DOCKET NO. 160134-EI
FILED MAY 24, 2016
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REQUEST TO ESTABLISH DOCKET

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Date:	**5/24/2016**
1. From Division / Staff:	GCL/Janjic -AM
2. OPR:	AFD
3. OCR:	ENG and GCL
4. Suggested Docket Title:	Petition for accounting recognition of Gulf Power Company's ownership in Plant Scherer as being in service to retail customers.
5. Program/Module/Submodule Assignment:	A/19

6. Suggested Docket Mailing List

a. Provide NAMES/ACRONYMS, if registered company		☐ **Provided as an Attachment**
Company Code, if applicable:	**Parties (include address, if different from MCD):**	**Representatives (name and address):**
EI804	Gulf Power Company	Jeffrey A. Stone, 501 Commendencia Street, Pensacola, FL 32502

b. Provide COMPLETE NAME AND ADDRESS for all others (match representatives to companies)

Company Code, if applicable:	**Interested persons, if any, (include address, if different from MCD):**	**Representatives (name and address):**

7. Check one:	☒ **Supporting documentation attached**	☐ **To be provided with Recommendation**
Comments:	Please move document No. 02768-16 from undocketed matters to new docket.	

E. Dixie Beggs
1908 – 2001

Bert H. Lane
1917 - 1981

B&L
BEGGS & LANE RLLP
ATTORNEYS and COUNSELLORS at LAW
SINCE 1883

Post Office Box 12950
Pensacola, FL 32591-2950
Telephone (850) 432-2451
Fax (850) 469-3331

Jeffrey A. Stone

jas@beggslane.com

May 6, 2016

RECEIVED
MAY - 9 2016
FLORIDA PUBLIC SERVICE COMMISSION
OFFICE OF THE GENERAL COUNSEL

Mary Anne Helton
Deputy General Counsel
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: FPSC Document No. 02768-16

Dear Mary Anne,

This follows our previous conversation regarding Mr. Connally's May 5 letter to Mr. Baez now on file with the clerk's office as Document No. 02768-16. We have prepared a companion Reference Compendium containing complete copies of 15 documents referenced in Mr. Connally's letter. Since the resulting file is too large to email, I have enclosed both a physical copy of the 377 page compendium and a DVD containing an electronic copy of the document for your use.

We have added consecutive page numbers to the bottom of each page in the Reference Compendium (RC-1 through RC-377) and a table of contents (ToC) at the beginning. For several of the items in the Reference Compendium, the portion dealing with Plant Scherer is a small subset of the entire document. The following "road map" may be helpful:

ToC item 1 – In Order No. 23573, the Scherer discussion appears on pages 12 and 13 (RC-12 and RC-13). The effects of the Scherer decision appear elsewhere in the Order.

ToC item 3 – Although the entire transcript of the 10/9/78 workshop is provided, the excerpt cited in Mr. Connally's letter begins on page 42 (RC-128).

ToC item 6 – In Order No. 9628, the Scherer discussion appears on pages 6, 7, 10 and 26 (RC-161, RC-162, RC-165 and RC-181).

ToC item 7 - Although the entire transcript of the 2/16/81 workshop is provided, the excerpt cited in Mr. Connally's letter begins on page 46 (RC-230).

ToC item 9 – In Order No. 10557, the quoted excerpt is found on page 41 (RC-275).

ToC item 10 – In Order No. 11498, the quoted excerpt is found on page 15 (RC-308).

501 Commendencia Street
Pensacola, Florida 32502

I hope the enclosure will be of assistance to you and to the Commission Staff. If you have any questions, please feel free to contact me.

Very truly yours,

Jeffrey A. Stone
For the Firm

cc: J. R. Kelly, Public Counsel
R. L. McGee, Jr., Gulf Power Company

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Reference Compendium
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Gulf Power Company
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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition of Gulf Power Company for an increase in its rates and charges.	DOCKET NO. 891345-EI ORDER NO. 23573 ISSUED: 10/3/90

The following Commissioners participated in the disposition of this matter:

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

Pursuant to duly given notice, the Florida Public Service Commission held public hearings in this docket on April 5, 1990, in Panama City, Florida; April 4, 1990, in Pensacola, Florida; and June 11 through June 21, 1990, in Tallahassee, Florida. Having considered the record herein, the Commission now enters its final order.

APPEARANCES: G. EDISON HOLLAND, JR. and JEFFREY A. STONE, Esquires, Beggs and Lane, P. O. Box 12950, Pensacola, Florida 32576
On behalf of Gulf Power Company

JACK SHREVE and STEPHEN C. BURGESS, Esquires, Office of the Public Counsel, c/o The Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400
On behalf of the Citizens of the State of Florida

GARY A. ENDERS, Major, USAF, HQ USAF/ULT, Stop 21, Tyndall AFB, Florida 32403-6001
On behalf of the Federal Executive Agencies

JOSEPH A. McGLOTHLIN and JOHN W. McWHIRTER, JR., Esquires, Lawson, McWhirter, Grandoff & Reeves, 522 East Park Avenue, Suite 200, Tallahassee, Florida 32301
On behalf of the Industrial Intervenors

RONALD C. LaFACE and WILLIAM L. HYDE, Esquires, Roberts, Baggett, LaFace and Richard, P. O. Drawer 1838, Tallahassee, Florida 32302
On behalf of the Florida Retail Federation

DOCUMENT NUMBER-DATE
08925 OCT -3 1990

ROBERT VANDIVER, MARSHA RULE and MICHAEL PALECKI, Esquires, Legal Division, Florida Public Service Commission, 101 East Gaines Street, Tallahassee, Florida 32399-0850
On behalf of the Staff of the Florida Public Service Commission

PRENTICE P. PRUITT, Esquire, Office of the General Counsel, Florida Public Service Commission, 101 East Gaines Street, Tallahassee, Florida 32399-0850
On behalf of the Commissioners

ORDER GRANTING CERTAIN INCREASES

BY THE COMMISSION:

On December 15, 1989, Gulf Power Company (Gulf or Company) filed its petition for permanent and interim increases to its rates and charges. In its petition, Gulf requested a permanent increase in its rates and charges designed to generate an additional $26,295,000 of gross annual revenues. This request was based upon a projected 1990 test year and a 13-month average jurisdictional rate base of $923,562,000. Gulf requested an overall rate of return of 8.34%, which assumed an allowed rate of return on common equity of 13.00%. The most significant basis for the requested increase, according to Gulf, was the commitment of over 500 MW of additional capacity from its Plants Daniel and Scherer to territorial service and the O&M expenses associated with this capacity. Additionally, the utility claimed an increase in net operating income resulting from substantial capital additions in the transmission, distribution, and general plant areas as well as increased O&M expenses.

Pursuant to Section 366.06(3), Florida Statutes, Order No. 22681, issued on March 13, 1990, suspended Gulf's permanent rate schedules and granted Gulf an interim rate increase of $5,751,000 in annual revenues.

The Federal Executive Agencies (FEA), and Industrial Intervenors (II) were granted intervention status in this docket by Orders Nos. 22363 and 22878, respectively. Order No. 22953, issued on May 18, 1990, granted intervention status to the Florida Retail Federation (FRF). The Office of the Public Counsel (OPC) is a party to this docket pursuant to Section 350.0611, Florida Statutes.

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I. <u>SUMMARY OF DECISION</u>

We authorize Gulf an increase in gross annual revenues of $11,838,000 for two years beginning September 13, 1990. Thereafter, we authorize Gulf an increase in gross annual revenues of $14,131,000.

We have set the rate of return on common equity capital at 12.55%. The reduced increase in gross annual revenues for the two years beginning September 13, 1990, reflects a 50 basis point penalty on return on equity imposed for mismanagement.

II. REVENUE REQUIREMENTS DETERMINATION

The revenue requirements of a utility are derived by establishing its rate base, net operating income (NOI) and fair rate of return. A test year of operations, traditionally based upon one year of operations, is used to derive these factors. Multiplying the rate base by the fair rate of return provides the net operating income the utility is permitted to earn. Comparing the permitted net operating income with the test year net operating income determines the net operating income deficiency or excess. The total test year revenue deficiency or excess is determined by adjusting the deficiency or excess by the revenue expansion factor.

III. THE TEST YEAR

The test year in a rate case provides a set period of utility operations that may be analyzed so the Commission can set reasonable rates for the period the rates will be in effect. A test period may be based upon an historic test year, adjusted to reflect typical conditions in the immediate future, which should make it reasonably representative of expected future operations. Alternatively, a test period may be based upon a projected test period which, if appropriately developed and adjusted, may reasonably represent expected future operations. We approved Gulf's choice of calendar year 1990 as a projected test year.

IV. TEST YEAR RATE BASE

To establish the Company's overall revenue requirements, we must determine its rate base. The rate base represents that investment on which the Company is entitled to earn a reasonable return. A utility's rate base is comprised of various components. These include: 1) net utility plant-in-service, which is comprised of plant-in-service less accumulated depreciation and amortization; 2) total net utility plant, which is comprised of net utility plant-in-service, Construction Work in Progress (CWIP) (where appropriate) and plant held for future use; and 3) working capital.

Gulf has submitted a proposed jurisdictional rate base of $923,562,000. Evidence developed during the course of the proceedings has led us to reduce that amount to $861,159,000. Our adjustments are set forth as follows:

1990 Rate Base
Jurisdictional (000's)

		GULF	ADJUSTMENTS	ADJUSTED RATE BASE
A.	Utility Plant-in-Service	$1,275,624	($ 57,337)	$ 1,218,287
B.	Accumulated Depreciation	(454,964)	(6,913)	(448,051)
C.	Net Plant-in-Service	820,660	(50,424)	770,236
D.	Construction Work in Progress	14,949	- 0 -	14,94(
E.	Property Held for Future Use	3,925	(135)	3,790
F.	Acquisition Adjustment	2,317	(2,317)	- 0 -
G.	Net Utility Plant	841,851	(52,876)	788,975
H.	Working Capital	81,711	(9,527)	72,184
I.	Total Rate Base	$ 923,562	($ 62,403)	$861,159

A. Plant-In-Service

The amount of plant-in-service proposed by Gulf was $1,275,624,000. We have made certain adjustments, described below, which reduce plant-in-service to $1,218,287,000.

(000s)

Plant-In-Service per Gulf		$ 1,275,624
Adjustments:		
1.	New Corporate Headquarters	(3,892)
2.	Navy House	(23)
3.	Appliance Division	(214)
4.	Tallahassee Office	(24)
5.	Leisure Lakes	(142)

6.	Plant Scherer	(52,987)
7.	Misc. Plant-In-Service	(55)
	Total Adjustments	(57,337)
	Adjusted Plant-In-Service	$ 1,218,287

1. New Corporate Headquarters

Gulf's new corporate office building occupies 17.42 acres on Bayfront Parkway overlooking Pensacola Bay. The building is five stories tall and each floor has approximately 50,000 square feet of space. A level below the building is for parking company vehicles. The building was occupied March 31, 1987.

The total building area is 308,634 square feet and consists of 149,945 square feet of office space, 57,057 square feet of parking garage, 41,237 square feet for specialty areas, and 8,832 square feet for the equipment room. The specialty areas are the mailroom and duplicating, cafeteria, system control and ready room, auditorium, MIS computer center, communications, and the like. In addition to the square footage described above, 51,563 square feet on the third floor is presently unfinished and used as a temporary storage and maintenance area.

We believe that the cost of the third floor of $3,840,807 should be removed from plant-in-service. Evidence developed during the course of the proceedings indicates that Gulf has adequate space for storage and maintenance functions at other locations. We find that the ratepayers of Gulf receive no benefit from Gulf's use of the third floor for storage and maintenance and therefore disallow $3,840,807. Gulf is allowed, however, to earn a deferred return on this plant investment and related expenses equal to the allowance for funds used in construction (AFUDC).

The Business Development Center occupies 495 square feet on the first floor of the Corporate Headquarters Building. The room was designed and furnished for presentations to representatives of businesses that are interested in moving to Northwest Florida, and for press conferences relating to weather-related emergencies. The Center is equipped with laser disk players, color monitors, and VCR's that allow prospective business customers to view various areas, industrial parks, and cities in Northwest Florida with an eye toward relocation to this area. The purpose of the laser disk players and VCR's is their use in economic development efforts. The investment capitalized for the Business Development Center in

1987 was $51,548. There has been no capital investment since 1987 and none is projected for 1990. We believe that $51,548 should be removed from rate base for the Business Development Center since the recruitment of business and industry to Florida is not a responsibility of a regulated public utility. The Chamber of Commerce and the Florida Department of Commerce perform that function. The total disallowance for the new corporate headquarters is $3,892,355.

2. Navy House

The Navy House is a former residence which became the property of the company when it purchased land needed to install a transmission line from the company's Bayou Chico Substation to serve the Pensacola Naval Air Station. The initial purchase price of the land and the home on the land was $110,000. We have no reason to believe the price paid was not proper; this amount is not at issue. In addition to the purchase price, however, the company completely renovated the residence to serve as additional training space for its employees. There appears to be ample training space at Gulf's Chase Street facility and at the new corporate headquarters. We therefore find that rate base should be reduced by $23,257 and that 1990 operating expenses for the Navy House be reduced by $7,516.

3. Appliance Division

Gulf has an appliance sales and service operation which is operated out of Gulf buildings which are included in rate base. A portion of this investment has been removed from rate base based on usage studies performed by Gulf. In several instances, the appliance operation has its own buildings which are recorded in non-utility plant.

Gulf made an error in allocating the plant investment to the appliance operation. Therefore, it would be proper to correct the error by reducing plant, accumulated depreciation and depreciation expense $214,000, $7,000 and $12,000, respectively.

4. Tallahassee Office

Gulf maintains an office in Tallahassee for use by its lobbyist, PSC liaison and other Pensacola-based employees while conducting business in Tallahassee. The office space is leased while the office furniture has been capitalized by the company and included in rate base. In addition, Gulf's lobbyist has a company car which is also included in rate base.

Gulf has agreed that 25% of the office investment which is used for lobbying activity should be removed from rate base. In addition Gulf agrees that 100% of the lobbyist's car should be removed. We believe these percentages are reasonable and make the following adjustments:

Reduce Plant-In-Service	$23,860
Accumulated Depreciation	11,193
Depreciation Expense	1,217

5. Leisure Lakes Subdivision (Greenhead Substation)

On October 18, 1984, in Docket No. 830484-EU, Gulf Coast Electric Cooperative, Inc. (Gulf Coast) petitioned the Commission for resolution of a territorial dispute between itself and Gulf Power Company. The dispute involved the Leisure Lakes Subdivision, which consists of approximately 2,300 acres divided into approximately 750 lots. The dispute arose when Gulf Power constructed 2.2 miles of distribution line from its transmission line to the subdivision along a graded county road. After Gulf Coast's petition was filed, and with knowledge of the Commission's jurisdiction over the matter, Gulf Power also constructed the Greenhead substation near the site. In Order No. 13668 we determined that Gulf Coast was entitled to provide electric service to the disputed area. It was also ordered that Gulf Power is prohibited from serving, either temporarily or permanently, the disputed area. In our order we encouraged Gulf Power to sell the facilities they built to serve Leisure Lakes to Gulf Coast, should Gulf Coast desire to purchase them.

Gulf subsequently sold all of its facilities built to serve Leisure Lakes and has no facilities in that area except the Greenhead substation. The book value of the facilities Gulf built to serve Leisure Lakes Subdivision was approximately $131,000 and the sale price to Gulf Coast was $130,353. The Greenhead Substation was not needed to serve load since neither the Sunny Hills or Vernon Substations have reached peak capacity. Therefore, the investment made by Gulf to serve Leisure Lakes subdivision should not be included in rate base. We reduce plant-in-service by $142,000 and depreciation expense by $5,000.

6. Plant Scherer

Gulf acquired 25 percent of Plant Scherer 3 in 1984 and it came on line in January 1987. Since Plant Scherer came on line after Gulf's last rate case, this is the first time Gulf has requested that a portion of Plant Scherer be included in rate base. Of Gulf's 212 MW share of Scherer 3, 63 MW is available to serve Gulf's territorial customers in 1990 and 149 MW is dedicated to unit power sales. The 63 MW of Scherer 3 that Gulf is requesting to be included in rate base includes 44 MW that would have been sold to Gulf States Utilities if they had not defaulted on a unit power sales contract. Gulf is requesting that 63 megawatts of its 212 megawatt share of Plant Scherer 3 be included in its rate base.

Gulf's reserves are reasonable with or without Scherer. Without Scherer, Gulf's reserves are 21.9 percent and with 63 megawatts of Scherer, Gulf's reserves are 25.5 percent. Gulf's parent corporation, Southern Company, maintains reserves which are 19.9 percent without Scherer and 20.1 percent with Scherer. It appears that with or without Plant Scherer, Gulf is well able to achieve its target reserves of 20 to 25 percent.

Gulf will be selling increasing amounts of Scherer's capacity as unit power sales starting in 1992. The following table shows the amount of Scherer dedicated to Gulf's territorial customers from the year 1990 to the year 2010.

Time	Capacity Available to Retail Customers
January 1990 - May 1992	63 megawatts
June 1992 - December 1992	11 megawatts
January 1993 - May 1993	37 megawatts
June 1993 - December 1993	16 megawatts
January 1994 - May 1994	17 megawatts
June 1994 - May 1995	35 megawatts
June 1995 - May 2010	0 megawatts

As shown above, Gulf is scheduled to sell increasing amounts of Scherer 3 under unit power sales agreements starting in 1992. By 1995, none of Scherer 3 will be available to serve Gulf's territorial customers. This capacity will not be available to serve Gulf's territorial customers until the year 2010. Since Gulf is dedicating this unit to unit power sales in years that Gulf's territorial load is expected to be greater than it is in 1990, it would appear that Gulf does not need the unit in 1990 for its territorial customers.

Under Southern's contract with Gulf States Utilities, Gulf had committed to sell 44 MW of Scherer 3 to Gulf States Utilities during the test year 1990 through May, 1992. Gulf States Utilities failed to perform its contractual obligations and on July 1, 1988, FERC ruled that Southern no longer had to perform under the contract. It is clear that Gulf would not have requested 63 MW of Scherer to be in rate base had Gulf States Utilities not defaulted on their contracts. When Gulf made the decision to purchase 25 percent of Scherer 3 it was aware of the potential that their contract with Gulf States Utilities might not be honored. Since the profits from the unit power sales go to Gulf's stockholder, they should bear the risk of default, and not Gulf's ratepayers. Therefore, we remove all of Plant Scherer from rate base. All profits and losses derived from unit power sales of Scherer, and any costs or benefits accruing from any settlement with Gulf States Utilities are to go to the stockholders of Gulf Power Company. Gulf's ratepayers, who will not see the profits from Gulf's unit power sales contracts, should not be required to pay when such a contract falls through.

As a result of our exclusion of Scherer 3 from rate base, we make the following rate base and Net Operating Income adjustments:

Plant-in-Service	$ 52,987,000
Accumulated Depreciation	6,557,000
Acquisition Adjustment	2,317,000
Working Capital	2,187,000
O&M - Expenses	722,000
Depreciation Expense	1,701,000
Amortization of Plant Acquisition Adjustment	73,000
Amortization of ITC	(96,000)
Other Taxes	245,000
IIC Offset	(4,792,000)

7. Miscellaneous Plant-In-Service

We have made miscellaneous plant-in-service adjustments in the amount of $55,000. This resulted from discovery of two work orders that were completed and ready for service but were not immediately transferred to Account 106 (completed construction not classified). As a result, Gulf over-accrued allowance for funds used in construction (AFUDC) by $55,000. We therefore reduce plant-in-service by this amount.

B. Accumulated Depreciation and Amortization

The amount of accumulated depreciation and amortization proposed by Gulf was $454,964,000. Our previously discussed adjustments to plant-in-service require a net reduction to accumulated depreciation and amortization of $6,913,000. Approved accumulated depreciation and amortization is $448,051,000, as follows:

	(000s)
Accumulated Depreciation per Gulf	$ 454,964
Adjustments:	
Appliance Division	(7)
Tallahassee Office	(11)
Plant Scherer	(6,557)
New Corporate Headquarters	(338)
Total Adjustments	(6,913)
Adjusted Depreciation	$ 448,051

C. Net Utility Plant-In-Service

Net utility plant-in-service is comprised of utility plant-in-service, less accumulated depreciation and amortization. We find that the appropriate amount of net utility plant-in-service for test year 1990 is $770,236,000.

D. Construction Work in Progress (CWIP)

The company has included $14,949,000 of construction work in progress in rate base. We believe this amount is appropriate.

E. Property Held for Future Use

Gulf has included in its rate base the sum of $3,925,000 in plant held for future use. We believe this is appropriate except for the 10% of Gulf's Caryville site which is allocated to the sod farm. The sod farm, known as "Southern Sod Company", occupies approximately 200 acres of property at Gulf's Caryville site, or 10% of the Caryville acreage. Southern Sod leases this acreage from Gulf. This is a non-utility operation and we therefore find that 10% of the value of the Caryville Site included in rate base ($135,200) should be removed. We therefore reduce plant held for future use by $135,000 to $3,790,000. We also remove from "other revenues" the $3,450 in lease payments received from Southern Sod.

F. Acquisition Adjustment

As a result of its purchase of a portion of the common facilities at Plant Scherer, Gulf requested an acquisition adjustment of $2,317,000. Since we have not allowed Plant Scherer in rate base, no adjustment for its acquisition will be allowed in rate base. We therefore reduce rate base by $2,317,000.

G. Net Utility Plant

Based upon the adjustments discussed above, total net utility plant for test year 1990 is $788,975,000.

H. Working Capital

The company has included $81,711,000 of working capital in rate base. We have made certain adjustments described below, which reduce working capital to $72,184,000.

	(000's)
Working Capital per Gulf	$ 81,711
Adjustments:	
1. Rate Case Expenses	(765)
2. Temporary Cash Investments	0
3. Heavy Oil Inventory	(576)
4. Light Oil Inventory	(123)
5. Coal Inventory	(6,017)
6. Plant Scherer	(2,187)
7. Caryville Subsurface Study	(28)
8. PIP	169
Total Adjustments	(9,527)
Total Working Capital	$ 72,184

1. Unamortized Rate Case Expense

The company has included $765,385 in working capital for unamortized rate case expense. Commission policy is to exclude unamortized rate case expense from working capital. We therefore reduce working capital by the entire $765,385.

2. Temporary Cash Investments

Gulf, in its rebuttal testimony, has requested $6,045,000 in working capital for temporary cash investments. The appropriate regulatory treatment of either continuing cash balances or temporary cash investments should depend upon their prudency. If the utility can demonstrate, through competent evidence, that their cash balances or temporary cash investments are necessary for the provision of regulated utility service, they should remain in rate base and earn at the utility's overall rate of return. Any earnings generated by these funds should then be used to offset revenue requirements. The burden of proof however is on the Company to demonstrate through competent evidence that their temporary cash investments are necessary for the provision of utility service.

Gulf gave the following reason that temporary cash investments are necessary for its provision of utility service:

> The test year amount for Temporary Cash Investments (13-month average amount) of $6,399,000 is approximately 10 percent of the average monthly disbursements. In addition we are projecting to borrow funds during five months of the test year. The Company again maintains that these funds are required and necessary in providing utility services for our customers. (Ex. 439)

During cross-examination Gulf's witness stated:

> ". . . we don't know of any other way to pay our bills than to have cash available. Either you are going to have temporary cash, cash, or short-term debt, one of the three, because if you -- once you stop paying your bills, you're going into bankruptcy at that stage, and you'll be shut down. You've got to have liquid assets . . ." (TR 793)

While we agree that a company needs to maintain a certain degree of liquidity to operate, we note that Gulf maintains substantial liquidity through short-term debt.

The Company has budgeted to pay $60,000 in 1990, for access to lines of credit totalling $42 million. In addition, the Company continues to keep compensating balances of $436,900 for additional lines of credit totalling approximately $6.2 million. Thus, the Company has access to approximately $48.2 million through lines of credit.

We do not dispute that the Company needs to maintain a certain degree of liquidity to operate. We believe, however, that the burden is on the Company to demonstrate that the additional liquidity provided by holding $6,045,000 in temporary cash investments is necessary. In our opinion the Company has not provided this proof. Statements such as, "its all our available cash" or "temporary cash investments represent less than 10 percent total monthly expenditures" do not constitute competent evidence. We therefore deny Gulf's request that $6,045,000 be included in working capital for temporary cash investment. It is not necessary for us to make an adjustment to working capital since Gulf has already removed temporary cash investments from its filing, consistent with our treatment of this matter in Gulf's last rate case.

3. Heavy Oil Inventory

Gulf has overcalculated the amount of heavy oil inventory necessary for standby fuel at Plant Crist Units 1, 2 and 3. Heavy oil inventory should be reduced to a level equal to seven days burn at 100% capacity factor.

A seven-day supply of heavy oil for Crist Units 1, 2 and 3 operating at 100% of their demonstrated capability would equal 32,774 barrels. Gulf Power has requested a heavy oil inventory of 78,533 barrels with an average price of $13.603 per barrel and valued at $1,042,000 (system). We will allow a heavy oil inventory level of 32,774 barrels at an average price of $13.603 per barrel. We reduce working capital by $596,178 (system), or by $576,462 (jurisdictional).

4. Light Oil Inventory

Gulf has requested that 650,895 gallons of light fuel oil (system) be included in working capital. We are of the opinion that Gulf has failed to justify its request for light oil inventory. We will allow a level equal to 30 days burn at the highest average monthly rate which calculates to 383,210 gallons. This would require a reduction in working capital of $125,339.

5. Coal Inventory

Gulf has requested a coal inventory level equal to 105 days projected burn. We are of the opinion that Gulf has failed to justify this request and will allow a level equal to 90 days projected burn or the amount actually maintained in the test year at each plant site, whichever is less. In Gulf's system this would amount to a total of 784,887 tons valued at $37,000,502 (system). This reduces working capital by $6,222,498 (system) or $6,016,717 (jurisdictional).

6. Plant Scherer

As previously discussed, our exclusion of Plant Scherer from rate base will result in an adjustment of $2,187,000 to working capital.

7. Caryville Subsurface Study

The subsurface study was a geological study of the Caryville site to determine if the land could support the weight of a power plant and supporting facilities. As pointed out in the company's brief, the results of the study are obviously still valid. Such a study would be necessary before any major construction of this type could be done on any site. Therefore, costs associated with the study should be considered together with the Caryville site itself. Since Caryville remains in Rate Base, the cost of the study or $568,000 should be allowed, however we will require that this amount be amortized to expense over a 10 year period. This necessitates a $28,000 reduction in working capital.

8. Productivity Improvement Plan (PIP)

The Productivity Improvement Plan (PIP) is a part of the total compensation plan for the top 11 employees of the company. Due to a change in the design of the PIP program after the budgeting process was completed, the company feels a reduction in the program is in order. The original amount for this program was $438,473. The company's new amount is $99,066. Since it appears that Gulf's overall salary and benefits program is not excessive, and this plan was allowed in the last rate case, the expenses in the amount of $99,066 for this program will be allowed. Therefore, expenses should be reduced $339,000.

Since this adjustment reduces Accounts Payable, a current liability in working capital, the 13-month average of working capital will be increased by $169,187.

I. Total Rate Base

Gulf has submitted a proposed jurisdictional rate base of $923,562,000. Based upon the above described adjustments we have reduced rate base by $62,403,000 to $861,159,000. See Attachment 1 for a complete breakdown of rate base.

V. FAIR RATE OF RETURN

The Commission must establish the rate of return which the Company should be given an opportunity to earn on its investment in rate base. The fair rate of return should be established so as to maintain the Company's financial integrity and to enable it to acquire needed capital at a reasonable cost.

A. Capital Structure

The ultimate goal of providing a fair rate of return is to allow the utility an appropriate return on its investment in rate base. Because all sources of capital cannot be clearly associated with specific utility property, the Commission has traditionally considered all sources of capital (with appropriate adjustments) in establishing a fair rate of return.

The establishment of a utility's capital structure serves to identify the sources of the capital employed by a utility, as well as the amounts and cost rates associated with each. After establishing the sources of capital, all capital costs, including the cost of equity capital, are weighted according to their relative proportion to total capital. The weighted components are then added to provide a composite or overall cost of capital. The weighted cost of capital multiplied by the net utility rate base produces an appropriate return on rate base, including a return on equity capital invested in rate base.

B. Cost of Common Equity Capital

To arrive at a fair overall rate of return, it is necessary that we utilize our judgement to establish an allowable rate of return on common equity capital.

This issue was the subject of prefiled testimony by several witnesses. By stipulation of all the parties, their testimony was inserted into the record as though read and the witnesses presence and cross-examination were waived.

The following three witnesses presented testimony on the appropriate cost of equity capital:

Dr. Roger A. Morin, Professor of Finance at the College of Business Administration, Georgia State University and Professor of Finance for Regulated Industry at the Center for the Study of Regulated Industry at Georgia State University. (On behalf of Gulf Power) Dr. Morin recommends the adoption of a return on common equity of 13.5%.

Mr. James A. Rothschild, President, Rothschild Financial Consulting. (On behalf of the Citizens of the State of Florida) Mr. Rothschild recommends that the proper calculated return on equity for Gulf Power is 11.75%.

Mr. Scott A. Seery, Regulatory Analyst, Bureau of Finance, Division of Auditing and Financial Analysis, Florida Public Service Commission (On behalf of the Florida Public Service Commission Staff) Mr. Seery recommends the adoption of a return on common equity of 12.25%.

The witnesses used three different equity costing methodologies to arrive at their estimates of Gulf's cost of equity. Witness Morin used the risk premium, discounted cash flow (DCF) and capital asset pricing model (CAPM) methodologies. Witness Rothschild relied primarily on the DCF method. Witness Seery used the DCF and risk premium methods.

When analyzing the cost of equity one should realize that it is a subjective process. Based on the evidence in the record and a review of the equity costing methodologies presented, we find that a reasonable allowed rate of return on common equity capital for Gulf is 12.55%. This rate of return on common equity will allow Gulf the opportunity to raise capital on fair and reasonable terms and to maintain its financial integrity.

We believe a 12.55% cost of common equity is well supported by the evidence presented and represents the best estimate of the Company's cost of equity. To put this finding in perspective, at the time revised testimony was filed by these witnesses, the average yield on long-term treasuries was 8.74% and the yield on A-rated utility bonds was 9.92% for April 1990. The average yield for June 1990 was 8.60% for long-term treasuries and 9.80% for A rated utility bonds as reported by Moody's Bond Survey, July 16, 1990.

C. Capital Structure Reconciliation

We require that there be a reconciliation of the rate base and the capital components which support the rate base. In order to determine the appropriate overall cost of capital for which the utility will be allowed to earn a return, several adjustments must be made to the capital structure as presented by the utility in its minimum filing requirements. First, as all parties agree, the preferred stock balance is to be presented net of discounts, premiums, and issuance expenses. The effect on capital structure is to reduce the preferred stock balance by $948,000 and to increase the common equity balance by $948,000.

Next, we believe all non-utility investment should be removed directly from equity when reconciling the capital structure to rate base unless the utility can show, through competent evidence, that to do otherwise would result in a more equitable determination of the cost of capital for regulatory purposes. In the case of Gulf, we believe that the non-utility investments should be removed from equity. This will recognize that non-utility investments will almost certainly increase a utility's cost of capital since there are very few investments that a utility can make that are of equal or lower risk. Removing non-utility investments directly from equity recognizes their higher risks, prevents cost of capital cross-subsidies, and sends a clear signal to utilities that ratepayers will not subsidize non-utility related costs.

We believe that specific adjustments should be made to the tax components of the capital structure. We have specifically identified the effects of the rate base adjustments for the navy house, the Tallahassee office, Leisure Lakes, unamortized rate case expense, and Plant Scherer, including the plant acquisition adjustment, and have decreased the average balance of accumulated deferred income taxes by $5,877,000 and of investment tax credits by $2,402,000. The remaining amount of these rate base adjustments are then reconciled over all investor sources and customer deposits.

All other adjustments to rate base are on a pro rata basis over all sources of capital. We believe the remaining adjustments should be removed at the company's overall cost of capital.

Based upon the rate base/capital structure reconciliation that we discussed above and our review of the record of the cost rates and capital components, the appropriate capital structure for Gulf Power is as follows:

COMPONENT	AMOUNT	PERCENT OF TOTAL CAPITAL	COST RATE	WEIGHTED COST
Long Term Debt	311,950	36.22%	8.72%	3.16%
Short Term Debt	3,971	0.46%	8.00%	0.04%
Preferred Stock	51,358	5.96%	7.75%	0.46%
Customer deposits	14,134	1.64%	7.65%	0.13%
Common Equity	264,857	30.76%	12.55%	3.86%
Accumulated Deferred Income Taxes	175,796	20.41%	0.00%	0.00%
Deferred ITC - Zero Cost	823	0.10%	0.00%	0.00%
Deferred ITC - Weighted Cost	38,270	4.44%	10.26%	0.46%
	861,159	100.00%		8.10%

For a complete breakdown of Gulf's 13-month average capital structure see Attachment 2.

VI. MISMANAGEMENT

The record is clear: Gulf Power Company admitted that corrupt practices took place at Gulf Power Company from the early 1980s through 1988, including but not limited to theft of company property, use of company employees on company time to perform services for management personnel, utility executives accepting appliances without payment, and political contributions made by third parties and charged back to Gulf Power Company. The majority of the unethical/illegal activities involved Jacob Horton, the Senior Vice President of Gulf Power Company. Mr. Horton was killed in a plane crash on April 10, 1989.

The question then becomes whether the management of the power company knew or should have known of the illegal and/or unethical conduct that was taking place. At this point it is incumbent upon the Commission to note that there is no record evidence to indicate that Mr. Douglas McCrary, President of Gulf Power Company from May of 1983 through the present, knew that illegal or unethical conduct was taking place as it happened. Mr. McCrary testified under oath as to his lack of contemporaneous knowledge of the activities.

We do believe that Gulf Power's senior management should have known of some of these activities and should have acted sooner and with sterner measures with regard to Mr. Horton's activities. This inaction constitutes mismanagement. As a totally independent ground, the activities of Mr. Horton and his subordinates as Senior Vice President alone constitute mismanagement. This recommendation is premised upon the structure of Gulf Power management with four vice presidents reporting to the president. As one of those vice presidents, Mr. Horton's actions are those of Gulf Power management.

We believe that there were many early warning signals which indicated that illegal or unethical conduct was present. In December of 1983 Mr. McCrary received anonymous letters concerning employee misappropriation of goods. Mr. McCrary commissioned an independent investigation by security personnel from a sister company to avoid one peer investigating another. The result of this investigation was the "Baker-Childers report", which was Exhibit 391 at the hearing. This report focused on warehouse thefts directed by Kyle Croft. Also contained in this report were allegations of company personnel performing personal services for Gulf Power executives, including Mr. Horton, on company time with company materials. When Mr. Horton was asked about these allegations, Mr. Horton denied them, and no further action was taken. (R169) This incident did, however, raise suspicions about Mr. Horton. (R168)

With regard to the principal allegations contained within the Baker-Childers report, Mr. Croft was fired on a Sunday morning in late January 1984. However, Mr. Horton intervened and persuaded the president to rescind the firing decision and allow Mr. Croft to resign. Unknown to others in senior management at the time, Mr. Horton arranged for Mr. Croft's attorneys fees and health insurance to be paid and billed back to Gulf Power. Gulf's senior management learned of this payment in 1988. (R197) As part of Mr. Croft resigning from Gulf Power, Mr. Croft executed a promissory note for $15,986.62 to Gulf Power Company. This represented an estimate of the property Mr. Croft had stolen from Gulf Power. Concurrent with the execution of this note, Mr. Horton stated that Gulf Power would not enforce the note, and Mr. Horton executed a note payable to Mr. Croft for the same amount. (Ex. 396 at p. 55) This was done to protect Mr. Croft if Gulf Power decided to enforce the note. When the senior management learned of Mr. Horton's note in 1986 it also heightened suspicion of Mr. Horton. (R199)

In June of 1984 it was learned that Gulf Power had delivered approximately $10,000 worth of appliances to Mr. Ed Addison, former president of Gulf Power Company and now head of the Southern Company, the parent company of Gulf Power. Mr. Addison was not billed for these goods, and it was the intent of Gulf Power employees to give the appliances to Mr. Addison. (R183) The president learned of this arrangement and discussed the matter with the Mr. Addison. Mr. Addison was billed and then promptly paid for the appliances. (R184) The employees involved reported to Mr. Horton which again raised suspicion concerning Mr. Horton. (R186) No further investigation of the appliance division was made. (R187)

In July of 1984 Mr. Horton instructed a Gulf Power employee to solicit a $1,000 political contribution from a local architect that worked with Gulf Power Company. The president learned of this several days later. (R223) He spoke to Mr. Horton and "reemphasized" that pressure would not be placed on vendors to make political contributions. (R223) Mr. McCrary conceded that he was very much suspicious about Mr. Horton by July of 1984. (R225) Unknown to the president at the time was the fact that Gulf Power in fact reimbursed the architect for the political contribution. (Ex. 396 at p. 21) In the fall of 1986, the president learned that Gulf Power had reimbursed Mr. Graves (the architect), and had Mr. Graves reimburse Gulf Power Company, and then had Mr. Horton reimburse Mr. Graves. Any suspicion created in 1984 by this situation should have been greatly increased by the 1986 transactions.

On October 31, 1989 Gulf Power Company entered quilty pleas to two felony counts in the United States District Court for the Northern District of Georgia, Atlanta Division. Gulf Power paid a $500,000 fine for these crimes. (Ex. 413) This negotiated plea agreement grew out of Gulf Power activities from 1981-1988. Over 120 counts were detailed in Exhibit 413. Basically Gulf Power management, through Mr. Horton and his subordinates, "systematically, repeatedly and willfully instructed its outside vendors, such as its advertising agencies, to submit false or inflated invoices to Gulf Power Company for payment by Gulf Power Company in order to reimburse those vendors for payments they had made to political candidates and others at the direction of Gulf Power Company." (Ex. 413 at p. 13) These illegal acts were not isolated cases and are factually indistinguishable from the Graves contribution which the senior management knew of 1984 and learned more about in 1986.

We believe that the explicit warnings the senior management received concerning Mr. Horton, coupled with the Baker Childers Report in early 1984, the Addison appliances in June of 1984, the Graves contribution in July of 1984, the 1986 Kyle Croft lawsuit revealing more information concerning Mr. Croft's resignation and the subsequent information in 1986 regarding the 1984 Graves contribution all indicate that Gulf's senior management should have been aware of Mr. Horton's activities. This is especially true in light of the close business relationship between the two senior executives (CR 219; 231; 236; 245, 246). An investigation of Mr. Horton's activities was clearly indicated by 1986.

In the fall of 1988 senior management became aware of the Appleyard ledgers. It was known at that time that violations of the law were involved. (R244) These accounts were handled by the organization reporting to Mr. Horton. Mr. Horton was informed that he was to be separated from the company on April 10, 1989. (R4192) As of May 1, 1989, the company had not undertaken an investigation of Mr. Horton, despite the events described above. See Exhibit 382 at p. 16A. We believe that the lack of action regarding Mr. Horton constitutes mismanagement because management should have been aware of Mr. Horton's activities or started an investigation into Mr. Horton's activities based on the events discussed above.

Not only did management fail to initiate an investigation of Mr. Horton, but Mr. Horton has never received a written reprimand. (R4186-87) This lack of written reprimands is troubling considering management's subsequent knowledge of Mr. Horton's promissory note, the Graves Contribution, and paying Mr. Croft's legal and insurance costs. In one case (the Graves situation) Mr. Horton lied to the president in 1984 and the president knew he lied in 1986. In another case (paying the legal and insurance costs for Mr. Croft) Mr. Horton directly disobeyed the president's explicit instructions. (R197) Mr. Horton also received Productivity Improvement Program payments for his job performance in 1983, 1984, 1985, 1986, and 1988 and his base salary rise each year from 1983-1988. (Ex. 547)

Although we believe Gulf's lack of action regarding Mr. Horton constitutes mismanagement, we believe that given Mr. Horton's position, his actions alone constitute mismanagement regardless of senior management's inaction. Gulf Power has over 1600 employees. Mr. McCrary is the leader of these employees, and four executives reported directly to him, as well as the director of Public Relations. (See R192; Ex. 414) Thus all policy decisions and supervision of all Gulf Power personnel are vested in this management team. We do not use the term "management team" loosely. The president expressed it this way:

> I did that [consulted the vice-presidents on the decision to fire Mr. Croft] because we operate that

> company on a-- in a manner such that all very important decisions that we make, we try to do as a group, so that all vice presidents are satisfied that they have had their input and they agree with the decision.

(R193; See R217; 3050)

Given this management philosophy and practice, we believe it totally appropriate to find Mr. Horton's actions as those of Gulf Power management. Mr. Horton was one of the five people who management Gulf Power. In carrying out his duties as Senior Vice President, he committed illegal and unethical acts on behalf of the utility. Therefore, Gulf Power Company was guilty of mismanagement.

In terms of the scope of the corruption taking place at Gulf Power Company, several company programs were initiated to deal with the problem. Among these programs were adoption of a company Code of Ethics in August of 1984 and the implementation of an amnesty program around the same time. The Code of Ethics was adopted in response to the "myriad of things that had been going on in the early 1980s." (R204) The president agreed that every large well run utility should have a Code of Ethics and he couldn't say why Gulf Power lacked a Code of Ethics prior to that time. (Id.) All existing and new employees were required to sign a compliance statement. To implement the Code, Gulf Power had a series of meetings to explain the Code and the reason for it. The president was unable to point to anything Gulf Power did to further implement the Code from August of 1984 through January 5, 1989. On January 5, 1989, the Audit Committee of the Gulf Power Board of Directors adopted a resolution to reiterate the Code of Ethics and ordered management to take certain actions to implement the Code. (R206) The president explained the action as follows:

> We thought it was in -- that what we should do is to reemphasize the Code of Ethics; to have an educational program; to have a program of ethics awareness, and to generally have employees focus on the Code of Ethics being a real and living document. (R206)

The Code of Ethics was adopted in 1984 to combat the embezzlement of Gulf Power property and by 1989 different sorts of ethical violations were apparent, indicating that some employees ignored the Code or failed to take it seriously. (R214-15) We believe the 1989 measures should have been in effect in 1984 and there was haphazard enforcement of the Code from 1984 to 1988.

Gulf Power's amnesty program was initiated in the summer of 1984. This program was implemented in response to numerous allegations against Gulf Power personnel in the Baker-Childers Report. (R128) An outside law firm administered the program in order to shield the identity of the participants from the company. (Ex. 396 at p. 40-41) The program was designed to allow company employees that had improperly obtained goods or services from the company to make restitution to the company and then be subject to no further action. (R128) Gulf Power had no way of knowing whether the amounts collected under the amnesty program were correct. (R136; 140) A total of $13,124.23 was collected pursuant to this program. Of this amount, $10,500 (80%) came from two individuals in leadership positions at Gulf Power Company. (R138; 201; See Ex. 414)

On January 1, 1988, one of the persons who reported directly to the president was involved in three automobile accidents while driving a company vehicle. He was charged with D.U.I. and a number of traffic violations at the scene of the third accident. The president believed it would be very damaging to Gulf Power if the incident were reported in the media and he made a conscious decision not to have the accident reported as required by company procedures. (Ex. 396 at p. 66) Although this activity constituted a violation of the Code of Ethics, the individual involved received no written reprimand. (R180) He was orally reprimanded, although it is not clear by whom. (R181) Two points concerning this incident appear relevant to our analysis. First, it would appear that this incident supports the lack of commitment to enforcement of the Code of Ethics from 1984 to 1988. Second, it also raises the issue of Gulf Power treating executives differently concerning ethical violations than other employees. This is buttressed by the lack of investigation of allegations concerning personal use of company materials involving an ex-president of the Southern Company. (R134) Discriminatory enforcement is further indicated by considering that a lower-level employee was fired for stealing a gallon of gas and certain other unspecified violations. (R107; 128; 182)

Gulf Power also did business in 1983 with Scott Addison, the son of Ed Addison, the Chief Executive Officer of the Southern Company. Although this specific transaction does appear prudent in and of itself, we do question the propriety of doing business with relatives of the parent company personnel. This is especially true when the transaction was not handled in the normal manner and Gulf Power conceded that absent the family connection, the person would probably not have received the same treatment. (See R3841-3844)

To summarize, we believe the events described above support a finding of mismanagement on the part of Gulf Power Company. The finding of mismanagement is premised on the activities of Mr. Horton, the president's lack of knowledge of those activities despite the incidents discussed above, the lack of investigation of Mr. Horton, the lack of written reprimands to Mr. Horton, the circumstances relating to the readoption of the Code of Ethics, the uneven enforcement of same, the various executives accepting goods or services without payment and the other factors discussed above. These factual circumstances as well as the fact that the illegal activity continued for at least eight years, lead us to agree with Ms. Bass, "that the corporate culture was such that employees believed these types of illegal activities were, at the least, condoned by top management." (R2994; See Ex. 391 at p. 10; 28; 33) This is particularly true when one considers that illegal activity continued for at least eight years.

Given the foregoing discussion, the issue becomes what action the Commission should take. Gulf Power argues that the Commission lacks authority to lower the return on equity in absence of a demonstrable impact on rates or service from the mismanagement. (Gulf Power Brief at 110; See Id. at 107-138) In United Telephone Co. of Florida v. Mann, 403 So.2d 962, 966 (Fla. 1981), the court stated that after the rate of return is calculated, "the commission can make further adjustments to account for such things as accretion, attrition, inflation and management efficiency." (Emphasis supplied) We believe this case, in conjunction with the fact that public utility regulation is an exercise of the police power (See Section 366.01, Florida Statutes) and other statutory provisions (See Sections 350.117, 366.041, 366.07, and 366.075, Florida Statutes) grant this Commission ample authority to take management efficiency into account in setting rates.

The statutory provisions cited above give the Commission authority to consider management efficiency in setting rates. In consideration of relative efficiency, the Commission should reward the more efficient and give less relief to those operating in a less efficient manner. As the court stated in Deltona Corp. v. Florida Public Service Commission, 220 So.2d 905, 907 (Fla. 1969):

> A statutory grant of power or right carries with it by implication everything necessary to carry out the power or right and make it effectual and complete.

We believe the proper method of dealing with mismanagement is through the return on equity. The New Hampshire Public Utilities Commission has acted in conformity with this principle:

> The method of addressing managerial inefficiency which is most soundly rooted in proper regulatory principles and is most appropriate to the instant situation is a reduction in the allowed return on common equity. Re: Public Service Commission of New Hampshire, 57 PUR4th 563, 594

In the instant case there were various ongoing criminal conspiracies reaching to the highest levels of management. These events, widely reported in the media, have hurt the company's relationship with its customers, as was made clear from the testimony customers gave at the service hearings. It is axiomatic that the involvement of managerial personnel in criminal activities lessened the efficiency of management in providing electric service.

As previously discussed, expert testimony of record established that a fair rate of return on equity (ROE) for this utility lies between 11.75% and 13.50%. Analysis of the cost of equity is a subjective process and an exact figure is impossible to measure precisely. The Commission must evaluate the testimony presented and then utilize its expertise to arrive at a fair rate of return for the particular utility at issue. As previously discussed, we believe the appropriate ROE for Gulf Power Company to be 12.55%. Were the previous pages recounting Gulf Power mismanagement not in the record of this proceeding, we could stop there. This record reflects a disregard for the ratepayers and public service, however. Accordingly, we will reduce Gulf Power Company's ROE by fifty (50) basis points for a two year period. This results in a final ROE of 12.05%.

This final ROE is well within the parameters established as fair and reasonable by expert testimony of record. This reduction in the authorized ROE for a two year period is meant as a message to management that the kind of conduct discussed above, which was endemic for at least eight years at this company, will not be tolerated for public utilities which operate in Florida. We have limited the reduction to a two year period to reflect our belief that Gulf Power has turned the corner on dealing with the extensive and long-standing illegal/unethical behavior within the company.

VII. NET OPERATING INCOME (NOI)

Having established the Company's rate base, and fair rate of return, the next step in the revenue requirements determination is to ascertain the net operating income (NOI) applicable to the test period. The formula for determining NOI is Operating Revenues less Operating Expenses equals NOI.

The Company has proposed a net operating income of $60,910,000. Evidence developed during these proceedings has led us to increase this amount to $61,085,000. Our adjustments are set forth as follows:

JURISDICTIONAL NET OPERATING INCOME
(000's)

	Gulf	Adjustments	As Adjusted
* VIII. Operating Revenues	$ 255,580	108	$ 255,688
* IX. Operating Expenses			
A. O&M	113,382	762	114,144
B. Deprec. & Amort.	47,701	(1,893)	45,808
C. Taxes - Other	20,822	(274)	20,548
D. Current Income Taxes	13,185	529	13,714
E. Def.Income Taxes (net)	1,621	712	2,333
F. ITC (net)	(2,041)	96	(1,945)
G. Total Oper. Exp.	194,670	(67)	194,603
H. Net Operating Income	$ 60,910	175	61,085

*Operating Revenues and Expenses are net of fuel and conservation.

VIII. OPERATING REVENUES

The Company proposed an operating revenue for test year 1990 of $255,580,000. We have made adjustments increasing operating revenues for 1990 by a total of $108,000 to $255,688,000. Our adjustments to revenues are as follows:

(000's)

Company Test Year Revenues	$ 255,580
Adjustments:	

A.	PXT misbilling:	16
B.	Non-utility electric billing:	35
C.	Sod Farm revenues	(3)
D.	Appliance division-use of logo	-0-
E.	Revision of OS-I and OS-II Revenue	66
F.	Revision of OS-III and OS-IV Revenue	(6)
Total Adjustments		$ 108
Adjusted Operating Revenue		$ 255,688

A. PXT Misbilling

A PXT customer experienced a forced outage during September 2 and 3 of 1989, and took standby power of 7959 KW during that outage. The PXT customer had taken a generator off line for maintenance to repair the boiler during the period in question. Nonetheless, the customer was not billed for standby power as it should have been (see Commission Order No. 17159).

Additional revenues of $16,325 should therefore be imputed for 1990 as the customer should properly have been billed for standby power of 7959 KW.

B. Non Utility Electric Billing

The company has several non-utility operations including the sod farm, vision design, and the appliance sales and service. In the past and currently, Gulf has allocated the cost of the metered electric consumption to these operations at the actual cost of generation.

We believe that these non-utility operations are being subsidized in part by paying less for electricity than they would have if their consumption had been billed-out at the appropriate tariff rate. It is therefore appropriate to increase revenues by $34,913.

C. Sod Farm Revenues

We have previously ruled that the percentage of the Caryville site devoted to the sod farm (10%) be excluded from rate base. Therefore, it is appropriate to remove from other operating revenues $3,450 in rental revenues received from the sod farm operations.

D. Appliance Division - Use of Logo

After considering the briefs of the parties on this issue we have decided that the value of the Gulf logo to the non-utility appliance sales division should be recognized. It follows that an appropriate allowance for the use of the logo should be credited to the company as revenue above the line.

In the record before us however, we find no evidence concerning the dollar value of Gulf's corporate logo to the appliance division. In the absence of a record basis, we therefore make zero ($0) adjustment.

E. Adjustment to OS-I and OS-II

The company failed to use the revenues shown on their most recently revised MFR Schedule E-16 for these classes. It is, therefore, appropriate to increase revenues by $66,000.

F. Adjustment to OS-III and OS-IV

The company failed to correctly transfer revenues from MFR Schedule E-16d to E-16a. This resulted in the utility overstating its current revenues. We therefore decrease revenues by $6,000.

IX. OPERATING EXPENSES

Gulf has requested total operating expenses of $194,670,000. We have made additional adjustments reducing total operating expenses by $67,000 to $194,603,000.

A. Operating and Maintenance Expense (O&M)

Gulf has proposed total O&M expense of $113,382,000. We have determined that this amount should be increased by $762,000 to $114,144,000 as follows:

	(000's)
Operating and Maintenance Expenses Per Company	$ 113,382
Adjustments:	
1. Navy House	(8)

2.	Plant Scherer-Net of IIC Offset	4,070
3.	Out-of-Period, Non-Recurring, etc.	(190)
4.	Industry Association Dues	(20)
5.	Current Rate Case Expenses	(250)
6.	Cogeneration & Industrial Programs	(426)
7.	Good Cents Incentive Program	(50)
8.	Presentation/Seminars Program	(55)
9.	Shine Against Crime	(92)
10.	Economic Development	(687)
11.	Lobbying Expenses	(264)
12.	IRS, Grand Jury, etc.	(5)
13.	Research & Development Projects	(32)
14.	Transmission Rents	(423)
15.	Labor Complement Vacancies	(403)
16.	Productivity Improvement Plan	(339)
17.	Employee Relocation & Development Programs	(56)
18.	Management Perks	(65)
19.	Caryville Subsurface Study	57
20.	Pension Expense	0
21.	Retirement Medical and Life Insurance	0
	Total Adjustments	$ 762
	Adjusted O&M Expenses	$ 114,144

1. Navy House

As discussed earlier, we find that 1990 operating expenses for the Navy House should be reduced by $7,516.

2. Plant Scherer - Net of IIC Offset

The Intercompany Interexchange Contract (IIC) is a methodology for equalizing the capacity reserves among the various operating companies of the Southern Company. Since Plant Scherer is being excluded from the rate base, it is also appropriate to exclude the $4,792,000 capacity payment that Gulf would receive for the Plant Scherer capacity. This would have the effect of increasing operating and maintenance expenses by $4,792,000.

On the other hand, the exclusion of Plant Scherer from rate base would also have the opposite effect of reducing operating and maintenance expenses by $722,000 (the cost of operating and maintaining the plant). The net of these two adjustments results in an increase in operating and maintenance expenses of $4,070,000.

3. Out of Period, Non Recurring or Non Utility

For 1990, Gulf budgeted $1,663,247 for other non-recurring expenses compared to a 5-year averge of actual expenses of $1,473,407 or a difference of $189,840. Gulf did not offer any explanation as to what activities were projected for 1990 in support of the $1,663,247 non-recurring expenses. Since these expenses affect all functional categories of expenses, the adjustment has been included in the O&M benchmark schedule as a single adjustment to total O&M expenses. We have therefore reduced O&M expenses by $189,840.

4. Industry Association Dues

We have adjusted the company's budgeted industry association dues from $167,193 to $147,172. This includes a disallowance of $19,378 for that portion of the Edison Electric Institute Dues which is used for lobbying (1/3 of $58,133 total dues), and $643 associated with miscellaneous organizations that were not identified by the company except as "Organization to be joined in 1990."

5. Current Rate Case Expenses

The company projected rate case expense at $1,000,000. This amount is not contested and consists of:

Outside Consultants	$ 248,000
Legal Services	164,000
Meals and Travel	37,000
Paid Overtime	7,000
Other Expenses*	544,000
Total	$1,000,000

*Includes SCS expenses, postal charges, printing costs and transcripts.

At issue is the amortization period over which the expense will be spread. Commission policy is to amortize rate case expense over a period of time because a rate case benefits not only the current period, but future periods as well. In Gulf's last rate case, in Order No. 14030, we allowed a two year amortization period. In Gulf's 1982 rate case, in Order No. 10557, we allowed a three year period. In the FPUC-Fernandina Beach Division rate case, we approved a 5 year amortization period since it had been approximately 15 years since the company's last rate case. (Order No. 22224, Docket No. 881056-EI).

Gulf's witness testified that a two year amortization period was appropriate because over the past ten years Gulf has had five rate cases for an average of one rate case every two years.

It has been six years since Gulf's last rate case. Pursuant to Chapter 366, Florida Statutes, Gulf must file Modified Minimum Filing Requirements (MMFRs) in 1994. We believe that the amortization period should be greater than the two years ordered in Gulf's last rate case but less than the six years between cases, since the company must file MMFRs in four years. Therefore, rate case expense will be amortized over four years. Expenses should be reduced by $250,000.

6. <u>Cogeneration and Industrial Programs</u>

We do not believe that expenses related to Gulf's Industrial Customer Activities Cogeneration Program should be allowed. From the record in this docket, this program appears to be little more than a load retention program for large industrial customers.

As justification for this expense, Gulf states that this program provides benefits to the general body of ratepayers by preserving revenues. This presents us with the age old question of the benefits of high load factor customers to the general body of ratepayers.

Gulf contends that the retention of high load factor customers benefits all customers. On the other hand, in this rate proceeding the company has requested that additional plant be placed in base rates. From this record it cannot be concluded that high load factor customers have necessarily benefitted Gulf's general body of ratepayers.

In addition, Gulf has proposed an Energy Audit and Technical Assistance Program as part of its overall conservation plan. This program not only addresses conservation measures, but cogeneration applications, and appears to duplicate the Industrial Customer Activities Cogeneration Program in several respects. We therefore find that the amount budgeted for the Industrial Customer Activities Cogeneration Program ($426,464) should be disallowed.

7. Good Cents Incentive Program

The Good Cents Incentive program offers merchandise and travel packages to contractors for the installation of energy efficient appliances. It also offers these incentives for the retrofit of gas furnaces to electric heat pumps. The provision of these appliances does not require the use of an incentive. The general public, as well as the real estate community, is well aware of the benefits of having an energy efficient home. In fact, energy efficiency has become a major selling point as customers have come to demand energy efficient homes.

Since the provision of incentives to contractors is not necessary, we believe that the $50,000 budgeted by Gulf for the Good Cents Incentive Program should be disallowed.

8. Presentation/Seminar Program

Gulf had budgeted $55,429 for its Presentation/Seminar Program. Gulf contends that this program provides presentations to local contractors about the energy efficiency of electric appliances. This appears to be a duplication of the company's Education and Good Cents programs. Today's contractors are well aware of the importance of an energy efficient home. While these presentations and seminars do foster a better relationship between Gulf and the local contractors, we do not see any additional benefits accruing to the general body of ratepayers. We therefore disallow the $55,429 budgeted for this program.

9. Shine Against Crime

The Shine Against Crime program is simply an outdoor lighting program. These types of programs have been in existence for some time mainly to replace inefficient lighting with more efficient high pressure sodium lighting. This practice reduces kwh consumption and conserves resources. In addition to this purpose however, Gulf's program promotes the installation of new outdoor fixtures.

Section 366.80-.85 of the Florida Statutes, also known as the Florida Energy Efficiency and Conservation Act (FEECA), mandates that utilities control energy growth. While the replacement of inefficient outdoor fixtures helps to reduce energy requirements, the promotion of "new" outdoor installations increases energy requirements. It is this facet of the Shine Against Crime program that we take exception with. The promotion of off-peak load does not contribute to reducing energy requirements and may be contrary to FEECA. The company's witness stated that approximately 35 to 37% of the expenses for this program are attributable to changeouts of existing fixtures. This means that 63% of the expenses, or $91,761, is attributable to new installations and the promotion of off-peak sales. We therefore disallow $91,761 of the $145,652 Gulf has budgeted for this program.

10. Economic Development

Gulf contends that its well-being is directly related to that of the community, and that it has a direct stake in the community's overall development. As a result, Gulf has developed a marketing and promotional campaign designed to attract new businesses to the area.

It appears that Gulf has assumed some of the responsibilities of local chambers of commerce or development boards. Traditionally, those organizations have been in the forefront of attracting businesses to expand and relocate in their area. Gulf is duplicating these efforts. The company admits that it has "assumed a leadership role in furthering the capability of communities in its service territory to attract and/or expand the industrial base." In seeking to expand industry or business activity in general, Gulf is actively attempting to increase sales of electricity.

This type of marketing expense might be expected of a company operating in a non-regulated environment. A desire to increase sales or market share against the competition is normal and healthy when there is competition. Gulf however, has no competitors supplying electrical power in the same geographic area it serves.

We do not believe that this expense should be passed on to Gulf's ratepayers. We therefore disallow the entire $687,000 Gulf has budgeted for economic development.

11. Lobbying Expenses

We have removed $263,534 used for lobbying and lobbying-related activities from operating expenses. This adjustment removes $96,643 for SCS expenses for Outside Consultants and $119,923 for expenses incurred by Gulf's registered lobbyist and 25% of the office rent on the Tallahassee office. In addition, 10% of the expenses of Gulf's Regulatory Matters Coordinator or $5,375 should also be removed. This is consistent with Gulf's book treatment of these expenses in 1989.

Further adjustments are necessary to remove 25% of the expenses allocated to Gulf for the Governmental Affairs office in Atlanta and Washington or $41,593. Because of the similarities between these Governmental Affairs offices and the Tallahassee office it is appropriate to make this adjustment (TR 3855-3856).

12. IRS, Grand Jury Expenses

At the time of its filing, Gulf identified $615,000 in expenses related to grand jury and IRS investigations which it agreed to remove from its 1990 test year budget. Since its filing Gulf discovered an additional $5,000 used for a presentation made by Gulf's outside auditors to its Board of Directors. Gulf has stipulated to the removal of this amount and we therefore disallow $5,000.

13. Research and Development Projects

Gulf has budgeted $210,000 in O&M expenses for research and development. Of this amount, the $31,813 Gulf has budgeted for the Acid Rain Monitoring Program is an extension of a previous acid rain program and not a new research and development program. In removing this amount from Gulf's proposed 1990 budget, we are not disallowing funds for acid rain research. Rather, we find that Gulf has failed to sustain its burden of proof in justifying this variance from the 1990 benchmark.

14. Transmission Rents

Transmission rents, or facilities charges, are a cost effective alternative to Gulf building its own transmission lines to receive power from Plants Daniel and Scherer, which are physically located outside the State of Florida.

Since we have removed Plant Scherer from Gulf's rate base it is also appropriate that we remove the associated transmission expenses. We therefore remove $423,000 in transmission rents from Gulf's O&M budget.

15. Labor Complement Vacancies

An adjustment in O&M expenses is necessary to remove the effect of vacancies on the labor complement. On the average there were fifty (50) vacant positions in Gulf's labor complement over the twelve month period ending May, 1990. Four positions were eliminated however in Gulf's 1990 budget, leaving a net average vacancy rate of 46 positions. We therefore reduce O&M expenses by

$403,222 and payroll taxes of $29,982 to remove the effect of vacancies on the labor complement. This adjustment is in addition to adjustments made by Gulf recognizing vacant positions.

16. Productivity Improvement Plan

As previously discussed, the Productivity Improvement Plan (PIP) is part of the total compensation plan for Gulf's top 11 employees. Due to a change in the design of the PIP program after the budgeting process was completed, a reduction in O&M expenses is in order.

The original amount budgeted for this program was $438,473, whereas the amount now budgeted is $99,066. We therefore reduce O&M expenses by $339,407.

17. Employee Relocation

Gulf's employee relocation plan covers a variety of costs involved in moving an employee and his family. These costs include appraisals, inspections, insurance, closing costs, broker expenses, moving expenses, and living expenses until a new home is purchased.

