Institute in Columbus, Ohio.

Jul. 24-28 1978: "Energy Use Modelling of the Iron and Steel Industry," Summer Computer Simulation Conference.

Nov. 12 1977 "Energy Conservation in Industry," Northeastern Political Science Association meeting, Mt. Pocono, Pennsylvania.

Related Professional Activities

Elected to Three-Year Term as a member of the Research Advisory Committee of The National Regulatory Research Institute, October 1, 1988 - September 30, 1991.

Awards and Honors

1968-1974: Faculty Fellowship, Physics Department Columbia University.

1966-1970: New York State Regents Fellowship.

1967-1968: Adam Leroy Jones Fellow in Philosophy, Columbia University.

Exhibit___(RAR-2)

GULF POWER COMPANY

Total Commitments from Scherer 3
Under Old and New UPS Contracts

Year	Total Commitment to UPS (MW)	Remainder from 212 MW Share to Serve Retail Load
1987	185	27
1988 (Jan.-June)	193	19
(July-Dec.)	149	63
1989 (Jan.)	149	63
(Feb.)	163	49
(Mar.-Dec.)	149	63
1990-1991	149	63
1992 (Jan.-May)	149	63
(June-Dec.)	201	11
1993 (Jan.-May)	175	37
(June-Dec.)	196	16
1994 (Jan.-May)	195	17
(June-Dec.)	177	35
1995 (Jan.-May)	177	35
(June-Dec.)	212	0
1996 -2010 (May)	212	0

GULF POWER AND SOUTHERN SYSTEM RESERVE MARGINS (1990 – 2010)

YEAR	GULF POWER	SOUTHERN COMPANY SYSTEM
1990	25.5%	20.1%
1991	23.0%	19.1%
1992	17.2%	15.6%
1993	15.3%	15.4%
1994	13.7%	16.1%
1995	16.4%	16.1%
1996	13.6%	16.3%
1997	11.6%	16.3%
1998	15.8%	16.0%
1999	13.7%	16.1%
2000	12.1%	16.3%
2001	16.8%	16.0%
2002	14.0%	16.1%
2003	11.9%	16.0%
2004	15.7%	16.2%
2005	15.6%	16.0%
2006	13.9%	16.2%
2007	11.9%	16.2%
2008	15.4%	16.1%
2009	9.7%	16.0%
2010	16.7%	16.3%

Source: Company Response to Citizens' Interrogatory No. 94.

SUMMARY OF CAPACITY, DEMAND, AND RESERVE MARGIN
****SOUTHERN BASE CASE****

Year	(MW)	% of Peak	Annual Assisted LOLP	Annual Assisted LOLP	Annual[b] EUE (%)
1988	3,893	15.4			0.00025
1989	5,817	22.5	(a)	(a)	0.00004
1990	5,176	19.5			0.00018
1991	5,299	19.5			0.00016
1992	5,399	19.5			0.00026
1993	5,777	20.4			0.00144
1994	5,420	18.7			0.00107
1995	5,951	20.1			0.00059
1996	6,115	20.2			0.00134
1997	6,284	20.3			0.00066
1998	6,398	20.2			0.00059
1999	6,535	20.2			0.00138
2000	6,605	20.1			0.00059
2001	6,785	20.2			0.00052
2002	6,941	20.3			0.00056
2003	7,010	20.1			0.00052
2004	7,104	20.0			0.00044
2005	7,325	20.2			0.00034
2006	7,389	20.0			0.00032
2007	7,579	20.2			0.00031

Note: (a) Not used by Southern
(b) EUE (Expected Unserved Energy) - An annual probabilistic determination of total territorial energy not served, measured as a percent quantity

ECONOMICS OF REMOVING SCHERER 3 FROM RATES IN 1990 EXHIBIT___(RAR-5)

REMOVAL OF SCHERER 3 FROM RATE BASE WITH ASSOCIATED COSTS	$8,551
CREDIT TO COMPANY FROM IIC SALES	(4,944)
NET DECREASE IN REVENUE REQUIREMENT RESULTING FROM REMOVAL OF SCHERER 3	$3,607

Source: Citizens' witness Hugh Larkin, Jr.

