BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of | DOCKET NO. 010949-EI

REQUEST FOR RATE INCREASE
BY GULF POWER COMPANY.
_______________________________/

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VOLUME 7
Pages 601 through 724

PROCEEDINGS: HEARING

BEFORE: CHAIRMAN LILA A. JABER
COMMISSIONER J. TERRY DEASON
COMMISSIONER BRAULIO L. BAEZ
COMMISSIONER MICHAEL A. PALECKI
COMMISSIONER RUDOLPH "RUDY" BRADLEY

DATE: Monday, February 25, 2002

TIME: Commenced at 9:30 a.m.
Recessed at 6:24 p.m.

PLACE: Betty Easley Conference Center
4075 Esplanade Way, Room 148
Tallahassee, Florida

REPORTED BY: MARY ALLEN NEEL, RPR

APPEARANCES: (As heretofore noted.)

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P R O C E E D I N G S

(Transcript follows in sequence from Volume 6.)

CHAIRMAN JABER: And the next witness would be Mr. Labrato, Gulf; is that right?

MR. STONE: That is correct.

Thereupon,

RONNIE R. LABRATO

was called as a witness on behalf of Gulf Power Company and, having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. STONE:

Q Mr. Labrato, were you here earlier when the witnesses were sworn?

A Yes, I was.

Q And you took the oath at that time?

A Yes, I did.

Q Okay. Would you please state your name and business address for the record?

A My name is Ronnie R. Labrato, and my business address is One Energy Place, Pensacola, Florida.

Q By whom are you employed and in what capacity?

A Gulf Power Company. I am Vice President, Chief Financial Officer, and Comptroller.

Q Mr. Labrato, have you prefiled direct testimony consisting of 26 pages in this proceeding?

A Yes, I have.

Q Now, there have been a number of stipulations that have resulted -- there have been a number of modifications to positions that have resulted in stipulations that have taken certain issues out of contention in this case. Other than those stipulations, are there any changes or corrections to your testimony?

A No, there are not.

Q So if I were to ask you the same questions today, would your answers be the same?

A Yes, they would.

MR. STONE: We ask that the prefiled testimony of Mr. Labrato be inserted into the record as though read.

CHAIRMAN JABER: The prefiled direct testimony of Ronnie R. Labrato shall be inserted into the record as though read.

BY MR. STONE:

Q Mr. Labrato, did you have an exhibit to your direct testimony labeled RRL-1?

A I did.

Q And did that exhibit contain 21 schedules?

A Yes.

Q Are you sponsoring a section of the MFRs identified on Schedule 21 of your exhibit?

A Yes, I am.

Q Again acknowledging that there have been certain changes to the Company's positions that have resulted in the stipulation of certain issues that have been resolved thus far in the case, other than those, do you have any changes to the exhibits or to your portion of the MFRs?

A No, I do not.

MR. STONE: We would ask that his exhibit RRL-1 be identified for the record.

CHAIRMAN JABER: So identified. That would be Exhibit 37.

(Exhibit 37 was marked for identification.)

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
Ronnie R. Labrato
Docket No. 010949-EI
In Support of Rate Relief
Date of Filing: September 10, 2001

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

A. My name is Ronnie R. Labrato. My business address is One Energy Place, Pensacola, FL 32520. I am Vice President, Chief Financial Officer and Comptroller of Gulf Power Company.

Q. Please outline your educational background and business experience.

A. I graduated from the University of West Florida in 1974 with a Bachelor of Arts degree in Accounting. Following graduation from college, I was employed by the Florida Public Service Commission (FPSC) as Auditor and Accounting Analyst. In 1977, I accepted a position as Senior Accountant and Consultant with Deloitte, Haskins, and Sells in Dallas, TX. In 1979, I was employed by Gulf Power Company as Senior Financial Analyst. Since 1979, I have held various positions at Gulf Power, including Supervisor of Budgeting and Financial Planning, Manager of Financial Planning, Manager of General Accounting, and Comptroller. I currently serve as Vice President, Chief Financial Officer and Comptroller.

Q. What professional license do you hold in the field of Accounting?

A. I am a licensed Certified Public Accountant and a member of the American Institute of Certified Public Accountants and the Florida Institute of Certified Public Accountants.

Q. Briefly describe your duties and responsibilities as Vice President, Chief Financial Officer and Comptroller.

A. I am responsible for maintaining the overall financial integrity of the Company. My areas of responsibility include the Accounting, Regulatory Affairs, and Corporate Planning departments. I am also responsible for maintaining the overall financial and accounting records of the Company. Gulf Power Company maintains its books and records in accordance with generally accepted accounting principles and the rules and regulations prescribed for public utilities in the Uniform System of Accounts published by the Federal Energy Regulatory Commission (FERC), and adopted by the FPSC. Our books and records are audited by Andersen LLP, independent public accountants, and a copy of their latest audit opinion, for the year ending 2000, is included in the Company's 2000 Annual Report to Stockholders, which is filed as MFR F-1 in this case. Our books and records are also audited by the FERC and this Commission.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain the need for rate relief beginning with the commercial in-service date of Smith Unit 3 and to discuss the rate relief requested based on the June 2002 through May 2003 test year. In addition, I will present Gulf's financial forecast, which is the basis of the projected data for the test period; develop the test year rate base, net operating income, and cost of capital; and calculate the resulting revenue deficiency, which the Company has identified in this filing.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?

A. Yes. Exhibit (RRL-1) was prepared under my supervision and direction.

Counsel: We ask that Mr. Labrato's Exhibit (RRL-1), comprised of 21 schedules, be marked as Exhibit No. ____.

Q. What is the source of the figures shown in Exhibit (RRL-1)?

A. The projected data presented on the schedules of this exhibit was obtained from Gulf's financial forecast for the test period, which I will discuss later in my testimony.

Q. Are you the sponsor of certain Minimum Filing Requirements (MFRs)?

A. Yes. These are listed on Schedule 21 at the end of my exhibit.

Q. Please explain why a split calendar year was chosen as the test period.

A. The period June 2002 through May 2003 was chosen as the projected test year because Gulf's new combined cycle unit at Plant Smith is expected to be in commercial operation on or before June 1, 2002. As our testimony and exhibits will show, there is an immediate need for an increase in Gulf's retail rates beginning with the commercial in-service date of Smith Unit 3. The chosen test year is representative of Gulf's expected future operations after Smith Unit 3 is in service and is the first full year that new rates will be in effect.

Q. What is the amount of rate relief that Gulf is requesting in this case?
A. Gulf is requesting an annual increase of $69.9 million in our retail revenues. This amounts to an 11.9 percent increase in our retail revenues.

Q. Why is it necessary for the Company to seek rate relief at this time?
A. As authorized by the FPSC in Docket No. 990325-EI, Gulf Power is constructing a new 574-megawatt (mW) combined cycle unit at Plant Smith. Smith Unit 3 is expected to begin commercial operation on or before June 1, 2002. Smith Unit 3 is the first major generating unit to be built by Gulf Power Company in nearly 15 years. The addition of this generating capacity is necessary for us to continue to meet the electricity needs of our customers. The Company projects capital expenditures totaling $220.5 million for the construction of Smith Unit 3 and an additional $2.8 million related to improvements necessary to connect the new unit to the transmission system. These capital expenditures will result in a 20 percent increase in the Company's jurisdictional rate base. The new unit will also increase annual operation and maintenance (O & M) expenses by approximately $3.4 million in the test year. The total annual revenue requirement for the new unit is approximately $48 million.

Q. Are there reasons other than Smith Unit 3 for the Company's need for rate relief?

A. Yes. The additional $22 million of rate relief requested in this case is necessary to cover significant increases in O & M expenses and capital additions primarily in the production, transmission and distribution functions, which cannot be offset by revenue growth. Increases in production expenses relate to higher outage costs and an increase in costs to maintain Gulf's existing fleet of generating units. This maintenance is necessary to maintain plant efficiencies and minimize forced outages to enable the Company to provide reliable and cost-effective generation to our customers. Significant expenditures for transmission facilities are necessary to ensure the continued reliability of Gulf's transmission system as well as to meet the growing needs of the Company's customers. Increases in distribution expenses relate to maintenance of the Company's aging electrical infrastructure to reduce failures and maintain reliable service to our customers. The Company has also had to implement new technologies and productivity improvements to keep up with the growing service expectations of our customers. The Company's customers today are requiring a higher level of reliability with respect to blinking lights and momentary outages due to an increase in the use of computerized equipment. Mr. Moore, Mr. Howell, and Mr. Fisher will discuss reasons for the increases in O & M and capital additions related to these functions and the specific programs that the Company is implementing to ensure that we continue to provide dependable and reliable service to our customers.

Q. Has the Company's cost of providing electric service increased since 1990, Gulf's test year in the last rate case?

A. Yes. In addition to expenditures for the construction of Smith Unit 3, Gulf will have made capital expenditures of nearly $900 million for the 12.5-year period since 1990, the test year in the Company's last rate case, to the end of the test year in this case. Since the Company's last rate increase in 1990, increases in O & M have also been necessary. The adjusted non-fuel O & M level for the current test year is $69.5 million higher than the O & M level approved for the 1990 test year. However, the adjusted non-fuel O & M level for the current test year is $3.7 million under the amount determined using the Commission prescribed benchmarking process.

In addition to expenses related to Smith Unit 3, several factors have contributed to the increase in the Company's cost of providing electric service during the 12-year period since 1990, the Company's last test year, to the end of 2002. During this period, Gulf's customer base has increased by approximately 32 percent and the Company has experienced inflation of approximately 39 percent. The Company has also constructed new infrastructure of approximately 1400 miles of distribution lines and 90 miles of transmission lines.

Q. Has Gulf tried to avoid the need for rate relief?

A. Yes. Gulf Power has continued to make great efforts to maintain a low level of expenses to avoid the need for rate relief. For example, efforts have been made to run our business in a more efficient and effective manner while still maintaining quality service and high levels of customer satisfaction. These efforts have enabled the Company to reduce its work force by nearly 10 percent below the work force level in 1990. Gulf Power's commitment to creating value for our customers and our investors is reflected in the Company's low kilowatthour cost, high quality service, and excellent customer satisfaction ratings.

Q. Have you made a comparison of Gulf's residential rate to that of other companies?

A. Yes. I have compared Gulf's residential rate for 1000 kWh to those of 53 other utilities across the nation and in the State of Florida as of July 2001. As shown on my Schedule 1, Gulf's residential rate is among the lowest in the comparison group, with only 4 other utilities having lower rates than Gulf Power.

Q. Would Gulf's residential rate still compare favorably if the $69.9 million of rate relief requested in this case is granted?

A. Yes. As also shown on my Schedule 1, Gulf's proposed residential rate for 1000 kWh would remain among the lowest when compared to other utilities across the nation and in the State of Florida.

Q. Mr. Labrato, what are the projected rates of return for Gulf Power Company for June 2002 through May 2003 with present retail rates?

A. Although the Company is projecting to earn within its authorized return on equity range for the 2001 calendar year, the large investment in Smith

Unit 3, as well as other capital additions, and the significant increase in O & M expenses will cause a dramatic decrease in the Company's return on rate base and common equity. With present rates, the adjusted jurisdictional return on average rate base is projected to be 5.12 percent for the 12 months ending May 2003. This provides a return on the average common equity component of 4.43 percent, which is significantly below the 13.00 percent determined by Mr. Benore to be appropriate for Gulf Power Company.

Q. Do projections indicate that Gulf's earnings without rate relief will leave the Company in a weak financial position?

A. Yes.

Q. What are the implications of this weak financial position for the Company and its customers?

A. Investors provide a significant portion of the capital needed to construct our generation, transmission, and distribution facilities. In exchange, they expect, and they deserve, a fair return on their investment, which adequately compensates them for the risks undertaken.

Without rate relief, Gulf's ability to successfully access both the debt and equity markets on reasonable and acceptable terms would be jeopardized. The Company's inability to obtain required external financing on reasonable terms could ultimately restrict growth, inhibit reliability, and increase reliance on short-term debt, which would increase financial leverage and deteriorate the Company's financial condition.

A weakened financial position would prevent the Company from being able to offer securities with sufficiently attractive returns to investors. This would adversely affect capital attraction, as mentioned above, and would make it difficult for the Company to continue to provide reliable service at reasonable costs to our customers. Thus a continued ability to successfully attract investment capital is critical to the Company's ability to provide reliable and low-cost electric utility service to our customers. A strong financial position would enable the Company to attract capital on reasonable terms, maintain a sufficient level of financial integrity, and continue to meet the needs of our customers.

Q. Without rate relief, would your security ratings be put in jeopardy?

A. Yes. In a recent report on Gulf Power, the Moody's rating agency stated that Gulf's financial flexibility would be reduced as the Company begins construction of Smith Unit 3. Gulf currently receives high credit ratings that are supported by strong financial indicators, such as a pretax interest coverage ratio greater than 4 times and a funds from operations (FFO) interest coverage ratio greater than 5 times. Without rate relief, however, Gulf's ratios would be slightly greater than 2 times and 4 times for pretax interest coverage and FFO interest coverage, respectively. Also, the Fitch IBCA, Duff & Phelps rating agency reported recently that Gulf's credit protection measures are "weakened" due to higher capital expenditures related to the construction of Smith Unit 3.

Therefore, we believe that without adequate rate relief our debt and preferred stock ratings would be downgraded. Such events when combined with associated ramifications discussed earlier would increase the Company's overall financial risk and cost of capital while constraining its ability to access the capital markets on reasonable and acceptable terms.

Q. Mr. Labrato, you have indicated that you will present and support the financial forecast used in developing the June 2002 through May 2003 test year data. Please explain what you are supporting in this filing.

A. As noted by Mr. Saxon in his overview of Gulf's planning and budgeting process, there are eight component budgets which are prepared and supported by other witnesses in this proceeding. These component budgets are noted on Schedule 1 of Mr. Saxon's exhibit. I am supporting how the outputs from these component budgets were utilized, in conjunction with other information and data, to develop the Company's financial forecast and Annual Operating Budget. I have used the financial forecast and Annual Operating Budget in developing the Company's June 2002 through May 2003 test year rate base, net operating income, and capital structure.

Q. Please explain how the financial forecast is developed.

A. The outputs from Gulf's budgeting process, comprising the eight component budgets, are formatted and tailored in a manner to facilitate their input into the financial model, along with various other income statement and balance sheet amounts. The financial model in turn generates the financial and accounting statements that comprise Gulf's financial forecast.

