77,153

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In The Matter of	DOCKET NO. 891345-EI
Application of GULF POWER COMPANY for an increase in rates and charges.	HEARING SEVENTH DAY EVENING SESSION

VOLUME - XVI

Pages 2320 through 2515

FPSC Hearing Room 106
Fletcher Building
101 E. Gaines Street
Tallahassee, Florida 32399

Tuesday, June 19, 1990

Met pursuant to adjournment at 12:37 p.m.

BEFORE: COMMISSIONER MICHAEL McK. WILSON, CHAIRMAN
COMMISSIONER GERALD L. GUNTER
COMMISSIONER THOMAS M. BEARD
COMMISSIONER BETTY EASLEY

APPEARANCES:

(As heretofore noted.)

REPORTED BY: JOY KELLY, CSR, RPR
SYDNEY C. SILVA, CSR, RPR
Official Commission Reporters
and
LISA GIROD-JONES, CPR, RPR
Post Office Box 10195
Tallahassee, Florida 32302

I N D E X

WITNESSES

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EXHIBITS

EVENING SESSION

CHAIRMAN WILSON: Call your next witness.

MR. BURGESS: Yes, sir. Mr. Rosen.

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RICHARD A. ROSEN

was called as a witness on behalf of the Citizens of the State of Florida and, having been first duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. BURGESS:

Q Please give us your name and business address.

A Yes. My name is Richard A. Rosen. My business address is the Tellus Institute, 89 Broad Street, Boston, Massachusetts 02110.

Q Mr. Rosen, have you prefiled testimony in this docket?

A Yes, I have.

Q If the answers that -- if the questions that are posed in your prefiled testimony -- do you have any additions or corrections that need to be made to your prefiled testimony?

A Some minor corrections were made in the file copy of the testimony.

Q Would you please list those?

A Yes, I can.

Q Thank you.

A On Page 10, Line 8, the superscript "1" from this line was misplaced and should be placed after the $3.6 million figure on Line 10. Would you like me to repeat that?

Q No. On Page 27, and this happened on a few subsequent places -- Page 27, Line 14, change "150" to "44." On Line 15, change "2044" to "2150". On Line 17, change "16.8" to "22.9". Those three changes are all related.

On Page 28, Line 1, again change "16.8" to "22.9." On Page 32, Line 14, change the phrase,"consists of most of the extra 150.," to "includes the 44." And further down on that page on Line 18, change, again, "150" to" 44." And, similarly, on Page 34, Line 10, change "150" to "44."

And the only other change I noticed when coming down is that there are several places where I reference a date for the onset of new UPS sales from the Scherer 3 Unit, there are various pages in the testimony where that's mentioned, and it says 1993 in some of those places. The date should be 1992.

None of these changes that I've listed affect my conclusions or statements in any way, other than as designated.

Q Mr. Rosen, with those questions -- if the questions posed to you in the prefiled testimony were asked today, would your answers be the same?

A Yes, they would.

MR. BURGESS: Commissioners, we have provided to the court reporter a record copy, and I would ask that Mr. Rosen's testimony be inserted into the record as though read.

CHAIRMAN WILSON: Without objection his testimony will be so inserted into the record.

MR. BURGESS: Unless I'm mistaken, Commissioner, his exhibits have been identified as Exhibits 331 through 337, and have been stipulated for inclusion into the record.

(Exhibits No. 331 through 337 previously stipulated into evidence)

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, and by also excluding other Scherer 3 costs would reduce required revenues for retail customers by about $3.6 million[1] 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

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[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):

	Percent of Mix	
Capacity Type	Projected 1995	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 new 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 more 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 44 MW of capacity that served that UPS load from the total capacity of 2194 MW now available in 1990 to get 2150 MW. Dividing by the Company's peak load in July 1990 of 1750 MW, we obtain a reserve margin of 22.9 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 22.9 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 <u>required</u> reserve margin, and at most an 18 percent <u>planning</u> 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 includes the 44 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 44 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 44 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 calculatic.. 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 always 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.

MR. BURGESS: We will forego providing a summary to the Commission. The testimony is fairly straightforward, speaks for itself, and we simply move on to tendering the witness for cross examination.

MAJOR ENDERS: No questions, sir.

CROSS EXAMINATION

BY MR. HOLLAND:

Q Mr. Rosen, just for clarification purposes before I really get started, you mentioned in your corrections that the new sales start in 1992, is that what you stated?

A Where I mention UPS sales, and I cite the fact from Scherer 3 some sales will be coming out of the unit starting at a certain date. I believe that date should be June 1992, during the course of the year 1992, as reflected in Mr. Parsons' exhibits.

Q Okay. The new sales though, it's your understanding, I believe, started in 1993, is that correct? Or do you know?

A The new ones may start in '93, but some sales from Scherer come out again in 1992.

Q Mr. Rosen, I have reviewed your testimony with great care and believe I understand what your position is with respect to, and I believe you were testfying specifically with reference to Issue 26, and that is the inclusion of the 63 megawatts in rate base, and also some testimony about the revenue forecast, is that correct?

A Yes.

Q Having read your testimony, it's my impression, and I believe I'm correct in this, that you do not make a finding, that the decision by Gulf Power Company in the early '80s to invest in Plant Scherer Unit 3 was imprudent. Is that a fair characterization?

A Yes.

Q Is it also your testimony that despite the fact that it was prudent at that time, that because it is uneconomical, as you define the term "uneconomical" to include the 63 megawatts in 1990, that it should be therefore disallowed for rate base purposes?

A No, that would not be a fair characterization of my position.

First of all, I did not say that it was prudent to purchase Scherer 3, I just have not made a finding of imprudence.

Second of all, it's not just a matter of Scherer 3 being uneconomical in a particular year, like 1990, that causes me concern and has led to my conclusions, but the fact that the unit will only be in service for territorial ratepayers for a brief time and then will be removed again. So it's not just the fact that it's not economical for a single year or a couple of years, you have to look at the whole time frame out quite a ways into the future.

Q Let me refer you to Page 25 of your testimony, specifically Line 17 through 19.

CHAIRMAN WILSON: What page?

MR. HOLLAND: 25.

Q Would you agree that the statement that's made there, that the basis for your proposed adjustment for the test year is the degree to which Scherer 3 capacity is not economical during the 1990 test year?

A Yes. What that means, and I can see why you might have been a bit confused, perhaps there is an ambiguity. The degree to which the unit is not economical in 1990 was the mathematical basis for the adjustment, is how Mr. Larkin derived the adjustment that I then used. The fact that it's not economical in 1990 is not the only reason for making an adjustment, there are many reasons.

Q One of those reasons, was it not, was the fact that you had calculated a reserve margin, excluding 150 megawatts of Daniel capacity which you, at least in your originally-filed testimony, thought was being sold?

A No. There was an error which, of course, now I've corrected in the original testimony on that one point. But it was correct in the testimony in most places, and that was not a basis for my coming to the conclusions that I did.

Q You did not rely, at all, on the fact that you had calculated a 16.8% acceptable level of reserves for Gulf Power Company using that 150 megawatts?

A Not in that single year, no, because as I point out, the level of reserves falls over time according to Gulf Power's own plans. It was not any particular year that was at issue; it was looking at the trend over time and then looking at the long term, which I point out. Gulf Power was only planning to have, in fact, about 14% on average in the late '90s in terms of reserves, so that particular year was not of any consequence.

Q It's your testimony then, that in those years in which your are over which you deemed to be a reasonable level, that you are imprudent and you have excess reserves and it should be disallowed, and in those years under which you deem to be acceptable, that's okay?

A No, I wouldn't use the term "imprudent" at all, in this regard.

What I've said, or certainly meant to say here, and what I've said in many other jurisdictions in the United States, is that in my view the ratepayer should not be the party to accept all the risk for the outcomes of decisions made by utility management. So that while perhaps it may or may not have been prudent for Gulf Power to have purchased a 25% share of Scherer 3 back in the early '80s, whenever it made that series of decisions, the fact it was or wasn't prudent only bears on, but is not determinate of what ratemaking treatment should be made at this point, if there is excess capacity on the system.

In other words, there are many things that change over time. If it turns out now that there is excess capacity on the Gulf Power system, if it turns out now for whatever reason, including the fact that the Company has not succeeded in selling that power-off system, or in this case the reason that some off-system sales fell through, it is not the ratepayers that should be, as I put it, "the insurer," or the, you know, the protector of last resort to protect the stockholders income.

Q Okay. Let's follow that line of thought. I think I understood your answer to be that even if -- and let's assume for the record that this Commission has -- and I don't want to get into that I think the record speaks for itself.

But let's assume for purposes of this question that this Commission made a determination in the early '80s; that Gulf's purchase of an interest in Scherer 3 was prudent, was in the long term best interest of Gulf Power's ratepayers. Is it your testimony today that if in the period in question, the 1990 test year, given that determination there are excess reserves, that they should be disallowed and excluded from investment?

A I'm saying yes, that's a reasonable conclusion to draw based on the entire circumstances of the case, absolutely. In fact, most excess capacity cases that I've been in, there has not been an issue of prudence. Many plants just like Scherer have been planned and pronounced on by their relevant Commission as having been prudent, but excess capacity adjustments are subsequently made. The most recent case like that was the recent Philadelphia Electric rate case where the Limerick 2 plant was at issue. The Commission had said that completion of that unit was prudent, And I believe it was 1986, but they just made an excess capacity adjustment based on my testimony.

CHAIRMAN WILSON: What was the reasoning for

that?

WITNESS ROSEN: Pardon?

CHAIRMAN WILSON: What was the reasoning behind the --

WITNESS ROSEN: The reason for the Commission decision in Pennsylvania?

Well, I believe the Commission more or less accepted my argument. And, of course, you should probably look at the order and draw your own conclusion.

But Pennsylvania has a very specific law which governs excess capacity. It gives you the hurdles that the utility has to overcome to justify excess capacity in a test year. And it gives both an economic and a physical interpretation to "excess capacity."

In my testimony, I argued that both there was physical excess capacity on the system and that that capacity was not economical for ratepayers and thereby met the definition of the Pennsylvania Statute. And I believe the Commission more or less agreed.

CHAIRMAN WILSON: How much capacity was it in excess, do you recall?

WITNESS ROSEN: I believe it was of order of about 300 megawatts. But because the Commission changed the reasoning that we had a bit, I don't remember exactly where they came out. But I believe that was the correct order of magnitude.

CHAIRMAN WILSON: And do you recall how large the Limerick plant is?

WITNESS ROSEN: Yes. The Limerick plant is approximately 1,050 megawatts. So it was perhaps about a third of the plant.

Q (By Mr. Holland) Mr. Rosen, I'm very familiar with that statute. It is a very detailed statute, is it not, that prescribes what the Commission can and cannot allow in rate base in terms of investment?

A Well, I mean it specifies certain options the Commission has. I see them as actually a fairly broad range of options, but describe it as you will.

Q And there is language in the statute relative to disallowing capacity that is deemed to be, quote, "excess"?

A Certainly, yeah.

Q Do you know if Florida has any such statute?

A I'm not aware of any such statute, no.

Q Are you familiar with what the law is and what the Commission, how the Commission has applied that law in past rate cases relative to investment in plant and whether it should be allowed in rate base or not?

A I'm not familiar with any other excess capacity type of cases here, no.

Q How many utilities do you think would invest in or build plant if they thought that in the years in which the capacity was in excess of what was deemed to be a reasonable level it was going to be disallowed in rate base?

A Well, excess capacity decisions have been made, you know, reasonably often. But I think that's a distortion of my position. The implication behind that question is a distortion of my position.

Because as I said earlier, I am not proposing that this Scherer 3 capacity be disallowed because it's uneconomical in the early part of its lifetime. That would be true of many baseload units. What I'm objecting to is the fact that it's uneconomical for a period of time; and then as it might become economical, the Company is selling it off-system and the ratepayers then will not get the benefit of the period when it will become economical.

That's the problem I have, that the ratepayers will not have access to that capacity again until the year 2011, approximately. So most baseload plants are uneconomical for the first few years and then become more and more economical over time.

Q Well, let me ask you this then. If in 1987 there had been no UPS sales and Scherer 3 had come on line, and there was no intent to sell the Scherer 3 capacity off-system, let's say -- and I'll give you an example. It's in the record. I don't think you were here, but when Crist 7 came on line at Gulf Power in 1973, I believe, '71 or '73, Gulf's reserves went from a negative 4% to a positive 70%.

Given that scenario and given the scenario that Scherer 3 did come on line, Gulf's reserves exceeded 25%, would it be your recommendation that the amount over a certain level be disallowed for inclusion in rate base?

MR. BURGESS: I want the witness to know if he was unable to follow all of, and track all of the variables contained in the question, he can have it broken down into a more simplified.

CHAIRMAN WILSON: Sure.

A Let me give my interpretation of what the question is and we'll make sure that we're communicating properly.

My interpretation of the question is basically if there were no issue of off-system sales for the moment, hypothetically, and if a fairly standard baseload unit came on a system that was fairly small so that the increment in size had the effect of increasing the reserve margin for that system quite a bit above 25% for a few years until demand grew, would I consider that this would be an appropriate situation to follow excess capacity for some period of years? Is that?

Q That's a fair statement, yes.

A My answer is one would have to look at the facts of the situation. Yes, it might have represented excess capacity and it might be suitable for a Commission disallowance and it might not. And that would have a lot to do with the reason why the reserve margin was so high? What caused it? Was it anything within the control of the Company management or not? Did the Company management in fact try to sell the capacity in a timely fashion or not?

I mean, you can't conclude these things, I think, on a totally generic basis. You have to look at the facts of the case.

Q You recommend that Plant Daniel be included in retail rate base because the average embedded cost for Plant Daniel is less than pool capacity, is that an accurate statement?

A Yes. Or putting it another way, it's economical for serving ratepayers at this time.

Q In Issue 25, the Office of Public Counsel had taken no position. Can I assume that it is your position, based on that testimony, that Plant Daniel, all of the Plant Daniel capacity should be included in retail rates?

A I'm sorry, I'm not familiar with Issue 25. Could you --

Q Issue 25 is the issue relative to the investment in Plant Daniel.

CHAIRMAN WILSON: Read him that. It's only one or two lines.

Q "Should 515 megawatts of Plant Daniel be included in Gulf Power's rate base?"

A Personally, I see no reason why it shouldn't.

Q Do you know any reason why your client would disagree?

MR. BURGESS: For the record, we don't disagree, we have no problem with Plant Daniel being included in the rate base.

CHAIRMAN WILSON: All right.

COMMISSIONER BEARD: He wasn't listed to testify on that issue, was he?

MR. BURGESS: Pardon? No, he was not.

MR. HOLLAND: He is the only witness that does.

CHAIRMAN WILSON: No. But he was testifying on it.

MR. HOLLAND: He does testify on it.

COMMISSIONER BEARD: On 26, not on 25.

MR. HOLLAND: No, he does on 25.

CHAIRMAN WILSON: Well, he just testified on 25.

COMMISSIONER BEARD: I'm sorry, he wasn't listed then. I missed it.

CHAIRMAN WILSON: No, he's not listed.

MR. BURGESS: Oh, okay.

CHAIRMAN WILSON: He's not listed; however, he just testified.

MR. BURGESS: He testified.

CHAIRMAN WILSON: He did not pretestify on the subject.

COMMISSIONER BEARD: There was no retroactive reconciliation of the previous statement?

Q (By Mr. Holland) Mr. Rosen, given your caveat stated earlier with respect to your statement on Page 25, you're recommending that Daniel capacity be allowed in the test year because it's the same or less cost as pool capacity, yet you're recommending that Scherer capacity be disallowed because it cost more than pool capacity.

If utility systems planned for generation additions based on whether they could bring them on less than the average embedded cost of their system, would they ever add capacity?

A Again, the answer is probably not. But that's not the basis for my conclusion in this case. It has nothing to do with whether new capacity is more or less expensive than average pool capacity. It has to do with the stream of benefits that will be available from that plan to retail ratepayers. In particular, the time period that the capacity is available. And when it disappears.

It's just not relevent to my testimony verv directly.

Q But you did state that, did you not?

CHAIRMAN WILSON: Let me understand.

MR. HOLLAND: Okay.

CHAIRMAN WILSON: On Plant Daniel, the reason -- is the reason that you suggested it be included in Gulf Power's rate base that you don't see any reason why it shouldn't, or because the cost is less than what, the pool capacity?

MR. HOLLAND: It's on Page 34, Commissioner, the bottom of the page, the last paragraph.

MR. BURGESS: Is this the basis for your statement -- I have to find out from Counsel, because he made the statement in the question that you -- Dr. Rosen has said that Plant Daniel should be in plant capacity because it's lower than the average pool capacity, and I'm trying to -- is this the basis --

MR. HOLLAND: That's the basis of the statement.

CHAIRMAN WILSON: That's what I'm trying to understand, because I thought I just heard him say that's why it ought to be included, and then the next question was, "Is that why it ought to be included?" And he said "No." At least that's what I think I heard. I'm trying to reconcile those two things for myself.

WITNESS ROSEN: Well, if you look at Mr. Parsons' Exhibit 1, Schedule 10, you see that there is no planned UPS sales in the future from Plant Daniel. So since Plant Daniel is now economical and certainly will be in the long run, it's not going to be removed from serving retail ratepayers. That's an additional reason why I believe it should be in rate base now, because it's not going to disappear from the service of retail ratepayers.

CHAIRMAN WILSON: So the distinction you are drawing between Plant Daniel and Plant Scherer is that Plant Scherer is going to -- if Plant Scherer were not going to be used for UPS, then would your opinion be different?

WITNESS ROSEN: Quite likely it would. I would, of course, have to look at the issue in a bit more detail.

CHAIRMAN WILSON: Sure, I understand.

WITNESS ROSEN: But, I suspect that it would, although I do find puzzling the -- Mr. Howell's Late-Filed Exhibit No. 1, which he refers to in his rebuttal testimony where he claims that he shows that it's economic to retail ratepayers to sell Scherer 3 as part of these new UPS sales. And I frankly have not been able to thoroughly analyze that study, it being a late-filed exhibit, but I find that extremely puzzling.