GULF POWER COMPANY
CAPACITY SETTLEMENT CREDITS CALCULATION--SCHERER 3 OUT OF RATEBASE
1990

MONTH	NET PURCHASES/ (SALES) (MW-MONTH)	SALES TO CREDIT (MW)	PURCHASES TO CREDIT (MW)	MONTHLY SELLING RATE ($/KW)	MONTHLY PURCH. RATE ($/KW)	TOTAL CREDIT ($)
JAN	(86.4)	63.0	0.0	6.616251	0.000000	416,824
FEB	91.5	0.0	63.0	0.000000	5.133883	323,435
MAR	22.4	0.0	63.0	0.000000	6.393613	402,798
APR	(103.5)	63.0	0.0	6.634917	0.000000	418,000
MAY	(148.4)	63.0	0.0	6.671000	0.000000	420,273
JUN	(140.4)	63.0	0.0	6.717417	0.000000	423,197
JUL	(105.4)	63.0	0.0	6.747833	0.000000	425,113
AUG	(102.4)	63.0	0.0	6.747417	0.000000	425,087
SEP	(116.7)	63.0	0.0	6.721333	0.000000	423,444
OCT	(87.3)	63.0	0.0	6.695000	0.000000	421,785
NOV	(179.8)	63.0	0.0	6.658583	0.000000	419,491
DEC	(45.1)	45.1	17.9	6.791334	6.622016	424,823
TOTAL						4,944,270

Source: Company Response to Citizen's Interrogatory No. 280-J.

Exhibit ___ (RAR-6)

GULF POWER COMPANY--SHORT-TERM RETAIL FORECAST ACCURACY

	1983	1984	1985	1986	1987	1988	1989	JAN-FEB 1990
Customers - Average Number								
Actual	227,428	239,944	253,124	263,637	271,439	277,876	283,824	286,034
Forecast	226,437	234,965	249,441	264,562	274,951	279,191	284,698	286,488
Deviation	991	4,979	3,683	(925)	(3,512)	(1,315)	(874)	(454)
% Deviation	0.4%	2.1%	1.5%	-0.3%	-1.3%	-0.5%	-0.3%	-0.2%
Annual MWH Sales								
Actual	5,596,976	5,905,103	6,298,523	6,635,869	6,895,620	7,226,256	7,573,658	1,072,820
Forecast	5,545,765	5,572,218	5,946,279	6,543,120	6,658,231	7,276,471	7,566,302	1,203,892
Deviation	51,211	332,885	352,244	92,749	237,389	(50,215)	7,356	(131,072)
% Deviation	0.9%	6.0%	5.9%	1.4%	3.6%	-0.7%	0.1%	-10.9%
Weather Adjusted	5,700,049	5,887,342	6,327,383	6,620,841	6,762,324	7,287,515	7,575,022	1,167,299
Deviation	154,284	315,124	381,104	77,721	104,093	11,044	8,720	(36,593)
% Deviation	2.8%	5.7%	6.4%	1.2%	1.6%	0.2%	0.1%	-3.0%
Base Rate Revenues ($000)								
Actual	342,906	357,566	378,994	215,510	224,476	233,417	244,031	33,532
Forecast	334,201	339,543	373,261	212,733	217,507	237,200	245,206	38,299
Deviation	8,705	18,023	5,733	2,777	6,969	(3,783)	(1,175)	(4,767)
% Deviation	2.6%	5.3%	1.5%	1.3%	3.2%	-1.6%	-0.5%	-12.4%

Sources: Docket No. 891345-EI, Company Response to Citizen's Interrogatory No. 277, p. 2.
Docket No. 881167-EI, Company Response to Citizen's Interrogatories 159 and 160.