Q. What is the financial model to which you have referred?

A. The financial model is a proprietary computer-based model that simulates Gulf's actual financial and accounting results based on a given set of inputs. Schedule 2 is a summarized flowchart of the financial model inputs and outputs required in producing the financial forecast.

Q. Please describe the financial statements shown on Schedules 3 and 4.

A. Schedule 3 is Gulf's projected Balance Sheets for the periods ended May 2002 through May 2003, which are the basis for developing the rate base and capital structure. Schedule 4 is the projected Income Statements for the twelve months ended May 31, 2003, used in developing net operating income. These financial statements from the financial model are based on current budget estimates for 2002 and 2003.

Q. You have summarized utility plant data on your Schedule 3. Have you prepared a report with a further breakdown of the plant balances?

A. Yes. Schedule 5 presents a further breakdown of the utility plant balances along with the monthly activity in these accounts for the periods ended May 2002 through May 2003. The accounts shown include non-depreciable and depreciable property, plant held for future use, construction work in progress, and accumulated provision for depreciation. The projected plant data is based on the 2002 and 2003 Capital Additions Budgets, which are supported by various witnesses as noted on Mr. Saxon's Schedule 2.

Q. Have you prepared a schedule which shows the derivation of rate base?

A. Yes. Schedule 6, entitled "13-Month Average Rate Base for the Period Ended May 31, 2003," reflects Gulf's test year rate base. Column one includes the budget data previously presented on Schedules 3 and 5. The second column includes the regulatory adjustments required in order to restate the system or per books amounts to the proper basis for computing base rate revenue requirements. The third column includes the Unit Power Sales (UPS) adjustments, which I will address in more detail later in my testimony. The resulting net amounts have been jurisdictionalized in the cost of service study filed in this case by Mr. O'Sheasy as Schedules 1 through 5 of exhibit (MTO-1).

Q. Please explain the rate base regulatory adjustments in column 2 of Schedule 6.

A. These adjustments are listed on page 2 of the schedule. Adjustments 1 and 4 were made to remove the utility plant investment and accumulated depreciation which have been allocated to our Appliance Sales function. Since the last rate case, the amount of these adjustments has decreased significantly, which I will discuss later. Adjustments 2, 3, 5, and 6 were made to remove investments and related accumulated depreciation which are recovered through the Environmental and Energy Conservation Cost Recovery Clauses. Adjustments 7 and 8 were made to accumulated depreciation to reflect an increase in depreciation expense based on the

Company's new proposed depreciation rates and dismantlement accruals, which have been filed in Docket No. 010789-EI with the Commission on May 29, 2001, through the Company's 2001 Depreciation and Dismantling Study, and to reflect the revised estimate of the depreciable life for Smith Unit 3. These adjustments to reflect the new proposed depreciation rates and dismantlement accruals and the 20-year depreciable life of Smith Unit 3 are further discussed later in my testimony when I cover net operating income adjustments to depreciation expense. Adjustments 9 and 11 were made to remove the construction work in progress (CWIP) amounts for projects which are recovered through the Environmental and Energy Conservation Cost Recovery Clauses. Adjustment 10 is for the removal of the interest bearing CWIP included in the forecast. Since these projects are eligible for Allowance for Funds Used During Construction (AFUDC), they have been removed from rate base. Adjustment 12 represents working capital adjustments, which are included on Schedule 7.

Q. Please explain Schedule 7, entitled "13-Month Average Working Capital for the Period Ended May 31, 2003."

A. As shown on this schedule, all items on the balance sheet which are not included in Net Utility Plant or Capital Structure were considered in developing working capital. These remaining accounts were examined, and I have excluded the amounts related to the Appliance Sales function, Environmental Cost Recovery Clause, and accounts which earn or incur interest charges. The total of the amounts excluded is shown in column 2 on page 1 of Schedule 6 as adjustment 12. The adjustment to working capital in column 3 of Schedule 6 reflects the amounts allocated and directly assigned to UPS for fuel stock, materials and supplies, prepayments, and other working capital. The resulting total adjusted working capital, as shown in column 4, was then allocated to the retail and wholesale jurisdictions by Mr. O'Sheasy.

Q. Was an adjustment made to the rate base related to the third floor of the corporate office building?

A. No. The Company did not make an adjustment to remove the cost of the third floor of the corporate office building from rate base. In Gulf's last rate case, the Commission ordered the Company to remove investment of $3.8 million and depreciation reserve of $338,000 from the rate base related to the third floor. The Company believes that the third floor investment should be included as part of the rate base and should begin to be depreciated. This space is primarily used for records retention, spare office furniture, miscellaneous supplies, and other storage for the print shop, safety and health, and power delivery functions. It also contains a workshop for building maintenance. In February of 1999, after completing a tour of the third floor, an auditor with the FPSC concluded that over 90 percent of the square feet of space was being utilized. The Company currently utilizes 100 percent of the square feet of space. In addition to including the investment and accumulated depreciation related to the third floor in the test year rate base, we have also included in the calculation of net operating income the amortization of the accumulated balance of the deferred return on the third floor over a period of 3 years.

Gulf is currently operating under a revenue sharing plan resulting from a stipulation approved by Order No. PSC-99-2131-S-EI. Our treatment of the cost of the third floor described above is consistent with the provision included in Gulf's revenue sharing plan allowing Gulf the discretion to amortize up to $1 million per year to reduce the accumulated balance of the deferred return on the third floor.

Q. You have previously mentioned that the rate base was adjusted for amounts related to the Appliance Sales function. Please describe the reason for the significant decreases in these adjustments.

A. In July 2000, Gulf Power discontinued its Appliance Sales operation. On August 31, 2000, the Company sold $9.1 million of its merchandise accounts receivable to a third party and will continue to handle billing and collections for a monthly servicing fee. Therefore, the amount of investment now allocated to the Appliance Sales function is minimal and represents only the building space and office furniture and equipment utilized in the servicing of the merchandise loans. Also, the adjustment to working capital is minimal due to a small amount of merchandise receivables remaining on the Company's books.

Q. Before leaving the area of rate base, were there any other adjustments made to rate base in the 1990 rate case that you are not making in this case?

A. Yes. There were several adjustments made in the last rate case which are not necessary in this case because the items have either been fully amortized, sold, or removed from electric operations. The Commission adjustments not made are listed on MFR A-11. Also, no adjustments were made to working capital for the inventory levels of coal, natural gas, or light oil. As discussed by Mr. Moore in his testimony, the inventory levels for coal, natural gas, and light oil included in working capital represent optimum levels necessary to ensure against disruptions in supply.

Q. Now moving to Net Operating Income (NOI), please explain Schedule 8 entitled "Net Operating Income for the Twelve Months Ended May 31, 2003."

A. This schedule is formatted in the same manner as the rate base schedule. The first column is based on the June 2002 through May 2003 budget data from Schedule 4. The second column includes the regulatory adjustments, while the third column includes the UPS amounts. The jurisdictional factors and amounts were obtained from Mr. O'Sheasy's Schedule 1. The regulatory adjustments in column two are listed on pages 2 and 3 of Schedule 8, with more detailed calculations presented on separate schedules as noted under the heading of Schedule Reference. As mentioned earlier, I will discuss the UPS adjustments and calculations later in my testimony.

Q. Have you made the proper adjustments to remove all revenues and expenses related to the various cost recovery clauses from NOI?

A. Yes. As noted on pages 2 and 3 of Schedule 8, the fuel clause adjustments are 1, 6, and 7, the purchased power capacity clause adjustments are 4 and 8, the environmental clause adjustments are 5, 16, 18, and 25, and the energy conservation clause adjustments are 2, 10, 19, and 22. Since these revenues and expenses are recoverable through the retail cost recovery clauses, they must be removed from NOI when determining base rate revenue requirements. The calculation of these adjustments is summarized on Schedules 9 through 12.

Q. Please explain the franchise fee adjustments 3 and 23 on Schedule 8.

A. These adjustments are necessary to eliminate county and municipal franchise fee revenues and expenses from consideration in setting base rates. As required by Commission Order 6650 in Docket No. 74437-EU, franchise fees are added directly to the county or municipal customer's bill and are not considered in determining base rate revenue requirements.

Q. Please explain adjustment 9 related to marketing support and bulk power energy sales activities.

A. Expenses related to marketing support activities have been removed from NOI in accordance with the Commission's policy to disallow expenses that are promotional in nature as stated in Commission Order 6465 in Docket No. 9046-EU. Expenses related to bulk power energy sales activities were also removed from NOI in the calculation of retail revenue requirements since these expenses relate to the wholesale business.

Q. What does the adjustment for economic development represent?

A. Adjustment 12 related to economic development represents the removal of five percent of economic development expenses for the test year, which is consistent with FPSC Rule 25-6.0426 related to the recovery of economic development expenses. Section 288.035 of the Florida Statutes provides the FPSC with the authority to permit public utilities to recover reasonable economic development expenses. Ms. Neyman's testimony provides further discussion of the Company's economic development expenses.

Q. Please explain adjustment 14 related to purchased transmission.

A. FERC account 565 includes expenses incurred for the transmission of the Company's electricity over transmission facilities owned by others. These expenses are recovered through the Fuel Cost Recovery Clause and, therefore, were removed from the calculation of NOI.

Q. Was an adjustment made for industry association dues?

A. Yes. Industry association dues were treated in the same manner as economic development expenses. We have removed five percent of industry association dues related to chambers of commerce and other organizations that engage in economic development activities in accordance with FPSC Rule 25-6.0426 related to the recovery of economic development expenses. As mentioned previously, Section 288.035 of the Florida Statutes provides the FPSC with the authority to permit public utilities to recover reasonable economic development expenses. This state legislation defined an economic development organization as a "state, local, or regional public or private entity, which engages in economic development activities" and listed city and county economic development organizations and chambers of commerce as qualified organizations. The adjustment to remove five percent of these expenses from NOI is shown as adjustment 15 on Schedule 8, page 3 of 3. Schedule 13 presents a listing by association of the dues included in the NOI calculation and shows the calculation of adjustment 15.

Q. Were any adjustments made for advertising?

A. Yes. Advertising expenses related to the Energy Conservation Cost Recovery Clause were removed as part of adjustment 10 on Schedule 8. All other advertising expenses are appropriate for recovery and are supported by Ms. Neyman in her testimony.

Q. Please explain the adjustments made related to depreciation.

A. Adjustments 17 and 20 were made to reflect the Company's new proposed depreciation rates and dismantlement accruals, which have been filed in Docket No. 010789-EI with the Commission on May 29, 2001, through the Company's 2001 Depreciation and Dismantling Study. Gulf Power has requested for the proposed rates to be effective January 2002. Therefore, the changes in depreciation expense on plant-in-service investment balances for the test year were included as adjustments to NOI. Adjustment 17 represents the change in depreciation of transportation equipment, which is charged to a clearing account and then allocated to the appropriate O & M accounts, and adjustment 20 represents the change in depreciation expense and dismantlement accruals for other plant-in-service investment balances.

The depreciation study filed by Gulf with the FPSC on May 29, 2001, was based on December 31, 2001, projected investment and, therefore, did not include Smith Unit 3, which is expected to go in service in the Spring of 2002. The forecasted depreciation expense for Smith Unit 3, included as part of Schedule 4 of my exhibit, was calculated assuming a depreciable life for Smith Unit 3 of 30 years. Since the financial forecast was developed, Gulf requested an opinion from Deloitte & Touche, the firm that performed the Company's depreciation study, on the appropriate depreciable life for Smith Unit 3. The firm reviewed the manufacturers' information and capital forecast for Smith Unit 3. In addition, the firm reviewed responses made by Florida Power & Light to FPSC data requests concerning its combined cycle units. Based on its review, Deloitte & Touche recommended an average service life of 20 years. The memo from Deloitte & Touche containing its recommendation is attached as Schedule 14 of my exhibit. The estimated 20-year depreciable life for Smith Unit 3 is also consistent with depreciable lives approved by the FPSC for other combined cycle generating units operating in Florida. Therefore, adjustment 21 was made to NOI to reflect an estimated depreciable life for Smith Unit 3 of 20 years, which is consistent with the Deloitte & Touche recommendation and the treatment of other combined cycle units in Florida.

Q. Please explain adjustments 26 and 27 to taxes other than income taxes.

A. Adjustment 26 on Schedule 8 is required to reflect the gross receipts taxes and FPSC assessment fees that are associated with clause revenues and franchise fee revenues, which were removed in adjustments 1 through 5. Schedule 15 shows the calculation of this adjustment. Adjustment 27 represents the addition of property taxes related to Smith Unit 3 to reflect twelve months of property taxes in the test year. The calculation of Smith Unit 3 property taxes is discussed in Mr. McMillan's testimony.

Q. Please explain adjustment 28 on Schedule 8 to income taxes.

A. This adjustment is required to reflect the federal and state income taxes related to adjustments 1 through 27. Schedule 16 shows the calculation of this adjustment.

Q. Have you calculated the appropriate adjustment to income taxes to reflect the synchronized interest expense related to the jurisdictional adjusted rate base?

A. Yes. Adjustment 29 on Schedule 8 reflects the tax effect of synchronizing interest expense to rate base, and Schedule 17 shows the calculation of this adjustment. The jurisdictional capitalization amounts and cost rates were taken directly from Schedule 18, and total company interest expense was taken from Schedule 4.

Q. Do you have anything further to add to your discussion of how NOI was developed?

A. Yes. In addition to the adjustments made above, adjustments 11, 13, and 24 on Schedule 8 were made to NOI consistent with the Commission's direction in the last rate case to exclude management tax preparation services and lobbying expenses. Also, I would like to point out that O & M expenses included in the calculation of NOI are justified and supported by several witnesses in this case as noted on Mr. Saxon's Schedule 3.

Q. Have you also developed the jurisdictional capital structure and cost of capital for the June 2002 through May 2003 test year?

A. Yes. Schedule 18, page 1, shows the jurisdictional 13-month average amounts of each class of capital for the year ended May 31, 2003. It also shows the average cost rates and weighted cost components for each class of capital. Page 2 of this schedule shows how the jurisdictional capital structure was derived starting with the system amounts. Pages 3 and 4 show the calculation of the cost rates for long-term debt and preferred stock.

Q. How were the cost rates for short-term debt, customer deposits, and investment tax credits determined?

A. The short-term debt cost rate of 6.02 percent was based on an April 2001 forecast of interest rates, which was developed by Southern Company Services utilizing forecast data obtained from Regional Financial Associates, now known as Economy.com, Inc. The customer deposit cost rate of 5.98 percent was based on the effective rate for the twelve months ended May 31, 2003. The weighted cost for investment tax credits of 9.70 percent was calculated in accordance with current IRS regulations using the three main sources of capital.