Relocation expenses cannot be neatly extrapolated from year to year. Unlike salaries or plant maintenance relocation expenses vary, as shown below:

Year	Actual Amount
1984	$ 263,066
1985	121,536
1986	113,552
1987	285,361
1988	205,287
1989	468,246

Relocation expense increased in 1989 primarily due to company reorganization. Gulf budgeted $324,100 for test year 1990. We believe that $324,100 is too high because of the extensive changes which occurred in 1989 are unlikely to recur soon. We believe a more reasonable approach is to allow $268,112, the amount of the 1986-1989 average yearly expense for relocation. Therefore, Gulf's 1990 budget for relocation expense should be reduced by $55,988 from $324,100 to $268,112.

18. Management Perks

Gulf's ratepayers should not pay for tax services and fitness programs for executives. These expenses should be borne by the stockholders. Expenses are reduced by $65,100.

19. Caryville Subsurface Study

As we have previously discussed, the subsurface study was a geological study of the Caryville site to determine if the land could support the weight of a power plant and supporting facilities. Since Caryville remains in Rate Base, this study ($568,000) should be allowed, however we will require that this amount be amortized to expense over a 10 year period. Amortization of the subsurface study over ten years results in a $57,000 increase in O&M expense. In addition, we have previously made a $28,000 adjustment in working capital for 1/2 year in 1990.

20. Pension Expense

Gulf presented three projections for pension expense in 1990. First, the company budgeted $0 for pension expense and included this in its petition for a rate increase.

The second amount presented by Gulf was on MFR Schedule C-66, Pension Cost. This MFR reports projected net periodic pension cost to be ($11,020). This is an early projection of pension cost under SFAS 87.

The third amount presented by Gulf to project pension expense for 1990 is a letter dated June 1, 1990, from the actuary retained by Southern Company. The letter indicates that the revised estimate of pension cost under SFAS 87 for 1990 is $199,000.

Historically, Gulf's pension expense has been on the decline for the past three years. For 1987, 1988, and 1989; Gulf's pension expense was $1,538,000, $1,385,000, and $47,000, respectively. These are the amounts recorded under SFAS 87.

Consistent with the utility's treatment of pension expense for 1987-1989, we believe that pension expense should be recorded under SFAS 87; however, the estimates of pension cost vary from ($11,020) to $199,000. Although the $199,000 is the most current estimate available, it is not supported by a full actuarial valuation. Because of the new estimate provided, we believe that the pensi cost will probably be greater than ($11,020). Since the 19 pension costs are still estimates and the 1987-1989 trend of pension expense is downward, we approve a pension expense of $0 as originally filed by Gulf. We are not approving $0 because we are certain that Gulf won't contribute to the pension fund. Rather, $0 is our estimate of what pension expense will be under SFAS 87, based upon the three different projections submitted by Gulf.

21. Post Retirement Medical and Life Insurance

We made no adjustments to Gulf's budgeted post retirement medical and life insurance benefits. However, we will require that Gulf's retirement medical and life insurance benefits be recognized using the accrual basis of accounting. Accrual accounting more accurately charges the cost of providing service to the customer who is receiving service. At this time, we do not believe that Gulf should be required to follow the exposure draft for accounting for post retirement benefits that has been released by the Financial Accounting Standards Board. The exposure draft will not be implemented until some future date.

B. Depreciation and Amortization

The Company has proposed test year depreciation expense of $47,701,000. As a result of our adjustments we have reduced depreciation and amortization expense by $1,893,000 to an approved amount of $45,808,000 as follows:

	(000's)
Depreciation and Amortization Expense Per Company	$ 47,701
Adjustments:	
1. Appliance Division	(12)
2. Tallahassee Office	(1)
3. Leisure Lakes	(5)
4. Plant Scherer	(1,774)
5. New Corporate Headquarters	(101)
Total Adjustments	(1,893)
Adjusted Depreciation & Amortization Expense	$ 45,808

C. Taxes Other than Income Taxes

Gulf has projected taxes other than income taxes to be $20,822,000 for test year 1990. We have made adjustments of $274,000 and reduced taxes other than income to $20,548,000.

The exclusion of Plant Scherer from rate base will result in a reduction of $245,000 in taxes other than income. In addition, a reduction in taxes other than income of $30,000 must be made to remove the effect of vacancies in Gulf's labor complement. Finally, an increase in taxes other than income in the amount of $1,000 should be made as a result of the additional revenue imputed for 1990 due to a PXT customer being misbilled by Gulf (as previously discussed in the rate base section of this order). These adjustments total $274,000 and reduce taxes other than income to $20,548,000 as set forth above.

D. Income Taxes Currently Payable

We have decreased current income tax expense by $143,000 fo the net tax effect of other adjustments we have made to ne operating income. We made a combined interest reconciliation adjustment and investment tax credit interest synchronization adjustment, increasing income tax expense by $672,000. The effect of these adjustments results in an increase of $529,000 in income taxes currently payable.

E. Deferred Federal Income Taxes (Net)

The company has projected $1,621,000 in deferred Federal Income Tax expense for test year 1990. Our elimination of Plant Scherer from rate base increases deferred Federal Income Taxes by $668,000. In addition, our previous adjustment to depreciation for test year 1990 increases deferred Federal Income Taxes by $45,000. These two adjustments totalling $712,000 result in total deferred Federal Income Tax expense of $2,333,000.

F. Investment Tax Credit

Gulf's budgeted investment tax credit amortization for test year 1990 was $2,041,000. As a result of our exclusion of Plant Scherer 3 from rate base we have decreased this by $96,000, resulting in a remaining amortization of $1,945,000.

G. Total Operating Expenses

Total operating expenses, as adjusted are $194,603,000.

H. Total Net Operating Income

The net operating income is determined by subtracting total operating expenses from operating revenues. For 1990 Gulf's net operating income is $61,085,000 ($255,688,000 - $194,603,000). For a complete breakdown of Gulf's net operating income see Attachment 3.

X. REVENUE EXPANSION FACTOR

The purpose of the revenue expansion factor (NOI multiplier) is to gross up or expand the Company's net operating income deficiency to compensate for income taxes and revenue taxes that the Company will incur as the result of any revenue increase. All parties agree that the appropriate revenue expansion factor in this case is 1.631699 developed as follows:

Revenue Requirement	100.000000
Uncollectible Accounts	(0.113300)
Gross Receipts Tax	(1.500000)
Regulatory Assessment Fee	(0.125000)
Net Before Income Taxes	98.261700
State Income Tax Rate	5.5000%
State Income Tax	5.404394
Net Before Federal Income Taxes	92.857307
Federal Tax Rate	34.000%
Federal Income Tax	31.571484
Net Operating Income	61.285822
Net Operating Income Multiplier	1.631699

XI. REVENUE REQUIREMENTS

Having determined the Company's rate base, the net operating income applicable to the test period, and the overall fair rate of return, it is possible to calculate any excess/deficiency of revenues. Multiplying the rate base value for 1990 of $861,159,000 by the fair overall rate of 8.10% yields an NOI requirement for 1990 of $69,746,000. The adjusted net operating income for the test year amounted to $61,085,000 resulting in an NOI deficiency of

$8,660,000. Applying the appropriate NOI multiplier of 1.631699 to this figure yields a deficiency of $14,131,000 in gross annual revenues.

As discussed earlier, we have reduced Gulf's return on equity by fifty (50) basis points for a two year period as a penalty for corporate mismanagement. After applying the fifty basis point penalty, Gulf's authorized annual revenue increase is reduced to $11,838,000 the calculation of which is detailed below:

(000s)

		After 50 Basis Point Reduction
Adjusted Jurisdictional Rate Base	$861,159	$861,159
Required Rate of Return	8.10%	7.94%
Required Net Operating Income	69,746	68,341
Adjusted Achieved Test Year Jurisdictional Net Operating Income	61,085	61,085
Jurisdictional NOI Deficiency	8,660	7,255
Revenue Expansion Factor	1.631699	1.631699
Revenue Increase	14,131	11,838

In view of the above, we authorize Gulf an increase in gross annual revenues of $11,838,000 for two years beginning September 13, 1990. Thereafter, we authorize Gulf an increase in gross annual revenues of $14,131,000.

XII. INTERIM INCREASE

Order No. 22681 issued on March 13, 1990, granted Gulf an interim rate increase of $5,751,000 pursuant to Section 366.071, Florida Statutes. The interim increase was calculated based on a test year consisting of the twelve (12) month period ending September 1989 (October 1988 - September 1989). We approved the interim rate increase for collection, subject to refund, pending the outcome of further evaluation of the Company's request for permanent rates. Now that the evaluation is complete, th appropriate level of interim relief must be calculated.

Under Section 366.071, Florida Statutes, a refund of interim rates should be ordered if it is necessary to reduce the utility's rate of return during the pendency of the rate case proceedings to the level of the newly authorized rate of return which is found fair and reasonable on a prospective basis.

In this docket, the interim increase was calculated using an 8.26% rate of return, which is higher than the 8.10% rate of return approved herein. Therefore, we will require a refund of $2,052,000 on an annual basis, the calculation of which is detailed below:

(000s)

	Interim at 8.26% Rate of Return	Interim at 8.10% Rate of Return	Amount to be Refunded
Jurisdictional Adjusted Rate Base	$ 785,912	$ 785,912	
Required Rate of Return	8.26%	8.10%*	
Required Net Operating Income	64,916	63,659	
Jurisdictional Adjusted NOI	61,392	61,392	
NOI Deficiency (Excess)	3,524	2,267	
NOI Multiplier	1.631699	1.631699	
Revenue Deficiency (Excess)	5,751	3,699	$ 2,052
Required Return on Equity	13.00%	12.55%	

*Without 50 Basis Point ROE Reduction

XIII. FUEL NEUTRALITY

A. Top Gun Video

The "Top Gun" video was produced in 1987 and shown to a group of contractors and builders at Gulf's annual awards seminar. The video shows fighter aircraft shooting gas appliances out of the air and indicates that the contractors could be top guns in their areas. One has to wonder at the overall intent of not only the video but Gulf's entire seminar presentations.

Our fuel neutrality policy can be summarized by stating that a utility should not promote its product by showing a competitive fuel in a bad light. This policy objective is set forth in Order Nos. 9974 and 12179 which were issued in 1981 and 1983.

Gulf's Top Gun video is clearly in violation of our fuel neutrality policy, and Gulf's management should be held accountable for its production and distribution.

B. Gas Busters "T" Shirt

A total of 559 of the tee-shirts in question were distributed in 1985 to Gulf Power employees. Gulf states that "[t]he shirts were made available to employees during a series of meetings during 1985 and were intended to explain and gain commitment to the Company's strategic marketing plan titled EMPACT (EMPloyee ACTion). The shirts themselves were an inappropriate reaction to the promotional efforts of other energy suppliers that was very much in the public focus during this timeframe."

The production and distribution of these shirts having a "Gas Busters" logo, was contrary to our policy regarding fuel neutrality.

C. Good Cents Incentive

The Good Cents Incentive programs were in existence during 1987 through 1989. These programs were specifically tailored to reward customers for the replacement of gas furnaces with heat pumps. The contractors were paid anywhere from $25 to $100, in cash or merchandise, for each installation. In addition "electropoints" were awarded to contractors which were redeemable for trips, awards, and merchandise.

These programs not only provided incentives for the replacement of gas heat but also increased the Company's winter peak demand and annual energy. The good cents incentive programs clearly promoted electric over gas appliances and were contrary to our policy regarding fuel neutrality.

D. Withholding Good Cents Certification

In 1987, a commercial building received energy awards from both the U.S. Department of Energy and the Governor's Energy Office yet did not receive Good Cents certification because of a small amount of backup gas power. This practice was contrary to the Commission's policy regarding fuel neutrality.

Gulf has contended all along that the Good Cents logo is synonymous with energy efficiency. Why then wouldn't a highly efficient building that received other awards be granted Good Cents certification? Gulf is not practicing what it preaches; the promotion of the most energy efficient building for its ratepayers.

E. Misleading Advertising

Gulf ran a series of advertisements in which it compared the energy efficiency of its all electric "Good Cents" home to other homes which contained gas appliances. According to the ads, the "Good Cents" homes were consistently more energy efficient. The ads did not point out however that the homes had different levels of insulation and sizes of equipment. Both of these attributes will affect the energy usage of the home that is modeled, yet the advertisements did not mention this fact. If the general public were to read these ads, they would believe that the homes were identical. This is misleading to Gulf's general body of ratepayers.

The Company's justification for these ads is that they were responding to advertising by local gas companies that Gulf thought was misleading. We do not find this justification acceptable.

We believe that the preceding five subsections demonstrate that Gulf has consistently and blatantly violated our policy regarding fuel neutrality. Although at this time we will not make an adjustment based on these violations, we warn Gulf and other utilities under our jurisdiction that in the future such violations will not be tolerated.

XIV. COST OF SERVICE AND RATE DESIGN

Having ascertained the Company's revenue requirement and the amount of revenue increase necessary, we now turn our attention to rate design. We must determine the rate of return currently earned by each rate class, the increase in revenue requirement to be allocated to such class, and how each class's revenue responsiblility will be spread between the customer, energy, and demand charges. In this rate proceeding, we have also reviewed the continued appropriateness of several aspects of the company's rate structure. We begin first with the cost of service studies presented in this case.

A. Cost of Service Methodology

Several methodologies were put forth for consideration as follows:

Gulf Power - 12 month Coincident Peak and 1/13 Energy Methodology; Public Counsel - Equivalent Peaker Cost Methodology; and Industrial Intervenors - Near Peak Methodology. The equivalent peaker methodology implies a refined knowledge of costs which is misleading, particularly as to the allocation of plant costs to hours past the break-even point. The near peak method includes too narrow a spread of peak hours in our view. We heard extensive testimony on each of these methodologies and believe that the Gulf Power proposed methodology is appropriate with the following revisions:

1) All of Account 364 will be classified as demand-related and allocated on class NCP.

Commission policy has been that no distribution system costs other than service drops (Account 369) and meters should be classified as customer-related. In addition, for customers served at primary or higher voltage only the meter is classified as customer-related. (O'Sheasy, TR 1863-1864) Therefore, we believe it was inequitable to the secondary voltage customers to classify secondary wire in Account 364 as customer-related when there was no similar classification of wire for higher voltage customers.

2) Uncollectable expense will be allocated to all classes on the basis of revenue and be classified as revenue-related. It will not be classified as customer-related or included in the customer charge.

3) Fuel inventory (stock) should be allocated on energy and classified as energy-related.

4) The coincident and noncoincident demands should be developed using the same methodology used for all other rate classes. The SEP KWH should not be excluded in the development of the CP KW and NCP KW.

5) The revenues, billing determinants and development of the 12 CP and NCP demands for the Standby Service Class will be based on the assumption that the PXT customer that is not migrating from PXT has a Standby Service Capacity of 7959 KW for the test year.

6) Service drops will be allocated to the OS classes for at least recreational lighting and advertisement or billboard customers. Meter costs, which reflect the current level of metering will be allocated to the recreational lights.

All the recreational lights have meters. (Exhibit 508) There are probably service drops for each of these installations. (O'Sheasy 1858-1860) Therefore, the cost will be allocated to the class for these customers.

7) The rate base for additional facilities for OS-I/OS-II and the expenses [associated] with these facilities will be allocated to OS-I/OS-II.

In his prefiled testimony on how a cost of service study is performed, Mr. O'Sheasy stated that "Certain costs are directly associated with one particular group of customers and are, therefore, assigned to that group." (TR 1807) This assignment was not done with respect to the additional facilities for OS-I/OS-II. The class has been credited with revenues of $424,653 but the rate base and expenses associated with the facilities except for those booked in Account 373 were not assigned to the class. (See TR 1861 and Exhibits 500, 231 and 501.) The rate of return in the revised study is 5.96 percent compared to 7.43 percent in the company's study in Exhibit 231. We believe the expenses should be matched with the costs so that the class' rate of return will not be significantly overstated to the detriment of the other rate classes.

8) Expenses for maintenance of cooling towers and coal pulverizers (grinding mills) will be allocated on energy and classified as energy-related.

The company has changed the classification of some O&M expenses from energy to demand in the cost of service study compared to that of Docket No. 840086-EI. In Docket No. 881167-EI, Mr. Haskins stated that maintenance for both coal grinding mills and cooling towers vary with the KWH to be generated. (TR 1763) In response to cross examination Mr. Lee agreed that operation and maintenance expenses for coal pulverizers and the operation expenses for cooling towers vary with KWH generated but that the amount of maintenance varies little with KWH. (TR 1468)

9) The test year expenses for the four conservation (Good Cents New Home, Good Cents Improved Home, and Commercial Presentations/Energy Education Seminars) programs which were denied conservation cost recovery by the Commission on May 2, 1989 will be

classified as energy-related and allocated on energy to the rate classes in the revenue class to which the cost has been assigned by Gulf Power.

The test year expenses for these programs have been classified as customer-related by the company and included in the customer unit costs. Thus, the same amount of program cost is allocated to and recovered from a small RS customer as a large RS customer. (O'Sheasy, TR 1861-1863) Therefore, we believe it is more equitable to continue to recover these costs on a per KWH basis rather than on a per customer basis. Demand-related costs are collected through the energy charge for the residential class. Therefore, if there is less demand-related cost allocated to the class due to demand reductions from class participation, the customers with large usage will benefit more from the conservation program than customers with small bills.

Unfortunately we do not have a 12 CP and 1/13th cost study incorporating this combination of revisions. Because two of these problems significantly impact the rate of return of the rate classes directly involved, the company's 12 CP and 1/13th cost study (no migration study Ex. 231) has been adjusted for the two problems. One problem is the crediting of the revenues for additional facilities without the assignment of the cost for some of these facilities for OS-I and II. The second is the exclusion of the SE KWH in developing the 12 CP demands of the PXT and LPT classes. For example, a comparison of the rates of return in column 1 of Schedule 1 to those in column 3 shows that there is a 1.47 percentage point difference (7.43 percent versus 5.96 percent) for OS-III.

For the PXT and LP/LPT classes, rate base was increased by 6.84 percent ($2,778,000) and .79 percent ($592,000), respectively, of the transmission and demand-related production net plant and the demand-related production materials and supplies. The NOI for these classes was reduced by 6.84 percent ($316,000) and .79 percent ($68,000), respectively, of the total transmission and demand-related production O&M expenses, production plant A&G expenses and transmission and demand-related depreciation expenses. These are the major items allocated on the 12 CP KW. For OS-1/OS-II, the rate base and NOI from the staff-requested 12 CP and 1/13th cost of service study (Exhibit 501), which reflect the assignment of the cost to the class for all its additional facilities, was substituted for the values in Exhibit 231. All classes' rate base and NOI were adjusted proportionately to equal the company's filed levels of rate base and NOI.

1. Distribution System Costs

Our policy since the early 1980s has been to classify only the service drop and meter portion of the distribution system as customer-related. The Industrial Intervenors (II) and the utility advocate classifying a significant portion of the remainder of the distribution system, including poles, conductors, and transformers, as customer-related. This method is often referred to as the Minimum Distribution System concept. There is a fundamental flaw in this proposal in that only part of the distribution system is classified as customer-related. None of the subtransmission and transmission system would be classified as customer-related. Hence, customers served at primary voltage through dedicated substations, and customers served at higher voltages would not pay for any of this network path.

We believe this minimum distribution system approach should be rejected because it is inequitable and inconsistent to apply the concept to only those customers served at secondary voltage or at primary voltage through common substations when the network path must be there to serve each and every customer.

In our opinion distribution facilities that function as service drops or dedicated tap lines should be directly assigned to the classes whose members the facilities serve. No distribution costs other than service drops and meters should be classified as customer-related. Demand-related cost should be allocated on a demand allocator, and customer-related cost on a customer allocator.

2. Uncollectible Expense

The company assigned uncollectible accounts expense to the RS, GS and GSD classes on average number of customers and classified the expense as customer-related. The result of this classification and assignment or allocation of uncollectible accounts expense is that the expense is included in the customer charge unit cost. If the customer charges for these classes have been and are set at or near unit cost, all customers in the RS, GS and GSD rate classes pay an equal amount for uncollectible expense each month, regardless of the size of their bills. Commission policy has been to allocate uncollectible expense on revenues and not include it in the customer unit cost.

Our policy of not classifying uncollectible expense as customer-related should be continued. The company's classification of the cost as customer-related is inequitable because it results in a small customer paying as much uncollectible expense as a large customer (within and between the RS, GS and GSD classes), if customer charges are set at unit cost. However, if the account of a customer becomes uncollectible, a customer with a large bill would cause the company to incur much more uncollectible expense than a customer with a small bill.

Uncollectibles should be classified as revenue-related so that cost responsibility for uncollectible expense would be proportional to the size of a customer's bill.

3. <u>Fuel Stock</u>

The company has allocated fuel inventory in rate base on the 12 CP and 1/13th average demand, the same allocator they have used to allocate production plant investment. Thus, 12/13ths or 92.3 percent of the inventory has been classified as demand-related and allocated on each class's estimated demands during the system's 12 monthly peak hours. The other 7.7 percent has been classified as energy-related and allocated on energy.

In the company's last rate case we approved projected daily burn for 107.5 days as the basis for the calculation of the appropriate level of fuel inventory to be included in working capital. Since projected average daily burn is a function of KWH projected to be generated and used in the test year, fuel stock should be classified as energy-related and thus allocated on energy. The energy classification and allocation of fuel more closely track cost causation than the company's 92.3 percent allocation on 12 CP demands.

Since we have based the level of fuel stock allowed in rate base on a specific number of days burn which is a function of the KWH projected to be generated in the test year, fuel stock should be classified as energy-related and allocated on energy.

4. <u>Estimate of CP and NCP Demands</u>

The twelve monthly coincident peak hour demands (12 CP) are used to allocate demand-related production plant and transmission plant costs in all but the near-peak cost of service study. These demands must be estimated for all classes when using a projected test year. The 12 CP and class peak demands were estimated by class by dividing the 1990 KWH by 1987 KWH and multiplying that ratio times the 1987 12 CP for rate classes RS, GS and GSD. Under this method each class' 12 CP KW for the test year are increased over the historic load research data by the same percentage their KWH are projected to increase in the same time period, i.e., each class's 12 CP load factor is assumed to be the same as it was in the year of the historic load research data. Thus, each class's demand or use in the 12 monthly coincident peak hours relative to total KWH usage is projected to be the same in the test year as the historic load research year.

For those customers taking service on the SE rider, "supplemental energy" KWH were excluded from this calculation. The resulting 12 CP demand of 104,728 KW for the PXT class would have been 6.8 percent higher if the KWH had been included (111,893 KW). The effect on the estimated demands of the LP/LPT class was insignificant (.79 percent) because the LP/LPT customers' response to the SE rider was minimal. The 104,728 KW represents a 12 CP load factor of 107 percent in the test year for PXT. Thus, the PXT class would have been allocated about 6.8% more demand related production and transmission plant cost if these KWH had not been excluded. The effect of this adjustment or methodology is to reduce the costs allocated to the PXT class and thereby avoid or reduce a rate increase by inflating the class's rate of return.

The company's reason for excluding these KWH apparently is that it expects the SE customers to have a higher 12 CP load factor in the test year, i.e., to use less energy in the 12 monthly peak hours relative to their total usage. However, the data below shows the 12 CP load factor for 1989 for the three groupings of PXT customers decreases instead of increases in 1989. The significant decrease from 101 percent to 91 percent for PX/PXT customers on the SE rider was inconsistent with the company's assumed <u>increased</u> load factor for the class.

<u>12 CP LOAD FACTORS</u>

	Actual 1987	Actual 1989	Projected 1990
PXT Class as a whole	101	95	107
PX/PXT Customers on the SE Rider	101	91	
PX/PXT Customers not on the SE Rider	100	97	
LP/LPT Class as a whole	83	83	84
LP/LPT Customers on the			

SE Rider	80	83
LP/LPT Customers not on the SE Rider	84	84

If the company's projection of a 107 percent 12 CP load factor for PXT due to an assumed changing usage pattern of SE customers is to be realistic or representative of 1990, it is only reasonable to expect the load factor for the PX/PXT SE customers would have been higher in 1989 than 1987.

Other data indicating that it is unreasonable to expect the 12 CP load factor for the PXT class to increase from 95 percent in 1989 to 107 percent in 1990 includes:

(1) The number of supplemental energy KWH projected for 1990 is 20 percent less than 1989. (Exhibit 486)

(2) The number of hours projected to be designated as SE hours in 1990 is less than either 1988 or 1987. (Exhibit 487)

(3) The SE rider has been in effect since 1985 without revision. (Order No. 17568)

Therefore, one would not expect a markedly different response to the rider in 1990 than in 1989.

The company has not presented any data or evidence supporting the use of a load factor higher than the historic value. All of the PX/PXT customers have time-recording meters so that their 12 CP values are actual metered numbers and not estimates. Therefore, the company had the 12 CP load factor data for the first four or five months of 1990 and could have entered it into the record during the hearing as evidence supporting the increased load resulting from their methodology. The company did not enter the data. It is reasonable to assume that the data would have been entered if it corroborated the assumptions behind their methodology.

It was also unreasonable to use 104,728 12 CP KW for 1990 for PXT because the 1989 actual (not estimated) value was 119,448 KW and the PXT KWH were projected to decrease only 1% from 1989 to 1990. (Data on Exhibits 488 and 209)

We are concerned about Gulf's departure from the policy (MFR Schedule E-14) of using the load characteristics determined from the load research collected pursuant to the Commission's Rule 25-6.0437 Cost of Service Load Research in developing various peak demands by class for the test year. The policy assumes the load characteristics, including load factor, are the same in the test year as the historic load research year. The primary purpose of the rule is "to require that load research that supports cost of service studies used in ratemaking procedures is of sufficient precision to reasonably assure that tariffs are equitable and reflect the true costs of serving each class of customers." The utilities have spent large amounts of money to collect the load research required by this rule. Gulf's departure from the use of historical load characteristics for the PXT class undermines the purpose of the Commission's Cost of Service Load Research Rule. It is inequitable and should not be allowed.

The company's exclusion of "supplemental energy" KWH in the development of the 12 monthly coincident peak hour demands and the class noncoincident peak demand for PX/PXT and LP/LPT underestimated these demands and resulted in an underallocation of production and transmission cost to the two classes. The PXT 12 CP KW should have been 6.8 percent higher and the LP/LPT's .79 percent higher. The exclusion of these KWH was inappropriate. The method employed by the company to develop its estimates by class of the 12 monthly coincident peak hour demands and the class noncoincident peak hour demands is inappropriate and Gulf's use of the methodology is denied.

B. <u>Allocation of Revenue Increase</u>

The revenue increases that we have authorized should be spread among the rate classes in a manner that moves class rate of return indices closer to parity. In so allocating the revenue increases we adhere to the following guidelines:

> No class will receive an increase greater than 1 and 1/2 times the system percentage increase of 2.79 percent with adjustments.
>
> The classes below parity will be given the maximum increase (RS and OS-II).
>
> The GS class will be brought to 1.45 times parity. The approved reduction to the GS class is $1,655,000.
>
> The OS-III class will be brought down to 2.34 times parity.

The balance of the increase will be spread across the remaining classes to retain as closely as possible their existing relationships.

Attachment 4 sets forth the approved spread of revenue increase by class. Attachment 5 provides the approved rates by class.

C. Seasonal Rates

The company currently has seasonal rates for the RS and GS rate classes. These seasonal rates do not track the company's cost of capacity when Gulf buys power from the Southern pool. These costs represent a significant portion of Gulf's cost of service during those hours Gulf buys power. Thus, the price signal sent by the present seasonal differential under the RS and GS rate classes may not represent the true cost to the ultimate consumer on Gulf's system, thereby tempering the reduction in peak-related costs, improvement of system load factor, and conservation of summer consumption sought by the seasonal design. A flat charge per KWH based on average costs for the RS and GS classes may produce a clearer price signal than the seasonal rate design proposed by the company.

We therefore eliminate seasonal rates for the RS and GS classes because the seasonal pricing differential does not appear to be cost-based and may not be sending the appropriate price signal during the hours Gulf buys power from the Southern pool.

D. Customer Charges

Customer charges are designed to recover costs associated with the number of customers served. These costs include primarily the costs of billing and metering and customer service. Given that costs are properly allocated to the customer component, the charge for each class should reflect the cost to provide such services. The customer charges are set as follows:

Rate Class	Unit Cost	Current Charges	Approved Charges
RS	$ 7.94	$ 6.25	$ 8.00
RST		9.25	11.00
GS	17.34	7.00	10.00
GST		10.00	13.00
GSD	41.47	27.00	40.00
GSDT		32.40	45.40

Rate Class	Unit Cost	Current Charges	Approved Charges
LP/LPT	447.83	51.00	225.00
PX/PXT	1,222.21	146.00	570.00

E. Transformation Ownership Discounts

Gulf currently offers a discount to customers who own their transformation equipment and for the losses absorbed by the customer metered at primary or transmission level. Gulf proposed adjusting these credits by any variance of the demand and energy charges from unit costs. FEA proposed substantial increases in the transformation discounts to include the costs of poles, overhead/underground conductors, lines, and transformers.

We agree with staff that such a large discount could encourage uneconomic duplication of facilities to the detriment of the general body of ratepayers. Further, we agree that the adjustment for variance from unit costs proposed by Gulf is an unnecessary complication. Therefore we approve a transformer ownership credit for primary level customers of $0.35/KW/Month for GSD/GSDT and $0.42/KW/Month for LP/LPT. The transformer ownership credit for transmission level customers should be set at $0.41/KW/Month for GSD/GSDT, $0.52/KW/Month for LP/LPT, and $0.11/KW/Month for PX/PXT customers.

Such transformation credits should also be applied to the SS and ISS classes and should be based on 100 percent ratcheted billing demand in order to match the calculation of the local facilities demand charge applicable to standby service. Metering voltage discounts should be set equal to the otherwise applicable rate schedule for SS and ISS customers and apply to both the KW and KWH charges.

F. Time of Use Rates

Two methodologies were presented at the hearing for the design of time of use rates. Gulf's testimony supports use of the load factor methodology approved by the Commission in the company's last three rate cases. We believe that the major drawback to the load factor methodology is that it does not track costs as well as the time of use methodology (TOU) proposed by OPC.

OPC supports the use of a methodology which would recover distribution-related plant costs from the maximum demand charge; production and transmission-related demand costs through the on-peak demand charge; and energy-related production plant and operations and maintenance expenses through the energy charge. This approach also includes a ratchet for recovery of local distribution plant costs. We believe the rate design for the maximum demand charge should be based on actual metered demand and not ratcheted KW as proposed by OPC.

We therefore calculate time of use rates as follows:

1) The on-peak and off-peak non-fuel energy charges would be set equal to the energy unit cost from the cost study. (This would include the energy-related production plant and operations and maintenance expenses).

2) The maximum billing demand charge (which is applied to the customer's maximum demand whenever it occurs) would be equal to the distribution plant unit cost.

3) The on-peak demand charge would be an amount sufficient to recover the remaining revenue requirement including the transmission plant and the demand-related production plant.

G. <u>Standby Service</u>

1. <u>Determination of Daily Standby Service Billing Demand</u>

The following formula is Gulf's current formula for calculating daily standby service demand on Gulf's firm standby service (SS) tariff:

> Daily Standby Service (KW) =
>
> Maximum totalized customer generation output occurring in any interval between the end of the prior outage and the beginning of the current outage.
>
> Minus the customer's daily generation output (KW) occurring during the on-peak period of the current outage.
>
> Minus the daily on-peak load reduction (KW) that is a direct result of the customer's current generation outage.

The customer's daily generation output (KW) and daily on-peak period load reduction (KW) that are used in the formula must occur during the same 15 minute interval as the daily Standby Service (KW) that is used for billing purposes.

The language in the above formula for calculating daily standby service demand should be changed from:

> Maximized totalized customer generation output occurring in any interval between the end of the prior outage and the beginning of the current outage

to:

> The amount of load in KW ordinarily supplied by the customer's generation.

This change would satisfy the Industrial Intervenors' request for adjustment for seasonal variation in generation output in calculating daily standby service demand. It would also ensure that self-generating customers (SGCs) are not billed for standby power when they reduce generation for purely economic reasons. We believe that this change in the formula will result in a more accurate determination of standby power used.

The Industrial Intervenors proposed formula would result in standby power used by SE rider customers not being properly billed as standby power.

The language in the formula in the interruptible standby service (ISS) should be replaced with the language in the formula we are approving herein for firm standby service.

2. <u>Design of Standby Service Charges</u>

The present standby service rates are based on system and class unit costs from Docket No. 840086-EI. We believe the standby rate schedule (SS and ISS) charges should be adjusted to reflect unit costs from the compliance cost of service study for this rate case and the 1990 IIC capacity charge rates.

The SS charges should be designed using this compliance cost of service study and the rate design specified in Order No. 17159. The forced outage rate to be used to calculate the reservation charge would be that approved herein. If the resulting charges generate either more or less revenue than the class' revenue responsibility as approved herein, all charges except the customer charge should be decreased or increased by the (same) percentage required to generate the class' revenue requirement. The ISS charges should be the same as the SS charges except for the reservation and daily demand charges. The sum of the CP KW transmission unit cost plus an average IIC monthly charge rate of $6.69 should be used as the unit cost to develop these charges. Having decided herein to bill SE customers for distribution system costs on their maximum metered KW whenever it occurs, the billing KW in Exhibit 510 should be used to calculate the local facilities charges.

The customer charge should be the LP/LPT customer charge plus $25 except for those standby customers taking service on PX/PXT for whom the charge should be the PX/PXT charge plus $25.

The company should provide the staff a compliance cost of service study and the SS rates calculated in accordance with this decision. A spread sheet of component costs by function (retail revenue requirements) for the compliance study should also be provided.

With respect to the definition of the capacity used to determine the applicable local facilities and fuel charges, we are denying Gulf's proposed changes because they are not in conformance with the terms and conditions prescribed in Order No. 17159 for standby service.

3. SS Rate Forced Outage Factor

In the Standby Order No. 17159, a 10 percent forced outage rate was specified as the outage rate to be used in the calculation of the Reservation Charge. The overall reliability of the forced outage data in the record is questionable, however, in that the company was apparently accepting without review the forced outage data provided by self-generating customers (SGCs) and the SGCs may not have understood they were to report these outages, even if they signed up for zero standby power. Additionally, data was provided by only three of the four SGCS.

While we are tempted to rule that the assumed 10 percent forced outage rate should not be continued, there appears to be no practical alternative in the absence of sound, reliable data to support an alternative value for the forced outage rate.

Therefore, in the absence of reliable data to support a different value for the forced outage rate used to develop the reservation charge, the 10 percent forced outage rate prescribed in Order No. 17159 should continue to be used.

4. <u>SE Rider Availability in Lieu of Standby Service</u>

This issue is whether self-generating customers who are experiencing a forced outage or an outage for scheduled maintenance of their generating system can be billed on the SE rider rather than the standby service rate for standby power taken during the outage if the customer has another generator with which he could generate but chooses not to use for economic reasons. In other words, the issue is whether a self-generating customer can have standby power billed under a different rate tariff than the standby service if he has additional generating capacity available but which is less economic. Under the current standby service rate schedules, self-generating customers may reduce generation for economic reasons and take additional capacity and energy as supplementary service, including supplementary service with the SE rider applied.

Order No. 17159 at page 6, in addressing the issue of whether non QF standby customers would be entitled to the same service as QFs, requires the standby tariff resulting from that proceeding to be mandatory for <u>all</u> self-generating customers unless there is evidence to demonstrate that their load characteristics resemble those of normal full requirements customers. To allow such a customer to choose a different rate because it would result in a lower bill would allow that customer to escape costs properly assigned to him.

There is also a basic cost recovery problem if standby service is allowed to be billed on the provisions of the SE rider. The standby service rates have been developed by dividing the utility's full demand-related production and transmission unit cost per coincident peak kilowatt of demand by the average number of days per month that contain on-peak hours (21). Using this rate requires a standby customer who imposes load every day to pay the full demand-related unit cost per coincident peak KW because it is virtually certain that his load was on at the time of the system's peak.

The average number of days in 1988 and 1989 for which a self-generating customer would be billed daily demand charges if standby power was taken and billed pursuant to the SE rider is six. Thus, if a customer were using standby power for maintenance every day in a given month, the customer would be paying, on average, 6/21ths of the full demand-related unit cost per coincident peak KW even though it was virtually certain that his load was on at the time of the system's peak. In this scenerio, the rates for standby service should be recovering the full demand-related unit cost.

Additionally, to allow standby power to be taken under the terms and conditions of the SE rider if the customer had generating capacity available but less economic would discriminate against self-generating customers with only one generator versus those with multiple generators.

KWH and capacity purchased to replace energy and capacity normally generated by a customer's generator which is experiencing a forced outage or an outage for scheduled maintenance, is clearly standby power and should be billed as standby power. However, to ensure that power taken to replace reduced generation for purely economic reasons is billed as supplemental power, the definitions of backup service and maintenance service should be more specific. Two sentences should be added to the definition (in the tariff) of backup service and maintenance service, the two forms of standby service, to indicate more clearly what constitutes scheduled and unscheduled outages. In the definition of backup service, an unscheduled outage should be defined as the loss or reduction of generation output due to equipment failure(s) or other condition(s) beyond the control of the customer. Similarly, under maintenance service a scheduled outage should be defined as the loss or reduction due to maintenance activities of any portion of a customer's generating system.

5. Waiver of Ratchet Provision for Reservation Charge

All demands registered during any maintenance outage of a self-generating customer, regardless of whether the maintenance outage is fully coordinated with Gulf, should be subject to the ratchet provision of the SS rate for the local facilities charge. The ratchet provision is appropriate because the scheduling of the outage does not affect the capacity of the local facilities to serve the customer. Scheduling the outage will not enable Gulf to avoid local facilities cost as the capacity of the local facilities, particularly dedicated substations, must be sufficient to serve the customer's maximum demand whenever it occurs. An increase in demand should properly result in an increase in the billing demand for the local facilities charge.

The Company should excuse demands registered during such periods from the ratchet provision applicable to the reservation charge if (1) the maintenance outage is usefully coordinated with Gulf and (2) the maintenance is used in hours that do not include a peak hour(s) that determines Gulf's IIC payments or revenues. The ratchet provision should not be waived for maintenance power used during the peak hours that determine Gulf's IIC payments or revenues because the cost impact continues for three years.

H. Supplemental Energy (SE) Rider

1. No Separate SE Rate Class

Order No. 17568, Docket No. 850102-EI, approved the experimental Supplemental Energy (SE) (Optional) Rider as a permanent rate schedule on the condition that it become a separate rate class in the company's next rate case. In this docket however, Gulf has not provided separate cost of service analyses for the two rate classes employing the SE Rider, LPT-SE and PXT-SE.

The necessity for a separate rate class depends on the differences between billing KW and peak demand KW characteristics of SE customers, as opposed to these in the general LP/LPT and PX/PXT classes and considerations of local facilities costs. From the record in this docket it appears that there is a large dissimilarity in the ratios of billing KW to 12 CP KW and maximum metered KW between PXT-SE and LPT-SE classes and that these customers should not be grouped into a single class. The data implies that to put all SE customers into one class would create a serious cost recovery problem between the LPT-SE and the PXT-SE customers. Therefore, a separate rate class consisting of LPT and PXT customers on the SE rider should not be implemented in this rate class.

It does, however, appear that there may be sufficient dissimilarity between the ratios of billing KW and 12 CP KW and maximum metered KW to warrant separate rate classes for the LP/LPT SE customers and for the PX/PXT-SE customers. Since we do not have a cost of service study with LP/LPT-SE and PX/PXT-SE each as a separate rate class, the question of whether a separate rate class(es) should be implemented for either PX/PXT-SE or LP/LPT-SE customers should be considered in the next rate case. Gulf is instructed to file its cost of service study in that case with LP/LPT and PX/PXT <u>each</u> broken into SE and non-SE classes and with totals for LP/LPT and PX/PXT.

2. Distribution System Costs for SE Customers

The SE rider presently provides forgiveness of the demands incurred during SE periods both with respect to on-peak and off-peak billing KW. Five of the six SE customers have dedicated substations (Exhibit 517). The sum of the average billing KW for the three SE customers for whom dedicated substations were built in 1989 is only 53 percent of the capacity of these substations. However, the PXT-SE customers are billed on only 59 percent of their maximum metered KW. Therefore, to ensure that the SE customers pay for the dedicated facilities that have been sized to serve their maximum demands whenever they occur, SE customers should be billed for distribution system costs on their maximum metered demand whenever it occurs. The provision of the SE rider for forgiveness of demand in the SE period would continue to apply to on-peak demand.

Therefore, Gulf shall bill SE customers for distribution system costs on their maximum metered KW whenever it occurs as per these guidelines.

I. Applicability Clause, GSD, LP and PX Classes

The applicability clause of the three demand classes (GSD, LP and PX) is stated in terms of the amount of KW demand for which the customer contracts. This is not an appropriate basis for determining applicability.

In the past, contracts have not been required of all these customers, and contract demand often bears little relationship to actual measured demand. As a part of this docket, tariffs should be modified to state that the applicability for both demand and the PX/PXT 75 percent load factor should be based on measured maximum billing demand. For SE customers, this would be the actual measured billing demand in non-SE periods. Customers whose annual load factor is less than 75 percent should not be allowed to opt for PXT because the PX/PXT rate is based on the costs of high load factor customers.

J. Minimum Charge Provisions for GSD/GSDT and LP/LPT

The current GSD/GSDT and LP/LPT rate schedules have minimum charges equal to the customer charge plus the demand charge for the minimum KW to take service on the rate schedule for customers opting for the rate schedule. This minimum charge provision is not appropriate. This provision unduly penalizes customers who opt for this higher rate class because they pay for the minimum KW to qualify for the class even if their usage falls below this level. Customers who meet the class minimum even once in every 12 month period, do not pay a minimum but pay only for their actual demand, even if it falls below the minimum.

We therefore eliminate the minimum charge provisions of the GSD/GSDT and LP/LPT rate schedules.

K. No Local Facilities Charge

The company proposed the implementation of a local facilities demand charge for LP/LPT and PX/PXT customers, which would be applied when the customer's actual demand does not reach at least 80 percent of the Capacity Required to be Maintained (CRM) specified in the Contract for Electric Power. We are denying the implementation of this charge because it is inequitable to apply the charge to the contract capacity because the contract demand for many customers bears little relationship to measured demand. Furthermore, it is an ineffective charge because no customers would have to pay the charge in the test year.

L. Service Charges

The following service charges are approved:

Initial Service	$20.00
Reconnect a subsequent subscriber	16.00
Reconnect of existing customer after disconnect for Cause	16.00
Collection Fee	6.00
Installing and Removing Temporary Service	60.00
Minimum Investigation Fee	55.00

M. Outdoor Service (OS)

1. Elimination of OS General Provisions

The company proposes to eliminate the general provisions pertaining to replacement of lighting systems on the Outdoor Service Rate Schedule (OS). We believe this is appropriate and that the present general provisions relating to the replacement of mercury vapor lighting fixtures with high pressure sodium fixtures should be removed.

The current provisions pertaining to replacement of lighting systems on the OS schedule are deleted as proposed by the company and no new provisions are adopted.

2. Street and Outdoor Lighting Rate

We approve the methodology used in developing the Street (OS-I) and Outdoor (OS-II) lighting rates. This entails setting the energy charges at levels which will collect the total non-fuel energy, demand, and customer-related costs at the class-approved rate of return. Maintenance charges were set so as to recover the total maintenance and administrative and general expenses allocated to OS-I and II in the cost of service study. The fixture charges were set at a level to collect the remaining revenue requirement after subtracting the energy, maintenance and additional facilities revenues. Attachment 6 sets forth the approved street and outdoor lighting rates for Gulf.

Gulf at present does not have records indicating the number of poles and other facilities in place which are dedicated to additional facilities. Because of this, it was not possible to develop cost-based rates for additional facilities in this rate case. We are directing Gulf to take the steps necessary to obtain this information so that cost-based additional facilities charges can be developed when the next rate case is filed.

3. Applicability of OS-III

The language in the OS-III (Other Outdoor Service) tariff will be modified to reflect that only customers with fixed wattage loads operating continuously throughout the billing period, such as traffic signals, cable TV amplifiers and gas transmission substations, will be allowed to take service on the OS-III rate.

N. Sports Fields Rate

Since the company's last rate case, sports fields taking service on Rate Schedules GS and GSD were allowed to transfer to the OS-III rate schedule. The company has now proposed an OS-IV rate for sports fields.

In deriving the 12 CP and NCP allocators for OS-IV, the company assumed that all recreational lighting customers would require service at a constant rate every day of the year from sunset to 10:00 p.m. A review of the customer accounting memo sheets for the sports fields customers indicates that approximately 36% of the billing months showed zero kwh usage. The company has no load data for sports fields, and does not intend to obtain such data using load research meters. The OS-IV rate was thus designed in the absence of reliable load research data.

In 1981 and 1982 the Commission eliminated special rates for sports fields, poultry farms and other uses. Addition of a special rate for sports fields is philosophically at odds with these past actions.

In spite of these problems, we will allow the rate design for OS-IV to be implemented. This is because the estimated OS-IV kilowatt hours have not been broken down into summer and winter components, and thus cannot be added to the kilowatt hours for GS and GSD to determine an accurate energy rate for those classes. In addition, the OS-IV as designed will not vary significantly from the GS rate. However, when the company files its next rate case they will be required to transfer their sports field customers to the appropriate GS or GSD rate schedules.

XV. CONCLUSIONS OF LAW

1) Gulf Power Company is a public utility within the meaning of Section 366.02, Florida Statutes, and is subject to the jurisdiction of the Commission.

2) This Commission has the legal authority to approve and use a projected test period for ratemaking purposes. Calendar year 1990 is an appropriate base test period.

3) The adjustments to rate base made herein are reasonable and proper. The value of the Company's 1990 rate base for ratemaking purposes is $861,159,000.

4) The adjustments made to the calculation of net operating income are proper and appropriate. For ratemaking purposes, Gulf's net operating income for 1990 is $61,085,000.

5) The fair rate of return on the equity capital of Gulf is 12.55%.

6) As a result of our finding of corporate mismanagement, Gulf's return on equity has been reduced by fifty (50) basis points for a two year period. This results in a return on equity of 12.05% for two years beginning September 13, 1990.

7) Gulf Power Company should be authorized to increase its rates and charges by $11,838,000 in annual gross revenues effective September 13, 1990. Gulf Power Company should be authorized to increase its rates and charges by $14,131,000 beginning September 13, 1992.

8) The rate schedules prescribed and approved herein are fair, just and reasonable within the meaning of Chapter 366, Florida Statutes.

9) The new rate schedules shall be reflected upon billings rendered for meter readings taken on or after September 13, 1990.

Accordingly, it is

ORDERED by the Florida Public Service Commission that the findings of fact and conclusions of law set forth herein are approved. It is further

ORDERED that the petition of Gulf Power Company for authority to increase its rates and charges is granted to the extent delineated herein. It is further

ORDERED that Gulf Power Company is hereby authorized to submit revised rate schedules consistent herewith designed to generate $11,838,000 in additional gross revenues annually for two years beginning September 13, 1990. The Company shall include with the revised rate schedules all calculations and workpapers used in deriving the revised rates and charges. It is further

ORDERED that the revised schedules authorized herein for the $11,838,000 revenue increase shall be reflected upon billings rendered for meter readings taken on or after September 13, 1990. It is further

ORDERED that Gulf Power Company is hereby authorized to submit revised rate schedules consistent herewith designed to generate $14,131,000 in additional gross revenues annually for two years beginning September 13, 1992. The Company shall include with the revised rate schedules all calculations and workpapers used in deriving the revised rates and charges. It is further

ORDERED that the revised schedules authorized herein for the $14,131,000 revenue increase shall be reflected upon billings rendered for meter readings taken on or after September 13, 1992. It is further

ORDERED that Gulf Power Company shall return to its ratepayers on a "per KWH basis" that portion of its interim increase set forth in the body of this order. It is further

ORDERED that Gulf Power Company shall include in each customer's bill, in the first billing of which the increase is effective, a bill stuffer explaining the nature of the increase, average level of the increase, a summary of tariff charges, and the reasons therefore. The bill stuffers shall be submitted to the Division of Electric and Gas of the Florida Public Service Commission for approval before implementation. It is further

ORDERED that in its next rate case Gulf Power Company shall file a cost of service study with LP/LPT and PXT each broken into SE and non-SE classes, with totals calculated for LP/LPT and PX/PXT. It is further

ORDERED that when Gulf Power Company files its next rate case that it transfer its sports fields customers from the OS-IV rate to the appropriate GS or GSD rate schedules. It is further

ORDERED, Gulf shall take the steps necessary to determine the quantity of street and outdoor lighting facilities dedicated to additional facilities prior to the filing of the next rate case, in order that cost-based rates can be developed for these facilities.

ORDERED that this docket be closed should no petition for reconsideration or notice of appeal be timely filed.

DISSENTING VOTES

Commissioner Beard dissented as follows:

1) From the Commission's allowance of the total cost of Gulf's Bonifay and Graceville Offices in rate base.

2) From the Commission's allowance of 90% of the Caryville site as land held for future use. Commissioner Beard would have disallowed the amount budgeted for the Caryville site because there are no plans to use the site for 20 years.

3) From the Commission's approval of $457,390 for the Good Cents Improved and $1,023,995 for the Good Cents New Home Programs. Commissioner Beard would have disallowed these expenses as an unnecessary cost to ratepayers to assure compliance with the state building code.

4) I respectfully dissent from the majority opinion on the mismanagement issue. My disagreement stems from a different interpretation of evidence before the Commission. This interpretation results in my belief that the reduction to the return on equity should have been greater than fifty basis points. I would reduce the return on equity to 11.75%, the minimum amount necessary for Gulf Power Company to achieve a fair rate of return according to the record.

At page 19, the majority states that there is no record evidence to indicate that the president of Gulf Power <u>knew</u> that illegal or unethical conduct was taking place as it happened. (Emphasis in original) The Order then goes into various incidents from 1983 through 1988 involving the president and Mr. Jacob Horton, Executive Vice President of Gulf Power. There is no need to recount those incidents again here. Suffice to say that in this case repeated instances of unethical/illegal activity over the years by a close business associate give rise to knowledge in my view. This is particularly true in light of the warnings Mr. McCrary had received concerning Mr. Horton's mode of operation and the repeated warnings given by Mr. McCrary to Mr. Horton. I also have serious reservations concerning disparate disciplinary treatment between executives and lower-level employees. See majority opinion at pages 23-24.

The unfortunate pattern of conduct present in this case should not be analyzed in terms of legal abstractions, but rather how a utility conducts its business in the real world. In my mind, the proper analysis holds Gulf Power management responsible for the activities here and then reduces the return on equity in conformity with that responsiblity. I would set the return on equity at 11.75%.

<u>Commissioner Wilson dissented as follows</u>:

1) From the Commission's approval of Gulf's 1990 material and supply level. Commissioner Wilson would leave materials and supplies at the 1989 level.

2) From the Commisson's approval of a 12.55% return on equity. Commissioner Wilson favored a 12.8% ROE.

3) From the Commission's reduction of the GS class to 1.4% times parity. Commissioner Wilson favored a greater reduction.

4) From the Commission's vote to eliminate seasonal rates for the RS and GS rate classes. Commissioner Wilson favored retaining seasonal rates.

Commissioner Easley dissented as follows:

1) From the Commission's vote setting the coal inventory as the lesser of 90 days burn or the amount maintained at the plant.

2) From the Commission's classification of fuel stock as energy-related. Commissioner Easley would classify fuel stocks as demand-related.

Commissioner Gunter dissented as follows:

1) From the Commission's disallowance of $31,813 for acid rain research.

By ORDER of the Florida Public Service Commission, this 3rd day of OCTOBER, 1990.

STEVE TRIBBLE, Director
Division of Records & Reporting

(S E A L)

MAP/RDV

by: Kay Flynn
Chief, Bureau of Records

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

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

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

COMPANY: GULF POWER COMPANY
DOCKET NO.: 891345-EI
TEST YEAR: DECEMBER 31, 1990

COMPARATIVE RATE BASES

SCHEDULE 1
16-Aug-90
01:59 PM

LINE NO.	CO. ADJ. NO.	ISSUE NO.	DESCRIPTION	COMPANY FILING: SYSTEM PER BOOKS	COMPANY FILING: JURISDICTIONAL PER BOOKS	COMPANY FILING: ADJUSTMENTS	COMPANY FILING: JURISDICTIONAL ADJUSTED	COMMISSION VOTE: ADJUSTMENTS	COMMISSION VOTE: JURISDICTIONAL ADJUSTED
1			PLANT IN SERVICE		$1,275,624				
2		2	PLANT IN SERVICE						
3		3	SCHERER TAX ADDER ADJUSTMENT					(55)	
4		4	SCHERER ACQUISITION ADJUSTMENT					0	
5		5	NEW CORPORATE HEADQUARTERS					0	
6		7	NAVY HOUSE					(3,892)	
7		8	APPLIANCE DIVISION					(23)	
8		9	TALLAHASSEE OFFICE					(214)	
9		10	BONIFAY/GRACEVILLE					(24)	
10		12	LEISURE LAKES					0	
11		16	UNIT POWER SALES					(142)	
12		25	PLANT DANIEL					0	
13		27	PLANT SCHERER					0	
14		29	REBUILDS & RENOVATIONS					(52,987)	
15		30	NETWORK PROTECTORS					0	
16								0	
17			Total plant in service	0	1,275,624	0	1,275,624	(57,337)	1,218,287
18									
19									
20			ACCUMULATED DEPRECIATION		454,964				
21		3	SCHERER TAX ADDER ADJUSTMENT						
22		5	NEW CORPORATE HEADQUARTERS					0	
23		8	APPLIANCE DIVISION					(338)	
24		9	TALLAHASSEE OFFICE					(7)	
25		11	JDITC UNDERSTATEMENT					(11)	
26		16	UNIT POWER SALES					0	
27		25	PLANT DANIEL					0	
28		27	PLANT SCHERER					0	
29		29	REBUILDS & RENOVATIONS					(6,557)	
30		30	NETWORK PROTECTORS					0	
31								0	
32			Total depreciation reserve	0	454,964	0	454,964	(6,913)	448,051
33									
34			Net plant in service	0	820,660	0	820,660	(50,424)	770,236
35									
36									
37			CONSTRUCTION WORK IN PROGRESS		14,949				
38		13	LEVEL OF CWIP						
39		14	NON-AFUDC CWIP					0	
40								0	
41			Total CWIP	0	14,949	0	14,949	0	14,949
42									
43									

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COMPANY: GULF POWER COMPANY
DOCKET NO.: 891345-EI
TEST YEAR: DECEMBER 31, 1990

COMPARATIVE RATE BASES

SCHEDULE 1
16-Aug-90
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				COMPANY FILING				COMMISSION VOTE	
LINE NO.	CO. ADJ. NO.	ISSUE NO.	DESCRIPTION	SYSTEM PER BOOKS	JURISDICTIONAL PER BOOKS	ADJUSTMENTS	JURISDICTIONAL ADJUSTED	ADJUSTMENTS	JURISDICTIONAL ADJUSTED
43									
44			PROPERTY HELD FOR FUTURE USE		3,925				
45		6	CARYVILLE SOD FARM					(135)	(135)
46		15	LEVEL OF PHFFU					0	0
47									
48			Total prop. held for future use	0	3,925	0	3,925	(135)	3,790
49									
50									
51									
52			ACQUISITION ADJUSTMENT		2,317				
53		4	SCHERER ACQUISITION ADJUSTMENT					(2,317)	
54									
55			Total acquisition adjustment	0	2,317	0	2,317	(2,317)	0
56									
57									
58			Net utility plant	0	841,851	0	841,851	(52,876)	788,975
59									
60									
61			WORKING CAPITAL		81,711				
62		16	UNIT POWER SALES					0	
63		18	PREPAID PENSIONS					0	
64		19	RATE CASE EXPENSES					(765)	
65		20	FUEL/CONSERVATION OVERRECOVERIES					0	
66		21	TEMPORARY CASH INVESTMENTS					0	
67		22	HEAVY OIL INVENTORY					(576)	
68		23	LIGHT OIL INVENTORY					(123)	
69		24	COAL INVENTORY					(6,017)	
70		25	PLANT DANIEL					0	
71		27	PLANT SCHERER					(2,187)	
72		28	CANCELED SCS BUILDING					0	
73		31	OTHER INVESTMENTS					0	
74		32	OTHER ACCOUNTS RECEIVABLE					0	
75		33	MATERIALS & SUPPLIES					0	
76		34	OTHER CURR. ASSETS & MISC. DEF. DEBITS					0	
77		35	CARYVILLE SUBSURFACE STUDY					(28)	
78		36	EXPENSE ADJUSTMENTS					169	
79									
80									
81			Total working capital	0	81,711	0	81,711	(9,527)	72,184
82									
83									
84			TOTAL RATE BASE	0	923,562	0	923,562	(62,403)	861,159

RC-74

Gulf Power Company
13-Month Average Capital Structure
Test Year Ending 12/31/90

COMMISSION VOTE	LONG TERM DEBT	LONG TERM NOTE	SHORT TERM DEBT	PREFERRED STOCK	COMMON EQUITY	CUSTOMER DEPOSITS	DEFERRED TAXES	ITC's Zero Cost	ITC's Wtd. Cost	TOTAL
Company Per Book	439,734	42,089	4,432	67,432	367,404	15,775	203,823	858	48,068	1,189,615
Company Adjustments (Specific)	(98,837)	(42,089)		(10,278)	(63,994)		(14,785)		(5,793)	(235,776)
Subtotal	340,897	0	4,432	57,154	303,410	15,775	189,038	858	42,275	953,839
Commission Adjustments (Specific)	7,282	0	0	169	(7,793)	0	(5,877)	0	(2,402)	(8,621)
Subtotal	348,179	0	4,432	57,323	295,617	15,775	183,161	858	39,873	945,218
Prorata (Other Sources) (1)	(23,159)	0	(295)	(3,813)	(19,663)	(1,049)	0	0	0	(47,979)
Subtotal	325,020	0	4,137	53,510	275,954	14,726	183,161	858	39,873	897,239
Prorata Adjustments	(13,070)	0	(166)	(2,152)	(11,097)	(592)	(7,365)	(35)	(1,603)	(36,080)
TOTAL	311,950	0	3,971	51,358	264,857	14,134	175,796	823	38,270	861,159
io	36.22%	0.00%	0.46%	5.96%	30.76%	1.64%	20.41%	0.10%	4.44%	100.00%
t Rate	8.72%	0.00%	8.00%	7.75%	$\boxed{12.55\%}$	7.65%	0.00%	0.00%	10.26%	
ighted Cost	3.16%	0.00%	0.04%	0.46%	3.86%	0.13%	0.00%	0.00%	0.46%	$\boxed{8.10\%}$
basis pt reduction to equity	8.72%	0.00%	8.00%	7.75%	$\boxed{12.05\%}$	7.65%	0.00%	0.00%	10.04%	
Weighted Cost With Reduction	3.16%	0.00%	0.04%	0.46%	3.71%	0.13%	0.00%	0.00%	0.45%	$\boxed{7.94\%}$

RC-75

Calculation of JDIC Rate

Capital Components	Adjusted Amount	Ratio	Cost Rate	Wtd. Cost
Common Equity	264,857	42.16%	12.55%	5.29%
Preferred Stock	51,358	8.18%	7.75%	0.63%
Long-Term Debt	311,950	49.66%	8.72%	4.33%
Total	628,166	100.00%		10.26%

Calculation of JDIC Rate with 50 basis pt reduction on the equity cost rate.

Capital Components	Adjusted Amount	Ratio	Cost Rate	Wtd. Cost
Common Equity	264,857	42.16%	12.05%	5.08%
Preferred Stock	51,358	8.18%	7.75%	0.63%
Long-Term Debt	311,950	49.66%	8.72%	4.33%
Total	628,166	100.00%		10.04%

(1) Deferred taxes and ITCs have been specifically identified for these items.