Exhibit ___ (RAR-7)
Sheet 1

GULF POWER COMPANY--SHORT-TERM RETAIL FORECAST ACCURACY

	SALES (MWH)			CHANGE FROM PREVIOUS YEAR (MWH)			FORECAST GROWTH (MWH)		FORECAST ERROR (%)
YEAR	ACTUAL	WEATHER ADJUSTED	FORECAST	ACTUAL	WEATHER ADJUSTED	FORECAST	FROM ACTUAL	FROM ADJUSTED	FORECAST INCREASE VS. ACTUAL INCREASE
1983	5,596,976	5,700,049	5,545,765						
1984	5,905,103	5,887,342	5,572,218	308,127	187,293	26,453	(24,758)	(127,831)	-108.0%
1985	6,298,523	6,327,383	5,946,279	393,420	440,041	374,061	41,176	58,937	-89.5%
1986	6,635,869	6,620,841	6,543,120	337,346	293,458	596,841	244,597	215,737	-27.5%
1987	6,895,620	6,762,324	6,658,231	259,751	141,483	115,111	22,362	37,390	-91.4%
1988	7,226,256	7,287,515	7,276,471	330,636	525,191	618,240	380,851	514,147	15.2%
1989	7,573,658	7,575,022	7,566,302	347,402	287,507	289,831	340,046	278,787	-2.1%

Sources: Docket No. 891345-EI, Company Response to Citizens, Interrogatory No. 277, p. 2.
Docket No. 881167-EI, Company Response to Citizens' Interrogatories 159 and 160.

Exhibit ___ (RAR-7)
Sheet 2

GULF POWER COMPANY--SHORT-TERM RETAIL FORECAST ACCURACY

YEAR	ACTUAL SALES (MWH)	ACTUAL SALES INCREASE (MWH)	ACTUAL SALES INCREASE (%)	WEATHER-ADJUSTED SALES (MWH)	WEATHER-ADJUSTED SALES INCREASE (MWH)	WEATHER-ADJUSTED SALES INCREASE (%)	FORECAST SALES (1) (MWH)	FORECAST SALES (1) INCREASE (MWH)	FORECAST SALES (1) INCREASE (%)
1983	5,596,976	--	--	5,700,049	--	--	5,545,765	--	--
1984	5,905,103	308,127	5.5%	5,887,342	187,293	3.3%	5,572,218	26,453	0.5%
1985	6,298,523	393,420	6.7%	6,327,383	440,041	7.5%	5,946,279	374,061	6.7%
1986	6,635,869	337,346	5.4%	6,620,841	293,458	4.6%	6,543,120	596,841	10.0%
1987	6,895,620	259,751	3.9%	6,762,324	141,483	2.1%	6,658,231	115,111	1.8%
1988	7,226,256	330,636	4.8%	7,287,515	525,191	7.8%	7,276,471	618,240	9.3%
1989	7,573,658	347,402	4.8%	7,575,022	287,507	3.9%	7,566,302	289,831	4.0%
1990	--	--	--	--	--	--	7,699,490	125,832	1.7%
1991	--	--	--	--	--	--	7,910,119	210,629	2.7%
1992	--	--	--	--	--	--	8,103,748	193,629	2.4%
1993	--	--	--	--	--	--	8,310,108	206,360	2.5%
ANNUAL GROWTH									
5-YEAR AVERAGE (1984-89)		333,711	5.1%	--	337,536	5.2%	--	398,817	6.4%
3-YEAR AVERAGE (1986-89)		312,596	4.5%	--	318,060	4.6%	--	341,061	5.0%
3-YEAR AVERAGE (1990-93)		--	--	--	--	--	--	203,539	2.6%

Sources: Citizens' Interrogatories 277, p. 2 and 279, pp. 2-4.
Docket No. 881167-EI, Company Responses to Citizens' Interrogatories 159 and 160.

Notes: (1) Forecast for 1990 and beyond based on 1990 budget year forecast as reported, Citizens' interrogatory #279.

Exhibit ___ (RAR-7)
Sheet 3

CERTIFICATE OF SERVICE
Docket No. 891345-EI

I HEREBY CERTIFY that a true copy of the foregoing has been furnished by U.S. Mail*, hand-delivery**, or by facsimile*** to the following parties on this 27th day of April, 1990.

*G. EDISON HOLLAND, JR., ESQ.
JEFFREY A. STONE, ESQ.
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Stephen C. Burgess
Deputy Public Counsel