Q. Please explain how the jurisdictional capital structure was developed.

A. As shown on page 2 of Schedule 18, I started with the 13-month average total company capital structure by class of capital. These total company amounts were calculated based on the projected balances on Schedule 3 of my exhibit. In columns 2 through 6, I have identified 5 adjustments which were removed from specific classes of capital, and the remaining adjustments required to reconcile the rate base and capital structure were made on a prorata basis as shown in column 9.

Q. Please explain the 5 items for which you have made adjustments to specific classes of capital.

A. The first item, shown in column 2, reflects the transfer of preferred stock issuance expense previously charged to retained earnings. The next two items, "common dividends declared" and "unamortized debt premiums, discounts, issuing expenses and losses on reacquired debt," are account specific and have been directly assigned to the common stock and long-term debt classes of capital, respectively. The fourth item, shown in column 5, is the removal of non-utility amounts from the common stock class of capital. The last item, shown in column 6, is the removal of the UPS capital structure amounts. The UPS capital structure adjustments are based on the debt, preferred stock, deferred taxes, and common equity that is recovered from UPS customers in the UPS contracts.

Q. Does this conclude your discussion of how you developed the requested cost of capital?

A. Yes. These calculations result in a cost of capital of 8.64 percent based on a requested return on equity of 13.00 percent, which is supported in the testimony of Mr. Benore.

Q. Have you calculated the jurisdictional revenue deficiency for the test period brought about by the difference in Gulf's achieved jurisdictional rate of return of 5.12 percent and the proposed rate of return of 8.64 percent?

A. Yes. The revenue deficiency is $69,867,000, as calculated on Schedule 19, which references the schedule where each figure was derived. Schedule 20 shows the calculation of the NOI multiplier.

Q. You have previously mentioned that you are supporting the UPS calculations that have been used in developing rate base, NOI, and capital structure in this filing. Would you explain how these amounts were calculated?

A. The UPS amounts, which have been identified on Schedules 6, 8, and 18, were computed in exactly the same manner as the amounts allowed in our 1990 rate case. The rate base and NOI adjustments reflect the removal of all amounts related to Plant Scherer. The general plant investment and administrative and general expenses were allocated to

Plant Scherer Unit 3 based on salaries and wages, and then allocated to UPS based on the UPS sales ratio (100 percent) in accordance with the UPS contracts.

Q. Please summarize your testimony.

A. Gulf Power is committed to meeting the needs of our customers and investors and strives to maintain low rates, high quality service, and excellent customer satisfaction ratings. Despite Gulf's continued efforts to control costs and keep expenses low to avoid the need for rate relief, there has been an increase in the cost of providing electric service since the Company's last base rate increase in 1990. The most significant factor contributing to the increase in cost is the construction of Smith Unit 3, which was the least cost alternative available to enable Gulf to continue to meet increasing load requirements and provide reliable service. The annual revenue requirement for Smith Unit 3 is approximately $48 million. In addition to the revenue requirement for Smith Unit 3, approximately $22 million of rate relief is necessary to cover increases in O & M expenses and capital additions primarily related to the production, transmission and distribution functions, which cannot be offset by revenue growth. These increases in costs are necessary to enable the Company to maintain reliability and keep up with the growing service expectations of our customers. The Company's customers today are requiring a higher level of reliability with respect to blinking lights and momentary outages due to an increase in the use of computerized equipment. Mr. Moore, Mr. Howell, and Mr. Fisher will discuss reasons for the increases in O & M and capital additions related to these functions and the specific programs that the Company is implementing to ensure that we continue to provide dependable and reliable service to our customers. Factors contributing to the increase in the cost of providing electric service are the 32 percent increase in customers, inflation of approximately 39 percent, and the construction of new infrastructure.

Under present retail rates, the projected return on average common equity for the test year is 4.43 percent, which is significantly below the 13.00 percent determined by Mr. Benore to be appropriate for Gulf Power. Such a low return would leave the Company in a weak financial position. In order for Gulf to attract capital on reasonable terms, maintain a sufficient level of financial integrity, and continue to meet the needs of our customers, the Company must maintain a strong financial position. Therefore, based on the revenue deficiency calculated for the test period, Gulf is requesting an annual increase of $69.9 million in our retail revenues.

Q. Does this conclude your testimony?

A. Yes.

BY MR. STONE:

Q Mr. Labrato, would you please summarize your direct testimony?

A Yes. The purpose of my testimony is to explain the need for rate relief, beginning with the commercial in-service date of Smith Unit 3, and to discuss the rate request based on the test year June 2002 through May 2003. In addition, I will present Gulf's financial forecast, which is the basis of the projected data for the test period, develop the test period rate base, net operating income, and cost of capital, and calculate the revenue, resulting revenue deficiency.

Gulf Power is requesting an annual increase of 69.9 million in our retail revenues. The most significant factor contributing to the need for rate relief is the construction of Smith Unit 3. The projected capital expenditures for this project total 220.5 million, which results in a 20% increase in the Company's jurisdictional rate base. The annual revenue requirements of Smith Unit 3 are approximately $48 million. In addition to the revenue requirements of Smith Unit 3, approximately 22 million of rate relief is necessary to cover the increase in O&M costs and capital additions primarily related to production, transmission, and distribution functions which cannot be offset by revenue growth. These increases in costs are necessary to enable the Company to maintain reliability and to keep up with the growing service expectations of our customers.

As Mr. Bowden mentioned this morning, under present retail rates, the projected return on average common equity for the test year is 4.43%, which is significantly below the 13% determined by Mr. Benore to be appropriate for Gulf Power. Such a low return would leave the Company in a weak financial position and jeopardize Gulf's ability to successfully access both the debt and equity markets on reasonable and acceptable terms.

Without rate relief, the Company's financial indicators, such as interest coverage ratios, would be significantly low. Without strong financial indicators, the Company's debt and preferred stock security ratings would be downgraded. Such events caused by a weak financial position could ultimately restrict growth and would make it difficult for the Company to continue to provide reliable service at reasonable cost to our customers. In order for Gulf to attract capital on reasonable terms, maintain a sufficient level of financial integrity, and continue to meet the needs of our customers, the Company must maintain a strong financial position.

Gulf Power is committed to meeting the needs of our customers and investors and strives to maintain low rates, high quality service, and excellent customer satisfaction ratings. Gulf's residential rates are among the lowest in Florida and the nation. Despite the continued efforts to control costs and keep expenses low to avoid the need for rate relief, there has been an increase in the cost of providing service since the Company's last base rate increase in 1990. Therefore, in order to continue to meet the needs of our customers and investors, Gulf is requesting an annual increase of 69.9 million in our retail revenues.

Even after this increase in retail revenues, Gulf's proposed residential rates will remain among the lowest in the nation and in the State of Florida. In a comparison of Gulf's proposed residential rates per thousand kilowatt-hours to those of 53 other utilities across the nation and in the State of Florida through the JEA survey, only 13 of those 53 utilities would have lower rates than Gulf Power.

That concludes my summary.

MR. STONE: We tender Mr. Labrato for cross examination.

CHAIRMAN JABER: FEA?

MR. ERICKSON: No questions.

CHAIRMAN JABER: Mr. Gross?

MR. GROSS: No questions.

CHAIRMAN JABER: Ms. Kaufman?

MS. KAUFMAN: Yes. Thank you, Chairman Jaber.

CROSS EXAMINATION

BY MS. KAUFMAN:

Q Mr. Labrato, I'm Vicki Kaufman for the Florida Industrial Power Users Group. I feel like I'm so far away from you down here.

Mr. Labrato, you're one of the witnesses that is dealing with Issues 34 and 37; is that correct?

A That's correct.

Q Okay. I just have a couple of questions for you in that regard.

A Okay.

Q Mr. Labrato, would you agree with me that a utility should strive to provide the most reliable, the safest, and the most adequate service it can at the lowest rates that it can?

A Yes, I do.

Q Would you agree that a utility should strive to have the lowest possible number customer complaints that it can?

A Yes.

Q And should it do all that it can to reduce any customer complaints that it might receive and to resolve them promptly?

A Yes.

Q Should a utility do all that it can to comply with the Public Service Commission's rules and to avoid any violation of those rules?

A Yes.

Q And should a utility do all it can to respond quickly to outages and to restore service as soon as it can to its customers?

A Yes. Our Company has done all those things that you mentioned.

Q Would you agree that a utility should have appropriate training programs for its personnel?

A Yes, I would.

Q And would it be Gulf's intention to do anything less than its best in these areas on a going-forward basis?

A No, it would not.

Q And would it be Gulf's intent to change its behavior in any way if the Commission does not agree that some sort of a performance reward is appropriate?

A I think if we're given adequate rate relief to cover the costs of those programs to continue to do that, we would. But I certainly think the Commission, you know, should recognize our past performance and our ongoing performance.

Q I understand Gulf's position, Mr. Labrato. My question simply is, is the Company going to take action to do anything other than its best in these areas if the Commission does not agree with your position on Issue 34 and Issue 37?

A No, that would not be our intention.

MS. KAUFMAN: Thank you.

CHAIRMAN JABER: Mr. Burgess?

CROSS EXAMINATION

BY MR. BURGESS:

Q Mr. Labrato, can I get you to reference your testimony at page 6?

A Yes.

Q And the answer beginning on line 3, where you make a reference to capital expenditures of nearly $900 million since 1990.

A Yes.

Q Is that -- that's the amount that you have invested in capital projects; is that correct?
A That's correct.
Q That is not the net amount of increase in the rate base accounts associated with that?
A No, because it would be depreciation.
Q In other words, the depreciation over that same 12-and-a-half-year period would offset that, and you've been receiving the --
A Some of that.
Q Would offset some of that.
A That's correct.
Q And you've been receiving the depreciation expense on that over those years?
A That's right.
Q Let me ask you if you would go down a little bit further where you -- beginning on line 9 where you reference Gulf's coming in $3.7 million under the benchmark.
A Yes.
Q Haven't all Florida's IOUs been substantially under the benchmark over that decade?
A I'm not aware if they are or not.
Q Well, haven't all Florida's IOUs for the most part avoided any rate cases over that period of

time?

A Yes, I would agree with that.

Q And haven't there been various revenue sharing plans and rate sharing plans between the customers and the IOUs during that period of time?

A Yes. We've had one ourself.

CHAIRMAN JABER: Mr. Labrato, I need you to speak right into the microphone.

THE WITNESS: Okay.

BY MR. BURGESS:

Q Doesn't it seem that the 1990s have been marked by unprecedented efficiency gains by the Florida IOUs?

A I would say that we've done a good job of avoiding rate increases and been able to enter into some of these other programs.

Q And that's we as an industry?

A Yes, that's correct.

Q Can I get you to look at page 15 of your prefiled testimony? And I wanted to discuss the third floor of the office building.

A Okay.

Q When did the earnings deferral begin?

A It began at the last rate case, which was the 1990, somewhere in the 1990 time frame.

Q And can you tell me, is depreciation expense included in that deferral, or has depreciation expense been above the line on that?

A There has been no depreciation expense.

Q Okay. So the --

A We did not depreciate that investment.

Q So in essence, it's a deferral of the entire amount of any earnings or return of the investment or on the investment associated with the third floor; is that right?

A That's right. That's what that represents.

Q Why do you think three years is the proper amount? If the Commission allows recovery of that, why do you think three years is the proper amount of time to recover that?

A Three years was the basis we -- a few years back when we entered into an earnings sharing plan that ultimately became our revenue sharing plan, the proposal we had with the staff and the Commission had a three-year amortization there, so that was the basis for that. Also, in the revenue sharing plan that we entered into with the Office of Public Counsel, there was a provision that allowed us to amortize a million a year if earnings permitted, and we did that the last couple of years.

And so the number we came up with was around that number, but there's nothing -- you know, I think that's a reasonable time to do it, but there's nothing cast in concrete about three years.

Q Let me understand fully about that portion that was not depreciated, the 10 years or 12 years of undepreciated amount. Is that part of the accumulation that would then be amortized over three years, the past depreciation expense that otherwise would have been collected along with the deferred earnings, or have you simply sought to depreciate that over the remaining life of the building?

A That was not depreciated, so that investment, you know, was still there, the original cost, and it's not in the deferred account. So we would -- part of our asking is to begin to depreciate the investment in the third floor, as well as amortize the --

Q And what you're --

A -- deferred return.

Q I'm sorry.

A That was it.

Q And what you're asking, though, with regard to the return of the investment is that you simply recover that over the remaining life of the building rather than over a shortened period as you're asking with the deferred earnings; is that correct?

A Say that again, if you will.

Q Okay. With regard to the value, the capital value of the third floor that went undepreciated during the 12-and-a-half-year period, you are not asking for a three-year return of that, are you?

A We're asking for three years on the 3.8 million deferred return, and we're asking to begin to depreciate the original balance over the remaining life of the corporate office building.

Q Now, would you agree that any shortened plan or any plan to allow recovery of the deferred earnings puts the current and future customers in the position of paying for something that previous customers didn't pay for because of a decision by the Commission? Is that correct?

A Could you restate that?

Q Well, let me put it this way.

A Okay.

Q Why should current and future customers pay for earnings on a portion of plant that was disallowed presumably because it wasn't necessary for service at that time?

A When the Commission made the decision to have us defer a return, I think there was an expectation of future recovery. Otherwise, we would not have been able to have deferred that return, you know, for an income statement purpose. So there was an expectation of future recovery, and --

Q Okay. But outside of expectations -- I'm getting at the philosophical question of recovery here and really am not looking for what the Commission ordered in the last case, but rather why you think it would be justified for current customers to pay that.

Let me ask you this. Why did the Commission not allow current recovery during that period of time of a return on the third floor?

A I don't recall specifically, but I believe that the -- that floor was not -- it was not utilized for office space. It was vacant. It was an unfinished floor of the building, and there was a disallowance that we would not include that in current rates, but would consider that at a later time. I don't think there was an expectation at that time that we would go as long as we have without another rate case. And so that's why, you know, the number is as high as it is.

Q If it was disallowed -- if the customers from 1990 till the present were not required to pay a return on it or to pay depreciation expense on it because it wasn't being used, why should current customers and future customers make up for that in future rates by paying the deferred return in the future?

A The floor is being utilized now. It's utilized for storage, unfinished space that's being fully utilized for storage. The Company incurred those costs and has deferred that return in anticipation of future recovery, and since that space is utilized, I think it's appropriate for the present customers to pay those costs.

And when you've got construction work in progress, when you're building something, you know, you have AFUDC that you're accumulating and you get that recovery through future costs, this is a somewhat similar situation.