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COMPANY: GULF POWER COMPANY
DOCKET NO.: 891345-EI
TEST YEAR: DECEMBER 31, 1990

COMPARATIVE NET OPERATING INCOME

SCHEDULE 3
16-Aug-90
02:32 PM

				COMPANY FILING				COMMISSION VOTE	
LINE NO.	CO. ADJ. NO.	ISSUE NO.	DESCRIPTION	SYSTEM PER BOOKS	JURISDICTIONAL PER BOOKS	ADJUSTMENTS	JURISDICTIONAL ADJUSTED	ADJUSTMENTS	JURISDICTIONAL ADJUSTED
1			REVENUE FROM SALES OF ELECTRICITY		249,813				
2		48	PXT / STANDBY RATES					16	
3		49	NON-UTILITY ELECTRIC BILLINGS					95	
4									
5			Total sales of electricity	0	249,813	0	249,813	111	249,924
6									
7									
8			OTHER OPERATING REVENUES		5,767				
9		6	CARYVILLE SOD FARM					(3)	
10		47	APPLIANCE DIVISION - USE OF LOGO					0	
11									
12			Total other operating revenues	0	5,767	0	5,767	(3)	5,764
13									
14									
15			Total operating revenues	0	255,580	0	255,580	108	255,688
16									
17									
18			OPERATING EXPENSES:						
19			OPERATION & MAINTENANCE		113,382				
20		7	NAVY HOUSE					(8)	
21		27	PLANT SCHERER - NET OF IIC OFFSET					4,070	
22		29	REBUILDS & RENOVATIONS					0	
23		30	NETWORK PROTECTORS					0	
24		35	CARYVILLE SUBSURFACE STUDY					57	
25		50	SALARIES & BENEFITS					0	
26		51	BAD DEBT EXPENSE					0	
27		52	FUEL REVENUE & EXPENSES					0	
28		53	CONSERVATION REVENUE & EXPENSES					0	
29		54	OUT-OF-PERIOD, NON-RECURRING, etc.					(190)	
30		55	INDUSTRY ASSOCIATION DUES					(20)	
31		56	CURRENT RATE CASE EXPENSES					(250)	
32		57	881167-EI RATE CASE EXPENSES					0	
33		58	BANK FEES & LINES OF CREDIT					0	
34		59	OUTSIDE SERVICES					0	
35		60	CUSTOMER ACCOUNTS					0	
36		61	COGENERATION & INDUSTRIAL PROGRAMS					(426)	
37		62	GOOD CENTS INCENTIVE PROGRAM					(50)	
38		63	GOOD CENTS IMPROVED & NEW HOME PROGRAMS					0	
39		64	ESSENTIAL CUSTOMER SERVICE PROGRAM					0	
40		65	ENERGY EDUCATION PROGRAM					0	
41		66	PRESENTATION / SEMINARS PROGRAM					(55)	
42		67	SHINE AGAINST CRIME					(92)	
43		68	ECONOMIC DEVELOPMENT					(687)	
44		69	[illegible]CTION RELATED A&G					0	
45		70	[illegible] A&G					0	
46		71	[illegible]ING EXPENSES					(264)	
47		73	SCS EXPENSES					0	

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COMPANY: GULF POWER COMPANY
DOCKET NO.: 891345-EI
TEST YEAR: DECEMBER 31, 1990

COMPARATIVE NET OPERATING INCOME

SCHEDULE 3
16-Aug-90
02:32 PM

				COMPANY FILING				COMMISSION VOTE	
LINE NO.	CO. ADJ. NO.	ISSUE NO.	DESCRIPTION	SYSTEM PER BOOKS	JURISDICTIONAL PER BOOKS	ADJUSTMENTS	JURISDICTIONAL ADJUSTED	ADJUSTMENTS	JURISDICTIONAL ADJUSTED
48		74	IRS, GRAND JURY, etc.					(5)	
49		75	PENSION EXPENSE					0	
50		76	STEAM PRODUCTION PERSONNEL					0	
51		77	RESEARCH & DEVELOPMENT PROJECTS					(32)	
52		78	EPRI / SCS DOUBLE COUNTING					0	
53		79	PLANT DANIEL ASH HAULING					0	
54		80	TRANSMISSION RENTS					(423)	
55		81	PUBLIC SAFETY INSPECTION & MAINT.					0	
56		86	EMPLOYEE RELATIONS PLANNING UNIT					0	
57		87	LABOR COMPLEMENT VACANCIES					(403)	
58		88	TURBINE & BOILER INSPECTIONS					0	
59		89	PLANT DANIEL					0	
60		90	1989 UNCOLLECTIBLES CREDIT					0	
61		91	EMPLOYEE SAVINGS PLAN					0	
62		92	PRODUCTIVITY IMPROVEMENT PLAN					(339)	
63		93	PERFORMANCE PAY PLAN					0	
64		94	EPRI NUCLEAR RESEARCH					0	
65		95	PLANT SMITH ASH HAULING					0	
66		96	EMPLOYEE RELOCATION & DEVELDPMENT PROGRAMS					(56)	
67		97	OBSOLETE MATERIAL					0	
68		98	MANAGEMENT PERKS					(65)	
69		99	DUCT & FAN REPAIRS					0	
70		100	CUSTOMER SERVICES & INFORMATION					0	
71		101	MARKETING EXPENSES					0	
72		102	O&M BENCHMARK					0	
73									
74									
75									
76									
77			Total operation & maintenance	0	113,382	0	113,382	762	114,144
78									
79									
80			DEPRECIATION AND AMORTIZATION		47,701				
81		3	SCHERER TAX ADDER ADJUSTMENT					0	
82		4	SCHERER ACQUISITION ADJUSTMENT					0	
83		5	NEW CORPORATE HEADQUARTERS					(101)	
84		8	APPLIANCE DIVISION					(12)	
85		9	TALLAHASSEE OFFICE					(1)	
86		12	LEISURE LAKES					(5)	
87		27	PLANT SCHERER					(1,774)	
88		82	REASONABLENESS					0	
89									
90			Total depreciation and amortization	0	47,701	0	47,701	(1,893)	45,808
91									

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COMPANY: GULF POWER COMPANY
DOCKET NO.: 891345-EI
TEST YEAR: DECEMBER 31, 1990

COMPARATIVE NET OPERATING INCOME

SCHEDULE 3
16-Aug-90
02:32 PM

LINE NO.	CO. ADJ. NO.	ISSUE NO.	DESCRIPTION	COMPANY FILING: SYSTEM PER BOOKS	COMPANY FILING: JURISDICTIONAL PER BOOKS	COMPANY FILING: ADJUSTMENTS	COMPANY FILING: JURISDICTIONAL ADJUSTED	COMMISSION VOTE: ADJUSTMENTS	COMMISSION VOTE: JURISDICTIONAL ADJUSTED
98			TAXES OTHER THAN INCOME		20,822				
99		27	PLANT SCHERER					(245)	
100		48	PXT / STANDBY RATES					1	
101		83	REASONABLENESS					0	
102		87	LABOR COMPLEMENT VACANCIES					(30)	
103									
104									
105			Total taxes other than income	0	20,822	0	20,822	(274)	20,548
106									
107									
108			INCOME TAXES CURRENTLY PAYABLE	0	13,185				
109		84	REASONABLENESS					0	
110		85	Interest expense reconciliation					672	
111		N/A	Effect of other adjustments					(143)	
112									
113			Total income taxes - current	0	13,185	0	13,185	529	13,714
114									
115									
116			DEFERRED INCOME TAXES (NET)	0	1,621				
117		N/A	EFFECT OF ADJS. TO DEPRECIATION					45	
118		27	PLANT SCHERER					668	
119									
120									
121									
122									
123			Total deferred income taxes (net)	0	1,621	0	1,621	712	2,333
124									
125									
126									
127			INVESTMENT TAX CREDIT (NET)		(2,041)				
128		27	PLANT SCHERER					96	
129									
130									
131			Total investment tax credit (net)	0	(2,041)	0	(2,041)	96	(1,945)
132									
133									
134			(GAIN)/LOSS ON SALE		0				
135									
136									
137			Total (gain)/loss on sale	0	0	0	0	0	0
138									
139									
140			TOTAL OPERATING EXPENSES	0	194,670	0	194,670	(67)	194,603
141									
142									
143			NET OPERATING INCOME	0	60,910	0	60,910	175	61,085

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GULF POWER COMPANY
DOCKET NO. 891345-EI
APPROVED REVENUE INCREASE BY CLASS
BASED ON COMPANY'S 12 CP AND 1/13TH COST OF SERVICE STUDY
SUMMARY OF CLASS ROR'S AND % INCREASE (000 DOLLARS)

AUGUST 10, 1990

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	
RATE CODE	APPROVED RATE BASE	APPROVED PRES.NOI	PRESENT ROR/ INDEX	INCREASE FROM SERVICE CHARGES	INCREASE FROM SALES OF ELECTRICITY	TOTAL INCREASE IN REVENUE	REQUIRED NOI	RECOMMENDED ROR/ INDEX	% INCREASE IN REV FROM SALES OF ELEC W/ADJ	BASE
RS	$475,918	$29,345	6.17% / 0.87	$47	$8,652	$8,699	$34,676	7.29% / 0.92	4.19%	6.58%
GS	$33,448	$4,835	14.46% / 2.04	$47	($1,655)	($1,608)	$3,850	11.51% / 1.45	-8.39%	-11.04%
RS-GS	$509,366	$34,180	6.71% / 0.95	$94	$6,997	$7,091	$38,526	7.56% / 0.95	3.10%	4.77%
GSD	$176,009	$13,846	7.87% / 1.11	$1	$1,817	$1,818	$14,960	8.50% / 1.07	2.00%	3.50%
LP/LPT	$104,427	$7,435	7.12% / 1.00	$0	$2,351	$2,351	$8,876	8.50% / 1.07	3.91%	8.06%
PX/PXT	$54,208	$4,363	8.05% / 1.13	$0	$395	$395	$4,605	8.50% / 1.07	1.03%	2.41%
OSI-II	$13,431	$872	6.49% / 0.92	$0	$202	$202	$996	7.42% / 0.93	4.19%	5.38%
OS-III	$613	$143	23.33% / 3.29	$0	($48)	($48)	$114	18.60% / 2.34	-9.58%	-14.29%
SS	$3,105	$246	7.92% / 1.12	$0	$29	$29	$264	8.50% / 1.07	3.30%	3.68%
TOT.RET	$861,159	$61,085	7.09% / 1.00	$95	$11,743	$11,838	$68,340	7.94% / 1.00	2.79%	4.72%

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ATTACHMENT 5
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PROPOSED RATES FOR GULF POWER COMPANY - DOCKET NO 891345-EI

	CURRENT RATES	COMPANY PROPOSED	COMMISSION VOTE	AFTER EXPIRATION OF MANAGEMENT PENALTY
INCREASE IN REVENUES		$26,137,000	$11,838,000	
RATE CLASS				
RESIDENTIAL				
CUSTOMER CHARGE	$6.25	$8.00	$8.00	$8.07
ENERGY				
Oct - May	$0.03148	$0.03489		
June - Sept	$0.03716	$0.04114		
NON SEASONAL			$0.03487	$0.03518
RESIDENTIAL TOU				
CUSTOMER CHARGE	$9.25	$11.00	$11.00	$11.10
ENERGY				
ON PEAK	$0.07797	$0.08623	$0.10218	$0.10308
OFF PEAK	$0.01378	$0.01608	$0.00529	$0.00534
GENERAL SERVICE				
CUSTOMER CHARGE	$7.00	$10.00	$10.00	$10.09
ENERGY				
Oct - May	$0.06174	$0.05441		
June - Sept	$0.06348	$0.06423		
NON SEASONAL			$0.05086	$0.05131
GENERAL SERVICE TOU				
CUSTOMER	$10.00	$13.00	$13.00	$13.11
ENERGY				
ON PEAK	$0.14727	$0.14324	$0.15711	$0.15849
OFF PEAK	$0.02296	$0.02188	$0.00511	$0.00515
GS-DEMAND				
CUSTOMER CHARGE	$27.00	$40.00	$40.00	$40.35
KW D[illegible]	$6.25	$4.52	$4.52	$4.56
ENERGY	$0.00641	$0.01424	$0.01289	$0.01300
GS DEMAND TOU				
CUSTOMER	$32.40	$45.40	$45.40	$45.80
KW DEMAND				
MAXIMUM	$2.96	$2.17	$2.15	$2.17
ON PEAK	$3.42	$2.44	$4.97	$5.01
ENERGY				
ON PEAK	$0.01395	$0.03269	$0.00445	$0.00449
OFF PEAK	$0.00302	$0.00692	$0.00445	$0.00449

APPROVED RATES FOR GULF POWER COMPANY - DOCKET NO 891345-EI

		CURRENT RATES	COMPANY PROPOSED	COMMISSION VOTE	AFTER EXPIRATION OF MANAGEMENT PENALTY
INCREASE IN REVENUES			$26,137,000	$11,838,000	
RATE CLASS					
LP					
	CUSTOMER CHARGE	$51.00	$225.00	$225.00	$226.98
	KW DEMAND	$6.25	$8.52	$8.50	$8.57
	SE MAXIMUM CHARGE			$1.81	$1.83
	ENERGY	$0.00861	$0.00568	$0.00528	$0.00533
LP TOU					
	CUSTOMER CHARGE	$51.00	$225.00	$225.00	$226.98
	KW DEMAND				
	MAXIMUM	$2.97	$4.15	$1.81	$1.83
	ON PEAK	$3.35	$4.52	$7.21	$7.27
	ENERGY				
	ON PEAK	$0.01928	$0.01211	$0.00417	$0.00421
	OFF PEAK	$0.00390	$0.00300	$0.00417	$0.00421
PX					
	CUSTOMER CHARGE	$146.00	$570.00	$570.00	$575.01
	KW DEMAND	$7.50	$8.25	$8.25	$8.32
	SE MAXIMUM CHARGE			$0.68	$0.69
	ENERGY	$0.00521	$0.00445	$0.00409	$0.00413
PX TOU					
	CUSTOMER CHARGE	$146.00	$570.00	$570.00	$575.01
	KW DEMAND				
	MAXIMUM	$3.56	$3.97	$0.68	$0.69
	ON PEAK	$3.99	$4.32	$7.66	$7.73
	ENERGY				
	ON PEAK	$0.01299	$0.00984	$0.00406	$0.00410
	OFF PEAK	$0.00242	$0.00262	$0.00406	$0.00410

GULF POWER COMPANY
APPROVED STREET AND OUTDOOR LIGHTING RATES
891345-EI

TYPE OF FACILITY	FIXTURE CHARGE	MAINTENANCE CHARGE	ENERGY CHARGE	TOTAL MONTHLY CHARGE
HIGH PRESSURE SODIUM (OS-I)				
5,400 LUMEN	$1.95	$1.34	$0.74	$4.03
8,800 LUMEN	$1.96	$1.06	$1.05	$4.07
20,000 LUMEN	$2.26	$1.56	$2.13	$5.95
25,000 LUMEN	$2.81	$2.03	$2.68	$7.52
46,000 LUMEN	$3.17	$1.61	$4.24	$9.02
20,000 LUMEN *	$4.31	$1.79	$2.13	$8.23
46,000 LUMEN **	$9.09	$2.00	$4.24	$15.33
20,000 LUMEN **	$10.79	$1.79	$2.13	$14.71
8,800 LUMEN ***	$6.14	$1.56	$1.05	$8.75
MERCURY VAPOR (OS-I)				
3,200 LUMEN	$1.44	$1.40	$1.03	$3.87
7,000 LUMEN	$1.43	$1.04	$1.76	$4.23
9,400 LUMEN	$1.91	$1.66	$2.50	$6.07
17,000 LUMEN	$2.22	$1.73	$4.00	$7.95
48,000 LUMEN	$6.03	$3.16	$9.79	$18.98
HIGH PRESSURE SODIUM (OS-II)				
5,400 LUMEN	$1.95	$0.84	$0.74	$3.53
8,800 LUMEN	$1.75	$0.79	$1.05	$3.59
20,000 LUMEN	$2.26	$1.05	$2.13	$5.44
25,000 LUMEN	$2.80	$1.50	$2.68	$6.98
46,000 LUMEN	$3.17	$1.10	$4.24	$8.51
20,000 LUMEN #	$4.27	$1.92	$2.21	$8.40
46,000 LUMEN #	$3.81	$1.79	$4.39	$9.99
8,800 LUMEN ***	$6.15	$0.76	$1.05	$7.96
MERCURY VAPOR (OS-II)				
7,000 LUMEN	$1.41	$0.65	$1.76	$3.82
17,000 LUMEN	$2.21	$1.29	$4.00	$7.50
17,000 LUMEN #	$4.11	$1.84	$4.29	$10.24

NEW OFFERING, DIRECTIONAL, COASTAL

** NEW OFFERING, DIRECTIONAL

DIRECTIC[illegible]

RC-82

ATTACHMENT 6
ORDER NO. 23573
DOCKET NO. 891345-EI
PAGE 82

GULF POWER COMPANY
APPROVED STREET AND OUTDOOR LIGHTING RATES
891345-EI

ENERGY RATES ($ PER KWH)

RATE CLASS	RATE
OS-I AND OS-II	$0.02631
OS-III	$0.03751
OS-IV	$0.03711

OS-IV CUSTOMER CHARGE: $10.00

ADDITIONAL FACILITIES CHARGES

30-FOOT WOOD POLE	$2.00
30-FOOT CONCRETE POLE	$4.50

Gulf Power Company
Post Office Box 1151
Pensacola, Florida 32520
Telephone 904-434-8381

Gulf Power
the southern electric system

E. L. Addison
President

August 25, 1978

Mr. David Swafford
Executive Director
Florida Public Service Commission
101 East Gaines Street
Tallahassee, Florida 32304

Dear Mr. Swafford:

The present schedule for the proposed Caryville Electric Generating Plant would have the first 500 megawatt unit placed in service in 1985 when our present estimates indicate that we need additional capacity. However, a possible alternate source of capacity may now be available to us at a substantial savings.

The first 500,000 kilowatt unit at the Caryville Plant is estimated to cost $673 million or $1,346 per kilowatt. Georgia Power Company is constructing four 818 megawatt units at its Scherer Plant in Georgia at an estimated cost of $574 per kilowatt. The primary reasons for the dramatic difference in estimated costs between the two plants are (1) the earlier commitments for the Scherer Units negated some inflationary effects, (2) the Federal Clean Air Act of 1970 and the amendments of 1977 to such Act requires SO_2 scrubbers at the Caryville Plant, but apparently does not require scrubbers at the Scherer Plant, and (3) the economy of size between the 800's and the 500's. Due to a reassessment of the future demand for electricity in their service area, Georgia has tentatively offered to sell Gulf 432 megawatts of capacity to be constructed at the Scherer Plant. This 432 megawatts of capacity would cost $333,504,000 ($1,346 - $574 x 432,000) less than an equivalent amount of capacity at the Caryville Plant.

It is quite apparent that this would be of immense benefit to the customers of Gulf Power Company; however, the Company must cancel present construction plans at the Caryville Plant in order to take advantage of this offer from Georgia Power Company. The total costs involved in cancellation, including cancellation charges from manufacturers, would be approximately $20 million. Our auditors would require that this total amount be written-off in the year the decision is made unless we have approval from the Commission with primary jurisdiction (Florida Public Service Commission) to write such charges off over a reasonable period of time "above the line" for rate-making purposes. With such approval, the auditors could, under addendum to APB Opinion No. Two, allow us to account for the write-off in the same manner as allowed for rate-making purposes.

Obviously, Gulf Power Company cannot suffer the total destruction of its financial viability that would result with a $20 million write-off in one fiscal year. We would lose our bond ratings, preferred stock ratings, commercial paper ratings, minimum indenture and charter coverages, and of course, would be unable to obtain funds from any external source.

Therefore, we respectfully request that the Florida Public Service Commission approve the write-off over a five-year period of the total costs resulting from the cancellation of the present construction plans at the Caryville Plant that will enable us to negotiate for the purchase of the capacity in Georgia with potential savings to our customers in excess of $300 million.

We know you will have questions and need additional information. We await your advice as to how we should proceed to obtain the requested approval. Your cooperation and prompt attention concerning this request will be greatly appreciated.

Sincerely,

E. L. Addison

E. L. Addison

ELA:paj

bc: Messrs. E. B. Parsons, Jr.
A. E. Scarbrough

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of :

The presentation from GULF POWER COMPANY describing alternatives to the construction of its planned Caryville generating unit being considered by the company, and to explore the possible accounting treatment of cancellation charges associated with pursuing an alternative course. :

DOCKET NO. 780714-EU

INFORMAL WORKSHOP

ORIGINAL FILE COPY

RECEIVED
OFFICE OF COMMISSION CLERK
OCT 16 1978
Florida Public Service Comm.

FPSC Hearing Room
Fletcher Building
101 East Gaines Street
Tallahassee, Florida 32304

Monday, October 9, 1978

Met pursuant to notice at 3:00 p.m.

BEFORE: COMMISSIONER PAULA F. HAWKINS, Chairman
COMMISSIONER WILLIAM T. MAYO
COMMISSIONER ROBERT T. MANN

APPEARANCES:

ROGER VINSON, of Beggs and Lane, Post Office Box 1290, Pensacola, Florida, 32576, Telephone Number (904)432-2451, for Gulf Power Company.

JOSEPH A. McGLOTHLIN, 101 East Gaines Street, Tallahassee, Florida, 32304, Telephone Number (904)488-7921, for the staff and the public generally.

BARRETT G. JOHNSON, Commission General Counsel's Office, 101 East Gaines Street, Tallahassee, Florida, 32304, Telephone Number (904)488-7464, as advisor to the Commissioners.

REPORTER BY: CAROL C. CAUSSEAUX, RPR
Commission Hearing Reporter

P R O C E E D I N G S

CHAIRMAN HAWKINS: I understand that this is to be informal today but we will take appearances for appearance's sake.

MR. VINSON: Madam Chairman, I am Roger Vinson, of the firm Beggs and Lane, Pensacola, Post Office Box 1290, 32576, for Gulf Power Company.

MR. McGLOTHLIN: I am Joseph A. McGlothlin, 101 East Gaines Street, Tallahassee, Florida, appearing for the staff and the public generally.

MR. JOHNSON: I am Barrett G. Johnson, Commission General Counsel's Office, 101 East Gaines Street, Tallahassee, Florida, appearing as advisor to the Commissioners.

CHAIRMAN HAWKINS: Would you like to introduce the people at your table, since we are doing this informally?

MR. ADDISON: Yes, Madam Chairman, I will be glad to do that. I am Ed Addison, President of Gulf Power Company, Post Office Box 1151, Pensacola, 32520.

On my far left is our Manager of Power Supply, George Layman, and on my right Arlan Scarbrough, who is Vice-President and Comptroller of the company. Next is Earl Parsons, who is Vice-President of Electric Operations, and then Jim Babbitt, who is Manager of System Planning.

We will proceed if you are ready.

CHAIRMAN HAWKINS: Surely.

MR. ADDISON: Pursuant to our letter of August 25, 1978, when we wrote to Mr. Swafford with a discussion of our generation expansion plans and the desire to possibly make some changes, it is my understanding that the Commission did want us to appear this afternoon and informally discuss what we have in mind and then be available to you to answer any questions.

With that in mind, I will cover, hopefully fairly briefly and if you will pardon me because I have got a bad throat today, but I will get through it as quickly as we can, and then my associates and I will be glad to answer your questions.

I think I will start back and say that prior to the oil embargo, that the load forecasting business was a little more simple than it is today, and has been between the oil embargo and now. Prior to that time Gulf Power Company's system demand had been growing, varying somewhere between 9 and 11% but with some fair degree of consistency for a number of years.

In 1971 Gulf had under construction at that time a 500-megawatt unit at our Crist plant in Pensacola. It was due to come on the line in 1973, which it did. At that time, in our system planning studies and load projections, it was obvious to us that we needed additional capacity on our system somewhere in the late '70's, either '78 or '79, it appeared at that time. So we set to work, working jointly with the site planning people and Southern Company Services and our own people, and we actually reviewed probably 30-some odd sites in a preliminary sort of a fashion and gradually narrowed them down. Then by October of 1973 we budgeted for the construction of two 500-megawatt units. The first one was to go on the line in '79 and the next one was to go on the line in 1981. And this at the time appeared to be necessary to fill our growing demand in our system.

At that time really the units were not

located. We had narrowed the sites down to three possible sites and it appeared that possibly the Smith plant might be a site that we would decide on and really when the units were first budgeted they were shown as going to the Smith plant in, or near, Panama City.

In February of 1974, though, with studies progressing along, it was apparent at that time that the most economic location for those units would be in Caryville and so they were officially designated to go into the Caryville area with the '79 and '81 dates remaining the same.

In October of 1974 the units were deferred to 1980 and '81 due to a change in our load growth, a slight decrease in our load growth. During this time, along in 1974, we started the site certification process at Caryville. Our studies had shown initially, and still do, that that site was capable, and is capable, of housing about 3,000 megawatts. So we set out and ultimately, as far as the state is concerned, certified the site for 3,000 megawatts, even though at the time we were only talking about the first two units of 500 megawatts each.

The licensing process was slow, and because it was slow it began to be apparent that we might have a problem getting the first unit on the line in 1980. Again, this was because of the fact that the oil embargo had already started having some very sharp effects on the load forecasts, not only in our system but obviously across the country, but I will deal only with those on our system, on the Southern Company's system.

Mississippi had two units under construction in Jackson County, Mississippi, later to be called the Daniel plant, and they were probably hit the hardest right off because Mississippi's load is more heavily industrial and they responded more quickly, I suppose, to the action of the Arabs, so they found immediately that they were going to have some capacity that they did not need. So, faced with that, they started looking around for a market for that capacity. They could either delay it, which would, of course, to some degree increase the cost of it, or they could try to market that capacity on the Southern system, or otherwise for that matter.

It appeared to us that it was an excellent opportunity to buy capacity. At that time that unit was scheduled on the line in 1979, but it was pretty obvious that it could be delayed a couple of years, if necessary, without any undue effect on the overall cost. So we made a decision, then, to defer Caryville further and to purchase the Daniel unit, one of the Daniel units, or half of those two 500-megawatt units in Mississippi, and in October of 1975 we put that unit in our budget. At the time we made that decision the estimated cost of the Daniel unit was $283 a kilowatt and of the Caryville units, the first unit, $687 a kilowatt.

COMMISSIONER MAYO: Would you give me those figures again, please?

MR. ADDISON: Yes, sir. At the time we placed the Daniel unit in our budget and made the decision to negotiate with Mississippi and purchase half of that plant, the per unit cost at Daniel was $283 per kilowatt and at Caryville it was $687 per kilowatt.

At the time, then, when we made that decision the Caryville units were further deferred until 1982 and 1984. In 1976, with load projections continuing to go down, the

Daniel unit was deferred to 1980. In 1977, with the same trend continuing, Daniel was deferred until 1981. That is the second Daniel unit. The first Daniel unit went on and went on the line but our purchase was to be effective when the second unit went in service. So at the same time in 1977 Caryville No. 1 was moved to 1985 and Caryville No. 2 to 1987.

Now, in 1977 the Congress passed the 77 amendments to the Clean Air Act, and later in '77 it was pretty obvious to us then that the effect of thos amendments would be to cause the units at Caryville to have to have scrubbers, which would greatly increase the cost of them, obviously. Now, we began at that time to study what alternatives might be available to us late in 1977, but at that time there were none that we could see.

All of the companies on the Southern system were continuing to look at their loads, as we do, and the system planning group of Southern Company Services was continuing to take a look at the combined loads and the combined generating capacity being constructed on the Southern system. I have some firsthand knowledge of that because at that time I was serving as Executive Vice-President of Southern Company Services and the planning area was one of my primary responsibilities.

Early in 1978 Georgia began a new load forecast study and we in the planning group of the service company at that time felt that it was a pretty certain thing that the Georgia load would be decreased again because the trends were just indicating still a further downward direction for their load growth. We went to work and put together some possible alternatives then to Caryville and one of those alternatives was for Gulf and Mississippi to study the possible purchase of a portion of the Scherer units if Georgia no longer needed them.

There was another alternative that we considered, and which I really don't think we need to get into but I will just mention it so you will not think that we are just concentrating on one thing, and that was that we were taking a look at the possibility of changing the 500 units possibly to 800-megawatt units if we could find someone to share them with us, because with the addition of scrubbers the per unit cost spread was becoming much greater between the 500s and the 800s. So that was an alternative that we were also looking at.

In April of 1978 Georgia did, in fact, revise its load forecast, which indicated that there was some capacity available in the Scherer that could be put on the market. Because of the fact that the Scherer units have been under a program of continuous construction, as we view it, under the specifications of the amendments to the Clean Air Act of 1977, it appears to us that the Scherer units will not have to have scrubbers and that makes them a much lower cost unit than we will ever see built on the Southern system again.

CHAIRMAN HAWKINS: Is that an actuality? In my letter it says "Apparently it does not require scrubbers." Why "apparently" because it either does or it doesn't, or are they negotiating?

MR. ADDISON: In dealing with the federal government we have gotten to the point that we don't ever say anything is for sure. Georgia has all of the permits that they need.

CHAIRMAN HAWKINS: The Scherer plant is permitted in toto?

MR. ADDISON: In toto, yes, and our people, Mrs. Hawkins, who work with this thing every day tell us that almost a positive fact is that the first two units will not have to have scrubbers. There is some possibility that there could be an interpretation that would require the last two units to have scrubbers. It is our firm belief that none of the four should, under the amendments of 1977, be required to have scrubbers. We think that all of the criteria is met and they will not have to have scrubbers. That is the best that we can do. That is our best information, and I will talk about the cost involved if we are wrong in just a minute.

CHAIRMAN HAWKINS: All right.

MR. ADDISON: Following the decision in April by Georgia to lower their load forecast again, Mississippi and Gulf and representatives from the planning group in Southern Company Services had a meeting to discuss the possibility of us purchasing into the Scherer plant. The planning people had been talking to the Georgia folks, they were willing to take a look at it and were willing to talk about it. We stopped all expenditures on Caryville at that time. We felt that the little bit of loss of time and savings in dollars could be very meaningful. The savings in the dollars could be very meaningful and the loss of the time would not be that great until we could get some resolution as to whether or not it was a viable thing for us to participate in, so we stopped expenditures at that time.

On the 4th of August we met for the first time with Georgia. Mississippi and Gulf and the Southern Service Company was also present. We discussed how we might go about purchasing capacity from the Scherer units. The meeting went very well and it gave us reason to believe that there is a good possibility that we could work out a purchase and work out the transmission requirements and can, in fact, bring it about with a little hard work on our part.

On the 8th of August we came to have a preliminary and very informal discussion with the staff of the Commission, to tell them what we were about because we were in registration for a bond sale and we felt that we had to say something about it in the registration statement and did not want the Commission reading about it in the newspapers. Plus the fact that we really wanted to start getting something started here to consider what might be involved. Then on the 25th of August, we, pursuant to our discussion with the staff, wrote a letter to Mr. Swafford outlining what we proposed to do.

Now, the cost of the Scherer units, if we are to buy into them, we will buy a portion of all four units. We will buy into the units on a timely basis, beginning in 1985, and we would pay on the construction of Unit No. 3 on the same type of schedule as though we were building a plant that would go into service in 1985. So in 1985, then, we would purchase 216 megawatts, and that would be 216 megawatts out of all three units, total amount of capacity, but it would not be just Unit No. 3 but would be in all three units.

In 1987, when the fourth unit goes on the line, we would again be purchasing another 216 megawatts, which would make a total of 432 megawatts out of that plant, and we would then own 13.37, I think it is, percent of the total plant.

Now, the cost to us, the present estimates say, and these figures are a little bit different than the figures in my letter because we are constantly updating them, but our present estimate of the first unit at Caryville is that it will cost us $1,405 per kilowatt; that the four units at Scherer will average out $592 a kilowatt. If you multiply those two figures by the 432 kilowatts involved, it would say that on that amount of capacity we could save $51.3 million by buying that amount of capacity from Scherer rather than constructing a like amount of capacity at Caryville.

There are three basic reasons for the difference, the very dramatic difference in cost. Number one, the units a Scherer will not have to have scrubbers. Number two, the economy of scale between the 500s and the 800s and, number three, the time frame during which those units are being constructed and the affects of inflation during that time frame.

Now, in order for us to do that we would cancel the two 500 units on order for Caryville, which we have, in fact, stopped construction on pending a final decision. It is our estimate at the present time, subject to further detailed review and final negotiations with the manufacturers and the suppliers, that our cancellation charges will be somewhere in the neighborhood of $20 million. We are fairly certain that it will not be greater than $20 million. The land would remain because it is a good plant site and we believe that we will build a plant there in the future. The environmental licensing effort, we think that we will be able to utilize this in the future when we build whatever size unit we might build there, and so those two costs we would continue to carry on our books.

Now, in the event that the second two units at Scherer have to have scrubbers it will add some additional cost, and I thought I had those numbers but I don't, but we can get them for you, and we end up still with a tremendous savings compared to the Caryville units. It does very little to -- of course, it adds a large number of dollars but yet it does not nearly wipe out the difference between the savings.

So what we are saying to you is this: That we have been through a long and arduous planning process leading toward the construction of two units at our Caryville plant, a sound planning process. This Commission reviewed that planning process subsequent to the licensing and found that we needed additional capacity. They said at that time that if we could find any alternatives that we should continue looking for them, and we did one at Daniel and now I think we have the opportunity again at Scherer. I think that our planning has been good and prudent, it still is a good plan, we can continue, but I think that it would be foolish for us to continue if, in fact, we can buy capacity somewhere else with the kind of savings that we are taking a look at.

Now, my accounting people tell me that $350 million if you stretch it out over the 30-year life of the plant, would mean at least $1.5 billion to our customers.

In order for us to be able to do that and to proceed, we need help with this Commission, as I outlined in my letter, to allow us to recover these costs, and we have suggested that the $20 million, we have suggested over a five-year period, obviously that can be adjusted, otherwise we are forced by accounting principles, et cetera, to write it off in the year that the decision is made and it would financially ruin our company. I pointed out some of the details on that in my letter.

So we are here today to discuss it with you and to ask you for some prompt and positive action on our request so that we can proceed in our negotiations with Georgia to see if we can't bring this to a successful conclusion.

COMMISSIONER MANN: What is the transmission problem?

MR. ADDISON: There are transmission problems because obviously with that amount of capacity that distance away from Gulf intitially we will have some additional transmission costs. However, our studies show that by the time we get to 1985 -- what is the date?

MR. BABBITT: I believe it's 1992.

MR. ADDISON: That by 1992 the transmission charges will have equalized because then we are coming back and putting capacity at Caryville.

So we will have some transmission costs early on but, again, it is not that substantial. One of the reasons for that is because we are an integrated system and that is one of the things that we are going to have some hard negotiations with Georgia about because, obviously, Georgia wants to make sure that they aren't giving anything away, and we want to make sure that we are not paying for something that we are not getting. But that is something that is going to be one of the toughest things in the neogiations is to determine how to settle the equity in the transmission costs. But, as far as electrically speaking, it really is not a great problem.

COMMISSIONER MANN: So what you are saying is that the transmission line presently in place is adequate to accommodate this change in your plans?

MR. ADDISON: No, sir, I would not say that. I think that we will have to add transmission and it depends to some degree on what is done inside of Georgia, but I think that very definitely we will have to see a 500 line built from the Farley plant in Alabama down into our service area, into the Caryville site and on over toward Crestview. So we will have to build that early on. However, we would ultimately have to build that, anyway, but we will have that construction earlier. So we will have some transmission costs earlier than we would otherwise.

COMMISSIONER MAYO: Why would you have to build it?

MR. ADDISON: In order to move that amount of power into our service area.

COMMISSIONER MAYO: You said that you would have to build it ultimately, anyway.

MR. ADDISON: To handle the shifting of the loads. Just to handle the loads at that time out of Caryville. It will have to be built to move the power because we are dealing with a situation where if you have say a unit at Caryville, in whatever, 87, 89, somewhere out in there, and let's say that you lost that unit, then you have got to have the transmission capability to move that.

COMMISSIONER MAYO: So what you would be doing, then, would really be strengthening your already existing in-ties with the other stations?

MR. ADDISON: Yes, that is correct.

COMMISSIONER MANN: How far away is Scherer, where is it located?

MR. ADDISON: Scherer is about half-way between Atlanta and Macon, if I have that correct, and I believe it's about 300 miles, if I am not mistaken.

COMMISSIONER MANN: What is the route by which that electricity comes into the Gulf system?

MR. ADDISON: Right now the most direct route that we have is the 230,000-volt line that goes from our Smith plant in Panama City up into Thomasville, Georgia. That is the strongest tie that we have at the present time and that is one of the reasons that we would have to strengthen the transmission system going into Georgia.

Georgia will have at that time, by 1985, a 500-line coming from Plant Hatch, I believe it is, in Georgia down to Plant Farley. Am I correct? Okay. That's Plant Farley in Alabama, and Plant Farley is near Dothan, as you may recall, and then we would have to work out an arrangement with Alabama to get 500 KV constructed from Farley down into Florida.

COMMISSIONER MAYO: What would your continuing transmission loss be on this arrangement, as opposed to the Caryville plant?

MR. ADDISON: Jim, can you answer that for me? What is the additional transmission loss? Is there any great amount of additional losses involved?

MR. BABBITT: I don't think there will be a lot of difference in losses.

MR. ADDISON: Not a lot of difference in losses, and sometimes that is hard to understand but, again, it is because of the integrated system effect.

MR. PARSONS: May I expand on that?

MR. ADDISON: Sure.

MR. PARSONS: I think essentially the Caryville site, the original plans, that we got it certified for four units but the original plans were to build two 500-megawatt units. Those two 500-megawatt units could be handled by a 320 KV transmission line. The load center primarily would be still in the Caryville area to serve the total part of the northwest part of the state. By buying into the Scherer unit we would need the 500 KV line from Plant Farley down into the Caryville area, and the fact that you had the different distance the 500 KV would account for some of those losses that you would have had in the lower transmission voltages. So the fact that we are going to 500 now can bring that amount of power down to this location rather than have a plant there accounts for some of it. I don't know that we made any studies on the transmission losses per se because of the fact that we are still in the negotiating stages now.

COMMISSIONER MAYO: What about this Daniel plant? As I understand it, the first unit, you are going ahead with that?

MR. ADDISON: Yes, sir.

COMMISSIONER MAYO: And the second unit has been indefinitely delayed?

MR. ADDISON: No, sir. The second unit will come on line in 1981. The first unit is on the line and running and the second unit will come on the line in 1981, and at that time then Gulf will own an undivided one-half interest in that plant.

COMMISSIONER MAYO: So you are going ahead with your plans, then,for the acquisition of an

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interest in Mississippi?

MR. ADDISON: Yes, sir.

COMMISSIONER MAYO: And the plans that you are talking about now are all up into what year?

MR. ADDISON: There's a 1985, the first purchase would be 216 megawatts in 1985, and the second 216 in 1987.

COMMISSIONER MAYO: So you are 8 or 9 or 10 years away from any further utilization of the Caryville site, is that correct?

MR. ADDISON: Yes, that is correct.

COMMISSIONER MAYO: How much land do you have there?

MR. ADDISON: I think we have about 1400 acres and we need about twice that much now that we have to use scrubbers. So we probably are going to start a pretty -- not intensive -- but pretty aggressive plan to go ahead and purchase some more land there.

COMMISSIONER MAYO: What about the Daniel plants, do they have to have scrubbers?

MR. ADDISON: No, sir, they don't. They have to burn low sulfur coal and they are buying that coal from out west. If they did not burn low sulfur coal they would have to have scrubbers.

But the amendments to the Clean Air Act of 1977 take away that right. You cannot meet the standards by using low sulfur coal. You have got to remove a certain percentage of the sulfur dioxide regardless of the percentage of sulfur coal that you are burning.

COMMISSIONER MAYO: What about the fuel at the Scherer plant?

MR. ADDISON: The Scherer plant will burn low sulfur coal and the majority of that is contracted for.

COMMISSIONER MAYO: And they won't require scrubbers there?

MR. ADDISON: No, sir, and that's what we are saying. We do not believe that but there is a possibility that the last two units would have to have, but we don't believe that they will, although there still would be an economical advantage to us.

COMMISSIONER MAYO: Now you have been planning on these Caryville units, and you started off talking about dates a long time ago. Is that going back to 1971?

MR. ADDISON: We started looking at the need for additional capacity in 1971. Really, the first date we ever put down for additional capacity that ultimately ended up being the Caryville plant was for 1978, and that was rather short-lived, and then there was the 1979 target date that we had.

COMMISSIONER MAYO: When did you start planning this $20 million?

MR. ADDISON: Well, the $20 million I guess was started from the time we really zeroed in on the site, because when you get the site decided upon at that time the requirements were already here about what we had to do for site licensing. We started doing the environmental monitoring, environmental studies, preliminary engineering studies, layouts, and so on, at that time. It is a long process. When you take a look now at building a new site, a new fossil-fired site, you are looking at seven or eight years and this is an awfully long time. When you think that those two units alone would cost us in the neighborhood of one and a quarter billion dollars, it would seem that we were just awfully lucky to catch it when we hadn't spent but $20 million.

COMMISSIONER MAYO: How much of this $20

million is so-called cancellation charges?

MR. ADDISON: Really, there are very little "cancellation" charges, as I would put it. Most of this money is dollars that have already been spent by the manufacturers in engineering, design, and some manufacturing. And so that is why we are not all that definite with you about the figure. We put in a little bit of fluff in there to take care of some cancellation charges, per se, but most of the money we feel will be for work that has actually been done, money that has been expended in getting ready.

COMMISSIONER MAYO: Are these units so unique in design that the work that has been done by the manufacturers might not be completely salvageable with some other unit ordered by somebody else at some other time in the fore-seeable future?

MR. ADDISON: There is a possibility of that but the problem that we are faced with is that every other utility in the United States has had the same thing happen to them that happened to us, and that is load growth curtailed, and so the manufacturers just have a lot of capacity on their hands and there are a lot of units that people are looking to cancel. So we have that problem now and that is another facet of some of the equipment. We think that there is a possibility that some of this equipment can be used elsewhere on the system and we are taking a look at that and any equipment that could be used, of course, would be a reduction in this amount of money that we are talking about.

CHAIRMAN HAWKINS: But you don't have a list of that yet?

MR. ADDISON: No, ma'am, but just as an example, one thing is the precipitators. We have a commitment for the precipitators for these two units. There is a possibility that we are going to have to add new precipitators on our Crist 6 and 7 units at Pensacola at a cost of about $35 million to get that much more out of the stack, and if we do then, you know, we know for a fact that one of these precipitators could be used there. Whether or not they both could, I don't know, and so if that took place then that money would not be lost at all but we would be utilizing that equipment.

COMMISSIONER MAYO: I notice that you have not made any reference to any of the planning for construction within the Southern companies of nuclear units. You have some, don't you?

MR. ADDISON: We have some, yes. Georgia has one unit that is on the line and one coming on, or it is already on. Is Hatch 2 on or not?

MR. BABBITT: It's scheduled for 1979.

MR. ADDISON: Well, I think it will make it in '78, but in Alabama the Farley plant is there, they have one unit on the line and another one coming on shortly. The Vogle plant in Georgia, which is jointly owned by Georgia and some of its neighbors up there, as is the Scherer plant, in fact, they had about $100 million invested in the Vogle units and they have been trying to find a way to get them underway again and they have now done that in cooperation with OEMC, MEAG and the City of Dalton.

Beyond that, there are no nuclear units on the drawing board on the Southern system for the simple reason that the capital cost is so very high and the licensing so uncertain that it's worse than going to Las Vegas. You are really taking a tremendous gamble that we don't feel prudent businessmen can take to initiate further construction of nuclear units until something is done about licensing policies in this country.

COMMISSIONER MAYO: But none of your planned acquisition of power from sister companies, whether it be Mississippi or Georgia, involves any nuclear generation?

MR. ADDISON: No, sir.

COMMISSIONER MAYO: They are going to keep the best for themselves?

MR. ADDISON: Yes, sir, and I don't know whether we could financially do it. The cost per kilowatt is pretty high and there are other restrictions, too.

CHAIRMAN HAWKINS: Will any of this expense benefit any other customer in Florida besides the Gulf Power customer?

MR. ADDISON: No, ma'am.

CHAIRMAN HAWKINS: It's restricted to those?

MR. ADDISON: That's right. Of course, you are well aware that we serve Florida Public Utilities and four co-ops.

CHAIRMAN HAWKINS: Are you still exempt from the Grid bill?

COMMISSIONER MANN: Administratively but not legally.

MR. ADDISON: Thank you, Judge, for that ruling.

COMMISSIONER MAYO: Let's turn this thing around for a minute. You have talked to us about the potential savings to Gulf to go this route.

MR. ADDISON: It's to our customers, really.

COMMISSIONER MAYO: All right, Gulf and its customers. But, now, savings usually work two ways. Somebody has got some surplus power that they obviously don't need in order for Gulf to be able to do this.

MR. ADDISON: Yes, sir, that is correct.

COMMISSIONER MAYO: What are the advantages on the other side of the coin, to the Georgia Power Company and its customers? What is this happy marriage all about?

MR. ADDISON: Georgia is faced with the possibility of having to delay the units, which will increase the cost of them if they are delayed. Not only will it increase the cost of them from the inflationary standpoint, but it will increase the cost of them by forcing the addition of scrubbers. It just really looks as if it would not be the prudent thing to do, if Georgia could market that capacity, to have constructed additional capacity at lower cost that we will ever see again.

COMMISSIONER MAYO: Is there any way to bring about any sharing of these savings between the Gulf ratepayers and the Georgia ratepayers?

MR. ADDISON: That is exactly what we are proposing to do, is for us to share in the savings available in those units. That is exactly what we are talking about.

COMMISSIONER MAYO: So they are going to save something, too, if they can avoid delay.

MR. ADDISON: Well, it is going to mean that those units will not cost more money ultimately.

COMMISSIONER MAYO: So they are going to save?

MR. ADDISON: Yes, I think that they are going to save, that's right, but I don't think their savings will be as great as ours. I think it is a prudent move on both our parts, to be straightforward about it.

CHAIRMAN HAWKINS: If Georgia had to cancel what would their cancellation costs be?

MR. ADDISON: Mrs. Hawkins, I really have

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no idea, and they would not cancel. What I would suspect that they would do would be to simply delay those units because it would not be, probably would not be an undue delay.

I think one of the problems that Georgia is faced with is that they are under contract with their associates in Georgia, the municipal group, the co-op group and the City of Dalton, to have this capacity on the line on the dates that it is scheduled, and I think that that is one of the things that is motivating them because they want to honor those contracts, they want to have that capacity available for them, and trying to find some way to market the additional capacity so that they can proceed on that schedule, and this is one of the ways that they see to manage that without building capacity ahead of their needs.

COMMISSIONER MAYO: You may have already told us this but if you did I have forgotten. What part of the total capacity of these Georgia plants, now, are you contemplating acquiring percentages of?

MR. ADDISON: All right, sir. We will be acquiring roughly 26.7% of those four units.

That is a total of 818 times 4, which is the total capability of that plant site.

CHAIRMAN HAWKINS: Who owns the balance?

MR. ADDISON: Excuse me, excuse me just a minute. Ours is half of that, I'm sorry. That's what Georgia owns. Georgia has 26.7%. That's what Georgia will own if we do what we are talking about. OEMC, which is the Oglethorpe Electric Membership Co-operative, will own 30%. The Municipal Electric Association of Georgia, or MEAG, will own 15.1%. Gulf and Mississippi each will own 13.37%, and the City of Dalton will own 1.4%. The one qualifier I might put on that is that I do not believe that the Oglethorpe Electric Membership Co-operative, I don't believe that they have exercised that option yet but Georgia anticipates that they will. That's what the breakdown looks like.

COMMISSIONER MAYO: Is a certain factor of reserve capacity being built into these four plants to become a part of the overall reserve capacity of the Southern Company system?

MR. ADDISON: Yes, that is correct. Our targeted reserves right now, Mr. Mayo, are a minimum of 15%, which we do not believe to be an adequate level of reserves, but financially we believe that that is where we are going to have to go ultimately because of the fact that load forecasts have been coming down consistently, and we are still a ways from getting down to 15%. As an operating man I hope we never get there, because there are going to be some sad days and our phone is going to buzzing and your phone is going to be buzzing because the lights are going to be off when we get to 15%.

We have been operating on our system with reserves in the neighborhood of 20 to 25 to 30% and we have one or two days that I can recall that we had to cut customers off in some discretionary manner and we have had other days when we were so close to it that we all sweated until the sun went down and it cooled off in the evening. While we have done a great amount of work in improving the reliability of our units, the availability is up on our units, it is not going to compensate for the reduction in the service.

COMMISSIONER MAYO: I have about run out of questions. Does the staff have any questions?

MR. McGLOTHLIN: Yes, we have a few. I have a few questions, Mr. Addison. What is the time frame involved? Is there a point at which your cancellation charges will be greater than $20 million when you make the decision, or is there a point in time when Georgia Power will withdraw its offer to sell?

MR. ADDISON: Joe, I think the manufacturers are working with us as best they can and they have some constraints, too. Right now we are still at the stage of them saying, "Let's do something as quickly as we can, we are hurting," and obviously the longer we wait I think the more of a problem we will be into on that. I cannot give you a specific time.

As far as Georgia is concerned, I think they have to have a decision from us fairly early in the year and, really, the quicker we have a decision and conclude our negotiations the better off we will all be. But, other than saying maybe the first quarter or somewhere in that range, nobody has said to me point blank, you know, "This is what we have got to do." I know this, though; that construction is moving on on those first two units and they need to know where they are going. I think it is important that we, as early as is practical, give them an answer.

MR. McGLOTHLIN: But you really are looking at the first quarter of the coming year?

MR. ADDISON: Well, what I am saying is that I would like to have that be the outside.

MR. McGLOTHLIN: You have delayed construction of the Caryville units before. When you delay rather than cancel do you run into costs of any magnitude?

MR. ADDISON: Well, you do run into costs because all of these contracts have escalators based on costs of living, plus all of the various indices and, yes, we do run into costs for delay.

MR. McGLOTHLIN: Just for the sake of comparison can you tell us the costs that were incurred by delaying the last time around?

MR. ADDISON: No, I can't tell you that. I think the only thing that I could do would be to give you a little bit of a rundown to show you how the estimated total costs on the units have escalated over the years, and this has just been phenomenal.

That doesn't really answer your question but it speaks to it to some degree because when we first took a look at these units in 1973 our estimate at that time was that they would cost $316 per kilowatt, and everybody thought that was a good estimate, and now we are up to $1,405 per kilowatt and I think that is a good estimate.

MR. McGLOTHLIN: You have suggested a five-year amortization period. Is that beginning at any particular time or what leads you to suggest five years?

MR. ADDISON: I am going to let Mr. Scarbrough answer that, if you don't mind.

MR. SCARBROUGH: There is nothing magic about the five-year period. We felt like five years was a reasonable period of time, and that is the period of time that formerly the Federal Power Commission, now the Federal Energy Regulatory Commission, that is the period of time which they have allowed on several occasions in the past for write-offs of this type. So there is nothing magic about the five years but it is just what we consider to be a reasonable period and it seems to be a precedent that has been set, particularly by the FERC.

MR. McGLOTHLIN: But it wasn't geared to the time of construction or the alternative, or any other considerations?

MR. SCARBROUGH: No.

MR. McGLOTHLIN: You speak of being allowed to recover. Are you implying that this would entail the necessity of a base rate adjustment sooner than would otherwise be the case?

MR. SCARBROUGH: This is a hard question to answer. There is a possibility that it would. If we were allowed to write this off, of course, it would be put in as an expense into the 407 account, and whatever time our financial situation dictated that we had to come back and ask for rate relief, that would just be an additional expense that would be involved.

Now, when that time is, to say that that would accelerate that, I don't know, but I would certainly say that it would increase the possibility of a sooner request for an increase in rates but I don't have any particular point in time.

COMMISSIONER MAYO: What you are saying, is, that the net result of what you are talking about would be a net reduction of net operating income, which would affect rate of return at some point in time in the future, and to what extent at this time it's hard to tell. Is that correct?

MR. SCARBROUGH: That is absolutely correct, yes. Of course, naturally, this is a $20 million write-off that we are talking about but, you know, Uncle Sam would pay half of that so it would actually only come to about $10 million that would actually hit net operating income.

MR. McGLOTHLIN: Perhaps you just answered, but have you tried to project or quantify any impact upon the rate of return by following this alternative?

MR. SCARBROUGH: No, we really haven't, Joe.

MR. McGLOTHLIN: When would you be in a position to do that?

MR. SCARBROUGH: We are in the process, and, of course, we could do it right now based on the present projections, but we are in the process of going through our budgeting procedures at the present time and we will actually have our new forecast available probably early December, and at that particular time, of course, we would have the very latest estimates and this type of thing could be done more accurately based on the estimates. It could be done now based on the present estimates but it would not be as accurate a figure as we would have when we complete our present budget forecast that we are working on at the present time.

MR. McGLOTHLIN: Well, this is an informal meeting and, since we are trying to identify problems, isn't it fair to state that one of the problems, from the Commission's point of view, is that you are asking for a determination that is usually made in the context of a rate case situation? In other words, usually these expenses would have been incurred and reviewed by the Commission once that request was made?

MR. ADDISON: Yes, that's right. You see, what we are faced with, and this is the reason that we wanted to come before the Commission to discuss this, is that if we end up, say if we were to go forward without any direction at all and the Commission said, "Gee, I don't think you ought to be doing that," and we ended up having to write off $20 million in one year, that would destroy us financially and that is a risk that we just can't take. So whatever forum is necessary for us to have some assurance, that's what we are seeking.

MR. SCARBROUGH: : The fact of the matter is that, irregardless of when we came in for a rate increase, the fact of the matter is that when the decision is made that we are going to cancel the present construction plant, at that particular point in time under generally accepted accounting principles the total amount would have to be written off for a nonregulated industry in that particular year that the decision is made. No question.

Now, there are special provisions for a regulated industry that makes an exception to the generally accepted accounting principles under an addendum to Accounting Principle No. 2, which allows you to account in the same manner that you are regulated so, therefore, those folks who make the final decision, our audit opinion, an independent public accountant, and not just our particular firm but any firm of public accountants, if they could have some reasonable assurance that we would be able to recover these dollars for rate making purposes then, therefore, they could allow us, then, to spread this over some period of time and not write it off in one year. Absent that assurance, however, they are put in a position to require us to write it off in one year and, of course, $20 million written off in one year for a company our size could be just devastating. It would put us out of business for a year.

MR. ADDISON: Well, longer than that, because you would lose your bond ratings and the whole business would be lost and I don't know when you would ever recover.

COMMISSIONER MAYO: Well, let me ask you another question while they are thinking because they probably have some more questions. I would like to ask you a question or two, and they may be brutal but I think that it is what we all have to know in order to make an accurate determination.

MR. ADDISON: Sure.

COMMISSIONER MAYO: The first question would be to suppose that this Commission, as it is presently constituted, gave you no encouragement. What would you do?

MR. ADDISON: I think that we would then proceed to review the plans for construction for generation at Caryville. We might, if we could find a way, I would change the plans, if I could change the plans to go to a bigger unit, to lessen the cost per kilowatt and have somebody share it with us.

COMMISSIONER MAYO: But you would pass up what you consider to be the potential savings at the present time and pursue your Caryville plant?

MR. ADDISON: Mr. Mayo, with my understanding from Mr. Scarborough and the Arthur Anderson people, if my understanding of what they have told me is correct, I would have no other choice because we cannot absorb $20 million.

COMMISSIONER MAYO: Well, you just finished telling us a while ago that it would be ten.

MR. ADDISON: Well, I am talking about ten after taxes.

COMMISSIONER MAYO: All right, and then the other question was just the opposite. Suppose that this Commission, as it is presently constituted, gave you some type of encouragement but, as we have already explored it, this thing could not be finalized to a point of being quite positive perhaps until a rate case, but if this Commission gave you that encouragement and then come January in all probability there are certainly going to be changes of some kind, it would probably be in effect at the time your next rate case came about. This Commission would no longer be here, another one having taken its place, how much strength and confidence could you put in the encouragement that you got from this Commission?

MR. ADDISON: I would put a great deal in it because, contrary to what I heard Judge Mann say a couple of times, I believe that there is some continuity of commitment by this Commission. If you will pardon me, sir.

COMMISSIONER MANN: Sure.

MR. ADDISON: And we have to operate like that. I think we have to operate that way, that there is a continuity of commitment by this Commission.

COMMISSIONER MAYO: Of course, in the past you have had some right to assume that there was going to be a sufficient note of continuity there for at least two or three years to let you have an orderly process there, but this would be the first time that any regulated utility can state that it has come up to a chopping off point, so to speak.

MR. ADDISON: You can rest assured that we will consider that.

COMMISSIONER MAYO: I just wanted to know if you had considered that.

MR. ADDISON: Yes, sir, and it is something that certainly should give us cause for consideration but I think that we have to make a judgment based on what kind of a direction this Commission gives us.

COMMISSIONER MAYO: Even though you know that it was not a firm commitment; that it could not be?

MR. ADDISON: Well, it would be a commitment by this Commission as they sit today and as they see it today.

COMMISSIONER MAYO: But are you asking for a formal commitment or an informal commitment?

MR. ADDISON: I am asking for a formal commitment.

COMMISSIONER MAYO: Are you asking for words of encouragement?

MR. ADDISON: No, sir.

COMMISSIONER MAYO: Or an order of some kind that would spell out, if we see fit to do it, the idea that this Commission was going to some degree accede to your request?

MR. ADDISON: Yes, sir. I would like to have a formal order that sets out an accounting procedure to handle the $20 million if we are successful in this negotiation.

COMMISSIONER MAYO: So you would be on slightly safer ground than we are right now?

MR. ADDISON: Yes, sir.

COMMISSIONER MANN: You would not, then, object to the formal order embodying the conditions under which any utility facing similar circumstances might very well spread a write-off of this nature?

MR. ADDISON: I'm not sure I understand.

COMMISSIONER MANN: Well, I am apprehensive about the Commission getting into management. I think what you are faced with is a management decision and part of your management decision goes back to the problem of writing something off or spreading it.

MR. ADDISON: Yes, sir.

COMMISSIONER MANN: But whether you write it off or spread it, the economic cost of providing electric generating capacity is, if your figures are correct, clearly lower if you buy a share, if you share it, than it would be if you proceeded with Caryville.

MR. ADDISON: Yes, sir.

COMMISSIONER MANN: So it doesn't make any sense whatever to pay more than you have to pay for electric generating capacity, and certainly to do that in order to take advantage of an accounting device does not make sense to me. But I don't think the Commission can commit itself prospectively against a rigorous review of your facts, as they may appear at the time, in any future rate case. Particularly with respect to costs which may perhaps be unanticipated at this time.

I think we have to evaluate the quality of service of any utility in the light of the wisdom of its managerial decisions and that's why it seems to me that it would be an unwise thing to pass up an opportunity to save $350 million, but I don't want to say that I know all of the facts at this time.

CHAIRMAN HAWKINS: I was just wondering if the Southern Company, the parent company, helped in the decision that was made in over-building Georgia, the same company.

MR. ADDISON: I'm not sure I follow you, Mrs. Hawkins.

CHAIRMAN HAWKINS: That the parent company would be involved, the same company, in the decision making process of selling that excess capacity to a sister system in Florida.

MR. ADDISON: Well, let me just sav, too, that the service company performs the services which we ask them to perform.

CHAIRMAN HAWKINS: And who did that in Georgia? You used to be with the Southern Company there, did you not?

MR. ADDISON: I was Southern Company Services, that's right.

CHAIRMAN HAWKINS: Who helped Georgia Power decide to build these plants?

MR. ADDISON: Well, I must say that the whole system works together, all of the companies, and the reason that we do that is because we buy and sell to each other through the process of the interchange contract and we want to make sure, each of us, that one of the companies is not overbuilding because if they do then we would have more reserves than we would consider to be prudent.

Now, the decision to build generating capacity, each company has to ultimately make that decision itself and it's based on the load forecast. So what has happened is that the decision has not been made to overbuild and the decisions that were made were not bad decisions, they were good decisions at the time, but the circumstances have changed; that is, load growth patterns have changed drastically and it brings us to this situation where there is capacity now available in Georgia that they do not need in the time frame in which it is scheduled.

Now, Georgia works in this area, we work in this area, the service company works as consultants to both of us, and we all use the best tools that we have available to us.

COMMISSIONER MAYO: You have mentioned a five-year write-off period, and I am not wedded to anything but I am just going to throw a hypothetical question out.

If this were changed to a ten-year write-off period and certain savings in generating capacity were to come about because of this joint venture, what would be the net effect, in your opinion, to the Florida ratepayers over a ten-year write-off period versus the savings? In other words, we ask them to help eat the $20 million problem so what could they hope to gain in the next ten years to offset it?

MR. ADDISON: We figured that over and above the write-off, in the 30-year life of the plant, at least one and a half billion dollars savings.

COMMISSIONER MAYO: That would be $500 million?

MR. ADDISON: Yes, at least $500 million.

COMMISSIONER MAYO: Yes, I know that I heard him say that, I know what he said, but I asked him about a ten-year write-off and I am taking the first ten years of the 30-year period and that's one-third, and a half a billion, and that is $500 million.

Now, am I to gather, from my roundabout

question, that the Gulf Power ratepayers could expect to save, and they might have to help digest $20 million, but --

MR. ADDISON: Well, but even after they have done that.

COMMISSIONER MAYO: All right, after they have done that then they should save $500 million in the next ten years?

MR. ADDISON: Yes, sir, or in the ten years following, yes, that's right.

COMMISSIONER MAYO: I am just trying to put this in as palatable a form as I possibly can.

MR. ADDISON: I don't believe that you can put it in any more palatable form than that because that is really what the bottom line is.

COMMISSIONER MANN: How do you plan to finance, through Gulf Power bonds?

MR. ADDISON: Bonds and preferred and equity.

COMMISSIONER MANN: And equity from the Southern Company?

MR. ADDISON: Yes, sir.

MR. SCARBROUGH:: We would propose to finance it roughly 55% from bonds and probably 11 or 12% preferred stock, and the balance of

33% or 34% investiment by the Southern Company.
COMMISSIONER MANN: What is your bond rating now, A?
MR. SCARBROUGH: It's a split rating. With Standard and Poor's we have a AA rating and with Moody's we have A rating.
COMMISSIONER MANN: And is Georgia Power graded?
MR. SCARBROUGH: Georgia Power's rating is BBB.
COMMISSIONER MANN: Triple B?
MR. SCARBROUGH: Yes, sir.
COMMISSIONER MANN: So, actually, Gulf can borrow cheaper than Georgia?
MR. SCARBROUGH: That's right, yes, at the present time.
CHAIRMAN HAWKINS: How much cheaper is it on BBB than A?
MR.SCARBROUGH: Probably at least one percent. Probably today it would be the difference between 9% and 10%.
MR. ADDISON: But that is a speculative thing, it varies and fluctuates.
MR. SCARBROUGH: It is very speculative, yes.

CHAIRMAN HAWKINS: How many plants do you have under construction in Georgia?

MR. ADDISON: They have the Scherer plant under construction, the Wansley, and --

MR. SCARBROUGH:: There's Wallace Dam, and Rocky Mountain Hydro near Rome, Georgia, Plant Vogle, Plant Scherer and Plant Hatch, which is scheduled for the latter part of this year.

MR. ADDISON: And not Wansley, I don't believe.

COMMISSIONER MANN: So Scherer is the closest to your operating area?

MR. ADDISON: I'm not sure about that.

MR. PARSONS: I believe that Plant Wansley may be a little closer in airline miles.

MR. ADDISON: But it is not under construction at the present time.

MR. PARSON: It is not under construction, no, so Plant Scherer would be the closest to our area.

COMMISSIONER MANN: Are these all coal-fired?

MR. ADDISON: Except the Vogle plant and it is nuclear. Of course, Wallace Dam is a hydro and pump storage, I guess, also.

COMMISSIONER MAYO: Why is all of this construction going on in Georgia but there is lack thereof in Florida? I know that you don't serve the whole State of Florida but you do practically the whole State of Georgia, don't you?

MR. ADDISON: Yes, sir. Georgia is about ten times the size we are here.

COMMISSIONER MANN: Where is Plant Vogel?

MR. ADDISON: Near Augusta, Georgia.

COMMISSIONER MANN: What is the cost of that nuclear plant per kilowatt?

MR. ADDISON: The first unit, which is scheduled to go on the line in 1984, is presently estimated at $1,389 per kilowatt. The second unit, which is scheduled to go on the line in 1987, is $1,142 per kilowatt.

CHAIRMAN HAWKINS: If this Commission were to allow you to make this trade with the Scherer plant would Georgia still have excess capacity that they would be trying to market in addition to this, in light of all of the plants that they have under construction?

MR. ADDISON: I cannot answer that. I am

not sure if they have any other capacity available or not. I really don't know.

CHAIRMAN HAWKINS: I read in the trade journals that they are wanting to sell capacity and that Florida Power and Light has contacted them about buying it.

MR. ADDISON: I think it is the same capacity that we are talking about.

CHAIRMAN HAWKINS: It is the same?

MR. ADDISON: I believe it is, Mrs. Hawkins. This is the only capacity that I know of that Georgia has on the market are these Scherer units.

CHAIRMAN HAWKINS: And you don't know if, indeed, the Commission were not to allow you to do this, and it was not allowed to be written off, you would go ahead and construct your own and you don't know if Georgia would sell this to Florida Power and Light? Is that their second plant?

MR. ADDISON: It is my understanding that Georgia has talked to four or five different entities off the Southern Company system, one of which is Florida Power and Light, and that is the extent of my knowledge of it.

COMMISSIONER MAYO: Well, more than likely they would be able to rid themselves for a stipulated period of time whatever surplus would result, but that would not alleviate your problem even if you did not participate in it, in facing the higher cost of construction of your own unit?

MR. ADDISON: That is correct, yes, because we have got to have some additional capacity.

MR. JOHNSON: Ed, I have one question. What is the basis of your feeling that Scherer 3 and 4 will not have to have scrubbers?

MR. ADDISON: Barrett, I really cannot answer that for you except to tell you that our laywers who read the law, and our environmentalists who work in this thing every day, that that is their interpretation of Scherer versus the amendments of 1977. Now, George, can you respond to that a little more definitively?