CHAIRMAN WILSON: Maybe we'll all find out the answer to that puzzle by the end of this proceeding.

Q (By Mr. Holland) Let me make sure I understand, Mr. Rosen. You did state that the primary basis for recommending Daniel was that it's less than pool capacity and that a primary reason for the basis for disallowing Scherer is that it's more than pool capacity, but you're now saying that the primary basis upon which you base your recommendation is that Scherer 3 is being sold in UPS in future years; is that a fair statement of what you just --

A Well, I'm not changing my position. Obviously, it's stated very clearly, I believe, in my testimony that it's conjuction of both reasons. It's not one or the other, it's both.

Q Okay. And you are puzzled by the fact that it might be in the long-term best interest of the customers to sell Scherer capacity in UPS beginning in 1993, the 63 megawatts?

A I'm surprised. If Mr. Howell's economic study is right, then I'm certainly right that the 63 megawatts of Scherer 3 should not be in rate base now, because if it's not even economical on a present-worth basis between 1993 and 2010, it certainly shouldn't be in rate base now, but the reason I'm puzzled is while it may be true that Mr. Howell's study is correct, it shows that in fact my points about the Gulf Power system being out of balance and that it has too much baseload power and too little peaking, shows that it -- I was even more correct than I thought initially when I wrote my testimony, because it looks like it's way out of balance, if this study is correct.

Q Let's talk about that for a minute because I found that very interesting in your testimony.

You base a lot of your testimony in terms of the mix and whether it was appropriate for Gulf to add baseload in the early '80s on the '84 optimal mix study, Is that correct?

A Well, I point out in my testimony that the '84 optimal mix study was not directly relevant to what was added in the '80s, because unfortunately the Company never asked the question about should the capacity that it was planning to be added in the '80s, should that, in fact, happen, or should it be replaced by peaking capacity. So that the Company, to my, you know, knowledge, never analyzed the issue of the '80s. They always assumed that what they were planning to bring on line in terms of baseload capacity in the '80s would, in fact, come on line, and I state that in my prefiled testimony. So the optimal mix study really went to the issue of what should be added after the '80s.

Q And, in fact, what should be added in the late '90s and into the year 2015, is that correct?

A Yeah, but I think the results of the study are an indicator of, in fact, what should have happened in the '80s that did not happen. I mean, I've done a lot of generation planning studies, as you may be aware, and while it's true that changes in fuel prices and whatever can change the optimal mix in a system, for a system like Gulf Power, I tend to think it wouldn't change it very much between the mid '80s and the mid '90s. So I think what the Company itself showed would probably be true for the mid '90s probably would have been more optimal in mid '80s as well.

Q Is it your testimony then that the prudent or advisable course of action for Gulf Power Company in the early '80s, late '70s, early '80s, would have been to have added combustion turbine units?

A I'm saying that continuing to add only baseload units was a risky -- was a high-risk strategy.

Q And are you familiar with the Fuel Use Act?

A Yes, I'm very familiar with the Fuel Use Act.

Q Are you familiar with this Commission's position in the -- during the '80s, relative to the construction of combustion turbines?

A No, I'm afraid I'm not familiar with this Commission's position on that issue.

Q Would you agree that the reserve margin that has been calculated, I think Mr. Parsons was at 25.5 and you were at 25.4 with the 63 megawatts does not take into account pool capacity sales, it's not a levelized reserve margin?

A I'm sorry. Could you repeat the question, I didn't hear it all?

Q Yes, I can.

The reserve margin which you've calculated of 25.5% is not a levelized reserve margin, does not take into account pool capacity sales.

A You mean sales due to the capacity equalization provisions of the pool agreement?

Q Right. Exactly.

A That's correct, but it wasn't supposed to.

Q If these sales are, in fact, being made to the pool, would it not make sense to look at the levelized?

A I do discuss that in my testimony. I point out that in July and August of 1990 over 100 megawatts will be sold from the Gulf system to the pool, so I acknowledged that situation.

Q And would you agree that if you do levelize and you do take into account that hundred or so megawatts that's being sold, that Gulf's levelized reserves are below 20%?

A That's part of the whole point. It shows that there is at least 100 megawatts of access on the Gulf system, even relative to pool agreement, which itself, only equalizes capacity at whatever the pool average is. It doesn't say what an adequate reserve margin is.

Q Okay.

A Those are two totally separate issues.

Q Well, they are and they aren't.

This Commission has used a 20 to 25% reserve margin for planning purposes, has it not?

A Well, I know the Company has used a range with a minimum of 20% but, of course, in practice is only targeting at 16% in terms of investment.

Q In terms of investment for this year, is that correct?

A The Company's long-run plan, as I discuss in my testify, targets 16% over the long run, in terms of actually concretely planning to invest in facilities.

Q Have you read Mr. Parsons rebuttal testimony?

A Yes, I have.

Q Have you or did you seek to determine what the purpose of that 16% reserve margin was?

A Well, I think we also discussed it in your offices and I mean I believe I understand that it's a cautious approach to planning, but perhaps I'm not getting the gist of your question.

Q Well, let me ask you this: Is it not somewhat based on a concern about the treatment that regulators might give to capacity additions in the future?

A I don't remember Mr. Parsons saying that. Perhaps I read the rebuttal testimony too quickly, but I'm afraid I don't remember that.

Q Are you aware that since Gulf's last rate case in 1984, it has increased the capacity of its existing units by 55 megawatts, largely as a result of Gulf's participation in this Commission's GPIF program?

A Yes, I am.

Q Would you agree that this program has actually increased Gulf's reserve in 1990 by about 3.1%, subject to check?

A That's about right, yes.

Q Should we follow your logic and penalize or disallow that amount that Gulf has increased its reserves as a result of its participation in this program?

A No. Because my logic does not focus, strictly speaking, just on capacity. It focuses on the combination of certain amounts of capacity on the system as well as the economics of having that capacity. In fact, I think Mr. Howell agrees with that point because I believe in his rebuttal testimony he also said that, or perhaps it was in a data response.

I believe he said that one could invest in more than adequate reserves if it was economical to do so and that's my position, too. And the flip side of it is if it is not economical to have those excess reserves then ratepayers shouldn't necessarily have to pay for them.

Q Okay. We're back to the economics and measuring the economics and the benchmark against which we're comparing it then as to pool capacity?

A No. It's not just the pool capacity. It's whatever the alternatives are. If off-system sales outside the pool were an alternative you'd have to take those costs and benefits into account. If -- whatever the alternatives are would be part of what goes into evaluation of the excess capacity.

Q Okay. Then I have to assure that a determination made at the time of the investment, in this case in 1984, where all the studies showed that investment in Plant Daniel was the most economical alternative to meet the long-term best interest of Gulf's customers, should be ignored by this Commission, should not be taken into consideration?

A It should not have much weight for the following reason: That there are many decision points between 1984 and the current date where the Company could have made decisions, either the same or different, from what it did in terms of selling the capacity off system or not.

Now, again, the Company chose to sell it off system. That agreement collapsed. It seems to me perfectly appropriate for the Company to collect through the courts and not through the ratepayers in this case.

Q Let me make sure I understand that. Gulf Power Company -- is there any disagreement as to Gulf's intent, its rationale, its reason for investing in Plant Scherer? You disagree that the original intent and the long-term intent was to do that which was in the long-term best interest of its ratepayers and provide them with the lowest cost capacity available.

A I don't question the intent of the Company, but I also have not validated the Company's assumption that Scherer 3 was the best option to purchase at the time. I haven't made a detailed study of that issue.

Q Nor have you reviewed the Commission's orders with respect to its review of the wisdom or prudency of that decision?

A That's correct, I've reviewed the Company's planning studies going back to the early '80s.

Q So, it's your testimony that if Gulf made the right decision, the original intent was to provide for the long-term best interest of its ratepayers, but because of intervening circumstances with respect to the default by Gulf States or load forecast or whatever, for any reason this Commission should or could disallow capacity from Plant Scherer that it deemed to be excessive?

A It could disallow the capacity, yes. I think you have to look at all the relevant evidence.

Q Wait just one second. (Pause) Mr. Rosen, on Page 13 --

CHAIRMAN WILSON: Can I ask a question that just occurred to me?

MR. HOLLAND: Yes.

CHAIRMAN WILSON: Is it your testimony that an appropriate capacity reserve margin is 15 to 18% or I thought I heard you earlier say something about in excess of 25%. What is --

WITNESS ROSEN: No. I think earlier I was referring to a question the Company asked -- that the Company used a range of 20 to 25%, but that's not what I feel is appropriate.

CHAIRMAN WILSON: What is your opinion?

WITNESS ROSEN: Well, as the testimony says, I believe that because of the excellent availability of the Southern Company units, which the Company states is

89% availability on average, that probably as low as 15% would be appropriate, because other utility systems that I've examined such as the American Electric Power System, their own internal criteria for adequate capacity on their system is about 17% and they have average availability far lower than the Southern Company. There's is, I think about only 77 - 78, so there's over 10 percentage points lower availability on the AP system, and that would translate into at least 2 or 3%. In fact, probably more of a reduction on, you know, an adequate reserve margin.

CHAIRMAN WILSON: Does the growth rate in population or in consumption in the state, or capacity demand in a state influence -- would that influence your opinion about adequate capacity reserves?

WITNESS ROSEN: Well, I would make a distinction between sort of a snapshot; you know, right now, this year, what's adequate and what you have just introduced, which is what I'd call the need for a planning reserve margin, that would be somewhat a function of growth rate. So I'd say yes, a planning reserve margin should take growth rate into account. And that's why I said that while 15 might be perfectly adequate, if you're taking a snapshot instantaneously of the system that you might go as high as say 18 because of fairly significant growth rates.

CHAIRMAN WILSON: In a growth state like Florida, would you consider 15% to be adequate?

WITNESS ROSEN: I would say that for planning purposes, no, that I would go up to about 18 for a system like Gulf.

Now, if there's another -- I mean the Gulf system is not growing all that fast. It's only in the 2 to 3% a year range. Other systems may grow faster and you might need to go above 18. But for Gulf, I feel 18 would be an upper limit given the high availability of the Southern Company plants.

CHAIRMAN WILSON: 18 would be an upper limit for an adequate reserve?

WITNESS ROSEN: For a planning reserve margin. 15 would be adequate instantaneously, I believe.

CHAIRMAN WILSON: What would be an ample or appropriate reserve? Are you saying that the one that is just barely adequate is the appropriate one or do you make that kind of distinction?

WITNESS ROSEN: Well again, I would distinguish between the short run, the snapshot and the planning reserve for the long run.

I'd say that -- I mean the issue isn't so much between adequate and ample in terms of a snapshot but the issue is more between what's adequate this year and what's reasonable for long-run planning purposes. That's the dichotomy I see.

CHAIRMAN WILSON: What's the basis of your opinion that 15% would be adequate? How do you arrive at that?

WITNESS ROSEN: Well, I just gave one example. The AEP system has done a lot of analysis of its units. It defines adequate reserves as up to 90 negative days per year, which means reliance on outside assistance from other systems, and it's not -- obviously, it's the opposite of extreme from the loss of load probability. And, you know, they meet that at around 17% with a far higher outage rate for their units. So, in fact, probably below 14 would be okay for the Southern Company. But I also base it on there's a whole series of reports that the Southern Company and Gulf Power has done for the reliability of its own system and there are, in fact, some recent discovery responses on this issue. I believe Staff discovery responses where the Staff asked the Company to analyze system reliability at different levels of reserves, and a review of all that material convinces me that the Southern Company System would have adequate loss of load by their own definition or adequate reliability by their own definition, which is EUE. It's basically an energy outage rate. Add 15. So I've reviewed the Southern Company's studies, I've reviewed reliability studies from many other systems. We've done many of them in our offices. I mean, that's the basis of my conclusion.

CHAIRMAN WILSON: To what extent would the presence of substantial amounts of cogeneration on a system affect your opinion of what capacity adequate reserve would be, adequate capacity reserve would be?

WITNESS ROSEN: Well, cogeneration I think can have a couple of possible effects. Often cogeneration stands for units, you know, measured in megawatts that are sort of below the average size of utility plants. So maybe the average cogenerator is 10 or 50 megawatts, whereas the average utility plant might be several 100 megawatts.

If a cogenerator is on average or below the average size, then they enhance the reliability of the system. To enhance the reliability of a utility system you want a lot of little units, okay and, in fact, you want a lot of little units scattered around the transmission system as well, because that enhances transmission reliability as well as generation reliability. And in particular then you have to look also at the forced outage rates of the cogenerators, and at least in the northeast that I'm most familiar with, Most cogenerators, in fact, have lower forced outage rates than the utilities. Now, for the Southern Company System, their outage rates are so good that that might not be true. So if we hypothesize that the average cogenerator might have about the same outage characteristics as the utility, but have smaller plants in size, then they probably benefit the system so that you could go with a lower required reserve margin.

CHAIRMAN WILSON: What about independent power producers, larger units, 2, 300, 400 megawatts?

WITNESS ROSEN: Again, the rough first order demarcation mark is to compare the average size of your independent power producers to the average size of your utility-owned unit. If the average size of IPPs is lower, then reliability is relatively better. If it's bigger, than it's worse. It's not a simple mathematical formula.

CHAIRMAN WILSON: What about the relative contribution or percentage that either cogeneration or independent power producers bear to your total capacity requirements on peak? If you had a capacity requirement of 10,000 megawatts and 2000 megawatts of those were represented by independent power producers or cogenerators, what would you say, would you say that would affect reserve margin?

A No, I mean I don't think the percent of share of independence on a system necessarily affects the reserve margin. The real question is the reliability of those units and their average size.

CHAIRMAN WILSON: Would whether they are dispatchable or not by the utility have some effect?

WITNESS ROSEN: Yes. But the dispatchability again affects more the cost, or the value of having them on the system than the reliability of the system, because the utility knows which ones are dispatchable and which ones aren't and dispatches its plants accordingly. So I don't think that directly impacts system reliability. I mean, for instance, the state of Maine has probably more than 20% of its power now being provided by independent power producers. Now, of course, the state of Maine has a lot lower capacity in total, but it's more than 20% and, of course, it's all dispatched by NEPOOL and there is certainly no problem. In fact, I believe that most people would agree that the IPPs and QFs enhance system reliability.

CHAIRMAN WILSON: If you had a system where 10% of your capacity were IPP and your capacity reserve margin were 15%, in fact, isn't the system in the position where the independent power processers control the reserve margin?

WITNESS ROSEN: Well, in some sense, yes. But the question is what's the risk of them actually going off line? I mean, that, to me, is the key question.

CHAIRMAN WILSON: Well, that is the key question, yeah.

WITNESS ROSEN: And then if you're aware of conditions where they might all go off line for some reason and they actually have the choice in doing so, you know, obviously, then it directly affects the reserve margin quite considerably.

CHAIRMAN WILSON: In that situation you would need a higher reserve margin than 15%?

WITNESS ROSEN: Yeah. If there were conditions under which they might all go off line, certainly. But that's no different from a utility system where you have one major unit that has a poor outage rate that's also 10% of load and it might go off during peak.

So, I mean, one of the advantages, it seems to me, of The Southern Company in this case is that it's such a large well-interconnectd system that system reliability is, you know, excellent. So I don't see inpendence as being much of an issue for Gulf; perhaps for other Florida companies. In other Florida companies, it may have --

CHAIRMAN WILSON: Whenever I have a witness that I can ask a question that I have a little curiosity about, I just go ahead and do it whether it's relevent or not. I apologize for bringing that in, and I thank you for your indulgence.

WITNESS ROSEN: No problem.

CHAIRMAN WILSON: Would you like to resume?

Q (By Mr. Holland) Mr. Rosen, with respect to the availability, and I know the management appreciates your opinion relative to the high availability of their units. It would be two factors, would it not: One, that management has taken those steps necessary to make sure the units stay on line, and the other would be the pool that you talked about and the ability to share reserve?

A Yeah. Those are definitely two positive factors.

Q Okay. Have you reviewed the study that the consultant for the Public Service Commission issued, I believe in 1986?

A I don't believe so, no.

Q Relative to capacity planning, forecasting and reserve level?

A No. It doesn't ring a bell.

Q Have you done any studies of your own relative to a determination as to the appropriateness of the the 20 to 25% versus some other reserve level?

A Well, I described why I believe 20 to 25% for Gulf Power is far too high.

Q But have you done any kind of in-depth, you know, analysis, other than what you've seen? You've not done a study, have you?

A Not specific to Gulf Power, but I have done them specifically to many other utility systems, and Gulf Power is not particularly different. I mean, it's a strongly coal-based system, and I have analyzed many other coal-based systems.

Q What might be appropriate, though, for one system might not be appropriate for another?

A No. I disagree strongly. Most utility systems are actually quite similar when you actually look at the reliability, if they're large enough. And when you get to a system as large as the Southern Company, then it's more a matter of what the average outage rate looks like or the average availability is than the details of the system.

Q Are you familiar with the brownouts that occurred in South Florida during the winter of '89?

A I have heard about them through the news media, yes.

COMMISSIONER GUNTER: Brownouts?

MR. HOLLAND: Blackouts, I'm sorry, wrong color.

COMMISSIONER GUNTER: I was going to give you a color lesson.

MR. HOLLAND: Usually when I do something like that, I get a poke from behind.

COMMISSIONER BEARD: Remember, when you get hit in the face, it's a black eye, not a brown eye.

MR. HOLLAND: Okay.

Q (By Mr. Holland) Are you familiar with those?

A Yes, I am.

Q Do you know what the reserve margin was for the South Florida utilities at the time that occurred?

A No. I'm not aware of what it was.

Q Mr. Rosen, on Page 13 of your testimony, have you got that?

A Yes.

Q On Lines 5 through 7, you state that Goat Rock was a planned pump storage hydrofacility. Do you have any evidence to support the statement that the

Southern Company ever planned to construct a pump storage hydroplant at Goat Rock?