Q What is the depreciation rate of the entire building? How many years is the expected life?

A One moment.

I don't have that. I can get that for you, but I don't have it.

Q Do you have some idea of how much it is?

A I guess about 25 years.

Q All right. Well, if it's --

CHAIRMAN JABER: Mr. Burgess, what was your question?

MR. BURGESS: What is the depreciable life of the building, of the office building.

BY MR. BURGESS:

Q If it's 25 years and we've taken the first 12 years and deferred income and have not had any depreciation expense, and then we take those amounts and collect them from future customers, then am I correct that on a rough basis, the third floor is costing the customers about twice as much as either of the other two floors? Is that right?

A I'm not sure I'm following you.

Q If you've gone 12 and a half years without a return that has been deferred into the future, 12 and a half years without depreciation that's being deferred into the future, and it's a 25-year life, then we're ending up charging the future customers about double for that floor than we did for the others from this point forward.

A I don't -- I would agree that it's somewhat more. I'm not sure it would be double.

Q Do you think that as storage space that it has double the value to current and future customers than the rest of the building has?

A That space is less expensive than the rest of the building because it was not finished, so it's not -- the value originally was less than the value of the other floors. There's no walls, you know, air conditioning ducts, that kind of thing, so it was less to begin with.

Q Do you know how much less it was per square foot?

A I don't have that information.

MR. BURGESS: Thank you, Mr. Labrato. That's all I have.

CHAIRMAN JABER: Staff?

CROSS EXAMINATION

BY MS. STERN:

Q Good afternoon, Mr. Labrato. I have just a few questions for you.

It's your position that Gulf deserves an increase in the ROE used for setting rates and a broader range on equity; correct?

A That's correct.

Q Okay. And these are for Gulf's quality of service?

A I'm sorry. I couldn't hear what you said.

Q And these would be rewards for the high quality of service that Gulf has provided in the past; correct?

A High quality and low rates, yes.

Q Okay. Do you agree that the quality of service is an important component of the value, overall value of service to the customer?

A Absolutely.

Q Okay. And the better the quality of service, the better the value to the customer?

A Yes.

Q Okay. And you've said that the low rates are also a component of the value to the customer?

A That's correct.

Q Okay. So what's more valuable to a customer, excellent service at a high rate or excellent service at a low rate?

A Well, I think excellent service at a low rate. If you're given those two choices, that would obviously be the case.

Q Well, excellent service, the lower the rate, the more the value to the customer; correct?

A Repeat that, please.

Q Okay. Given the constant of excellent service as a constant in the value, overall value of the service to the customer, as the rate goes down, the value of the service to the customer goes up. Would you agree with that?

A Given that the level of service is maintained?

Q Yes.

A Given your assumption, yes, I would agree.

Q Okay. Now, if the level of Gulf's service remains the same, but the rates go up, would you agree then that the value to the customer goes down?

A I suppose I would. I would just -- you know, you still have to look at the value relative to what the cost is other places, you know, what their other choices would be. But just -- if I'm following your chain of thought there, I would agree.

MS. STERN: Okay. That's all I have.

CHAIRMAN JABER: Thank you, Ms. Stern.

Commissioners, do you have any questions?

COMMISSIONER PALECKI: I have just one question, and it's the same question I asked Mr. Moore earlier in the hearing with regard to Smith Unit 3.

In the previous docket that Gulf filed and then withdrew, you gave us some really good reasons that running or selling the output of Smith Unit 3 to Gulf through a long-term contract was the best deal for the ratepayers, and I just would like some -- I would like to know what -- you know, whether the ratepayers are not getting the best deal by running this plant through rate base.

THE WITNESS: Yes, Commissioner. In the analysis that we did -- I sponsored an exhibit in that docket where we showed over the 10-year life -- it was a 10-year contract -- that basically on a cost basis or price to the customer, it was the same to the customer. So as far as price, there was no differential, or very little differential, present value in the revenue stream under rate-basing the unit compared to the price that we had in the purchased power agreement.

As you may recall, when we filed that, we had a short period of time. We asked for expedited treatment by the Commission, and we had a short period of time to get a final decision in that docket so that we would know whether we needed to file this case, and we were looking for a final decision around the first of September. In late August it became apparent to us that we were not going to get a final decision in that docket. And given the revenue requirements of the Smith unit, we had to withdraw that and proceed with this docket.

But I would say over the 10-year period, I think the rates, you know, were the same. The concept of the PPA was a lifetime commitment of the unit versus a 10-year commitment of the unit.

COMMISSIONER PALECKI: And I think the reasons you gave that the contract was better was for the period after the initial 10 years of the contract, that the ratepayers would no longer bear that risk, especially with the -- with regard to the electric industry now being a declining cost industry with improved efficiencies and whatnot.

And what I'm trying to get to is, does that still hold true, and are we approving something that's not the best deal for the ratepayers if we go ahead and put this plant in rate base?

THE WITNESS: No, I don't think you're making a bad decision for the ratepayer. The 10 years -- I don't think we ever took a position that we knew what the price was going to be. It was just that the options would be open to whatever the market would have beyond the 10-year period. If they would be lower, obviously, that would be beneficial. They could be higher. But it opened other options to us beyond the 10-year period.

But we were in a situation as a company, with the revenue requirements being what they are on the unit, that we could not afford a lengthy delay there and uncertainty of knowing -- of getting recovery for the unit. But still the customer is getting the output of this unit. It's the most efficient unit available at a good cost, and I think the ratepayers, you know, are getting a good benefit from this unit being added.

COMMISSIONER PALECKI: I know as a Commissioner I have to weigh the interests of the Company against the interests of the ratepayer, and I understand the Company's reason for withdrawing that docket. What I'm trying to explore is the impact on the customer. And my question to you is, do you have an opinion as to whether or not running this plant through a long-term contract such as your previous filing is a better deal for the ratepayer?

THE WITNESS: I would say in my opinion, for the first 10 years it's the same, and beyond that, I do not know. I don't know what the -- you know, what the market prices will be beyond that time.

COMMISSIONER PALECKI: So with regard to the aspect that that's a risk that under the previous docket the Company would have borne, or the Southern Company, and under this docket the ratepayers need to bear that risk, as a Commissioner should I view the previous docket as actually having been a better deal for the ratepayers?

MR. STONE: Commissioner, if I may, we never were able to follow that docket through to conclusion. And although we did propose that PPA in that docket, there was no hearing, and there was no final determination as to whether or not it was in the best interests of the customers.

There was very strong opposition by other parties who are now represented in this rate case, and that very strong opposition is one of the reasons why we could not have a final decision in a timely manner in order to be able to assure the financial markets that we could finance the unit.

Now, I do not know the outcome, what would have happened under that docket. I do not know whether the Company would have prevailed or whether the intervenors would have prevailed. And I do not know -- none of us know what the future holds 10 years from now.

The point of what we were presenting when we filed that contract last summer was to give the Commission options. Yes, there was an evaluation -- there was an evaluation that in the 10 years, the contract was essentially a wash, and there was an element of risk at the end of 10 years, and there was a question of which way that risk was being borne. The arguments being made by the Office of Public Counsel and the Florida Industrial Power Users Group was that it was not a shifting of risk to the Company, but rather was a shifting of risk to the ratepayers by having the PPA.

So I don't believe that we can answer today which is in the best interest of the customers. And it's purely an academic exercise, because the PPA option is no longer available to us, because that option was only available for a very short period of time. In order to finance the unit, we had to have a final decision in a time frame that was not available to us, and so we had to move forward with the rate case option, and that's why we are here today.

I guess what I'm trying to say is, we did not have a final determination in that docket, and so I don't believe that the Commission is being asked to do anything inconsistent with that docket.

COMMISSIONER PALECKI: I understand your position. At the same time, I can't be like an ostrich and put my head in the sand and pretend like there was never any representation made by the Company that there was a better deal for the ratepayers, and that --

CHAIRMAN JABER: I think -- Commissioner Palecki, I think the more important point perhaps that Mr. Stone did not touch on is, we don't have evidence in this record as to what the outcome of the PPA proceeding would have been, nor can we fully evaluate whether that would have been a better option in this case. Set aside what Gulf's position is, because I, like you, don't like making decisions in a vacuum, but I think we're also bound by the evidence we have in this case. And the truth of the matter is, we don't have evidence in this case on what the outcome through the PPA process would have been.

COMMISSIONER PALECKI: Well, Madam Chairman, that was the last question on the whole issue. So if the witness does have an opinion, I would like to know what it is.

CHAIRMAN JABER: Ask your question again.

COMMISSIONER PALECKI: I'll try to briefly reask it, because I think it was a very long question, but I asked if you had a personal opinion as to whether a situation where -- like in your initial filing, where the Southern Company would have the risk after the initial 10 years, would bear the risk of paying for that plant, was not a better deal for the ratepayers.

THE WITNESS: I do not have an opinion on whether that would have been a good deal.

COMMISSIONER PALECKI: Thank you.

CHAIRMAN JABER: Commissioner Deason?

COMMISSIONER DEASON: I have just a few questions on the third floor of the office building.

THE WITNESS: Yes, sir.

COMMISSIONER DEASON: I'm sure you're probably tired of hearing about it.

THE WITNESS: Not at all.

COMMISSIONER DEASON: Maybe you can refresh my memory a little bit. What was the basis of the Commission's decision at that time?

THE WITNESS: The best I can recall, Commissioner, was that the floor -- let me look here a second and give you a --

COMMISSIONER DEASON: I kind of hesitate to ask, because I think I may have been a part of that decision. I'm not sure.

THE WITNESS: At that time, it said we had adequate space for storage and maintenance functions at other facilities. And I think the bottom line issue was that when the office was built, it was built with the additional floor, and that it was not needed at that particular time. There was an anticipation, I think, because of the deferred return, that it would be utilized in the future, as it is, and that we would be allowed future recovery.

As I mentioned earlier, I don't think there was an anticipation that the period of time would go that long and that we would have such a big amount.

I will say, as I mentioned earlier, that under the revenue sharing agreement, we have written off 2 million of that over the last couple years without rates to -- you know, any additional rate relief to recover that. So, in essence, the stockholder has eaten some portion of that through that amortization.

But that's the best I understand as to why it was not allowed in rate base at the time and the deferred return was allowed.

COMMISSIONER DEASON: I think that the -- in all honesty, I don't recall this decision. It may have been that -- I maybe was not on the case. It may have been when we were dealing with some of these rate cases on panels. But maybe I was.

MR. STONE: Commissioner Deason, it was before you became a Commissioner.

COMMISSIONER DEASON: Oh, okay. Well, I'm glad that -- I've been here a long time.

CHAIRMAN JABER: That can't be possible. That can't be possible.

COMMISSIONER DEASON: See, I've been referred to as the Commission's historian, and I'm glad to know there's something before my time.

CHAIRMAN JABER: And you used to do rate cases as panels?

COMMISSIONER DEASON: Yes, there was a time when we did rate cases -- we had, I think, all the companies in at one time. And as I recall, I remember -- I believe Commissioner Easley and myself did one rate case, and I believe it was TECO and not Gulf.

MR. STONE: I was going to say that would have been before my time, because every case I've been involved in has been the full Commission.

COMMISSIONER DEASON: Anyway -- well, let's go back. Whatever, it was contemplated by the Commission's decision that at some point this office space would be utilized and that -- it was the decision of the Commission to allow you to calculate a return, but not fund the return. It was basically a noncash return, and you were able to amor -- I'm sorry. You were able to --

THE WITNESS: Defer it.

COMMISSIONER DEASON: Defer it, with the idea that you would have some future recovery?

THE WITNESS: That's correct.

COMMISSIONER DEASON: This also applied to the depreciation, that the depreciation would cease, and that depreciation -- that that amount would go undepreciated for a period of time until it was put back into rate base?

THE WITNESS: Yes.

COMMISSIONER DEASON: That was part of the decision as well, or that was just your interpretation?

THE WITNESS: That's my interpretation of the decision.

COMMISSIONER DEASON: Now, you mentioned in your testimony that there was an accumulated balance of depreciation associated with this, some $338,000. Was this the amount that was depreciated prior to the Commission's decision in the rate case?

THE WITNESS: Yes, it was.

COMMISSIONER DEASON: How did you account for the deferred return for surveillance reporting?

THE WITNESS: It was -- for surveillance purposes, it did not show up. You know, we removed the investment from the rate base as a rate base adjustment, and then the deferral was a debit to a 182 regulatory asset, and then the credit was below the line to a miscellaneous nonoperating income.

COMMISSIONER DEASON: So for surveillance reporting purposes, just to make sure I understand, the amount of the investment was taken out of rate base, and the earnings were below the line, so it did not impact your surveillance earnings; correct?

THE WITNESS: That's correct.

COMMISSIONER DEASON: And how about for financial statement reporting? How was it accounted for?

THE WITNESS: We accounted for it the same way. It was recorded below the line. And, of course, the regulatory asset was sitting on the balance sheet for financial reporting purposes as well, anticipating a future recovery.

COMMISSIONER DEASON: So it's your position that investors, the financial community realized that this amount was being deferred and anticipated a future recovery at some point?

THE WITNESS: That's correct. And your audit staff, you know, in their audit report speaks to the utilization of the third floor, and it is fully utilized now.

COMMISSIONER DEASON: Thank you.

CHAIRMAN JABER: Commissioners, any other questions?

Okay. Redirect?

MR. STONE: No redirect. We would move the admission of his exhibit, Exhibit 37.

CHAIRMAN JABER: Exhibit 37 shall be been admitted into the record without objection.

(Exhibit 37 was admitted into the record.)

CHAIRMAN JABER: Thank you, Mr. Labrato.

And our next witness is Mr. O'Sheasy. Now, remind me, Mr. Stone. Two of -- it looks like only two issues remain outstanding for Mr. O'Sheasy. Had you agreed on stipulating his testimony in, or no?

MR. STONE: We did not agree to stipulate his testimony in. In fact, he goes to the heart of the disagreement.

CHAIRMAN JABER: Okay. I just wanted to make sure.

MR. BADDERS: Mr. O'Sheasy is taking the stand. Just one minute, please.

CHAIRMAN JABER: For those of you in the audience who are wondering how long we are going to go tonight, we are going to stop working at 6 p.m. The Commissioners will stop working at 6 p.m. The parties will continue to negotiate and discuss these matters further, but 6 p.m. And I do intend to try to get through Gulf Power's witnesses by 6 p.m. That's a goal.

MR. BADDERS: We're ready to proceed.