MR. LAYMON: Yes, I certainly can. Scherer Unit No. 1 was started in September of 1974, a little ahead of the amendments of 1977, so, therefore, it was grandfathered in. The first equipment arrived on the job site in 1977 and is in storage. The base slab for Unit No. 1 is completed, the structural steel is going up on Unit No. 1, and the concrete is being poured for Unit No. 2, and the ground has been cleared for Unit No. 3.

MR. JOHNSON: When did they start on Unit 2 and Unit 3?

MR. LAYMAN: Barrett, I'm sorry, I don't have those dates but they have 60% of the clearing done for the entire plant site so that would include part of Unit 3 and part of Unit 4.

MR. ADDISON: I think one of the key things is that all of the licensing is completed, all of the permitting.

CHAIRMAN HAWKINS: Is all of the permitting done prior to construction?

MR. ADDISON: It was all done prior to whatever that magic date is in the amendments of 1977. What is that date?

MR. LAYMAN: That is August 7, 1977.

MR. JOHNSON: And that can waffle out somewhat into next year, at least as far as Crystal River 4 and 5 are concerned, and probably some others? Apparently the EPA is, if anything, moving in the direction of getting flexible on the extensions, and I was just curious as to the start of the continuous construction because that seems to be very critical.

MR. LAYMAN: From what I was told this morning it was September of '74 that continuous construction started and it has not stopped.

CHAIRMAN HAWKINS: Does the staff have any more questions?

MR. McGLOTHLIN: Yes, a couple. Mr. Scarborough, you said that your auditor would require some reasonable assurance. I would like to ask you, if you could, to either tell us now or to investigate if that could take some form other than a formal order specifying a particular item?

By way of example, we recently had the case of the South Dade unit, Florida Power and Light's South Dade unit, being cancelled. I am informed that the company was told by letter from the Commission to amortize that below the line over five years and that served to serve the purposes of their reporting requirements for a five-year period. The same letter stated that any question of recovery would take place in the context of a rate case. I just wonder if something along those lines, something other than a formal order, would suffice in this case?

MR. SCARBROUGH:. Joe, that type of letter that was written in the South Dade case I do not believe is going to be adequate in this particular case because of the magnitude of it; in other words, the size of our company versus the Florida Power and Light who, of course, had the South Dade cancellation. The amount of dollars that they were cancelling there relative to the net income of that company in an equivalent period relative to 20 million, or 10 million bottom line, compared to the net income of our company in a 12-month period, the materiality of it makes it probably -- well, I just don't believe, and I am aware of the fact that they were able, with that and some other things,/to satisfy their particular auditors, which is a different group of auditors than ours are but they still should be operating under the, you know, same criteria.

But I think the problem is materiality because I have discussed this thing with our auditors, that very fact that you just mentioned, and they tell me that, because of the materiality of the size of the dollar that we are talking about versus the size of our company and the size of our operating income, that they would not feel that at this particular point in time that would satisfy them as to assurance and, you know, that's where we stand. That's what they have told me.

MR. McGLOTHLIN: Well, could I ask Mr. Addison, or do you, or does perhaps Mr. Vinson, do you agree in principle with the comment that Commission Mann made a few moments ago; that is, that whatever authority the Commission gives Gulf in this instance should not prejudice its ability to review whatever facts come before it in a later rate case proceeding?

MR. VINSON: It is my understanding, Joe, that the Commission would have that authority inherently.

MR. McGLOTHLIN: Does the ability of Georgia Power to finance and construct these units, even considering the participation of others, become a factor? Is there any question of their ability to construct these units with the aid of other participants?

MR. ADDISON: I know of no problem there. Obviously, things can happen to change that picture in Georgia, too, but to our knowledge right now, you know, they fully intend to construct the units as scheduled and they think that they can do so.

MR. McGLOTHLIN: Since we are speaking in terms of possibility, then, and keeping in mind that you want to use this Caryville site later on, is it possible that Gulf Power Company could eventually benefit from the cancellation of another unit somewhere else and take advantage of a salvage situation and construct there in years to come?

MR. ADDISON: Yes, it's possible because we do intend to build a plant there and I think that when we do that we will be looking at bigger units, hopefully, because of now the difference in the economy of scale, and we would be looking for other participations so I would hope that we could find something like that.

COMMISSIONER MAYO: What is the largest unit that you have presently?

MR. ADDISON: 500 megawatts.

MR. JOHNSON: Ed, I don't recall offhand, but isn't the statute of limitations in your permit for the Caryville site five years, and if you haven't started something by then you have to come back for recertification?

MR. ADDISON: Could somebody else answer that?

MR. VINSON: Are you talking about site certification?

MR. JOHNSON: Right.

MR. LAYMAN: Site certification is good for 15 years.

MR. JOHNSON: Well, my memory may be bad, but on the ones that we have done recently there has been a clause in there to the effect that if you don't commence within five years of the date of certification that you come back for another look, and that other look is fairly cursory if you come back in five years and a day, but the farther out you go the more thorough and time consuming that look is.

MR. LAYMAN: Since ours was the first one in Florida I don't believe that clause is in there. We have a clause that states that if the environmental rules and regulations are changed that Gulf will meet those environmental rules and regulations as promulgated when and if they were the same date that the site was certified, or something to that effect, but I don't believe we have that five-year thing in there, no.

MR. McGLOTHLIN: The staff has no further questions at this time.

COMMISSIONER MAYO: I have one final question, I believe. I believe the letter indicated that there was some degree, and I don't know exactly what, of urgency about a decision. What is that urgency, as it relates to this agreement with Georgia Power?

MR. ADDISON: At the time that we wrote the letter I was under the impression that Georgia needed an answer from us pretty definitively by the end of the year. It now appears that maybe by the end of the first quarter would be all right but, again, the thing is kind of on the block, the capacity is, and I don't think that we ought to unreasonably hold them up. I would like to be able to proceed as early as we can. So I wouldn't say to you that the urgency is as great as it was maybe when I wrote the letter but we are anxious to be able to get on with it and so we would appreciate it if it could be expedited.

COMMISSIONER MAYO: Now, just in clarification of the reserve capacity being on the block, do you mean there that they have got somebody nibbling at it and if you don't get it they are going to try to do something else with it?

MR. ADDISON: Yes, I think that is correct. They have talked to a number of other companies and I feel reasonably sure that they will attempt to market it if Gulf and Mississippi do not proceed with their plans.

COMMISSIONER MAYO: Well, I just did not want to leave you with the feeling that your own reserve capacity, as it relates to the welfare of your own customers, was at issue here today.

MR. ADDISON: No, sir, because if we don't do this then we will have to proceed to construct capacity of our own in one fashion or another.

COMMISSIONER MAYO: Well, I guess that gives us something to dwell on, doesn't it?

MR. ADDISON: Just let me say to the

Commission that we are grateful for the opportunity to come and talk to you about this problem.

CHAIRMAN HAWKINS: If there are no further questions or discussion we will be adjourned.

(Thereupon workshop was adjourned at 4:30 p.m.)

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FLORIDA)
:
COUNTY OF LEON)

CERTIFICATE OF REPORTER

I, CAROL C. CAUSSEAUX, Registered Professional Reporter, and Notary Public, State of Florida at Large, do hereby certify that the matter of the presentation from GULF POWER COMPANY describing alternatives to the construction of its planned Caryville generating unit being considered by the company, and to explore the possible accounting treatment of cancellation charges associated with pursuing an alternative course, was heard by the Florida Public Service Commission, Docket No. 780714-EU, on Monday, October 9, 1978, commencing at 3:00 p.m., in Tallahassee, Florida.

I further certify that I was authorized to and did report in shorthand the proceedings held at such time and place; that the same has been reduced to typewriting under my direct supervision, and that the foregoing pages numbered 1 through 65, inclusive, constitute a true and accurate transcription of my shorthand notes of said proceeding.

IN WITNESS WHEREOF I have hereunto set my hand and official seal at Tallahassee, Florida, Leon County, this 16th day of October, A. D., 1978.

Carol C. Causseaux

Carol C. Causseaux, RPR
101 East Gaines Street
Tallahassee, Florida 32304
Commission Hearing Reporter

My Commission expires
12-3-78

State of Florida

Commissioners:
PAULA HAWKINS, CHAIRMAN
WILLIAM T. MAYO
ROBERT T. MANN

Accounting Department
WILLIAM D. TALBOTT, DIRECTOR
(904) 488-8147

Public Service Commission

December 4, 1978

Mr. E. L. Addison, President
Gulf Power Company
Post Office Box 1151
Pensacola, Florida 32520

Re: Docket No. 780714-EU, Amortization of Caryville Cancellation Charges

Dear Mr. Addison:

Your letter of August 25, 1978 has been referred to me by Mr. David L. Swafford, Executive Director, for appropriate response.

After thoroughly reviewing both your written request and the transcript of the Informal Workshop held on October 9, 1978, this matter was placed on the December 4, 1978 Agenda for Commission disposition.

As you know, this Commission has adopted the Federal Energy Regulatory Commission's Uniform System of Accounts for Public Utilities and Licensees. As such, no further approval is necessary as regards the proper accounting for plant cancellation costs. In other words, the prescribed accounting, which is consistent with your request, is to record the cancellation costs in Account 182 (Extraordinary Property Losses) and amortize those costs above the line to Account 407 (Amortization of Property Losses). The suggested write-off period appears reasonable. I understand that the five-year amortization of total cancellation charges of approximately $20 million would begin January 1, 1979.

I am sure, however, that you are aware that this authority is without prejudice to the Commission as presently constituted, or to future Commissioners to require some other disposition of these costs, after a rigorous review of all of the facts in a subsequent formal proceeding.

Certainly it would be reasonable to assume that action which could result in material contingent net savings to the ratepayers - short-run savings due to the difference in construction costs of the Caryville and Scherer plants of at least a quarter of a billion dollars and long-run savings in carrying costs over the 30 year life of the Scherer Plant in excess of one billion dollars - would ultimately receive the unconditioned sanction of any Regulator. Nevertheless, until management's decision can be thoroughly and publically reviewed, the Commission cannot, as with any other item of expense, give your company 100% advance approval and/or assurance that the amortization of the Caryville cancellation charges will in fact be recovered from the ratepayers.

In order to highlight this item for subsequent review and analysis, it would be helpful if the rates of return calculations, submitted in your monthly surveillance reports, could be calculated both with and without this amortization expense during the interim period that said item remains subject to final approval.

If you have any questions concerning this letter of authority, please feel free to contact me.

Yours very truly,

William D. Talbott

William D. Talbott
Accounting Director

WDT/bc

cc: Chairman Hawkins
Commissioner Mayo
Commissioner Mann
William B. DeMilly, Commission Clerk
David L. Swafford, Executive Director
General Counsel
Engineering Department
Legal Department
Rate Department

January 22, 1980

Mr. Robert W. Scherer, President
Georgia Power Company
Post Office Box 4545
Atlanta, Georgia 30302

Dear Bob:

As a result of your letter of August 14, 1979, representatives of Gulf Power Company, Georgia Power Company, and Mississippi Power Company have continued to discuss the feasibility of joint ownership of certain generating capacity at Plant Scherer. This letter is to inform you of Gulf's desire to purchase 25 percent of Plant Scherer Unit No. 3 and 25 percent of Plant Scherer Unit No. 4. Present construction plans indicate that Unit No. 3 will begin commercial operation in 1987 and Unit No. 4 will begin commercial operation in 1989.

It is the intent of Gulf to continue negotiations with Georgia Power Company for the satisfactory resolution of the technical and economic problems associated with the transmission of energy from the plant site to our service territory. Also, a satisfactory agreement must be reached concerning the schedule of payments, construction, operation, and maintenance of that portion of the Scherer generating units which Gulf will own.

We appreciate the opportunity to participate in this project. We trust that this transaction can be consummated at an early date.

Sincerely,

E. L. Addison

ELA:jsa

cc: Messrs. V. J. Daniel, Jr.
W. B. Reed
J. H. Miller, Jr.
B. M. Guthrie
H. G. Baker, Jr.
F. B. Parsons, Jr.
A. E. Scarbrough

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition of Gulf Power Company for an increase in its rates and charges.	DOCKET NO. 800001-EU (CR) ORDER NO. 9628 ISSUED: 11-10-80

The following Commissioners participated in the disposition of this matter:

ROBERT T. MANN, CHAIRMAN
WILLIAM T. MAYO
GERALD L. GUNTER
JOSEPH P. CRESSE
JOHN R. MARKS, III

Pursuant to duly given notice, the Florida Public Service Commission held public hearings on this matter in Pensacola, Florida, on July 24 and 25, 1980, and in Tallahassee, Florida, on September 4, 5, 9, 10, 11, 12 and 16, 1980. Having considered the entire record herein, the Commission now enters its final Order.

APPEARANCES: C. Roger Vinson and Ed Holland, Beggs and Lane, 7th Floor Brent Building, Post Office Box 12950, Pensacola, Florida 32576, for the Petitioner.

John W. McWhirter, Jr., Post Office Box 2150, Tampa, Florida 33601, for Air Products and Chemicals Corporation, American Cyanamid Company, Monsanto Company and St. Regis Paper Company, Intervenors.

Robert N. Kittel, Assistant Counsel-Utilities, Naval Facilities Engineering, Department of Navy, 200 Stovall Street, Alexandria, Virginia 22322, and Lieutenant Colonel Jack Ruttan, Base Staff Judge Advocate, Eglin Air Force Base, for the executive agencies of the federal government, Intervenors.

Jack Shreve, Steve Burgess, Ben Dickens, Roger Howe, and Michael McK. Wilson, 4 Holland Building, Tallahassee, Florida 32301, for the Citizens of the State of Florida.

Joseph A. McGlothlin, Pamela Johnson, and Paul Sexton, 101 East Gaines Street, Tallahassee, Florida 32301, for the Commission staff.

Prentice P. Pruitt, 101 East Gaines Street, Tallahassee, Florida 32301, as counsel to the Commissioners.

ORDER AUTHORIZING CERTAIN INCREASES

BY THE COMMISSION:

BACKGROUND

This proceeding involves the request by Gulf Power Company (referred to herein as Gulf or the Company) for authority to increase its rates and charges by approximately $46,376,576 annually. Gulf filed its petition and proposed rate schedules on March 3, 1980. Thereafter, we suspended the proposed rates pursuant to our authority under Section 366.06(4), Florida Statutes (Order No. 9311, April 2, 1980).

The Company also filed a Motion for Interim Relief with its petition, wherein it sought interim rate relief pending a final order in this proceeding. By Order No. 9311, we authorized an interim increase in the amount of $6,257,000 annually, subject to refund pending the final disposition of this case.

Extensive public hearings on Gulf's request have been held in this docket. These hearings extended over nine days and resulted in a record comprising 3,140 pages of transcript and 88 exhibits. We have also had active participation by numerous parties, including representatives of the public, governmental agencies, and large industrial customers. Having considered the entire record herein, including briefs filed by the various parties, we find that consent should be given to the operation of rate schedules designed to produce additional annual gross revenues of $40,623,065 on a permanent basis. This will provide to the Company an opportunity to earn an overall fair rate of return (established herein) of 8.90%. The basis for our decision is set forth below.

THE COMPANY

Gulf Power Company is a wholly owned subsidiary of the Southern Company and is subject to our jurisdiction under Chapter 366, Florida Statutes. Since 1925 it has provided electric service through generation, transmission, distribution and sale of electric energy, and now serves more than 197,000 customers in ten counties in Northwest Florida.

The Company was last authorized to adjust its rates in 1977 (Order No. 7978, Docket No. 760858-EU, 9/27/77). At that time, we determined that the Company's fair rate of return fell within the range of 8.32% to 8.46%. The Company states that since that time it has experienced a declining rate of return, caused by continuing high rates of inflation, a very sharp increase in construction and capital costs required in part by established environmental standards, and escalating operating expenses. Gulf now asserts that, in order to maintain its financial integrity and to provide reliable electric service, it must have additional annual gross revenues totaling $46,376,576. This increase, according to the Company, is required to provide the opportunity to earn a rate of return of 9.20%, which it alleges is fair and reasonable under prevailing conditions. This amount includes an attrition allowance of $7,336,507, which the Company contends is needed to ensure its opportunity to earn that rate of return.

PUBLIC COUNSEL

The Office of Public Counsel presented testimony of five witnesses during the course of this proceeding. In their prefiled testimony, Public Counsel's witnesses proposed that the Commission establish an average overall rate base of $376,137,000, an adjusted net operating income of $31,396,000, and an overall rate of return of 8.48%, with a return on common equity capital in the range of 13.0% to 14.0%. Public Counsel proposed an attrition allowance in the range of .40% to .50%. He also proposed that the expenses and investments related to the cancellation of the Caryville plant be disallowed, that the Commission disallow charitable contributions as an expense for ratemaking purposes, and that the Commission should adopt an overall working capital allowance of $30,754,000. In addition, Public Counsel contended that no amount of construction work in progress should be included in the Company's rate base. Public Counsel asserted that the Company's federal income tax expense should be limited to its proportionate share of the consolidated tax liability that was incurred and actually paid to the federal government, rather than the tax liability otherwise due if the Company was treated as filing an independent tax return. Public Counsel proposed that the Commission adjust the Company's test year revenues to remove the effects of unrecovered fuel expenses in the amount of $1,541,714.59. Public Counsel also presented testimony in the area of rate structure and design, which will be treated in a later portion of this Order.

INDUSTRIAL INTERVENORS

The industrial intervenors consisted of Air Products and Chemicals Corporation, American Cyanamid Company, Monsanto Company, and St. Regis Paper Company. These industrial intervenors presented testimony of five witnesses and were concerned solely with matters of rate design.

THE FEDERAL EXECUTIVE AGENCIES

The Department of Navy and other federal executive agencies presented the testimony of two witnesses. One addressed the cost of common equity capital and the fair rate of return, while the other testified concerning capacity needs of the Company and the appropriate revenue responsibility of customer classes. These intervenors proposed a cost of common equity capital between a range of 13.5% to 14.2%.

THE COMMISSION STAFF

The Commission Staff presented testimony of five witnesses, who addressed the issues of capital structure, fair rate of return, service complaint statistics, rate design, an alternative treatment of deferred taxes and customer deposits, conservation and economic efficiency.

THE TEST YEAR

In regulatory ratemaking, it is customary to select a test year or period for the purpose of evaluating revenue requirements of the utility under consideration. A historical test period should be based on the utility's most recent actual experience, with adjustments for known changes which will occur within a reasonable time after the end of the period. The most appropriate test year utilizes the most recently available data for a 12-month period, adjusted for known changes. In the present proceeding, the Commission approved the test period consisting of the 12 months ending December 31, 1979.

THE RATE BASE

One primary objective of a revenue requirements case is to determine the amount of revenues the regulated utility requires to meet its necessary operating expenses and provide a fair return on its investment. For this purpose, the net operating income realized during the test period is developed, and is then related to the value of the rate base for the period to determine the achieved rate of return. The "rate base" is the value of the investment devoted to providing service, less accumulated depreciation, and such investment must meet the statutory requirement of being "used and useful" for that purpose. The Company has proposed to use a rate base valuation of $525,347,439 for the purpose of determining revenue requirements in this case. Our analysis of the rate base-related issues leads us to modify that amount to $522,453,008. The adjustments are as follows:

Working Capital Allowance

One traditional component of rate base is the value of the working capital committed to the regulated enterprise. Historically, this Commission has allowed working capital to be computed by the use of a "formula approach," which utilizes a factor of 1/8 of operating expenses as an approximation of the difference between the time when services are provided to or by the Company and the time when payment is received. More recently, in the case involving the petition of Tampa Electric Company, (Docket No. 800011-EU, Order No. 9599), we employed the "balance sheet" approach advocated by Public Counsel. This method defines working capital as the difference between current assets and current liabilities (exclusive of cost-free current liabilities).

In this case, the Company proposed a jurisdictional working capital allowance of $47,089,341. This amount reflects materials and supplies, fuel inventory, cash working capital and a deduction for income tax lag, and is the result of a hybrid of the formula and balance sheet approaches. Mr. Deason, testifying for the

Public Counsel, used the balance sheet methodology to arrive at a proposed working capital of $30,754,000.

We observe here, as we did in the recent TECO case, that the balance sheet approach to the determination of working capital offers certain advantages over the use of a formula, including greater precision and a better correlation between rate base valuation and the capitalization of the Company. We have decided to adopt the balance sheet approach in this case; however, we believe certain adjustments must be made to the manner in which Public Counsel's witness applied the concept.

The first adjustment concerns the exclusion by Mr. Deason of $13,594,000 in temporary cash investments from gross working capital. This adjustment was made on the assumption that another witness for Public Counsel, Mr. Feaster, would recommend excluding the earnings from temporary cash investments from the Company's operating revenues. While Mr. Feaster failed to do so in his prefiled testimony and exhibits, he agreed with the proposition that both the temporary investments and the related earnings should be either included or removed from the rate base and NOI computations. In our judgment, temporary cash investments should be included in the working capital and related earnings should appear in the income statement.

The next adjustment is related to the Company's declared dividends payable for common stock. Analysis of Exhibit 53 indicates that the 13-month average for Dividends Declared is $2,584,615. Mr. Deason considered these declared dividends to be cost free sources of capital, and therefore reduced the working capital allowance by that amount. He did agree, however, that these dividends were classified as retained earnings prior to being transferred to the dividends declared account. We view the declared dividends for common stock as representing investor-supplied capital. The declaration of dividends does not decrease the shareholder's capital, but the payment of the cash dividend does. Accordingly, the amount of $2,584,615 should be included in working capital.

After incorporating the above adjustments into Mr. Deason's proposed working capital allowance, we find that $45,658,813 ($49,559,615 System) represents the Company's investment in working capital for the test year. It is necessary to reduce the Company's proposed working capital allowance of $47,089,341 by $1,430,528 to reflect the adoption of the balance sheet approach. Our decision in this regard also eliminates the effects of any attrition allowance contained in the Company's requested provision for fuel inventory within working capital.

Computation of the working capital allowance can be depicted as follows:

Public Counsel's Recommendation	$30,754,000	
Adjustments:		
1. Temporary Cash Investments $13,594,000 x 92.12663%		12,523,694
2. Dividends Declared $2,584,615 x 92.12663%		2,381,119
Total		$14,904,813
Adjusted Jurisdictional Working Capital		$45,658,813

Construction Work in Progress

Expenditures by a utility for construction projects may be accounted for in either of two ways. When Allowance for Funds Used During Construction (AFUDC) is utilized, the carrying charges associated with financing a project are capitalized as a component of construction costs until such time as the project is closed to plant in service. The other side of the accounting entry is a "credit" to "interest expense" for the debt portion of AFUDC and a credit to "other income" for the equity portion of AFUDC. These income statement credits are merely "paper" earnings, because cash earnings are only generated for assets which are included in rate base. Alternatively, construction work in progress (CWIP) may be included in rate base. In this case, the base rates established reflect a current return on the value of the plant under construction, and the utility realizes actual cash earnings. The utility does not charge AFUDC on the value of CWIP included in rate base.

The Company has requested that $111,183,151 of construction work in progress be included in system rate base. This amount is the sum of two items: The 13-month average amount (1979 test year) of CWIP ($110,869,978) and $313,173 of very small cost projects or projects of very short duration to which the allowance for funds used during construction (AFUDC) has not been applied.

The Company feels that this amount of CWIP should be included within rate base for several reasons:

1. The test year ending amount of CWIP was $126,148,069.

2. CWIP at the end of 1980 is projected to be $221,941,000 (Exhibit No. 3, Page 2 of 2 of Exhibit No. 53).

3. In the first five months of 1981, CWIP will increase another $20,493,000 to a total of $242,434,000 (same reference as No. 2 above).

4. The Company contends that the inclusion of CWIP in rate base is a sound regulatory practice, as the quality of earnings improves, resulting in a lower overall cost of capital to Gulf, and an ultimate savings to the customer.

5. A current return on CWIP will improve interest coverages and enhance the Company's ability to issue new debt.

From the Company's point of view, several advantages are associated with allowing CWIP in rate base. First of all, investment analysts regard earnings which consist largely of the "income credits" resulting from charging AFUDC as inferior in quality. This view is reflected in the form of higher perceived risk and higher costs of obtaining capital for those utilities having an unacceptably large proportion of earnings generated by AFUDC. Including an amount of CWIP in rate base would replace the AFUDC paper credits with real cash earnings on that portion of the Company's construction program, lowering the measured risk and thereby having positive effects on the Company's cost of capital. CWIP in rate base also improves a company's cash flow and debt coverages.

Mr. Hugh Larkin, expert witness for the Public Counsel's office, presented the Public Counsel's position that no amount of CWIP should be allowed in rate base. Mr. Larkin argued that to place CWIP in rate base would require the Company's customers to assume the role of equity investors while receiving no related benefits. Further, he stated that the practice unfairly requires present ratepayers to subsidize future customers, and shifts the risks of investment from the Company's shareholders to its customers.

While the Federal Executive Agencies (FEA) believe that the inclusion of CWIP is warranted, they contend that to allow CWIP in the rate base in the full amount requested would not be equitable. They feel that this is unfair to consumers for several reasons: 1) Current customers would be called upon too greatly to subsidize future customers; 2) Gulf will have less incentive not to over-invest in new plant; 3) Gulf will not be penalized for bad investment decisions. All these scenarios are harmful to the consumer, according to the FEA. Therefore, FEA concludes that the proper amount of CWIP to be included in the rate base is 75% of the amount requested.

We believe the decision with regard to the CWIP issue represents an area of policy and judgment, in which the Commission must weigh several valid and competing considerations. We note in this case that the percentage of net income composed of AFUDC has risen dramatically, and is expected to grow to 92% in 1980. We find that inclusion of CWIP in the amount of the average for the test year ($111,183,151 on a system basis) is warranted in this case. We are sensitive to the argument that to allow a present return on too large an increment of CWIP could encourage the building of unneeded or excessive capacity - a prospect which would be directly contrary to one of our most important regulatory objectives - and we intend to monitor this aspect of the CWIP issue in subsequent proceedings.

Unamortized Caryville Cancellation Charges

The Company proposes to include $10,569,855 of unamortized Caryville Generating Center cancellation costs in system rate base. The Caryville unit was to be a generating facility located near Pensacola, which Gulf had originally planned to bring in service in the late 1970's. Continued decreases in load forecasts, however, pushed the anticipated in-service date back several times. Finally, in 1978, Gulf notified the Commission that it wished to cancel the Caryville facility, and instead purchase a portion of Georgia Power's Plant Scherer Units #3 and #4. Gulf claimed that this would be a much cheaper alternative, with tremendous savings to flow to the ratepayers as a result.

At that time, Gulf estimated that the cancellation costs would be approximately $20,000,000. Through negotiations with vendors and other creditors, Gulf was able to reduce this amount to $11,964,000. Gulf has requested that it be allowed to write off these cancellation costs over a five year period and began the amortization in June, 1979. This Commission had authorized this action, with the understanding that the requested accounting treatment would be reviewed in the context of Gulf's next rate case. The Company now proposes to include the unamortized balance of the cancellation charges in rate base as well as include the current amortization in operating expenses for ratemaking purposes.

The Public Counsel contends that the Caryville cancellation costs could have been avoided through more prudent management decision making. Therefore, Public Counsel feels that the requested accounting treatment is inappropriate and that the stockholders should bear the cost of the cancellation. Additionally, the Public Counsel feels that these imprudent expenditures were "not investments in property actually used and useful in the public service." He argues that the "non-used and non-useful" nature of those expenditures disqualifies them as rate base items.

The Federal Executive Agencies (FEA) contend that the loss associated with the cancellation of the Caryville unit should be borne equally by Gulf and the ratepayers. They feel that since the proposed plant never met the used and useful criteria, the unamortized balance should not be included in rate base (Brief p. 25). However, they do believe that the amortization should be allowed, but have suggested an amortization period of ten years rather than five years.

At the time of Gulf's initial request for approval of the amortization of the Caryville expenses, and again in its direct evidence presented in this case, the sole justification relied upon by the Company was the economic advantage associated with purchasing the Scherer capacity in lieu of constructing the

Caryville facility. This alternative was portrayed in very definite terms and Gulf states that its intention is to proceed with that transaction. The record of this case, however, reveals that Gulf does not at this time have a contract with Georgia Power Company to buy into the Scherer plants, and circumstances have arisen which place a degree of uncertainty upon that transaction. While it appears that realization of the purchase upon the terms contemplated by Gulf would be beneficial to Gulf's ratepayers, we cannot at this time provide final approval of the treatment of the cancellation charges sought by the Company. Therefore, while we have determined that the unamortized portion of the expenses should be placed in rate base and amortized over a five year period, we require that the associated revenue effect be collected subject to refund in the event the transaction relied upon is not consummated or the cancellation has not otherwise been justified within one year of the effective date of this Order. The revenue requirement associated with the amortization expenses recognized in the test year will be treated similarly.

FERC Audit Adjustments

The Federal Energy Regulatory Commission (FERC) completed an audit of the Company for the years 1975-1979 during mid-1980. The principal exceptions noted by FERC concerned the improper capitalization of certain maintenance expenditures that should have been expensed in the year in which they were incurred. As a result of a staff request, the Company provided a list of the adjustments that the Company had agreed to make as a result of the FERC audit findings. The adjustments result in a $1,589,012 reduction in the Company's system rate base for the test year. We find that these adjustments should be included for ratemaking purposes.

Accordingly, the Company's proposed rate base shall be reduced by $1,463,903 ($1,589,012 System) to reflect the results of the FERC audit.

Plant Held for Future Use

The Company has included $1,255,565 of plant held for future use in its proposed rate base. This amount represents the land that was purchased for the Caryville plant site. The Company maintains that this amount belongs in rate base because the Company ultimately intends to construct an 880 MW generating facility at that site, with an in-service date of 1995. The Company also contends that the Caryville site is one of the few sites in northwest Florida suitable for that purpose.

The Company contends that if it cannot earn a return on this investment in land, serious consideration will have to be given to the propriety of retaining the property. It is the Company's contention that if the property is not included, the stockholders would have no motivation to hold the land and the Company might be required to dispose of it. If this were actually done, argues the Company, it would either have to repurchase the land sometime in the future at a greatly inflated price, or purchase an alternative site. In addition, the Company would have to go through the costly and time consuming site certification process again.

The Public Counsel has not taken a position on this issue. The Federal Executive Agencies (FEA), however, stated in their brief that the Company has not met its burden of proof in establishing that the plant held for future use meets the criteria of "used and useful." These agencies claim that Gulf does not have a definite plan for the site. Therefore, they contend that this property should be excluded from the rate base.

We believe that the Caryville site should be included in rate base. Although a degree of uncertainty does exist as to when a generating facility will be constructed there, the weight of evidence in this case supports the proposition that a plant will ultimately be constructed on the site. We agree with the Company that its plans for the site are sufficiently definite to warrant its inclusion, and that to deny the request would be to the disadvantage of ratepayers in the long run.

Merchandising Operations

The Company engages in an appliance sales program for persons living within its service area. The appliance operation shares facilities with utility-related operations at several locations. The question whether the Company had removed the appropriate amount of investment in the appliance operation from its proposed rate base arose in this case. However, we find that the net amount of plant that the Company deducted from its system rate base related to the appliance operation, $349,985, is proper and that no adjustment for this item is warranted.

Adjusted Jurisdictional Rate Base

Our adjustments result in a jurisdictional rate base of $522,453,008 for the 1979 test year. The analysis is summarized below.

Proposed Jurisdictional Rate Base Per Exhibit No. 5, Schedule 3	$525,347,439
Adjustments:	
1. Balance Sheet Working Capital Allowance ($1,554,098) x 92.12663%	(1,430,528)
2. FERC Audit Adjustments -	(1,463,903)
Adjusted Jurisdictional Rate Base	$522,453,008

NET OPERATING INCOME

To determine the rate of return on rate base achieved by the Company during the test period, it is necessary to analyze the revenues received by the Company and determine those operating expenses which were prudently and appropriately incurred in the operation of its business. This comparison yields a net operating income figure which can then be related to rate base. Gulf Power contends that its net operating income for the test period was $31,866,165. For the reasons detailed below, we have made certain adjustments to Gulf Power's submission which result in a net operating figure of $31,944,596.

Underrecovery of Fuel Expense

The parties to this proceeding agreed that the Company had experienced an underrecovery of fuel and purchased power expense during the test year. At the prehearing conference, the parties and the staff agreed that the test year revenues and expenses should be adjusted so as to eliminate underrecovery of fuel expense in light of the adoption of the projected fuel cost recovery clause (Order No. 9514, Page 3).

The amount of the underrecovery, however, was a matter of dispute during the hearing. Various calculations of the amount were presented, and the amounts ranged from Mr. Feaster's high of $2,021,000 to Mr. Scarbrough's low of $20,687.

We believe that many of the calculations related to the above amounts are based upon faulty methodologies. Mr. Feaster's amount of $2,021,000 was based on the data filed by the Company in RCD A-8 (Ex. 48) and he adjusted that data to reflect a zero lag in the recovery of fuel adjustment revenues. This calculation is deficient in that the base fuel revenue used by Mr. Feaster contained revenue tax amounts, and in that the Company's unbilled revenues were not reflected in RCD A-8. Additionally, Mr. Feaster's "no-lag" methodology was not the methodology that was in effect during the test year, which ended prior to the adoption of the new fuel cost recovery clause.

The amount of $1,524,784, first sponsored by Mr. Scarbrough, is simply a revision of RCD A-8 that eliminates the revenue tax amounts from the base revenues and the fuel adjustment revenues. This revision, however, did not incorporate the unbilled revenues that were actually recorded on the Company's books during the test period.

In response to a staff request, Exhibit M to Exhibit No. 59 was prepared by the Company. This exhibit shows the amount of the Company's unrecovered fuel and purchased power expense to be $299,271 for the test year. Due to an apparent misunderstanding on the part of the Company, however, this exhibit failed to show the prior month's actual adjustment for the month during which it was actually recorded. This resulted in a total fuel and purchased power expense that did not represent the actual expense that was recorded on the Company's books during the test year. The exhibit did include the Company's unbilled kilowatt hour related revenues, however.

In Exhibit No. 76, the Company restated the amount of the prior month's actual adjustment to reflect when those adjustments were actually recorded by the Company. The amount of $103,862,652 reflected on this exhibit represents the Company's total recoverable fuel and purchased power expense for the test year as recorded on its books. In determining the amount of the expense applicable to its retail customers, the Company used a composite separation factor of 90.6835% based on KWH sales. However, Mr. McClanahan, the witness who sponsored Gulf's cost of service study, testified that the factor used in the derivation of the Company's requested revenue increase was 90.8%.

We find that the total recoverable fuel and purchased power expense of $103,862,652, as shown on Column 3 of Exhibit No. 76, accurately reflects the Company's fuel and purchased power expense for the test year. We further find that $94,165,624 of total fuel revenue shown on Column 8 of Exhibit No. 76 is the proper amount of retail fuel revenue, excluding revenue tax amounts, recorded on the Company's books during the test year. This amount does properly include the unbilled revenues that the Company records on its books. Using the appropriate separation factor of 90.8%, we determine that the Company's submission included $142,494 in unrecovered fuel expense. Test year operating revenues should therefore be increased by this amount. The calculation of this adjustment is given below:

Total Recoverable Fuel & Purchased Power Expense (Ex. 76, Col. 3)	$103,862,642
Retail Separation Factor (TR 1851)	X 90.8008%
Retail Fuel & Purchased Power Expense	94,308,118
Retail Fuel Adjustment Revenues (Ex. 76, Col. 8)	94,165,624
Unrecovered Fuel & Purchased Power Expense	$ 142,494

Amortization of the Caryville Cancellation Charges

The Company has requested that its test year amortization expense be increased by $998,255 to reflect the annual amortization expense related to the Caryville cancellation charges. The Company contends that this annualization adjustment is necessary in determining net operating income on which rates should be set. The proposed annual amount of the amortization expense is $2,392,909, based on a proposed five year amortization period. The Federal Executive Agencies support the inclusion of the amortization expense, but recommend a ten year amortization period. Public Counsel contends, however, that the amortization expense should not be allowed as an operating expense.

As discussed in an earlier part of this Order, we have decided to permit Gulf to include the annualized amortization expense for ratemaking purposes. As with the unamortized balance in the rate base, however, we require that the associated revenues be collected subject to refund, in the event the Scherer transaction has not been consummated within a year of the effective date of this Order. The overall revenues subject to the refund condition amount to $4,225,176 annually.

Revenues and Expenses Related to Daniel Plant

The Company has proposed that $1,369,766 in revenues from the rental of common facilities at the Daniel Plant be eliminated from the Company's operating revenues during the test period. The Company has also proposed that its operating expenses be reduced by $1,463,053 for expenses related to the Daniel Electric Generating Center. These revenues and expenses are related to the leasing of the Company's share of the common facilities at Daniel to Mississippi Power Company. We agree with the Company that they should not be included in the determination of net operating income for ratemaking purposes.

Bank Service Charges

The Company has proposed that its operating expenses be increased by $102,645 (system), gross of income taxes, to reflect the estimated bank service charges that it would have incurred if minimum bank balances and compensating bank balances had not been maintained. Mr. Scarbrough suggested that these minimum and compensating balances should be included in the working capital provision in rate base. In his testimony, Mr. Deason pointed out the hypothetical nature of the Company's bank service charge calculation. It was also Mr. Deason's opinion that the Company would be compensated for its minimum and compensating bank balance through his recommended working capital allowance based on the balance sheet approach.

We agree that the adoption of the balance sheet approach in the determination of the working capital allowance has removed the need and justification for the bank service charge adjustment proposed by the Company. Therefore, we shall reduce the Company's operating expenses by $96,623.

FERC Audit Adjustments

The Federal Energy Regulatory Commission (FERC) completed an audit of the Company for the years 1975-1979 in mid-1980. As a result of a staff request, the Company provided a list of the adjustments that the Company has agreed to make as a result of the FERC audit findings. The adjustments result in a $304,577 reduction in system net operating income for the test year. We find that these audit adjustments should be incorporated for ratemaking purposes in this case. Accordingly, we shall reduce NOI by $286,707 to reflect these items.

Deferred Income Taxes (CWIP)

In an earlier part of this Order, we authorized the inclusion in rate base of an additional $100,598,263 in construction work in progress. It is necessary that the deferred tax expense in the income statement be reduced to reflect the elimination of AFUDC on that amount of construction work in progress. The Company has proposed a $1,325,334 ($1,407,938 system) reduction in its deferred tax expense for the test year. We find that this calculation is correct and should be approved.

Property Insurance Expense

In this case, the Company requested that the annual accrual of the Property Insurance Reserve be increased from $809,717 to $1,200,000 before income taxes. This adjustment would result in a $390,283 increase in the Company's test year operating expenses. Mr. Scarbrough explained that the accrual level of $809,717 was first approved in 1975 in Docket No. 74427-EU and that this level was later retained in 760858-EU despite the Company's request for a higher level.

As an example of the inadequacy of the reserve, Mr. Scarbrough discussed the impact of Hurricane Frederick upon the Company. As a result of Hurricane Frederick, the Company incurred expenditures of $2,100,000. The property insurance reserve, however, had a balance of only $1,300,000.

Although this area was not specifically addressed by Mr. Feaster, it can be inferred from his calculation of net operating income that he agrees with the Company's position. In his determination of the Company's operating expenses, Mr. Feaster has included an item entitled "Adjustment*" in the amount of $295,000. The asterisk refers to the footnote at the bottom of the page which indicates that Mr. Feaster has included the Company's requested increase in its property insurance expense.

Having reviewed the matter, we find that the Company's proposed adjustment to its property insurance expenses is proper. However, it has been pointed out that the Company has not determined an appropriate ceiling or cap on the amount of the property insurance reserve. We will undertake this determination in the Company's next ratemaking proceeding.

Income Tax Expense

Gulf Power Company did not adjust its computation of income tax expense to reflect the effect of parent company debt. Under the 1935 Public Utility Holding Company Act and Securities and Exchange Commission practice, Southern Company is not allowed to issue debt without special approval of the SEC. Upon securing SEC approval, Southern executed on March 15, 1976, a loan agreement for $125,000,000. This was an intermediate term loan which comprised at the end of the test period, December 31, 1979, 4.76% of Southern's capital structure at an interest rate of 11.5%. No loans had been made during the ten year period prior to 1976. The amount of the loan which is presently outstanding is $84,000,000, of which amount $42,000,000 will be paid on March 15, 1981. The remaining $42,000,000 will be paid March 15, 1982 (late filed Exhibit 68). Thus, the balance outstanding and the percentage of capitalization will be declining during the period for which rates can reasonably be expected to be set in this proceeding. Under the SEC requirements, $33,549 of Southern's interest expense of $14,776,031 for the test period was allocated to Gulf (Exhibit 68). Income from temporary cash investments was used to directly offset interest expense before an allocation was made. This offset is not consistent with the intent of Order No. 9192, Docket No. 790084-TP and Order No. 9208, Docket No. 780777-TP. Therefore, we shall adjust the Company's income tax expense to recognize the tax effect of parent company debt by the amount of $199,872.

Public Counsel agrees with the nature of this adjustment. However, while the expansion factor employed by Public Counsel's witness included a provision to recognize income tax expense, he argues that income tax expense should be disallowed in its entirety for Gulf's failure to support its calculation with substantial competent evidence. We believe this contention to be without merit.

Advertising Expenses

The Company's total test year advertising expenses were $714,371 and are treated by the Company as above-the-line operating expenses. Most of the advertising conducted during the test year appears to have been informational, conservational, and safety-oriented in nature, and should be allowed for ratemaking purposes. However, particular advertisements do not fall within such categories, and related expenses should be disallowed.

To determine the cost of each advertisement to be disallowed, the staff requested a break-out from the Company to determine the dollar value of each ad and the account number to which each was charged. The area development magazine ads on RCD A-11, Pages 76 and 77, entitled "Our Business has the Energy to Help your Business," appear outside of the Company's service area boundaries and attempt to interest prospective business investors to build new plants in Northwest Florida. These two ads appear to be purely promotional in nature and represent an advertising expense of $25,163 that we believe should not be paid for by the ratepayers. The remaining five advertisements shown on RCD Pages 78 through 82 are oriented toward the stockholders or potential investors in the Company, and promote the image of the Company with no apparent benefit to the Company's ratepayers. In response to questioning about one such ad, Mr. Scarbrough admitted that this type of advertising was "image building of the company type of advertising". Commission Order No. 6465, Docket No. 9046-EU entitled "General Investigation of Promotional Practices of Electric Utilities" states that "advertising which has as its primary objective the enhancement of or preservation of the corporate image of the utility and to present it in a favorable light to the general public and to investors" shall be disallowed for ratemaking purposes. The total cost of the image building ads is $54,659. The total cost of all seven advertisements to be disallowed is $75,139.

Miscellaneous General Expenses

The Company's miscellaneous general expenses for the test year were $1,370,120 (Exhibit No. 48, RCD A5, Page 17) and are considered by the Company as above the line operating expenses. Of this amount, $81,250 is specified as "Total Industry Association Dues."

Having reviewed these items, we believe that dues paid to Associated Industries of Florida in the amount of $1,540 and to chambers of commerce in the amount of $7,122 should be disallowed for ratemaking purposes.

Charitable Contributions

The Company requests that $16,817 in charitable contributions be included in operating expenses for ratemaking purposes, on the theory that acts of corporate "citizenship" are a necessary part of doing business in its service area. Public Counsel objects to the inclusion of any amount of charitable contributions, arguing that, when such expenses are allowed, the utility merely serves as a conduit for donations collected from ratepayers, rather than demonstrating its own good "citizenship." We regard this area as essentially one of policy, and one in which the Commission has discretion. Our established policy is to allow contributions which are reasonable in amount and which are made to recognized charities to be included in operating expenses. Until that policy has been reviewed and modified on a broader generic basis, we intend to apply it consistently. Accordingly, we find that contributions in the amount of $16,817 meet the necessary criteria and should be included in operating expenses. Because the Company's proposed adjustment falls short of the amount reflected on RCD A-10, operating expenses shall be increased by $251.

Unbilled Revenues

Unbilled revenues are those which are owed to the Company for service rendered but which have not yet been collected through the mechanism of the billing cycle. Gulf Power Company is the only major investor-owned electric utility under the Commission's jurisdiction that records unbilled revenues. Unbilled revenues for the 1979 test year were ($584,567). This "negative" amount of unbilled revenues occurs when unbilled revenues in the current accounting period are less than the unbilled revenues in the immediately preceding accounting period. This is precisely what occurred during the Company's test year. Having reviewed the methodology used by the Company, we find that unbilled revenues in the amount of ($584,567) should be recognized for ratemaking purposes in the determination of net operating income.

Injuries and Damages Expense

The Company requested in this case that the injuries and damages expense be increased by $170,113 to reflect the Company's actual test year accrual of $532,613. Mr. Scarbrough stated that the annual accrual to the injuries and damages reserve was limited to $362,500, per Order No. 7978 in Docket No. 760858-EU. He also pointed out that a target reserve balance of $1,000,000 was established in that docket. Mr. Scarbrough explained that the Company is self-insured up to $1,000,000 for each occurrence and that the Company had recently settled one claim for $932,000, which exceeded the reserve balance.

We believe that the Company has adequately demonstrated that the $170,113 accrual in excess of that last allowed is proper. Since the Company has already made this adjustment, no further adjustment is necessary. There is some question, however, regarding the adequacy of the target reserve balance of $1,000,000. As stated by Mr. Scarbrough, verdicts in excess of $1,000,000 for a single occurrence are now relatively common. In our opinion, some adjustment to the targeted reserve balance of $1,000,000 is warranted. Therefore, the Company will be required to determine an appropriate target reserve balance to be submitted in the next rate proceeding.

Bad Debt Expense

The Company proposes to increase bad debt expense by $78,000. The rationale offered is that because of an increase in sales and also because of "an increase in the unit price of our product, our accounts receivable balance has increased significantly, and yet our reserve balance hasn't increased." The Company contends that it is trying to maintain a reserve balance of approximately 2% of the accounts receivable to bring the reserve balance more in line with the accounts receivable balance. (Ex. 59 Page 102).

In the past, the Company was using what in effect was a direct write-off method of accounting for bad debt expense. Although it had a reserve for uncollectible accounts receivable, the balance never changed because bad debt expense was a function of the amount of bad debts written off during the period.

The method that the Company has elected to follow in this rate case is a much more theoretically sound approach. The only item open to question is the target reserve of 2% of accounts receivable. Experience is needed to determine if this reserve will prove to be inadequate or excessive for purposes of determining the net realizable value of accounts receivable, given the assumed operating conditions described by Mr. Scarbrough. We believe the Company's proposal should be implemented with that view in mind.

Adjusted Jurisdictional Net Operating Income

Our determination of Gulf's net operating income for the test period is summarized as follows:

Proposed Jurisdictional Net Operating Income Per Exhibit No. 5, Schedule 9	$31,866,165
Adjustments:	
Unrecovered Fuel Cost $142,494 x .513 x 100%	73,099
Bank Service Charges $102,645 x .513 x 94.132981%	49,567
FERC Audit Adjustments $304,577 x 94.132988%	(286,707)
Consolidated Tax Return Adjustment $199,872 x 100%	199,872
Advertising Expenses $79,822 x .513 x 94.132988%	38,546
Industry Association Dues $8,662 x .513 x 94.132988%	4,183
Charitable Contributions $(267) x .513 x 94.132988%	(129)
Total	$ 78,431
Adjusted Jurisdictional Net Operating Income	$31,944,596

FAIR RATE OF RETURN

One well established regulatory principle is that a regulated utility is entitled to an opportunity to earn a fair rate of return on its investment devoted to public service. The determination of a fair rate of return for Gulf Power Company is the next step in the determination of its revenue requirements. This undertaking requires that we establish the appropriate capital structure for the Company, and analyze the costs associated with each source of capital. Our final result must conform to established legal parameters. The rate of return which we establish must be sufficient to preserve the Company's financial integrity, insure its ability to provide the service required of it by law, and attract needed capital on reasonable terms.

We have chosen to utilize, for purposes of determining the revenue requirements of the Company, the capital structure as it existed at the end of the test period (December 31, 1979). Our selection of the year end structure obviates the need to address the issue of whether short-term debt should be included as a component, inasmuch as Gulf had no short-term debt outstanding at that time.

Deferred Taxes and Customer Deposits

This Commission has historically treated deferred taxes and customer deposits as cost-free sources of capital to the utility. Alternatively, these items could be excluded from the capital structure, with appropriate adjustments to rate base and operating expenses. In theory, the resulting revenue requirements would be identical; however, because rate base in practice does not precisely equal total capitalization, the revenue requirements will vary to some degree. As stated in the recent Tampa Electric Company decision, Order No. 9599 (Docket No. 800011-EU), we believe that to recognize these items as sources of capital better reflects reality. Therefore, we shall continue to include them in the capital structure.

Return on Equity Capital

The costs associated with debt or preferred stock are arrived at contractually, and the utility's experience in this regard can be calculated from historical data. However, the assessment of a fair return on common equity capital requires an exercise in judgment and opinion.

Four witnesses presented testimony on the issue of a fair and reasonable return on equity capital for Gulf Power. During the examination of these experts, the applications of the analytical tools used by them were scrutinized carefully. All used theoretically sound quantitative models to arrive at their estimated returns. Differences among the proposed required rates of return are due to subjective judgment employed by each in the selection of variables and in the interpretation of the results. The estimated returns range from Dr. Legler's 13-14% to Mr. Seligson's 16.26%. The applicant requests a 16% return on equity in this case.

Dr. Dietz concluded that the fair return on equity for Gulf Power is 15 to 16% through the use of a risk premium analysis, the discounted cash flow approach, and the comparable earnings approach. The risk premium used by Dr. Dietz was derived from a Paine Webber survey of 100 institutional investors. This risk spread of 4.87% may be biased upward by the manner in which the survey questionnaire was worded. In his implemention of the discounted cash flow approach, Dr. Dietz utilized a "holding period return" model rather than the Gordon model, thus requiring additional subjective assumptions to be made. If Dr. Dietz's variables had been used in the Gordon model, the resulting required return would have been 14.75%, rather than the holding period return of 15.0-15.8%. Although the holding period method does provide a feel for the investors' long run expectations, the Gordon model better provides an estimate of the investors' current requirements.

Dr. Seligson based his required return for investors on a risk premium approach, utilizing the risk spread between three-month Treasury Bill rates and the electric utility industry's return on equity for 1972. This witness was of the opinion that 1972 was more representative than any following year. However, his testimony discloses that the risk spread in 1972 was higher than any other year since 1966. In addition, by using a spread based on the electric utility industry, the results from this model would be applicable to any electric company, not just Gulf Power. Because of the general nature of this approach, it would be inappropriate to use 16.26% as the required return of an individual company, such as Gulf Power. Further, Mr. Seligson's recommended return would provide an interest coverage ratio in excess of the industry's average for the last seven years, another indication that his analysis overstated the required return on equity.

Dr. Rettenmayer, who testified for the Department of the Navy, updated his testimony at the hearing to reflect recent changes and supported a required return on equity of 13.8-14.5%. The results from the discounted cash flow approach were cross checked with his capital asset pricing model. The dividend yield of 11.5-11.75% that was used in Dr. Rettenmayer's DCF analysis reflected the one and two-month average dividend yield ending July 7, 1980. If Dr. Rettenmayer had used either a 52-week average or a spot rate at the time of the hearing, the resultant rate of return would be slightly higher at 14.76%, a rate which approximates the result of Dr. Dietz's data in the Gordon model. The estimate for 20-year Government Bond Yields used in Dr. Rettenmayer's capital asset pricing model of 10% is about one percent lower than the current average yield and is equal to Dr. Rettenmayer's own estimate of the inflation rate. If the capital asset pricing model was adjusted to reflect this more up-to-date bond yield, the resulting return would be 14.6%.

Dr. Legler, the financial expert for the Office of Public Counsel, suggested that 13-14% is the required rate of return on equity for investors in Southern Company stock. Dr. Legler employed three methods in his determination of the return: discounted cash flow, risk premium, and comparable earnings analyses. His DCF growth rate was similar to that used by both Dr. Dietz and Dr. Rettenmayer, but the market price of $13.50 which he employed was considerably higher. Since July of 1979 to July of 1980, every weekly closing price of Southern stock was under $13.50 except for one week, June 23, 1980. Although this price was a three week average prior to the hearing, the price of Southern stock has since dropped to a level equivalent to the average of the last year, approximately $12.00 per share. The use of the 52-week average gives a return of 14.76%. In his second approach, the risk premium analysis, Dr. Legler estimates his own risk spread of 3.0 to 3.5% over the average bond yield from AA public utility bonds. The average bond yield used by the witness, of 9.9 to 10.4% was shown to be significantly lower than current levels of bond yields. In fact, the 1980 low for the first eight months of this year for AA rated public utility bonds was 11.43% and for A rated public utility bonds the low yield was 11.9%. Since no testimony was presented that suggested a projected decline in interest rates, we feel that Dr. Legler's estimate of return on equity based on the risk premium approach is understated. If the witness' risk premium of 3.0% is applied to the 1980 low yield for A rated public utility bonds, the required return on equity which would result would be 14.9%.

After analyzing the proposed rates of return on equity of the four financial witnesses and making adjustments to compensate for what we believe are over- or understatements of the variables which they employed, we observe that the resulting returns are clustered in the range of 14.6-14.9%. Dr. Dietz's variables, applied to a Gordon model for the DCF, yield a 14.75% rate of return. Dr. Rettenmayer's DCF, utilizing a 52-week average which approximates the current spot rate, resulting in a return of 14.76%. If Dr. Legler's DCF is adjusted for a more realistic market price, the resultant return is 14.76%; and if his risk premium approach is adjusted to reflect the current year's bond yield rather than the bond yields of 1979, the return required by investors would be 14.9%.

For purposes of their analyses, the witnesses who addressed the issue of the fair return on equity capital used Gulf Power Company's parent, the Southern Company, as a surrogate for Gulf. This would present no issue if the risks associated with the two entities were identical. As Dr. Legler and Dr. Rettenmayer testified, however, if existing differentials are not taken into account, the ratemaking effect would be to require ratepayers of one jurisdiction to subsidize those of another. We agree with Dr. Legler that Gulf is less risky than its parent. Therefore, we shall use the lower end of the "cluster" previously identified, or 14.6%, to develop a fair return for Gulf. When an appropriate factor to recognize flotation costs associated with the issuance of $200,000,000 in 1980 is added, a return (rounded) of 14.75% results. We believe that this return should represent the midpoint of a range of 13.75-15.75%, which range we find to constitute a fair return on equity capital for Gulf at this time. In recognition of the fact that Gulf Power's management has exhibited a conspicuous commitment to an effective conservation program, we shall focus upon 14.65% rather than the midpoint for the purpose of calculating revenue requirements.

The range which we have established for the return on equity capital results in an overall fair rate of return of 8.90%, illustrated as follows:

GULF POWER COMPANY
Capital Structure
Year-end

Description (1)	Amount (2)	Ratio % (3)	Cost % (4)	Weighted Cost (5)
Long-Term Debt	$283,194,000	47.66	7.43	3.54
Preferred Stock	70,162,000	11.81	8.28	.98
Common Stock Equity	172,073,966	28.96	13.75-14.85-15.75	4.30
Customer Deposit	5,661,815	.95	8.00	.08
Deferred Taxes	63,120,074 (average)	10.62	-0-	-0-
	$594,212,455	100.00%		8.90%

Overall range
8.58-9.16%

ATTRITION FACTOR

In the regulation of public utilities, the term "attrition" has become a word of art used to describe the deterioration in rate of return which a regulated enterprise charging fixed rates experiences when it incurs higher-than-embedded capital costs, increased operating costs, or incrementally higher plant additions. Prevailing economic conditions have led us in recent cases to provide an "allowance" to offset the anticipated effects of attrition.

The parties and the staff agreed that it would be appropriate to provide for an attrition allowance in this proceeding. At issue, however, is the form and the amount of such an allowance. The Company has proposed that it be allowed an attrition factor of 140 basis points. Mr. Feaster, testifying for Public Counsel, contended that an attrition factor of 40 to 50 basis points would adequately compensate the Company for any attrition that it might experience in the future.

In developing the Company's attrition factor of 140 basis points, Mr. McClellan used an "incremental customer" approach based on the difference between the test year and the projected 12-month period ending May 31, 1981. Mr. McClellan's approach considers net operating income attrition, rate base attrition and cost of capital attrition. It should be noted that Mr. McClellan's methodology develops an attrition allowance in terms of a proposed number of dollars, and that the equivalent number of basis points then become a function of the size of the rate base. Mr. McClellan's recommended attrition factor of 140 basis points is derived by dividing his computed attrition allowance of $7,336,507 by the Company's rate base of $525,347,439. As stated in the footnote on the bottom of Exhibit No. 9, Schedule 1, Page 1 of 9, any adjustment to the rate base would necessarily change the needed percentage factor.

At the staff's request, both Mr. McClellan and Mr. Scarbrough submitted revised data for the computation of the attrition allowance. This revised data included the Company's actual results of operations for the months of June 1980 and July 1980 and data on the Company's financing plans. These revisions were contained in Exhibit Nos. E, F, and G to Exhibit No. 59 and Exhibit Nos. A, B, C, and E to Exhibit No. 54. The inclusion of the appropriate revisions and the establishment of a (midpoint) return on equity of 14.75% would result in an attrition allowance of $6,676,758.

Mr. Feaster, on the other hand, developed an attrition factor of 40 to 50 basis points based on his examination of the Company's historic attrition rates. Mr. Feaster indicated that his recommendation was "slightly below the Company's more recent attrition experience," but that he believed that it was "representative of prospective conditions." Mr. Feaster further stated that his methodology does not compensate for cost of capital attrition, but that he felt that the use of an end-of-period capital structure would provide some degree of attrition offset in this area of operations.

Having considered the methodologies offered by these two witnesses, we can accept neither. We believe that Mr. Feaster's subjective interpretation of historical data does not yield a factor which is representative of future conditions, and in particular fails to account sufficiently for anticipated capital cost attrition. While Mr. McClellan looks to the future, we cannot accept with confidence his estimates.

In the recent Tampa Electric Company rate case (Docket No. 800011-EU), we developed an attrition allowance by combining the three year attrition rate from Mr. Feaster's attrition study with an allowance for cost of capital attrition. We find the same methodology to be appropriate for this case.

Based on Exhibit No. 16, Schedule I, page 2 of 2, the Company's three year attrition rate is 62 basis points. During February 1980, the Company issued $50,000,000 of First Mortgage Bonds at 15% and $10,000,000 of Preferred Stock at 11.36%. Since these securities were issued after the end of the test year, they are not included in the Company's test year capital structure. The effects of including these securities can be determined from Exhibit No. 5, Schedule 11, page 2 of 4. Based on the capital structures contained in that exhibit and substituting the midpoint of the range for return on equity (14.75%), the test year overall cost of capital would be 8.84% and the pro forma overall cost of capital would be 9.36% which includes the securities issued in February 1980. The difference between these two amounts is .52% (52 basis points) which represents the attritional effect of the securities issued in February 1980.

Combining the three year attrition rate with this provision for future capital cost attrition yields a factor of 114 basis points, which we approve as the attrition factor to be allowed in this case.

REVENUE EXPANSION FACTOR

The Company's proposed revenue expansion factor of 51.482% includes an adjustment for the 20% income tax lag and utilizes a regulatory assessment fee rate of 1/8th of 1%. The Public Counsel, however, contends that the revenue expansion factor should not contain a 20% income tax lag adjustment and that the current regulatory assessment fee rate of 1/12th of 1% should be used. After making these adjustments, the Public Counsel's proposed revenue expansion factor is 50.4878%. Neither the Company nor the Public Counsel has advocated the continuation of the State Income Tax "Sharing" concept.

Because we have applied the balance sheet approach to the determination of working capital, we agree with Public Counsel that the inclusion of a 20% income tax adjustment in the revenue expansion factor is not appropriate in this case. We also agree with Public Counsel that the current regulatory assessment fee rate of 1/12th of 1% should be used to determine the revenue expansion factor. This rate is appropriate because it will be in effect when the Company is allowed to implement its revised rates.

Accordingly, we shall utilize a net operating income multiplier of 1.980677 (1 divided by 50.4878%) to expand net operating income requirements into needed operating revenues.

DETERMINATION OF REVENUE DEFICIENCY

Relating the net operating income realized during the test year of $31,944,596 to the rate base of $522,453,008, we find that Gulf Power Company achieved a rate of return during the test period of 6.11%. When compared to the fair rate of return of 8.90%, which we have identified for use in this proceeding, a rate of return deficiency of 2.78% results. Application of this return deficiency to the rate base value yields a net operating income deficiency of $14,553,723. Use of the NOI multiplier of 1.980677 translates this figure into a revenue deficiency of $28,826,224.

The revenue requirement associated with the attrition allowance must be developed similarly. When the established rate base value of $522,453,008 is multiplied by 1.14% (114 basis points), an NOI requirement of $5,955,964 results. Application of the same NOI multiplier used above results in an additional operating revenue requirement associated with the attrition allowance of $11,796,841. Thus, the total additional operating revenues which Gulf Power Company should be authorized to collect on an annual basis amount to $40,623,065.

REFUND OF INTERIM REVENUES

The interim increase which Gulf has collected subject to refund in this case included $142,494 of unrecovered fuel expense. Consistent with our decision in the TECO case, Docket No. 800011-EU, we find that this amount represents a non-recurring item that, having been excluded from the permanent award, must also be eliminated from the interim revenues. Maule Industries, Inc. v. Mayo, 362 So.2d 63 (Fla. 1977). Accordingly, $144,000 on an annual basis must be refunded from the interim revenues collected pursuant to Order No. 9311.

RATE DESIGN

Having determined the amount of revenues which Gulf is entitled to collect, we must consider the manner in which the revised revenue requirement should be distributed among its classes of customers. Accompanying the Petition which initiated this proceeding were rate schedules designed by the Company to generate additional revenues in the amount of $46,376,576 annually. Inasmuch as we have authorized only a portion of the request, modification of the schedules submitted will be necessary. In addition, while we approve certain of the principles underlying the changes proposed by the Company, we find certain others to be unacceptable, and also find additional changes to be supported by the record.

Cost of Service Methodology

Many considerations have been historically applied in distributing the revenue responsibility among customer classes. These considerations have included cost of service, historical patterns and customer acceptance.

It was generally agreed by witnesses who testified on cost of service that the distribution of revenues among classes of customers should be based primarily on the cost of service. The witnesses disagreed, however, as to how to determine the actual cost of servicing each of the classes of customers. The Company, the industrial intervenors and the federal intervenors proposed cost allocations based upon a traditionally accepted embedded cost of service methodology. Public Counsel proposed cost allocations based upon a "marginal cost" methodology.

Traditionally, embedded cost of service studies attempt to assign costs to classes of service based on several forms of analysis. Such cost of service studies allocate utility plant and expenses to the various customer classes to determine the rate of return earned from each class of service for the test year. The studies involve separation of plant and expenses into functional groups of production, transmission and distribution and other classifications. Formulas are then developed to allocate these items to the various classes of service. The final step is the allocation of costs and a determination of the ratio of operating income to net utility plant, including working capital. Revenue is not allocated, but is separated according to receipts by each class of service. A comparison of the utility plant, expenses and revenues assigned to each class indicates the relative rate of return achieved with each class. Appropriate adjustments can then be made to achieve the desired distribution of revenue responsibility among classes. Establishing relatively equivalent rates of return among classes of service has been a traditional goal in the allocation of costs.