A Well, obviously, if you feel that I have mischaracterized Goat Rock, I would have to check back in the report that I'm referring to. I could have made an error. I thought I didn't so --

Q You're not sure whether Goat Rock was ever a --

A No. I'd have to check it, now that you've raised the question about it.

Q Mr. Rosen, I want to ask you a few questions now relative to your test year sales forecast. You would agree, would you not, that the forecast methods employed by an electric utility have a significant impact on the accuracy of the forecast results?

A Yes.

Q And you would agree also, I believe, that in drawing conclusions regarding the accuracy of Gulf Power's 1990 test year forecast, it's appropriate to evaluate the Company's historical accuracy over a period during which the same basic models and techniques were used that produced the test year forecast?

A Well, they're certainly relevant, yes, of course.

Q What is your assessment of the basic approach in models used by Gulf Power Company as they're described in Mr. Kilgore's testimony?

A The basic assessment of the forecast models?

Q Yes. Is the methodology appropriate, I guess is what I'm asking for.

A The general methodology is appropriate in the following sense: That there's a separate model used for the residential sector and the commercial sector forecast. And then I believe the industrial sector is handled on a more ad hoc basis. And, frankly, while we've reviewed the residential and commercial forecast methodology somewhat, we've not been able to spend much time reviewing the basis for the industrial forecast, so I can't comment on that very significantly.

Q Mr. Rosen, on exhibit -- I'm not sure what number it is -- it's your Schedule 1, Sheet 9 of 13, you reference a report that you made in May of '84 regarding power planning in Kentucky, assessing uses and choices, project summary. Are you familiar with that report?

A I was six years ago.

Q Do you recall what your recommendations were to that Commission concerning the forecast methods which you felt that Kentucky utilities should use?

A I, frankly, can't remember at the current time.

Q Well, let me show it to you. (Copies of document distributed.)

MR. HOLLAND: Commissioner Gunter, I would like to get a number, if I could.

MR. VANDIVER: 608.

COMMISSIONER GUNTER: Let me find it.

COMMISSIONER GUNTER: All right. We'll identify it as "Power Planning in kentucky, Assessing Issues and Choices." It will be identified as Exhibit No. 608.

(Exhibit No. 608 marked for identification)

Q (By Mr. Holland) Mr. Rosen, are you familiar with this document?

A Yes. I'm familiar with it.

Q Was it prepared, or were you the project manager for this project?

A Yes. I was.

Q You would agree, would you not, that the methodology which you described in this document, and that is a disaggregated end-use methodology, is essentially the same one being used by Gulf Power Company?

A Well, at that general descriptive level, yes, there are a lot of similarities, definitely.

Q What would you consider to be an acceptable level of forecast error for growth and retail base rate revenues, expressed in terms of percentages?

A When you say "acceptable," you mean acceptable for what purposes?

Q Margin of error in terms you could determine as reasonableness, looking back?

A Looking back historically?

Q To judge the appropriateness of it.

A I wouldn't necessarily judge the appropriateness of a methodology just by forecast error, particularly. I mean, I think that's just one of many considerations.

Q But that is a primary basis upon which you base your recommendation here, is it not?

A Well, yeah. I think it's important, particularly when you're looking just one year ahead to look at the track record, in the past, of forecast error for accuracy.

Q Did you propose an adjustment to Gulf Power's 1989 test year rate base revenues in the prior rate case, Docket 881167-EI?

A Yes.

Q Would you agree that your adjustment and result of test year revenues were made with the benefit of the several months of actual data for 1989, almost a full year after Gulf Power forecasted?

A Yes.

Q Did you review the results of your test year adjustment in Docket No. 881167-EI, and compare them with the accuracy of the Company's forecast?

A I didn't personally. I saw reference to it in Mr. Kilgore's rebuttal testimony, but I have not reviewed the numbers.

Q Would you agree, subject to check, that your test year retail base revenue growth component was 2,401,822, or 22% greater than the actual?

A That could be, I'd have to check that.

Q And that the error of Gulf Power was $1,175,790, or about --

A Did you say dollars or are you reading gigawatt hours.

Q Dollars.

A I would have to check those figures.

Q Assuming for purposes of the question that your margin of error was 22.6% compared to Gulf's error of 11.1%, or a difference of approximately 104%, does that in any way indicate to you the accuracy of the methodology which you're proposing?

A I wasn't proposing a different forecast methodology, I was just --

Q The appropriateness --

A -- Proposing an adjustment, yes.

COMMISSIONER GUNTER: One at the time, gentlemen; question and answer, don't override one another.

A In fact, what I'm proposing in this case is that the Commission, in setting rates, rely on the Company's forecast methodology. In fact, I'm saying rely on the Company's long run forecast over the next few years -- I shouldn't say "long run," -- but medium-run forecast produced by the Company's model but not just rely on the one downward dip in the forecast and then it comes back up from the 124 gigawatt hour increase to the 204 gigawatt hour increase. I'm saying rely on the medium-term forecasts produced by the Company and its methodology.

Q But you are making a proposed adjustment just as you did in the '89 case, is that correct?

A Yes, that's correct.

Q Based on the same type analysis here?

A Yes. But it's not based on a criticism of the Company's methodology in the medium term. It's based on the fact that since there's this downward blip in the forecast that -- you know, I don't want to attribute bad motives to the Company, but, I mean, it's a little suspicious just when a rate case comes up.

So I think it's probably better policy, unless one knows that there's going to be a rate case in each year into the future, that the Commission rely on a somewhat longer term forecast; namely, the Company's medium-term forecast.

Q Are you aware of the Company's results through March, April, in terms of its forecast accuracy, whether revenues are above or below?

A No, I haven't seen the data as through April yet, no.

Q Would it influence you at all to know that base rate revenues through April are 5.8% below that forecast?

A It's certainly relevant, yes. I'd have to analyze it and look at the reason.

Q You would agree, would you not, that to the extent we have actual data, just as you used in 1989, that we ought to make use of it in terms of trying to make the appropriate decision?

A Absolutely. One should use as much data as possible.

Q Mr. Rosen, refer back to what has been marked as Exhibit 608. If you would, turn to Page 1. Do you have that?

A Yes.

Q In the middle of the first paragraph with reference to Case No. 8666, would you agree that the purpose of this docket and ultimately your study that you performed was an investigation into alternative load forecasting methods and planning considerations for the efficient provision of electric generation and transmission facilities?

A Yes.

Q And that as part of that project, you looked at a number of areas of utility planning, including conservatic.. as a planning option?

A Yes.

Q Would you also agree and specifically with reference to Page 3 and 4, at the bottom of that page, that as part of the forecasting methodology that you recommended that you deemed it appropriate that up-to-date information be obtained for purposes of the load forecast, including "employment forecasts by category of business; housing construction trends by type, size, thermal integrity level, and space conditioning source; and inventories of residential and commercial electricy-consuming equipment by appliance type and unit energy consumption"?

A Yes.

Q On Page 4, in terms of forecasting recommendations, you -- in Recommendation 2, there, you recommended that customer surveys and statistical analysis be performed relative to employment projections, equipment and building inventories, is that accurate?

A That's correct, yes, sir.

Q And on Page 6, in terms of your findings with respect to conservation planning in Kentucky, you deemed it appropriate that the companies which you surveyed and made recommendations with respect to, that they provide energy audits of residential premises outside the framework of the residential conservation service. And in finding 9 -- let's go over to Page 7, Recommendation 8, you stated that "additional conservation was appropriate and that the initial phase of the new conservation program might include enhanced audit and information services, incentive to promote penetration of high-efficiency equipment, incentives to promote weatherization of structures, incentive to conserve hot water" --

MR. BURGESS: Excuse me. Is this directed towards his testimony on the forecast of --

MR. HOLLAND: Yes.

MR. BURGESS: -- of the sale?

MR. HOLLAND: Yes.

MR. BURGESS: Excuse me. I'm sorry for the interruption.

Q (By Mr. Holland) On Page 45, Mr. Rosen.

A Yes.

Q Again there, I think you were speaking with respect to the art of forecasting, and that it involves the endeavor to reduce uncertainty, and that one way to do that is in the building sector, houses, apartments, et cetera, you model energy consumption by major end-user type of consumption, as well as by major building type and the manufacturing sector, separate industries are considered, and you classify those?

A That's correct.

Q On Page 47, under 5.5, specifically No. 3, you state that "for large customers, which may represent a significant fraction of the Utility's sales, customer-specific information is frequently relied on." Is that correct?

A That's correct.

Q Then on Page 50, specifically No. 4, the third sentence, begins, "The use of end-use disaggregated procedures." There you state that for purposes of forecasting that it would be appropriate to produce more reliable and useful forecasts than result from employing time-trend methods or aggregate econometric methods; for you to look at "Residential sales, electric space heating and other fuel-competitive end-uses of electricity such as water heating and cooking; new housing types, sizes and insulation levels, and the further insulation of existing dwellings; and efficiency improvements in heat pumps and other appliances."

And I won't read them, but on the next page, No. 8, you indicate that residential appliance saturations surveys should be conducted; No. 9, that residential housing construction trends should be monitored and data collected on types and sizes; that with respect to No. 10, to commercial customers, that you should maintain data on them as well with respect to their use of electricity and characteristics; and in No. 11, with respect to industrial sales, that it would be appropriate to supplement systematic forecasting methodology with customer contacts to help establish judgmental assumptions regarding load growth for specific companies and that these estimations should be discussed with the customer. Is that accurate?

A Yes, it is.

COMMISSIONER GUNTER: How many more of these we going to read?

MR. HOLLAND: That's it. That's it.

Q (By Mr. Holland) With respect to the study which you performed, Mr. Rosen, is it fair to state that with respect to both forecasting methodology, least cost planning, et cetera, that it is important to have contact with and obtain information from, participate in the decision-making process of a customer?

A I believe so, yes.

Q Would it be your testimony then that the customer does not expect and that it is not in the best interest of the customer that the Utility simply provide electricity to the meter?

MR. BURGESS: Excuse me. I thought this had to do with the question on sales forecast.

MR. HOLLAND: That's fine. I'll save it for Mr. Schultz. I withdraw the question.

MR. BURGESS: Okay, then I'm afraid I have got an objection to the previous entire line of questioning if it didn't have to do with forecasts.

MR. HOLLAND: It did have to do with forecast.

MR. BURGESS: It seems to me he's asked beyond the bounds of this witness' testimony into the testimony of -- for the purpose of dealing with other issues, issues to which this witness doesn't testify.

MR. HOLLAND: Commissioner Gunter, this exhibit was performed by Mr. Rosen. It is specifically related to forecasting methodologies and a judgment of the forecasting methodologies used by the Kentucky Commission. That's the purpose for which I've asked -- I withdrew the question with respect to the other area. I don't think that would preclude me from asking that question of Mr. Schultz, who does testify directly with respect to what utilities should be involved in with respect to their customers.

MR. BURGESS: I understand that. I just think it's clear the questions weren't being asked for the purpose of dealing with the forecasts.

COMMISSIONER GUNTER: Well, that's what the questions dealt with though, and out of an '84 study, I had already put it away, the '84 study, because I knew Mr. Holland was going to read it for me. So I didn't need to look at it. So I'm going to overrule the objection.

MR. HOLLAND: That's all I have.

COMMISSIONER GUNTER: Staff?

CROSS EXAMINATION

BY MR. PALECKI:

Q We have just a couple of questions about Plant Scherer.

Dr. Rosen, the 63 megawatts being sold, or the 63 megawatts which are in contention here as being sold in increments, until 1995, when all 63 megawatts will be sold as unit power sales, how would you feel if the Commission implemented an incremental phase out of the 63 megawatts from rate base to the point that in 1995 it was not included at all in rate base?

A Well, are you saying how would I feel if that were done as opposed to in test year 1990 eliminating?

Q Yes. What is your opinion?

A Well, my opinion is that, of course, when Sherer is not being used to serve retail customers, it can't be in rate base. There would be no logic to it, but I don't see how phasing out in the future is, you know, directly relevant to my proposal for how to deal with this test year 1990. I mean, maybe I'm missing some aspect of your question.

Q Well, the testimony that's come forth from Gulf is that the 63 megawatts has been used. It has -- even since the Gulf States default, that they have used this power and that, therefore, it is used and useful, it is something that is being used by their territorial customer. Your testimony is that the power is not needed. How does that -- how does that -- how do you resolve the conflict between the two positions?

A I don't think there is any conflict. In my view, it's certainly true that the plant is being used, but it's not used and useful. Useful relates to the whole, you know, picture of whether the power is economical and if the plant will be available under a reasonable time frame during which it will be economical.

So if it's not economical in 1990, which I think Mr. Howell and I agree on according to his rebuttal testimony, then the question is. "Is it economical over a long enough period of time for ratepayers that it deserves to be in rates during 1990? And my answer is, no. So, I don't see that there is any conflict between the plant being used and it being used and useful.

Q So your testimony would be that it's not economical in 1990 and, therefore, any sort of phase-out of the 63 megawatts would not be the appropriate treatment?

A No. My position would be the plant will have to be phased-out of a rate base when it's not even being used to serve retail ratepayers, but even now when it's used for them, it's not used and useful for them.

MR. PALECKI: Thank you.

COMMISSIONER BEARD: Is that it?

MR. PALECKI: We have no further questions.

MR. BURGESS: I have no redirect.

COMMISSIONER BEARD: That's it. We need -- we don't have any exhibits.

MR. BURGESS: They have been stipulated into the record.

COMMISSIONER BEARD: Okay. Let's take a five-minute break.

(Recess)

MR. BURGESS: Mr. Schultz, have you been sworn?

MR. SCHULTZ: Yes, I have.

HELMUTH SCHULTZ, III

appeared as a witness on behalf of the Citizens of the State of Florida, and after being first duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. BURGESS:

Q Would you please state your name and address?

A My name is Helmuth Schultz, III, my address is Larkin and Associates, 15728 Farmington Road, Lavonia, Michigan.

Q Do your friends call you Helmuth?

A Sometimes.

Q Have you prefiled testimony in this docket?

A Yes. I have.

Q Do you have any correction that you need to make to the testimony as prefiled?

A I have a few minor corrections.

Q Would you go ahead and please proceed with the corrections.

A In the testimony itself, I have made corrections on Page 19, Line 2, the amount should be $4,615,532. On Line 4, the amount should be $724,468. On Line 8, the amount should be $4,602,000. On Line 10, the amount should be $738,000. And on Line 12, the amount should be $724,468.

On Page 48, Line 16, there's two percentages in there, they both should say 37.17%.

COMMISSIONER EASLEY: Line 16?

WITNESS SCHULTZ: That's correct.

COMMISSIONER EASLEY: 37?

WITNESS SCHULTZ: 17.

On Page 59, Line 17 should read, the amount should be, $833,914. On Line 18 --

MR. BURGESS: I'm sorry, you'll need to slow down, some people are trying to catch up.

MR. HOLLAND: Could you start over on this page, and what page you're on?

WITNESS SCHULTZ: Page 59.

CHAIRMAN WILSON: Would you state your name for the record (Laughter).

WITNESS SCHULTZ: On Page 59, Line 17, the amount should be $833,914. On Line 18, the amount should be $275,086.

Page 66, Line 11, the amount should be $425,474.

I believe that's the corrections to my testimony. And I have made corrections on Exhibits 1, 2, 5, and 11.

MR. BURGESS: Mr. Chairman, we have handed out the corrected pages of the exhibits. We have provided a record copy with the corrections for the court reporter of both the testimony and the exhibits.

Q (By Mr. Burgess) Mr. Schultz, after noting the corrections that you have just presented to the Commission, if the questions posed in your prefiled testimony were asked today, would your answers be the same?

A Yes, they would.

MR. BURGESS: Mr. Chairman, we would ask that Mr. Schultz' testimony be entered into the record as though read.

CHAIRMAN WILSON: Without objection it will be so entered into the record.

MR. BURGESS: Thank you. And we would note that Mr. Schultz' exhibits have been previously identified as Exhibits 300 through 317, and have been stipulated into the record.

(Exhibits Nos. 300 through 317, inclusive, stipulated into evidence.)

DIRECT TESTIMONY OF HELMUTH W. SCHULTZ, III

ON BEHALF OF THE CITIZENS OF FLORIDA

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

GULF POWER COMPANY

DOCKET NO. 891345-EI

I. INTRODUCTION

Q. WHAT IS YOUR NAME, OCCUPATION AND BUSINESS ADDRESS?

A. I am Helmuth W. Schultz III, a Certified Public Accountant, registered in the State of Michigan. I am a partner in the firm of Larkin & Associates, Certified Public Accountants, registered in Michigan, with offices at 15728 Farmington Road, Livonia, Michigan 48154.

Q. HAVE YOU PREPARED AN APPENDIX WHICH DESCRIBES YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. I have attached Appendix I which is a summary of my experience and qualifications.

Q. HAVE YOU PREPARED ANY SCHEDULES SUPPORTING THE RECOMMENDATIONS MADE IN YOUR TESTIMONY?

A. Yes. I have prepared OPC Exhibits 300 (HWS-1) through Exhibit 316 (HWS-15). These are attached to this testimony and were prepared by me or under my direct supervision.

II. OPERATING INCOME

Q. HAVE YOU PREPARED A SCHEDULE WHICH SUMMARIZES YOUR RECOMMENDED ADJUSTMENTS TO OPERATING INCOME AND EXPENSE?

A. Yes. OPC Exhibit 300 (HWS-1) presents adjusted net operating income. It starts with the Company's "per book" figures and reflects each step of the adjustment process.

I am also sponsoring OPC Exhibit 301 (HWS-2) which summarizes my recommended adjustments to test-year operating expenses.

Budgeting Process

Q. MR. SCHULTZ, HAVE YOU REVIEWED THE COMPANY'S 1990 OPERATIONS AND MAINTENANCE EXPENSE BUDGET WHICH IS INCLUDED IN THE TEST YEAR FOR THIS FILING?