Thereupon,

MICHAEL T. O'SHEASY

was called as a witness on behalf of Gulf Power Company and, having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. BADDERS:

Q Mr. O'Sheasy, were you sworn in this morning? Were you present?

A Yes, I was.

Q Please state your name and business address for the record.

A My name is Michael T. O'Sheasy. My business address is 5001 Kingswood Drive, Roswell, Georgia 30075.

Q And my whom are you employed?

A I'm employed by Christensen Associates, Inc.

Q And in what capacity?

A Vice president.

Q Have you prefiled testimony consisting of 18 pages?

A Yes, I have.

Q Do you have any changes or corrections to that testimony?

A No, I do not.

Q If I were to ask you the same questions today, would your answers be the same?

A Yes.

MR. BADDERS: We ask that the prefiled testimony of Mr. O'Sheasy be inserted into the record as though read.

CHAIRMAN JABER: Yes. The prefiled direct testimony of Michael T. O'Sheasy shall be inserted into the record as though read.

BY MR. BADDERS:

Q Mr. O'Sheasy, do you have one exhibit attached to your testimony consisting of seven schedules?

A That is correct.

Q And that is labeled MTO-1?

A Yes.

Q Are you also sponsoring a section of the MRFs identified on Schedule 7 of that exhibit?

A Yes.

Q Do you have any changes or corrections to that exhibit or to any of the MFRs that you're responsible for?

A Yes, I do, one slight correction. On Schedule 6.2, there's a typo. The third line from the bottom of my Schedule 6.2 reads, "Zero intercept unit cost equals $350." It's a typo and should read, "Minimum size unit cost equals $350." That's the only correction.

Q Thank you.

CHAIRMAN JABER: Hold on a second, Mr. O'Sheasy. Schedule --

THE WITNESS: 6.2.

CHAIRMAN JABER: Okay. And what page would that be, just for --

THE WITNESS: Two of ten.

CHAIRMAN JABER: Okay. And the change is what?

THE WITNESS: The third line from the bottom, it currently reads, "Zero intercept unit cost equals $350." It should read, "Minimum size unit cost equals $350."

CHAIRMAN JABER: Thank you.

THE WITNESS: You're welcome.

MR. BADDERS: We ask that Exhibit MTO-1 be identified. I believe that's Exhibit 38.

CHAIRMAN JABER: Yes. MTO-1 is Exhibit 38.

(Exhibit 38 was marked for identification.)

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony of
Michael T. O'Sheasy
Docket No. 010949-EI
In Support of Rate Relief
Date of Filing: September 10, 2001

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

A. Michael T. O'Sheasy, 5001 Kingswood Drive, Roswell, Georgia 30075. I am a Vice President with Christensen Associates, Inc.

Q. State briefly your education background and experience.

A. I received a Bachelors of Industrial Engineering from Georgia Institute of Technology in 1970. In 1974, I earned a Masters in Business Administration from Georgia State University. From 1971 to 1975, I was employed by the John W. Eshelman Company -- Division of the Carnation Company -- as a plant superintendent in their Chamblee, Georgia operation. From 1975 to 1980, I worked for the John Harland Corporation initially as an assistant plant manager and then as a plant manager in their Jacksonville, Florida plant, and finally as their plant manager in Miami, Florida. I joined Southern Company Services in 1980 as an engineering cost analyst and progressed through various positions to the position of supervisor, during which time I began serving as an expert witness in costing. I have testified as Gulf Power Company's cost of service witness and provided other support to Gulf in matters before the Florida Public Service Commission. In 1990, I became Manager of Product Design for Georgia Power Company and have testified before the Georgia Public

Service Commission as an expert witness on rate design and pricing. I retired from Georgia Power Company on May 1, 2001 and became a consultant with Christensen Associates.

Q. Please state specific dockets in which you have previously testified before this Commission?

A. I testified before this Commission on behalf of Gulf Power Company as their cost-of-service witness in their last rate case filing, Docket No. 891345-EI, and was extensively involved in the preparation of exhibits and MFRs in that case. Also, I was the back-up cost-of-service witness for Gulf Power Company in its previous rate case, Docket No. 840086-EI, where I helped prepare the related analyses. I also testified in Docket No. 850673-EU, regarding standby rates.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to support the development and results of the cost-of-service study.

Q. Do you have an exhibit that contains information to which you will refer in your testimony?

A. Yes. My exhibit was prepared under my supervision and direction by the Costing Analysis Department of Southern Company Services (SCS) which is the service company in the Southern electric system. SCS provides engineering and other technical support for Gulf Power and the other system operating companies. I have thoroughly reviewed the schedules in my exhibit and agree with their content.

Counsel: We ask that Mr. O'Sheasy's Exhibit comprised of seven schedules be marked for identification as Exhibit No. __________ (MTO-1).

Q. Are you the sponsor of certain Minimum Filing Requirements (MFRs)?

A. Yes. The MFRs I am sponsoring, in part or in whole, are listed on Schedule 7 of my exhibit. To the best of my knowledge, the information contained in these MFRs is true and correct.

Q. Please describe the contents of your exhibit.

A. My exhibit consists of seven schedules setting forth the results of the cost-of-service study used as a basis for this case. Each schedule was prepared for Gulf Power Company in the manner approved by this Commission in its final order for Gulf Power Company's last retail rate case, Docket No. 891345-EI with one slight modification. This modification was to utilize the Minimum Distribution System to more properly account for customer related cost.

Q. What is a "cost-of-service study" and why is one necessary?

A. A "cost-of-service study" separates a utility's total electric investments, revenues, and expenses among the jurisdictions which an electric utility serves and then among the rate classes within each jurisdiction. In order for a regulatory commission to review a utility's earnings and to evaluate the contribution made by rates within their jurisdiction, an analysis of the cost to serve the respective rate classes is necessary.

Gulf Power Company, like other electric utilities, maintains its books and records in accordance with the Uniform System of Accounts as directed by the Federal Energy Regulatory Commission (FERC) and this Commission. Although this system of accounting reveals company-wide information, it does not separate the Company's investments, revenues, and expenses by jurisdiction or by rate classes within jurisdiction. The cost-of-service study that has been performed for Gulf Power Company accomplishes this objective.

Q. How is a cost-of-service analysis performed?

A. In order to determine the cost to serve each group of customers of the regulatory jurisdictions in a fair and equitable manner, the utility company's records are analyzed to determine how each group of customers influenced the actual incurrence of cost by the utility. This review discloses certain direct costs that should be assigned to the specific rate class for which these costs were directly incurred. This review also discloses costs which are incurred to perform a function within the electric system for various customer classes, referred to as common costs, which are then allocated to the various classes.

Q. Please elaborate on the distinctions between various types of costs.

A. Certain costs are directly associated with one particular group of customers and are, therefore, assigned to that group. Many other costs, however, are used jointly to serve numerous customer rate classes. An example of this might be Account 312-Boiler Plant Equipment. In order to allocate these common costs to the rate groups, consideration must be given to the type and classes of customers, their load characteristics, their number, and various other expense and investment relationships in order to find the cost causative link.

Research of the cost causative relationship reveals that costs normally possess three attributes that identify the link between customer and company. This cost categorization or componentization can be viewed as: (1) customer related, which are those costs which vary with the number of customers or the fact that they are a customer; (2) energy related, which pertain to those costs that vary with energy consumption (kWh); and (3) demand related, which are those costs that are incurred to serve peak needs for electricity.

Once the various common accounts have been analyzed to disclose their appropriate cost component(s), the corresponding allocator can be applied to apportion common cost to the area of responsibility. By summing these allocated common costs and assigned direct costs by jurisdiction and rate class, the rate of return for each group can be determined.

Q. How was the study used by Gulf Power Company in this rate filing?

A. The jurisdictional separation of rate base and net operating income developed in Schedules 1, 2, 3, and 4 of my exhibit was used by Mr. Labrato to determine the proposed jurisdictional revenue increase needed in order to achieve the requested rate of return. These jurisdictional separation factors were calculated according to accepted cost-of-service principles and followed the methodology approved by the Commission. In addition, information from the cost-of-service study was used by Mr. Thompson as a basis for the design of proposed rates in this docket.

Q. Please explain Schedule 1 of your exhibit.

A. Schedule 1 of my exhibit is the result of the cost-of-service study in summary form for the test year utilizing the Company's present rates. It shows the Company's total rate base, revenues, expenses, and net operating income, along with the corresponding responsibilities of the retail jurisdiction, as well as the rate classes within the retail jurisdiction. The column denoted Wholesale represents Gulf's wholesale customers while the remaining column represents Gulf's Unit Power Sales customers, all of which are under the jurisdiction of the FERC. Sub-schedule 1.00 is the present rate summary. Sub-schedule 1.10 reveals the overall rate of return for each class that will exist under the Company's proposed rates.

Q. What is the purpose of Schedule 2?

A. Schedule 2 analyzes investment related accounts, and either assigns or allocates them to jurisdiction and then to rate class within the retail jurisdiction. It includes Gross Plant Sub-schedule 2.10, Accumulated Depreciation Reserve Sub-schedule 2.20, Materials and Supplies Sub-schedule 2.30, Working Capital Sub-schedule 2.40, and Other Rate

Base Items Sub-schedule 2.50. Together these schedules flow to the summary Schedule 1 to provide rate base by jurisdiction and rate class.

Q. What do the remaining schedules provide?

A. Schedule 3.0 provides the Analysis of Revenues. Sub-schedule 4.10 details the allocation of O & M expenses to jurisdiction and rate classes. Sub-schedule 4.20 describes the Depreciation expense allocation, and Sub-schedule 4.30 presents the Analysis of Taxes Other Than Income Taxes. Schedule 5.0 contains the Table of Allocators and Percentages. The results of these various schedules are summarized in Schedule 1. Schedule 6 is the development of the Minimum Distribution System.

Q. Please outline the actual development of the cost-of-service study shown in your exhibit?

A. The development began with the collection and analysis of load research data. The number of customers and their respective demand and energy sales by voltage level of service were used to produce the allocators.

The load research data for the test year was supplied by Mr. McGee. He also provided total territorial supply and losses for annual energy and for demand based upon the average of the twelve monthly coincident peaks (12-MCP) projected for the test year. In addition, annual energy sales, 12-MCP demands, non-coincident peak demands (NCP), and the average number of customers for the test year were provided by rate class and voltage level. These inputs were then used to calculate the "12-MCP," "NCP," "energy," and "number of customers" allocators.

Q. Please describe the 12-MCP and NCP concepts.

A. The 12-MCP demand is the sum of the highest kilowatt load predicted to occur in each month of the test year divided by twelve. This concept incorporates the fact that Gulf's system is planned and operated for the purpose of meeting these demands for electricity every month of the year. It also reflects a consideration for scheduled maintenance, unscheduled outages, firm sales and purchase commitments, and reliance on interconnections.

The significance of Gulf's monthly peaks was further highlighted by this Commission at page 31 of its final order in Docket No. 840086-EI, where it observed that ". . . the size of all of Gulf's monthly peaks is important in that Gulf receives from or makes payments to the Southern system on the basis of whether its monthly reserve margins, which are a function of Gulf's monthly peaks, are larger or smaller than Southern's margin." In addition 12-MCP has been the FERC's preferred allocation technique for determining wholesale jurisdictional obligations.

The 12-MCP allocation technique was combined with 1/13 of the energy allocator to produce a 12-MCP and 1/13 energy allocation methodology for appropriate Level 1 (generation level) accounts within the retail jurisdiction. Transmission, subtransmission, and distribution accounts found at Level 2 (transmission lines and related equipment at 46 kv and higher) and Level 3 (substations making a transformation from transmission voltage to distribution voltage) were allocated upon a 12-MCP allocator.

The NCP demand for each retail rate class is the highest demand occurring for that rate class during the test year. This method was used to allocate distribution costs at Level 4 (primary distribution) and Level 5 (secondary distribution) and was similarly employed in Gulf's last rate case.

Q. Please explain the steps involved in producing the demand and energy allocators.

A. Balanced system load flows for demand and energy were first developed through a load flow program, which spreads total system losses to each voltage level. These levels, which are defined in more detail in MFR E-14, are used to describe the flow of electricity from generation, through the various transformations, across the various transmission and distribution lines, and the eventual delivery to the customer.

The load flow process begins by taking the total energy sales at Level 5, the secondary distribution level, multiplies these sales by the loss percentage at Level 5, and then combines these calculated losses and sales. This amount is then added to the sales at Level 4, and this new total is in turn multiplied by the loss percentage at Level 4. This procedure is continued up through Level 1, the generation level. The program adjusts the loss percentages at each level and then iterates the above process until the sum of the losses at each level matches the total system losses, and a balanced flow is produced. These total system loss percentages are then applied to the rate classes by voltage level thus computing energy allocators for each respective voltage level. A similar process is used to calculate the 12-MCP demand allocators. The NCP demand allocators for Levels 4 and 5 are developed using the loss percentages calculated by the 12-MCP demand flow since there is no territorial input for NCP with which to balance.

Q. What was the next phase in the development of Gulf Power Company's cost-of-service study?

A. Mr. Labrato provided the financial information for the projected test year. These investment, revenue, and expense items were then assigned to jurisdiction and rate if a direct cost causative relationship was known, or allocated to jurisdiction and rate using the previously developed allocators.

Q. How were Unit Power Sales (UPS) treated for cost-of-service purposes?

A. Investment, revenues, and expenses associated with UPS were identified and removed from the Total Electric System before any allocations were made. The remaining investment, revenue, and expense items were then allocated to the retail and wholesale jurisdictions and the rates within the retail jurisdiction. This method is consistent with the methodology filed by Gulf and approved by this Commission in Gulf's last rate case.

Q. How were the allocations made between the wholesale and retail jurisdictions?

A. The jurisdictional separation was based upon the 12-MCP allocation. Again, this methodology is consistent with the one approved in Gulf's last rate case. The methodology also conforms to MFR E-1.

Q. Can you describe the analysis within the retail jurisdiction?

A. The techniques for allocation within the retail jurisdiction conform to those approved by this Commission in its final order for Gulf's last rate case. Generation level accounts were allocated on the basis of 12-MCP and 1/13 energy. Energy related accounts were allocated upon the kWh allocator. Transmission and subtransmission were allocated upon the 12-MCP concept. Primary and secondary distribution were apportioned on the corresponding NCP allocators, and customer related cost upon the respective customer allocator.

Q. Are you recommending any changes to your cost of service methodology from the previous rate case filing?

A. Yes. There are several allocation techniques resulting from the previous filing with which we do not completely agree. However, in general these philosophical differences do not result in major cost allocation variances with our preferred method nor do they significantly impair Gulf from designing efficient rates with the exception of one concept. The process of determining customer related costs is critical to an accurate allocation of cost and ultimately to the development of the customer charge for tariff design. Consequently, this process must be carefully re-examined from the conclusions of the prior case.