The Company relied upon a cost of service study prepared by Mr. McClanahan, which used 1978 data to establish the one hour peak five-day average demand, and took into account certain policy considerations expressed by Mr. Haskins. Mr. McClanahan considered the one hour peak five-day average methodology to provide an appropriate allocation of responsibility for utility plant and expenses between customer classes.

Utilizing the results of Mr. McClanahan's study, Mr. Haskins constructed the Company's proposed allocation of revenue among the customer classes. Mr. Haskins considered several principles in designing rates, which were as follows: cost of service, fairness of rates among customers, reasonable transition from previous rates, and the premise that electricity should be used wisely and not wasted. Mr. Haskins also proposed specific changes in the rate schedules that will be discussed later. All of the rates proposed by Mr. Haskins contained flat energy charges.

Mr. Brubaker, testifying for the industrial intervenors, analyzed the cost of service study prepared by Mr. McClanahan, as well as the rates proposed by Mr. Haskins. Mr. Brubaker considered the annual peak demand methodology used by Mr. McClanahan to be appropriate for the Company and emphasized the differences in service characteristics between customer classes that justified the results shown by Mr. McClanahan's study. Mr. Brubaker criticized the Company's proposed revenue allocation as not properly allocating revenue responsibility among customer classes. He stated that the Company's proposed rates tended to move revenue responsibility away from levelized rates of return between customer classes. He proposed, instead, a separate revenue allocation that allocated revenue responsibility among customer classes to more closely equate rates of return between classes.

Mr. DeFrawi, appearing for the federal agencies, relied upon Mr. McClanahan's cost of service study to show the need for allocating any rate increase among customer classes so as to shift more responsibility for any rate increase to customer classes that were not covering the full cost of service assigned to them.

Dr. Wells proposed that revenues be allocated among customer classes by a marginal costing methodology, as he had proposed in Docket No. 800011-EU (Tampa Electric Company). Utilizing a measure called system lambda, Dr. Wells established what he considered to be the long run marginal cost for the system, which he testified was an appropriate indicator of marginal cost. By comparing the relative price of residential, commercial and industrial rates per kwh to the system lambda, Dr. Wells concluded that industrial customers' rates should be increased by a higher amount in relation to residential and commercial customers if any rate increase is granted.

As he had done in Docket No. 800011-EU, Dr. Wells noted that the current and proposed rate levels for the Company did not reach marginal cost. He stated that since regulatory ratemaking sets rate levels below marginal cost it would be necessary to adjust existing rates to provide marginal cost price signals, while producing total revenues below the amount which would be produced by pricing at marginal cost. Dr. Wells proposed to place all customer, demand and energy related costs in the kwh, or energy, charge. This would establish a kwh charge that would act similarly to pricing at marginal cost. To allow for revenue stability, Dr. Wells proposed a minimum bill of $2 per month per customer.

After reviewing the testimony presented in this matter, we conclude that the cost of service methodology employed by Mr. McClanahan is the most appropriate methodology available to us in this case. However, we intend to direct the utilities to improve and make more uniform the cost of service methodologies used in future proceedings.

As we concluded in Order No. 9599, Docket No. 800011-EU, we cannot embrace Dr. Wells' marginal cost pricing theory without further exposure to the concept. By November, 1980 the four major investor-owned utilities are required by the Public Utility Regulatory Policies Act to file marginal cost of service studies. These filings will give the Commission an opportunity to evaluate various methodologies and become familiar with the topic. In addition, marginal cost of service studies will be considered in the cost of service docket, Docket No. 790593-EU.

Revenue Allocation between Customer Classes

Although the Company and Mr. Brubaker relied upon Mr. McClanhan's cost of service study to allocate the rate increase among customer classes, the allocation proposed by the Company differed from that proposed by Mr. Brubaker. Mr. McClanahan's study, which we have previously approved, shows existing relative rates of return, by customer class, as follows:

Rate Class	Rate of Return %
Residential	3.84
General Service	6.33
Large Power	7.65
Large High Load Factor Service	7.91
Outdoor Service	10.04
General Service Demand and Small Power all Electric	11.32

Considering our approval of a $40,623,065 rate increase, we find the following increases of rates, by customer class, to be appropriate:

Rate Class	$ Increase	Percentage Increase
RS	25,023,000	29.8
GS	1,756,000	25.4
GS-D	5,437,000	13.6
LP	5,585,000	18.6
PX	2,490,000	14.6
OS	321,000	14.7
TOTAL	$40,623,000	22.56

*Revenue effect of increased connection charges.

Additionally, in designing its rates the Company shall take into account the revenue effect of unbilled revenues, illegal use of electricity, and the fuel roll-in authorized hereinafter. The rates should be designed to produce the appropriate revenue increase as closely as possible.

Customer Charges

The Company has proposed increases in the level of the customer charges for all rate classifications. As in Order No. 9599 in Docket No. 800011-EU, we feel that the distribution costs which should be included in the customer charge consist of those related to distribution from the pole to the customer's house. We therefore find the following customer charges to be appropriate.

Rate Schedule	Customer Charge
RS	5.00
GS	5.00
GS-D	13.00
LP	178.00
PX	4,083.00

Demand Charges

The Company has also proposed increases to the demand charges for their demand metered rates. The Company's present GS-D and LP rates include hours/use blocking in the energy charges related to load factors of 25% and 50% respectively. RCD R-11 (exhibit 48) shows the actual demand costs to be higher than proposed by the Company. We find that higher demand charges would more accurately reflect the cost of service and would provide an incentive for high load factor customers. In light of our decision to reject declining block demand charges in rate LP (see below), we conclude that the following demand charges are appropriate.

Rate Schedules	Demand Charge/kw
GS-D	4.00
LP	5.00
PX	5.00

Winter/Summer Differentials

The saturation of air conditioning in Gulf's service area is in the range of 80-85% for residential customers. The Company has a much lower saturation of electric heating. The air conditioning load contributes to the system's maximum demand, with the result that Gulf Power Company consistently is a summer peaking utility. The Company proposed to retain its winter/summer rate differentials in the energy blocks of the RS and GS rates. The staff witness, Mr. Makin, concluded that the differential was justified, based on the data in RCD R-6 (Exhibit 48). Dr. Wells reached the same conclusion based upon his analysis of System Lambda. We find that the winter/summer differential should be retained.

Applicability Provision of GS, GS-D, LP and PX rates

At present the applicability clauses of these four rates require various demand levels. The breakpoint between rates GS and GS-D is 20kw and the breakpoint between rates GS-D and LP is 500 kw. Rate PX requires a demand of 7500 kw and an annual load factor in excess of 74%. The current applicability provisions appear to be practical and reasonable and should be retained.

Declining Block Demand Charge for LP Schedule

In its filing the Company proposed to retain the two step declining block demand rate for its LP schedule. It is apparent that the Company considered Order No. 9329 in Docket No. 790571-EU to address only energy charges. This is not the case. We believe a flat demand charge is appropriate for the LP rate schedule.

Generation from Renewable Energy Resources

Mr. Makin proposed a rate schedule containing an energy surplus rate so that a self-generating customer utilizing renewable resources with a design capacity under 15 kw would be able to sell surplus energy to the utility. This matter is now under consideration in Docket No. 780235-EU and should not be considered in this proceeding.

Primary and Transmission Voltage Discounts

The current discounts to customers receiving service at primary or transmission voltages are based upon historical values and are not supported by a current cost study. The current discounts are 16¢ per kw for service at the primary distribution level and 32¢ per kw for service at the transmission level. We find these discounts to be unreasonably high and require them to be lowered to 10¢ per kw and 20¢ per kw, respectively, until the Company submits a cost study justifying different levels of discounts.

Inverted vs. Flat Rates

As in Docket No. 800011-EU, inverted residential rates were proposed by witnesses to this proceeding. Consistent with Order No. 9599 entered in the above docket, we find that flat rates rather than inverted rates, should be approved in this proceeding. Inverted rates will be considered on a generic basis in conservation-related proceedings.

Textual Changes in Certain Rate Schedules

The Company proposes textual changes in tariff sheets 4.6, 4.7, 4.7A and 4.13. The Company proposes to raise the minimum charge for standby service from $2.00/mo. per kw to $7.00/mo. per kw. Since the demand charge for GS-D, LP and PX rates, approved herein, is only $5.00 per kw, we find no justification for a minimum bill of $7.00 per kw for standby service. The minimum bill on tariff sheet 4.7A shall be $5.00 per kw.

Fuel Roll-in and Modifications of the Fuel Clause

The Company proposes to increase the amount of fuel in the base rates by 9.837 mills/kwh (.9837¢/kwh), from 13.3 mills/kwh, to a total of 23.137 mills/kwh so as to more accurately reflect the current price of fuel. Under Mr. Brubaker's proposal, all fuel costs would be included in the fuel adjustment and the kwh charges would be smaller. This method would conflict with peak load pricing and would require separate on-peak/off-peak fuel adjustments for each customer class. We feel that using the average fuel cost of the four major electrics (2.5¢/kwh) would provide an appropriate base fuel cost and a better basis for comparison. This amounts to a roll-in of 1.189¢/kwh into base rates, including taxes. Therefore, the revised fuel adjustment for October, 1980 - March, 1981 will be a credit of .224¢/kwh and will be effective with the rates approved herein.

Mr. Brubaker also proposed to allocate fuel costs among classes with consideration of line-losses experienced by each class. We find Mr. Brubaker's proposal to be reasonable. The allocation of fuel cost between classes in the base rates should be adjusted to reflect the effect of line losses at different service levels, which are as follows:

Rate Schedule	Line Loss Factor
RS, GS, GS-D, OS	9.0749
LP	6.43
PX	3.35

Outdoor Lighting

The Company has proposed the elimination of the present rate for 140,000 lumen high pressure sodium vapor (HPS) lamps because of its limited application and has proposed to include rates for 5400 lumen high pressure sodium lamps in lieu of the 3500 lumen mercury vapor lamp in the interest of energy conservation. The company has also proposed to close the mercury vapor street lighting rates to new customers. We have reviewed the proposed rates for high pressure sodium vapor lamps and find that we are not satisfied that the rates are cost justified. In addition, the HPS rates are substantially higher than the rates for mercury vapor lamps. As a result, we will not require, nor permit, the closing of the mercury vapor schedules to new customers at this time.

We will, however, permit the proposed HPS rates to be placed in effect so as to allow a more energy efficient alternative for Gulf's customers. The present HPS and mercury vapor rates should be divided into an investment and kwh rate to effectively reflect the costs of capital investment and energy components. The Company is required to submit a cost study to justify the proposed HPS rates within six months of the date of this Order. In addition, outdoor lighting service should be offered so as to allow a customer the option of owning and maintaining the fixture when receiving service.

Connection Charges

At present the Company charges $8 for reconnection and charges $10 for either an initial connection or a reconnection after disconnection for cause. The Company has proposed an increased charge of $10 for reconnections. It also submitted, in late filed Exhibit No. 83, an analysis which shows costs of $9.32, $9.78 and $10.36 for initial connections, reconnections and reconnections for cause, respectively. We find that the Company proposal of increasing the reconnection charge to $10 is reasonable and should be approved.

90% Power Factor Provision

The present demand rates contain power factor provisions showing a reactive demand charge based on reactive capacity and 90% power factor. The Company proposed no change to its current power factor provision. Neither the intervenors nor the staff offered changes to the clause. Therefore, we find that the present power factor provision should be retained.

Elimination of SPAE and PLP Rates

In the prehearing order, the parties and staff stipulated to the elimination of the SPAE and PLP rates. Customers now served under SPAE rate will be transferred to the GS-D rate. The SPAE and PLP rates are to be eliminated upon the effectiveness of the rates approved herein.

REFUND OF EXCESS INTERIM AWARD

Effective May 2, 1980, the Company was granted an interim increase of $6,257,000 on an annual basis, amounting to a 3.4756% across the board increase on base rate revenue. We have previously concluded that only $6,113,000 should have been granted, resulting in a refund of $144,000 on an annual basis. Since these rates will have been in effect approximately six months when the final rates go into effect, approximately $76,000 plus interest will need to be refunded. The Company should calculate the amount to be refunded, to include interest at a rate for 30-day commercial paper as defined in refund criteria established in Order No. 9306, Docket No. 800400-CI. In that the refund amounts to only 2% of the interim increase, we feel the administrative costs of recalculating each customer's bill during the interim period would not be cost justified. The refund amount should be refunded through a reduction in the fuel adjustment. This docket will remain open pending a report by the Company of the final disposition of the refund.

Since the eight month file and suspend period ends November 3, 1980, the rates under this Order shall become effective for bills rendered for meter readings on or after the date of this Order.

The Company will also provide a notice to accompany the first bill for service under the final rates explaining the amount of the increase and the reasons therefor. A copy of said notice shall be submitted for the Commission's approval prior to mailing.

ADDITIONAL FINDINGS OF FACT AND CONCLUSIONS OF LAW

Consistent with and in addition to the matters treated above, the Commission finds and concludes as follows:

1. Gulf Power Company is a public utility subject to our jurisdiction within the definition of Section 366.02, Florida Statutes.

2. With appropriate adjustments, calendar year 1979 represents a reasonable test period for purposes of our review in this proceeding.

3. During the test period, Gulf Power Company realized net operating income of $31,866,165.

4. The value of the average rate base for the test period is $522,453,008.

5. The earned rate of return for Gulf Power Company during the test period was 6.11%.

6. The capital structure utilized herein is reasonable and appropriate for ratemaking purposes.

7. Gulf Power Company should be authorized to earn in the range of 13.75-15.75% on common equity capital. The overall fair rate of return lies within a range of 8.58-9.16%. For purposes of determining revenue requirements herein, a return of 8.90% is fair and reasonable.

8. To offset anticipated attrition, Gulf Power Company should be provided an attrition allowance of 114 basis points.

9. Gulf Power Company should be authorized to place into effect revised rate schedules designed to generate $40,623,065 in additional revenues annually.

10. The amount of $4,225,176 annually related to the Caryville cancellation charges should be placed under a refund provision, and the Commission should retain jurisdiction over this matter.

11. The rate schedules prescribed herein constitute fair and reasonable rates within the meaning of Chapter 366, Florida Statutes.

12. Gulf Power Company should be required to refund to its ratepayers that portion of the interim increase related to the unrecovered fuel expense contained in its filing, or $144,000 on an annual basis. The interim revenues should otherwise be approved.

Accordingly, it is

ORDERED by the Florida Public Service Commission that all findings and conclusions herein are approved and adopted. It is further

ORDERED that Gulf Power Company is authorized to submit revised rate schedules consistent herewith, designed to generate $40,623,065 in additional annual revenues. Said rate schedules shall become effective and applicable to bills rendered for meter readings taken on and after November 10, 1980. It is further

ORDERED that the amount of $4,225,176, or that portion of the total annual increase related to the Caryville cancellation charges, is hereby subjected to a refund condition in the event the Scherer transaction relied upon by the Company as justification for the cancellation is not realized within one year of the date of this Order, or the cancellation is not otherwise justified to the Commission's satisfaction. The Commission retains jurisdiction over this issue and related amounts for that purpose. It is further

ORDERED that Gulf Power Company refund to its customers the portion of the interim revenues related to unrecovered fuel expense in the manner delineated herein. It is further

ORDERED that the Company provide to its customers with the first bill reflecting this increase a notice describing the nature of and reason for the increase. A copy of the notice shall be furnished to the Commission's Electric and Gas Department prior to issuance.

By Order of the Florida Public Service Commission, this 10th day of November 1980.

Steve Tribble
COMMISSION CLERK

(S E A L)

JAM
PS

MANN, Chairman, Concurring in part, Dissenting in part

The order in this case is far too long, and I hesitate to lengthen it with my separate comments. My views which have not won majority support on the Commission are expressed in prior opinions. I will comment on the reasons for my concurrence in the rate of return allowed and on the allowance of substantial amounts for construction work in progress.

Electric utilities are at present in a period of financial difficulty which warrants the concern of regulatory agencies for cash flow and earnings adequate to insure that the company's obligations to the public will be met. Generating plant now coming on line was planned long before I came on the Commission and ought to be provided for. I have reservations about the continuance of the build-more, sell-more, cost-plus mentality in the electric industry. The attrition allowance and the rate of return approved here are sufficient to allow this company to sell less over the next few years until this Commission finds a mechanism for pricing electricity in such a way that those who cause the markedly higher costs of today pay those costs. Correspondingly, I think that the effects of inflation should be visited less stringently on consumers who practice sound conservation policies. Twenty years ago selling more electricity meant more efficiency, and the marginal cost was less than the average cost of each unit. We haven't shifted our thinking to take account of the fact that today marginal cost is higher than average cost. I remain hopeful that the Commission will address this issue.

In the meantime, Gulf Power Company has the highest average consumption by residential consumers. Fortunately, the top management of this company has the best attitude toward conservation I have observed in Florida. Management deserves a chance to prove that new capacity requirements can be minimized and that Gulf's customers can reduce their demands on the system.

Commissioner Marks dissenting in part:

The majority has again decided to allow the ratepayers to pick up the tab for charitable contributions. The amount in this instance is $16,550. My opposition to this is well-known; therefore, I will not repeat the arguments as stated in the United Telephone and the General Telephone cases. The Public Counsel agrees that charitable contributions are a legitimate expense of the shareholders rather than the ratepayers and the Commission's staff is similarly convinced. As indicated in the Public Counsel's brief, the question is not a matter of appropriateness of the amount or the worthiness of the cause. The proper focus was well stated by the New Mexico Public Service Commission:

> Even if these charitable contributions had been shown to have been made in New Mexico, to New Mexico charities, they should be disallowed for the reason that there is no evidence demonstrating any relationship to such expenses and the lowering of overall expenses which would benefit the ratepayers and justify their bearing such expenses.
>
> Re <u>El Paso Electric Company</u> (1977) 23 PUR4th 131, 142 citing
> Re <u>Southern Union Gas Company</u>, 12 PUR4th 219, 230 (1975).

Another issue which bears equal attention is properly raised by our staff. It is the amount of $81,250 specified as Industry Association Dues. The staff accurately points out that the benefits to the ratepayers that might be obtained from certain of the trade and industry association dues were unknown and unquantified in the record. Accordingly, they recommend that such dues be disallowed to the extent they are of no definite benefit to the ratepayers. The majority disagreed with the staff on this issue and chose to allow <u>all</u> of the industry association dues even if there was no benefit to the ratepayers. I must agree with the staff's analysis. I would only allow those dues which provide a proper nexus between the utility and a definitive benefit to the ratepayers. As such, dues to the Amercian National Standards Institute, the Florida Electric Power Coordinating Group and the Southeastern Electric Reliability Council should be allowed. All others should be disallowed.

There is one other issue in which I find myself out of step with the majority: by vote of four to one the Commission has decided to allow construction work in progress (CWIP) of $110,869,978 to be included in the company's rate base. I am simply not convinced by this record that the company carried the burden in proving that CWIP should be allowed in the rate base. As indicated by Public Counsel "there are many improprieties which arise from the practice of including CWIP in the rate base which were not squarely addressed by the company and which have significant detrimental effects upon its ratepayers." I along with the Public Counsel believe that placing CWIP in the rate base forces the customers to assume a role of equity investor without the benefits which would follow from such a role. The practice unfairly discriminates against the company's current ratepayers by forcing them to finance plants which will only benefit a future generation of ratepayers. As such, it improperly shifts the risk of investment from the company's stockholders to its ratepayers. Further, I can find no evidence that it is cheaper to include CWIP in the rate base as opposed to future recovery of construction costs and close analysis indicates the CWIP method generally ignores the time value of the ratepayers' money. Finally, the most compelling argument I can find against allowing CWIP in the rate base is that in the competitive marketplace, which regulation should emulate, a business cannot earn a return on an investment that does not provide goods or services to its customers. (See brief of Public Counsel.)

It is not my intention by this statement to pass on the substantive propriety of allowing CWIP in the rate base. I simply believe it is the burden of the company to establish by competent evidence that such allowances should be made. As a result of listening to the testimony of all the witnesses on all the issues stated above and reading the briefs of the various parties, I am of the opinion that the positions stated by the company are not substantiated in the record.

The calculation showing the above adjustments is presented below. If those adjustments were made as I have indicated, the total operating revenue requirement of Gulf Power Company would be $20,268,862, as opposed to the majority's revenue requirement of $40,622,826.

COMPANY RATE BASE (JURISDICTIONAL)	$ 525,347,439	
ADJUSTMENTS		
Balance Sheet Working Capital	$(1,554,098)X92.12663%	$ (1,431,738)
FERC Audit Adjustments	$(1,589,012)X92.12663%	$ (1,463,903)
CWIP	$(110,869,978)X92.12663%	$(102,140,774)
ADJUSTED JURISDICTIONAL RATE BASE		$ 420,311,024
COMPANY NET OPERATING INCOME (JURISDICTIONAL)		$ 31,866,165
ADJUSTMENTS		
Unrecovered Fuel Cost	$142,494 X.513X100%	$ 73,099
Bank Service Charges	$102,645 X.513X94.13298%	49,576
FERC Audit Adjustments	$(304,577)X94.13298%	(286,707)
Consolidated Tax Return	$199,872 X 100%	199,872
Advertising Expenses	$ 79,822 X.513X94.13298%	38,546
Industry Association Dues	$ 36,022 X.513X94.13298%	17,395
Charitable contributions	$ 16,550 X.513X94.13298%	7,992
Total		99,764
ADJUSTED JURISDICTIONAL NET OPERATING INCOME		31,965,929
EARNED RATE OF RETURN		7.605303%
ROUNDED		7.61%

(CONTINUED ON NEXT PAGE)

JURISDICTIONAL RATE BASE		$ 420,311,024
RATE OF RETURN		
Allowed Rate of Return	8.900000%	
djusted Earned Rate of Return	7.605303%	
Deficiency		X1.294697%
NET OPERATING INCOME DEFICIENCY		$ 5,441,754
NET OPERATING INCOME MULTIPLIER		X1.980677
OPERATING REVENUE REQUIREMENT		10,778,357
ATTRITION ALLOWANCE		
Jurisdictional Rate Base		$ 420,331,024
Attrition Factor		1.14%
NET OPERATING DEFICIENCY		4,791,546
NET OPERATING INCOME MULTIPLIER		X1,980677
OPERATING REVENUE REQUIREMENT		$ 9,490,505%
TOTAL OPERATING REVENUE REQUIREMENT		$ 20,268,862

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of

To hear a presentation by representatives of GULF POWER COMPANY concerning the merits of purchasing an undivided 25% interest in Units 3 and 4 at the Scherer Plant located in Georgia.

UNDOCKETED

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115 Fletcher Building
101 East Gaines Street
Tallahassee, Florida 32301

Monday, February 16, 1981

Met pursuant to notice at 3:00 p.m.

BEFORE: COMMISSIONER JOSEPH P. CRESSE, Chairman
COMMISSIONER GERALD L. GUNTER
COMMISSIONER JOHN R. MARKS, III
COMMISSIONER KATIE NICHOLS
COMMISSIONER SUSAN W. LEISNER

IN ATTENDANCE:

ROGER VINSON, Beggs & Lane, Post Office Box 12950, Pensacola, Florida 32576, Telephone No. (904) 432-2451, appearing on behalf of Gulf Power Company.

E. L. ADDISON, ARLAN E. SCARBROUGH, and EARL B. PARSONS, 75 North Pace Boulevard, Pensacola, Florida 32505, Telephone No. (904) 434-8111, appearing on behalf of Gulf Power Company.

JOE McGLOTHLIN and PAUL SEXTON, 101 East Gaines

ATTENDANCE CONTINUED:

Street, Tallahassee, Florida 32301, Telephone No. (904) 487-2740, appearing on behalf of the Commission staff.

PRENTICE P. PRUITT, 101 East Gaines Street, Tallahassee, Florida 32301, Telephone No. (904) 488-7464, appearing on behalf of the Commissioners.

JACK SHREVE and BENJAMIN DICKENS, Office of Public Counsel, Room 4, Holland Building, Tallahassee, Florida 32301, Telephone No. (904) 488-9331, appearing on behalf of the Citizens of the State of Florida.

DAVID SWAFFORD, 101 East Gaines Street, Tallahassee, Florida 32301, Telephone No. (904) 488-7181, appearing on behalf of the Public Service Commission.

WILLIAM TALBOTT, 101 East Gaines Street, Tallahassee, Florida 32301, Telephone No. (904) 488-3248, appearing on behalf of the Public Service Commission.

REPORTED BY: HOLLY L. KIRCHMAN, RPR
Commission Hearings Reporter

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P R O C E E D I N G S

MR. SWAFFORD: Mr. Addison, I'll turn the meeting over to you.

CHAIRMAN CRESSE: I understand this is kind of a little informal hearing or formal hearing or trying to get an update --

MR. SWAFFORD: Yes, sir. They requested, they wanted to show us, it's an informal meeting to show, as I understand it, the benefits of buying into the Scherer Plant or the possibility of buying into the Scherer Plant in Georgia.

CHAIRMAN CRESSE: All of you know the new Commissioners? Has everybody met here?

MR. ADDISON: This is Earl Parsons here, Vice-President of Electric Operations with our company, and this is Arlan Scarbrough who is Vice-President of Finance, and Roger Vinson over here who is counsel for the company.

(Off the record briefly.)

MR. ADDISON: Well, we thank you very much for the opportunity to meet with us this afternoon. Before we get into the subject at hand, I want to mention just one little thing that's going on over in our service area right now that's certainly important to us, and I think is of concern to you all. In January of 1981, we had 93% higher heating degree days than we did in January of 1980. As a result of that, we sold 28% more kilowatt hours in January of 1981 than we did in

January of 1980. And it's working a pretty good hardship on a number of our customers. And a number of calls and complaints and concerns we're getting is very high compared to the norm. And I'm sure that if our ratio has gone up to that extent, then your ratio has gone up also.

The thing that I wanted to say to you is that we are concerned, and we're working on an individual basis with those customers who are calling us to make certain that we do everything we can to help them manage their situation. And I just wanted to say that to you because we have the opportunity to do it, and we're not cutting people off who are coming in and talking with us. We're making the effort to try to do something about it. So I think we're doing everything we possibly can to manage that situation. But I felt we ought to say that to you.

I really will not go as far back as I might for the two lady Commissioners to give all of the background and our participation or possible participation in the Scherer generating units in Georgia. But I'll just try to give you a brief look at that so you'll have some feel for why we're here today. Since the Arab oil embargo, Gulf, like all other utility companies in the country have experienced a steady decrease in our load projections, and the result of that, it comes about as a result of increased costs and the conservation ethic, I think, that's going on in this country, and our own efforts in the conservation field.

Now because of that, the kind of planning and construction of new generating units that we have experienced historically began to change. We had planned to, in the late '70s, to have a generating unit come on the line at Caryville, a 500 megawatt unit. And we had actually gotten started on the engineering, had actually done the environmental permitting on that site. But as we moved under that time frame, it became pretty obvious to us that we were not going to need that capacity during that time frame. So we began to delay that unit. One of sister companies, Mississippi Power Company, was in the same situation and had a unit that was further along as far as construction is concerned than the Caryville Unit, and we ultimately made a decision to buy into that unit or to buy one of those two units, which we have done. And it's at a great dollar savings to our customers.

Then after the purchase of that unit, we still were considering the construction of the first Caryville Unit. However, Georgia Power Company at the same time had been experiencing the decrease in load projections. And as a result of that, they had capacity under construction, either under construction or permitted for that they no longer needed in the time frame that it was originally scheduled for. And rather than go through the agonies of cancellation, Georgia began trying to market some of that capacity, and they have indeed marketed quite a bit of that capacity, portions of the unit to other entities within the State of Georgia. However, they still had additional capacity available.

At the time we began looking at it in 1978, it appeared to us that we would need capacity in the 1987-1989 time frame. We found that there was capacity available there that we could buy at a tremendous savings as compared to us going forward with the Caryville Unit. And we'll talk about some of the numbers in just a minute. So we made the decision to cancel the Caryville Unit and to buy into the Scherer Units in Georgia, the last two units. At first, we were not sure if we'd be buying a portion of all four of the units at that time or if we would be buying into the last, the third and fourth unit. As it turned out, our proposal now is to buy into the third and fourth units, 25% of each one of those units, and they're 818 megawatt units. So altogether we'll be purchasing a total of 404 megawatts of capacity.

Now we came to the Commission in the fall of 1978 and asked for permission to put into effect an accounting statement that would allow us to write off the cancellation charges of Caryville over a period of five years. We are retaining the site; the environmental permitting is still in effect; it will be 15 years. But those expenses that had to do with engineering and expenses already committed by manufacturers had to be dealt with. When we came to the Commission, our outside estimate was that we were looking at a write-off of about $20 million. We said that that was an outside figure and that we hoped to reduce it. But the end result is that we did in fact reduce it to about $12 million as a result of finally refining some figures and doing some very good negotiating with the equipment manufacturers.

And, so the Commission at that time in late 1978, allowed us an accounting treatment to write-off above the line those expenses over a five-year period, retaining the right, of course, to reconsider the validity of those expenses in a rate case that might follow. In the rate case which we have just concluded, the Commission again considered that matter and questioned us as to whether or not we had entered into the contract with Georgia for the purchase of those units, and we had not for a number of reasons. Our load projections continued to show some decrease, and it became obvious to us that unless something else happened, that we really would not need that capacity in the '87-89 time frame for our retail customers. However, there were some things also beginning to come along that looked as though it might make it feasible to proceed on that schedule, and that is that a number of utilities whc are predominantly oil-fired generators were looking for the opportunity to buy displacement energy and/or capacity that was coal-fired. So it appeared to us that if we could wait until we got some of that in focus, we could make a better business decision about proceeding with the Scherer Units. The Commission in the order which we received following the hearings allowed us the write-off of those expenses. However, because we had not entered into a contract yet with Georgia for the purchase of the units, said that if that within a year we had not signed the contract for the purchase of those units or come forth with some other justification for having canceled the Caryville Units, that we would have to refund that portion of the rate increase to our customers.

Now as I mentioned to you earlier, our load projections have continued to decrease. As it stands now, if we were not to purchase the Scherer Units, we would not need the Caryville capacity until 1993. The cost comparison as we calculate it today is that the Caryville capacity if constructed and goes into service in 1993 would cost us $2,662 a kilowatt. The Scherer Units in 1987 and 1989 average out to a cost of $855 a kilowatt. There are three reasons for that. Primarily because of the early commitment of the Georgia units and the time frame in which they are constructed. They were larger units than the units that we had originally planned at Caryville, but now if we built a unit a Caryville, it would be the same size unit. The other major factor is that there are no scrubbers on the units at Scherer. Scherer is grandfathered and will burn low-sulfur coal and will not have to have scrubbers. But the time frame of the commitment for the major equipment is the basic, one of the largest factors.

So the situation we now face is that Scherer is scheduled to be available to us six and four years ahead of what our need really is for our retail customers. However, we have the opportunity to sell at least a portion of that capacity to other utilities to displace oil-fired generation until that capacity is needed by our customers. At that time, they will greatly benefit as demonstrated by the cost comparisons.

Now our dilemma is this. If we wanted to be short-sighted and bury our head in the sand, we could live a lot easier life for the next five or six years, and our stockholders would fair better if we did not participate in the Scherer Units. However, we're not in a short-term business. We are definitely in a long-term business, and our customers ultimately will greatly benefit from our participation in Scherer.

In addition to the benefits to them, there is the benefit to this state of reducing oil consumption by selling that capacity into the State of Florida, or at least a portion of it. Now we are ready within a matter of a few days to sign the contract with Georgia Power Company for the purchase of that capacity. There is no doubt that if we move down the road and it's been demonstrated by our decision on Caryville, it's very easy after you pass a point in time to be second guessed about your business decision. Now we simply cannot take the business risk of having that kind of second guessing as we move down the road with the Scherer Units. We cannot embark on this program without assurance from this Commission that they are supportive of our actions. In spite of the fact that some of this capacity will not initially be used by our retail customers, they are the ultimate beneficiary.

Consequently, the cost of this program must be reflected in our retail rates from the outset.

I'd like to ask Mr. Scarbrough, who is our financial vice-president, to talk a little bit about the numbers. Mr. Scarbrough.

MR. SCARBROUGH: When we were working on these figures and trying to calculate the savings, it reminded me there are a lot of ways, several different ways at getting at something, and Mr. Cresse reminded us of that several times at the hearings he referred to a few minutes ago. It reminded me of a little story I heard, that this economist had a son who was a jogger, and the son came home one afternoon and said, "Dad, I ran behind the bus to town today and saved 15¢." His father said, "Why didn't you run behind a taxi and save $5?" So it depends on where you're coming from.

Okay. The figures, this chart is depicted to show you the absolute and the present value of savings of the Scherer Plant versus the Caryville Plant. The annual savings and depreciation expense is $23,722,000. The calculation here is that the Caryville Plant, the estimated construction cost of Caryville is just a little over $1 billion. The estimated cost of the Scherer capacity is about one-third of that, $345 million. The actual kilowatt hours involved in Caryville are 397 megawatts, and at Scherer, 404 megawatts. So basically, the same amount of megawatts, and you're looking at about, the Caryville Plant was estimated to cost about three times what Scherer would in absolute dollars. Of course, in different time frames.

So your actual annual savings in depreciation expense alone is $23 million a year.

COMMISSIONER MARKS: When you're talking about Scherer now, you're talking about the 25% interest in both of those plants?

MR. SCARBROUGH: Right. We're talking about 404 megawatts or 404,000 kilowatts out of that Scherer capacity, and we're talking about 397 megawatts out of Caryville. Obviously, these units are 818 megawatt units. The Caryville Unit in all likelihood would be an 818 megawatt unit. What that's telling you is, we wouldn't own all of any of them even if we built Caryville, we would not own all of that; we would have to share that with somebody. We don't know who, but we would have to share it with somebody.

Now the carrying costs between the two units, the carrying costs, and these carrying costs are calculated at 9½% which is our present overall actual cost of money at the end of December 1980, the return on equity last allowed by this Commission of 14.85, the 9½% cost of money. The carrying cost on Caryville would be $99 million a year; on Scherer, it would be $32 million a year, or a savings of $66 million a year. Now the absolute savings on an annual basis is $90 million a year, absolute dollars. If you were looking at, this plant would probably in all likelihood have a 30-year life, so you're looking at an absolute dollar savings between the two units over the life of about $2.7 billion in absolute dollars. But really, that doesn't really tell you a whole lot because they're in different time frames, and in order to get this thing down to a common denominator so you've got an exact match up, you have to present value this.

So what we've done is, we've taken and present valued this annual savings at 1993, which is the date that we now need capacity from something in 1993. We either need it out of Caryville or we need it out of Scherer for our own customers in 1993. So what we've done is present valued this figure at 1993 out for 25 years.

Now the reason we did it for 25 years, and the plant has a 30-year life, is because if we constructed Scherer, we expect it to go on line in '87 and '89, which is an average of five years prior to the time that we would need that capacity for our own customers. And during that interim period, we would attempt to sell this off system to other customers.

So that's the reason we use the 25 years which is the remaining 25-year life of Scherer and the first 25 years of Caryville in order to get an exact match. And then what we did, we present valued that figure back to 1/1/81, January the 1st, 1981. And the present value savings, the present value of yearly savings over the life is $263 million. Scherer versus Caryville. In other words, if a customer, if all of our customers had to date in 1981 to go deposit in the bank enough money to pay for all the capacity that they would consume over a 30-year period from both of these plants, they would have to put 263 1981 dollars in the bank in order to get Caryville versus Scherer. The present value savings is $263 million in 1981 dollars.

Now this chart was put together to show you the revenue requirements if you include construction work in progress in the rate base during the construction period. Here we're strictly talking about the construction period. Now you can see, of course, all these dollars are in thousands of dollars. We've got the period of years from 1981, the present year which is the year we plan to buy into the Scherer Plant, down through 1992, which is the year preceding the year in which we would need the capacity for our own customers.

Now if we get under the Scherer Unit and buy into

Scherer, these would be the construction work in progress balances each month or each year, at the end of each year. This would be the revenue requirements if construction work in progress were included in the rate base. And this is the present value of those revenue requirements at January 1st, 1981. Now if you, of course, the construction period for Scherer would be '81, '82, '83, '84, '85, '86, and in '87, the unit, Unit 3 would go into service, and then we would continue to construct. And then the second unit, Unit 4, would go into service in January of 1989. You can see the total revenue requirements, $90 million, the present value of those revenue requirements at 1/1/81 is $55 million for the Scherer Plant.

I might point out that these revenue requirements do not take into consideration any increased cost of financing. Obviously, the revenue requirements would be significantly increased to the extent that any new, that we had to finance these dollars to the extent that the cost of money, which, obviously, in all likelihood, would be considerably higher than our embedded cost, to the extent that those financing costs were higher than the present embedded costs, you would, of course, have an increase in the overall cost of money and an increase in revenue requirements from that alone. This simply is reflecting the revenue requirements of construction work in progress in the rate base.

Now the Caryville scenario is that if we build that unit to come into service in 1993, the same period here, '93, this would be the construction work in progress balances at the end of those respective years beginning in '87. In other words, if we were to bring this unit in 1993, we would have to start constructing no later than 1987. We'd actually have to do, the fact that we could even wait this long is because we already have the site, it's already licensed, and we've already done a lot of engineering, a lot of work that you have to do on a plant, and that's already been done. So, therefore, at the very latest, we could start the actual continuation of construction in '87 to have it available for 1993.

You might have a question as to why this is $890 million, and I told you before it was going to cost $1 billion. The difference between this $890 million and the $1 billion is that these figures do not include AFUDC because construction work in progress, I assume, would be included in the rate base, and you would have no AFUDC. The billion dollars that I referred to would have the carrying costs capitalized and included in it. You can see that the revenue requirements for the Caryville Plant would be $244 million just during the construction period versus $90 million for the Scherer Unit or $154 million worth of absolute savings. But if you put it on a present value basis and take into consideration the fact that you would be spending these dollars much earlier, of course, than you're spending these dollars, if you present value this back to 1/1/81 so you've got an exact match and get credit for the fact that these dollars are spent earlier, then you've got a difference between the present value of 55 million versus 89 million or a present value savings during the construction period, assuming that construction work in progress is in rate base, of $24 million between the two plants.

Now there's two things that are significant here. One is as Mr. Addison mentioned in his remarks, that if we stuck our head in the sand and took the easy way out for our company and for our stockholders, that there was a period of time when we could stay out of the money markets; in other words, stay out of the briar patch for a little while. We've been in the briar patch for a little while. Well, we've got an opportunity to get out a little bit now, and if we buy into this plant, we're going to jump right back into it. And what he was referring to, is this period of time out here. The major generating unit that we have under construction right now is the Daniel Plant. Most of the money has already been spent on it; it goes commercial June the 1st of this year. If we don't get into Scherer, we don't have to have major construction again until 1987. That gives us a period from 1981 through 1986 that we've got essentially little or no external financing which, obviously, would be quite an advantage to our company as far as the pressure brought upon it and on the stockholders to put additional money into the company. I might say, at probably below book value.

Now the other thing that Mr. Addison referred to is this period of time right here. We do not need this capacity until 1993. Scherer is only available, if you buy it, it's either available for '87-89 or it's not available at all. You either buy into it because it's going to be constructed by Georgia Power Company for '87 and '89 in-service, Unit 3 in '87 and Unit 4 in '89, no alternative. So during this period of time, we have commitments, pretty definite commitments for a significant portion of the output of Scherer already. We are confident, we are confident, although we do not have definite commitments, we are confident that we can market all of that output during that period of time. So that there would be no revenue requirements at all on our customers during the period from the initial commercial operation of that unit until it was actually needed on our system. Because it would be pulled out of rate base and, of course, these sales would be subject to FERC regulations. They would not even be in the rate base of our retail customers. They would be pulled completely out, and there would be no revenue requirements, there would be no rate base or anything relative to Scherer during this period of time. That would be taken care of by whoever we sold the power to and, of course, some of that, a significant amount of that in all likelihood is going to be sold in the State of Florida.

Now one of the things that needs to be pointed out is that you can see in 1981 you've got neary $10 million that we would have to spend in 1981. Actually, these are direct expenditures, nearly 10 million bucks. This was, I might just mention in passing that this, initially until we just in the last two weeks, this was initially supposed to be $40 million. And the reason for it is the deal that they had struck for us had us buying the common facilities. In other words, the first two units of Scherer are already, well, Unit 1 will go into service in 1982. So there are units, there's a significant amount of facilities that are constructed with the first unit, the stack and so forth that come into all the units. And the idea was that initially we were-going to have to pay our fair share; in other words, the four 818 megawatt units, buying 25% of two, we were going to have to pay one-eighth of all those common facilities up front. We since have negotiated a deal where we do not have to pay for those common facilities up front. We don't have to pay for them up until 90 days prior to the time it goes into service and we need the common facilities to actually operate the unit.

So in any event, these figures have been reduced significantly because of that item that was negotiated in the proposed contract. But you can see the amount of dollars that we're talking about. In 1984, $116 million; in 1985, $140 million. It's obvious that at the very maximum Gulf Power

Company would be able to, let's say, generate entirely maybe 50% of those dollars. That means the other 50%, we'd have to go outside and get it, sell bonds, preferred stock, or we'd have to get it in the form of common equity from Southern. With the cost of money being what it is today, with the prime rate being 20% with single A bonds, which our bonds are rated at, going anywhere from 14 to 15%, and our embedded cost of debt preferred is somewhere around 8½, it's pretty obvious that any of this financing we do in today's economy is going to drive the overall cost of money up. If you drive the overall cost of money up, obviously, you're going to create additional revenue requirements.

Now I think from looking at the figures that it's pretty obvious that this is a good deal for everybody concerned. It's a good deal for Gulf Power customers; it's a way to save absolute dollars over the life of the two plants, $2.7 billion for our customers. Even on a present value basis, we can save $263 million for the same amount of capacity for our customers. So it's good for our customers. It's good for our company. It reduces our financial requirements. It's good for the State of Florida in that we're able to get some coal-fired generation available to other companies in the State of Florida. It's a good deal for everybody concerned.

The problem that we have is, even though we recognize that it's such a good deal and it's a good buy, relative to the alternative, is that we have to somehow be able to get from here to there. In other words, we have to be able to get the dollars and have the cash flow and have the ability to do the financing necessary to take advantage of this. It doesn't matter how good a deal this is, it doesn't matter how good a deal it is or how much savings there are, we somehow have to be able to take advantage of it. And the only way we can take advantage of it is, of course, to have the support of this Commission. We must be allowed to include a significant portion, or if not all, of construction work in progress in the rate base in order to provide coverages which will give us the ability to finance. We today, right today, are dead in the water as far as issuing bonds and preferred. We can't issue either one because our coverages are not high enough.

So we need construction work in progress in the rate base for that. We need it in order to get the cash flow. We need it in order to improve the quality of our earnings. But the primary reason we need it is in order to have the ability to pay for it, the ability to finance. The cash flow generated by it plus the ability to issue the securities with it that would be necessary.

Now in addition to that, there is going to be increased cost of money as we do this financing to finance this, it's going to drive the overall cost of money, and we must be able to recover these carrying costs during this construction period. We don't have to worry about this period right here because that's going to take care of it, as far as the construction work in progress, the carrying costs. But for this period, we must be able to recover the increased carrying cost.

Now in order -- and this sort of repeats what Mr. Addison said, but I reckon it's worth repeating because it's our whole purpose for being here. As he said, we're right on the verge of getting ready to sign this contract. These people have, in effect, told us, you know, "Make up your mind, either do it or forget it, one or the other." And, so we're right at that point where we're either going to make a decision to do it or not to do it. But before we can embark on this type of financial endeavor, we must have the assurance of this Commission and the support of this Commission in our so doing. And the thing that really concerns me, because of a lot of the second guessing we received on Caryville and other projects, is that when we come in for rate relief during this period of time, during this construction period, asking to get some of this construction work in progress in the rate base, asking to get these increased carrying costs because of financing, if the decision made by the Commission in granting the required revenues is influenced by the fact that this capacity will not be initially used by our customers and we get some type of negative regulatory treatment because of that one fact, then our company is going to be in serious trouble. And that's what concerns us; that if we dive off in this water, we must have the support of this Commission before we're going to be able to do it. Because if we get into it and get down the road, and then we start getting different treatment and saying, "Well, wait a minute, you know, that capacity initially is going to be used by somebody else and not your customers," then our company will be in very, very, very serious trouble, and we just can't allow it to do that. Because, after all, there is only one reason and one reason only that Gulf Power -- now there's some fringe benefits. Obviously, if we build the Scherer Plant, it provides a coal-fired capacity during this time frame right here for some other Florida companies to displace oil by. That's a fringe benefit. The reason, however, the main reason, in fact, the only reason really as to whether we will build Scherer is because of our customers, it was to the benefit of our customers. Because that capacity is needed. We need some capacity in 1993 according to our estimates for our own customers in Gulf Power territory, and the best alternative and the cheapest way to get it is to buy into Scherer. And that's the reason we're looking to make that decision. And, therefore, if we're making that decision for our customers in their best interest, naturally, of course, they are going to have to pay the tab.

And I suppose that at this point in time we could open it up for questions, and Mr. Addison will handle that.

CHAIRMAN CRESSE: If he doesn't shift them. Mr. Parsons, I can see you're getting ready to do a lot of work.

(Off the record briefly.)

COMMISSIONER MARKS: If we went to the Caryville alternative, what happens to -- I notice that you don't start any equipment until 1987. What happens to the equipment that's been accumulated up until now?

MR. ADDISON: There is none, and that's part of what the $12 million went for that was treated in our rate case. And that is when we made the decision, it was so early that thank heavens we made the decision as early as we did. And the equipment, some of it was beginning to be manufactured, and we had to pay for materials and engineering and so forth. But there is no equipment.

MR. SCARBROUGH: Are you referring to the amount that was allowed in the last case? That was for plant Daniel, and we're fixing to take care of that. That was 100 million bucks, and we're fixing to bring $200 million worth of plant in-service come June.

COMMISSIONER MARKS: That wasn't quite what I was getting at. I think Mr. Addison answered what I was getting at. It's included in the $12 million figure.

MR. ADDISON: And there is no equipment. And that $12 million does not include the cost of the site or the environmental work or anything like that because we think that is something that we are going to be using.

COMMISSIONER MARKS: One other question I have on the Scherer alternative. In 1989, you estimate that that would be replacing or displacing some oil-fired generation. You don't know how much, or do you, or do you have any estimate or whatever, any kind of figure on that?

MR. ADDISON: Earl, do you want to try to answer that? I'm not sure we can get any specific figures on that.

MR. PARSONS: We have the capacity at Scherer that is available for sales off our system, and we are working now with Florida Power & Light in the '89 time frame to sell them at that period of time, 1,000 megawatts.

MR. ADDISON: That's not from our company now, that's from the total output of that plant. We'll be selling a proportionate share of it.

MR. PARSON: That's right. And then we also are working with Jacksonville Electric Authority for a portion of our capacity also.

COMMISSIONER MARKS: Is it safe to say that if you sell of that capacity during that four-year period, that all of it will be displacing oil?

MR. ADDISON: I think that's a safe statement.

COMMISSIONER MARKS: I assume it would be. I just want to ask you that.

MR. ADDISON: That's about the only economic thing.

Because if the companies had existing coal-fired generation, it would probably be more economical.

COMMISSIONER GUNTER: I think one of the things that John is getting at is when we have the power plant siting hearing as far as the Big Bend Plant, the TECO plant, they addressed the same issue that you're addressing here. They will have over capacity during that time period, but they had already cut a deal for X number of years if that plant went into service, that Florida Power & Light would receive that portion on a declining scale up until they required all that generation for their own system. And I think John was relieved, that's my interpretation of his question. During the '89 to '92, two things -- a demonstration, you know, that it would be sold off system, which, of course, it would be. And secondarily, that you're replacing that oil-fired generation or supplementing.

MR. PARSONS: The two contracts that we are very close to signing would be for a total in '89 of 258 megawatts of Scherer, 260 in '90, 282 in '91, and 298 in '92. However, we have offers out to other utilities that would take all of the capacity, our portion of capacity out of Scherer.

COMMISSIONER GUNTER: That was the question I had.

MR. SCARBROUGH: This is showing four years here. Remember that that first unit goes in in 1987. So we actually are anticipating selling energy starting in '87 and '88 out of

Unit 3. And then beginning in '89, out of 4. So you really have sales back up here in these two years also out of Unit 3.

CHAIRMAN CRESSE: I understand. I guess that that contingency in that last order has gotten you all's attention, and this is the result of all that, and I appreciate it, Mr. President. Because the Commission is concerned, and I think properly concerned, as to whether or not the conditions and so forth, we're really concerned whether or not Georgia Power was going to go ahead and continue to build that situation up there. And it got all tied up in our conservation deal and with the idea of shipping coal by wire and the construction now being much cheaper than later construction, and that's what some of those figures, in fact, I believe, demonstrate.

A question, though, that comes up in my mind in this is, is that the question of CWIP or AFUDC. Now based on the projections the Commission has had presented to it in the TECO case, those people who buy electricity from Gulf Power, because of this capacity, ought to be paying the entire cost, the entire capitalized cost during that period of time. And then whenever the plant comes on line to the Gulf customers, then they would benefit from the lower construction cost.

So it seems to me in the equation you've got an issue of CWIP or AFUDC, and I take it that you all are suggesting CWIP, and I can't figure out how, if you get CWIP during that period of time, that you start charging those customers, I mean, those wholesale customers, you're going to be getting AFUDC from them in the entirety, how that's going to equate back and so forth. And I'm just wondering why you can't AFUDC that sucker, charge the people that entire cost, and it comes back to depreciating --

MR. ADDISON: We're going to charge them the full cost.

CHAIRMAN CRESSE: It's a great deal except for that little niche.

MR. SCARBROUGH: What we would propose to do, we are showing here and, granted, this chart -- and I did this simply for the purposes of simplicity -- showed all the construction work in progress in rate base. But what we would propose to do to only include that amount of construction work in progress that related to the period of time which our customers would use it. Obviously, for the period of time which somebody else is going to use it, they're going to pay those carrying costs.

CHAIRMAN CRESSE: Yes. But the rates you're going to sell that electricity at has got to be the total capitalized cost of that.

MR. SCARBROUGH: It will -- we've got a situation that we just got into, Mr. Cresse, and it's a very good point. When the deal that we are negotiating right now -- what I'm saying is, these contracts for these sales have not been signed yet, obviously. The Georgia contract hasn't been signed, and the contracts for these definite commitments have not been signed on the dotted line. They're both pretty close. But a problem came up exactly as to what you are addressing now. And what had happened is, because we had some construction work in progress in the rate base, we had the potential for down the road having in the Scherer Plant, having a plant that was on your books that didn't reflect all of the carrying costs during the construction period. Because to the extent that we had construction work in progress in the rate base, we would not be calculating carrying charges. So, therefore, your construction work on the books would not have all the carrying costs in it.

And the contract that we were negotiating said that you used book investment costs, and they already calculated the rate. We pointed out to them, and at first they were a little chagrined, and finally they agreed with us, and that is the deal we're striking, is that we would impute the carrying cost. In other words, so that they would have, in fact, paid the full payment. In other words, even though it wasn't recorded on our books that you would impute those carrying costs and were calculating the rates during that period of time, it would be as if all those carrying costs were calculated. And that's the deal that we are striking.

CHAIRMAN CRESSE: It's simple to do that, you just

AFUDC it, then the books would be right --

MR. ADDISON: The problem with doing that total thing, I think, comes back to the same problem we had in our recent case in looking at the Daniel Unit, and that is we may end up with all our earnings being in AFUDC and not having the quality of earnings that --

MR. SCARBROUGH: Well, you know, the quality is important, but what's even more critical than that, it's the ability, the ability to finance it without some significant portion of construction work in progress in rate base in order to get the coverages. We don't have the coverages right now. You are limited, a very small portion of AFUDC can be included for coverage purposes.

CHAIRMAN CRESSE: Have you done the tests on projecting AFUDCing it as opposed to CWIPing it?

MR. SCARBROUGH: We've done all kinds of runs, and it all centers around on how close we come to earning our allowed return. And our history hasn't been very, very good or anywhere close to earning the return allowed by this Commission. The runs that we show, show --

CHAIRMAN CRESSE: That's in the days when you had to eat all your conservation costs, you had the fuel adjustment clause that didn't even give you the opportunity to recover your fuel cost and all those wonderful things and, you know, you had a very narrow band on your rate of return.

MR. SCARBROUGH: It simply, if you run the studies like you're discussing, and we have, it depends on what assumption you'll make about what kind of return. If you assume that you're going to earn your allowed return, sustain it consistently on a sustained basis, you know, you don't have to have as much construction work in progress in rate base in order to have the ability to finance. But if you have the returns like we've experienced in the last five to 15 years relative to what you're allowed, being allowed a return on equity of 14 and that type of thing and earning 8, you've got to have it all in order to have the coverage. So it depends on what you're earning.

CHAIRMAN CRESSE: I understand that. And, obviously, I think the question -- well, we don't guarantee it, and you've got regulatory lag and those things, and maybe a confidence level can overcome some of those regulatory lag factors. But I haven't got clear in my mind yet how all those dollars are going to be reflected if you put CWIP in the rate base on one side for your retail customers, and then you take that amount of CWIP and treat it as though if it would be AFUDCed when you start selling it to your wholesale customers, I don't see any minuses there on the CWIP revenue requirements after 1987 and 1989.

It strikes me that you're going to have a minus in there somewhere to get the pot right.

MR. SCARBROUGH: You're exactly right. If we do it like this, including all the construction work in progess, you've got to show the minuses here. I'll agree.

CHAIRMAN CRESSE: I don't see them.

MR. SCARBROUGH: They're not there.

(Laughter.)

CHAIRMAN CRESSE: I can see they're not there.

MR. SCARBROUGH: I was trying to make this simple. But what we would actually envision would be that you wouldn't have all the construction work in progress in rate base. This reflects all of it. But what we would envision is only including that proportion that was in proportion to the period of time in which our customers would use those facilties. So they all wouldn't be in there. If you don't put it all in there, you don't need the minuses. But the way we've got it reflected, you're right. If we put it all in there, we'd have to have the minuses.

MR. ADDISON: But if the wholesale customers are going to use it for five years, and the retail customers for 25 years, then the CWIP ought to reflect the 25 years, it seems like. Isn't that what you said?

MR. SCARBROUGH: That's exactly right. And then to the extent that we did not capitalize AFUDC and that our books reflect those carrying costs when we actually priced it out during this first five-year period of time, we would impute those carrying charges and make sure that we got that back from the wholesale customers.

COMMISSIONER GUNTER: Arlan, how much of a difference does it make with CWIP -- you brought up a point that I had not thought about concerning the coverage factors of AFUDC versus CWIP.

MR. SCARBROUGH: With a construction program like this, depending upon the level of the earnings, it can be the difference between being able to issue bonds and not being able to issue bonds. Because you can only include a small portion of AFUDC --

COMMISSIONER GUNTER: How small?

CHAIRMAN CRESSE: That varies company by company, depending on their bond and debenture, doesn't it?

MR. SCARBROUGH: And in our particular case, it can't exceed 10% -- I'm trying to think of the exact formula -- I don't remember the exact formula, but I do know this, that the maximum that we could use is somewhere around 5 million bucks.

COMMISSIONER GUNTER: Okay. That's the thing I've got to get quantified.

MR. SCARBROUGH: So once it goes over that, we can't use it.

CHAIRMAN CRESSE: Well, then, I think you've got a situation here where, in fact, until you can get an indication, I don't think the Commission can possibly give you an indication in an informal environment. But I think prudency on your part and on our part, too, would require maybe that we actually go into this. And I think you've done a good deal in getting those folks to say, "Yes, we will complete that deal up there. And, yes, we'll sell it to you if you want it." It looks like an outstanding kind of a deal, and all we're talking about here is the method of financing and the timing of that method of financing.

It seems to me that's the overall issue. And I just think probably we need to rapidly set a formal hearing and let the folks in there, because it's a major, major decision on a company as small as Gulf when you're talking about an investment of approximately $350 million, as I calculate it, over a period of seven or eight years. And whether or not you have the ability to finance it and how it will be financed, and recognizing that the company would be selling that electricity to other utilities at the end of that period until it's needed is what really puts the wrinkle in terms of the other wrinkles that are involved, CWIP. And I think probably the proper thing to do is to tell you that we appreciate this report, and I think that we ought to accelerate any kind of a formal, so you can get a formal expression from the Commission on this issue and allow those that are interested in this subject to express themselves also.

And if there's anything else we can do -- because I know it's very critical to you, and time is of the essence, and we'll take the time to do it. I think you've done what the Commission wanted you to do. I believe in pursuing that item that we brought to your attention rather forcibly, if that would be the right word, saying, you know, "We'll tell you what you can do about that." And you brought us an "opportunity" to review what you've done about it. And I think probably because of the significance of it, it might be appropriate to put it in a formal environment.

And Public Counsel is present with me operating informally and so forth. But that's kind of my gut reaction without having much legal advice. Maybe I should ask Mr. Pruitt.

COMMISSIONER MARKS: That's what I was going to find out. What kind of a formal environment are we going to put this decision making process into? We've heard one, obviously, you know, one side of the situation. There may be other views as to, you know, the method that they should proceed under or that we should proceed as a Commission. I don't even know if we've got a docket open or if this is a continuing docket.

CHAIRMAN CRESSE: I know the docket is still open because the issue is under bond, and the docket has still got to be open. I know that.

COMMISSIONER MARKS: So are we going to ask them to put this before us?

MR. PRUITT: We can proceed in that docket.

CHAIRMAN CRESSE: We can get a report back in that docket in a formal decision.

MR. McGLOTHLIN: Mr. Cresse, that docket is open for the purpose of conditioning the cancellation charges and the treatment of those. I think probably we can expect to see Gulf Power in this kind of ratemaking proceeding asking some appropriate treatment of any additional investment of the Scherer opportunity. Mr. Addison, maybe we should just ask, I took it as sort of an informal progress report, and I gleaned from your comments and those of Arlan that you either would like to have or expect to have some expression from the Commission in some form from the Commission.

But, undoubtedly, you understand the informal context we're in here and the limitations of the regulator in getting any kind of blank check authority or prior authority. And, most of all, you understand that those business decisions are yours to make and not the Commission's. So maybe you could just elaborate on what you would like to see come out of this informal presentation.

MR. ADDISON: All right. I think that the informal --

MR. TALBOTT: If I may, I'd like to make a few comments that I think would put it back in what I'd say would be a more proper perspective. And I think we're talking past each other or we're not, in my opinion, really making the point that's important on this. And it's not, in my opinion, whether the Commission would or would not put CWIP in the rate base, whether they would or would not go the other route of charging AFUDC, it's not whether they would or would not allow all of the capital costs, anymore so than it would be if that unit were being built for Gulf Power's customers for Gulf Power's use from the very point in time that it was put into service.

All of those issues are issues that the Commission would be required to address irrespective of that unique aspect. I think what's important about this presentation is that unique aspect, and that is, would the Commission -- and I think that's the important question, whether it's answered informally or formally, you know, is something I would refer to the attorneys -- but it's that unique aspect that would have to be addressed somewhere along the line. Would the Commission, just because of the fact that that unit has a unique aspect, i.e., there will be an interim period of time there that it will not be used or needed by Gulf Power's customers, would that unique aspect and that aspect alone result in the Commission treating that unit different than it otherwise would have? And that doesn't require a decision, whether you would or wouldn't include CWIP or whether you would or wouldn't include financing.

MR. SCARBROUGH: That's a good point, and maybe, if

I could elaborate on that a little bit, Bill, is that forget Scherer.

CHAIRMAN CRESSE: I understand what he's saying. It seems to me that the major issue that you're really saying is, because you acquire it earlier, would you penalize us as though you went ahead and treated it in a normal situation as though you had waited to build Caryville.

MR. SCARBROUGH: If we don't have Scherer and we build Caryville, we're going to come in here, you know, we're not going to worry about somebody else using it first and that type of thing. And all we're saying is, we do not, you know, as Bill pointed out, the Commission has policies on construction work in progress in rate base and allowed rates of return and all that kind of stuff. And you're going to treat that, if we build Caryville, you're going to treat that in some way or the other.

And what we're simply saying is that we want to have some type of assurance that this won't be treated different during this construction period than this would be simply because our customers are not going to be the initial users. That's really the only point. We're not really debating at this point in time whether we include construction work in progress or not. All we're saying is, if you would include construction work in progress over here, include it over here. Whatever allowed return you allow over here, allow it over here. Don't treat us different simply because we've got an unusual situation in that our customers would not be the initial users.

That's really the only thing that we're asking for assurance of, not whether you're going to include construction work in progress in rate base or not. That's a policy the Commission will address at that particular time.

MR. VINSON: And why this is of particular concern to Gulf is that every other utility now has to come before the Commission under the Plant Siting Act and get approval in advance of the need for the plant for capacity to be built. And we're not in that situation, and you've already seen you're fair game, that once you go through these things and people get to questioning whether there was a need. And we would like to have all the assurance we can going in and recognizing that according to our load forecast, we really don't need it until 1993. There's obviously a gap there, and there's obviously a great deal to be gained by building it now, but there's also a great deal to lose if, for some reason, the Commission decides that's not the way we should have gone in retrospect.

COMMISSIONER GUNTER: That's analagous of the TECO petition in building their plant. They didn't need it, and they were selling the capacity on the front end. They had a contract to provide that first year, 75%, I believe it was, on a declining scale for some several years, a time period very closely approximating this one. So it parallels as far as Commission consideration, I think, and it would have been at least a drip.

MR. SCARBROUGH: Absolutely. I think this is in lieu of what you gave TECO on their last petition because your plant is not being built in Florida, and we don't have to do that. But we still would like something from the Commission saying, "Hey, we're with you on doing this."

MR. SHREVE: I'll be frank with you, this is in a little different light than I am understanding now than the first part of the presentation. I think it started with Bill's comments. And I certainly see your thoughts on the capacity that's needed now and what arguments would come out as far as approval in the future. But if you are trying to just say that you do not want to be penalized because the retail customers will not use it until sometime in the future, that's one thing. I think I was getting the reading that you wanted some assurances that you were going to be allowed a certain amount of CWIP in there which, to me --

MR. ADDISON: I don't think we can ask for that.

MR. SHREVE: Okay. If we can be very frank about that, because, I'll be frank with you, I couldn't express it as well as Chairman Cresse did, but I really don't understand the total way it would work out as far as the retail ratepayers paying the CWIP, and how it would jive with coming in with

AFUDC later. So if it's perfectly clear that you wanted to be treated the same and you're not going to try and use this, the fact that you're putting the plant in, as any leverage to get or assure yourself of having CWIP, that's a different ball game.