A. Yes, I have.

Q. ARE YOU FAMILIAR WITH HOW THIS EXPENSE BUDGET WAS DEVELOPED?

A. Yes. I have reviewed the budgeting process employed by the Company.

In general, the operations and maintenance budget begins with the issuing of a budget message. This budget message provides a budget schedule, and the parameters and assumptions that will be used by the Company in determining the O&M budget. This budget message begins with the Budget Committee establishing the 1990 operations and maintenance budget reference level excluding the direct Energy Conservation Cost Recovery (ECCR) costs, the fuel and purchased power reference levels and the 1990 corporate controlled expenses. The reference level is the 1989 budget, less any nonrecurring expenses, less corporate controlled expenses, less 1989 budgeted personnel additions not added to the complement as of June 30, 1989 and all unapproved vacancies which have not been filled since June 1988. The ECCR costs are budgeted separately. The Company's operations and maintenance budget is divided into 24 in-house planning units, plus units for Plant Daniel, Plant Scherer, and Southern Company Services. Each planning unit is instructed to prepare the 1990 budget at a level which will allow the planning unit to maintain its normal level of operations.

Procedures require all requested expenditures for new or modified activities to be justified on an activity analysis form. This justification is to be in sufficient detail to allow management to make a decision as to whether the new or modified activity should be approved. After the planning units prepare their budgets, the budgets are submitted to the Operations and Maintenance Review Committee for approval. The budgets are then provided to the Budget Committee for final approval.

Q. DO YOU BELIEVE THAT THE PROCESS USED IN PREPARING THE 1990 BUDGET FOLLOWED THE PROCEDURES ESTABLISHED BY THE COMPANY?

A. The Company's procedures appear to have been followed; however, I do not believe the Company's reference levels are properly developed. The reference level for the 1990 budget was to be the 1989 budget, less the following items: non-recurring items, corporate controlled items, 1989 budgeted personnel additions not added to the complement, and vacancies in the complement which have not been authorized to be filled since June 1988. The use of the 1989 budget is my first concern since, in our review of the 1989 budget in Docket No. 88-11667-EI, we discovered that problems existed with its development.

Q. WHAT PROBLEMS WITH THE 1989 BUDGET COULD FLOW INTO THE 1990 BUDGET?

A. The reference level for the 1989 budget was supposed to be the 1988 budget, less nonrecurring and corporate controlled expenses. However, in many instances, the Company's reference level was not the 1988 budget, but an adjusted amount. An attempt was made to trace the approved 1988 budget amount into the 1989 reference level. Even after allowing for nonrecurring and corporate controlled amounts, the 1988 budgeted amounts, as approved, were not used as a reference level for 1989 in 14 of the 21 planning units checked. Examples of differences between the 1988 budget and the 1989 reference level include: (1) the changing of a recurring cost to a nonrecurring cost, (2) shifting other dollars to labor dollars and vice versa, (3) unidentifiable inclusions or exclusions, (4) including items that were not even approved in the 1988 budget, and (5) failure to deduct controlled items that were to be deducted in developing the reference level.

The Company begins its budget process by sending a budget message to its planning units that establishes guidelines and rules to be followed in preparing their budgets. Before the planning units even received the budget message, the Company modified the rules outlined in its message. Of the five modifications that I have previously mentioned, only one was identified in the budget message as being an appropriate modification to the budgeting process. This modification was the shifting of the sales tax expense budgeted in 1988 from a recurring to a nonrecurring item.

While none of the modifications above were noted in the development of the 1990 budget, the 1989 problems are incorporated in the 1990 reference level.

Q. HOW DO THESE MODIFICATIONS IN THE BUDGETING PROCESS AFFECT THE USE OF THE COMPANY'S BUDGET AS THE SOURCE FOR TEST YEAR DATA USED TO ESTABLISH RATES?

A. I believe it lessens the credibility of the Company's budgeting process. In some cases, the modifications are proper and have no adverse effect on the budget. However, in other cases, the modifications do not appear to be proper. I believe the credibility of the budgeting process must be considered, particularly when the budget itself is being used as the test year in determining rates.

Q. MR. SCHULTZ, WHAT WERE SOME SPECIFIC EXAMPLES OF INAPPROPRIATE MODIFICATIONS TO THE 1989 BUDGET PROCESS MADE BY THE COMPANY?

A. The Power Delivery Planning Unit, the Security Planning Unit, and the Public Relations Planning Unit all had labor and other dollars shifting back and forth. For each of these planning units the total dollars remained the same, but there was a shift among the categories without justification. Any shifting of dollars between different cost categories should be justified, otherwise the budget amounts lose their identity.

Unidentifiable adjustments included a deletion of $31,736 from the Central Division budget reference level, and an addition of $32,711 to the Western Division.

It appears that a $4,567 amount for uncollectibles which was included in the Eastern Division should have been excluded. This amount was deducted during the 1988 approval process but somehow was inexplicably included in the reference level for 1989.

It is of concern that the Company's budget process was modified without justification. These modifications, though immaterial in respect to dollars, still have an impact on future budgets and also represent a weakness in the budget process.

Q. DID YOU NOTE OTHER MODIFICATIONS WHICH HAD A CREATER IMPACT?

A. Yes. Proper budgeting procedure requires the planning units to remove controlled costs from the prior year's budget in developing the current year's reference level. Once the current year's budget base (i.e., expenses excluding controlled and/or nonrecurring costs) is determined, the controlled costs are calculated and added to the planning units' budgets. During the 1989 budget review, at least two of the planning units inappropriately included 1988 controlled expenses in their 1989 budgets. One planning unit, Employee Relations, had a material error that has resulted in an overstatement of the reference level.

<u>Employee Relations</u>

Q. PLEASE EXPLAIN THE PROBLEM IN THE EMPLOYEE RELATIONS PLANNING UNIT.

A. The Employee Relations Planning Unit included 1988 controlled expenses in its 1989 reference level budget, specifically, three adjustments to the 1988 budget which were related to employee benefits. Employee benefits in the past, and in 1989, were treated as controlled expenses. Therefore, I believe these items should have been deducted in determining the reference level for 1989. The net impact of these three adjustments was $663,523.

The Employee Relations Planning Unit also failed to remove the full amount of the 1988 controlled costs from its 1989 reference level in two cases. The amount for pensions, which are controlled costs that were deducted in determining the reference level for 1989, was $48,673 less than the 1988 budget amount. For the employee savings plan, the amount deducted in determining the reference level for 1989 was $16,630 less than the 1988 budget amount.

The 1989 reference level for the Employee Relations Planning Unit was, therefore, overstated by a total of $728,826.

In prior years these benefit costs do not appear to have been included in the budget base for employee relations, prior to the addition of nonrecurring or controlled expenses for the current year. For 1989 these costs are included in the budget base, and additional pension and employee savings plan costs have also been added as a controlled expense.

The 1987 operations and maintenance budget was $135,280 in the "other" category. This excluded ECCR, nonrecurring and controlled expenses for employee relations. In 1988 the "other" category budget for employee relations, was $114,534, exclusive of controlled, nonrecurring and ECCR expenses. However, in 1989, exclusive of nonrecurring, controlled and ECCR expenses, the "other" budget amount was $1,102,980.

These employee benefit items, have historically been categorized as controlled expenses in the employee relations 1989 reference level. Unless the Company can justify their inclusion, I recommend that the total amount of 1988 employee benefit costs which have been included in the 1989 reference level and in turn flowed into the 1990 reference level be deducted from the budget as an error in the budgeting process.

Q. HAVE YOU PREPARED A SCHEDULE DETAILING YOUR RECOMMENDED ADJUSTMENT?

A. Yes. The calculation of this adjustment to the Employee Relations Planning Unit budget, totalling $728,826, is shown on OPC Exhibit 302 (HWS-3).

Labor Complement and Payroll Taxes

Q. OTHER THAN THE ITEMS YOU HAVE ALREADY DISCUSSED, ARE THERE ANY OTHER AREAS IN THE BUDGETING PROCESS WHICH ARE OF CONCERN TO YOU?

A. Yes, there are. My first concern is the labor cost budgeted for 1990. The Company has established a complement of employees to be used in the budgeting process. For 1989, this complement was 1,626 employees. Of the 1,626 employees, an estimated 26 vacancies were to be subtracted from the complement in the development of the 1990 labor budget. Even with this reduction in the labor complement, the Company still ended up with 1,625 budgeted positions. This is shown in the listing of 1990 budgeted positions and 1990 budgeted labor by planning unit received from the Company on March 22, 1990 as part of the Production of Copies of Selected Planning Unit 1990 Budget Working Papers. If these budgeted positions are not filled permanently at the beginning of the year, then the labor budget will be overstated and able to absorb budget overruns for other costs the unit incurs.

Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S 1990 LABOR BUDGET?

A. The Company's labor budget is overstated. The Company has projected an increase in the work force. The Company's workforce has remained relatively stable. A review of the labor statistics from prior years indicates that the Company's 1986 budget included 1,573 full-time employees. At the end of 1986, 1,504 positions were filled. On average, during the year 1986, Gulf had 1,471 employees. In 1987, the Company budgeted for 1,588 employees, yet the year-end employment level was only 1,557 and the average for the year was 1,528. In 1988, the Company budgeted for 1,628 positions, yet the year-end number of employees was

1,561 and the average was 1,564.

For 1989, the Company budgeted 1,626 employees, yet the year-end number of employees was only 1,571 and the average was 1,562.

For 1990, the Company budgeted 1,625 employees. According to the February 1990 monthly operating report, 1,567 employees were on hand at month-end. If added properly, the March 1990 monthly operating report shows 1,575 employees. On the March 1990 report, the Company listed a total of 1,615 employees, but adding the detailed positions produces a total of 1,575.

Q. DIDN'T THE COMPANY MAKE AN ADJUSTMENT TO THE LABOR BUDGET TO ELIMINATE THE SALARIES ASSOCIATED WITH THE VACANCIES?

A. The Company did make a $378,417 adjustment for the "hiring lag". This adjustment, however, is inadequate. The Company considered only 38 vacancies, at an average starting salary for newly hired employees, and only for a portion of the year. For this assumption to be reasonable, the Company would be required to maintain a complement of 1,613 employees throughout the remainder of the year. With only 1,567 employees as of February 1990, and the Company's historical tendency to overstate budgeted employee levels, the attainment of that complement does not seem possible.

Q. HAVE YOU CALCULATED AN ADJUSTMENT RELATED TO THE COMPANY'S OPERATING LABOR BUDGET?

A. Yes. As of February 1990, the company's budgeted complement of employees exceeded the actual number by 58. Using an annualized wage rate as of December 31, 1989, I have determined the Company's operating labor budget is overstated by $990,381 after allowing for the Company's hiring lag of $378,417. The calculation of this operating labor expense overstatement appears on OPC Exhibit 303 (HWS-4).

Exhibit 303 (HWS-4) also reflects the related payroll tax expense that is overstated by $78,406 as a result of the Company's overbudgeting of labor dollars. This labor adjustment is conservative since it was calculated using annualized salary amounts which do not include overtime. Additionally, the Company has shown in MFR Schedule C-57, page 87, that its budgeted test-year labor expense has exceeded the Company's calculated benchmark in the areas of steam production and administrative and general, by $1,736,000, cumulatively.

Q. MR. SCHULTZ, ARE THERE ANY OTHER PROBLEMS WITH THE LABOR BUDGETING PROCESS?

A. The Company has a model for determining the budgeted payroll for its planning units; however, some planning units choose not to use this model and, instead, calculate the payroll dollars using their own methods. This does not necessarily mean that calculations performed using methods other than the model are incorrect, but it does show that there is a lack of consistency in the operation of the Company's formal budgeting process.

Q. HAVE YOU FOUND PROBLEMS WITH THE BUDGETING PROCESS RELATED TO "OTHER" DOLLARS?

A. Yes. Although inconsistent methods among planning units are used in developing the labor budget, the Company does attempt to verify the total labor budget amount by checking calculations either within the units or by using the model. It appears however, that a similar verification of the total cost budgeted in the "other" category is not performed. In addition, some of the reference levels themselves for the "other" category are questionable.

Q. PLEASE EXPLAIN.

A. The Company's reference level is theoretically the 1989 approved budget. Any additions or adjustments to the reference level should be justified on the Company's "B4" Forms. Therefore, if the Company happens to be over or under the budget which had been established at a certain level in the prior year, the reference level could remain unadjusted and would not reflect any over or under budgeting in the prior year. An example of an item that could affect the budget reference level would be a variance in the budgeted and actual inflation rates. Over the years, this variance could become significant.

A review of the Company's budgeting process and the budgeting forms indicate that in compiling the 1990 budget, adjustments increasing the reference level were predominant while few adjustments were made decreasing the reference level. The adjustments were for projected expansions of current programs or expenses, new programs, inflation and some reductions of program costs. Few, if any, adjustments to the reference level were attributable to a variance in the prior year budget-to-actual comparison. There does not seem to be any summary available that details total expenses by type and reconciles them back to the budget amount. For example, the labor budget was developed using a reference level plus adjustments. It appeared to be supported by a calculation of the total labor costs through the model or through a calculation performed within the planning unit on its own. In contrast, in the category for other costs budgeted, the Company begins with the reference level and, in most cases, appear only to justify the changes. Except for Plant Crist, only portions of the necessary documentation were provided to us in support of total budget costs in the "other" category.

Q. PLEASE GIVE AN EXAMPLE OF A QUESTIONABLE REFERENCE LEVEL.

A. A good example of a questionable reference level involves the Employee Relations Planning Unit which was discussed previously. In the 1988 budget, the "other" category budget amount was $114,534. When sent for approval, this amount was reduced by $49,479. This reduction left $65,055 as the approved amount in the 1988 budget for the "other" category. According to the Company's "budget message" instructions for the budgeting process, this $65,055 amount should have been the reference level for employee relations for the 1989 budget. The Company's "B3" forms, which identify the reference level and adjustments, show a 1990 reference level amount of $793,881. The Company's "B4" forms, are supposed to be used to substantiate adjustments to the reference levels. The "B4" forms show the 1989 reference level amount for the Employee Relations Planning Unit to be $428,645. This is for the portion of the reference level being adjusted alone. It therefore appears the Company increased the reference level by <u>at least</u> $363,590 without any justification, and this increase is carried forward to 1990.

The Company's budget procedures require the planning unit to justify changes in this year's budget over last year's budget. However, the planning units are not required to rejustify their prior year's budget level. Rather, the prior year's budget, which is an accumulation of programs or costs, some of which may no longer exist, is merely carried forward.

Q. PLEASE CONTINUE IN YOUR DISCUSSION OF THE BUDGETING PROCESS.

A. The next area to be discussed is the corporate controlled items included in the budgeting process, and I used the term "control" loosely. It is my understanding that corporate controlled items are those costs allocated to the various planning units for which the planning units are not to be held accountable. The underlying assumption is that these are costs that cannot be controlled by the planning units themselves. These are costs that either are not normal or recurring or costs that must be determined in total for the Company, as opposed to being determined individually by the planning units.

Q. PLEASE DISCUSS THE SPECIFIC CORPORATE CONTROLLED COSTS INCLUDED IN THE 1990 BUDGET.

A. These items are discussed in the following sections of testimony.

Turbine & Boiler Inspections

Q. IS THE 1990 BUDGETED TEST YEAR AMOUNT FOR TURBINE AND BOILER INSPECTIONS REASONABLE?

A. No, it is not. The Company has budgeted $5,340,000 for turbine and boiler inspections in 1990.

These inspections follow a cyclical pattern. In some years, expenses will be at relatively low levels; in others, periodic maintenance and inspection expense will be higher. Therefore, expenses incurred in one year will not necessarily be representative of what will occur in the following year.

Q. ARE YOU RECOMMENDING AN ADJUSTMENT FOR TURBINE AND BOILER INSPECTION COSTS?

A. Yes. On Exhibit 304 (HWS-5), I computed the average actual cost of turbine and boiler inspections for the five-year period 1984-1989. I have taken the actual expense in each of these years and restated that expense for inflation. This has enabled me to compute a historical average stated in current dollars which can be compared to the 1990 expense using the same basis of measurement. As shown on Line 10, the actual annual average expense for turbine & boiler inspections was $4,615,532. The Company's budgeted amount for 1990 of $5,340,000 is unreasonable and unrepresentative when compared with historical data. The $724,468 in excess of the annual actual average expense should be disallowed.

On Lines 12-17 and 19, I have computed average annual forecasted turbine and boiler inspections expense for the years 1990-1994 to be $4,602,000. Even when using the forecasted average, which is by definition less accurate than an actual average, the 1990 test year amount is $738,000 in excess of the average five-year forecasted amount.

I am therefore recommending an adjustment to reduce turbine and boiler inspections expense by $724,468, the amount by which the budget exceeds the actual, inflated annual average. I have used the actual average in making this adjustment because it is a more reliable indicator of the true expense than the forecasted data.

Plant Daniel Expenses

Q. PLEASE DISCUSS THE NEXT AREA OF CORPORATE EXPENSES IN THE COMPANY'S BUDGET.

A. I would like to discuss the "controlled expenses" associated with Plant Daniel and Plant Scherer, particularly those costs related to Plant Daniel. The Company considers the costs for Plant Daniel and Plant Scherer to be so-called corporate "controlled" items. I believe "controlled" is the key word in these cases because the budget for Plant Daniel is controlled by Mississippi Power Company, and the budget for Plant Scherer is developed by Georgia Power Company. In the deposition of Mr. Gilbert, Docket No 881167-EI, on February 21, 1989, an inquiry was made concerning the budgeting process for Plant Daniel and Plant Scherer. On page 64, line 2 of that deposition transcript, Mr. Gilbert stated:

> "...--Georgia Power Company and Mississippi Power Company has [sic] their own budgeting process. So they've got approvals within this process. We have input to them. They've got their own review and approval of the plant now, Plant Daniel and Plant Scherer expenses. So it's gone through an approval process. It's just external to ours."