Q. Why is it important that costs get allocated accurately?

A. The goal of a cost-of-service (COS) study is to reveal what costs are incurred to provide service to certain groups of customers. If it is performed well, it can be a useful (and often times the primary) tool for determining the adequacy of current rates. For those rates which the COS study reveals as inadequate at current tariff levels, the COS study is an appropriate tool for determining what rate changes should be made. On the other hand, if a COS study is not performed well, erroneous conclusions can be drawn with resulting negative consequences. As mentioned earlier in my testimony, there are three primary drivers in causing cost to be incurred by an electric utility: (1) peak demands, (2) kilowatthours (kWhs), and (3) customers. Peak demands refer to costs incurred to meet the highest quantity of electricity required over a short time interval. KWhs relate to costs incurred to serve the total quantity of electricity requested over a longer time interval. Customer costs are those driven by the fact that a customer is simply requesting to be served (to be "hooked-up" to the electric system). Each of these three drivers has its own separate and appropriate allocator to spread its respective costs to the associated rate and jurisdiction.

If costs have been misclassified, then the allocator will spread these costs to rate and possibly jurisdiction incorrectly. The results of the COS study will then be less accurate and less meaningful. Conclusions drawn from the study can be misleading and potentially harmful.

Q. Can you give an example of the importance of proper allocations?

A. In general, a meter is necessary to measure the amount of electricity provided to a customer, but the meter can operate adequately regardless of the maximum demand and overall quantity of electricity requested.

Bottomline, the cost of the meter incurred by the utility to serve the customer does not vary with quantity; it is driven by the fact that each customer needs a meter. As a result, utilities will usually consider meters to be customer related, and therefore, allocate their costs to a rate group upon an allocator which reflects the number of customers in these rate groups.

If meters were misclassified as kWh related, then the corresponding kWh allocator would spread more meter cost to large customers and less meter cost to small customers despite the fact that the large customers and the small customer both required the same meter with related cost incurrence by the utility. The large customers overall rate adequacy would ultimately be understated and that of the smaller customers would be overstated.

Q. What FERC accounts require this cost classification scrutiny for the customer component?

A. Accounts 364-370 usually require an analysis to apportion properly their overall costs into those which are customer related and those which are demand related.

Q. Does the National Association of Regulatory Utility Commissioners (NARUC) advocate accurate cost classification and allocation of these accounts?

A. Yes. Its official guidebook, the **Electric Utility Cost Allocation Manual,** offers clear instructions. The following is an except from page 90 of its

January, 1992 edition:

> *Distribution plant Accounts 364 through 370 involve demand and customers costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system. As shown in table 6-1, each primary plant account can be separately classified into a demand and customer component. Two methods are used to determine the demand and customer components of distribution facilities. They are, the minimum-size-of-facilities method, and the minimum-intercept cost (zero-intercept or positive-intercept cost, as applicable) of facilities.*

Q. Can you give us some idea of the magnitude of harm that can be caused by inaccurate classification?

A. Yes. For example, if a residential customer charge is under priced by $7/customer/month and there are 300,000 residential customers, then the revenues collected through the customer charge would be approximately $25 million below the customer related costs.

Q. What are the other customer related costs?

A. Basically, they can be found in FERC mass distribution accounts and relate to the cost of merely providing services. In other words, regardless of the quantity of electricity demanded, the mere fact that the utility must be prepared to provide service at any time drives cost to be incurred. These are customer related costs driven by the simple fact that a customer wants to be hooked up.

Q. How do you determine these costs?

A. The process of revealing customer related costs uses the concept of Minimum Distribution System. It relies on the fact that in order to simply hook-up a customer to the power system, a minimum amount of facilities and equipment are necessary. The minimum distribution facilities, along with meters and service drops, make up the plant investment portion of customer related costs. The distribution facilities in excess of the minimum are classified as demand related costs because they relate to capacity.

Q. How does one determine this minimum amount of facilities and equipment?

A. There are two common ways to do so: (1) minimum size (MS) and (2) zero-intercept (ZI). The philosophy of MS is that in order to simply hook-up a customer to the system, a minimum size of equipment is necessary. The cost of this minimum size equipment is then categorized as customer related cost. For example, suppose that a 10 kVa line transformer represents the smallest size transformer normally used. Then the unit installed costs of a 10 kVa transformer would be employed as the basis for the customer cost of transformers with the residual as demand related. This methodology, although logical, has a flaw because even the smallest standard size equipment such as the 10 kVa transformer, is capable of carrying load, i.e., it has capacity, which is a demand-related component and should therefore be embedded within another price component. The second method, Zero-Intercept (ZI) is an improved technique for determining customer related costs, and by definition, has removed any ability of carrying load.

Q. How does the Zero-Intercept method work?

A. The ZI method is based on a regression analysis of equipment costs for several sizes in order to determine the zero capacity unit cost. The resultant regression equation is then extrapolated back to a level of no-load. This can be observed in Sub-schedule 6.1 of my Exhibit. Note that Schedule 6.2, which employed the minimum size method overestimated customer related costs (due to its inherent load carrying capability).

Q. How does one account for inflation when developing the ZI regression equation?

A. All equipment is regressed using current replacement costs. This is necessary since some equipment in inventory is more current vintage than others. Once the ZI unit costs for the customer piece are computed, these costs are multiplied by the number of units in inventory to develop the aggregate amount. The remainder of "current replacement cost" is the demand related costs. This resultant split of replacement cost into a customer price and a demand price is then used to allocate the prevailing embedded vintage cost for the equipment into appropriate customer and demand component costs. This is done for all those various types of equipment which possess a customer and a demand related portion within their inherent make-up. Any equipment which has strictly either a demand-only make-up or a customer-only make-up (for example meters) is directly assigned to the respective component. An appropriate customer allocator then allocates customer related costs to rate classes in the cost of service study and demand related costs are subsequently allocated upon a demand related allocator to rate class.

Q. What FERC mass distribution accounts are done in this manner?

A. Distribution accounts 364, 365, 366, and 368 use this ZI methodology. Account 367 uses MS due to the fact that there were not enough different sizes to develop a ZI regression equation for it. Any expense related accounts (for example depreciation expense) would utilize these corresponding 364-368 accounts to appropriately split expenses into customer and demand related prices. Sub-schedules 6.3 to 6.7 reveal the methods for accounts 364-368. Accounts 369 (service drops) and 370 (meters) remain as all customer related as shown in Schedules 6.8 and 6.9.

Q. Do any other electric utilities use MDS to determine the customer related costs?

A. Yes. In fact, two sister companies in the Southern electric system, Georgia Power Company and Mississippi Power Company, do so.

Q. You mentioned early that use of MDS is a change from the direction set forth in Gulf's last rate order. Is this change appropriate?
A. Yes. The electric industry today is very different from 12 1/2 years ago. It is now appropriate to migrate the customer charge in Gulf's service territory to a cost based approach, and the MDS is the appropriate method to use.

Q. In your opinion, are the results of the cost-of-service study accurate representations of the rates of return?
A. Yes. The cost-of-service results shown on Schedule 1 of my exhibit are indeed fair and accurate statements of the rates of return produced by jurisdiction and by rate class for Gulf Power Company's test year.

Q. Does this conclude your testimony?
A. Yes, it does.

BY MR. BADDERS:

Q Mr. O'Sheasy, will you please summarize your testimony?

A Yes, I will. The purpose of my testimony and participation in this proceeding is to support the development and results of the cost-of-service study. The cost-of-service exhibits and minimum filing requirements were prepared by the costing analysis department of Southern Company Services. I have thoroughly reviewed them and agree with their content.

The goal of a cost-of-service study is to reveal the rate of return by jurisdiction and the contribution of the rate groups within. To do a cost-of-service study accurately requires four activities: One, functionalization of those costs; the levelization of them; thirdly, the classification of them; and finally, the allocation or the assignment to the various customer groups within the jurisdiction.

The cost-of-service methodology in this filing by Gulf Power Company is identical to the methodology approved in Gulf's last rate case, except for the inclusion of the Minimum Distribution System, referred to as MDS. The MDS was employed in order to best classify Gulf's distribution accounts into customer and demand components, thereby enabling better allocations of these costs. Doing so will produce a more sound and accurate cost-of-service study reflecting cost causation.

Remember, in the four-step cost-of-service process, functionalization, levelization, classification, and finally, allocation or assignment, you must classify before you allocate. If you misclassify, you will misallocate.

Failure to use the MDS will result in a less accurate cost-of-service study. This omission would be especially harmful to a utility like Gulf, which possesses such a preponderance of residential customers and has experienced a significant growth in investment in these particular accounts. MDS is a commonly accepted practice. NARUC accepts it, as evidenced by the 1992 costing manual.

Now, MDS was dismissed in the prior rate case before this Commission, and I believe one of the primary reasons for this is a concern that its adoption could impact residential customers. However, I ask that we do not confuse costing with rate design. This Commission can obviously direct whatever revenue and rate design which it chooses. Rate design may or may not be strictly cost based. In fact, there are a lot of sound reasons why it shouldn't always arbitrarily be cost based.

I merely and respectfully ask this Commission to permit us to allocate costs on the most sound cost-causative basis. This will enable this Commission to accurately observe any existing cross-subsidies and afterwards determine to what extent they should not or should continue in actual rate setting.

Bottom line, if we don't allocate costs correctly, you cannot accurately evaluate earnings and cross-subsidies. I strongly recommend that this Commission adopt Gulf's filed cost-of-service study methodology.

MR. BADDERS: Mr. O'Sheasy is tendered for cross examination.

MR. ERICKSON: We do have a few brief questions for Mr. O'Sheasy. Can you hear me?

CHAIRMAN JABER: You should have -- the green light should be on. You might have to get closer to the micro -- there you go.

CROSS EXAMINATION

BY MR. ERICKSON:

Q Hi, Mr. O'Sheasy.

A Good afternoon.

Q I didn't expect to see you today.
A Well, I didn't either, but I'm delighted.
Q Mr. O'Sheasy, from your prefiled testimony, you state that you testified on cost-of-service issues at the last rate case for Gulf 12 years ago; correct?
A Yes, sir, that is correct.
Q Now, I also note from your prefiled testimony, you're aware of the situation regarding MDS methodology and some sister companies of Gulf in the Southern Company system; correct?
A Yes, sir.
Q Can you explain that situation for us?
A Well, I think what you're referencing is other operating companies within the Southern system that used this MDS methodology. Gulf -- in addition to what we've proposed with Gulf, Georgia Power uses it. Mississippi uses it. Savannah Electric in their current filing is using it.
Q Now, specifically, do you know what happened in December of 2001 in the Mississippi rate case and the Georgia rate case?
A Well, in both cases, the regulatory commissions approved the filed cost-of-service study by those two operating companies, and those filed cost-of-service studies included the Minimum

Distribution System.

Q Does this seem to work okay? All right.

Now, are you also aware of the situation regarding -- in Alabama regarding or concerning Alabama Power?

A Well, I'm not sure exactly which situation you're referring to. I guess you mean their rate case situation. Is that what you're referring to?

Q Yes. What -- do they use a particular methodology?

A Well, Alabama Power, Mr. Bowden was explaining earlier, has a rate earnings mechanism that doesn't require that they go in for rate cases very often. In fact, I can't really remember the last time they went in for a full-blown traditional rate case. And the -- I'm sure your question relates to the Minimum Distribution System and how it's used in Alabama Power Company.

No one can tell me exactly at Alabama Power what was the methodology that they used to derive their classification of customer and demand costs for the distribution system. It's merely a carryover from many years back. So I'm just hesitant to say exactly which methodology they used, because they have just not had any rate cases recently.

Q Now, reference was made in your prefiled testimony to the NARUC Electric Utility Cost Allocation Manual; correct?

A Correct.

Q Now, to your knowledge, this manual was most recently revised after Gulf's rate case 12 years ago; correct?

A Well, the manual that I excerpted from was a January 1992 edition.

Q Okay. Now, does the NARUC manual propound any other cost-of-service methodology besides MDS?

A Not in terms of the splitting of demand and customer related costs in the distribution system, no.

Q There's not a non-MDS methodology in the manual?

A Correct.

Q Now, please elaborate on what changes have occurred in the last 12 years to necessitate use of the MDS methodology now.

A All right. I'll do that, but let me say first, even if no changes had occurred, it would be appropriate to delve into this issue here. It's always appropriate to seek out the most sound costing technique possible so this Commission and any Commission can determine what is indeed the correct and appropriate earnings that the various rate classes are contributing to that company so they can determine what cross-subsidies are currently existing.

But beyond that, there have been changes to Gulf Power Company in the last 12 years since the last rate case that I think make it even more paramount today that we address the subject.

For one thing, the existence of cross-subsidies are a bigger issue now than they've ever been. Competitive pressures on our customers are certainly stronger than they've ever been. There have been structural changes to our economy that have permitted international competition at new levels, NAFTA, for example.

In addition to this, I mentioned in my prefiled summary that these particular accounts are growing faster in magnitude than the other distribution accounts that Gulf possesses.

And then finally, Gulf, as I mentioned earlier, because of its unique characteristics, having such a preponderance of residential customers and the existence of significant seasonal customers, in my opinion, makes it even more important that we discuss this subject today.

Q Now, you believe that MDS is the best

methodology for identifying rate class cross-subsidization; correct?

A I do, and that would be true for any utility, not just Gulf Power Company.

Q Correct. Can you elaborate on that, why you believe it is?

A Well, we have to go back to the process of allocating costs or determining cost of service. It's really not rocket science. It's a relatively easy procedure. You merely take the Uniform System of Accounts, which is designed by the FERC, and you functionalize those costs, then you levelize those costs by voltage level, and then you classify them. Now, you classify them in three categories, and these categories are cost-causative forces.

One is energy related. Those would be costs that would be directly related to the amount of kilowatt-hours requested by a customer. Fuel cost would be an example of a energy related item.

Secondly is demand costs. Demand costs go up as the peak requirements of a customer increases. For example, generating capital costs go up with increase in demand requirements. That's why we've got Smith 3 in the case today.

And then thirdly and finally are customer related costs. These are costs that go up merely because the customer is requesting service to be available. For example, every customer for the most part has to have a meter, so a meter is an excellent example of customer related cost.

So that's that third category that I referred to earlier, the classification of costs into cost-causative components. Now that we've done that, we've broken our costs down into function, level, and classification, then we can choose the appropriate allocator to take those costs to the jurisdiction and then to the appropriate class. As I said earlier, if we misclassify, we misallocate.