CHAIRMAN CRESSE: It seems to me that what we're faced with and what the company is faced with is that, one, it's an opportunity to acquire a plant which is known by all reasonable standards to cost a lot less than if we wait to build one in real times. We have an interim kind of financing problem, and that the mechanism with which to accomplish that, one, if you've got a deal to acquire something cheaper earlier and the long-range total cost is going to be less by acquiring it earlier, the regulatory process ought to provide a mechanism for handling that in some way without committing to anything. If it's a good deal in terms of total dollars, there ought to be a way in which the ratepayers can benefit from that other than waiting.

Obviously, if you went the alternative route of waiting to build Caryville with the additional cost that would come as a result of inflation, with the additional cost that would come because of a different type of construction requirement to meet environmental problems and so forth, the long-range cost is going to be a whole lot greater.

And, basically, if that created financial problems, then, the question of CWIP and the appropriateness of it would be an issue. And you're just saying that basically because the plant is going to be completed and operational earlier than it would be if you waited and spent a larger amount of money, please don't hold that against us. That's what it amounts to, bottom line.

MR. ADDISON: I think that we use the CWIP in the presentation in order to kind of put the dollars in perspective, if you will, to make a comparison between the two deals, the two oppositions. But we have, our major concern, I think we've kind of got it in focus now, is that we just simply have to have some assurance that we're not going to be treated differently.

We can't ask you to make those kinds of decisions unless we go through the formal process. And right now the time element with us is such that it might destroy our ability to go forward with the deal.

MR. SHREVE: There are a couple of other considerations that you'd like to have considered, the fact that part of the funds are subject to refund are still clouded at this point, and also, I guess, the fact that capacity arguments on the siting --

MR. ADDISON: I think this, that if we get so that we get that satisfied feeling and can go ahead, then I think we could make a formal petition to the Commission to remove the cloud over those.

MR. SHREVE: That's accomplished by --

(People talking simultaneously.)

MR. ADDISON: So we've got to bring something in with ink on it or the Commission is not going to be very responsive.

CHAIRMAN CRESSE: The problem is how do you get from here to there. We're saying, "Show us the contract," and you're saying, "We'd like to come back and get that cloud removed, but the Commission is not going to accept anything less than the contract. Now we've got a deal here that looks pretty good to us," you all, without specifically formally saying, "How does this look to you all?" We're saying if it can be worked out in ways that it won't have additional burden on the customers, we ought to work to achieve that particular goal. Without committing to anything one way or the other in terms of when you bring us that contract and say that you want that cloud removed, and then we'll address that issue when you bring it to us.

But I think the Commission does appreciate the effort of the company to get that thing resolved. I know the people that get to use that, if you do conclude that contract, the people that get to use that cheaper electricity during that period of time in comparison to what all the projections say oil-fired electricity will, are going to appreciate it. I suspect that you'll get the key to the city, to the City of

Jacksonville based on what I've been hearing over there. Sometime when you start sending it to them, they'll probably send you the key.

COMMISSIONER GUNTER: I don't know about the key, but they'll probably give them part of the city.

MR. SCARBROUGH: In addition to the paradoxical thing on the situation we have on getting the cloud lifted, getting the contract signed, but we need the contract signed soon, but we've also got the other situation is, is that we've got some people that's wanting to buy this capacity, and we don't have any capacity to sell them until we sign this contract and, yet, we don't want to sign the contract until we get the capacity. So we're really caught. We've got to do something.

CHAIRMAN CRESSE: It strikes me you've got a real good deal. If you get a contract to build it, you're going to own it. And then if we mess you up between now and whatever time we mess you up in, you'll probably go out and sell that sucker at a profit. We're going to try to keep you from selling it.

MR. SCARBROUGH: Once it gets constructed, it's during the construction period that really worries us.

CHAIRMAN CRESSE: You can probably sell your construction agreement.

MR. TRAPP: Could I just ask Mr. Addison one question for my own clarification? Is it my impression in this that it's Gulf intent in this to offer, say, a first right of refusal to other Florida utilities for the purchase of the Scherer capacity, or are you going out in the open market for the Georgia built --

MR. ADDISON: The truth of the matter is that we are in the open market. I don't know of a Florida utility -- and, Earl, you can correct me on this -- why don't you tell them exactly what we've done?

MR. PARSONS: All right. We have been dealing with Florida Power & Light and Jacksonville. Both of those utilities, we expect Florida Power & Light to sign very soon. Jacksonville has approximately 30 days after Florida Power & Light signs to have in the future a right of first refusal for any deal that's made in addition to the two original deals. So if we find another utility, as I said, there's an offer now to pay for it now, we're working with those people. Then the first two utilities will have a right of first refusal to get any deal that we offer someplace else, the same deal --

MR. ADDISON: But I think that the other question he's asking is, haven't we also made it known to really all utilities in Florida as well as other places that we have capacity available?

MR. PARSONS: Yes, and we have. Five or six different utilities.

MR. TRAPP: Have you had any interest outside the State of Florida?

MR. PARSONS: Right now there's two utilities that showed some interest outside the State of Florida.

MR. SHREVE: I know you've always been free to give us other information, but I would like to pursue probably with some of you on exactly how you would look to handling some of this.

MR. ADDISON: We'd be very pleased to do that.

MR. SHREVE: I think we can certainly work in the direction, as long as we have the assurance not to try to use this as leverage to get additional CWIP.

CHAIRMAN CRESSE: I understood him to say they don't want any discrimination against the company.

MR. ADDISON: You can rest assured that when we come we're going to be asking for it. You can just put that on and know that that's what we're going to do. But also you can know that we understand that this particular arrangement does not give us any leg up on getting it or from any other way. And really, Mr. Chairman, the truth of the matter is, as I see it, we kind of felt like we were between the devil and the deep blue sea because, in a way, this Commission has addressed this issue twice with us already. Number one was in the original accounting treatment and number two was in the rate order itself in which, like you said, kind of forcibly got our attention. And it seems to me that's a pretty positive direction for us to go do it.

And, yet, because of the financial impact on our company, we really felt the necessity to come back and have some discussion and to see if we were in agreement that this is a sound business decision and for the benefit of our customers so that we can move forward with it. And that's kind of where we are.

CHAIRMAN CRESSE: I think there is, what got this thing to us, Commissioner, was that during the course of the last rate hearing, we got some word through one of the publications and so forth that the terms and conditions and the explanations which were given in 1978 for writing it off may not be able to be accomplished because of some reluctance on not be able to be accomplished because of some reluctance on the part of going ahead to construct the Scherer Plant which they would have an interest in. Essentially, in '78 they said, "We've got a better idea. We'll cancel Caryville and buy Scherer. And in '80 we had a deal that says, 'that was a great idea to cancel Caryville, but we're not so sure they're even going to build Scherer.'"

And Commissioner Gunter is an avid reader, and he read that there was a little something going on up there and that they may not build Scherer and we said, "Wait a minute. If it was a good deal, if the concept, terms, and conditions of which we allowed to write it off in '78 aren't going to come to some successful conclusion, maybe we ought not let you write it off." So we said, "We'll put that under bond and give you 12 months to come in and tell us what you're going to do or to otherwise justify the decision to cancel Caryville was a wise decision."

Of course, since that time the cost of fuel has gone up tremendously and all those kinds of things have happened. And, so, we were using some hindsight. But I think we did get their attention, and I don't think that the Commission is, I hope has never accused -- I hope we're never guilty of discriminating against a company that uses a little long-range planning and long-range thought processes in providing the most economical service to their customers.

On the other hand, I'd rather think that we would be unhappier with a company that was not willing to do something innovative and different than the customary "wait-until-the-last-minute" to build, construct, do those things that we're only obligated to do without taking a longer view.

I think you're taking a longer view, and I don't believe that the Commission will discriminate against your company because you're taking a longer view.

COMMISSIONER GUNTER: If you want to look at the other side of that order where we ordered that money held until you did it, that maybe is a backwards way of looking at encouragement.

MR. ADDISON: We looked at it as encouragement.

CHAIRMAN CRESSE: I think it was. I don't think anybody needs to kid themselves; that the Commission at that time felt that it was to the ratepayers in Florida's advantage for you to get that cheaper generating capacity out of Georgia than it was to build in Florida under the terms and conditions that you have to build in Florida. It's just that simple. You know, coal by wire is cheaper than oil generated locally based on all the data we have before us. And it's still cheaper by substantial amounts than oil generated locally.

I think maybe those companies who are going to buy it in the interim period of time except those we regulate, maybe ought to pay you a premium for it except for those we regulate.

MR. ADDISON: Thank you very much.

(Whereupon the presentation was concluded at 4:15 p.m.)

F L O R I D A)
COUNTY OF LEON)

CERTIFICATE OF REPORTER

I, HOLLY L. KIRCHMAN, RPR, do hereby certify that the undocketed matter of a presentation by representatives of GULF POWER COMPANY concerning the merits of purchasing an undivided 25% interest in Units 3 and 4 at the Scherer Plant located in Georgia, was heard by the Florida Public Service Commission on Monday, February 16, 1981, commencing at 3:00 p.m.

I further certify that I was authorized to and did report by stenotype the proceedings held at such time and place; that the same has been reduced to typewriting under my direct supervision, and the foregoing pages numbered 1 through 49, inclusive, constitute a true and accurate transcription of my stenotype notes of said proceeding.

IN WITNESS WHEREOF I have hereunto set my hand and official seal at Tallahassee, Florida, Leon County, this 23rd day of February, A.D., 1981.

Holly L. Kirchman

Notary Public, State of Florida at Large
My Commission Expires Sept. 13, 1984

Holly L. Kirchman, RPR
101 East Gaines Street
Tallahassee, Florida 32301

Commission Hearings Reporter

Internal
Correspondence

Gulf Power

Date February 18, 1981

Re Plant Scherer Capacity

From E. L. Addison

E L Addison

To Mr. E. B. Parsons, Jr.

As a result of the hearing we were granted before the Public Service Commission on Monday afternoon and the subsequent conversations between you, Mr. Scarbrough, Mr. Vinson, and myself, I feel we are clearly in a position to move ahead in signing the contract for Gulf's purchase into the Plant Scherer capacity. As we discussed, the comments of the Commissioners and the Public Counsel indicated their favorable disposition toward our participation in the project. I think they made it very clear we could expect the same type treatment in regard to the expenditures incurred in constructing these units that we might receive in the construction of any other units in spite of the fact we all recognize the capacity will be available to Gulf on the average of five years earlier than our planning now indicated it to be needed.

I believe the record is now established with (1) the Commission's letter in late 1978 according proper accounting treatment for the Caryville write off so that we could proceed with the purchase of Scherer, (2) the strong language in our rate order issued in November 1980 requiring us to complete the purchase of Scherer in order to remove the cloud over the revenues related to the Caryville cancellation, and (3) the transcript of the informal hearing held before the Commission this past Monday, February 16.

Additionally, as soon as the contract for the Scherer units is in hand, we will formally petition the Commission to remove the cloud from the revenues related to the Scherer purchase and that will again indicate clearly the Commission's intention for us to proceed in this manner.

You should now move with all dispatch to complete the negotiations with Georgia and have the contracts ready to sign at the earliest date.

ELA:jsa

cc: Mr. A. E. Scarbrough

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition of Gulf Power Company for an increase in its rates and charges.	DOCKET NO. 810136-EU (CR) ORDER NO. 10557 ISSUED: 2/1/82

The following Commissioners participated in the disposition of this matter:

JOSEPH P. CRESSE, Chairman
GERALD L. GUNTER
JOHN R. MARKS, III
KATIE NICHOLS
SUSAN W. LEISNER

Pursuant to duly given notice, the Florida Public Service Commission held public hearings on this matter in Pensacola, Florida, on October 28, 1981, in Panama City, Florida, on October 28, 1981, and in Tallahassee, Florida, on November 11, 12, 13, and 30, 1981, and on December 2, 3, 7 and 8, 1981. Having considered the entire record herein, the Commission now enters its final Order.

APPEARANCES

C. ROGER VINSON, ESQ. and EDWARD HOLLAND, ESQ., P. O. Box 12950, Pensacola, FL 32576, for Gulf Power Company.

JOHN W. MCWHIRTER, JR., ESQ., P. O. Box 2150, Tampa, FL 33601, for Air Products and Chemicals Inc., American Cyanamid Company, and Monsanto Company, Intervenors.

JACK SHREVE, ESQ., ROGER HOWE, ESQ., and SUSAN BROWNLESS, ESQ., Office of Public Counsel, Room 4, Holland Building, Tallahassee, FL 32301, for the Citizens of the State of Florida, Intervenors.

MAJOR ROBERT T. LEE, and GARY ROSNICK, ESQ., Law Center/JA, Armament Division, Eglin Air Force Base, FL 32542, for the Federal Executive Agencies, Intervenors.

PEGGY WELLS DOBBINS, ESQ., 150 East 42nd Street, New York, NY 10017, for St. Regis Paper Company, Intervenor.

JOSEPH A. MCGLOTHLIN, ESQ., PATRICK K. WIGGINS, ESQ., PAUL SEXTON, ESQ., ARTHUR R. SHELL, JR., ESQ., and BONNIE E. DAVIS, ESQ., 101 East Gaines Street, Tallahassee, FL 32301, for the Commission Staff.

PRENTICE P. PRUITT, 101 East Gaines Street, Tallahassee, FL 32302, as counsel to the Commissioners.

ORDER AUTHORIZING CERTAIN INCREASES

BY THE COMMISSION:

SUMMARY OF DECISION

Gulf Power Company's original petition requested additional revenues in the amount of $38,663,000. The Company requested, inter alia, a return on common equity capital of 18%; the inclusion of $30,000,000 of construction-work-in-progress (CWIP) in rate base; and an attrition allowance of $14,964,000 designed to offset future increases in expenses which Gulf projected on a per customer basis.

In this Order, we have determined that Gulf should be authorized an increase of $5,543,620 annually. In reaching this decision, we have concluded that the test of adequate financial integrity warrants the inclusion of only $16,364,958 of CWIP in rate base, and that Gulf should earn 15.85% on common equity capital, which includes an award of .10% to recognize the Company's conservation activities. We have rejected Gulf's originally proposed method of computing an attrition allowance and have used in its place an adjustment designed to reflect the annual effect upon investment, revenues, and expenses of Plant Daniel, which was placed in service during the test period. Because we find that Gulf's past load forecasting techniques were inadequate to enable the Company to cope with excess capacity by the timely development of off-system sales of capacity, we have adjusted test year revenues by $3,099,000 to prevent Gulf's ratepayers from contributing to the 1981 revenue requirements associated with Plant Daniel.

BACKGROUND

This proceeding involves the request by Gulf Power Company (referred to herein as Gulf or the Company) for authority to increase its rates and charges by approximately $38,663,000 annually. Gulf filed its petition and proposed rate schedules on May 29, 1981, and complied with the minimum filing requirements on June 26, 1981. Thereafter, we suspended the proposed rate schedules pursuant to our authority under Section 366.06(3), Florida Statutes (Order No. 10164, July 27, 1981).

Extensive public hearings on Gulf's request have been held in this docket. These hearings extended over nine days and resulted in a record comprising 4425 pages of transcript and 123 exhibits. We have also had active participation by numerous parties, including representatives of the public, governmental agencies and large industrial customers. Having considered the entire record herein, including briefs filed by the various parties, we find that consent should be given to the operation of rate schedules designed to produce additional annual gross revenues of $5,543,620 on a permanent basis. This will provide to the Company an opportunity to earn an overall fair rate of return (established herein) of 9.70%. The basis for our decision is set forth below.

THE PARTIES

The Company

Gulf Power Company is a wholly owned subsidiary of the Southern Company and is subject to our jurisdiction under Chapter 366, Florida Statutes. Since 1925, it has provided electric service through generation, transmission, distribution and sale of electric energy to its customers in ten counties in Northwest Florida.

The Company was last authorized to adjust its rates in 1980 (Order No. 9628, Docket No. 800001-EU, 11/10/80). At that time, we determined that the Company's fair rate of return fell within the range of 8.58% to 9.16%. Gulf now asserts that to maintain its financial integrity and to provide reliable electric service, it must have additional annual gross revenues totaling $38,663,000. This increase, according to the Company, is required to provide the opportunity to earn a rate of return of 10.49%, which it alleges is fair and reasonable under prevailing conditions. This amount includes an attrition allowance of $14,964,000, which the Company contends is needed to ensure its opportunity to earn that rate of return.

Public Counsel

The Office of the Public Counsel (Public Counsel) presented testimony of four witnesses during this proceeding. Public Counsel proposed that the Commission establish an average rate base of $575,194,000 and an overall rate of return of 9.36%, with a return on equity capital of 14.75%. Among other things, Public Counsel opposed the use of a projected test period. He also objected to inclusion of construction work in progress in rate base, inclusion in rate base of Plant Daniel, the Caryville construction site, or the unamortized balance of the Caryville cancellation charges. In addition, Public Counsel proposed that working capital should be established by the balance sheet approach, that industry association dues, charitable contributions, and all advertising be disallowed from operating expenses, and that temporary cash investments and the associated revenues be excluded from rate base and net operating income, respectively. Public Counsel also participated in several issues regarding rate structure and design.

Industrial Consumers

Air Products and Chemicals, Inc., American Cyanamid Co., and Monsanto Company, which are industrial customers served by Gulf Power, intervened together in this proceeding. They will be referred to collectively as the industrial customers.

These intervenors raised several issues in the area of cost of service and rate structure, and presented the testimony of two witnesses in this area.

St. Regis Paper Company

St. Regis Paper Company (St. Regis) intervened in this proceeding and presented the testimony of one witness in the area of cost of service and rate structure.

The Federal Executive Agencies

The United States Air Force and other Federal Executive Agencies (FEA) receiving service from the Company intervened in this proceeding. The FEA proposed a cost of equity capital in the range of 14.4 to 15.3%. The FEA opposed the inclusion of CWIP, the Caryville Plant Site, and the unamortized balance of the Caryville cancellation charges in rate base. The FEA proposed that working capital be established using the balance sheet approach, that deferred taxes be deducted from rate base and that temporary cash investments be excluded from rate base.

The FEA also participated in the area of cost of service and rate design.

The Commission Staff

The Commission Staff participated in the proceeding and presented the testimony of two witnesses dealing with the cost of equity capital and the number and nature of consumer complaints against the Company.

LEGAL ISSUES

The Commission was presented with two legal questions during the course of the proceeding.

Legality of Projected Test Year

Public Counsel has again raised the question of the permissibility of employing a projected test year. We have previously concluded that we have authority to utilize projected data (Docket Nos. 800119-EU and 810002-EU).

Public Counsel continues to assert that the language of Section 366.06(1), Florida Statutes, serves to prohibit the Commission from employing projected data. We continue to believe that, as the Court indicated in Shevin v. Yarborough, 274 So.2d 505 (Fla. 1974), the statutory language relied upon by Public Counsel should not be so restrictively interpreted. As Gulf points out, the statutes do not expressly dictate which test period should be used. We believe that we have the discretion to utilize projected data.

Legality of Including Unamortized Balance of Caryville Cancellation Charges in Rate Base.

In the last Gulf case, the Commission authorized the Company to amortize the Caryville cancellation charges, and also to place the unamortized portion in the rate base. The rate base treatment was appealed by Public Counsel, and is presently before the Supreme Court. There and here, he relies upon the same type of "used and useful" criterion described above. His position ignores the fact that the Commission's treatment was based upon the belief that the cancellation would realize net economic benefits to ratepayers. As with the issue of projected data, we believe that the Shevin v. Yarborough case demonstrates that Public Counsel's narrow and restrictive definition of what should receive rate base treatment should not prevail. We conclude that it is within our lawful discretion to allow the unamortized cancellation charges in rate base.[1]

1 After our decision and prior to the release of this Order, the Supreme Court of Florida affirmed our treatment of the unamortized cancellation charges in Citizens v. Cresse, Case No. 60437, opinion dated January 28, 1982.

THE TEST YEAR

The function of a test year in a rate case is to provide a set period of utility operations that may be analyzed so as to allow the Commission to set reasonable rates for the period the rates will be in effect. A test period may be based upon an historic test year with such adjustments (often extensive) as will make it reflect typical conditions in the immediate future, and make it reasonably representative of expected future operations. Alternatively, a test period may be based upon a projected test year which, if appropriately developed and adjusted, may reasonably represent expected future operations.

As in other recent major electric utility cases, this case is predicated upon a projected test year. The Company proposed to use calendar year 1981 as a test period, and received preliminary approval of the test year at the outset of the proceeding. Having considered the record herein, we affirm the appropriateness of the test year for purposes of this case. As adjusted herein, we believe the test period reasonably represents expected operations during the period the rates will be in effect.

RATE BASE

To establish the Company's overall revenue requirements, we must determine the value of its "rate base," which represents that investment upon which the Company is entitled to earn a reasonable return. Once that is done, the net operating income applicable to the test period can be developed, and related to the rate base to determine the rate of return which would be realized under existing rates.

Reasonableness of Assumptions and Projectons

The Company has proposed a test year rate base on the basis of projected data relating to the Company's 1981 operations. As previously noted herein, Public Counsel has again questioned the permissibility of relying upon projected data. In addition, the parties raised the issue of the reasonableness of the projections and assumptions used to develop the proposed rate base. We have concluded that we have the legal authority to utilize projected data for ratemaking purposes. We now find that the assumptions and projections relating to rate base investment are reasonable and adequate for review and analysis.

The rate base proposed by the Company is based upon its normal budgeting process. The company sponsored several witnesses who explained the development of the Company's 1981 budget and test year. Numerous exhibits describing the budgeting process and variances between projected and experienced operations were placed in evidence. The budgeting process used to develop the test year rate base is the same process that was used to develop the projected net operating income, which will be discussed later.

The Company's Director of Corporate Planning, Mr. Gilbert, sponsored testimony and exhibits describing the methodology used by the Company in forecasting both rate base and balance sheet data. The construction budget for the following calendar year is normally completed by October 1 of the current year. The budget includes estimates of expenditures based upon current construction schedules and cost estimates. Construction projects are reviewed by the Company's budget committee for necessity, cost and the Company's ability to finance them. Approved projects are subject to further review and approval by the Board of Directors. In this case, the construction budget was prepared using forecasted construction expenditures as of February 1, 1981, estimated by projects. Net additions by primary accounts for the budget year were added to actual plant-in-service as of February 1, 1981, to produce the balance for the test year.

The plant in service and plant held for future use are forecasted through an analysis of expected plant additions and retirements and land expected to be purchased, disposed of or transferred into CWIP during the period. (Ex. 4, Schedule 9). Balance sheet data is forecasted by the financial model from data obtained from other segments of the model and from known changes expected for the year. Mr. Gilbert also sponsored Exhibit No. 83, which showed the change in the Company's balance sheet data between its previous 1979 test year and the 1981 test year data. Explanations were provided for all variances. Schedule 5 of Mr. Gilbert's Exhibit No. 43 compared actual balance sheet data with projected test year data through September of the test year. These exhibits showed that the Company's rate base projections through September have been very accurate and that large increases in plant-in-service since the 1979 test year resulted from the addition of Plant Daniel #2 during the 1981 test year.

Mr. Bell, a partner in Arthur Anderson and Company, testified as to the results of his review of Gulf's financial forecasting system and of the forecasted data on which the Company's filing was based. Mr. Bell's review was in conformity with accepted accounting and auditing procedures as set forth by the American Institute of Certified Public Accountants in its "Guidelines for Systems for the Preparation of Financial Forecasts". It was Mr. Bell's conclusion that Gulf's forecasting system "conformed with relevant professional standards, is adequate for its purpose, is complete and logically well founded and can be relied upon to produce consistent, reliable results".

We are of the opinion that the Company's projected rate base data, as adjusted herein, is reasonable and adequate.

Gulf Power Company has submitted a proposed jurisdictional rate base of $675,375,345. Evidence developed during the course of the proceeding has led us to reduce that amount to $628,574,431. In addition, we have considered certain issues which did not result in adjustments. Our adjustments to the Company's proposed rate base are as follows:

<u>Construction Work In Progress</u>

Construction work in progress can be accounted for by either of two methods. An Allowance for Funds Used During Construction (AFUDC) may be applied to the balance, to be capitalized and later recovered through depreciation charges once the plant is placed in service. When this method is chosen, the financial statements of the Company reflect paper income "credits" associated with AFUDC, but the utility realizes no current cash earnings from the investment in construction work in progress.

Alternatively, CWIP may be included as a portion of rate base. Where this treatment is allowed, CWIP generates cash earnings, which provide cash flow and increase coverage ratios. Of course, no AFUDC is taken on that portion of CWIP which is included in rate base.

In this case, the Company contends that the rate base should include $30,000,000 of CWIP on a system basis. The Public Counsel and the FEA, however, recommend that no CWIP be allowed in the rate base.

The Company's requested $30,000,000 of CWIP is an approximation of the test period year-end amount of $32,203,000, which excludes any CWIP related to Plant Daniel. The Company used the year end amount, rather than the average amount of $96,298,000 for the test year, because it contends that the year end amount is more representative of the CWIP balances to be experienced during the first year that the new rates will be in effect.

Mr. Scarbrough supported the Company's request to include $30,000,000 of CWIP in rate base by asserting that cash flow would be improved, interest coverages would be increased, and capital costs would be lessened. He stated that investment analysts view with apprehension earnings which are comprised in significant degree of AFUDC credits. Mr. Scarbrough opined that the inclusion of CWIP would reduce revenue requirements in the long run, and would lead to phased-in, less dramatic increases in rates.

For the Federal Executive Agencies, Witness Miller maintained that the inclusion of CWIP is inappropriate because it is not "used and useful". He likened the inclusion of CWIP to coerced investment of the ratepayers in the utility. Both Mr. Miller and Mr. Dittmer, a witness for Public Counsel, pointed out that ratepayers' money, like that of the utility, has an associated time value that the Company ignored in its assertions. Mr. Dittmer pointed out that the Company had not quantified any savings in capital costs, and maintained that the Company's coverage ratios and cash flow were adequate without the inclusion of construction work in progress in rate base.

While the average amount of CWIP for the test period is $96,298,000, that amount includes $76,124,000 of CWIP related to Plant Daniel, which went into service during the test year. Adjusting Plant Daniel from the total yields an average for the test period of $20,174,000.

The amount of $20,174,000 includes expenditures related to the Scherer transaction. Mr. Scarbrough testified that the projected expenditures for Plant Scherer represented the buy-in costs that the Company expects to incur when the contract to purchase part of Plant Scherer is closed. Mr. Scarbrough further testified that no expenditures had actually been made to date and that he was uncertain when the expenditures might be made. The date of the closing has been extended to June 30, 1982, and the closing is subject to the approval of the SEC. It appears from the record that the Company will not incur any costs related to Plant Scherer during the test year. The $2,569,000 of CWIP related to Plant Scherer should not be included in the test year average amount of CWIP. When the $20,174,000 is reduced by the $2,569,000, the resulting amount of CWIP is $17,605,000.

Another adjustment is necessary to eliminate a cancelled project. The Company originally projected that it would spend $306,000 to increase the capacity at the Blountstown substation to serve a wholesale customer. It appears that a portion of those expenditures may have been allocated to the retail customers. Since this project has been cancelled and relates solely to the wholesale jurisdiction, we believe that the $17,605,000 should be further reduced by $306,000, leaving a system average amount of $17,299,000 in CWIP. The jurisdictional portion of this amount is $16,364,958, which includes non-interestbearing CWIP.

In recent orders, we have recognized that both proponents of the inclusion of CWIP in rate base and those who resist inclusion have advanced arguments having merit in support of their respective positions, and those arguments have been repeated in this case. Where necessary to provide and maintain adequate financial integrity, it has been our policy to include what we deem to be an appropriate amount of CWIP in rate base for the purpose of increasing cash flow and coverage ratios, and decreasing the percentage of earnings comprised of AFUDC, on the conviction that the resulting strengthened financial integrity would lead to a lower cost of capital. It follows, however, that only that amount of CWIP needed to assure adequate financial integrity should be placed in rate base. This criterion, and not the Company's effort to arrive at an amount representative of future balances, will govern our decision. In this case, we find that, while the inclusion of a portion of CWIP is justified to achieve satisfactory financial integrity, the $30,000,000 requested by the Company is not needed for the intended purpose. Instead, we find that the inclusion of $16,364,958 (resulting from the adjustments described above) yields a satisfactory financial condition, when measured by coverage ratios and the amount of AFUDC included in earnings. Accordingly, we have reduced rate base by $12,430,306.

Working Capital Allowance

The Company has computed its working capital allowance based on a combination of selected balance sheet accounts and a lead-lag study. The Public Counsel has calculated a working capital allowance based on the balance sheet approach. The FEA supports the use of the balance sheet method for computing the working capital allowance.

The Company claims that a lead-lag study is the proper methodology for calculating the working capital allowance whenever such a study is available. Of the Company's total system working capital requirements of $130,105,000, the lead-lag study was used to develop the requirement to finance the net lag in collections from customers of $14,758,000, which represents 11.3% of the total claimed working capital requirements. The Company has utilized the balance sheet approach to develop the remaining $115,347,000 (88.7%) of its requested working capital allowance.

Mr. Bell offered testimony in support of the lead-lag study methodology used in developing the $14,758,000. Mr. Bell testified that the lead-lag study is better than the balance sheet method because it overcomes the following shortfalls of the balance sheet method:

(1) The application of the measurement factors determined in the lead-lag study to the cost of service results in an amount of working capital that is internally consistent with those costs and, in this sense, is more "precise" than the balance sheet method.

(2) The lead-lag measurement factor can be more readily applied to the jurisdictionally separated cost of service than the balance sheet method.

(3) The lead-lag study is based on an annualized cost of service representing 365 days of activities as opposed to month-end balances.

Mr. Bell also claimed that the balance sheet method is clearly inadequate as a predicting device when based on historical data and that it is a highly biased sample because it is based only on month end data.

The Public Counsel and the FEA, however, contend that the balance sheet methodology is the proper methodology for calculating the working capital allowance. Mr. Larkin, a witness for the Public Counsel, calculated a working capital allowance based on the Company's 13 month average balance sheet accounts. This 13 month average component of rate base was then included within a consistently calculated rate base and the total rate base was related to a capital structure that matches and supports the Company's total investment.

Mr. Larkin contends that "the only reasonable approach to determining the rate base for Gulf Power Company would be through the use of balance sheet data". The balance sheet data which would be most appropriate to use would be a balance sheet which reflects the investments which generated the income during the test period. This, of course, would be the average investment for the test period ending December 31, 1981." Mr. Larkin, therefore, has used the adjusted current assets and liabilities from the Company's balance sheets to compute the working capital allowance for the test year.

We believe that the balance sheet method is the proper methodology to use to develop a working capital allowance. During cross-examination, Mr. Bell admitted that his criticism of the historical balance sheet approach was negated by the fact that the working capital allowance was calculated using projected balance sheet accounts. In fact, Mr. Bell is the only witness on the subject who used historical data. Mr. Bell testified that he analyzed historical data to determine the leads and lags. These leads and lags were then applied against the projected data, based on the assumption that the historical data is representative of the future.

Mr. Bell also stated that the use of month end balances resulted in a highly biased sample. The majority (88.7%) of the Company's working capital allowance, however, is based on the use of month end balances. In fact, 97.9% of the Company's total system rate base is based on the use of month-end balances. It is inconsistent to claim that month-end balances are representative and appropriate for virtually all of the Company's rate base components, while contending that they are not appropriate for determining its total working capital requirements.

It was also brought out during cross-examination by the Public Counsel that some of Mr. Bell's assumptions did not reflect the actual experiences of the Company, and that he had used averages in developing some of his assumptions.

The Company has failed to demonstrate that the lead-lag study sponsored by Mr. Bell produces a more representative working capital allowance than the balance sheet method. We agree with Public Counsel that the balance sheet approach should be utilized in the calculation of the working capital allowance.

The Company claimed a working capital allowance of $130,105,000. Public Counsel computed a working capital requirement of $64,243,000. We have reduced the Company's requested allowance to $102,273,000, based upon the following adjustments:

A. We have reduced assets by $4,589,000 to eliminate the effects of the Company's appliance sales and service operation. This operation is non-utility in nature.

B. We have reduced assets by $508,000 to eliminate loans to employees, which is a non-utility function.

C. We have reduced assets by $129,000 to eliminate interest and dividends receivable. These amounts represent earnings on other assets and should not be included in working capital.

D. We have reduced liabilities by $141,000 to eliminate the effects of the Company's appliance sales and service operation.

E. We have reduced liabilities by $3,692,000 to remove common dividends declared. In our opinion, common dividends declared represent stockholders' funds until such time as they are actually paid, and, as such, they should not be used to reduce working capital.

F. We have reduced liabilities by $6,753,000 to remove $6,741,000 of customer deposits and $12,000 of current maturities of long term debt. These items have a cost associated with them and are included in the Company's capital structure.

G. We have reduced liabilities by $14,000 to reduce accrued taxes payable to recognize the effects of the Economic Tax Recovery Act of 1981. A corresponding increase of $14,000 has been made to the deferred taxes included in the Company's capital structure.

H. We have reduced liabilities by $3,445,000 to reduce accounts payable for the amounts related to the Caryville Cancellation which have been netted against the extraordinary property loss and included separately in rate base.

I. We have reduced fuel inventory by $7,269,500. In doing so, we have rejected the recommendation of the staff to remove from rate base $10,665,000 associated with the Plant Daniel fuel inventory. In our view, a more appropriate approach is to gauge the total system inventory.

Gulf's Earl Parsons testified that the policy of the Company is to maintain an inventory adequate to last 60 days when burned at full "nameplate" capacity. We have accepted this policy as an appropriate management decision for the purpose of our review. Dividing the 60 days by the system average capacity factor of 60% yields an average inventory goal (expressed in terms of normal burn rate) of 100 days. The record reflects that the average daily inventory cost was $469,000 and that, when measured systemwide, the Company had on hand 115 1/2 days of inventory. Therefore, we have removed from the working capital component of rate base 15 1/2 days of coal inventory valued at $469,000 per day, or $7,269,500.

The net effect of these adjustments reduces the Company's system working capital allowance of $130,105,000 to a total of $102,273,000. By applying a separation factor of 94.51% to the system amount of $102,273,000, the resulting jurisdictional working capital allowance is $96,658,212.

Rail Car Investment

We have removed from the value of the Daniel plant in rate base the amount of $7,994,611, which represents Gulf's investment in rail cars which serve the unit. We believe it would be more appropriate to reflect the full cost of transportation in the cost of fuel, as is done by all other investor-owned utilities in Florida. This adjustment will better enable us to make meaningful comparisons among the utilities we regulate. In addition, such costs of transportation should be reflected in the price of any economy energy sold from the Daniel unit.

New Service to Exxon

The rate base proposed by the Company did not include investment incurred to provide new service to Exxon. We find that it is appropriate to increase rate base to reflect the 13 month average amount associated with that service, or $91,800.

Separation Study

As discussed elsewhere in this Order, we have decided to approve and adopt the cost of service study sponsored by Mr. Pollock, a witness for certain large industrial customers, for the purposes of this case.

According to Mr. Pollock's cost of service study, the jurisdictional rate base is $158,814, lower than the rate base contained in the Company's filing. The $(158,814) represents the following adjustments:

Plant in Service	$(519,209)
CWIP	37,857
CWIP Not Bearing Interest	(5,421)
Property Held for Future Use	4,214
Caryville Cancellation Charges	10,689
Accumulated Depreciation & Amortization	71,348
Working Capital	241,708
Total Adjustments	$(158,814)

Accordingly, we have reduced the Company's jurisdictional rate base by $158,814.

RATE BASE ISSUES NOT RESULTING IN ADJUSTMENTS

Temporary Cash Investments

The Commission staff recommended that we remove the amount of the Company's temporary cash investments from working capital as unrelated to utility service, and eliminate associated earnings from the determination of net operating income. However, we regard cash management as part of the utility's normal business, and thereby have included temporary cash investments in working capital.

Plant Daniel Start-Up Costs

The Company included in plant in service some $1,551,863 (system) of capitalized start-up costs associated with the Daniel #2 unit. The Company contended that no adjustment should be made to share these costs with Mississippi Power Company (MPC), since customers of Mississippi Power absorbed 100% of the start-up costs of the Daniel #1 unit.

Company Witness Scarbrough testified that MPC assumed 100% of the start-up costs of Daniel #1 and that these costs were passed to MPC customers through the fuel adjustment clause. Therefore, Gulf agreed to assume 100% of the start-up costs of the Daniel #2 unit. Rather than pass all of the Unit #2 start-up costs through the fuel adjustment clause, as MPC did with the Unit #1 costs, Gulf was forced to capitalize that portion of the Unit #2 costs which were over and above what the operating costs would have been had the unit been operating under normal operating conditions. This was done in accordance with our FPSC Accounting Department Bulletin (ADB) 76-7, issued on April 28, 1976.

Mr. Scarbrough further testified that the $1,551,863 was capitalized out of total start-up costs of $15,251,098 for Daniel Unit #2 and if Daniel #1 start-up costs had been accounted for on a basis comparable to the method used for Daniel #2, it would be necessary to capitalize $1,678,256 out of the total start-up costs of $11,801,968. Therefore, if the Unit #1 costs were accounted for in the same manner as the Unit #2 costs and both are shared equally between Gulf and MPC, Gulf would be required to decrease rate base by $775,932 (system) for half of the Unit #2 costs, while at the same time increasing rate base by $839,128 for half of the Daniel #1 costs borne entirely by MPC. The net effect of these adjustments would increase Gulf's requested rate base by $63,196, (system). Mr. Scarbrough adds that "there is no way, we (Gulf) can collect an adjustment from MPC in any event".

Public Counsel has taken the position that one-half of the capitalized Daniel #2 start-up costs $795,607 (system) should be borne by MPC, and Gulf's rate base should be reduced in the same amount. Executive Agencies did not address this issue.

We find that the Company has accounted for the Daniel Unit #2 costs in accordance with the Uniform System of Accounts and ADB 76-7.

Company Witness Scarbrough testified that although Gulf had committed to a participation agreement on Daniel Unit #1, prior to the in-service date of the unit (TR 1521), the start-up costs of Unit #1 were incurred and passed to MPC customers prior to any equalization payments being made by Gulf Power. When these equalization payments were made, no Unit #1 start-up costs were included, since the Unit #1 costs had been passed to MPC customers. (TR 1522) If not for ADB 76-7, the Unit #2 costs would have been accounted for in exactly the same manner as the Unit #1 costs, and the entire $15,251,098 could have been passed through the fuel cost recovery clause to Gulf's customers. No capitalization would have been necessary. Another alternative would have been to account for the Unit #1 costs,, in accordance with ADB 76-7; however, this would result in a net increase in Gulf's rate base of some $63,196. Since the Unit #1 costs have already been disposed of in Mississippi, this latter treatment, absent any adjustment by the Mississippi Commission, could result in either Gulf's or MPC's stockholders absorbing the $775,932 of Unit #2 costs that would be transferred to MPC.

Due to the different time periods and jurisdictional regulations involved with this transaction, we are satisfied that Gulf took the appropriate action, and make no adjustment to the Company's treatment of this matter.

Caryville Site

In this case, the Company proposed to continue to include the value of its Caryville plant site in property held for future use. Public Counsel took the position that the site should be removed from rate base. The Federal Executive Agencies proposed that the site be removed, but that the Company be allowed to charge AFUDC on the site.

The Commission staff recommended that only 30% of the site's value be included in property held for future use, based upon the indication that Gulf may build a plant on the site in 1995 and participate with Mississippi Power Company on a 30% - 70% basis. However, we find this possibility too speculative to entertain. We find that the site meets the criteria for property held for future use and have allowed the full value of the site to remain in rate base.

Caryville Cancellation Charges

In the Company's last rate case, Order No. 9628, we determined that Gulf's decision to cancel its Caryville facility was prudently based upon an economic advantage to Gulf's customers associated with purchasing the Scherer capacity in lieu of constructing the Caryville facility. In the order, we allowed these cancellation charges to be amortized above-the-line, and allowed the unamortized balance of the charges to be included in rate base. Revenue requirements associated with both amounts were ordered to be placed subject to a refund until such time as the Company's contract to purchase a portion of the Scherer Plant is consummated.

In the current case, the Company has taken the position that no evidence has been presented concerning the prudence of the Caryville cancellation or the prudence of Gulf's decision to buy into the Scherer Plant. It contends that no adjustment is warranted for this issue.

Public Counsel has taken the position that the unamortized cancellation charges should be removed from rate base, since they are not "used and useful" within the meaning of Section 366.06(1), Florida Statutes. Public Counsel has attempted to support this position through an "interpretation" of Section 366.06(1), Florida Statutes, and by reference to past Commission orders and court cases.

Executive Agencies have also taken the position that cancellation charges should be excluded from rate base. However, they propose a "sharing" arrangement, whereby the unamortized balance of cancellation charges will be excluded from rate base, but the amortization of these charges will be allowed as an above-the-line expense in the income statement. This they believe will "protect" the investors from loss of capital by allowing recovery of the expenses while "protecting" the ratepayers from paying a return on unused and useful property.

In our opinion, this matter was fully aired and resolved during the last case, and nothing of an evidentiary nature has been offered to persuade us to depart from our earlier findings. With regard to the legal issue, we reiterate that we are of the opinion that Section 366.01, Florida Statutes, does not prohibit the inclusion of the unamortized cancellation charges in rate base. While we have decided to continue the ratemaking treatment of this matter which was afforded in the last case, we wish to make it clear that we shall also continue the condition that was placed upon associated revenues, pending consummation of the Scherer transaction.

Southern Company Services

The prehearing order in this case identified as an issue the question of whether Southern Company Services effectively and efficiently provides fuel procurement services for Gulf Power Company. This issue was not explored in depth during this case. We find that no basis for an adjustment to rate base is warranted by the record that has been developed. We direct the Company to provide to the fuel procurement section of the Commission's Electric and Gas Department a copy of the independent audit performed by Theodore Barry and Associates which was referred to by the Company during the course of the hearing.

Deferred Taxes

The Executive Agencies have proposed that $83,077,000 (system) of deferred taxes and investment tax credits be deducted from the Company's proposed rate base, rather than be treated as zero-cost capital in the Company's capital structure. This position was supported by Executive Agencies' Witness Mr. Miller, who asserted that deduction from rate base is necessary to insure consistency in the Company's capital structure, since the Company is requesting a year end capital structure and IRS regulations require the use of 13 month averages for deferred taxes and investment tax credits.

Both the Company and Public Counsel are of the opinion that deferred taxes and ITC should be treated as zero-cost capital, as opposed to deductions from rate base. Both parties cite past Commission policy as support for this position.

We agree with the Company and Public Counsel on this issue. Our policy consistently has been to affirm the treatment of deferred taxes, ITC and other non-investor supplied capital as zero-cost capital, rather than deductions from rate base. We find no persuasive evidence in this record that would indicate that this policy should be changed. Accordingly, we have accepted the Company's proposed rate base treatment for this item.

Our adjustments to rate base may be depicted as follows:

SCHEDULE OF RATE BASE ADJUSTMENTS

Adjusted Jurisdictional 13 Month Average Rate Base per Company	$ 675,375,345
Staff Adjustments	
CWIP	(12,430,306)
Working Capital	(26,308,983)
Plant Daniel Investment	(7,994,611)
Caryville Plant Held for Future Use	-0-
Plant for New Service to Exxon	91,800
Cost of Service Adjustment	(158,814)
Total Adjustments	(46,800,914)
Staff Adjusted Jurisdictional Rate Base	$ 628,574,431

NET OPERATING INCOME

Having established the Company's rate base, the next step in the revenue requirements formula is to determine the net operating income applicable to the test period.

Reasonableness of Assumptions and Projections

The Company has based its projected net operating income upon the same budgeting process that served to establish its projected rate base. Public Counsel has challenged the legality of reliance upon projected NOI data. In addition, the parties have raised the issue of the reasonableness of the assumptions and projections that support the Company's proposed net operating income. We have already concluded that use of projected data is permissible. We further find that the Company's proposed net operating income, as adjusted herein, is based upon reasonable assumptions and projections.

Company Witness Gilbert sponsored testimony and exhibits to explain the O&M budgeting process in general. He also presented justification for 1981 budgeted expense levels which were over 1980 actual levels (Ex. 4, Schedule 3); 1981 budgeted NOI items compared to NOI used in the Company's last rate case (Ex. 83, revised 11/24/81); and a comparison of 1981 budget vs. actual data though October of 1981 (Ex. 97). Mr. Gilbert testified that "Gulf uses the budget process as a comprehensive management tool to both plan and control the Company's operations."

The customer forecast by class is prepared by the Marketing and Load Management Department and approved by the Budget Committee. It then becomes an input to the preparation of the energy and revenue budget, which is also approved by the Budget Committee. The peak demand forecast is developed by the Power Delivery Department based upon the approved customer and energy budgets.

The budgeting process is administered by the Company's budget committee. The budget committee develops a corporate business plan, a budget schedule and various guidelines to be used in developing the budget. Each major department then prepares functional business plans for review and then prepares a zero-base budget for its operations based upon the budget committee's approved economic assumptions contained in its budget guidelines. The budget committee reviews the individual budgets and the final O&M budget.

Mr. Bell's review of the Company's budgeting process included a review of the budget process used to develop the Company's proposed net operating income. His conclusions, cited in a previous portion of this order treating rate base, are equally applicable to the Company's proposed net operating income.

We are of the opinion that the Company's test year NOI data, as adjusted herein, is reasonable and appropriate to use in this case for ratemaking purposes.

Gulf Power Company proposed a net operating income figure of $58,705,261. We have modified this amount to $62,199,775, based upon the following adjustments:

<u>Bank Service Charges</u>

The Company contends that it is entitled to increase operating expenses by $112,000 (system) to compensate the Company for the minimum bank balances that the Company maintains. The Public Counsel disagrees and points out that bank service charges are a hypothetical expense and that the use of the balance sheet working capital approach compensates the Company for its investment in minimum bank balances.

By maintaining minimum bank balances, the Company is able to avoid the imposition of bank service charges. The Company has requested a hypothetical bank service charge because its approach (lead-lag) to working capital does not include the amount of the minimum bank balances that are maintained. Since we have adopted the use of the balance sheet working capital approach, the inclusion of the hypothetical bank service charge in operating expenses is unnecessary, as minimum bank balances are included in working capital.

Accordingly, we have reduced operating expenses by a jurisdictional amount of $107,218 to eliminate bank service charges.

Dues to Industry Associations

It is our policy that dues expended for the purpose of supporting lobbying activities and dues to Chambers of Commerce should not be borne by ratepayers. An examination of the Company's Operations and Maintenance expenses reveals that the amount of $14,477 was paid to various industry associations for this purpose. We have eliminated that amount from recoverable expenses for ratemaking purposes.

The Company failed to include in operating expenses dues paid to the Edison Electric Institute in the amount of $26,866. After eliminating 2% of the dues to represent that portion spent on lobbying activities, we have added $25,112 to recoverable operating expenses.

Charitable Contributions

The Company has included $24,845 (system) of test year charitable contributions as an above-the-line component of its test year Operations and Maintenance (O&M) expenses.

Company Witness Scarbrough sponsored Schedule 13 to his Exhibit #9, which gave a listing of each recipient and the amount donated. In addition, Mr. Scarbrough testified as to the benefits of these contributions to Gulf's customers and that "through the good will maintained by such charitable contributions, the Company was able to operate more effectively and efficiently within its service territory".

Public Counsel has taken the position that charitable contributions are not expenses related to providing utility service, and that these expenses should therefore be disallowed for ratemaking purposes.

We are of the opinion that charitable contributions, if treated above-the-line, effectively become involuntary contributions on behalf of the Company's ratepayers. Such contributions do not in our opinion constitute ordinary and necessary expenses incurred to provide electric service to customers.

We have reduced the Company's test year O&M expenses by $23,784 ($24,845 system) to remove charitable contributions from recoverable expenses.

Advertising Expenses

The Company has included $106,900 (system) of advertising expenses related to shareholder and area development advertising in test year O&M expenses. This is supported primarily through the testimony and exhibits of Company Witness Fisher.

Mr. Fisher testified that the purpose of the Company's shareholder and area development advertising was to "attract industry into the Company's under-developed service area, provide jobs and stimulate shareholder interest in providing equity capital for the Company." In addition, Mr. Fisher stated that this advertising allowed the Company to "get in on the ground floor with an incoming industry" and "plan the energy conservation techniques and features into their new project."

In our opinion, however, shareholder and area development advertising falls within the category of image building and promotional advertising as defined by the Commission in Order No. 6465 (Docket No. 9046-EU, General Investigation of Promotional Practices of Electric Utilities). As such, it should be disallowed for ratemaking purposes. This treatment is consistent with our action in the Company's last rate case.

Accordingly, we have reduced test year O&M expenses by $102,335 ($106,900 system) to eliminate advertising expenses associated with shareholder and area development advertising.

Economy Energy Transactions

At the outset of the proceeding, all parties stipulated that both revenues and expenses associated with sales of economy energy should be included in the determination of net operating income. No stipulation was reached as to the proper amounts which should be assigned to each category.

The Company on several occasions admitted that revenues and expenses from economy sales were not included in its forecast of 1981 test year revenues and expenses. Company Witnesses Scarbrough and Bell testified that economy sales revenues and expenses were not forecasted because it is difficult to estimate a reasonable figure for the level of economy sales. Company Witness Usry further explained that such sales are in no way assured, and depend upon other power availability and sales arrangements with interconnected neighbors. In fact, economy sales increased 14.18% between 1979 and 1980 but decreased 34.20% between 1979 and 1981.

The Company has agreed that test year revenues should be increased by $6,008,460 and that test year O&M expenses (including fuel) should be increased by $5,063,792, yielding a profit (before taxes) of $889,877. This calculation reflects 10 1/2 months of actual results and 1 1/2 months of projected revenues and expenses for test year economy sales. This information was furnished as Exhibit No. 77, (revised 12/2/81) pursuant to the stipulation entered into by all parties.

Public Counsel has taken the position that (1) the expenses associated with economy sales have been included in test year O&M expenses and (2) test year revenues should be increased to reflect a representative level of future economy sales.

However, we are satisfied that the amounts of revenue and expenses reflected in the Company's revised Exhibit No. 77, which are based upon 10 1/2 months of actual data, are those required to adjust test year revenues and expenses to include both economy sales and expenses in test year data. Accordingly, we have decreased purchased power expenses by $889,877 to reflect the net effect of economy sales transactions that were not included in the Company's projected test year data.

Service to Exxon

Earlier, we adjusted the Company's proposed rate base to reflect the additional investment related to new service to Exxon. Similarly, test year NOI must be increased by $4,439 to recognize the revenues and expenses associated with that service.

Estimated O&M Expenses

In projecting the level of operations and maintenance expense, Gulf Power Company simply spread the variance between the originally budgeted amounts and actual totals for the months of January and February 1981 over the remaining ten months of the test year.

The Company claims that spreading the variance between January and February 1981 budgeted and actual amounts does not overstate expenses, because those variances represented delays in the incurring of expenses during the test year, rather than deferrals to other years. Mr. Scarbrough testified that the monthly accuracy "of the occurrence of an expense is not nearly so accurate as our expectation that we will in fact in the calendar year 1981 have the particular expenditure". Mr. Scarbrough did admit, however, that some expenses included in the Company's rate filing had been deferred from 1981 to 1982. Mr. Scarbrough was asked to provide a list of those deferred expenses, and it was identified as Late Filled Exhibit No. 58.

We accept Mr. Scarbrough's statement that it is easier to project expenses on an annual basis, rather than on a monthly basis. However, an adjustment should be made for expenses that have been deferred beyond the test period. Based on Exhibit No. 58, we find that test year O&M expenses must be reduced by $777,232 (811,900 system) to eliminate expenses deferred beyond the test year.

Earnings From Temporary Cash Investments

Earlier we determined that temporary cash investments should be included as part of working capital. It follows that earnings associated with such temporary investments should be included in the calculation of net operating income. Gulf Power's original submission was based upon returns projected at the outset of the test period. Based upon more current projections and more complete data provided at hearing, we find that net operating income should be increased by $772,050.

Flow Back of Deferred Taxes

The change in the corporate income tax to a 46% rate requires a decision as to the proper amount of time over which to flow back deferred taxes which were created at 48%. Public Counsel's witness, Mr. Larkin, recommended that the difference be flowed back to customers over a period of two years. The staff recommended that the difference be flowed back over the life of the assets to which the deferred taxes are related. We have decided to adhere to the policy established in recent cases, and require that the difference be flowed back over a period of five years. This results in an increase to NOI of $293,960.

Conservation Expenses

Because this Commission has adopted a Conservation Cost Recovery Clause that features a true-up provision, it is necessary to adjust conservation revenues so that they equal related expenses for ratemaking purposes. Exhibit No. 68 reflects an underrecovery of $27,208 for the test year. Accordingly, test year revenues should be increased by this amount.

Non-recurring O&M Items

A fundamental principle of ratemaking is that the effect of non-recurring items, which tend to make the test year atypical, should be eliminated. Exhibit No. 43, sponsored by Gulf Witness Gilbert, lists the following non-recurring O&M items:

ATB Maintenance	$ 65,000
Office Building Rentals	15,747
Manpower Planning Consulting Fees	100,000
Corporate Planning Consulting Fees	95,000
Total (system)	$275,747

To this amount must be added $25,000, the cost of a tree trimming optimization study, for a total of $300,747 (system). The jurisdictional adjustment is $287,905; we have removed that amount from text year O&M expenses.

Rate Case Expense

Gulf's Witness Mr. Gilbert stated that the Company budgeted $320,392 for expenses incurred as a result of the Company's rate case. In our opinion, the expenses incurred for a rate case benefit not only the current period, but also future periods. In addition, rates should not be set to recover the total amount of rate case expenses each year, since retail rate cases are not normally filed every year.

We find that a three year period is appropriate for amortizing rate case expenses. Based on a three year amortization period, the rate case expenses of $320,392 must be reduced by $213,595.

Cost of Service Adjustment

In the rate base portion of this order, we concluded that Mr. Pollock's cost of service study, and not the Company's, should serve as the basis for the jurisdictional separation. Utilizing this study, we find that the Company's proposed net operating income must be reduced by $4,516, excluding income taxes.

Excessive Generating Reserves

Three significant issues which were separately identified in the prehearing order have, in our opinion, become closely interrelated during the development of the case. The first is what portion of Plant Daniel should be reflected in rate base. The second is whether excess generating margins exist on Gulf Power's and/or the Southern Company system; and, if so, whether the costs of excessive reserves should be borne by Gulf Power's ratepayers. The third is whether Gulf's management prudently attempted to identify and/or respond to changes in load growth patterns in the 1970's.

There is no question but that Gulf's installed generating reserves are well above those required during the test year. Gulf projected that it would have a 66.2% reserve margin in 1981; for system planning purposes, a margin of 25% is considered adequate. Gulf's position is that, while reserves are higher than needed, the operation of the intercompany interchange contract between the operating companies of the Southern pool serves to share those reserves among the companies.

The excess in capacity on Gulf's system can be properly associated with the addition of Gulf's ownership interest in Plant Daniel during the test year. Taking into account the operation of the interchange contract, the following table indicates the net impact of Plant Daniel on the cost (in terms of revenue requirements) to Gulf's ratepayers:

Net Test Year Revenue Requirement
Increase Due to Plant Daniel

With Plant Daniel	1981
Jurisdictional Annual Revenue Requirements Associated with Plant Daniel In Rate Base[2].	$ 24,243,000
Jurisdictional Annual Revenue Requirements Associated with Plant Daniel in Operations.	5,871,000
Jurisdictional Revenue Requirements Associated with Interchange Contract Capacity Payments.	(11,268,000)
Jurisdictional Revenue Requirements Associated with Non-Associated Utility Sales (Schedule B).	(11,678,000)
Net Annual Revenue Requirements Associated with Plant Daniel.	7,168,000
Without Plant Daniel	
Jurisdictional Revenue Requirements Associated with Intercompany Interchange Contract Capacity Payments.	4,069,000
Net Annual Revenue Requirements Increase Due to Plant Daniel.	$3,099,000

Thus, taking into account the capacity credits of $11,268,000 which would be received from Gulf's sister companies through the workings of the interchange contract, and the $11,678,000 associated with Schedule E sales to non-system utilities, Gulf's ratepayers would still be required to contribute $3,099,000 toward Plant Daniel's revenue requirements, absent any adjustment.

Cross-examination of Gulf Witness Earl Parsons established that the utility's system planners attempt to respond to new load forecasts or changes in existing load forecasts by measures such as increasing the number of units, by either slowing or speeding the construction of planned units, or by developing sales of

[2]Reflects rate of return approved below.

capacity to utilities off the system. Mr. Parsons testified that Gulf and the Southern system have established an ongoing mechanism for evaluating the need for sale of capacity off the system. Notwithstanding the existence of that mechanism, no negotiations for the sale of excess capacity from Daniel No. 2 took place until 1980. This was because Gulf was relying upon load forecasts which early in 1979 indicated that with Daniel Unit 2, Gulf's reserves would be 36.44% and Southern's would be 21.95%; without Daniel No. 2, Gulf's reserves would have been 2.18%, and Southern's 19.72%. It was because of this projected scenario that no activity concerning possible off-system sales took place at an earlier point in time.

We believe that the erroneous load forecasts resulted from the failure of Gulf's management to prudently identify and quantify the factors affecting load growth. Prior to 1977, Gulf's peak hour demand forecast was done with simple time trends. As shown in Exhibit No. 34, this method resulted in forecasts of the 1981 summer peak demand of 2098 megawatts (MW), 1859 MW and 1723 MW in the 1975 through 1977 Ten Year Site Plans. The actual 1981 summer peak demand for Gulf was 1309 MW. Thus, Gulf's forecast for 1981 was too high by the following amounts: 60.3% in 1975, 42.0% in 1976, and 31.6% in 1977.

Gulf's forecast error for the 1981 summer peak demand is significantly greater than that projected by peninsular Florida electric utilities and the PSC staff. As revealed in Exhibit 34-A, the peninsular Florida forecast exceeded the actual 1981 summer peak demand by 19.3% in 1975, 8.6% in 1976, and 5.6% in 1977. The staff's forecast error for peninsular Florida was 23.1% in 1975, 3.3% in 1976, and (0.5)% in 1977. The staff's projections for Gulf's 1981 summer peak demand exceeded the actual by 35.5% in 1975, 21.1% in 1976, and 10.5% in 1977.

Gulf's management was repeatedly advised by the staff that Gulf's forecast was considered to be too high for planning purposes. During cross-examination, Gulf's Witness Oerting read into the record the following staff comment: "The projected growth rate of 9.67 percent as reflected in the 1975 Ten-Year Site Plan is considered to be too high for planning purposes." He further quoted the following staff comments: "Gulf's load projections as shown in their 1976 Ten-Year Plan is 9.7 percent for the 1976 through 1985 period. This is similar to the Commission high forecast and very close to their historical average growth rate. Planning on the basis of this high forecast is, in our opinion, not warranted. As is true of the rest of the state, Gulf should be planning based on a 5 to 6 percent growth rate." Mr. Oerting agreed that Gulf's 1977 Ten-Year Plan forecast of a 7.0 percent growth rate exceeded the staff's banded forecast of 4.2 to 6.2 percent. Additional concern with Gulf's forecasting methodology is expressed in Exhibit No. 47, which is page 21 of Order No. 7978, dated September 27, 1977. In that order, we directed Gulf to prepare an econometric load forecast and stated that, "Because of its importance in terms of economic impact upon the ratepayers, it is incumbent that a utility use all available techniques in making such a forecast".

Mr. Oerting stated that Gulf began development of a computerized, econometric/end-use model for long range energy and demand forecasting in 1974. Although the model became operational in late 1976, it produced a higher demand forecast than Gulf's consolidated load factor process and was used for comparison purposes only. Witness Oerting further stated that, "Since mid-1980 we have made concerted efforts to improve the accuracy of the model" and "we will begin using the model results as the primary output of our peak-hour demand forecasting process in the near future". We believe that prudent management would have led Gulf to begin a concerted effort to develop accurate forecasting methods much earlier than mid-1980. More significantly for the purposes of this case, more accurate forecasting at an earlier point in time would have signalled to Gulf's system planners the need to develop greater sales of capacity off the system, and would have provided the lead time required for measures designed to prevent Gulf's ratepayers from paying for excess capacity. Because of our finding that Gulf failed to use prudent measures in developing its load forecasts, we are adjusting net operating income by $3,099,000 so that the ratepayers will not be called upon to bear the shortfall in the revenue requirements associated with Plant Daniel in the 1981 test period.

Income Tax Effect of Adjustments

This adjustment is mechanical in nature, and serves to reflect the effect upon income tax expense of the various other adjustments we have made to the Company's proposed net operating income. The effect is to decrease NOI by $3,044,735.

Other NOI-Related Issues

During the course of the case, we have heard and considered other NOI-related issues, the resolution of which, we find, do not result in adjustments to the Company's proposed net operating income. They include the following:

Projections of Customers, Energy Sales, and Revenues

The Company contended that it properly and accurately projected the number of customers, energy sales, and revenues. The Office of Public Counsel asserted that Gulf failed to provide projections of energy sales on a total territorial basis.

A comparison of actual revenues from sales of electricity with budgeted revenues for January through November, 1981, shows that budgeted revenues exceed actual revenues by only eight-tenths of one percent. This difference is not large enough to warrant an adjustment in NOI.

The differences between budgeted and actual numbers of customers and sales by class were greater than the difference in revenues. For example, the actual average number of residential customers exceeded the budgeted number by 1.7% through September, and the actual commercial class sales exceeded the budgeted amount by 6.6% (Exhibit 31). However, the individual class errors offset each other, resulting in total company numbers that are within a reasonable margin of error. No adjustment to net operating income is warranted by variances of this magnitude.

Fuel Expenses and Revenues

Because the Commission has adopted a fuel cost recovery clause with a true-up mechanism, it is appropriate to assure that test year fuel revenues equal fuel expenses. The Company has made an adjustment to decrease operating revenues by $9,000 to eliminate an overrecovery of fuel expense. We find that no further adjustment is necessary for this purpose.

Pricing of Plant Daniel Capacity Sales

Under the existing Intercompany Interexchange Contract governing transactions between operating companies of the Southern system, the pricing of sales of Plant Daniel capacity is based upon the average, system embedded costs of fossil units. Public Counsel suggests that test year revenues be increased by $20,040,600 on an annual basis to reflect the effect which basing the price of sales from Gulf to the Southern Company pool associated with Gulf's ownership in Plant Daniel upon the incremental costs of the Daniel unit would have.

The theory behind the contract's average embedded pricing mechanism is that capacity and energy sold to the pool by a selling company are sold out of the aggregate resources of that company. It should be noted that the IIC is a mutually agreed upon contract between each of the Southern Companies. The IIC is reviewed annually by the member companies and, as such, can be expected to evolve year by year. Further, its terms are subject to the approval of the Federal Energy Regulatory Commission. In our opinion, no basis for an adjustment has been demonstrated.

Adjustment to Recognize March 1981 Decrease in Revenues

The Company has included in its filing an adjustment to reduce test year operating revenues by $169,000, to reflect a March 1981 rate decrease ordered by this Commission and to adjust its test year revenue forecast to account for the January 1981, implementation of time-of-use rates by one of the Company's major industrial customers.