Later in the deposition, Mr. Gilbert was asked who prepares and approves these budgets. Mr. Gilbert indicated the budget for Plant Daniel was approved by Mississippi Power. (See line 22 of page 64.) Mr. Gilbert was then asked:

> They're not submitting anything for approval really. I guess Gulf Power would assume that all the right questions have been asked and everything has been tightened down as close as it can be tightened?

On page 65, Mr. Gilbert responded to this question stating:

> We have a contract with Mississippi Power Company by which we have fifty percent ownership. They're our agent. They operate the plant. Theoretically, under that contract of agreement out in the

> real world, you would probably not have a whole lot of say-so about how that plant is run if your contracting for somebody to be an agent. We do have a committee that we have input to that allows us to have some say-so in the operation of those plants. On times we have told them, we don't want to do that, and at times they have said to us, well, we recognize that and we're not going to do it. Other times they as agent have said that, we feel this is the best decision that needs to be made and as agent we've got to do this.
>
> So we do not control those. We have input. And that would be similar for pensions and fringe benefits. Although Gulf's management has input into them and certainly sits on the committee, there are times when the decision is made to the--outside the process. And as far as budget process is concerned, that's a fixed cost at that point. You don't decide not to pay twenty-five percent of the Daniel expenditures because after the fact that it wasn't a good decision. Contractually, you're obligated to pay that cost. So when you get to that point in the budgeting process, it is almost like a fixed cost.

It is my understanding that Gulf Power Company has a limited amount of input into the budgeting process for Plant Daniel. The Company is provided with a budget by Mississippi Power Company for Plant Daniel that it must accept, "almost like a fixed cost." The costs being charged by Mississippi Power to Gulf, therefore, are not reviewed from the standpoint of whether they are proper in light of the standards of the Florida Commission and whether such costs should be borne by Florida ratepayers.

It is also my understanding that the Company does not audit the costs of Mississippi Power Company for Plant Daniel to verify the propriety of the expenses charged to Gulf Power Company. Therefore, even though the

Company may feel that the audit of Mississippi Power billings performed by the Internal Auditors of Southern Company Services is a means of assuring compliance, I don't believe that independence and objectivity exist in this affiliated relationship.

Mr. Gilbert suggested that "out in the real world you would probably not have a whole lot of say so about how that plant is run." However, I believe in these circumstances, where Gulf Power is a fifty percent owner, that some provision should be made so that the costs charged by Mississippi Power for Gulf Power's half of the cost for operation of the plant could be audited and subject to adjustment if improper by Florida Commission standards or excessive.

During the typical rate proceeding, this Commission may find costs that a utility incurs or spends that are not properly chargeable to ratepayers. Without an adequate review, it is not possible to ascertain whether Mississippi Power incurs and charges Gulf for similar costs that would not be acceptable to this Commission. Some of the costs that Mississippi Power is charging to Gulf Power through the Plant Daniel budget may be inappropriate for this rate case.

Q. WHAT ADJUSTMENT ARE YOU PROPOSING?

A. I am recommending that the $646,000 variance between the Company's budgeted amount for 1990 of $6,572,000 and the 1990 benchmark of $5,926 000 as shown on MFR Schedule C-57, page 44 of 94, be deducted from the Company's O&M budget. This adjustment results in the Company appropriately reflecting its budgeted amount for Plant Daniel at the benchmark level. It also provides an effective means of controlling the costs charged to Florida ratepayers for Plant Daniel, since the Company does not seem to be able to control these costs on its own.

<u>Plant Daniel Transmission Line Rentals</u>

Q. PLEASE DISCUSS THE NEXT CORPORATE BUDGET ITEM.

A. In Order 14030, the Commission deducted $425,000 from the budget of Gulf Power to reduce the proposed budget to a benchmark level of $962,000. The Company, in this case, has added back the $425,000 previously deducted by the Commission in deriving its benchmark amount for Plant Daniel transmission line rentals. The Company included this amount in the base to be multiplied by the escalation factor for 1984 to 1990 to arrive at the new 1990 benchmark. The Company's calculated 1989 benchmark of $1,729,000 exceeds its budgeted amount for Plant Daniel line rentals of $1,195,324. However, if the Company were not allowed to add back the $425,000 disallowed in the prior case, the 1990 benchmark for Plant Daniel would be $1,199,000, which is $3,676 more than the $1,195,324 amount budgeted. Therefore, the Company's adjustment to the benchmark amount is not necessary for Plant Daniel and should not be allowed because of the cushion it would provide the Company.

Plant Daniel A&G

Q. DID ANY OTHER PLANT DANIEL DISALLOWANCE FROM THE PRIOR CASE AFFECT THE 1990 BENCHMARK CALCULATION?

A. Yes. In Order 14030, the Commission disallowed $1,573,000 of A&G expense related to Plant Daniel. The Commission found that the A&G expense for the new plant was accounted for in the base O&M; thus, to allow the $1,573.000 expense amount to be included in the budget for Plant Daniel would have resulted in a double count.

The Company added back this disallowance to the base expense amount used in calculating its benchmark for 1990 A&G expense. The total production related A&G expense budgeted by Gulf Power for 1989 is $5,655,000, as shown in MFR Schedule C-53. The Company-calculated benchmark for 1990 is $6,445,000 per the same schedule. The benchmark exceeds the budgeted amount by $790,000. This variance, however, would reverse and the budgeted amount would exceed the benchmark by $1,435,000, as shown on Exhibit ~~4~~ 5 (HWS-6), if the Company had not inappropriately added back the Plant Daniel A&G expense amount that was disallowed in Order No. 14030 and an amount for Plant Scherer, which I will discuss later in my testimony to its base in calculating the 1990 benchmark.

Q. WHAT ARE YOU RECOMMENDING?

A. I am recommending that the Company's budgeted A&G expense be reduced by $1,172,000 (the proper benchmark variance of $1,435,000 - $263,000 budgeted to Plant Scherer) to adjust the Company's budget to the 1990 benchmark.

I should note that we have been unable to assess the amount of the 1990 A&G expense budget which is specifically applicable to Plant Daniel in terms of its relationship to the 1990 benchmark. This is because the portion of the total 1990 A&G expense benchmark amount which is applicable specifically to Plant Daniel has not been identified. The Commission should investigate the means by which all benchmark amounts could be apportioned to all applicable budget units in order to provide a comparable base for all budget units to which budgeted expenses are allocated. Benchmark variances in either direction from the test year amount should require explanations to establish a better means of monitoring costs.

Plant Scherer - Production Expense

Q. PLEASE DISCUSS THE NEXT "CONTROLLED" EXPENSE AREA IN THE COMPANY'S BUDGET.

A. The next corporate item involves Plant Scherer. As with Plant Daniel, the Company has limited control, if any, over the budgeting process for Plant Scherer. The Plant Scherer budget is given to Gulf Power by Georgia Power Company. Apparently, the Company is expected to adhere to this budget without having had much input in its development.

The 1990 Plant Scherer budget includes $1,957,000 for steam production expenses. The Company has included the same amount in the benchmark for 1990, which is shown on MFR Schedule C-53. I am not convinced that the Company has taken the appropriate steps to determine the propriety of the $2 million included in its budget for Plant Scherer steam production expenses.

Q. ARE YOU RECOMMENDING AN ADJUSTMENT AT THIS TIME?

A. I am not aware of any method to determine the propriety of the amount because of the lack of evidential matter to substantiate it. Therefore, I am not recommending an adjustment at this time. However, I do recommend that the Commission take this lack of supporting evidence into consideration and either set a benchmark level to limit the amount recoverable or require an audit be performed of Georgia Power Company's Plant Scherer costs to determine the propriety of the amount charged to Gulf Power.

<u>Plant Scherer - A&G Expense</u>

Q. ARE THERE OTHER ITEMS IN THE PLANT SCHERER BUDGET WHICH CONCERN YOU?

A. The Plant Scherer budget (hence, the Company's O&M expense) includes $3,000 for "transmission other" expense. The same amount has been included in the benchmark as determined by the Company on Schedule C-53 of the MFRs. The remaining amount included in the Plant Scherer Planning Unit budget is $263,000 for production related A&G expense. Based on the adjustment that the Commission made in Order No. 14030 regarding the inclusion of A&G costs for Plant Daniel, I am recommending that the $263,000 be disallowed as a double count of A&G expenses related to Plant Scherer. This adjustment of $263,000 plus the Plant Daniel production related A&G adjustment of $1,172,000 equal the $1,435,000 by which the production related O&M budget exceeds the benchmark.

Plant Scherer - Transmission Line Rentals

Q. PLEASE DISCUSS THE PLANT SCHERER TRANSMISSION LINE RENTALS.

A. The corporate controlled budget includes $1,822,000 in the Power Delivery Planning Unit budget for Plant Scherer transmission line rentals. I am recommending that the $1,822,000 be disallowed from transmission line rentals. All of Plant Scherer costs should be removed because Plant Scherer capacity is all for unit power sales.

I would like to point out that, even though the Company has adjusted Plant Scherer costs for the portion they claim to be associated with unit power sales, no adjustment by the Company could be identified as pertaining to Transmission Line Rents.

Southern Company Services

Q. PLEASE DISCUSS THE NEXT CONTROLLED BUDGET ITEM.

A. The next controlled item is the Southern Company Services budget. Again, this is a budget prepared by an associated company, in this case Southern Company Services, and given to Gulf Power. Again, we ask how much input does the Company have in the development of this budget. Gulf Power has indicated in the Company's response to Interrogatory OPC

1-53 that it does engage in some communication with Southern Company Services to discuss this budget:

> Proactive management control stems from the annual budgeting process. Southern Company Services, Inc. prepares estimates of its billings to Gulf Power Company and other affiliated companies of the Southern electric system through an extensive, interactive annual planning and budgeting process. In its planning phase, functional groups from Southern Company Services, Inc. receive input from the operating companies. (Emphasis added).

The Company states further that:

> Another form of management control over activities of Southern Company Services, Inc. is the work order authorization procedure. A service to be performed on behalf of Gulf Power Company by Southern Company Services, Inc. is first authorized through the establishment of a work order. This authorization is made through the completion of a work order request form. This form includes a description of the type of service to be rendered and its scope, and is approved by Gulf Power Company management who have requested and authorized the service. The work order is also approv_d by management of the service company function responsible for providing the requested service. (Emphasis added)

The majority of the discussions that take place appear to be limited to the activities specifically requested by Gulf Power for Southern Company Services to perform. The Southern Company Services budget also includes costs which are incurred for services performed in general for all the participants in the Southern Company System. Such costs are apportioned to Gulf Power based on a set percentage. These costs are not subjected to the same scrutiny by the Company as that of the costs of a specifically requested item. The question that should be asked is: Are these necessary expenses for Gulf Power and are they expenses that this

Commission would normally allow to be passed through to the ratepayer?

Because the Southern Company Services planning unit O&M budget makes up approximately $15 million, which is in excess of 10% of the total O&M budget, the budget should be subject to an audit or a detail review of the costs being charged to the ratepayer. There is no assurance that all the costs being flowed through from the Southern Company Services billings to Gulf Power are providing a benefit to the ratepayer. Without an audit of these costs by an independent party, the only alternative to curb expenses is the Commission's use of the benchmark analysis, as has been done in the past.

Q. HAVE YOU REVIEWED THE BUDGETED COSTS OF SOUTHERN COMPANY SERVICES IN CONJUNCTION WITH OTHER RATE CASES?

A. Yes. Larkin & Associates was retained by the Georgia Public Service Commission in 1986 and 1987 to perform a review of Georgia Power Company's budget. Georgia Power is a sister company of Gulf Power. In that engagement, we reviewed and evaluated the budgeting process of Georgia Power which included Southern Company Services' budget items charged to Georgia Power. Our review included an attempt to substantiate these budget line items from Southern Company Services' workpapers. However, we were unable to substantiate the budget line items because no Southern Company Services workpapers were available for review. Unless Southern Company Services can now substantiate the development of its budgets for Gulf Power or any other system affiliate, I would think it appropriate to question the costs included in the Southern Company Services budget.

Again, the question arises as to how some of the costs flow through to Gulf Power from Southern Company Services and the propriety of such costs. Additionally, some of the functions that are performed by Southern Company Services for all the sister companies should be questioned as to whether duplicate functions exist at these sister companies, including Gulf Power.

Q. ARE THERE OTHER REASONS WHY YOU BELIEVE THAT THE SUPPORT UNDERLYING THE SOUTHERN COMPANY SERVICES BUDGET IS INADEQUATE?

A. I question the extent of support that exists for the amounts that are included in the budget for Gulf Power by Southern Company Services since I have not been provided with details concerning such charges. Support, even in a form similar to that for the other planning units excluding Plant Daniel and Plant Scherer, is lacking. Public Counsel's First Request for Production of Documents, Item No. 12, stated:

> For any planning units that don't use the above forms in the previous questions, please provide the 1990 budget detail that is prepared or supplied to the Company in lieu of Forms B-3, B-4, B-5, B-6, B-7, and approval letters.

Basically, the information requested was for detail supporting the costs included in the 1990 budget for these units; justification for additional costs over the prior year's budget which is supposed to be contained on Form B-4; justification for capitalized costs, which is contained on Form B-5; and the allocations of costs to locations and FERC accounts, which are performed on Forms B-6 and B-7.

The Company's response for Southern Company Services was a 21 page listing of work orders that total $18,253,795. Besides the brief description for each of the work orders listed, there is no detail as to why the budget amount is different than 1989 or why it is necessary to increase or decrease the budgeted amounts.

The Public Counsel's First Request to Produce Documents, Item No. 13, stated: "Please provide copies of all Approval Letters for each Planning Unit for the 1990 budget."

In the Company's response, no approval letter was received for Southern Company Services, Plant Daniel, or Plant Scherer. Therefore, it is my assumption that the Company's response to Public Counsel's Fifth

Request for Production of Documents in Docket 881167-EI, Item No. 47, applies here. The Company's response was:

> The Budget Committee approves the budgeted expenses for Plant Daniel, Plant Scherer, and Southern Company Services in their Budget Approval Meeting. <u>No approval letters are issued for these planning units</u>. (Emphasis added).

Apparently, there is no detailed budget information for Plant Daniel, Plant Scherer, or Southern Company Services other than the dollar figures and FERC account distributions provided. The Company in its response to Public Counsel's First Set of Interrogatories, Item No. 28 showed an increase of $764,737 ($14,954,931 - $14,190,194) in its O&M expense budget. No justification was provided for any increases of the current budget over the prior year.

Additionally, OPC asked for a budget-to-actual variance summary for Southern Company Services. An analysis of the 1989 variances indicated that the actual expense was under budget by approximately $418,000. After adjusting for the $396,851 variance for the tax investigation, the 1989 actual expense was approximately $814,000 under budget.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE SOUTHERN COMPANY SERVICES COSTS INCLUDED IN GULF POWER'S 1990 BUDGET?

A. Considering the fact actual for 1989 was less than budget and that no detail explanations have been provided that justify the developed budget amounts, I believe that an adjustment is warranted. A $907,000 benchmark excess is shown on MFR Schedule C-57, page 3. This is the difference between the 1990 Southern Company Services' budget for steam production of $2,354,000 and the 1990 benchmark as determined by the Company of $1,447,000. Because of the lack of support for the Southern Company Services specific budget amounts, I am recommending that $617,595 as shown on line 5 of Exhibit 306 (HWS-7), page 1 of 3, be disallowed in the O&M budget.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT FOR SCS SERVICES TO GULF.

A. This adjustment has four parts. The first part removes certain research projects and studies because they are duplicative of the type of research Gulf pays for through Electric Power Research Institute (EPRI) dues. This adjustment is shown on Exhibit 307 (HWS-7), page 2 of 3, and results in the disallowance of $324,000.

The second part of the adjustment removes the cost of SCS Services which have been budgeted at amounts substantially in excess of actual average costs for such services. This adjustment is necessary to assure that the SCS-related charges are reflected in the test year at a reasonable level, and to counteract the Company's demonstrated tendency to overstate the amount of such costs in its budgets. The adjustment is shown on Exhibit 308 (HWS-7), page 3 of 3, and reduces O&M expense by $153,595.

The next part of the adjustment pertains to the Company's justification for the benchmark variance of $44,000 for Generating Plant Electrical System Application is provided on MFR Schedule C-57, page 31. The Company's justification is as follows:

> These SCS Services are for the continued research and engineering evaluations of new generators, exciters, transformers, voltage regulators and other electrical equipment used in electric generating plants. This work also provides for investigation of problems with Gulf's existing equipment problems at other utilities with equipment in place on Gulf's units.
>
> It is essential that this expertise be maintained at Southern Company Services to provide for analysis and trouble shooting of problems on Gulf's units and to provide for replacement of equipment at Gulf's electric generating plants. Gulf's plant personnel and engineering personnel in the corporate office do not possess the expertise to meet these essential requirements.

As a follow up, Interrogatory OPC 4-231 requested the Company to:

> Provide a list of Gulf plant personnel and engineering personnel and their respective qualifications and identify to what extent Southern Company Services' personnel are more qualified.

The Company's response to identifying the extent SCS personnel are more qualified, is as follows:

> Gulf cannot, due to its size, justify employing personnel in such a specialized area. Southern Company Services, by intent, is staffed to supply personnel who specialize in such areas to provide technical assistance to the entire Southern Company System, therefore reducing any duplication in the Southern Company System.

Nowhere in this response is any statement that specifies why SCS personnel are more qualified. Therefore, unless a more adequate justification can be provided, I am recommending the disallowance of the $44,000 for Generating Plant Electrical System Application.

The final part of the SCS Services adjustment is the SCS Services System Planning budget of $167,000 exceeds the 1990 benchmark of $71,000 by $96,000. The Company has attempted to justify this variance with various descriptions on planning activities performed by Southern Company Services for the Southern System. However, the Company does not provide any quantifiable justification for adjusting the benchmark. I am recommending the $96,000 variance be disallowed. If the Company can provide on a activity-by- activity basis a variance and an adequate justification for why the Southern System costs allocated to Gulf Power for system planning have increased over the benchmark, then I may be willing to reconsider my recommendation.