I'm a simple-minded person, and I use simple analogies, and a simple one that I think of is if basically if I've got customers who like apples and oranges, and I put an apple in a box of oranges, and I allocate to customers who want oranges, those customers are going to get apples when they should have only gotten oranges. That's it.

MR. ERICKSON: No further questions.

CHAIRMAN JABER: Mr. Gross and Ms. Kaufman?

MR. GROSS: No questions.

MS. KAUFMAN: Thank you, Chairman Jaber.

/ / /

CROSS EXAMINATION

BY MS. KAUFMAN:

Q Mr. O'Sheasy, I just have a couple of questions for you.

If you could turn to page 11 of your testimony, and I'm going to look beginning actually at the end of line 17.

A Yes, ma'am.

Q You say there, "The process of determining customer related costs is critical to an accurate allocation of cost." Can you explain why that component is critical in a cost-of-service study?

A I'm pretty much going to repeat what I said earlier. We've got a three-step process here, and we're taking the Uniform System of Accounts, and we're breaking them down into categories or components that we can then either assign to jurisdiction and rate class or allocate. And in that process of classification, I've got to properly allocate those costs into the appropriate bucket, if you will, and then choose the right allocator. My crude analogy before, if I put an apple in a bucket of oranges and I use oranges as an allocator, I'm going to misallocate.

Q And if you misallocate, would it be correct if you put the apple in the orange bucket that certain customers would be paying for costs that they did not cause?

A Correct, or on the other hand, other customers would not be paying for costs that they should.

Q Now, you mentioned the NARUC manual, and I think that has already been offered into evidence as -- I think it's Exhibit Number 23. Can you explain the purpose of that manual and what the Company uses it for?

A We use it has a guide. We believe that since this manual was basically created by the National Association for Regulatory Utility Commissioners, that it is a sound and reasonable guide for us to use in cost allocation. So that's basically it in a nutshell. We use it as a guide to direct us what's the best route to take in allocating costs.

Q Mr. O'Sheasy, I think it's fair to say that there's a disagreement between the Commission staff on one hand and the intervenors and the Company on the other in regard to the appropriate cost-of-service methodology. Is that your understanding of where we are right now?

A Yes.

Q And from where you sit as the cost of

service expert, can you explain to us what your understanding is of the staff's problem with the MDS methodology?

A Well, I really don't have a clear understanding. All I can propose or suggest or surmise is that, one, it has indeed been this Commission's preferred methodology, if you will, or absence of methodology for some time. And so I think you have the inertia of past precedent, if you will. And I think that's probably a concern of staff.

In addition to that, I think that staff is probably concerned that there might be some cost shifting to the residential class. Now, in my opinion, if that is their concern, first off, past precedent should not be a condition to continue a flaw. We ought to try to improve what we do every day.

But in addition to that, I don't think it's an issue of cost shifting. To me, it's more an issue of revealing what the true cost to serve is. That's my goal. That's my job. That's what I'm asked to do by Gulf Power Company. That's my responsibility to this Commission, to reveal what the true cost to serve is. And if the true cost to serve to the residential class is higher than we have possibly presented in the past, then I'm afraid that's the right answer.

MS. KAUFMAN: Thank you, Mr. O'Sheasy.

That's all I have, Chairman Jaber.

CHAIRMAN JABER: Mr. O'Sheasy, before we turn to staff -- and by this question, I don't want you to read into it that I'm asking you to comment on a competitive market or anything like that, or to speculate on what will happen in the energy area going forward. But there has been discussion the last two years about creating or facilitating a wholesale market in electricity. And one of the things that I've always been concerned about as it relates to transmission and a company's participation with RTOs is being able to separate transmission cost as it relates to participation an RTO from generation cost if at some point generation is allowed to compete, and then finally, distribution.

Is the MDS methodology used for that purpose as well, or is the MDS methodology truly just used for the purpose of separating costs and determining rate classifications?

THE WITNESS: It's the latter. Whether you use MDS or not, in my opinion, you can still functionalize costs for the sake of RTOs or competitive wholesale markets. It's simply that after you've functionalized distribution, now you're left with the question of what do I do with it.

Well, I'm suggesting that the best way to handle what you do with distribution is to first classify it into demand and customer and then take it from there.

CHAIRMAN JABER: Okay. So can the MDS methodology then be extended for use in how I describe it, to separate transmission costs from generation costs from distribution costs?

THE WITNESS: No. The MDS is strictly related to distribution costs.

CHAIRMAN JABER: Thank you.

THE WITNESS: You're welcome.

CHAIRMAN JABER: Staff?

CROSS EXAMINATION

BY MS. STERN:

Q As part of the MDS methodology, isn't it correct that you design a sort of hypothetical transmission -- distribution system and base costs on that?

A Not really. What we do is, we go into each separate distribution account, for example, 365, which would be your overhead conductors, and we determine what portion of that particular account is the minimum facilities and equipment necessary for us to merely provide service under the function of overhead conductors.

Q In your deposition transcript, I believe that you identified those accounts, and they were Accounts 364, 365, 366, 367, and 368; correct?

A Correct.

Q You go into each of those accounts?

A Correct.

Q Could you please describe -- could you please explain why it is appropriate to classify costs recorded in Account 364 as customer related?

A Well, we need to think about the concept of the Minimum Distribution System. The concept is that there are minimum facilities and equipment necessary simply to be able to provide service if a customer would want it. If, for example, I requested service of Gulf Power Company, then Gulf Power Company incurs certain costs regardless of whether I go about actually requesting any kilowatt-hours or not. That's what goes in the Minimum Distribution System. That's the concept.

Now, on Account 364 which you are referring to, which are poles and equipment, the idea there is that I need those poles to carry -- to be able to carry electricity under a minimum system concept for our customers. So if I am to stand ready to be able to provide service at a moment's call if a customer wants it, I have to have those poles out there. So that's why it's in there.

Q Could you describe what's covered by Account 365, please?

A I'm sorry. Could you repeat the question?

Q Describe what is covered -- what is Account 365 used for?

A It's primarily overhead conductors. There are some other items in there, such as switchers and reclosers and aerial cable. But the majority of it is simply overhead conductors.

Q And would you explain why it's appropriate to classify costs recorded in Account 365 as customer related?

A Yes. Once again, if I have to be ready to provide service to a customer at a moment's notice, I have to have a minimal amount of lines out there to carry that electricity. It has to be there.

Q Okay. Now, you will figure a minimal amount of line.

A Correct.

Q How do you decide what amount of line in the case of Gulf?

A Well, the minimum --

Q A minimal amount of line.

A What we do in the case of 365 is, we use what's called the zero intercept method, which is outlined in the NARUC manual. It's commonly used.

And basically what you do is, you look at the different sizes of conductors, overhead lines, and those various sizes in theory can carry different amounts of electricity, different amounts of power. Now, you set up a simple regression equation which would relate the unit cost of those different sizes of equipment with its load-carrying capability. And then you just take that linear equation, or nonlinear, and you regress it back to the Y intercept.

And by definition, when you've done that, you've got a minimum size wire, in theory, that can't carry any load because you regressed it back to the Y intercept. So now that you have that minimal unit cost -- in the case of 365, for example, it's roughly 20 cents per foot. Then what you do is, you take that minimal unit cost and you multiply it by the footage of Gulf's distribution system, and that represents the minimal investment in that distribution network that Gulf experiences.

COMMISSIONER DEASON: Is that based upon historical booked cost, or is that based upon replacement cost?

THE WITNESS: Replacement. Then what we do is, we take those replacement ratios and allocate the booked cost.

BY MS. STERN:

Q Okay. Would you please describe what Account 366 is used for and why it's appropriate to classify those costs as customer related?

A Yes. 366 for the most part is underground conduit. When we have underground wires, we have to have conduit that it rides in. And in addition to that, there's some other items in there, like manholes, splicing chambers, and sump pumps. There are some underground transformer vaults also. But the majority of it is conduit that our underground lines will reside within.

Now, if I have a minimal -- if I have a customer that requires minimal service, if I have to stand ready to provide him service and he has underground service, then I have to have these conduits out there to be prepared to do so.

Q Would you please describe what Account 367 covers and why it's appropriate to record those items as customer related?

A 367 is the underground conductors. Those are the wires that we run underground inside those conduits that we just referred to in 366. Once again, if I have to stand ready to provide service to a customer at a moment's notice, I have to have those lines out there. And that component -- once again, I go through a similar process that I did with 367. I go through a linear regression equation that predicts what is the minimal size underground conductor that in theory is not capable of carrying any load. And in the case of 367, we actually used minimal size, because we didn't have enough equipment to do the zero intercept. But we basically get the minimal type of equipment necessary to be ready to provide service to a customer, and that becomes the underground -- excuse me. That becomes the customer component of 367.

Q When you it use the zero intercept method and you come up with this minimum size, that's a theoretical minimum size; correct?

A Correct.

Q There may or may not be physical equipment in place that is of that size.

A Correct.

Q And it's theoretically minimum?

A Correct. And in fact, that's the beauty of it right there, because in theory, it can't carry any load. One of the -- the two major ways to classify distribution costs and demand and customer are minimum size and zero intercept. With minimum size, which is used on occasion, the problem with that technique is if you found the minimum type of equipment out there, even that equipment itself could carry some load. Well, if it can carry some load, then a portion of that ought to be in the demand bucket of costs.

Well, the zero intercept method solves that problem, because by regressing back to the zero intercept, you now have some equipment that, in theory, as you referred, can't carry any load, and you have the cost of it, and you just use that then to determine your customer classification.

Q One question that keeps coming into my mind is, you're calculating all these hypothetical minimums, and it doesn't necessarily -- I don't see how it relates to what is actually out there. We don't calculate hypothetical minimums for anything else when we assign costs in a rate case.

A Well, whether we do or not, those economic forces are there, and we have to recognize them. Just because we can't see it or feel it or touch it doesn't mean it's not there. And that's all this methodology does. It extracts from equipment that is out there that portion that would be necessary just to be able to provide service and then puts it into the appropriate bucket, if you will, and allocates it accordingly.

So the mere fact that there's no equipment out there of this size to me is not relevant. What's relevant is to take those costs and extract that portion that is customer related, and MDS does that.

Q Does MDS include the customer service drop to the meter?

A The customer service drop to the meter is normally recorded in Account 369, and traditionally utilities, and this Commission also, has recognized all of 369 as customer related. So whether you use MDS or not, 369 has traditionally been customer related.

Now, to answer your specific question, if you look at an MDS guideline from the NARUC manual, yes, 369 would all be customer related.

Q Okay. There's one more account that's included in MDS. It's 368. Would you please explain, as you have for the others, what 368 is used for and why it's appropriate to classify those costs as customer related?

A Yes. 368 are your line transformers. That's the transformer right outside your house, for example, that your service drop is connected to. The theory there is that, once again, if I must stand ready to provide service at a moment's notice, then I'm going to have to have a transformer out there.

How big does that transformer have to be? Well, that's where we use this zero intercept method once again. We take the various sizes of transformers and a unit cost, we set up a regression equation, we go back to the Y intercept, and then we extract that theoretical minimal size transformer, and that becomes the customer component for 368.

Q Okay. Thank you.

I would like to turn now to the cost-of-service studies, and I believe earlier you all -- you, Mr. O'Sheasy, as well as the parties and the Commissioners were handed a table --

A Yes.

Q -- that we've prepared.

MR. STONE: What is the source of this table? I mean, earlier today Mr. Burgess objected to the use of a handout that was a compilation taken from a witness's testimony and from his schedules. And this certainly is not something Mr. O'Sheasy has prepared, and we have not had a great deal of time to be able to go back and trace these numbers back to the source or to verify any calculations.

It seems to me that this is something that is akin to what happened earlier this morning when Mr. Burgess objected to Mr. Benore's handout as part of his summary.

MS. STERN: It is --

CHAIRMAN JABER: Ms. Stern?

MR. BURGESS: May I address that, since I was --

CHAIRMAN JABER: Excuse me.

MR. BURGESS: Oh, I'm sorry.

CHAIRMAN JABER: Ms. Stern?

MS. STERN: What we've prepared is simply portions of the MDS cost-of-service study and the other cost-of-service study and put it on a single page for the ease of everybody's reference. It's material that's in the cost-of-service studies, and we in fact would like Mr. O'Sheasy to take his time to verify that that in fact is what is summarized on that table. And I can tell you the exact pages and line numbers.

CHAIRMAN JABER: Mr. Stone, let me tell you it is not akin to what Mr. Burgess's objection was. First of all, both Mr. Burgess, and before him, Mr. McWhirter, were pointing out that via the stipulation you all reached to waive cross examination, they had not expected that an exhibit would be used along with the summary of testimony. This is an exhibit that has been put together by staff for purposes of cross examination. So if the witness can answer the questions, that's fine. If he can't, that's fine too, but I'm going to allow the use of the exhibit.

MR. STONE: May we have a few minutes for him to go through and verify the numbers and then also do the calculations?

CHAIRMAN JABER: Well, actually, if staff counsel does her job correctly, she's probably going to ask him to do just that.

BY MS. STERN:

Q Mr. O'Sheasy, what's show on this table are from pages 17 and 18 of the cost-of-service study using MDS, lines 71, 72, and 73. And it's --

COMMISSIONER PALECKI: Could you repeat those pages, please?

MS. STERN: Sure.

CHAIRMAN JABER: Marlene, your voice is

shifting away from the microphone.

BY MS. STERN:

Q Okay. Pages 17 and 18 of the cost-of-service study using the MDS methodology, if you turn to those pages and look at lines 71, 72, and 73, that's part of what is on this table.

A Yes, I agree.

Q Okay. The other part of what is on this table is from the other cost-of-service study, pages 106 and 107, lines 71, 72, and 73.

A Yes, I agree.

Q Okay. Thank you.

Isn't it correct that the total distribution costs to be recovered are the same no matter what cost allocation methodology is used?

A As long as the Commission allows rates to be set based on the cost-of-service study, and as long as customers don't what I refer to as negatively react to whatever the rates are -- in other words, if by chance a cost allocation technique, be it right or wrong, were to require rates to go unreasonably high, and those customers in turn left Gulf's system, then, no, we would not recover all of our rates. But ceteris paribus, everything else being equal, yes, indeed, you would recover your distribution costs if you misallocated them.

Q Well, I'm just starting with the basic distribution cost. You're allocating the distribution cost; correct?

A Correct.

Q But there's a number that's a distribution cost, and that total cost is going to be recovered no matter what cost-of-service method you use?