Public Counsel has taken the position that the adjustment is not justified, since "this is inconsistent with the use of two month actual/ten month projected test year."

We believe that the Company's pro forma adjustment is reasonable. The rate decrease/refund was by order of the Commission, and the refund would retroactively affect the actual revenues collected in January and February of 1981. We also agree with the Company's treatment of the rate schedule change by one of the Company's large industrial customers. Since the election to use time-of-use rates rests with the customer rather than with the Company, changes of this nature could not have been reasonably anticipated. Also, this adjustment to the forecast was made prior to the Company's filing and was included in the MFR/s when they were first filed.

Accordingly, we have accepted without modification the Company's pro forma adjustment.

Injuries and Damages Reserve

The Company has included in its filing a proposal to increase O&M expenses by $481,000 ($500,000 system) to allow for a $1.2 million (system) annual accrual to the Company's injuries and damages reserve. The Company also requests that the ceiling or cap for its reserve be raised from $1 to $2 million.

Company Witness Scarbrough supported the Company's position, stating that the Company's deductible for liability insurance is currently $1 million per claim and that "since verdicts in excess of $1 million per claim are now relatively common, it is only prudent to have a reserve that will cover two such claims". Mr. Scarbrough's Exhibit No. 9, Schedule 12 shows the history of the injuries and damages reserve for the period 1976 through 1980. This exhibit shows large claims of $958,789 and $1,202,817 occurring in 1977 and 1980, with other yearly claims averaging around $200,000. Mr. Scarbrough also testified that at the end of 1980, "the liabilities as estimated by our legal counsel for filed suits and outstanding claims against the Company amounted to an additional $1.2 million."

Based upon recent claims experience, we have decided to allow the Company to increase its Injuries and Damages Reserve by accruing $1.2 million per year. However, we shall eliminate the ceiling or "cap" and shall instead monitor the adequacy of the reserve during ratemaking proceedings. We prefer this approach to a situation in which the Company would utilize revenues associated with the size of the accrual for purposes other than building the reserve once the ceiling has been reached.

Treatment of Gains and Losses

It is the Commission's policy to require that gains and losses on dispositions of utility property be recorded above-the-line and amortized over a five year period. However, an examination of the record reveals that test year dispositions were so minute that any adjustment to conform to the policy would be immaterial for ratemaking purposes.

Gulf's Use of Comprehensive Interperiod Income Tax Allocation

Public Counsel prefiled the testimony of J. W. Wilson, who proposed the adoption of a method of normalization which would depart from Gulf's use of comprehensive interperiod income tax allocation. Mr. Wilson's method entails deferring the current tax effect of deferred taxes. His testimony was withdrawn upon the entry of a stipulation of parties requiring Gulf to request a ruling from the IRS as to whether this method would violate applicable provisions of the Internal Revenue Code or IRS regulations. Accordingly, no adjustment to Gulf's approach in this case has been made.

Southern Company Debt Expense

The prehearing order identified as an issue the question as to whether an adjustment should be made to impute the debt expense of Southern Company to its subsidiaries, including Gulf Power Company.

Under the 1935 Public Utility Holding Company Act and the practice of the Securities and Exchange Commission (SEC), the Southern Company is not allowed to issue debt without special approval of the SEC. Upon securing SEC approval, Southern executed a loan agreement March 15, 1976, for $125,000,000 of intermediate term financing. At the end of the test period, December 31, 1981, $42,000,000 of this amount was still outstanding at an interest rate of 11.5%.

This remaining balance of $42,000,000 is scheduled to be paid off March 15, 1982.

The policy of the Commission is to recognize for ratemaking purposes the income tax benefits to the subsidiary associated with parent company debt. In this case, however, because the remaining debt will be liquidated only weeks after the rates approved herein take effect, we shall not make such an adjustment.

Income Tax Liability

In this proceeding, Public Counsel, through his two witnesses, Mr. Hugh Larkin and Mr. Joe Jacobs, proposes that the tax expense to be included by Gulf Power in the determination of revenue requirements be computed using the effective consolidated tax rate of the Southern Company. Mr. Larkin testified to the mechanics and theoretical construction of this proposal, while Mr. Jacobs testified to the Internal Revenue Code implications of the same proposal.

Mr. Larkin contends that Gulf should not be treated as a separate entity for tax purposes because it is not a tax paying entity, and to treat it as such would require the Commission to determine an actual expense on a hypothetical basis. He urges that in order to recognize income taxes at all, the Commission must evaluate the method adopted by the Company to pay its taxes, and it must therefore consider the effects of consolidation. That consolidated returns allow for lower taxes is virtually a truism since few, if any, would be filed otherwise. According to Mr. Larkin, a determination should be made of that portion of profits that are ultimately paid out as taxes. This may be expressed as a percentage, an effective tax rate.

Mr. Larkin states that if properly calculated, an effective tax rate applied to the taxable incomes of profitable subsidiaries will provide sufficient funds to meet the consolidated tax liability. This effective tax rate, he says, should be determined by dividing the total consolidated tax liability before credits by the sum of the positive taxable incomes. This effective tax rate calculation lumps together regulated and non-regulated segments of the Southern Company.

Mr. Larkin's calculations, based upon the past 6 years' experience of the Southern Company and its subsidiaries, lead him to conclude that the Commission can reasonably expect that only 41.54% of Gulf's taxable income, before credits, will ultimately be paid out as federal income taxes. Additionally, Mr. Larkin states that, should the Commission opt for normalization, it should normalize at the effective tax rate.

Mr. Jacobs addressed the Internal Revenue Code implications of Mr. Larkin's effective income tax rate proposal. Mr. Jacobs contends that Mr. Larkin's calculation of Gulf Power Company's federal income tax liability for regulatory purposes properly allocates to Gulf its proportionate share of those taxes that will ultimately be paid to the federal government by its parent, the Southern Company. Mr. Jacobs feels that Larkin's methodology does not conflict with Internal Revenue Code Sections 167(L) and 46(F) or any Treasury Regulation of which he is aware.

The Company contends, through its witness Mr. Dean Hudson, that it has correctly computed the federal income tax expense to be allowed in this proceeding.

Mr. Hudson points out that, pursuant to Security and Exchange Commission Rule 45(C), Southern Company's tax allocation procedure cannnot result in an allocation of taxes to any one company which would exceed the amount of taxes of that company based upon a separate return, computed as if the company had always filed its tax return on a separate basis. To devise an allocation method other than the "separate tax return approach" would result, he stated, in a fictitious tax, which would bear no relationship to the income or expenses of the jurisdictional utility. According to Mr. Hudson, the differences between the 46% statutory tax rate and the effective tax rate calculated by Mr. Larkin are comprised of the following: 1) surtax exemption, 2) capital gains tax benefit, 3) the tax loss of the Southern Company and The Southern Company Services, Inc.

Further addressing the question of the allocation of the Southern Company loss, Mr. Hudson contends that only if the Southern Company were to allocate its expenses (loss) to the operating companies, and these expenses were included in the computation of Gulf's net operating income for ratemaking purposes, would it be appropriate for the related tax reduction to be included as an adjustment and "passed on".

Mr. Hudson also addressed the implications of using the effective tax rate to provide deferred income taxes on book-tax timing differences. He contends that the deferred tax provision must be computed using the current statutory tax rate of 46% and that the use of a tax rate lower than the statutory rate would result in flow through of deferred taxes. Mr. Larkin's proposal would, in his view, result in the reduction of Gulf Power Company's deferred income tax expense by the tax effect of future expenses of Southern Company, as well as by future capital gains tax savings. Lastly, Mr. Hudson concludes that pursuant to the Internal Revenue Code, the deferred taxes associated with accelerated depreciation must be equal to the incremental tax liability that would occur in the current tax year if accelerated tax depreciation were not taken. This requires that the current statutory tax rate of 46% be used to compute deferred income taxes.

We find that the effective tax rate computation, as sponsored by Public Counsel Witnesses' Mr. Hugh Larkin and Mr. Joe Jacobs, should be rejected for the following reasons.

1. Normalization Requirements

Mr. Jacobs testified that for purposes of establishing deferred federal income taxes, use of an effective tax rate will not violate Internal Revenue Code Section 167(L) and the related regulations. In other words, according to Mr. Jacbos, deferred taxes do not have to be provided at the margin. We believe this premise to be incorrect. For example, Treasury regulation 1.167(L) - 1(h)(1)(iii) - 1) requires a computation commonly referred to as a "with and without" computation to determine the amount of the federal income tax to be deferred. The amount of tax to be deferred is "the excess (computed without regard to credits) of the amount the tax liability would have been had a subsection (L) method been used over the amount of the actual tax liability. Such amount shall be taken into account for the taxable year in which such different methods of depreciation are used."

We believe this regulation illustrates that in the case of Gulf Power, whose taxable income has exceeded by a wide margin the $100,000 minimum needed to place Gulf in the top marginal tax rate in each of the 6 years used in Mr. Larkin's calculations, the "with and without" calculation required Gulf to provide deferred taxes at the top marginal rate. Effective as of 1979, the top marginal rate was reduced to 46%, where it remains today.

In our opinion, use of a rate less than the marginal rate will result in flow-through of accelerated depreciation, with a resultant forfeiture of the ability to claim the use of accelerated depreciation.

2. Principles of Accounting

An income tax provision, based upon any methodology other than a "separate tax return" approach, results in a tax provision that has no relationship to the revenues and expenses from which the provision should be calculated. Income taxes are not self-creating, but rather are a function of the income and expense items of the period. This accounting principle of matching taxes with the related items of income and expense is as important as the concept of matching revenues with the related expenses. The effective tax rate does not match these items correctly.

Additionally, as described by APB #11, effective tax rates cannot be used to establish deferred income tax provisions. Witness Larkin claims that APB #11 does not apply to regulated industries in those instances where the standards described in the addendum to APB opinion #2 are met. However, we believe that care should be exercised when deviations from opinions of the APB and statements of the FASB are contemplated; only compelling reasons, such as a material inequity or detriment to be suffered by the ratepayers, should justify such a departure.

3. Allocation of the Current Liability

Mr. Hudson testified that Southern Company allocates its tax liability in any given year pursuant to S.E.C. Rule 45(C). Under this rule, the allocation of tax to any one company shall not exceed the amount of tax of such company based upon a separate return computed as if the company had always filed its tax return on a separate basis. Admittedly, this allocation procedure is not binding on this Commission. However, we believe that the separate return method of income tax allocation is the only proper method for establishing the current tax expense for ratemaking purposes.

The two most significant items that impact the Southern Company and its subsidiaries for current tax allocation purposes are the allocation of parent company loss and the allocation of capital gains benefits. The most significant item of the two historically, has been the parent company loss. Under current allocation procedures, this loss has been allocated to all the operating companies. This allocation is made in exactly the same manner as the ordinary liability is allocated. It must be allocated to the subsidiaries per the portion of Rule 45(C). Since the parent had been considered a "perpetual loss" company (although for the test year 1981 they are projecting taxable income), and the loss could not have been utilized on a separate tax return basis, it must be allocated. We believe the allocation of this loss should be "below" the line; because the ratepayers of Gulf did not pay the expenses (loss) of Southern Company through cost of service; consequently, they should not receive the tax benefit of those expenses (loss). Similarly, had Southern Company shown taxable income historically, (as they are projected to do in 1981), it would not be proper to require Gulf's taxpayers to pay the tax expenses associated with that income.

In conclusion, we find that Gulf Power's income tax liability, as filed in this proceeding, represents the amount of income taxes that ultimately will be paid by Gulf to the Internal Revenue Service.

Specifically, with respect to normalization requirements, Gulf is in full compliance with the Internal Revenue Code and related regulations, Gulf's income tax accounting for ratemaking purposes complies with generally accepted accounting principles, and the allocation of the current tax liability by the parent, based upon the "separate return" approach, is the most reasonable and equitable approach for allocating this liability among the operating companies.

Property Insurance Reserve

Gulf Power Company has requested authority to continue to accrue $1.2 million per year to fund its property insurance reserve (storm damage reserve), and has also asked that a ceiling for the reserve be established at $3 million. The Company feels that a ceiling of $3 million would be appropriate, in light of a $1.6 million charge in 1979 that resulted from Hurricane Frederick. Witness Scarbrough described the property insurance reserve as similar to the injuries and damages reserve, with the difference that it covers a variety of non-routine catastrophic occurrences that result in damages to the Company's electric utility property.

We find that the request to continue the annual accrual of $1.2 million should be granted. However, as with the injuries and damages reserve, we decline to establish a ceiling or "cap" for the reserve. Instead we shall review and monitor the adequacy and level of the reserve during future ratemaking proceedings. We wish to add that we believe that, in the case of both the storm damage reserve and the injuries and damages reserve, the reserve accounts have not been clearly identified and to some extent have, in our opinion, been mislabeled. We shall direct the staff to analyze the purpose of such accounts and the nature of charges made against them for all companies subject to our jurisdiction. A need exists for a clearly defined catastrophy reserve account, so that guidelines exist to prevent inappropriate charges being made against the reserves.

Caryville Property Held for Future Use

In the rate base section of this order, we refused the recommendation of the staff to include only 30% of the value of the Caryville Plant Site in property held for future use, and instead allowed the full value of the site in rate base.

Similarly, we find that all jurisdictional revenues and expenses associated with the property should be included in the determination of net operating income. Accordingly, we have made no adjustment to those expenses and revenues included in the Company's filing.

Test Year Purchased Power Expenses

Exhibit No. 74 indicates that the actual purchased power credits received from Schedule E sales were some $289,000 less than those projected through September of the test period. The staff recommended that purchase power expenses be reduced to reflect that Schedule E sales were over-budgeted for the test period. However, we find that we should utilize the Company's test year projections for this item, and accordingly have made no adjustment to those expenses included by the Company in its filing.

Our adjustments to the Company's proposed net operating income may be summarized as follows:

Adjusted Jurisdictional NOI Per Company	$ 58,705,261
Adjustments	
Bank Service Charges	$ 107,218
EEI Dues	(25,112)
Dues	14,477
Charitable Contributions	23,933
Advertising	102,335
Deferred O&M Expenses	777,232
Temporary Cash Investments	772,050
Economy Sales	889,877
Exxon Revenues and Expenses	9,087
48% to 46% Tax Rate Change	293,960
Income Tax Effect of Adjustments	(3,044,735)
Conservation Revenues	27,208
Non-recurring Expenses	287,905
Rate Case Expenses	213,595
Cost of Service Adjustment	(4,516)
Excess Reserve Margins	$ 3,050,000
Total Adjustments	$ 3,494,514
Adjusted Jurisdictional NOI	$62,199,775

FAIR RATE OF RETURN

The Commission must establish the fair rate of return which the Company should be authorized to receive on its investment in rate base. The fair rate of return should be established so as to maintain the Company's financial integrity and to enable it to acquire needed capital at reasonable costs.

Capital Structure

The ultimate goal of providing a fair return is to allow an appropriate return on equity investment in rate base. Because, as a general rule, all sources of capital cannot be clearly associated with specific utility property, the Commission has traditionally considered all sources of capital (with appropriate adjustments) in establishing a fair rate of return.

The establishment of a utility's capital structure serves to identify the sources of capital employed by a utility, together with the amounts and cost rates associated with each. After establishing the sources of capital, all capital costs, including the cost of equity capital, are pro-rated according to their relative proportion to total cost of capital. The weighted components are then added to provide a composite or overall cost of capital. The weighted cost of capital multiplied by the net utility rate base produces an appropriate return on rate base, including a return on equity capital in rate base. The return is also sufficient to recover the annual cost of other types of capital, including debt.

Since a return on all sources of capital is provided by this treatment, actual debt and similar capital costs are not included in test year operating expenses, but are treated "below the line". This assures that such capital costs are not double counted for ratemaking purposes.

An appropriate capital structure is both economical and safe. Such a capital structure should minimize the cost of capital by obtaining capital through an appropriate balance between debt and other components of capital. The capital structure used for ratemaking purposes for a particular company should bear an appropriate relationship to the actual sources of capital to the Company.

Consistent with our decision to employ a projected test period in this case, we have decided to utilize the capital structure projected by the Company to be in place through 1981. We have adjusted the system capital structure to remove capital that is not being utilized to fund the jurisidictional rate base. Such adjustments are necessary to reconcile rate base with capital structure. The types and proportions of capital will be developed in a following schedule.

Gulf Power recommended the use of a year end capital structure, while Public Counsel recommended the use of an average capital structure. We believe that a 13 month average capital structure best represents the sources of funds used to finance Gulf's rate base. A 13 month average capital structure is a better representation of a utility's financing mix than a year end capital structure. Since capital must be raised in separate components, a single point in time may be too heavily weighted with one type of capital. A 13 month average capital structure smoothes the effects of a particular increment of capital. We previously expressed a preference for using a 13 month capital structure for these same reasons in Order Nos. 10306 (FP&L), 10418 (Gentel) and 10449 (Southern Bell).

To fully establish a capital structure, we must identify the sources of capital to be included and establish the cost of each source.

We have adjusted the system per books capital structure to remove the effects of wholesale operations and retail adjustments to the rate base. We consider non-utility retail operations to have their source in equity capital. We will adjust the capital structure accordingly. Since Gulf does not plan to use short term debt, none should be included in the capital structure. Deferred taxes and 3% investment tax credits are cost free sources of capital and should be included in the capital structure at zero cost. The 4% and 10% investment tax credits should appropriately earn the weighted average cost of capital and be included in the capital structure.

Cost of Long Term Debt

The Company's witness, Mr. Scarbrough, used an 8.69% cost of debt in his cost of capital calculations. Public Counsel's witness, Mr. Rothschild, proposed using an 8.75% cost rate for long term debt. The difference arises because Mr. Rothschild amortized associated expenses over one half the lives of the obligations. We believe that this adjustment is inappropriate. These expenses should be amortized over the life of the obligations; otherwise, Mr. Rothschild's adjustment would allow an over-recovery of these expenses. Therefore, we will use the year end long term debt cost of 8.69%, which we believe is a better indicator of the future than an average cost rate.

Cost of Preferred Stock

All parties agreed that the year end cost of preferred stock is 8.65%. We believe this rate best reflects Gulf's cost of preferred stock in the near future.

Customer Deposits

Mr. Rothschild and the Company's witness, Dr. Dietz, suggested that an 8.00% cost rate be applied to Gulf Power's customer deposits. However, this cost rate fails to reflect unclaimed or zero cost deposits. Mr. Scarbrough, Vice-President of Finance for Gulf Power, calculated the effective cost rate for customer deposits to be 7.84%. We consider this rate to be the appropriate cost of Gulf Power's customer deposits.

Return on Equity Capital

Five witnesses testified on Gulf Power's cost of equity capital; Dr. Dietz and Mr. Benore for Gulf Power; Mr. Miller on behalf of the Executive Agencies of the United States; Mr. Rothschild on behalf of the Public Counsel; and Mr. Hunt for the Commission Staff.

Dr. Dietz concluded that Gulf's cost of common equity is 18.20%. He used several variations of the discounted cash flow (DCF) method and a risk premium analysis to reach this conclusion. His risk premium analysis served as a check on his discounted cash flow analysis.

Dr. Dietz modified his original DCF equation to account for an increase in Southern's P/E ratio over a five and ten year period by assuming that Southern's stock would be selling at book value within five and ten years. We believe that changes in P/E ratios should not be included in the DCF formula, since changes in the ratio will be caused by lower capital costs, not higher returns.

We disagree with Dr. Dietz's calculated 18.7% cost of new common equity and the manner in which it was averaged. His formula discounts the price by 5% and double accounts for growth by applying a 3.0% growth factor. We believe an adjustment of .1% or .2% to the overall cost of equity best reflects Gulf's issuance costs, which are related to new common equity obtained in the market.

Dr. Dietz's risk premium analysis is less useful than his present value approach. We believe that the risk relationship between stocks and bonds has been overstated. Current risk premiums cannot be accurately estimated. Dr. Dietz emphasized a positive risk premium, but had difficulty in quantifying it. We believe that Dr. Dietz's testimony generates considerable doubt as to the usefulness of the risk premium method, and conclude that we should not rely upon it to determine the cost of equity for Gulf Power.

Mr. Benore testified that Southern Company's cost of equity is 18.5%, while Gulf Power's cost of equity is 18.0%. Mr. Benore used a DCF analysis of the S&P 400 Industrials and a risk premium analysis to support his recommendation. Once he obtained the results of these two methods, he tested the indicated returns by indirectly applying a DCF model to Southern's stock. Given the 18.5% cost of equity as derived from his DCF and risk premium methods, Mr. Benore multiplied an assumed retention ratio for Southern of 35% by the 18.5% estimated return, to derive a 6.5% growth rate. He combined this with an assumed 12.0% yield to derive a 18.5% DCF - derived cost of equity for Southern.

We believe Mr. Benore's estimates of Gulf's cost of equity are overstated. First, we do not believe that Mr. Benore's testimony demonstrates that Gulf's investment risk is equal to or exceeds the risk of the S&P 400 Industrials. We believe that Mr. Benore has ignored the fact that electric stocks were more overpriced in the 1960's than they are underpriced today. This fact explains the downward trend of his analysis. Mr. Benore also used statistical measures to quantify the risk differentials between electrics and the S&P 400 Industrials. We believe that this methodology is not a representative comparison of the investment risk that electric investors face relative to the S&P 400's and the S&P 500's. Mr. Benore's risk premium doesn't seem applicable to those investors purchasing electric stocks in general and Southern stocks in particular. Consequently, we do not consider it to be appropriate to rely upon Mr. Benore's risk premium to estimate the requirement of the market for electric stocks as a whole. We conclude that Mr. Benore's risk premium method is not useful in estimated Gulf Power's cost of equity.

Mr. Miller determined that the cost of common equity for Gulf Power is in the range of 14.4-15.3%, with a mid-point of 14.9%. Mr. Miller relied entirely on an analysis of all the electrics that are listed in Value Line, except for General Public Utilities. He believed that the cost of common equity for these 94 electrics is comparable to Gulf and Southern. Mr. Miller's 12.4% yield and 2.0-2.5% growth rate equated to a DCF cost of equity range of 14.4 to 14.9% before an allowance for flotation costs of new equity. Mr. Miller calculated the annual flotation costs for new Gulf common equity to be .2-.3% of the average common equity balances in each year.

Mr. Miller stated that there is a statistical relationship between electric utility common dividend yields and AFUDC ratios, He indicated that the AFUDC ratio for Gulf Power was much higher than the industry average in 1980, but that it will be much lower in 1981 and 1982. According to Mr. Miller, this factor indicates a reduction in the cost of common equity capital of .26 percent. Mr. Miller also adjusted his return to account for Gulf's lower equity ratio.

We generally agree with Mr. Miller's DCF methodology, with the exception of his growth rate and the period he chose to develop a dividend yield. We believe that a combination of dividend, earnings, and book value growth rates is more representative of expected growth rates than growth in book value alone. We also believe that the three month period of June-August, 1981, overstates the dividend yield. Consequently, use of a dividend yield calculated over a broader period of time and the combined growth rate of earnings, dividends and book value would indicate a range of 15.6-15.7%.

Mr. Rothschild initially determined that Gulf's cost of equity was in the 15.0 to 15% range. In response to more recent information, he reduced his mid-point from 15.25% to 14.75%. Mr. Rothschild used a DCF model and a comparable earnings technique to estimate Gulf's cost of equity.

Mr. Rothschild performed a DCF analysis on data from both Southern Company and from Moody's 24 electric utilities. His DCF analysis of Moody's 24 electrics assumed a 12.48% dividend yield, a 2.64-3.64% growth rate and a negative 1.2% factor, which reflected the effect of selling new equity below book value. Mr. Rothschild's DCF analysis of Southern Company assumed a 13.36% dividend yield (on March 31, 1981), a .51-3.23% growth rate and a negative 1.40% factor which reflects the effect of selling new equity below book value.

We believe that Mr. Rothschild's DCF calculations understate the cost of equity of electrics in general, and Gulf Power in particular. The amount of the downward bias in his calculations is primarily due to the negative 1.2-1.4% factors caused by the sale of new common equity below book value. Growth rates are lower when dilution occurs; however, the making of an additional adjustment in the DCF model encourages circular reasoning. Eliminating Mr. Rothschild's dilution factor produces an adjusted range of 15.12-16.12% for Moody's 24 Electrics and 13.87-16-59% for the Southern Company. Adding Mr. Rothschild's .32% leverage adjustment to Moody's 24 Electrics indicates Gulf's cost of equity range to be 15.44-16.44%. Subtracting .18% from Southern's range to reflect Gulf's higher equity ratio equates to a 13.69-16.41 range for Gulf, excluding financing costs. Adding Mr. Rothschild's .19% allowance for financing costs and market pressure produces a range of 15.63-16-63% for Gulf's cost of equity (derived from Moody's 24 Electrics) and 13.88-16.60% for Gulf's cost of equity (derived from Southern Company).

We believe that this range is slightly high, since Mr. Rothschild used point estimates of dividend yields. We consider an average dividend yield of 12.2% for Moody's 24 Electrics to be appropriate. This adjustment would lower the range of yields for Moody's electrics by .28% (12.48-12.2%) and move Gulf's range of equity cost to 15.35% to 16.35%. We also consider it appropriate to apply an average dividend yield of 13.25% to Mr. Rothschild's DCF calculation of Southern. This adjustment would lower the range for Gulf's equity by .25% to 13.63-16.35%.

Mr. Rothschild's Comparable Earnings Pricing Technique, or CEPT method was based on the theory that the market-to-book ratio achieved by a company is a function of the return on equity actually earned by that company. Mr. Rothschild's selection of industrials with market-to-book ratios of .75-1.25% seems to be a step in the right direction, but he failed to corroborate his selection process with additional risk measures.

Mr. Hunt testified that Gulf's cost of equity is between 16.2-17.8% with a mid-point of 17.0%. Mr. Hunt's testimony was based on one of two economic scenarios. His first scenario (which he used) assumed a "steady upward trend over time in the financial indicia used to determine the cost of equity." The second economic scenario (which he did not recommend) assumed that interest and inflation rates and other pertinent financial data will remain constant or decline. Mr. Hunt used a trend analysis in the first situation to estimate a 16.3% to 17.1% cost of equity for electrics.

Considering the range of equity costs indicated by these analyses and our comments thereon, we find that the proper return to the Company on its equity investment lies within the range of 14.75% to 16.75%, with a midpoint of 15.75%. Because Gulf has continued its commitment to an effective conservation program, we will focus upon 15.85% rather than the midpoint for purposes of calculating revenue requirements. Section 366.041(1), Florida Statutes.

Approved Capital Structure and Fair Rate of Return

Based upon our review of the record, we approve and adopt the following capital structure and indicated capital costs. The result is a range of reasonableness of 9.40% to a 9.94% with a focus upon 9.70%.

GULF POWER COMPANY
Capital Structure
13 Month Average

Description	Amount	Percentages	Cost Rates	Weighted Components
Long Term Debt	$292,435,000	46.24	8.69%	4.02%
Short Term Debt	-0-	-0-	-0-	-0-
Preferred Stock	65,545,000	10.36	8.65	.90
Common Equity	169,065,000	26.73	14.75 15.85 16.75	3.94 4.24 4.48
Customer Deposits	5,877,000	.93	7.84	.07
Deferred Taxes	66,924,000	10.58	-0-	-0-
Investment Tax Credits (3%)	1,754,000	.28	-0-	-0-
Investment Tax Credits (4% & 10%)	30,880,000	4.88	9.70	.47
TOTAL	$632,480,000	100.00		9.70%

OVERALL RANGE - 9.40%-9.94%

ATTRITION ALLOWANCE

In its original filing, the Company requested that it be allowed an attrition allowance of $14,964,000, which was developed and sponsored by Witness McClellan. This amount was later revised to $14,450,000, however, to correct an error made in "tax effecting" the amortization of the investment tax credit. The Public Counsel asserts that no attrition allowance is appropriate in this case.

The Company contends that an attrition allowance is necessary to recognize the increased cost of service and investment levels in 1982. Gulf claims that this is necessary because rates will not go into effect until 1982, but they will be based on 1981 data. In computing his attrition allowance, Mr. McClellan has used the difference between the projected 1981 data and projected 1982 data on a per customer basis. Mr. McClellan then multiplied the per customer data by the average number of customers for the test year to determine the revenue effect. It should be noted that Mr. McClellan is basically sponsoring a methodology for computing attrition, and agrees that any adjustments made to the Company's projected data would have to be reflected in the computation.

Mr. McClellan has also provided a calculation of an attrition allowance based on the methodology used in the Company's last rate case, which was a three year average of the changes in the Company's earned rates of return. For the period 1978-1981, the attrition allowance is $11,104,000 and is $6,019,000 for the

1977-1980 period. Mr. McClellan contends, however, that a rate of return before taxes is more appropriate than an after tax rate of return. On a before income taxes basis, the attrition allowance is $13,038,000 for the 1978-1981 period, and $10,019,000 for the 1977-1980 period.

The Public Counsel contends that the Company is actually using a 1982 projected test year as a result of using the difference between 1981 and 1982 to compute the attrition allowance. The Public Counsel also asserts that no determination of the reasonableness of the 1982 budget has been made. The Public Counsel also points out the many changes that would have to be made to the 1982 data if the Company's working capital allowance and capital structure were significantly revised by the Commission.

In view of the adequacy of the level of net operating income applicable to the test period, we find that it would be inappropriate to employ the methodology advocated by Mr. McClellan. We recognize, however, that this determination ignores the full impact of Plant Daniel on the Company's operations. Since Plant Daniel was not projected to be in-service until June 1981, only seven-thirteenths of it is included in the average rate base and the related expenses are only in the income statement for seven months.

An appropriate and justified attrition measure, in our opinion, would be to adjust the test year rate base and income statement to recognize a full year's operation of Plant Daniel in 1982.

The full effects of Plant Daniel should be recognized if rates are to function properly in the future. In doing so, we shall recognize both the investment and the related revenues and expenses assocaited with Plant Daniel. Exhibit 94 sponsored by Mr. Scarbrough, contains a methodology to accomplish this result, but we believe the following modifications to that methodology are necessary:

<u>Rate Base</u>

1. We have eliminated the net investment in coal cars for 1981 and 1982.

2. We have reduced the investment in fuel stockpile to a level consistent with the expected utilization of Plant Daniel in 1981 and 1982.

3. We have revised the jurisdictional separation factor to reflect the cost of service study adopted herein.

4. We have reduced the required rate of return to that approved as reasonable in this Order.

<u>Income Statement</u>

1. We have reduced depreciation and amortization expense to eliminate the depreciation related to the investment in coal cars.

2. We have revised the jurisdictional separation factor to reflect the different cost of service study.

After making these adjustments, we have computed an attrition allowance of $7,976,000 to recognize the difference between the revenue requirements of Plant Daniel included in the 1981 test year and the revenue requirements for 1982.

REVENUE REQUIREMENTS

Having determined the Company's rate base, the net operating income applicable to the test period, the overall fair rate of return, and the appropriate attrition factor, it is possible to calculate any excess/deficiency of revenues. Multiplying the rate base value of $628,574,431 by the fair return of 9.70% yields an NOI requirement of $60,971,720. The adjusted net operating income for the test year amounted to $62,199,775, showing an excess of $1,228,055. Applying the appropriate NOI multiplier of 1.980677 to this figure yields an excess of $2,432,380 in gross revenues prior to consideration of the attrition factor designed to annualize the impact of the addition of Plant Daniel. When the attrition allowance of $7,976,000 is incorporated, a total revenue deficiency of $5,543,620 results. We find and conclude that Gulf Power Company should be authorized to increase its rates and charges so as to generate this amount of additional revenues annually.

ADDITIONAL ISSUES

Generation and Transmission Expansion Plans

As stated by Witness Parsons, the goal in generation expansion planning is to have the most economical generating capacity available at the time it is needed. The Company contends that its generation and transmission expansion plans, including its involvement in Plant Daniel and Plant Scherer were prudently made. Public Counsel asserts that it is unreasonable to expect Gulf's customers to support, either as plant-in-service or CWIP, generating units that are intended to meet sales off the Company's own system.

The evolution of Gulf's planning with regard to its ultimate participation in the ownership of Plant Daniel is quite adequately shown in Mr. Parson's Exhibit 6. The Company first decided to participate in the ownership of Plant Daniel in 1975. At that time, the cost of Plant Daniel was estimated to be approximately $273/kw, as compared to the $825/kw cost projected for a plant at Caryville at the time. When coal cars and all auxiliary equipment are included, the cost per kilowatt of Plant Daniel is approximately $395, which appears to be considerably less than the alternatives available to the Company.

The Company's current generation expansion plan involves a 25% ownership of Scherer Units 3 and 4, scheduled to be placed in service in 1987 and 1989. Based on Gulf's current budget, the cost of this Scherer capacity is estimated to be $827/kw. The comparable cost of capacity installed at Caryville in 1987 is estimated to be $2052/kw. Hence, Gulf's 404 MW net ownership share in Plant Scherer is expected to result in an estimated $495 million savings to Gulf's ratepayers.

Based on Gulf's load forecasts, capacity from the Scherer units will not be required from a reliability standpoint until 1990. To minimize the impact of excess reserves between the in-service date of Plant Scherer and 1990, Gulf intends to sell unit power from Plant Scherer until the full capacity of these units is required on Gulf's system.

Elsewhere in this Order, we have faulted Gulf's past inadequate load forecasting, which in our opinion gave the wrong "signals" to system planners. However, the responses of the planners to the information provided them was, in our opinion, prudent and appropriate. No adjustment other than the one we have made as a result of the inadequate lead time to develop off-system sales of Daniel capacity is warranted in this matter.

Caryville Cancellation

This issue is closely related to that involving generation expansion plans. Moreover, the matter was closely examined during the Company's last rate case. In Order No. 9628, we agreed that the cancellation was prudent, based upon the justification presented, which was the economic benefits to be derived from purchasing Scherer capacity in lieu of building the Caryville unit. In that Order, we authorized Gulf to place the unamortized portion of the cancellation charges in rate base and amortize them over a five year period. The associated revenues were placed subject to refund pending consummation of the Scherer transaction. In this case, Company witnesses testified that the contract is awaiting SEC approval, and has been extended until June 30, 1982. Nothing of an evidentiary nature has been presented to alter the findings of Order No. 9628. We shall retain jurisdiction over this matter, and shall continue the refund condition on associated revenues.

Participation in Power Pool

The basic principle of pooling operations is that each member retains its lowest cost resources to serve its own customers. Surplus energy sold to the pool will be that energy obtained from higher-cost resources.

Article III of the Southern Systems Intercompany Interchange Contract defines interchange energy as the sum of associated interchange energy between the operating companies and non-associated interchange energy with others. If a member can generate power cheaper than the pool, then that power is retained for its ratepayers - any excess generation is sold to the pool at that member's incremental cost.

The associated interchange energy rates are established in order of highest cost for each fossil fuel generating unit and the cost to be applied hourly. The agent shall credit each operating company supplying associated interchange energy to the pool. Each hour, the agent shall charge the purchasing company energy received from the pool. This selling cost is an equalized credit shared by the operating companies which provided generation to the pool for the mutual benefit of all the operating companies.

Through the provisions of the IIC, Gulf will be a net seller of interchange energy in 1981. Gulf has also reduced its outage rates, thus making available additional capacity for sales to the pool. Gulf is projected to net $38,864,991 in interchange transactions in 1981. From the evidence presented, we find that Gulf's participation in the Southern System Power Pool through the pricing of interchange transactions is in the best interest of Gulf's ratepayers.

Gulf's Control Over Plant Daniel Expenses

The Company maintains that the record supports the position that Gulf has adequate input and control over expenses associated with Plant Daniel. The Public Counsel, however, contends that the evidence in the record shows that Gulf had no control over construction costs, fuel supply or operating expenses.

Mr. Parsons testified that Gulf has an operating agreement with Mississippi Power Company that outlines how certain procedures are to be handled. He is one of two members of a supervisory committee. He further stated that a task force is at Gulf's disposal to keep him informed relative to the budgetary and expense items. Mr. Parsons also stated that he is frequently contacted about operating decisions or decisions involving expenditures.

Public Counsel makes the following assertion to support the position that the Company has inadequate control of expenses:

1. Gulf had no control over the decision to purchase western coal.

2. Gulf is obligated to pay for 50% of the cooling capacity even if another unit is built at Plant Daniel and Gulf is not a participant.

3. Gulf is responsible for 50% of the expenses, excluding fuel, even if Gulf receives less than 50% of the energy output during a given month.

4. Gulf's decision to participate in Plant Daniel was not its own.

Pursuant to Paragraph 13-B of the operating agreement between Gulf and Mississippi, Gulf would be responsible for 50% of the payments for water service and principal and interest on the revenue bonds if another unit were added at Plant Daniel. This provision would apply even if Gulf was not a participant in that additional unit. It would appear that if another unit were added and Gulf was not a participant, that Gulf would pay more than its proportionate share of the costs incurred. At the present time, there are only two units at Plant Daniel and there is no effect on the test year.

Regarding the first contention, Mr. Parsons stated that Gulf had no control over the decision to buy western coal because Gulf was not involved in Plant Daniel at the time the decision was made. Concerning Item 3, Mr. Parsons testified that the provision related to one company receiving less than 50% of the output was nonoperational. As far as Item 4 is concerned, Mr. Parsons stated that the ultimate decision to participate, or not to participate, in Plant Daniel rested with Gulf. Any recommendation from Southern Company Services concerning long-range generation plans would be presented to the Operating Committee, but only with the complete approval of Gulf to do so.

With the potential exception of the cooling capacity, the record indicates that the Company does have adequate input and control over expenses associated with Plant Daniel. However, if an additional unit is constructed at Plant Daniel and Gulf is not a participant, the issue of the appropriateness of Gulf's obligation to continue to be responsible for 50% of the costs related to the cooling capacity shall appropriately be addressed in future ratemaking proceedings.

Basis for Decisions Concerning Expansion

The Company contends that decisions involving the expansion of Gulf Power are based on the needs of Gulf's customers, and are then coordinated with the other Southern Company members so as to provide for the long-term best interests of Gulf's customers.

The Office of Public Counsel suggests that Plant Daniel, Plant Scherer, and the Caryville Cancellation are part of the overall Southern System generation plan and, thus, should not be included in Gulf's rate base.

We believe the record demonstrates that the decisions involving the expansion of Gulf Power are based on the long-term best interests of Gulf's customers. The cost savings associated with Gulf's participation in Plant Daniel and Plant Scherer in lieu of Caryville are examples of Gulf's coordination with the Southern Company.

RATE STRUCTURE AND RATE DESIGN

Cost of Service Methodology

Two basic types of cost of service methodologies for allocating demand costs were advocated by the parties in this case. The Company, the Commission Staff and the Federal Executive Agencies supported a 12 monthly coincident peak (12 CP) method, while Air Products and Chemicals, American Cyanimid Company and Monsanto sponsored a five-day average CP method.

Mr. Pollock, the witness for the industrial customers, stated that the five-day average CP method should be used because Gulf exhibits seasonal load characteristics, with summer months being the peak months. He argued that demands imposed on Gulf during non-summer months bear causality for system expansion. Gulf refuted the five-day peak method as being inconsistent with the range in winter peaks for the last six years, all of which were within 81 to 95 percent of their respective summer peaks. This potential for winter peaking is expected to increase as Gulf becomes more interconnected to the rest of Florida (a winter peaking state). Gulf also receives or pays monthly demand credits which vary with Gulf's system demand, and are indicative of the importance monthly demand has upon Gulf ratepayers' net capacity costs.

Public Counsel took no position on this issue. St. Regis Paper Company requested that the Company be required to file another cost of service study based solely upon historical 1981 data (instead of projections) and using a peak responsibility cost allocation methodology.

As we have stated before, we believe that demand costs should not be assessed solely on the basis of peak responsibility. Instead, both peak responsibility and the amount of energy used should have some weight in the assignment of demand-related costs.

We therefore direct that the twelve months peak and average demand method (12 CP & Average) be used for allocating costs in this proceeding.

The PXT class's cost of service was reflected inaccurately in the Company's cost of service study performed by Mr. McClanahan. PX and PXT were directly assigned substation facilities that are used exclusively by these two classes. They were then allocated a portion of the common substation facilities that are not used by PX or PXT customers. This error overstated their rate base responsibility.

Mr. McClanahan also utilized sales projections to allocate costs which differed from those used to calculate revenues. His initial calculations assumed that each class's 1979 sales would increase by 3.1%, the projected increase in system sales from 1979 to 1981, instead of utilizing the Company's sales projections by rate class. In the case of the PXT class the sales actually decreased by 6% between 1979 and 1981.

A third error relating to the PXT class's treatment in the Company's cost of service study was reflected in the construction of the 12 CP demand allocator. Mr. McClanahan had assumed that each class's contribution to the 12 monthly coincident peaks would increase between 1979 and 1981 by the same percentage (1.1%) that the system's 12 coincident peaks were projected to increase. Therefore, although PXT's revised kwh consumption decreased by 6%, the demand allocator reflected a projected increase of 1.1%.

Witness Pollock performed an additional cost of service study to correct these errors. We believe that Mr. Pollock's cost of service study more accurately represents the PXT's rate of return as well as those of the other rate classes in this case. Therefore, we adopt Mr. Pollock's 12 CP and average cost of service study for use in allocating revenue responsibility and designing rates in this proceedings.

Load Research Data

In performing a cost of service study, load research data is used to estimate monthly coincidental and non-coincidental demands for each class of customers. These estimates are then used to develop demand allocation factors which are used to allocate demand costs among the customer classes. Because demand allocators allocate a majority of the rate base, reliable load research data is crucial to the validity of a cost of service study.

Mr. Ted Spangenberg testified for the Company in support of the load research data used to develop the demand allocators in the cost of service studies submitted in this proceeding. Mr. Spangenberg outlined the methods used to estimate demands for each of the customer classes.

The demand of the residential class, which accounted for approximately 50% of kwh consumption, was estimated using a statistical technique based on probability sampling. While this is certainly a step in the right direction, the magnitude of the sampling error exceeded the target levels currently required by

PURPA. Mr. Spangenberg testified that this was due in part to the size of the sample (the number of customers equipped with load research meters) and that the Company had subsequently increased the sample size to conform to the PURPA load research design requirements.

The remainder of the customer class demands which had to be estimated cannot even be statistically evaluated. To estimate the demands of LP commercial customers served at secondary voltage and GSD customers above the secondary level, data was taken from four metered circuit feeders. These circuit feeders serve both commercial and non-commercial customers. Mr. Spangenberg testified that he believed data taken from these circuit feeders was representative of the commercial class but he did not know what percentage of the customers on these feeders were commercial customers or the percentage of consumption measured by the feeders for which the commercial customers accounted. Yet, in using data from the feeders to estimate demands, he had to assume that the demands measured by the feeders were representative of the customer groups described above and that the demand ratio of the feeder and customer groups was equal to their kwh consumption ratio.

Load data from Georgia Power Company's five hundred largest customers was used to estimate demands for all but Gulf's six largest LP and GSD industrial customers. Mr. Spangenberg testified that he had to assume that the load shapes of Georgia Power's five hundred largest customers are representative of Gulf's large and small industrial customers and that the relationship between load shape and load factor was identical for the two groups. He also testified that he did not know in what type of industrial activities the Georgia Power customers were engaged.

Finally, the demands of Gulf's GS customers and GSD commercial customers served at the secondary level were estimated using what Mr. Spangenberg called a residual analysis. In this procedure all of the previously estimated demands and demands that are actually determined from metering data are subtracted from the Company's total system demand. The remainder is the residual demand. The residual demand was divided between the GS and GSD classes on the basis of their kwh consumption. The allocation assumes that the two classes have the same load factors. Since the residual analysis consists of subtracting demands estimated for other classes from the Company's total demand, if the estimated demands are erroneous, the demands attributed to the GS and GSD classes may be over- or underestimated. Thus, the accuracy of the demands estimated for the GS and GSD classes cannot be evaluated at all because it depends on the amount and direction of error for all other estimated demands, also an unknown.

We conclude that the load research data used by the Company (it was also used by the intervenors) to develop demand allocation factors for the cost of sevice studies is seriously deficient. It is not statistically reliable. It must be improved. The Company stands advised that in future rate cases, if the Company's load research techniques do not produce statistically reliable results, the Commission intends to treat the matter as a quality of service issue and accordingly adjust the allowed rate of return.

Allocation of Revenue Increase

The results of Mr. Pollock's 12 CP and Average cost of service study show the following rates of return earned by the various customer classes:

Code	Rate Schedule	Present ROR/Index
RS	Residential	8.30%/84
GS	General Service	11.21/113
GSD	General Ser. Demand	14.43/145
LP	Large Power Service	11.27/114
PX	Large High Load Factor	9.80/99
OS	Outdoor Service	9.04/81
TOTAL RETAIL		9.90/100

We have granted the Company an overall revenue increase of $15,543,620. Because we are committed to gradual progress toward ? uniform rates of return for all classes, the revenue increase will be divided between the residential (RS) and outdoor service (OS) classes so as to bring them both up to about the same rate of return as shown below. This amounts to a percentage increase without fuel of 5.71% for the RS rate and 5.34% for the OS rate. In so doing, we are departing from our policy in previous cases of limiting the increase to any one class to not more than 1.5 times the system average increase. Were we to apply that policy in this case, some classes whose present rates of return are above parity would receive an increase. Thus, the greater equity lies in allocating the increase to those classes with substantially lower rates of return. The rates of return by customer class with the revenue increase are:

Code	Rate Schedule	Approved ROR/Index
RS	Residential	8.48%/87
GS	General Service	10.74/111
GSD	General Ser. Demand	13.59/140
LP	Large Power Service	10.56/109
PX	Large High Load Factor	9.07/94
OS	Outdoor Service	8.45/87
TOTAL RETAIL		9.70/100

Customer Charges

Customer charges should be set at unit cost excluding any minimum distribution system cost, subject to the limit that no charge be increased by more than 50%.

The Company proposed a residential class customer charge of $8.00. However, the Company overstated the customer cost to this class by allocating an excessive number of service drops to it and by assigning monthly billing costs of $1.33 per customer to each class even though industrial and some commercial customers have much more complex bills. Therefore the customer charge for this class will remain at the present $5 per month.

The LP and PX customer classes presently pay customer charges greatly in excess of actual unit costs. We find no reason not to immediately decrease these charges to unit costs.

The approved customer charges are shown on the following schedule:

Rate Schedule	Present	Unit Cost	Company Proposed	Approved
RS	$ 5.00	$ 8.13	$ 8.00	$ 5.00
GS	5.00	11.84	8.00	7.00
GSD	13.00	24.79	28.00	19.50
LP	178.00	26.78	100.00	27.00
PX	4,083.00	59.97	2,480.00	60.00

Demand Charges

The present demand charges are well below unit costs and the Company proposed to increase these charges to move toward unit costs. The Commission staff recommended that demand charges be increased to 1.5 times the present charges in an effort to move closer to unit costs and, at the same time, lessen the impact on low load factor customers.

Drastic changes in demand charges are not warranted at this time. Perhaps those costs which are allocated in a cost of service study on average demand and included in the unit demand cost, should be recovered through the energy, rather than the demand charge. But we are not ready to decide how much, if any, of the demand costs should be allocated to the energy charge. Therefore, demand charges should be kept relatively stable.

The present demand charges are $5.00 per kw for LP (GSLD) and PX (GSLD1) and $4.00 per kw for GSD. Accordingly, we find that the demand charges should be set at $5.00 per kw for all demand metered rate schedules.

Demand Ratchets

The Company presently incorporates a ratchet provision as a feature of all demand metered rate schedules. The ratchet for the GSD, GSDT, LP (GSLD) and LPT (GSLDT) classes is 75% of the maximum demand during the summer (peak) months. The ratchet for the PX (GSLD1) and PXT (GSLDT1) classes (optional high load factor rate schedules) is 100% of the maximum demand at any time during the year. The Company proposed to continue the ratchet provisions.

The staff recommended that demand ratchets be eliminated and replaced with seasonal demand charges which are higher in the summer (peak) months.

We find that ratchets, while recognizing the benefits of peak load pricing, ignore the diversity of customers' peak loads. One customer may constantly be at his maximum demand throughout the peak season. Another customer may attain his maximum load only briefly and/or infrequently during the peak season. Yet, with a ratchet, both customers would pay demand charges based on their maximum demand. This seems inequitable.

In recent cases involving Florida Power Corporation (Docket No. 800119-EU) and Florida Power and Light Company (Docket No. 810002-EU), we eliminated ratchet provisions in all rate schedules. They should be eliminated in this case also. However, we do not accept staff's recommendation of a seasonal increase in demand charges in lieu of the ratchet. The revenue lost due to the elimination of the ratchet should be recovered through the energy charge in each applicable rate schedule.

PX and PXT Minimum Bills

Rate schedules PX and PXT are optional tariffs which require a customer to contract for at least 7500 kw and maintain an annual load factor of at least 75%. The minimum bill provision on these schedules is designed to insure that each customer maintains the required load factor. It is based on the customer charge plus the demand and energy charges necessary to maintain a 75% load factor.

The industrial intervenors objected to the calculation of the minimum bill. They asserted that it was designed to insure an 80% load factor requirement. These intervenors further objected to the inclusion of an amount for energy in the minimum bill. They asserted that practically all of the energy charge is fuel cost which can be avoided if customers reduce consumption and, therefore, should not be included in the minimum bill.

We agree that the minimum bill should not include fuel costs. However, the energy charge does recover costs other than fuel. We find the minimum bill should be redesigned to include only the non-fuel portion of the energy charge.

Voltage Discounts

Voltage discounts are given when a customer takes service at either transmission or primary distribution voltage. Discounts are given because the demand charge recovers costs incurred for the various transformations necessary to provide service at the secondary distribution level. Voltage discounts, or credits on the bill, return that portion of the demand charge related to transformation to customers who do not require it.

The present tariffs provide a discount for transmission voltage and primary distribution voltage of 10¢ per kw per month. The Company proposed to increase the discounts to 50¢ per kw per month for service at transmission level and 30¢ per kw per month for service at primary distribution level. We approve a transmission voltage discount of 45¢ per kw per month and a primary distribution voltage discount of 25¢ per month. The difference between the Company's proposed rates and the ones we approve lies in granting the Company a lower rate of return than that which they sought.

Reactive Demand Charge

A customer's (or a company's) power factor is the ratio of real power (kw) to apparent power (KVA) and is usually expressed as a percentage. Power factor improvement confers several benefits, most importantly, improved voltage conditions, reduced line losses, and released system capacity. These benefits are maximized when improvement occurs in the proximity of the equipment utilizing the power. Because of the benefits to the system of power factor correction, many electric utilities impose a reactive demand charge on customers who have poor power factors, thereby giving the customer an incentive to improve his electrical efficiency.

Gulf's present charge to customers with power factors below 90% is $1.00 per KVAR of reactive demand. The Company proposed to increase this to $1.40 per KVAR. This charge applies to all rate schedules with specific demand charges.

Power factor correction is usually achieved by installing power capacitors. Gulf based its proposed reactive demand charge on the cost to the customer of installing secondary capacitors. The Company provided an exhibit showing that the cost to the Company of correcting the customer power factor to 90%, if the customer does not, is 11¢ per KVAR per month.

Mr. Haskins testified that the reactive demand charge should be based on the customer's cost rather than the Company's cost for two reasons. First, to provide a proper price signal which will make it economically attractive for the customer to install the power factor correction. Secondly, it is a more efficient way of correcting the problem than if the Company installed the capacitance. If the capacitors are installed by the customer, he reduces the line losses in his equipment and might even free up capacity to avoid the need for enlarging his wiring and services. If the customer installs the capacitance, it is provided at the point where it is required. If the Company provides the capacitance at some point farther away from the equipment, the Company's and the customer's lines up to the point of correction have to carry useless current.

We agree that customer power factor correction is beneficial to both the customer and to the Company. Additionally, we find that it is more efficient for the customer to correct his power than for the Company to do so. There should be an incentive for the customer to correct his own power factor. However, considering the wide variance between the cost to the customer of providing his own capacitor ($1.40 per KVAR) and the cost to the Company of providing capacitance (11¢ per KVAR), we find that the proposed charge of $1.40 per KVAR was not adequately justified. The Company failed to show that having the customer add capacitance is more efficient by $1.29 per KVAR. Therefore, the present reactive demand charge of $1.00 per KVAR will be retained.

Service Charges

The Company proposed to increase its charge for initial connections, normal reconnections, and reconnections after delinquency in payment from $10.00 to $13.00. The Company also proposed to institute a collection charge of $4.00. It would be imposed when a company employee goes to a customer's place of service to disconnect service for nonpayment and the customer pays the arrearages to avoid disconnection. The purpose of the collection charge is to recover the cost of the trip to the customer's place of service. We find that the cost data submitted by the Company supports the proposed charges and approve them.

Poultry Farm Operations

Several years ago, the Commission required the application of the residential rate schedule to poultry farm operations. In recent rate cases, we excluded these operations from the residential rate because they are not residential in nature and should be served under a general service rate schedule. Mr. Haskins testified that poultry farm operations generally do not have the same load characteristics as residential customers. The Company, in its brief, agreed that poultry farm operations should be removed from the residential rate.

There are seven poultry farms taking service under the residential rate. They must be taken off this rate and reclassified as GS customers. However, if they were immediately placed on the GS rate, they would receive an increase in revenues of approximately 96%, without fuel, on an annual basis. To avoid excessive increases due to the transfer, we order the Company to design a transitional rate for them. This rate should not impose an increase of more than 1.25 times the present revenue from these customers without fuel. The transition rate will remain in effect until the next rate proceeding of this company.

Outdoor Service Rates

In its original filing, the Company proposed an increase for the three subrates (OSI, OSII, OSIII) served under the OS designation, but left the other features of these rates unchanged. In reviewing the Company's filing, Staff found several problems in the structure of these rates and outlined them at the prehearing conference. At the hearing, the Company agreed to work with Staff in redesigning these rates. We approve the new rate design worked out by the Company and Staff and will discuss the major features of it.

As originally filed, OSI contained street lighting customers where the street light fixtures themselves are owned by the Company. OSII included area lighting customers where the fixtures were owned by the Company. OSIII contained all customers who owned their own fixtures, including street lights, area lights, traffic signals, CATV amplifiers, and an undefined miscellaneous group, their sole known characteristic being that they owned their own fixtures. The Company agreed, and we find, that from a rate design standpoint, customers should be classified on the basis of load characteristics. The load characteristics of street lighting customers are the same regardless of who owns the fixtures. Thus, as revised, OSI will consist of all street lighting customers. All OSI customers will pay the same energy charge. OSI customers who are served by company-owned fixtures will pay separate fees to cover the Company's investment in those fixtures and maintenance costs.

The revised OSIII class will consist of traffic signal and CATV amplifier customers. These customers have similar load characteristics and essentially operate 24 hours a day. Also left in OSIII are the miscellaneous customers. They were not moved to another rate because they were not sufficiently identified to allow any intelligent statements about their load characteristics.

OSII, as revised, will include area lighting customers. Mr. Haskins testified that currently there are no customers who own their area lighting fixtures.

During cross-examination Mr. Haskins admitted that the energy charge for OSI and OSII and the maximum demand charge for OSIII were not cost based. Also, he failed to articulate a valid reason for charging OSI and II an energy charge expressed as cents per kwh and recovering essentially the same costs from OSIII customers via a maximum demand charge. In the revised tariff, Staff calculated and the Company accepted, cost based energy charges for all three rates, and the energy charge for OSIII is now expressed in the more understandable cents per kwh form. We use the term cost based energy charges with some caution, as all three of these rates were treated as one in the cost of service study. Staff developed a reasonable alternative way of allocating the revenue requirement between the three rates, but in the future, the Company must treat them separately in cost of service studies.

In addition to an energy charge, OSI and OSII customers pay a monthly maintenance charge. One component of the maintenance charge covers the cost of replacing burned out bulbs in the fixtures. For street lighting fixtures served under the OSI rate, the Company has an ongoing group rebulbing program whereby every bulb is replaced near the expiration date of its expected life. More expensive spot rebulbing is also necessary where the bulbs burn out sooner than expected. However, a group rebulbing program considerably reduces the frequency of spot rebulbing. The Company does not have a group rebulbing program for OSII fixtures. But, in calculating the OSII maintenance charge, the Company assumed the same spot rebulbing rate for OSI and OSII. As a result, the maintenance charge for OSII was understated. Staff recalculated the OSII maintenance charge using a more realistic spot rebulbing rate and we approve the modification.

OSI and OSII customers also pay a monthly facilities charge designed to recover the Company's investment in the fixtures used to serve these customers. As originally filed, the facilities charge for the various fixtures included an increment, varying in amounts, that the Company referred to as "system related investment costs". Mr. Haskins admitted that this increment was not added to the facilities charge in a cost based manner and was simply a devise to make high pressure sodium vapor fixtures more attractive to the customer than mercury vapor fixtures. Staff eliminated this component from the facilities charge. These costs will be collected through the energy charges applied to all OS customers since they are the production, transmission, and distribution costs allocated to this class in the cost of service study.

In redesigning this tariff, Staff recommended that the fuel adjustment charge for OSI and OSII customers recognize the fact that most of their consumption is off-peak. The Company concurred in this proposal and we also approve it as the on/off-peak consumption ratio for these customers is easily determined.

The Company proposed that when they are requested to replace mercury vapor fixtures on which the initial service contract has not expired with the more efficient high pressure sodium vapor fixtures, the undepreciated portion of the original cost of the mercury vapor lights plus removal costs less salvage value be recovered through the conservation cost recovery clause. While we support this conservation idea, these costs should not be recovered through the conservation cost recovery clause until a cost benefit analysis, filed with the Commission, shows the changeout of the various sizes of fixtures to be cost effective. The Company is ordered to file such an analysis with the Commission within six months of the effective date of this Order. Until the Company files the cost benefit analysis and it is approved by the Commission, the conversion costs must be borne by the individual customer who requested the change. We approve the Company's proposal to shorten the term of the initial contract for OSII customers served by high pressure sodium vapor fixtures from five to three years for nonresidential and two years for residential customers.

Finally, the Staff proposed, the Company accepted, and we approve various tariff format changes designed to make the tariff more informative and understandable. Specifically, they are:

1. Lamp offerings will be listed by wattage and kwh as well as by mean lumens on the tariff;

2. Pole, facility, maintenance and energy charges will be separately stated on the tariff; and

3. All charges will be stated as monthly rather than as annual charges.

<u>Seasonal Rates</u>

The Company presently has a seasonal rate for the GS and RS rates. The summer billing months include October. During the course of the proceedings, the Company admitted that there is little likelihood of the Company's summer peak occurring in the October billing period and agreed to switch the October billing month from the summer to the winter rating period. We approve this change.

The Gulf system is currently a summer peaking utility, and is not strongly connected with the transmission network of the rest of Florida. This suggests that, for the present time, Gulf Power should set winter and summer GS and RS rates which reflect this reality. That is, for the present time, Gulf should continue with a winter rate which is lower than the summer rate.

While Gulf Power is presently a summer peaking utility which is not strongly connected to the rest of the State, this stituation seems likely to change. We have encouraged Florida utilities to interchange power when it is economical to do so. Gulf Power Company has been encouraged to establish stronger transmission links to the rest of the state to facilitate such interchanges of power. Also, Gulf's winter peak has been increasing, getting closer and closer to the summer peak. As Gulf establishes stronger transmission ties with the rest of the state, and its winter peak approaches its summer peak, the result may well be elimination of any meaningful winter/summer differential in peak loads. Thus, customers should not be encouraged to make long-run equipment decisions, such as purchasing less efficient electric heating, in the anticipation that the present summer peaking situation will continue. RS and GS customers should be clearly informed of the likelihood of future elimination of the winter/summer rate differentials and we order the Company to give them this notice. This may be accomplished through bill stuffers or by any other reasonable means subject to the approval of the Rate Division of the Commission's Electric and Gas Department.

Seasonal Service Rider

The Company presently has an optional Seasonal Service Rider which affords demand customers an opportunity to pay more of their total annual demand costs during the summer peak period than demand customers usually do.

The present Seasonal Service Rider provides for an additional demand charge of $1.00 per kw during the summer months of June through October and an annual minimum bill of $40.00 per kw of actual demand. In exchange for these charges, the demand ratchet feature, as well as the minimum kw feature of the standard rate schedule is waived.

The Company proposed an increase to the charges under this rider based on the Company's requested rate increase in this case. Since no portion of the authorized revenue increase has been allocated to the demand metered rate schedules, we find that no change in the charges applicable to this rider is warranted. Furthermore, the months to which the additional demand charge applies must be changed to June through September to be consistent with the summer (peak) months chosen for the residential and general service seasonal rates.

Standby Service

The Company has had the same tariff for Auxiliary or Standby Service for many years. Under it, the rate applicable for such service is Rate Schedule LP (Large Power Service with demands of at least 500 kw). There are no customers taking standby service under this tariff provision. Residential customers with windmills are provided standby or supplementary service under the standard residential rate.

In its original filing, the Company proposed no change to the standby rate tariff. However, at the prehearing conference, the Company accepted the position of the Staff at the time that standby service should be provided at the time-of-use rate otherwise applicable to the customers. We find that the rate for standby service should be the rate applicable to the customer based on his kw demand. The customer may, if he so chooses, take service under the related time of use rate.

Mr. Harold Cook, testifying on behalf of St. Regis Paper Company, recommended that the Commission set guidelines for designing various auxiliary rates for cogenerators. He recommended different rates for three types of service. Supplementary power (energy used by a facility in addition to that it generates on its own) should be billed at the industrial rate the cogenerator would normally receive service under if he did not own his own generating equipment. Back-up service power available to replace power generated by a facility's own generation equipment during an unscheduled outage should be priced on the basis that the utility is providing reserve capacity for the customer's generation. Mr. Cook proposed that the rate for back-up service be the Gulf Power reserve criterion times the demand charge of the rate under which the cogenerator would be served if the customer did not own its own generating facility. A proper rate for maintenance power (energy supplied during scheduled outages of the qualifying facility) should contain no demand charge according to Mr. Cook, if the cogenerator and the utility are able to coordinate scheduled outages of the cogenerator's facilities. Maintenance power should be priced at the applicable energy rate that the cogenerator would be served under if the customer did not own its own generating facilities.

Mr. Cook's position boils down to the position that cogenerators should not be presumed to be firm customers unless proven to be so. We agree with the idea that these customers should not be assumed to be firm customers. The major device in the Company's tariffs which creates the presumption of firm service by any customer is the ratchet in both its traditional form (i.e., a percentage of maximum demand) and in the minimum kw bill provision.

The elimination of demand ratchets in all its forms (including minimum kw bill provisions) would eliminate the presumption that cogenerators are firm. Placing cogenerators, or anyone else, on rates in which they pay only for their use, when they use it, should satisfy the need for non-discriminatory maintenance, back-up, and auxiliary power service rates.

We have solved part of the problem by eliminating the ratchet. However, based on the record in this proceeding, we do not have sufficient information to eliminate the minimum billed kw provisions at this time. We do not know the revenue effect on the Company of the elimination of this provision, nor has the Company been given an opportunity to address this issue. Further, we find this matter should be treated on a generic basis involving all the investor-owned electric utilities as well as the municipals and cooperatives. Therefore, a generic docket will be opened to address the appropriateness of minimum-bill kw provisions in the rate schedules of all electric utilities.