Additionally, MFR Schedule C-57, page 3, lists a benchmark excess of $210,000 for Research and Development. This variance includes Atmospheric Fluidized Bed Combustion Research and Development budget of $52,000 and the Living Lakes, Inc. budget for $65,000. This is Gulf Power's allocation for Southern Company costs which are considered duplicative and/or unnecesssary. I am recommending that the $117,000 for these projects be deducted as part of the steam production for a total of $734,595 as shown on Exhibit 30 (HWS-7), page 1.

Finally, I recommend that the Commission make a line-by-line review of the other Southern Company Services budget amounts and compare them to what the benchmark would be for those specific line items, as opposed to looking at total Company budget/benchmark comparisons.

Uncollectible Expense

Q. PLEASE DISCUSS THE BUDGET AMOUNTS FOR UNCOLLECTIBLES.

A. The 1989 actual uncollectibles were $569,403 per the Company response to OPC-34. The Company's recent change in determining the uncollectible expense of $510,852, in my opinion, produces a representative amount for 1990. Therefore, I am not recommending that the 1990 budget for uncollectibles be adjusted. However, since the accounting change that resulted in a credit to the 1989 O&M expense in the amount of $813,000 was charged to the ratepayers over a period of years, it is appropriate that the effects of accounting change be amortized into rates. I am recommending that the $813,000 effect of this accounting change be amortized over 4 years. This rate of amortization would reduce the 1990 budget by $203,250 ($813,000/4).

Rate Case Expense

Q. PLEASE DISCUSS THE NEXT CORPORATE CONTROLLED ITEM.

A. The next corporate controlled item is rate case expense of $500,000. The Company has budgeted $1,000,000 for costs incurred in seeking its rate increase. It has elected to amortize this cost over a two-year period. In Order No. 14030 the Commission used a two-year amortization period for the rate case expense. However, the Company's last rate case commenced at the beginning of 1984 and the current case did not take place until the end of 1989. That time period suggests a representative time lag between the Company's rate increase requests. Therefore, I am recommending that the current rate case expense be amortized over a five-year period. Accordingly, the annual amount is reduced to $200,000, and an adjustment reducing the O&M budget by $300,000 is necessary. If the Commission finds that the Company is not entitled to a rate increase, I recommend that all rate case expense be disallowed.

Employee Benefits

Q. PLEASE CONTINUE WITH YOUR DISCUSSION OF THE BUDGET.

A. The final area of corporate controlled costs that I wish to discuss is that pertaining to employee benefits. Employee benefits are accounted for in two separate planning units. Charges for employee benefits totalling $6,135,300 are included in the Employee Relations Planning Unit. The credits transferring costs to accounts other than O&M are included in a category called "General to All Planning Units" and total $1,234,471. On Exhibit 309 (HWS-8), I show a breakdown of the employee relations expenses by type. On this exhibit, I also show the adjustments which are discussed in the following paragraphs.

The Company did not budget an amount for the pension plan. The pension plan is fully funded, and there will be no money expended by the Company for this item in the foreseeable future. Therefore, I concur that no amount should be budgeted.

The next items are two adjustments that pertain to the Company's change in accounting for post retirement benefits. These benefits were previously accounted for on a "pay-as-you-go" basis. However, as a result of a proposed, but not yet adopted accounting standard, the Company began accruing an expense for the future costs of other post retirement benefits. This is, in effect, a collection of funds from the ratepayers for this item, in advance of any payments by the Company.

The Company should only be allowed to collect from the ratepayers on a pay-as-you-go basis, not on an accrual basis. I believe the Florida Commission should protect the ratepayers from prepaying these costs. I am adjusting each of the other post retirement benefit amounts to the actual cash outlay projected for the 1990 budget year. The post retirement life insurance is adjusted to $110,000 per the Company's response to Public Counsel's First Set of Interrogatories, Item No. 13. This decreases post retirement life insurance benefits by $807,000. Similarly, post retirement medical benefits are reduced to $518,000, also per the Company's response to Public Counsel's First Set of Interrogatories, Item No. 13. This adjustment results in a decrease in budgeted expense for post retirement medical benefits of $475,000.

I would like to add that the Company's response to Public Counsel for Providing Copies of Selected Planning Unit 1990 Budget Working Papers for the Employee Relations Planning unit indicates zero funding for both post retirement benefits. If this is true, an additional reduction to the employee relations O&M budget of $628,000 ($110,000 + $518,000) would be required.

Q. PLEASE EXPLAIN THE OTHER CALCULATIONS SHOWN ON OPC EXHIBIT 301 (HWS-8).

A. The Company's budget provided for a transfer of a portion of other post retirement benefits to non-O&M accounts. The amount transferred by the Company to non-O&M accounts for post retirement life insurance was $171,923. For post retirement medical benefits it was $186,172. I calculated a ratio of the transferred amount to the total budgeted amount to determine the portion of my recommended budget adjustments for post retirement life insurance and medical benefits that should be transferred to non-O&M accounts. These transferred amounts increase the "General to All Planning Units" budget by $151,300 for post retirement life insurance and $89,055 for post retirement medical benefits. If the additional adjustment to post retirement medical benefits discussed earlier is made, then the General to All Planning Unit budget would require an increase in expense of $117,740 ($20,623 + $97,117).

Next, I adjusted the supplemental benefits, eliminating the entire budget of $363,800. This additional benefit budgeted for three executives is not a necessary expense that provides the ratepayer with any quantifiable benefit. This is additional benefits for employees over and above the normal IRS limitations.

The net effect of my adjustments to employee benefits decreases the administrative and general budgeted expense for 1990 by $1,405,445 as shown on Exhibit 309 (HWS-8), line 12.

Employee Savings Plan

Q. DOES THAT COMPLETE YOUR DISCUSSION OF THE CORPORATE CONTROLLED EXPENSES FOR O&M?

A. No. I would like to make one further comment regarding the Employee Relations Planning Unit budget.

The Company currently has an employee savings plan matching program. Under the formula, the Company will match a certain percent of the monies contributed to the plan by the employees. This program has been in effect for a number of years. I am not convinced at this point that charging the full cost of the plan to the ratepayer is proper and justified. At this time, I am not proposing any adjustment. I would like to recommend the Commission consider putting a cap on these costs in light of the numerous benefits provided the employees of Gulf Power.

Productivity Improvement Program

Q. WHAT IS THE PURPOSE OF THE COMPANY'S PRODUCTIVITY IMPROVEMENT PROGRAM?

A. The Productivity Improvement Program ("PIP") is a Southern electric system-wide program. The Company has described its purpose as follows:

> The purpose of the Productivity Improvement Program is to improve the financial and operating performance of the Southern electric system, by encouraging participants to engage in a more vigorous objective-setting and performance assessment process. Cash awards may be granted based on performance in two areas - the Individual Performance Component rewards achievement of individual objectives, and the Corporate Financial Performance Component rewards achievement of corporate objectives. (OPC Interrogatory 1-20, p.1 of 2.)

Q. WHAT AMOUNT HAS THE COMPANY BUDGETED FOR THE PRODUCTIVITY IMPROVEMENT PROGRAM?

A. The Company budgeted $464,177 for PIP. All of this amount has been recorded as O&M expense in the test year. The dollar amount budgeted for the test year is based on the 1989 actual dollar amount. See Company's response to OPC 4-182.

Q. HOW MANY GULF POWER COMPANY EMPLOYEES PARTICIPATE IN THE PRODUCTIVITY IMPROVEMENT PLAN?

A. In 1989, there were 15 participants from Gulf Power Company in the PIP. The following positions participated:

President-CEO
4 VP's
3 Division Managers
Director of Power Generation
Controller
Director of Employee Relations
Assistant to VP of Power Generation and Transmission
Director of Power Delivery
Director of Marketing and Load Management
Director of Corporate Communications

(Arthur Andersen 1989 audit workpapers, 47/3.)

The Company's response to OPC Interrogatory 4-183 states that, for 1990, PIP participation is budgeted for 11 Gulf employees.

Q. DOES IT APPEAR THAT THE COMPANY WILL ACTUALLY INCUR THE 1990 EXPENSE IT HAS BUDGETED FOR PIP?

A. No, it does not. According to the Company's Supervisor of Compensation, the Company expects the 1990 payout for the 1989 award will be considerably less than the amount accrued due to Gulf's poor return on common equity. See Arthur Andersen 1989 audit workpaper 47/3. More importantly, the amount the Company budgeted for the 1990 test year has also subsequently been substantially reduced:

> The amount budgeted in 1990 is $464,177 which was based on 100% payout. The present estimated amount for 1990 that will be paid in 1991 is $105,968. The reason for such a large change in the new estimate is due to a major change in the PIP plan that occurred subsequent to the preparation of the budget and an estimated payout based on 50% of the new maximum compensation. [Response to OPC 6-299(b)].

The Company has revised its budgeted amount of $464,177 down to $105,968. This is a reduction of $358,209.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING TEST YEAR PIP EXPENSE?

A. The Company's budgeted expense of $464,177 should be disallowed in total. A reduction of $358,209 should be made because the Company's budgeted amount is overstated, as explained above. Additionally, the remaining $105,968 should be removed because this PIP expense is not appropriate for ratemaking purposes.

Q. WHY IS PIP EXPENSE INAPPROPRIATE FOR RATEMAKING PURPOSES?

A. It is incumbent upon key management personnel, carefully selected, to fulfill their corporate responsibilities, regardless of any incentive compensation. Incentive compensation of this type duplicates salaries and wages which are legitimate ratemaking expenses. The cost of these benefits should be borne by the shareholders, not the ratepayers, who derive no direct benefit from incurring that expense.

<u>Performance Pay Plan</u>

Q. WHAT IS THE PERFORMANCE PAY PLAN?

A. The Performance Pay Plan is a new compensation package that has been developed for the Southern electric system. This plan is supposed to improve the link between pay and performance by increasing rewards to top performers and by reducing rewards for low performers.

The Performance Pay Plan includes all full-time and regular part-time exempt employees at Gulf Power Company who receive annual performance appraisals. The plan does not include temporary or co-op employees, or contractors.

Q. WHY DID THE COMPANY DEVELOP A NEW PERFORMANCE INCENTIVE PAY PLAN?

A. The Company's Performance Pay Plan Handbook states the following reason for the development of this new plan:

> Our business is rapidly changing. We are operating in an environment that is becoming more deregulated, more market oriented, and more competitive every day. The Performance Pay Plan will support our system's strategic direction to ensure that we remain a leader in our changing business environment. We needed a plan to encourage employees to be more productive. By rewarding employees for increasing productivity, the plan will help make our companies more competitive.

This explanation indicates that the impetus behind the Company's new Performance Pay Plan is deregulation, competition, and the changing business environment. It appears the Company could have continued to meet its primary purpose of providing safe, reliable, and reasonably-priced electric service without this new incentive plan.

Q. HOW IS THE COMPANY'S NEW PERFORMANCE PAY PLAN EXPECTED TO FUNCTION FROM AN EMPLOYEE'S PERSPECTIVE?

A Under the Southern electric system's new Performance Pay Plan, the eligible employees have the opportunity to earn incentives in the form of a lump-sum payment, in addition to their base salary increases. The Company's Performance Pay Plan handbook describes how this is supposed to function:

> Under the plan, top performers (Level 5) have an opportunity to earn up to 20 percent of their base salary in incentive pay. Level 4 employees have an opportunity to earn up to 14 percent of their base salary; Level 3 employees up to eight percent; and Level 2 employees up to two percent. These lump-sum payments are not limited by the performance level salary ceilings associated with your base salary.
>
> * * *
>
> Lump-sum incentive pay has three parts (1) Annual incentive based on your attainment of your individual key results areas; (2) Organization incentive based on your organization's attainment of its goals; and (3) Corporate incentive based on the Company's attainment of its goals.

Q. HOW MUCH HAS THE COMPANY BUDGETED FOR THE PERFORMANCE PAY PLAN?

A. The Company budgeted O&M expense of $198,953 for this plan in 1989 and $1,021,637 for the test year, 1990.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that the test year O&M expense amount of $1,021,637 be disallowed. I view the Southern electric system's new Performance Pay Plan as being unnecessary to the provision of safe, reliable, and reasonably-priced electric service. Moreover, since the Plan will allow annual bonuses in addition to the normal salary increases, I believe it is likely to result in excessive compensation. If the Southern Company wants to implement this plan on a system-wide basis, the additional costs associated with doing so should be absorbed by shareholders, not ratepayers.

<u>Edison Electric Institute Dues</u>

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO DISALLOW A PORTION OF EEI DUES.

A. Gulf's response to OPC 1-35(a) states that the Company budgeted $88,133 for EEI dues for the 1990 test year. Of this, Gulf excluded $30,000 for EEI Media Communications. Of the remaining basic membership dues of $58,133, I have excluded 37.17%. In support of the recommended 37.17% EEI membership dues disallowance, I reviewed a report prepared for the National Association of Regulatory Utility Commissioners addressing EEI expenses for the year 1987. To my knowledge, this is the most recent report available. Based on a review of that report, I have concluded that a disallowance of EEI membership dues of 37.17% or higher would be warranted.

In Gulf's last rate case and other electric rate cases, the Commission has excluded 33 1/3% of EEI. <u>See</u> e.g., Order 14030 (Docket 840086-EI), page 23. I believe, however, that a 37.17% disallowance is appropriate based on the percentage of EEI dues that are spent on lobbying activities, regulatory advocacy, legislative policy research, institutional advertising and litigation. This results in a $21,608 disallowance for EEI inappropriate in rates.

<u>Nuclear Power Research Expense</u>

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO DISALLOW THE COMPANY'S NUCLEAR POWER RESEARCH EXPENSE

A. For the 1990 test year, the Company has projected an expense for nuclear power research in Account 930-300 in the amount of $326,808. This represents the portion of the Company's EPRI dues directed towards nuclear power research. This expense should be disallowed for the following reasons. First, Gulf has no nuclear power plants, and therefore has little need for nuclear research. Second, Gulf presumably has excess generating capacity and will not need to add new capacity for some time. Third, Gulf has not demonstrated that its ratepayers receive direct benefits from nuclear power research. Finally, when Gulf does, at some point in the future, have to add capacity, it appears unlikely that such capacity will be nuclear. Gulf owns the Caryville land which has been certified by the Florida Power Plant Siting Act for a steam electric generating plant. See Gulf testimony, Parsons, pp. 18-20. For these reasons, the $326,808 budget amount for nuclear research should be disallowed.

Nonrecurring Items

Q. DO THE COMPANY'S TEST YEAR EXPENSES INCLUDE NON-RECURRING ITEMS WHICH SHOULD BE REMOVED?

A. Yes. Gulf's test year operating expenses include non-recurring items for rebuilds and renovations which should be capitalized, rather than expensed. Also included is excessive ash hauling and storage expenses that should not be allowed.

Rebuilds

Q. PLEASE DISCUSS NON-RECURRING EXPENSE FOR REBUILDS.

A. "Rebuilds" is a relatively new program for Gulf Power. Gulf Power is rebuilding heavy equipment that is used in the day-to-day operations instead of having the equipment rebuilt by an outside party. It is my understanding that when the work was done by an outside party, these costs were capitalized. However, to the extent that they are now being done in-house, the Company feels these items should be expensed.

The Company's response to OPC 4-250 stated:

> Since the component rebuilds (including rebuilding of components of cabs and chassis) are not defined as a retirement unit as described in the List established by the FPSC, expensing the rebuilding of components is appropriate. The List defines a retirement unit for each type of transportation equipment utilized. In each category, nothing less than the entire vehicle is defined as a retirement unit.

I disagree with the Company's change in accounting for these costs and recommend that such costs continue to be capitalized since the rebuild programs will extend the lives of the assets being rebuilt. Buying individual components and then assembling them into a complete unit, rather than acquiring the complete unit should not change the method of accounting for the costs. Such costs should still be capitalized. In either scenario, a complete unit results.

Rebuilds identified in the nonrecurring budget include $42,575 in the Eastern Planning Unit, $38,925 in the Central Planning Unit, and $35,000 in the Western Planning Unit, for a total of $116,500 to be deducted from the Company's O&M budget.

Also of concern is the substantial increase in the absorption rates for heavy equipment as a result of the Rebuild Program. This concerns me because, if the rebuilds are expensed and also included in the absorption rate, a duplication of the expense may be occurring. Also, the absorption rates are calculated by adding the annual expense to the total cost of the rebuild instead of an amortized portion of the total cost calculated based on the extended life of the asset.

<u>Renovations</u>

Q. PLEASE DISCUSS THE NEXT QUESTIONABLE EXPENSE.

A. Another item that should be capitalized is the $252,000 renovation to the Panama City Office. A renovation of this amount should extend the life of this asset. This expenditure represents an improvement to the property, as opposed to ordinary maintenance. I recommend that the budget for O&M be reduced by $252,000 to properly account for the costs associated with improving property as a capital item, rather than an O&M expense.

<u>Ash Hauling and Storage</u>

Q. DOES THIS COVER ALL OF THE ADJUSTMENTS RESULTING FROM YOUR INVESTIGATION OF NONRECURRING ITEMS?

A. No. One additional item that requires an adjustment is the Company's Plant Smith budget for nonrecurring expenses of $360,000 for ash hauling and storage. This budgeted amount is in addition to the $275,000 budgeted as a recurring expense.

The Company's response to OPC 4-238, provided the actual ash hauling and storage expense for 1986 ($199,000), 1987 ($806,000), 1988 ($752,000) and 1989 ($345,000). The average for the four years is $526,000. This is $109,000 less than the Company budgeted.

Also, the Company estimated that 240,000 cubic yards would be removed at an estimated cost of $2.48 per cubic yard, which equals $595,200. This is $39,800 less than the budget of $635,000. The Company overbudgeted under both scenarios.