A Well, it's the word "recovered" that was hanging me up. It's going --

Q It's going to be --

A -- to be allocated.

Q -- totally allocated.

CHAIRMAN JABER: Ms. Stern.

MS. STERN: I'm sorry.

CHAIRMAN JABER: Ms. Stern, I can't hear both of you talk. More importantly, the court reporter can't catch it. So ask your question again, the witness will answer, and then you get to ask your next question.

BY MS. STERN:

Q Okay. Mr. O'Sheasy, isn't it correct that the total distribution costs to be allocated are the same no matter what cost allocation methodology is used?

A Yes.

Q Okay. And the choice of cost allocation methodology simply determines how much of those total costs are allocated to each class?

A Yes.

Q Okay. Now, if you would, please refer to the table that we passed out earlier. Based on this table, would you agree that mathematically the use of the MDS increases distribution costs allocated to the RS, GS, and lighting classes?

A The way I would like to phrase it is, it reveals that the cost to provide service to RS and GS is higher than the non-MDS method.

Q Okay. And isn't it correct that under the MDS methodology, the costs to GSD, LP, Major Accounts, CSA, and OS-IV are left unchanged or reduced?

A Yes.

Q Okay. Thank you. Turning to your deposition, please, page 29.

MS. STERN: Can I back up one minute, please. We would like for this exhibit, our table, to become an exhibit.

CHAIRMAN JABER: We'll identify it as Exhibit 39, and that will be -- short title, Ms. Stern?

MS. STERN: Shift in Distribution Costs Among Rate Classes.

CHAIRMAN JABER: Okay. Exhibit 39.

(Exhibit 39 was marked for identification.)

THE WITNESS: I'm sorry, Counselor. Did you say page 29?

MS. STERN: Yes.

THE WITNESS: I'm there.

MR. ERICKSON: Madam Chairman, we would object to at this point -- I didn't hear the witness establish the veracity of the exact numbers. I heard some general discussion, but I still -- I join with Gulf here in my concern that Mr. O'Sheasy has not had a chance to actually crunch these numbers. He answered the very basic questions, but I don't think Ms. Stern has fulfilled the charter that I think you were expecting here, Madam Chairman.

CHAIRMAN JABER: And what charter might that be?

MR. ERICKSON: To go through these numbers and make sure they're accurate.

CHAIRMAN JABER: So what is your objection? That she hasn't laid an appropriate foundation?

MR. ERICKSON: Yes, ma'am.

CHAIRMAN JABER: All right. Ms. Stern, do you have a response?

MS. STERN: Well, I believe the only numbers that are calculated are the percentage changes in this table, and we would be happy to provide -- well, we can provide an exhibit, a revised exhibit shortly with those numbers deleted, or we can have Mr. O'Sheasy verify them.

CHAIRMAN JABER: Yes. I think the nature of the objection is that you haven't laid a proper foundation, so why don't you have the witness go through and agree where these numbers came from, Ms. Stern.

With respect to your objection, Major, I've identified it as Exhibit 39. It has not been admitted into the evidence yet. But, Ms. Stern, anticipating that you'll get an objection, go ahead and do what you need to do.

MS. STERN: Okay.

BY MS. STERN:

Q Mr. O'Sheasy, would you turn to page 17 of the MDS study, please?

A Which MDS study are you referring to?

Q I'm sorry. The MDS cost -- Section E, the cost of service and rate design schedules, Volume 1.

A Yes, ma'am. I'm there.

MR. STONE: Commissioner Jaber, if I may?

CHAIRMAN JABER: Yes.

MR. STONE: All we asked for was an opportunity for Mr. O'Sheasy to be able to track through each line and do the calculations. I think it would be a more efficient use of time if we did that at a break. It wouldn't take us very long, and it would be a lot less cumbersome than to try and do it item by item.

CHAIRMAN JABER: Okay. And perhaps you'll agree as to where the numbers came from and there wouldn't be an objection at all.

MR. STONE: That's correct.

CHAIRMAN JABER: All right. Let's go through to your next series of questions, and what we'll do with Mr. O'Sheasy is bring him back on the stand first thing in the morning and address that.

MR. STONE: It may something that could be done in just a matter of five minutes, Commissioner. I just --

CHAIRMAN JABER: Okay. Well, we'll re-evaluate when Ms. Stern is done.

Thank you, Mr. Stone.

BY MS. STERN:

Q Okay. Mr. O'Sheasy, would you please turn to page 29 of your deposition transcript?

A I'm there, Counselor.

Q On lines 22 and 24, 22 through 24, you indicated that the term "common" indicates that certain costs are demand related and would be allocated on a demand factor. Do you agree?

A I agree.

Q What is the demand allocator used for those costs?

A Noncoincident peak. And what that means is we take the rate class as a group, and we develop a load shape, an annual load shape for that rate class, and we look at the peak that that rate class contributes as a class, and that becomes that class's contribution to the overall allocator. The term "noncoincident peak" means that it is not coincident necessarily with Gulf's peak.

Q Thank you. And would you please turn to page 17 of your deposition transcript?

A I'm there.

Q Okay. On that page, would you agree that you indicate that one of the principles of rate design is gradualism?

A Yes.

Q And that is not raising rates too

drastically?

MR. STONE: Commissioner, I would object. Mr. O'Sheasy is not a rate design witness. He's a cost of service witness.

CHAIRMAN JABER: So, Ms. Stern, it looks like the objection is outside the scope of his testimony.

MS. STERN: Well, it's within -- he has testified to it. He was presented -- he was deposed on it. He is presented as an expert witness. He has spent 10 years at Georgia Power doing rate design, and we're asking for his opinion.

CHAIRMAN JABER: I'll allow the question.

MR. STONE: Commissioner Jaber, we did not submit Mr. O'Sheasy as a rate design witness. We have a rate design witness. It is beyond the scope of his direct testimony.

And the fact that he was deposed on it, the rules of discovery allow much more latitude in discovery than are allowed in witness examinations.

CHAIRMAN JABER: Mr. Stone, I'm going to allow the question.

Go ahead.

BY MS. STERN:

Q In your opinion, would you consider a 50%

increase in a customer charge to be a gradual increase from --

CHAIRMAN JABER: Ms. Stern, the question you asked that you have not yet had an answer to was what is his understanding of gradualism. That's the question that I allowed.

MS. STERN: I'm sorry.

BY MS. STERN:

Q Would you explain your understanding of gradualism, please?

A My concept of gradualism is that the overall rate package that you ask a customer to compensate the utility for service, that it does not change dramatically and quickly so that a customer's bill is extremely volatile. That's what I mean by gradualism.

CHAIRMAN JABER: Mr. Stone, who would you offer as the rate design expert in this case?

MR. STONE: The rate design witness Gulf has sponsored in this case is Mr. Thompson, who follows Mr. O'Sheasy.

CHAIRMAN JABER: Okay. Ms. Stern, I would ask that you remember that in asking your next questions.

BY MS. STERN:

Q In your opinion, Mr. O'Sheasy, is a 50% increase in a customer charge gradual?

A My concept of gradualism doesn't address a specific component of the overall rate. What it addresses is the overall rate package itself and the resultant total bill. So I'm not really dealing with a specific component like the customer charge. I'm dealing with the overall impact on the customer's bill.

So to answer your question, if a customer's bill went up 50% over what it should have or what the customer is used to or what a normal bill would be expected to be, I would be concerned. But if a particular component of the tariff like the customer charge were to increase 50%, that's not the relevant question. The relevant question is the total bill.

Q Okay. Thank you.

I have just a few questions that are in the nature of just some verifications for the record. Are you familiar with Mr. McGee's Late-Filed Deposition Exhibit Number 2?

A I am.

Q And there are two attachments as part of that late-filed exhibit that are called 4A and 4B; correct?

A Correct.

Q I'm sorry. Late-Filed Deposition Exhibit 2 was two cost-of-service studies; correct?

A Correct.

Q Were these cost-of-service studies prepared by you or under your direction?

A Yes.

Q Could you indicate how these cost-of-service studies differ from the studies that were filed in Gulf's original filing in MFR Schedule E-1?

A OS-I and II, which is outdoor lighting, there was some question as to the coincident peak contribution of those two rates in the process of this rate case. And as a result of that, we were requested to do a -- rather than look at a historical year, to determine when did this outdoor lighting class of customers, OS-I and II, were they on when Gulf was experiencing their system peaks in that year, rather than doing that technique, which is the way we filed it, go back and take the last five years and average them together, and that way you might avoid some unusual circumstances that might have occurred in one specific year.

So bottom line, we did a five-year average to develop the OS-I and II coincident peaks. Secondly, we did a similar thing for OS-IV. OS-IV is sports and recreational lighting. So we did a five-year average of that rather than look at one specific year. And then I believe there was also a correction that was made to the coincident peak and the noncoincident peak allocator for OS-IV in addition.

So there were basically three changes from the original filing for this late-filed exhibit of Mr. McGee's that you're referring to you. One is the five-year average of OS-I and II; two is the five-year average of OS-IV; and three is a correction to the CP and NCP allocators for OS-IV.

MS. STERN: Okay. Thank you very much, Mr. O'Sheasy. That's all the questions we have for you.

THE WITNESS: Thank you.

CHAIRMAN JABER: Okay. Let's take a 10-minute break. Mr. Stone, do you think you need more than that?

MR. STONE: No, Commissioner.

CHAIRMAN JABER: All right. Let's take a 10-minute break, have Gulf Power and the parties and staff talk about Exhibit Number 39, and give the witness time to do the calculations on Exhibit 39. We'll come back and address that, we will address redirect, and then we will conclude for the evening.

Commissioners, is that okay?

Okay. Ten minutes.

(Short recess.)

CHAIRMAN JABER: Let's go back on the record.

Mr. Stone, do you have an update for us on Staff Exhibit Number 39?

MR. STONE: Mr. O'Sheasy has had the opportunity to verify both the source of the numbers and the calculations, and we no longer have an objection on that basis to the exhibit.

CHAIRMAN JABER: Thank you, Mr. Stone.

MR. ERICKSON: No objection any more. We're satisfied. We were just trying to help protect record.

CHAIRMAN JABER: I know. I know. Thank you. We have mutual goals, I can assure you.

Okay. See, this was the risk you took by allowing me to take a break.

Okay. Exhibit 39. And that concluded all of your questions?

MS. STERN: Yes, it did.

CHAIRMAN JABER: Redirect, Mr. Stone, or Mr. Badders?

MR. BADDERS: No redirect, and we move his exhibit.

CHAIRMAN JABER: Okay. We have Exhibit 38 that can be admitted into the record without objection.

(Exhibit 38 was admitted into the record.)

CHAIRMAN JABER: Commissioners, did I ask you all if you had questions?

I'm sorry. Go right ahead, Commissioner Palecki.

COMMISSIONER PALECKI: I have one very quick question, Mr. O'Sheasy. Basically, you believe that this Commission should first allocate costs as accurately as possible, and we should know what the true cost to serve is, and that's step number one.

THE WITNESS: I believe that devoutly.

COMMISSIONER PALECKI: And after that we design rates. So if we see that there's a problem with rate shock or if we want to do something to incent conservation practices, we might stray from the actual exact allocations that we've already seen.

THE WITNESS: Yes, sir. It is perfectly sound to do so.

COMMISSIONER PALECKI: So let's say we want to do something to incent conservation. A very large customer charge might work against conservation, so we might not want to go with a large customer charge if we believe that will not be going -- would not be helpful for conservation purposes.

THE WITNESS: Well, once again, I'm a costing man, but speaking from a pricing perspective and its impact on customers, if the choice is a high customer charge and a low energy charge versus a high energy charge and a low customer charge, then I think you're correct in terms of conservation.

COMMISSIONER PALECKI: Or if we wanted to phase in rates in order to avoid rate shock, that might be something else we could do from a rate design standpoint.

THE WITNESS: Correct.

COMMISSIONER PALECKI: Thank you.

THE WITNESS: You're welcome.

CHAIRMAN JABER: Commissioners, any other questions?

Okay. Mr. Stone, still no redirect?

MR. BADDERS: No redirect, and we move Exhibit 38.

MS. STERN: Excuse me.

CHAIRMAN JABER: Exhibit 38.

MS. STERN: I thought it was Exhibit 39.

CHAIRMAN JABER: Gulf's Exhibit MTO-1 --

MS. STERN: Oh, I'm sorry.

CHAIRMAN JABER: -- is Exhibit 38, and that will be admitted into the record without objection. Your exhibit is 39, and that will be admitted into the record without objection.

(Exhibit 39 was admitted into the record.)

CHAIRMAN JABER: Thank you, sir.

THE WITNESS: Thank you, ma'am.

CHAIRMAN JABER: Okay. Mr. Stone?

MR. STONE: Commissioner Jaber, during the break we were able to confer with the parties, and I believe I can accurately reflect that no one has any cross for witnesses Bell and the panel of witnesses Silva and Twery, and we would ask that they be excused from attendance at this hearing and that at the appropriate time their testimony be inserted into the record as though read.

CHAIRMAN JABER: Okay. Witnesses Bell, Silva, and Twery may be excused from the hearing.

Anyone else, Mr. Stone, parties, staff?

MR. STONE: We had earlier asked for Mr. Kilgore to be excused from attendance at the hearing. I understand that there's a possibility that Mr. Durbin will be taking the stand. If that is the case, then we would like the opportunity for Mr. Kilgore to also take the stand, but we can resolve that tomorrow.

CHAIRMAN JABER: Okay. Remind me tomorrow, because I think Mr. Durbin was just going to be on the stand to answer a question that Commissioner Bradley raised regarding the number of complaints filed with Consumer Affairs.

MR. STONE: Mr. Kilgore may also have some relevant information in that regard.

CHAIRMAN JABER: Okay. So we will start with witness Thompson first thing in the morning at 9 a.m.

MR. STONE: Nine instead of 9:30?

CHAIRMAN JABER: Yes, we will start the hearing tomorrow at 9 a.m.

Thank you all, and thanks for all the parties' cooperation in moving this day along as quickly as you have. Thank you.

(Proceedings recessed at 6:24 p.m.)

(Proceedings continued in Volume 8.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, MARY ALLEN NEEL, do hereby certify that the foregoing proceedings were taken before me at the time and place therein designated; that my shorthand notes were thereafter transcribed under my supervision; and that the foregoing pages numbered 601 through 723 are a true and correct transcription of my stenographic notes.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, or relative or employee of such attorney or counsel, or financially interested in the action.

DATED THIS 26th day of February, 2002.

Mary Allen Neel

MARY ALLEN NEEL, RPR
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