Since the benchmark is zero, I am recommending that the Plant Smith ash hauling and storage budget be reduced $360,000 from $635,000 to the recurring budget amount of $275,000. This adjustment is necessary because the Company is incurring the nonrecurring portion in 1990 to complete a project that has been ongoing but will not be continuing at this level. The Company's Form B-4c for Plant Smith provided in response to Public Counsel's First Request to Produce Documents, Item No. 9 confirms this as follows:

As power is generated, the resulting ash is sluiced to a large pond where it settles and accumulates. In order to comply with environmental regulations, Smith Plant has diked and drained the southern half of this pond so that the ash can be removed and hauled to permanent dry storage sites called cells. This work has been going on for the past several years. Completion of cells 9 and 10 will "clean out" the remaining ash from the drained area, allowing the plant to operate for many years. Since this area is drained and diked, it is economically wise to complete this work before the area must be reflooded next year to accommodate ash again.

The $360,000 excess cost was budgeted as nonrecurring, is excessive, and should be disallowed.

Employee Relations - Relocation and Development Programs

Q. ARE THERE ANY OTHER AREAS WHERE THE BUDGET SHOULD BE ADJUSTED TO REMOVE INAPPROPRIATE COSTS?

A. Yes. The next two adjustments I am recommending involve the Employee Relations Planning Unit. This planning unit requested an increase of $176,690 in its relocation budget for 1989, and another increase of $8,100 for 1990, bringing the total for the relocation budget to $324,100. Part of this budgeted amount relates to the cost incurred for selling the homes of relocated employees. These costs are budgeted at approximately 22% of the average sales price of the homes. The Company workpapers that provide the support for this budget amount shows that the 1990 budget is for 10 homes. This would calculate to an average of $32,410 per home. This is well in excess of any fees charged by a realtor for selling a home

I am recommending that the entire budgeted amount of $172,460 associated with this percentage charge be eliminated from the O&M budget.

The Employee Relations budget also includes the costs of programs called "high potential development" totalling $47,250, and "executive development" totalling $25,000. These costs were new programs to the 1989 recurring budget carrying forward into the 1990 budget. These should be removed from the O&M budget until and unless they are justified through a cost-benefit analysis.

Bank Fees

Q. ARE THERE ANY OTHER ADJUSTMENTS YOU WISH TO DISCUSS?

A. Yes. The next area involves bank fees and line of credit charges. The Company in 1989 budgeted $192,000 for bank fees and line of credit charges. In 1990 these items flow through as part of the "recurring other", and the Company adds another $31,400 to the budget for a total of $223,400. The Company's justification in 1989 for the budgeted amount of $192,000 was that the Company had a line of credit which required it to maintain compensating balances. Such balances are supposed to compensate the bank for providing the credit line and offset any bank charges. After an analysis and comparison of alternatives, Gulf consolidated the disbursement accounts into one controlled disbursement account, which allows the investment of all idle cash until the checks are presented for payment. As a result, the Company no longer maintains funds with the bank in a form that compensates the bank for service, nor does the Company maintain any other compensating balances with the bank.

The Company stated on the 1989 form (B-4c) provided in Docket 881167-EI, that as a result of this change, it has received improved quality of banking service, reduced the cost of banking activity, improved control over the movement of cash, and optimized the use of available cash and overall savings when lower costs and additional reserves are considered. As a result, the Company estimates the revenue derived from the increased availability of cash to be $491,000. Comparing this to the budgeted amount of $192,000, this is a net savings, before tax, of $299,000. The Company estimated that the working capital requirement reduction saves the retail ratepayer $585,000.

Before this change, the ratepayers paid for maintaining compensating balances in the form of a $4.4 million working capital requirement in rate base. Ratepayers were required to provide $585,000 of funds while the Company's stockholders were not carrying any burden or paying any fees. With the change in banking procedures, the Company claimed it is saving the ratepayer $585,000 while requiring them to pay the full $192,000 from 1989 plus the $31,400 from 1990 associated with the change in banking. Even though a net savings of $361,600 would result, the Company's stockholders would enjoy the below-the-line estimated $491,000 of revenue earned on the idle funds. I am recommending that the $223,400 related to bank fees be removed from the O&M budget. This expense should be borne by the stockholders of the Company, since they clearly derive the benefits. This adjustment still leaves the stockholders of the Company with a $267,600 windfall.

<u>Obsolete Distribution Material</u>

Q. PLEASE EXPLAIN YOUR ADJUSTMENT FOR OBSOLETE DISTRIBUTION MATERIAL.

A. This adjustment is shown on Exhibit 310 (HWS-9). It reduces test year O&M expense by $83,000 to remove the amount in excess of the benchmark which the Company has not justified. The Company's identification of obsolete material may be an indication that it over-purchased or imprudently purchased such items in the past. Ratepayers have borne the cost of the Company's Communication Oriented Production Information System (COPICS), which was implemented in 1984 to supposedly enable the Company to better control its inventory. The substantial inventory write-offs the Company has budgeted for 1990, which exceed the pre-COPICS inventory write-offs, may be an indication of continuing laxity of inventory and purchasing controls.

Moreover the $109,000 write-off shown on MFR Schedule C-57 substantially exceeds the actual $49,000 expense for 1989, from OPC 4-248. Per OPC 4-248, the Company's 1989 budget amount was $99,000. Additionally, a five-year average of actual write-off, excluding the 1988 abnormal write-off, is $16,485. It appears the Company may be attempting to manipulate the year in which these obsolete inventory write-offs occur, which would result in ratepayers bearing inappropriately high levels of expense.

For these reasons, the $83,000 excess expense for obsolete distribution materials should be disallowed from test year O&M expense.

Officer & Management Perks

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO DISALLOW THE TEST YEAR EXPENSE FOR OFFICER AND MANAGEMENT "PERKS".

A. In response to OPC 1-29, the Company listed outside professional services budgeted for the test year. Exhibit 311 (HWS-10) lists the expenses for executive tax services and a fitness program which should be disallowed. Ratepayers should not pay for tax services relating to the personal tax returns of Gulf's executives and vice presidents. The fitness program is only available to high level employees, not on a Company-wide basis, and represents a personal expense for Gulf's executives which should not be borne by ratepayers. Therefore, the $65,100 test year expense for officer and management "perks" shown on Exhibit 311 (HWS-10) should be disallowed.

Duct and Fan Repairs

Q. PLEASE EXPLAIN YOUR ADJUSTMENT FOR DUCT AND FAN REPAIRS EXPENSE.

A. Gulf has budgeted $1,109,000 for duct and fan repairs expense for the 1990 test year. This amount is $684,000 over the O&M expense benchmark. This work is cyclical in nature. Once repairs are done on a particular plant, they should not be required again at that unit for several years. To develop a normalized level of duct and fan repair cost, on Exhibit 312 (HWS-11), I computed a six-year average. The expense for each year has been inflated by a CPI factor. The normalized expense for duct and fan repairs is $833,914. The test year excess over this projected by the Company of $275,086 should be disallowed.

Customer Service and Information

Q. SHOULD ALL THE 1990 BUDGETED TEST YEAR PROGRAM EXPENSES FOR CUSTOMER SERVICE AND INFORMATION BE RECOVERED IN RATES?

A. No, they should not. The Company is requesting base rate recovery of certain programs which were previously recovered through its Energy Conservation Cost Recovery Clause (ECCR). This clause provides for direct recovery of the Company's conservation costs. A review of ECCR programs is done periodically by the Commission. The Company is required to demonstrate, among other things, the conservation cost effectiveness of programs included or to be included for recovery under the clause. Effectiveness, for purposes of inclusion in the ECCR mechanism is defined as:

1. Generation reduction per customer.
2. Peak reduction per customer.
3. KWH reduction per customer.
4. Cost/benefit, i.e., cumulative present value of ratepayer benefits is greater than the cumulative present value of the cumulative costs of a program.

As a result of Commission review of the ECCR, several programs, previously included under the clause, have been rejected because they were unable to meet the cost/effectiveness criteria for inclusion in the clause. The Company is now seeking recovery of these programs through base rates.

Q. WHAT PROGRAMS DISALLOWED THROUGH THE ECCR MECHANISM IS GULF REQUESTING RECOVERY OF THROUGH BASE RATES?

A. The Company is requesting recovery of four programs through base rates: Good Cents New Home, Good Cents Improved Home, Energy Education, and Presentation/Seminars.

Q. SHOULD THE GOOD CENTS NEW HOME PROGRAM BE ALLOWED RECOVERY IN BASE RATES?

A. No, there are essentially three reasons why this program should not be allowed recovery in base rates.

Q. WHAT IS THE FIRST REASON?

A. This program was determined in Docket No. 860718-EG, to have a marginal cost/benefit ratio to participating customers. The program involves the promotion of appliances, and referrals of contractors. The program puts the Company in the role of promoting appliance sales and classifying homes as meeting "good cents" criteria, activities which are not necessary to the provision of electricity.

Q. WHAT IS THE SECOND REASON THE GOOD CENTS NEW HOME PROGRAM SHOULD NOT BE ALLOWED IN RATES?

A. The information and expertise which the Good Cents Home Program purports to impart to its customers is already available through the Florida Model Energy Efficiency Code.

In 1977, in response to Federal Requirements, the Florida Legislature passed two laws which required local governments to adopt energy efficient building standards.

In 1980, these two laws were combined, resulting in the Florida Model Energy Efficiency Code for building construction. The Florida Department of Community Affairs (DCA) is responsible for administering, modifying, revising, updating and maintaining the Energy Code. The DCA also is responsible for determining what cost-effective, energy-saving equipment and techniques are available and updating the Code to incorporate any such equipment or new techniques This is to be done at least every two years. The Code, which was designed specifically for Florida's climate, contains over two hundred pages outlining, diagramming, and presenting the Code and the requirements for energy efficient buildings. The Code is available to anyone through the State of Florida Department of Community Affairs Energy Code Program.

Mr. Bower has stated in his testimony that the Good Cents Home Program:

> offers superior services and benefits to our customers which are not provided through the Code. The Good Cents Program provides a vehicle to optimize compliance with the Code which is not universally enforced in Northwest Florida."

Whether Florida enforces its Energy Efficiency Code or not, does not change the fact that the Code sets guidelines for energy efficiency and makes that information available to the public.

Q. WHAT IS THE THIRD REASON RECOVERY OF THE GOOD CENTS NEW HOME PROGRAM SHOULD NOT BE ALLOWED IN RATES?

A. Gulf has been unable to demonstrate that the program has any effect on load or demand or even the program's conservation value. Consequently, all of Gulf's ratepayers must pay for this program when only some of them are participating.

Given that the program has not had any discernable effect on load, despite its inception in 1977, it is impossible to view the program as being cost-effective. Mr. Bower, however, would have us believe this program is necessary because of the unavailability of services of this type in Gulf's service area and because of customer demand for such services. The function of a public utility, however, is not to fill any gaps or niches in the free market, or to assume the activities of a governmental agency in disseminating building code information, and especially not at the expense of all ratepayers, whether or not they partake in such services.

If demand for these services is as great as Gulf believes it is, only those customers who demand such services should pay for them. On the basis of Mr. Bower's arguments, it would appear this program should stand on its own on a competitive basis. No program costs should be charged through rates.

I am recommending $1,023,995 be removed from test year cost of service for the Good Cents New Home Program.

Q. SHOULD THE GOOD CENTS IMPROVED HOME PROGRAM BE ALLOWED RECOVERY IN BASE RATES?

A. No. This program also was removed from ECCR recovery because Gulf was unable to demonstrate the cost effectiveness of the program in terms of any Kw and Kwh savings. This program, like the Good Cents Home Program, also promotes heat pumps and other electrical appliances. Such promotional expense is inappropriate in rates because it serves to increase load and could compete with other sources of energy, such as gas and propane.

Once again, Gulf has been unable to demonstrate the benefit of these services to all ratepayers. If Gulf believes customers demand these services and information, then the program should stand on its own on a competitive basis. The program is not a necessity to ratepayers and therefore those wanting such service should pay for them. If the program is truly cost effective and in such demand as the Company represents, revenues will equal expenses. I recommend the disallowance of $609,783 from test year expense for this program.

Q. SHOULD RECOVERY OF THE ENERGY EDUCATION PROGRAM BE ALLOWED IN BASE RATES?

A. No, the Company has described this program as including appliance selection and use, residential electric system design, optional energy use and application for household task, residential interior lighting, energy management, lifestyle information and economic efficiency of energy use.

The Company claims these programs are conservation programs although they have been unable to substantiate any quantifiable benefits realized from such programs. For this reason, recovery was denied through the ECCR.

Many of the services provided by this program are available through traditional sources. Assistance with appliance selection is available at an appliance or department store, interior lighting design from an interior designer. These activities are not the function of an electric company, are available elsewhere, and would appear to promote the use of electric appliances. Therefore, I am recommending the disallowance of $425,474 for this program in base rates.

Q. SHOULD THE RECOVERY OF THE PRESENTATIONS/SEMINARS PROGRAMS BE ALLOWED THROUGH BASE RATES?

A. No. This program also was removed from ECCR recovery because the Company was unable to demonstrate its conservation value.

The program involves presentations to commercial customers and local construction allies. Mr. Bower, in his testimony, is unclear as to exactly what the purpose of such presentations are. He merely states the presentations and seminars include discussions of technology assessment, improved load factor, improved demand-side management, increased productivity and improved planning ability. Gulf Power is an electric public utility and not a management or production consultant. Such presentations would appear to be more for public relations and sales activities and not conservation or load management objectives. These programs were removed from ECCR recovery because their benefits could not be demonstrated and they should be removed from base rates for the same reason. I recommend disallowance of $55,429 from base rates for the cost of these presentations and seminars.

Q. IN SUMMARY, WHAT IS YOUR ADJUSTMENT FOR THESE FOUR PROGRAMS?

A. I am recommending the removal of the Good Cents Programs, the Energy Education Program and the Presentations/Seminars Programs. This results in a $2,114,681 decrease in operating expenses as shown in Exhibit 313 (HWS-12).

Customer Service and Information Benchmark

Q. DO YOU AGREE WITH THE COMPANY'S DETERMINATION OF THE CUSTOMER SERVICE AND INFORMATION BENCHMARK VARIANCE?

A. No, I do not. The Company should show a 1990 benchmark level of $2,318,000. This would indicate a variance of $3,108,000 in excess of the benchmark.

Instead of showing the appropriate benchmark variance, and then providing the necessary substantiation, the Company has attempted to recompute its own benchmark base. They have done this by adding $2,248,000 of ECCR programs to the 1990 benchmark. The Company is attempting to recover the cost of these programs in base rates, as a consequence of recovery of these programs being denied through ECCR in Docket No. 860718-EG.

As a result of the Company's unauthorized addition to the 1990 benchmark, they show a variance of $281,000 under the benchmark. This is incorrect. The correct amount of the customer service and information variance is $3,108,000 in excess of the benchmark.

Q. ARE YOU RECOMMENDING ANY OTHER ADJUSTMENTS TO CUSTOMER SERVICE AND INFORMATION?

A. Yes, I am. The Company is $3,108,000 over the benchmark for this category. The Commission stated when instituting the benchmark analysis for Florida electric utilities that the purpose of a benchmark was to "flag" expenditures for further analysis and justification of such excesses. As a result of the 1990 benchmark excess, Customer Service and Information expenditures have been "flagged" for a review of their reasonableness, appropriateness in rates and justification of such.

Q. HAVE YOU MADE A REVIEW OF THE CUSTOMER SERVICE AND INFORMATION BUDGET?

A. Yes, I have.

Q. WHAT WERE YOUR CONCLUSIONS?

A. The Company has not justified the inclusion of a variance of this magnitude in rates.

Q. WHAT SPECIFIC ADJUSTMENTS TO CUSTOMER SERVICE AND INFORMATION EXPENDITURES ARE YOU RECOMMENDING BE REMOVED?

A. I am recommending an adjustment to Essential Customer Services, Energy Audits, Industrial, Residential and Commercial Technology Transfer, Industrial Quality Power Program, Industrial Presentations/Seminars and

Technology Assessment.

In response to OPC 2-114, Gulf Power stated:

> The progı ams Gulf has implemented are all designed to increase the efficiency and energy consumption and lower the cost of electric service to its ratepayers.

Conservation programs should properly be recovered through the ECCR mechanism, and not through base rates. If the conservation value of these programs is what the Company purports it to be, then the conservation clause will allow direct recovery of costs associated with these programs. If, however, through an ECCR review of these programs it is determined these programs do not actually have a direct conser ation effect, thereby precluding recovery through ECCR, it leaves one to doubt whether justification exists for their existence.

The effect of leaving these programs in base rates is to have all customers pay for services used by only some. The average customer is most likely unaware that his monthly electric bill includes expenses for programs and services which he may not need, care about, or even know of. The end result being, when a single customer participates in, for example, Gulf's so-called Essential Customer Services, all of his neighbors are paying for his participation. This is not fair, or even reasonable. If a customer needs or desires services beyond the provision of electric services, the customer who receives these services should pay for them, not his neighbors.

Q. HAVE YOU PREPARED AN EXHIBIT DETAILING THIS ADJUSTMENT?

A. Exhibit 314 (HWS-13), shows the detail of this adjustment. If these programs provide conservation benefits they belong in ECCR. If they provide no benefit conservationally, they constitute free services which under any other circumstance an individual desiring such services, would fully expect to pay fair value for. On Exhibit 314 (HWS-13), I have prepared a list of programs offered by Gulf Power which I am recommending be reviewed in ECCR as conversation expenses, as the Company has claimed they are. If a review finds that any of these programs are not in fact conservation programs, thereby not properly included in ECCR, then such programs should only be continued if revenues can be generated to equal the costs of the programs.

I am recommending an adjustment of $1,207,237 to Customer Service and Information.

Marketing

Q. ARE YOU RECOMMENDING ANY ADJUSTMENT FOR "MARKETING" EXPENDITURES IN THE 1990 TEST YEAR?

A. Yes, I am. Gulf has attempted to justify its increased marketing activities by attributing such activities to an allegedly increasingly competitive market.

One must remember when assessing the Company's explanations that Gulf Power is a regulated monopoly. If the market for Gulf's products is truly competitive, there would be no need for regulation. It would appear that Gulf is attempting to enjoy the advantages of a monopolistic environment while incurring costs for strategies associated with competing in a free market. The end result being the ratepayer must pay the high costs inherent in a natural monopoly which is relatively immune to free market forces and at the same time pay the costs of this same industry entering into free market activities. This is a contradiction which results in a waste of resources.

Q. IS GULF OPERATING IN A COMPETITIVE MARKET?

A. No, it is not. The Company has stated the following concerning the availability and preferences for electricity over natural gas:

> The first reason is the lack of available natural gas in Gulf's high growth areas during the last decade. Natural gas was not available, and in some instances it is still not available on the beaches where condominium construction dominated residential construction.
>
> The second reason is the type of growth Gulf has been experiencing, specifically multi-family and mobile homes. Multi-family construction, especially high rise, employs electric rather than natural gas appliances because of the lower cost of installation, safety, and maintenance. Piping multi-story buildings for natural gas adds to the cost of a project in a market that is very competitive. Developers, in order to remain competitive, will select the lowest cost alternative when selecting fuel sources. [Staff Interrogatory 2-44]

Gulf itself does not believe natural gas is competitive with electricity in its service territory.

Additionally, Gulf, in its 1990 Base Case Budget Forecast, has stated it serves an 80% share of the territory's population; it would not appear that there is any significant competition given Gulf's 80% share.

Q. WHAT BENEFITS HAS GULF CLAIMED IT HAS RECEIVED FROM ITS MARKETING EFFORTS?

A. Gulf claims its marketing efforts have reduced the overall cost of service to its customers. Additionally, the Company claims a few of its large industrial customers were considering the generation of their own electricity. Gulf was able to dissuade these customers from generating their own electricity through their marketing efforts.

Q. ARE GULF'S PERCEIVED BENEFITS OF ITS MARKETING EFFORTS VALID?

A. No, they are not. Gulf may view the loss of one of its commercial customers as detrimental, however in the long-run, the presence of large industrial customers who maintain their own generation facilities within a utility's territory can eliminate the need for investment in additional capacity. This phenomenon results because co-generators will sell off their excess capacity to the utility, allowing the utility's embedded costs to decline rather than increase.

Load management can be a beneficial tool to an electric utility enabling the Company to fill off-peak and valley sales, which, in turn, spreads more units of production across its investment. Gulf claims that marketing strategies have increased off-peak sales and not resulted in increased peak-hour demand. However, the Company has not substantiated this claim.

Load management is not the entire thrust of Gulf's increased marketing activities. Gulf, through its own admission, is aiming its marketing efforts at the active selling of electricity. This expense is totally inappropriate given our nation's continued dependence on foreign oil, conservation objectives in light of diminishing reservoirs of energy, potential hazards of nuclear energy and environmental and ecological concerns. The active selling and promoting of energy as defined in the FEECA should not be condoned nor supported by the ratepayer.

Q. WHAT ADJUSTMENT ARE YOU RECOMMENDING FOR MARKETING EXPENSE IN THE 1990 TEST YEAR?

A. I have identified $1,148,489 of marketing expense, as shown in Exhibit 315 (HWS-14). This may or may not be all of the expense related to marketing activities. I am recommending the removal of $1,148,489 from the test year, until such time as the Company can clearly show a definite benefit to ratepayers.

<u>Economic Development</u>

Q. IS GULF POWER COMPANY SEEKING RECOVERY OF ANY EXPENSES FOR ECONOMIC DEVELOPMENT?

A. Yes, the Company is seeking recovery of $687,000 for Economic Development.

Q. WHAT IS YOUR UNDERSTANDING OF THE PURPOSES OF THE ECONOMIC DEVELOPMENT EXPENSES?

A. Mr. Bowers in his testimony defined Economic Development as follows:

> The definition of economic development is creating wealth through the mobilization of human, financial, capital, physical and natural resources to generate marketable goods and services. Traditionally, economic development has been viewed as the "marketing" of Florida to domestic and foreign business and industry as a favorable place to relocate or expand their operations. The rapid emergence of global economic events such as heightened domestic and international economic competition, growing international trade, and rapid technological advancements, are mandating that economic development be looked at from a much broader perspective: one of assessing the strengths and weaknesses of an economy and making the investments necessary to improve the environment in which our existing businesses operate. Gulf Power has identified the need for and has committed resources to community development and not just generating economic growth. These activities, if successful, will be mutually beneficial to all ratepayers, society as a whole and the Company.

Q. SHOULD EXPENSES RELATING TO ECONOMIC DEVELOPMENT BE ALLOWED RECOVERY THROUGH BASE RATES?

A. No, they should not. Expenses incurred to "market" Florida to business and industries can hardly be considered necessary to the provision of electric service. If any relationship exists between an electric utility and the economic development of Florida it could only be that of selling more electricity.

Economic Development of Florida is outside the realm of providing reliable electric service. It should not be paid for by ratepayers. If Gulf believes it has a civic or market interest in the growth of Florida, it should support this interest at its own expense, not at the expense of ratepayers, who should be paying only for those expenses necessary in providing electric services.

Economic Development expenses have been incurred each year from 1984 through the present; however, they have not been recovered through base rates. (OPC 2-102). When Company witness McMillan was asked during OPC depositions why the Company has not removed Economic Development from the 1990 cost of service when these expenses had been removed in prior dockets, Mr. McMillan stated that in its previous dockets, these Economic Development costs were removed in adherence to Commission policy. However, for purposes of this docket, the Company believes these expenses are appropriate. Mr. McMillan further stated that the reason the Company now feels Economic Development expenses are appropriate in rates is not a result of any changes in the nature of the programs, but rather the Company felt it had "a good story to tell" this time.

Commission policy to date has been not to include these expenses in rates. The Company has indicated that the nature of this program has remained the same. Therefore, I am recommending the removal of $687,000 from O&M expense for the costs associated with Economic Development. This is consistent with Commission policy.

Benchmark Variances

Q. MR. SCHULTZ, IS THERE ANOTHER ASPECT OF THE COMPANY'S O&M BUDGET THAT YOU WOULD LIKE TO DISCUSS?

A. Yes. In the following section of my testimony, I would like to discuss some particular benchmark variances within the O&M budget. The adjustments resulting from my analysis of the benchmark variances, are summarized on Exhibit 316 (HWS-15).

Plant Crist

Q. PLEASE DISCUSS THE O&M BENCHMARK EXCESS FOR PLANT CRIST.

A. The first item to be discussed in relation to the steam production budget is condenser and cooling tower corrosion expense at Plant Crist. On page 42 of MFR Schedule C-57, the Company attempts to justify a benchmark variance of $289,000. The justification states that this cost is for necessary preventative maintenance and future cost savings.

This cost is in excess of the benchmark and should not be allowed unless the Company can provide a study that justifies the cost and shows a benefit to the ratepayers, such as a reduction to future maintenance costs.

Moreover, I question whether the total budget amount may be necessary since the 1988 budget deviation report showed that 1988 actual expense at Plant Crist was $360,000 under budget due to a reduced spending rate on cooling tower chemicals. Additionally, the 1989 third quarter budget deviation report indicated cooling tower chemical usage has been reduced. The Company's Form B-4C provided in response to Public Counsel's POD 1-9 for Plant Crist indicated a $129,000 decrease to the 1989 budget amount of $1,368,000 (Docket No. 881167-EI, Schedule C-16g, page 27 of 87). Subtracting the $129,000 from $1,368,000 equals $1,239,000 not the $1,296,000 as reflected in the Company's MFR Schedule C-57, page 3.

The actual expense has been under budget. The Company has reduced (though not as much as it claimed), the 1990 budget amount from the amount budgeted in 1989. Therefore, I believe the 1990 benchmark amount for condenser and cooling tower corrosion at Plant Crist, is adequate. Therefore, I am reducing the $1,296,000 budgeted for 1990 by $289,000 to the benchmark amount of $1,007,000.

Distribution System Work Order Clearance

Q. PLEASE DISCUSS THE O&M BENCHMARK EXCESS RELATING TO THE COMPANY'S DISTRIBUTION SYSTEM WORK ORDER CLEARANCE.

A. The Company has identified a $952,000 benchmark variance for Distribution System Work Order ("DSO") Clearance. The Company provided the following explanation for this benchmark excess:

> DSO clearance is the accounting process of allocating to expense the maintenance costs associated with distribution line construction accumulated on Distribution System Work Orders (DS0). Labor is allocated to maintenance expense when it is cleared from the work order in Construction Work in Progress (CWIP) to maintenance accounts after the work order is signed off and classified in the Company's Plant Accounting System.
>
> Prior to 1983, the method for clearing non-construction costs from work orders in CWIP was based on the engineer's final estimate of maintenance costs. This estimate was subtracted from the total cost of the job and the remaining costs were charged to plant and cost of removal accounts.
>
> After implementation of a new Plant Accounting System in January 1983, the total actual cost of the job was allocated over all items on the work order based on work standards for plant installed, plant removed, and maintenance expense. This process more accurately spreads the job costs over all estimated elements.
>
> In 1985, Gulf contracted with Jerry Robuck and Associates to develop a set of 630 different benchmarks which define the manhour requirements for distribution line construction and maintenance activities. Each standard was developed through the use of accepted industrial engineering techniques whereby each activity was broken down into its basic elements and then reassembled. These new manhour standards more accurately reflect the actual labor required to do construction and maintenance activities. The relative amount of dollars spent to do the work did not increase, but the distribution of charges between plant and

> maintenance accounts changed. A more accurate share of the job cost is charged to maintenance expense.
>
> The maintenance expense portion of DSO expenditures in 1984 was 8.0 percent. In 1987, the maintenance expense portion of DSO expenditures had risen to 12.9 percent representing an increase of 61 percent. The 1984 allowed amount for DSO CWIP clearance to maintenance expense did not reflect the change in the process based on the new standards. This resulted in the O&M Benchmark variance.
>
> In summary, since 1985, because of the development of manhour standards we are more accurately allocating less cost to capital projects and more cost to maintenance expense.

Q. DOES THIS COMPANY EXPLANATION TOTALLY JUSTIFY THE $952,000 BENCHMARK EXCESS?

A. No, it does not. GPC's explanation justifies a portion of the expense increase. However, an unjustified portion remains, which should be disallowed. The Company has stated that the new DSO system has caused a shift from capitalized items to expense. The Company has also stated that the maintenance expense portion of DSO increased from a 1984 level of 8.0% to a 1987 level of 12.9%. This represents a 61% increase in expenses. Concerning the overall level of distribution line construction and maintenance activities, however, the Company has stated:

> The relative amount of dollars spent to do the work did not increase, but the mix of charges between plant and O&M accounts changed.

A 61% increase over the 1984 allowed expense level of $1,190,000 indicates that the Company's explanation would justify an expense level of

$1,916,000 in 1987 as shown on Exhibit 317 (HWS-15), page 2 of 2. This is based on the Company's statements quoted above, including the Company's statement that: "The relative amount of dollars spent to do the work did not increase...." The 1987 expense is then increased by inflation for 1988 through 1990 resulting in a revised benchmark for 1990 of $2,326,846 as shown on Exhibit 317 (HWS-15), page 2 of 2. Thus, of the 1990 benchmark excess of $952,000, an amount of $418,154 ($2,745,000 incurred less the $2,326,846 justified) remains unjustified and should be disallowed.

Underground Line Extensions

Q. PLEASE DISCUSS THE COMPANY'S O&M BENCHMARK EXCESS ASSOCIATED WITH UNDERGROUND LINE EXTENSIONS.

A. The Company has identified a 1990 O&M benchmark excess of $351,000 associated with underground line extensions, and has provided the following explanation for this item:

> Between 1984 and September 1989, Gulf's miles of underground primary distribution lines increased 67 percent from 344 miles to 573 miles, and this trend is expected to continue. Our underground facilities are increasing at a rate far greater than customer growth and inflation for which the benchmark allows. Underground maintenance is very expensive due to the time it takes to find electrical faults, to remove earth or concrete and to resurface after the line is fixed. These additional manhours to restore service after outages are frequently done on overtime and with the assistance of contract crews. Also, the additional miles of underground lines and their aging is causing a related increase in maintenance costs in the 1990 budget.

The Company's explanation claims that because of the increased underground facilities, maintenance costs have increased. The Company indicates that the cost of maintenance on underground lines is 60% greater than that for overhead lines.

Underground facilities are increasing, but it is my understanding that the reason for installing underground cable is that it requires less maintenance. I would anticipate, therefore, that the lower maintenance requirements will produce an offset to the higher cost of maintenance associated with servicing underground lines. If this is not true, and the costs associated with overhead line maintenance are less than those of underground maintenance, then there is no cost-savings benefit to the Company or the ratepayers for the conversion to underground lines. The Company has not shown that the cost of maintaining underground facilities is less than that of overhead facilities. Therefore, I am recommending a disallowance of the $351,000 O&M benchmark excess as unjustified.

Network Protectors

Q. PLEASE DISCUSS THE BENCHMARK EXCESS ASSOCIATED WITH NETWORK PROTECTORS.

A. The Pensacola Underground Network System Repair expense discussed on MFR Schedule C-57, page 72, shows a variance of $135,000 over the 1990 benchmark of $39,000. According to the Company's explanation, the variance is $135,000 for the maintenance and remanufacture of network protectors. The Company has indicated that the network protectors are deteriorating to a point where they could fail to operate properly. Since this network system is 38 years old, Gulf determined it was necessary to overhaul the network protectors and replace necessary parts.

This remanufacture program is scheduled to be completed over a period of 3 years and will restore these protectors to a "like new" condition. These protectors lasted 38 years when they were originally installed, and it is anticipated that they will last at least half that long after being overhauled.

This program was originally budgeted at $155,200 in 1989. According to the budget variance reports for 1989, the work was deferred.

The 1990 budget process reduced the budgeted amount to $90,000 and the Company's budget form B-4(c) stated that this recurring expense would last through 1991. Therefore, I am recommending that the $90,000 be deducted from the operating budget and capitalized

Electric & Magnetic Fields Study

Q. PLEASE DISCUSS THE COMPANY'S STEAM PRODUCTION BENCHMARK EXCESS ASSOCIATED WITH THE ELECTRIC AND MAGNETIC FIELDS ("EMF") STUDY.

A. In MFR Schedule C-57, page 5, the Company has indicated that these costs were incurred for researching the correlation between (1) electric and magnetic fields from electric transmission and distribution facilities and (2) adverse health effects. Gulf participated with the Florida Electric Power Coordinating Group ("FCG") in funding research on this issue in Florida. Gulf also financially supports research on EMF through the Southern Company Services' ("SCS") investment in the Electric Power Research Institute ("EPRI"). Additionally, SCS funded a literature review of published material on this issue.

The Company had research expenses in its last rate case. The amount for research from the prior case--the benchmark base period--was not zero. Shifting the focus of research to cover a new area does not justify this benchmark excess. Moreover, I must question the need to fund different groups performing potentially duplicative research on the same issue.

Q. YOU MENTIONED THAT RESEARCH ON ELECTRIC MAGNETIC FIELDS WAS PERFORMED BY THE ELECTRIC POWER RESEARCH

INSTITUTE. PLEASE EXPLAIN.

A. According to EPRI's Research and Development Program for 1988 through 1990, EPRI plans to spend $4.3 million on research for electric magnetic fields in 1988. The expenditures of SCS to "study" this issue, therefore, could be duplicating EPRI efforts. The Company's explanation does not justify the benchmark excess. Accordingly, I recommend disallowing the entire $39,000 amount over the benchmark for EMF research as duplicative of what is already reflected in EPRI dues.

<u>Acid Rain Monitoring</u>

Q. PLEASE DISCUSS THE O&M BENCHMARK EXCESS ASSOCIATED WITH ACID RAIN MONITORING.

A. The amount of this benchmark excess is $43,000. The Company has explained that it incurred acid rain monitoring expenses associated with funding of the Florida Acid Deposition Study. On page 8 of MFR Schedule C-57, the Company claims that the amount allowed for this item in the 1984 benchmark was zero. Gulf Power's contribution to the Acid Rain Deposition Study in 1984 was not zero, but rather $47,452. (See Staff Interrogatory 4-1, Docket 881167-EI). Because the Company's explanation does not justify the benchmark excess, I am recommending a disallowance of $43,000.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING THE O&M EXPENSE OF GULF POWER COMPANY?

A. As part of the budget review, it was determined that some of the actual expenses from 1989 should be examined. This examination, as restricted in scope as it was, was intended to assist us in evaluating the Company's budgeting system, the type of expenses the Company was incurring and the propriety of such expenses. Approximately 225 invoices were selected for review and some of the selected invoices appear questionable. Some of the questionable costs the Company is incurring are expenses for lavish banquets and hotel accommodations, and gratuities such as golf balls, jewelry items, etc., just to name a few. More such questionable items were found in the sample and, presumably, more exist outside the sample. The nature of these expenses do not appear to be the type of costs that would be incurred by a Company in need of additional revenue, but those of a Company with money to spend.

To avoid duplication of adjustments, no adjustment is being proposed for these questionable items because they may be a part of the benchmark adjustment I am proposing.

Q. HAVE YOU SUMMARIZED YOUR ADJUSTMENTS TO THE 1989 EXPENSE BUDGET?

A. These adjustments are summarized on Exhibit 301 (HWS-2). The total effect of these adjustments is a reduction of test year expenses by $19,139,658. This total is carried over to Exhibit 300 (HWS-1) which summarizes the net operating income for the test year 1990.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

MR. BURGESS: Again, we would dispense with the presentation of a summary, primarily because it covers such a wide range of issues, all of which are underpinned by their individual rationale, and we would simply, at this point, offer Mr. Schultz, tender him for cross examination.

(Transcript follows in sequence in Volume XVII.)

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