Interruptible Rates

Order No. 10179 (August 3, 1981) required each company to offer interruptible rates to those industrial and commercial customers willing to have their power interrupted. Mr. Haskins testified that the Company has not filed interruptible rates because none of their customers have shown interest in such a rate and they prefer to design a rate for a specific customer who is interested in it.

Since the Company presently has excess capacity, shifting firm customers to interruptible rates is not going to promote capacity avoidance in the short run. However, the long run outlook may well be different. Therefore, we order the Company to file a plan, within six months, showing the Company's projections of when interruptible rates will allow capacity avoidance and be offered to their customers.

Inverted Rates

At the prehearing conference, Public Counsel took the position that an inverted residential rate structure should be implemented to encourage conservation. However, no evidence was presented on this issue at the hearing. We note that inverted rates are the subject of investigation in Docket No. 800708-EU.

Customer Rate Migration

Presently, the Company's demand metered rate schedules consist of GSD (customers with demands of 20 kw or greater), LP (customers with demands of at least 500 kw), and PX (an optional rate schedule requiring that the customer maintain a load factor of at least 75%). Gulf allows its demand metered customers to move from one rate schedule to another if they wish, regardless of whether their load characteristics are more consistent with the class they leave than the class they join. For example, if a customer with a demand of 650 kw (thus falling in the LP class) found that he could reduce his bill if he were billed under the GSD rate, he would be allowed to migrate to the GSD schedule where maximum demands are supposedly 500 kw and below. In the company's original filing, 75% of the LP customers would migrate to GSD.

Mr. Haskins testified that one of the criteria for good rate design is the establishment of classes with fairly homogeneous load characteristics. The load research which is used in the cost of service study assumes that in calculating the rates of return by class, load characteristics remain fairly consistent after revenue requirements are converted into rates. If large numbers of customers are allowed to move to any class they desire based solely on their economic considerations, very little can be said about the resultant rates of return by class or customer. Most importantly, changing customer groups after the cost of service study is performed destroys the match between costs allocated to a customer group and rates designed to recover those costs. Some customers will pay more than their fair share and some less. Finally, the probability samples used in load research are based on the makeup of the customer classes at the time the load research design is completed. If a large number of customers subsequently migrate to other classes, the statistical validity of the samples is impaired.

The migration problem can be solved by charging full unit demand and energy charges. Coincidence factors will always differ by customer groups, and, until an inexpensive demand meter which measures coincident demand rather than noncoincident demand is invented, differences in coincidence between classes will dictate different demand costs by class. Until then, we will not allow migration downward to lower demand rate schedules unless the customer qualifies by holding down his demand for a year. Customers may migrate to a higher demand schedule at any time provided they pay the minimum demand provisions of the higher demand schedule.

As a possible solution to the migration problem, the Company submitted an hour's use rate proposal. This is not a viable alternative because it discourages conservation by decreasing the energy charge as more kilowatt hours per kilowatt are used.

The Company must revise rate GSD to include a maximum demand limitation of 500 kw per month and a provision that a customer may not change from a higher demand rate to GSD unless his demand is less than 500 kw per month for the immediately preceding year.

Time of Day Peak Periods

Gulf proposed several modifications of their summer and winter peak periods used for time of day rates. The Company wanted to shorten the summer peak period from April through October to June through October, but lengthen the daily summer peak periods which are now 12 AM through 10 PM to 10 AM through 10 PM. Gulf wanted to lengthen the months considered winter from the current November through March to November through May, but shorten the daily winter peak hours which now are 6 AM to 10 AM and 6 PM to 10 PM by eliminating the 6 PM to 10 PM peak period. The Company argued that the proposed peak periods more closely match their actual peak demand periods.

What the Company's argument overlooks, however, is that in Docket No. 780793-EU, in which the current peak periods were established, a deliberate decision was made to treat the state as one pooled system and establish uniform statewide peak periods. This was done to facilitate implementation of the statewide energy broker system whereby lower cost generation can be bought and sold among Florida utilities on an hourly basis. While Gulf presently does not exchange much power with other Florida utilities, treating it as part of the state pool will have increasing merit as its interconnection with the rest of the state is strengthened. Therefore, the Company's present peak rating periods must be retained.

Lump Sum Payment Option for TOD Meters

Customers who choose to receive service under a time of day rate have the option of paying a monthly charge to cover the cost of the more expensive (relative to a standard) time of day meter or paying for the time of day meter in one lump sum. However, the company's proposed time of day tariffs do not show a specific lump sum payment amount. Instead, the tariffs state that the approved cost will be quoted at the time of customer application.

We have received numerous inquiries concerning the lump sum payment option and find that the ratepayers would be better served by showing the exact amount of the lump sum payment on the tariff. According to data submitted by Gulf in Staff Exhibit 118, the current cost of the time of day meters is $154.40 for RST customers and $282.24 for GST classes, and these amounts must appear on the respective tariffs.

Load Factors Used in Designing TOD Rates

In designing its time of day rates, the Company used class load factors to allocate the demand costs which must be recovered by the energy charge of the rate between peak and off-peak periods. Alternatively, these costs could be allocated between peak and off-peak periods using the system load factor.

One of the primary objectives of time of day rates is to encourage customers to shift their usage from peak to off-peak periods. The greater the differential between peak and off-peak prices, the greater the incentive to shift usage. The maximum differential between peak and off-peak energy prices is obtained by using the lower of the class or system load factor. The class load factors used by the Company were lower than the system load factor for all but the LP and PXT rates. Therefore these rates must be redesigned using the system load factor to allocate demand costs recovered through the energy price between peak and off-peak periods.

Late Payment Penalty

The Company proposed a late payment interest charge of 1.5% for delinquent bills. Mr. Haskins testified that the charge was necessary to compensate the Company for the investment opportunity it must forego when customers do not pay on time. He also testified that he believed that the presence of a late payment charge would cause more customers to pay their bills on time.

The Company has not met its burden of proof on this issue. The Company did not clearly demonstrate a need for a late payment penalty, and on cross-examination it became apparent that 1.5% was selected as the interest rate primarily because customers were familiar with it as the interest rate applied to credit card charges.

There are other ways by which the Company can encourage its customers to pay on time. For example, the Company could send out late notices twenty days after the first bill is mailed. And, in appropriate circumstances, the Company could increase the deposit required or discontinue service.

Our decision on this issue is consistent with our decision in Docket No. 800726-EU.

Investigation Fee

Gulf proposed to begin charging a minimum $25.00 investigation fee to cover the cost of investigation in a case involving an allegation of meter tampering. The Company proposes to collect this fee only in those cases where the investigation reveals evidence of meter tampering sufficient to support legal prosecution of the Company's claim.

Mr. Haskins testified that the minimum fee was set at $25.00 because that is the typical cost of investigation. If the Company's investigative expenses were higher than $25.00, the Company would attempt to collect the actual costs, either through negotiation or legal process.

We approve the $25.00 investigation fee because it will make those customers who cause the Company to incur the cost responsible for it. We do so subject to one caveat, that the tariff be amended to inform customers that they have the right to contest imposition of the fee to the Commission without interruption of service (assuming there are no other grounds for disconnection) while the issue is undecided.

Textual Revisions

The Company proposed several textual changes to its tariffs to conform them to current Commission rules and policy. We approve the proposed changes to these tariffs:

4.14 Testing of Meters
4.14.1 Fast Meter
4.14.2 Slow Meter
4.14.3 Non-Register Meter
4.14.4 Creeping Meters

Additionally, the Company must strike the word "material" from its tariff, Fifth Revised Sheet No. 4.12, concerning refunds of deposits, as it refers to an obsolete practice.

Fuel Component of Base Rates

The fuel and nonfuel components of the energy charge must be stated separately on all tariff schedules so that customers will be aware of the nature of the costs they are paying for in the energy charge. Energy charges on a tariff should appear as follows:

Energy Charge

(1) Nonfuel Charge	______¢/kwh
(2) Fuel Charge	2.5¢/kwh
Total	______¢/kwh

Fuel Costs in Base Rates

Staff and Public Counsel originally proposed that the 2.5¢/kwh of fuel cost currently contained in base rates be removed from base rates and shown as a separate item on a customer's bill. Public Counsel contended that this would promote conservation.

In Docket No. 810082-EU, a generic docket concerning customer billing, we ruled that the total fuel cost must be shown as a separate item on all bills, effective January 1, 1983. Therefore, we find that removing the 2.5¢/kwh fuel costs from base rates is not warranted at this time. Also, when the new billing format is implemented in January 1983, the total fuel cost in cents per kwh will be shown on the bill as will the total nonfuel costs n cents per kwh. Thus, the appearance of a base fuel cost on the tariff will not impart useful information.

EFFECTIVE DATE

The new rate schedules shall be reflected upon billings rendered for meter readings taken on or after February 12, 1982, which is thirty (30) days after the date of the vote of the Commission upon the Company's petition.

ADDITIONAL FINDINGS AND CONCLUSIONS

In addition to the foregoing, we find and conclude as follows:

1. Gulf Power Company is a public utility within the meaning of Section 366.02, Florida Statutes, and is subject to the jurisdiction of the Commission.

2. This Commission has legal authority to approve and use a projected test period for ratemaking purposes. The calendar year 1981 is an appropriate test period for this proceeding.

3. The adjustments to rate base made herein are reasonable and proper. The value of the Company's rate base for ratemaking purposes is $628,574,431.

4. The adjustments made to the calculation of net operating income are proper and appropriate. For ratemaking purposes, Gulf's net operating income for the test period is $62,199,775.

5. The fair rate of return on equity capital of Gulf Power Company lies in a range of 14.75-16.75%. A return of 15.85% should be used to determine revenue requirements.

6. The range of reasonableness for the overall fair rate of return for the Company is 9.40-9.94%, with a focus upon 9.70% for ratemaking purposes.

7. That the attrition allowance of $7,967,000 provided to reflect the full annual impact of Plant Daniel on investment, revenues, and expenses is reasonable and appropriate for ratemaking purposes in this case.

8. Gulf Power Company should be authorized to increase its rates and charges by $5,543,620 in annual gross revenues to provide it an opportunity to earn a fair rate of return of 9.70%.

9. The rate schedules prescribed and approved herein are fair, just and reasonable within the meaning of Chapter 366, Florida Statutes.

Accordingly, it is

ORDERED by the Florida Public Service Commission that the findings of fact and conclusions of law set forth herein are approved. It is further

ORDERED that the petition of Gulf Power Company for authority to increase its rates and charges is granted to the extent delineated herein. It is further

ORDERED that Gulf Power Company is hereby authorized to submit revised rate schedules consistent herewith, designed to generate $5,543,620 in additional gross revenues annually. The Company shall include with the revised rate schedules all calculations and workpapers used in deriving the revised rates and charges. It is further

ORDERED that the refund condition established in Order No. 9628, applicable to revenues associated with the Caryville cancellation charges as a result of the ratemaking treatment afforded those charges in Order No. 9628 and in this Order, be continued. The Commission retains jurisdiction over this matter. Gulf Power Company shall submit evidence of consummation of the Scherer transaction on or before June 30, 1982, the time frame specified by the contract between the parties. It is further

ORDERED that the revised rate schedules authorized herein shall be reflected upon billings rendered for meter readings taken on or after February 12, 1982. It is further

ORDERED that the Company provide to each customer a bill stuffer describing the nature of the increase and conforming to the requirements specified herein. It is further

ORDERED that Gulf Power Company provide to the Fuel Procurement Section of the Commission's Electric and Gas Department a copy of the independent audit performed by Theodore Barry and Associates referred to during the hearing. It is further

ORDERED that within six months of this Order, Gulf Power Company file with the Commission a cost benefit analysis on replacement of mercury vapor fixtures with high pressure sodium vapor fixtures prior to expiration of the service contract. It is further

ORDERED that the Company submit for Commission approval, within fifteen (15) days of the date of this Order, the request for ruling by the IRS which is the subject of the stipulation referred to and approved herein. It is further

ORDERED that the Company file a plan, within six months, showing the Company's projections of when interruptible rates will allow capacity avoidance and be offered to their customers.

By ORDER of the Florida Public Service Commission, this 1st day of February, 1982.

(S E A L)

Steve Tribble

STEVE TRIBBLE
COMMISSION CLERK

JAM/PS

Commissioner Marks dissents.

Commissioner Marks dissenting:

I disagree with the majority on the following issues:

1. I believe the majority's inclusion of CWIP in rate base to be erroneous for reasons I have stated in earlier dissents. In this instance, the majority have forsaken the "big jolt" theory and seized upon the "FERC Letter" criteria, also known as the "financial integrity" test. Applying the financial integrity test to the Gulf situation yielded results characterized at the bench as "close call". I prefer to resolve this close call to the benefit of today's customers.

2. Someday a plant will be built at Caryville. When it is built, Gulf will own 30%; Mississippi Power Company will own 70%. No construction is expected until 1995. By any measure, the site is held for future use. Property held for future use is the antithesis of property which is used and useful. Today's customers will enjoy precious little benefit resulting from the Company's plan to build a plant one day. Nonetheless, today's customers (and tomorrow's) will pay a return on this idle property. I vote to allow the property to earn AFUDC which would cause the benefitting customers to pay the costs of the benefits.

3. I accept the staff recommendation that a proper return on equity for this Company is 15.5%.

4. The majority have rewarded the Company ten basis points for its "continued commitment to an effective conservation program." An exhaustive search of the record in the case will disclose no evidence whatever probative of whether the program (if any) is continuing, committed, or effective. If the Commission is to pass out rewards to the companies it regulates, surely it should do so only upon a showing of such exemplary conduct as to impress even casual observers. Here, I am both more than casual and less than impressed. It appears to me that at the very least we should ascertain whether the benefits from conservation accomplished or to be accomplished, less the reward, results in a net benefit to the customers. In this record, neither question nor answer appears.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition of Gulf Power Company for an increase in its rates and charges.	DOCKET NO. 820150-EU (CR) ORDER NO. 11498 ISSUED: 1/11/83

The following Commissioners participated in the disposition of this matter:

GERALD L. GUNTER
JOHN R. MARKS, III
SUSAN W. LEISNER

Pursuant to duly given Notice, the Florida Public Service Commission held public hearings in Pensacola, Florida, on August 11, 1982; Fort Walton Beach, August 12, 1982; Panama City, Florida, August 13, 1982; and in Tallahassee, Florida, on October 5-8 and 11-14, 1982. Having considered the record herein, the Commission now enters its final order.

APPEARANCES:

C. Roger Vinson, Esq., Ed Holland, Esq., and Kenneth Bell, Esq., Beggs and Lane, P. O. Box 12950, Pensacola, Florida 32576 for Gulf Power Company.

Joseph A. McGlothlin, Esq., and John W. McWhirter, Jr., Esq., Lawson, McWhirter & Grandoff, P. O. Box 3350, Tampa, Fla. 33601, for Air Products and Chemicals Company, American Cyanamid Company and Monsanto Textiles Company.

Jack Shreve, Esq., Suzanne Brownless, Esq., Michael Wilson, Esq., Stephen Fogel, Esq., and Steve Burgess, Esq., Office of Public Counsel, Rm. 4, Holland Bldg., Tallahassee, Fla. 32301, for the Citizens of the State of Florida.

Major Robert T. Lee and Major Kenneth E. Bunge, United States Air Force, Law Center, Armament Division, Eglin Air Force Base, Florida, for the Federal Executive Agencies.

Bonnie E. Davis, Esq., Michael B. Twomey, Esq., Susan Clark, Esq., and Roger Howe, Esq., 101 E. Gaines St., Tallahassee, Fla. 32301, for the Commission Staff.

Prentice P. Pruitt, Esq., 101 E. Gaines St., Tallahassee, Fla. 32301, Counsel to the Commission.

ORDER AUTHORIZING CERTAIN INCREASES

BY THE COMMISSION:

SUMMARY OF DECISION

In this Order, we have determined that Gulf Power Company, (Gulf, the utility or the Company) should be authorized an increase in gross revenues of $3,366,000 annually. Gulf did not request an attrition allowance in this proceeding and none was granted. An index to this order appears on Appendix A of this order and a summary of adjustments is set forth on Appendices B and C of this order.

BACKGROUND

This proceeding was commenced on June 4, 1982, by the filing of Gulf Power Company's Petition for a rate increase that would provide $36,944,000 of additional annual revenue. This Commission suspended the proposed rates on June 23, 1982, by Order No. 10919. Gulf did not request interim rate relief.

Extensive public hearings on Gulf Power Company's request have been held in this docket. These hearings extended over 11 days and resulted in a record comprising 2,952 pages of transcript and 267 exhibits. We have also had active participation by numerous parties, including representatives of the public, governmental agencies and large industrial customers.

THE PARTIES

Gulf Power Company

Gulf Power Company is a wholly owned subsidiary of the Southern Company and is subject to our jurisdiction under Chapter 366, Florida Statutes. The Company has been engaged in the electric utility business since 1925, operating in 10 counties in the State of Florida, serving approximately 217,000 customers.

The Company was last authorized to adjust its rates in 1982, (Order No. 10557, Docket No. 810136-EU, 2/1/82). At that time, we determined that the Company's fair rate of return fell within the range of 9.40%-9.94%. Gulf now asserts that to maintain its financial integrity and to provide reliable electric service, it must have additional gross annual revenues totalling $36,944,000. This increase, according to the Company, is required to provide the opportunity to earn an overall rate of return of 10.46%, which it alleges is fair and reasonable under prevailing conditions and which would allow for a rate of return on common equity of 18.0%.

Public Counsel

Pursuant to Section 350.061, Florida Statutes, the Public Counsel is appointed by the Joint Legislative Auditing Committee to represent the general public of Florida before the Florida Public Service Commission.

The Office of the Public Counsel (Public Counsel) presented the testimony of three witnesses during this proceeding. Public Counsel proposed that the Commission establish an average rate base of $688,690,000, a return on equity of 15.05%, and an overall rate of return of 9.61%. Among other things, Public Counsel objected to the use of 1983 as the test year and to the inclusion of CWIP in rate base. In addition, Public Counsel proposed that working capital should be established by the balance sheet approach, that industry association dues, charitable contributions, and all advertising expenses be disallowed from operating expenses. Public Counsel also advocated that Gulf's entire interest in Plant Daniel be included in the retail rate base.

Air Products, et al.

Air Products and Chemicals Company, American Cyanamid Company and Monsanto Textiles Company, customers of Gulf Power Company who are members of the Florida Industrial Power Users Group (FIPUG), intervened in this proceeding. These intervenors sponsored witnesses on the subject of rate design.

Federal Executive Agencies

The Federal Executive Agencies of the United States intervened in this proceeding, sponsoring witnesses on the subjects of accounting, cost of capital and rate design.

St. Regis Paper Company

St. Regis Paper Company presented testimony on the subject of rate design.

The Commission Staff

The Commission staff participated in the proceeding and presented the testimony of one witness dealing with the number and nature of consumer complaints against the Company.

REVENUE REQUIREMENTS DETERMINATION

The revenue requirements of a utility are derived by establishing its rate base, net operating income and fair rate of return. A test period of operations, traditionally based upon one year of operations, is used to derive these factors. Multiplying the rate base by the fair rate of return provides the net operating income the utility is permitted to earn. Comparing the permitted net operating income with the test year net operating income determines the net operating deficiency or excess. The total test year deficiency or excess is determined by expanding this deficiency or excess for taxes.

THE TEST YEAR

The function of a test year in a rate case is to provide a set period of utility operations that may be analyzed so as to allow the Commission to set reasonable rates for the period the rates will be in effect. A test period may be based upon an historic test year with such adjustments (often extensive) as will make it reflect typical conditions in the immediate future, and make it reasonably representative of expected future operations. Alternatively, a test period may be based upon a projected test year which, if appropriately developed and adjusted, may reasonably represent expected future operations.

In other recent major electric utility cases, 1982 was used as the test year. Thus, as the other cases progressed we could compare actual data with forecasted data as a check on the reasonableness of the forecasted data. However, in this case, Gulf proposed calendar year 1983 as the test year. Gulf argued that use of a 1983 test year is appropriate because it will recognize cost levels that will be in effect when the new rates are in effect. Both Public Counsel and the FEA vigorously opposed use of a 1983 test year on the ground that use of 1983 forecast data was too far removed from available actual data to be adequately reviewed. There is some merit in the arguments of both parties. We must therefore weigh the benefit of a more exact match between the test period examined and the period in which rates will be in effect against the disadvantage of increased reliance on forecast, as opposed to actual, data.

In this case only, we are persuaded that the merits of a fully projected test year outweigh its disadvantages. By the time hearings were held in this case, October, 1982, actual data for 1981 was available as was data through June, 1982. This allowed a thorough review of 1981 actual to 1982 forecast and 1982 actual data. We also thoroughly reviewed the link between 1982 forecast and 1983 forecast data. Extensive testimony was received concerning the budgeting process and forecasting methods used by the Company to substantiate the projected test year rate base and NOI. Mr. Scarbrough, adopting Mr. Gilbert's testimony, provided an overview of the planning process, discussing the planning and budgeting process, and the assumptions used in developing the financial forecast. He also discussed the operation and maintenance budget process. Mr. Parsons testified about the operation and maintenance expenses of the Company, the construction budget, the generation expansion plan, the fuel program and Gulf's relationship with Southern Company Services. Mr. Shearer presented testimony concerning the 1983 forecast of the number of customers and energy sales, and the 1982-1991 forecast of customer and energy sales. Mr. Oerting discussed the development of both the short-range and long-range forecasts of the peak hour demand requirements of the Company's service area. Mr. Ludwig addressed the Company's fossil fuel procurement policies and practices. Mr. Scarbrough presented the Company's revenue requirements, rate base and net operating income and explained the adjustments that were made in these areas. His testimony concerned the end result of the Company's financial forecasting process.

Mr. Bell, a partner in the firm of Arthur Andersen and Company, performed a review of the budget or forecasting system used by the Company to develop the projected rate base and NOI. He stated that the Company's financial forecasting system was evaluated using the professional standards outlined in the AICPA's Guidelines for Systems for the Preparation of Financial Forecasts. Based on his review, Mr. Bell concluded that the financial forecasting system and the procedures employed in the preparation of the forecasted data complied with the guidelines of the AICPA, except for the fact that the Company did not include economy energy transactions in the forecast.

Mr. Bell did note, however, several areas where there were significant variances between the assumptions used by the Company and conditions as they subsequently developed. These areas were the inflation rates, long term debt and the additional revenues allowed the Company after this rate case filing was made.

We find that the Company's rate base, net operating income and capital structure are generally based upon reasonable projections and assumptions and that the forecasting methodology employed by the Company is reasonable. There are, however, certain areas where we question the reasonableness of specific projections and assumptions. These areas will be identified and addressed as separate issues. Except for these specific areas, the evidence presented demonstrates that the assumptions and projections relied upon by the Company in presenting its 1983 test year data are reasonable and may be relied upon as a basis for setting rates. As adjusted herein, we believe the test period reasonably represents expected operations during the period the rates will be in effect.

RATE BASE

To establish the Company's overall revenue requirements, we must determine the value of its rate base, which represents that investment on which the Company is entitled to earn a reasonable return. A utility's rate base is comprised of various components. These include: (1) net utility plant-in-service, which is comprised of plant-in-service less accumulated depreciation and amortization, (2) total net utility plant, which is comprised of net utility plant in service, Construction Work In Progress (where appropriate) and plant held for future use, and (3) working capital.

Gulf Power has submitted a proposed jurisdictional rate base of $674,607,000. Evidence developed during the course of the proceeding has led us to reduce that amount to $636,896,000. Our adjustments are set forth as follows:

Rate Base Adjustments
$(000)

	Per Company	Adjustments	As adjusted
A. Utility Plant in Service	$ 751,035	$ 24,094	$ 775,129
B. Accumulated Depreciation and Amortization	220,509	______	220,509
C. Net Utility Plant in Service	530,526	24,094	554,620
D. Construction Work in Progress	30,128	(24,094)	6,034
E. Property Held For Future Use	2,291	______	2,291
F. Net Utility Plant	562,945	0	562,945
G. Working Capital	111,662	(37,711)	73,951
H. Total Rate Base	$ 674,607	$ (37,711)	$ 636,896

A. Utility Plant In Service

The amount of plant in service originally proposed by the Company is $751,035,000. Utility plant in service should be increased to $775,129,000. Of the total amount of CWIP requested for inclusion in the rate base by the Company, $24,094,000 will begin commercial operation in 1983 and is more properly classified as plant in service in the test year.

B. Accumulated Depreciation and Amortization

The amount of accumulated depreciation and amortization originally proposed by the Company is $220,509,000. This is the proper amount and no adjustment is necessary.

C. Net Utility Plant In Service

Net plant in service is comprised of utility plant in service, less accumulated depreciation and amortization. We find that the appropriate amount of net utility plant in service for the test year is $554,620,000, based upon $775,129,000 of utility plant in service and $220,509,000 of accumulated depreciation and amortization.

D. Construction Work In Progress (CWIP)

In its original filing, the Company requested that $31,138,000 (juris.) of CWIP be included in its rate base. During cross-examination, Mr. Scarbrough indicated that of the $31,128,000 total, construction projects accounting for $24,094,000 will begin commercial operation in 1983. We think these projects are more properly classified as plant in service rather than CWIP. We must then determine whether the remaining $6,034,000 (including $3,918,000 of non-interest bearing CWIP) should be included in the rate base. In recent electric utility rate cases, we have articulated our policy of allowing some CWIP in rate base if it is necessary to establish or maintain the Company's financial integrity. It is our belief that including CWIP in the rate base increases cash flow and coverage ratios, and decreases the percentage of earnings comprised of AFUDC and that the resulting strengthened financial integrity of the utility leads to a lower cost of capital. Although financial integrity is a relative phenomena, it can best be measured by comparing significant fiancial indicators of Gulf with those of other electric utility companies with a bond rating of A. In this case, the significant financial indicators we used to assess Gulf's financial integrity are the coverage ratios showing the times interest earned (TIE) with and without AFUDC, which indicates the number of times a company's earnings (with and without AFUDC earnings) will cover its interest expense. In 1981, the TIE ratios for A rated companies are 2.9 (with AFUDC) and 2.4 (without AFUDC). Staff calculated that including all of the requested CWIP in rate base would result in TIE ratios for Gulf of 2.9 (with AFUDC) and 2.83 (without AFUDC). Staff indicated that classifiying a portion of the CWIP request as plant in service would have no effect on the TIE ratios. Because the majority of the CWIP projects included in the $6,034,000 are improvements or enhancements of existing plant, thus making irrelevant many of the arguments raised against the inclusion of CWIP in rate base, and because inclusion of that amount will allow the Company to maintain its financial integrity, we include $6,034,000 of CWIP in rate base.

E. The Caryville Site

Gulf included $2,291,000 of Plant Held for Future Use related to the Caryville site in its proposed rate base. Public Counsel contended that the site should be removed from the rate base. The FEA proposed that the site be removed from the rate base, but that the Company be allowed to accrue an allowance on that property similar to AFUDC. As it was in the present proceeding, this issue was thoroughly aired in the Company's previous two rate cases. In the previous cases, we found that the site meets the criteria for property held for future use and included the full value of the site in the rate base. Based on the evidence submitted in this case, we will continue that policy and include the full value of the Caryville site in the rate base.

F. Total Net Utility Plant

Based upon a net utility plant in service amount of $554,620,000, inclusion of Construction Work In Progress of $6,034,000 and property held for future use of $2,291,000, the total net utility plant for the test year is $562,945,000.

G. Working Capital Allowance

A traditional component of rate base is the value of the working capital committed to utility operations. In recent cases we have applied the balance sheet approach to determining the working capital allowance, as opposed to the formula approach previously utilized. The balance sheet approach generally defines working capital as current assets and deferred debits that are utility related and do not already earn a return, less current liabilities, deferred credits and operating reserves that are utility related and upon which the Company does not already pay a return.

The Company has proposed a $111,662,000 working capital allowance. We have determined that the appropriate working capital allowance is $73,951,000. Our adjustments are set forth as follows:

Adjustments to Working Capital Allowance
$(000)

Working Capital Allowance Per Company	$ 111,662
Adjustments:	
1. Fuel Inventory	(25,242)
2. Temporary Cash Investments	(13,453)
3. Nuclear Site PS&I	(1,752)
4. Property Ins. Res.	(1,147)
5. SCS Charges	(686)
6. Adj. for Inflation	(101)
7. Deferred O&M	4,683
Total Adjustments	(37,711)
Adjusted Working Capital	$ 73,951

A discussion of these adjustments follows.

1. Fuel Inventory

Coal Inventory

Fuel inventory is an element of working capital and, as such, the Company should earn a return on its investment in fuel stocks that are reasonably and prudently included in fuel inventory. Determining the amount of fuel inventory to include in the rate base is not an easy task. On one hand, there is the overriding concern that fuel inventory be adequate to reasonably ensure the continuous generation of electricity to avoid disruptions of service. On the other hand, is the desire to not require the ratepayers to support investment in fuel inventory beyond the amount necessary for the dependable operation of the generating system.

In this proceeding, Staff raised several issues concerning the Company's proposed coal inventory. Mr. Parsons and Mr. Ludwig testified extensively on the subject.

The first issue concerned the projected purchase prices and chargeout prices for coal during the test year. At the commencement of the case, all parties stipulated that the issue of the price paid for coal produced at the Alabama By-Products Company's Maxine Mine would be heard and decided in Docket No. 820001-EU. The parties further agreed to place subject to refund, that amount of the revenue increase awarded, if any, associated with the return on working capital, attributable to the Maxine coal, pending the outcome of Docket No. 820001-EU. We approve the stipulation and implement it by placing $13,442 of the Company's overall award subject to refund.

However, a question remains concerning the price paid for coal from other sources. In its original filing in MFR B-12, Gulf projected a 13-month average ending balance for system coal inventory of 1,496,714 tons valued at $94,614,317 or $63.2147 per ton. However, in Exhibit 240 Gulf indicated that it revised its forecast to 1,300,181 tons valued at $83,293,823 or $64.0633 per ton. This amounts to a reduction in total coal inventory as proposed by the Company, of $11,320,494. Although the Company settled on a system average price of $64 per ton, evidence adduced at the hearing showed that the average price for coal inventory for Plant Daniel is approximately $79 per ton. The delivered price per ton for the projected test year ranges from a low of $75.81 to a high of $85.58 or GEX coal and a low of $82.62 to a high of $92.38 for ARCO coal. While this issue was explored at the hearing, we conclude that the evidence presented to us raises a question but does not resolve it. We, therefore, make a carefully limited finding of fact that for the puposes of this rate case only, we will accept the purchase and charge out prices for coal proposed by the Company as reasonable. However, we intend to examine this issue in greater detail, either in Gulf's Fuel and Purchased Power Cost Recovery proceedings or in a separate investigation. Our acceptance of the Company's proposed costs does not preclude us from a prospective adjustment in a later, different docket, should we conclude that it is warranted on the basis of a complete record on this point.

Of its total inventory, the Company proposed to allocate $12,733,000 to its Unit Power Sales contract. It is the proper allocation and we approve it. If we were to make no further adjustments, the Company's proposed coal inventory, before application of the jurisdictional separation factor would be $70,560,823.

However, the next issue raised by Staff was whether the amount of coal in the Company's projected inventory is reasonable. Mr. Parsons testified that the Company has for many years followed a policy of maintaining its inventory at a 60-day nameplate capacity level. This means that assuming all of its coal fired generating plant operated at a 100% capacity factor, enough coal is on hand to operate the plants for 60 days. Assuming a more realistic capacity factor of 50%, this is roughly the equivalent of 120 days burn. Mr. Parsons further testified tht the projected test year inventory will exceed the 60-day nameplate target by 89,985 tons with a value of $5,759,059. Mr. Parsons stated it was not possible to precisely achieve the 60-day nameplate target and therefore the entire projected inventory should be included in working capital.

During his testimony, Mr. Parsons agreed that several different factors ought to be considered in developing a policy concerning the proper level of inventory. They include the demand for electricity based on historical and projected consumption, the reliability of coal suppliers and transportation including such things as labor contingencies, coal mining contingencies, supply versus demand for coal, supplier performance history, procurement leverage, the cost of maintaining alternative levels of coal, the cost of spot coal and the ability of the Company to purchase power from other sources and the cost of that power. Mr. Parsons testified that the 60-day nameplate policy has been continued not on the basis of any objective study weighing the importance and economic value of those factors; rather, the policy is based on the collective wisdom of the Company's management. He further testified that because all four operating companies of Southern follow the same 60-day nameplate policy, all have agreed to share their fuel supplies if one company experiences a fuel emergency. Mr. Parsons expressed concern that if Gulf unilaterally changed its policy, it might lose the perogative to call on members of the

Southern system if it encountered a fuel shortage. Other than to say that the 60 day nameplate target was difficult to achieve with precision, Mr. Parsons offered no real defense of that portion of inventory in excess of the 60-day nameplate level. He agreed that the test year fluctuation above the 60-day nameplate level may not be representative of future conditions.

With all deference to Gulf's management, a policy followed by management that has such a tremendous financial impact on ratepayers must be substantiated with more than an assertion that it is the result of collective management wisdom. We do not wish to substitute our judgment for that of management. However, we insist that management's judgment be substantiated in a way that permits intelligent review of it. In this context, this can best be accomplished by performance of an analysis or study that identifies all of the major factors that influence development of a coal inventory policy, indicates the relative weight that should be attached to each factor, and evaluates the benefits and costs, in light of these factors, associated with a range of alternate coal inventory levels. The reasons why a particular factor is selected, why a particular weight is attached to it, and how it is included in a cost benefit analysis of alternative inventory levels should be clearly stated. In the absence of that kind of empirical support for its position, we find that the Company failed to carry its burden of proof with respect to the soundness of its 60-day nameplate policy.

Staff urged us to make two adjustments concerning the Company's proposed inventory level. The first adjustment would reduce inventory to the Company's stated 60-day nameplate level. We accept this adjustment. From the evidence, we conclude that the coal inventory fluctuates above and below the 60-day nameplate target from one year to the next. The Company presented no persuasive evidence as to why the ratepayers should bear the fortuity of a test year inventory in excess of the Company's stated policy. Therefore, the Company's proposed inventory of $70,560,823 is reduced by $5,759,059 to $64,801,764, the 13 month average value of the coal inventory at a 60-day nameplate level.

Staff also urged us to reduce inventory by an amount ncessary to bring it down to a 90-day projected burn level. A 90-day projected burn policy would require the Company to maintain sufficient coal on hand to meet the expected burn for the immediately succeeding 90 days. While the 60-day nameplate level is a relatively static target, a 90-day projected burn policy implies a rolling adjustment. Adoption of Staff's recommendation would reduce inventory to 756,649 tons with a value of $46,812,917. However, we reject Staff's recommendation for the same reason that we rejected the Company's 60-day nameplate policy, namely, that it is not supported in the record by the sort of objective evidence that would permit us to make an intelligent assessment of it. Staff must provide the same sort of analysis in support of its proposed inventory policy that we earlier required from the Company.

We are left then with two proposed inventory values, one of $64,801,764 based on a 60-day nameplate level, and the other of $46,812,917, based on a 90-day projected burn level, the difference between the two being $17,988,847. Neither of the two policies is supported by sufficient evidence to allow us to say it ought to be the policy followed by the Company. We, therefore, will reduce the Company's proposed 60-day nameplate value by one-half of the difference between it and the Staff's proposed 90-day projected burn value, $8,994,424. We are in effect reducing the Company's proposed inventory value because the Company failed to prove that its 60-day nameplate inventory policy was a reasonable and prudent policy. In so doing, we neither endorse nor reject any particular coal inventory policy; the record does not permit us to determine what the Company's coal inventory policy ought to be. However, we cannot permit the Company to benefit from its failure to carry its burden of proof. Therefore, we have reduced inventory to a level that we believe to be within a zone of reassonableness. We hope that we will receive a full evidentiary presentation, as outlined above, in the Company's next rate case so that we may lay this issue to rest.

The final issue raised with respect to the coal inventory was the proper accounting treatment of base coal in the various coal piles maintained by the Company. Base coal is the coal at the bottom of the pile that has been pulverized to the point that it cannot be used as fuel. The evidence shows that base coal in Gulf's generating plants in Florida was included in inventory while the base coal at Plant Daniel in Mississippe had been treated as a capitalized expense. The base coal in Gulf's Florida plants totals 53,000 tons with a weighted average original cost per ton of $6.0649, a total value of $321,440. However, including base coal in inventory with a test year projected cost of $64.0633 per ton gives the same coal a value of $3,395,355. Staff recommended that no adjustment be made and that this issue be thoroughly explored in the Company's fuel adjustment proceeding. We accept Staff's recommendation inasmuch as the accounting treatment of base coal varies among the investor-owned utilities and we can more easily establish a uniform policy with respect to this issue in the fuel adjustment proceedings.

Our adjustments to the Company's proposed coal inventory are summarized in the following table and, as shown there, we approve a test year coal inventory of $52,582,960.

Adjustments to Company's Proposed Coal Inventory

Co.'s orignal proposed coal inventory per MFR B-12	$94,614,037	(system)
Adjustment for revised forecast per Ex. 240	(11,320,494)	
	83,293,823	
Adjustment for UPS contract	(12,733,000)	
	70,560,823	
Adjustment to reduce to 60-day nameplate level	(5,759,059)	
13 month average 60-day nameplate level	64,801,764	
13 month average 90-day projected burn level	46,812,917	
Difference between 60-day nameplate level and 90-day projected burn level	17,988,847	
1/2 difference between 60-day nameplate and 90-day projected burn level	8,994,424	
60-day nameplate level	64,801,764	
Less adjustment	(8,994,424)	
Approved coal inventory level	55,807,340	(system)
Jurisdictional separation Factor	.94223	
Approved coal inventory level	$52,582,960	(juris)

Heavy Oil Inventory

Mr. Parsons testified tht the Company maintains a heavy oil inventory of 88,000 barrels at a value of $1,182,720 for use at the Crist Units 1, 2 and 3 when natural gas is either unavailable or more costly than heavy oil. The oil inventory at Crist is approximately 27 days burn. The Company also maintains a heavy oil inventory of 126,000 barrels with a value of $1,753,222 (system) at Plant Daniel as Daniel has dual fuel capability. This level of inventory is approximately 10 days burn. Staff recommended that we include the heavy oil inventory at Crist in working capital but exclude the oil inventory at Plant Daniel. Staff contends that it is so unlikely that it will ever prove to be more economical to burn oil rather than coal at Plant Daniel that the oil inventory does not constitute property used and useful to serve retail customers. We reject Staff's recommendation as it is inconsistent with our policy of encouraging all new generating facilities as well as older facilities being converted from oil to coal to possess or retain dual fuel capability. Therefore, no adjustment will be made to the Company's proposed heavy oil fuel inventory.

No. 2 Oil Inventory

As with their coal inventory, the Company revised its forecast for its No. 2 fuel oil inventory, reducing its test year value by $144,361. We therefore have included the No. 2 fuel oil inventory in the test year rate base at a value of $938,647.

2. Temporary Cash Investments

Gulf included $13,453,000 related to temporary cash investments in working capital on the ground that they are a normal part of utility operations. However, inclusion of temporary cash investments in working capital will not affect the ratepayers only if the Company earns exactly the approved pretax rate of return on them, an unlikely event. If the temporary cash investments earn less than the approved rate of return, the ratepayers make up the difference; conversely, if the Company's return on temporary cash investment exceeds its approved rate of return, the ratepayers benefit. To prevent subsidization of the Company by the ratepayers or vice versa, temporary cash investments will be excluded from working capital. Therefore, working capital is decreased by a jurisdictional amount of $13,453,000. In a similar manner, earnings derived from temporary cash investments will be excluded from NOI.

3. Deferred Debits, Deferred Credits and Operating Reserves

In calculating its working capital allowance, the Company included $4,958,000 ($5,282,000 system) in deferred debits, deferred credits and operating revenues. This treatment is consistent with Gulf's last rate case and our recent decision in Docket No. 820007-EU and Docket No. 820097-EU. Public Counsel objected to inclusion of these items in Working Capital on the ground they are not used to meet day-to-day operating and maintenance expenses. However, we believe inclusion of these items in working capital provides a better match between rate base and capital structure and therefore will not depart from our established policy.

Having established the general principle of inclusion, we must review each item that falls within this categroy to determine whether on its own merits it is properly included in the Company's retail rate base. Staff recommended that we eliminate $1,752,000 from working capital, the amount included by the Company for the cost of evaluating a parcel of land for suitability as a nuclear plant generation site. We approve Staff's recommendation because the Company does not have any current plans to construct a nuclear facility at any time in the forseeable future.

Public Counsel urged us to exclude $1,039,000 from working capital, the amount included by the Company for the preliminary survey and investigation charges related to the Caryville site. Since the site is itself in rate base as plant held for future use, we will include the survey and investigation charges in working capital.

4. Property Insurance Reserve

The Company agreed with the Staff that the unfunded portion of the property insurance reserve represents a cost free liability to the Company that could be used to reduce working capital requirements. Public Counsel asserted that this item should be excluded from rate base. We think Staff's approach is correct; therefore, working capital is reduced by $1,147,000 so as to treat the unfunded portion of the property insurance reserve as a cost free liability.

5. Southern Company Services Charges

As a member of the Southern Company, Gulf purchases services at cost from the Southern Company Services, Inc. This arrangement gives Gulf access to the services of experts which Gulf, because of its size, cannot afford to retain in house. While we have no doubt that the services provided by Southern Company Services are valuable, we do question the reasonableness of the amount of payments to Southern Company Services budgeted by Gulf for the test year. In 1982, Gulf paid Southern a total of $13,282,135 while it has budgeted a total of $15,982,000 for 1983, an increase of 20.33%. When the Southern Company Services charges are differentiated into O&M expenses and capitalized expenses, the percentage increases are markedly different:

Southern Company Services Charges

	1982	1983	Increase	%Increase
O&M Expenses	$9,280,000	$10,136,991	$856,991	9.23%
Capitalized Expenses	4,004,135	5,845,009	1,842,874	46.05%
				20.33%

To analyze these increases, we first determined that Gulf's expected customer growth in 1983 is 3.63% and inflation is expected to be 6.1%; these numbers yield a compound growth rate of 9.95%. We use this as a standard of reasonableness against which to measure the anticipated increases in Southern Company Services charges. The expected increase in O&M expenses of 9.23% meets our standard but the 46.05% increase in capitalized expenses is far in excess of what can be accounted for by inflation and customer growth. The Company offered no adequate explanation of why services from SCS which would be treated as capitalized expenses are expected to increase by that amount. In the absence of an adequate explanation, we will disallow that portion of the increase that exceeds the 13 month average charge for 1982 for capitalized services plus 9.95%. The 13 month average for 1982 of $2,001,068 (assuming the expenses were incurred ratably over the period), plus 9.95% of that amount to account for inflation and customer growth is $2,200,174. The 13 month average for 1983 of $5,845,009, the amount budgeted by the Company, is $2,922,505. The jurisdictional difference is $686,000. We, therefore, reduce rate base by $686,000 to eliminate the excessive increase in test year SCS services which are treated as capitalized expenses.

6. Inflation and Escalation Rates

In another section of this Order, we set forth our reasons for reducing the 1982 and 1983 escalation rates used in projecting the test year rate base and operating expenses. The effect of using lower escalation rates is to reduce working capital by $101,000.

7. Employee Stock Ownership Plan - Accounts Payable

The Company contends that accounts payable related to its Employee Stock Ownership Plan (ESOP) should not be treated as cost free liabilities because they represent funds that have been set aside to purchase stock. Public Counsel asserts that the ESOP accounts payable are cost free liabilities. Having considered the record of this case, we find that we should consider ESOP accounts payable as cost free liabilities until such time as they are converted to common stock. The accounts payable are the result of an accrual process and the Company does not have any identifiable cost that could be applied to the accounts payable. Working capital should be reduced by $13,000 to recognize ESOP accounts payable as cost free liabilities.

8. Unamortized Expense Balance

In another section of this Order we set forth our reasons for requiring the Company to amortize expenses related to boiler maintenance and turbine inspection over a three year period. The unamortized balance of these expenses should be included in working capital; therefore, we increase the Company's proposed working capital allowance by $4,683,000.

Unbilled Revenues

The Company has been accruing and recording unbilled revenues for book and financial reporting purposes since 1974. All of the parties agree that the related assets and liabilities should be included in the working capital allowance since the Company actually records unbilled revenues. Previously, we have included unbilled revenues if a Company actually records them for book and financial reporting purposes. We will continue that policy and include the assets and liabilities related to unbilled revenues in working capital because the Company actually records them.

Transition Adjustment

All parties agreed that no adjustment was necessary to remove the effects of the transition adjustment granted in Docket No. 820001-EU from working capital since the working capital allowance proposed by the Company does not include any amounts related to the transition adjustment.

Materials and Supplies

The Company proposed to include $12,41,000 for materials and supplies in working capital. On a jurisdictional basis, this constitutes an increase of .72% from 1981 to 1982 and 1.49% from 1982 to 1983. The Company's projected increases are conservative when compared to anticipated inflation rates of 5-7% for the same period of time. The amount proposed by the Company is approved.

Common Stock Dividends Payable

In calculating its working capital allowance, Gulf did not treat common stock dividends as cost free liabilities. Public Counsel asserts that the dividends should be treated as a cost free source of funds. According to Public Counsel, the nature of these funds changes when dividends are declared and they become an ordinary liability of the Company. The Company contends that the dividends represent common equity over which the stockholders still maintain control.

In our opinion, common stock dividends should earn a return because they represent stockholders' equity until such time as they are actually paid. Therefore no adjustment is necessary.

Caryville Cancellation Charges

The Company included $1,962,000, the amount of the unamortized Caryville cancellation charges, in its proposed rate base. Public Counsel believes these charges should be eliminated from the rate base as they do not constitute property used and useful in serving Gulf's retail customers.

This issue has also been thoroughly examined in the Company's previous two rate cases. In both of those cases we found that the Company's "decision to cancel its Caryville facility was prudently based upon an economic advantage to Gulf's customers associated with purchasing the Scherer capacity in lieu of constructing the Caryville facility". (Docket No. 810136-EU, Order No. 10557, p. 13.) Nothing of an evidentiary nature has been offered in this case to persuade us to reverse our earlier findings. Thus, the Caryville cancellation charges will continue to be amortized above the line over a five year period, with the unamortized balance included in the rate base. As in the past, the resulting revenue requirements will continue to be collected subject to refund, pending the consummation of Gulf's contract to purchase a portion of Plant Scherer.

H. Total Rate Base

Based upon total test year net utility plant of $562,945,000 and a working capital allowance of $73,951,000, the total test year rate base is $636,896,000.

NET OPERATING INCOME

Having established the Company's rate base, the next step in the revenue requirements formula is to determine the net operating income applicable to the test period.

The Company has proposed a test year net operating income of $51,908,000. Evidence developed during the course of the proceeding has led us to increase that amount to $60,015,000. Our adjustments are set forth as follows:

Adjustments to NOI
$(000)

	Per Company	Adjustments	As Adjusted
A. Operating Revenues	$358,792	$9,142	$367,934
Operating Expenses			
B. Operating and Maintenance	240,644	(6,340)	234,304
C. Depreciation and Amortization	29,297	0	29,297
D. Taxes Other Than Income Taxes	14,251	18	14,269
E. Income Taxes Currently Payable	6,344	8,408	14,752
F. Deferred Income Taxes (Net)	10,490	(1,051)	9,439
G. Investment Tax Credit	5,858	0	5,858
H. Gain on Sale of Plant	0	0	0
I. Total Operating Expenses	306,884	1,035	307,919
J. Net Operating Income	$ 51,908	8,107	$ 60,015

A. Operating Revenues

Customer Sales and Demand Forecast

Mr. Shearer and Mr. Oerting testified about the Company's projected test year peak demand, number of customers, and KWH sales. We find that the Company's forecasting methodology and the resulting projections are reasonable. Mr. Shearer, Mr. Haskins, and Mr. Scarbrough attempted to explain how the billing determinants are derived from the forecasts made by Mr. Shearer and Mr. Oerting. We find that the Company's proposed billing determinants are reasonable and may be used to design the rates approved as part of this proceeding. Most of the projected billing determinants are based on historical relationships, modified due to known facts. Although we cannot check the test year data in this fashion, comparison of 1982 actual data to 1982 projected data shows no significant variation. Because the same methodology was employed to forecast the 1983 billing determinants, we find the projections are reasonable.

Revenues from Present Rates

After the Company filed a petition initiating this docket, the Commission took final action in the Company's previous rate case, Docket No. 810136-EU. In Order No. 10963, we authorized the Company to revise its rate schedules to generate $1,374,277 in additional gross revenues effective June 17, 1982. During the hearing, the Company submitted Exhibit No. 17 P, which is revised MFR Schedule E-4(a), showing the additional revenues resulting from Order No. 10963. Based on this exhibit, we will increase the Company's test year operating revenues by $1,148,000 to reflect the rates currently in effect.

Schedule E and Economy Sales Revenues

The Company did not include two other sources of revenue in projecting test year operating revenues. First, the Company did not include the income it receives from economy energy sales. The Company contends one, that economy energy sales cannot be forecasted accurately, and two, since the plant out of which economy sales are made is always available to serve retail customers, that the profits of economy energy sales should go to the stockholders rather than to the ratepayers. We disagree sharply with the Company's second contention. Since the ratepayers are paying the full cost of the generating facilities out of which economy energy sales are made, any income derived from the use of those facilities should inure to the ratepayers' benefit. Therefore, income from economy energy sales will be included in test year operating revenues. The real question is what level of economy energy sales income to anticipate for 1983. While disavowing its accuracy, the Company projected 1983 economy energy sales revenue of $345,815. Public Counsel and the FEA urged us to examine the level of sales for the years 1976-1982 and anticipate economy energy sales of $2,685,000 and $1,018,000, respectively. However, the historical figures are somewhat misleading because they occurred before the Company sold off much of its unused capacity in unit power sales. We are therefore inclined to adopt the Company's estimate of $345,815 as the best available. Our review of this whole issue has led us to conclude that the Commission should institute a generic investigation to consider a true up of economy sales forecasts for all electric companies in the fuel adjustment clause docket.

Second, the Company also failed to include $4,905,000 of Schedule E capacity credits it receives from its Schedule E customers. Again the Company argues that since the ratepayers pay for service, not ownership, of the facilities, and since Schedule E sales do not affect the cost of serving retail customers, the stockholders should receive the benefit of Schedule E capacity payments. Again, we disagree with the Company. Since the ratepayers must provide a return on the generating facilities from which both retail and Schedule E sales are made, capacity payments made by Schedule E customers should offset the return provided by retail ratepayers. Otherwise, the Company would earn a double return on a portion of its generating facilities because the retail and Schedule E customers would be paying a return on the same facilities. For these reasons test year operating revenues are increased by $4,905,000 to reflect Schedule E capacity payments that will be received by the Company during the test year.

Temporary Cash Investments

Another adjustment that must be made to operating revenues is the result of our decision to exclude temporary cash investments from working capital. Earnings related to those investments must be removed from test year operating revenues. Therefore, test year operating revenues are reduced by $2,649,000.

Adjustments Related to Unused Capacity

In 1975, Gulf decided to purchase from Mississippi Power Company an undivided one-half interest in Daniel Units 1 and 2 located in Jackson County, Mississippi, thereby increasing its generating capacity by 511 MW. In 1976, it was agreed that Unit 2 would be deferred from 1979 to 1980 and that Mississippi Power Company would complete and own Unit 1 when it became commercial in 1977. Upon commercial operation of Unit 2, Gulf and Mississippi Power would then each own 50% of each unit. Unit 2 was deferred again, beginning commercial operation in June 1981.

Although this Commission never formally approved Gulf's purchase of Plant Daniel, we included it in the Company's rate base in the last rate case. In this proceeding, Mr. Earl Parsons, testifying for Gulf, presented testimony showing that the purchase of an interest in Plant Daniel and an interest in Plant Scherer, in lieu of constructing a plant on Gulf's Caryville site, is the most economic way to meet the expected long term growth in demand on Gulf's system. While we do agree that the purchase of Plant Daniel is in the long term best interest of Gulf's ratepayers, it is equally clear that the purchase of Plant Daniel created a short term over-supply of generating facilities on Gulf's system. In its last rate case, Gulf projected that, before the reserve margins of all the Southern operating companies were equalized, it would have a reserve margin of 66.2% in 1981. For system planning purposes, a reserve margin of 25% is considered adequate. In this rate case, before the reserve equalization process, and before all-system sales are considered, Gulf's reserve margin is projected to be 55.3% in 1983. Thus, our overriding concern is to ensure that the Company made every reasonable effort, in a timely fashion, to minimize, if not avoid, imposition of the revenue requirements associated with Plant Daniel on retail customers for that period of time when the Daniel capacity is not necessary to serve them.

In Gulf's last rate case we penalized the Company for failing to prudently identify and quantify the factors affecting load growth during the 1970's, because Gulf's failure in that regard meant that it did not begin to negotiate off-system sales of its unused capacity until 1980. We concluded that had the Company acted prudently it would have attempted to arrange off-system sales in the late 1970's. We therefore refused to impose the revenue requirements associated with the unsued capacity at Plant Daniel on the retail ratepayers and adjusted test year revenues by $3,099,000.

In this case, we are presented with a somewhat different factual situation. Gulf has entered into a Unit Power Sales contract (hereinafter referred to as the UPS contract) with Florida Power & Light Company and Jacksonville Electric Authority. Under the terms of the contract, FPL and JEA will own

238 MW of Gulf's share of Plant Daniel and thus be exclusively entitled to the output of that portion of the plant, through the mid 1990's. Unlike other off-system sales made by Gulf, the UPS contract is a firm sale of capacity. The 238 MW will not be available to serve Gulf's retail or other wholesale customers during the life of the contract. The UPS customers will pay all of the fixed and variable costs associated with the 238 MW, including a return on Gulf's investment. Because the UPS contract is a wholesale transaction, it is regulated by the FERC. Our sole concern is whether Gulf has properly allocated all of the investment, operating costs, and revenues associated with UPS out of the retail jurisdiction. This issue was thoroughly explored during the cross-examination of the Company's witnesses, Mr. Carzoli and Mr. Parsons. Mr. Parsons testified that the fixed expenses were allocated between UPS and other customers on the basis of the ratio of 238 MW to 511 MW or 46.58%. The variable O&M expenses are allocated on the ratio of electricity provided to UPS and to other customers. Since the UPS customers are expected to receive 74.26% of the electricity expected to be produced in 1983 from Plant Daniel, they were allocated 74.26% of the variable costs of the unit.

In its original filing, the Company allocated $106,869,000 of rate base investment to the UPS contract as follows:

	System
Plant in Service	$105,131,000
Accumulated Depreciation	(15,197,000)
Net Plant	$ 89,934,000
Working Capital	
Fuel	12,162,000
Other	4,773,000
Total Working Capital	$16,935,000
Rate Base	$106,869,000

During his cross-examination, Mr. Carzoli agreed that as a result of the Company's revised coal inventory forecast, an additional $571,000 (system) should be allocated to the UPS contract, making the total fuel inventory allocation to UPS $12,733,000 (system). With that correction, we approve the Company's allocation of rate base to UPS. The Company's allocation of $88,663,000 (system) in operating revenues and $77,014,000 (system) in operating expenses as shown in the following table is also correct and we approve it:

Adjustment to Income Statement for the UPS Contract

	System
Operating Revenues	$ 88,663
Operating Expenses	
Fuel	56,999
Variable O&M	3,114
Fixed O&M	3,149
Depreciation	3,985
Amortization of ITC	(310)
Income Taxes-Cum. Pay.	2,433
Deferred Inc. Taxes	3,062
Taxes Other Than Inc.	3,252
Gross Receipts Tax	1,330
Total Operating Expenses	$ 77,014
Net Operating Income	$ 11,649

Public Counsel contends that Gulf erred in excluding the investment associated with the UPS contract from the retail rate base. Public Counsel argued that the unit power sales are an integral part of the Company's jurisdictional operations and should be included in the determination of the Company's revenue requirements. To do otherwise, would, in Public Counsel's opinion, force the retail ratepayers to subsidize unit power sales.

However, we have examined the UPS contract and the associated cost and allocation from all angles and we come to the opposite conclusion. If the proper amounts of investment, operating expenses and revenues are allocated to UPS customers, retail ratepayers will not only not subsidize UPS customers, but on the contrary, they will benefit handsomely from the sales, in the sense that they will not have to support the capacity sold in a UPS transaction for the life of the contract but the capacity will be available to serve them when they need it in the future, at a relatively reduced price when compared with the cost of future construction. Therefore, we reject Public Counsel's argument because the UPS contract is a wholesale transaction, not properly included in the retail jurisdiction and because we find that Gulf properly allocated investment, operating expenses and revenues between the UPS and retail customers. Thus, we find that retail customers are not subsidizing UPS customers, and that there has been a proper accounting of 238 of the 511 MW's and the dollars associated with that capacity.

We now turn our attention to the remaining 273 MW of Plant Daniel owned by Gulf. Under the Intercompany Interchange Contract (hereinafter referred to as the IIC) Gulf and the other operating companies on the Southern system buy and sell capacity from each other on an annual basis so that each company ends up with the same reserve margin, hovering around 25% from one year to the next. Under the terms of the IIC signed in November 1981, the contract which formed the basis for this rate case filing, Gulf is projected to sell 186 MW to the other members of Southern during the peak month of August in 1983. We assume that Gulf's projected sale of 186 MW to the pool was made possible by Gulf's purchase of a portion of Plant Daniel. We make this assumption because Plant Daniel was the incremental generating source added to Gulf's system, and by selling 238 MW off-system under the UPS contract and 186 MW to the Southern power pool, Gulf brings its projected reserve margin in 1983 down to the acceptable level of 23%. More importantly, Gulf's system average embedded capacity cost without Plant Daniel is $200 per KW,, whereas the test year net investment in Plant Daniel is $371 per KW. If Gulf must make off-system sales to bring its reserve margin to an acceptable level, as it must during the test year, it ought, if at all possible, to sell its most expensive capacity off-system, retaining its lower cost capacity for the benefit of its retail ratepayers. In this proceeding, Gulf failed to prove that its only available option was to sell 186 MW of its unused capacity through the ICC.

Therefore, as we did with the UPS contract, we must assure ourselves that this sale of capacity to the Southern pool does not require the retail ratepayers to subsidize the purchasers of that capacity. The annual revenue requirements associated with 186 MW of Plant Daniel are $19,806,409. For the 186 MW it sells to the Southern pool, Gulf was projected to receive $12,260,555 over the course of the year in capacity payments. Also, we must consider the fact that if Gulf did not have capacity from Plant Daniel to sell to the pool, it would end up a net purchaser of capacity from the pool over the test year. Therefore, in addition to crediting capacity payments it received from the 186 MW sale against the revenue requirements associated with that capacity, we also credit against the revenue requirements the capacity payments Gulf would have made during the test year if it had not purchased a portion of Plant Daniel.

Another source of income which should be credited against the revenue requirements of the 186 MW comes from the Company's projected test year Schedule E and economy sales. The Company projects income of $5,206,000 from Schedule E capacity payments and $367,000 from economy sales in the test year. We will credit a portion of this income against the revenue requirements of the 186 MW. The amount credited is based on the ratio of 186 MW to the Company's total installed capacity available to make those sales of 1,793 MW (the Company's total installed capacity less the 238 MW allocated to the UPS contract). Thus, we credit $578,125 of Schedule E and economy sales against the revenue requirements of the 186 MW. We allocate only a portion of the Schedule E and economy sales income to the 186 MW because Mr. Parsons testified that these sales are made from all of the Company's installed generating facilities, with the exception of the 238 MW associated with the UPS contract, and refused to agree that the sales were made primarily from Plant Daniel.

Having credited all possible sources of income against the revenue requirements of the 186 MW, there is still a shortfall of $5,722,602 (system). During the test year, the Company would have the retail ratepayers support the revenue requirements of the 186 MW in the amount of $5,391,931, despite the fact that the 186 MW is above and beyond the capacity necessary to maintain an adequate reserve margin for Gulf. The shortfall comes about because the Company is selling its marginal capacity at average embedded cost rates. While the embedded cost rate provision of the IIC may, in the long run, benefit Gulf's ratepayers, it will cost them dearly in the test year. In effect Gulf's ratepayers are providing a reserve margin for other Southern companies's ratepayers at average embedded cost rates, supplying the difference between average and marginal capital costs themselves. Had the Company proved in this case that the short term costs associated with the oversupply of capacity due to the purchase of Plant Daniel were outweighed by the long term benefits associated with the acquisition, and had they proved that disposition of 186 MW via the IIC was the best because it was the only possible sale from that capacity, our decision today might be different. These issues would of course again raise the question of the timelines of the Company's efforts to bring about off-system sales on more favorable terms. However, the Company has consistently taken the position that the retail ratepayers are fully compensated for the capacity sold under the reserve equalization process contained in the IIC. We simply disagree with that proposition. Therefore, we will reduce the Company's revenue deficiency by $5,391,931 so as to avoid retail ratepayer subsidization of off-system sales. Our adjustment is summarized in the following table:

Adjustment for Off-System Sale
of Plant Daniel Capacity

Revenue requirement associated with 186 MW of Plant Daniel	$19,806,409
Net difference in ICC capacity payments for 186 MW of capacity	(13,505,682)
$12,260,555 capacity payments received 1,245,127 capacity payments avoided $13,505,682	
Revenue Requirements Associated with Sch. E and Economy Sales	(578,125)
(186 MW / 1793 MW) X ($5,206,000 + 367,000)	
Net Annual Revenue Requirements associated with 186 MW of Plant Daniel	$5,722,602
Jurisdictional Separation Factor	.94221661
Jurisdictional Adjustment For Off-System Sale of Plant Daniel Capacity	$5,391,931

Our adjustment may be somewhat conservative when the Company's position under the IIC signed in November 1982 is considered. The projected capacity sales by Gulf during the peak month in 1983 have been revised downward from 186 MW to 72.4 MW. With no change in the level of utilization of Plant Daniel for the retail ratepayers, this leaves Gulf a projected reserve margin of 37.1% in 1983 corresponding to 88.1 MW of plant that is neither necessary to serve retail customers in the test year or off-set by an off-system sale. The test year revenue requirements associated with the 88.1 MW of capacity in excess of a 25% reserve margin are $10,383,281. We would credit $258,011 of income from Sch. E and economy sales agasint the revenue requirements of the 88.1 MW. To this must be added the adjustment of $3,977,740 which is the revenue shortfall resulting from the sale of the 72.4 MW under the IIC. The calculation of these adjustments is set out in greater detail in Appendix D. Suffice to say that if we based our adjustment on the November 1982 IIC, the adjustment would be $14,103,010 rather than the $5,391,931 we approve today. We base our adjustment on the November 1981, rather than the November 1982 contract, only because the latter was received as a late filed exhibit after the close of the hearings held in this case and has not received the full review given the 1981 contract.

A portion of Plant Daniel will be used to serve retail customers during the test year. After accounting for UPS and IIC sales, 87 MW are available to serve retail customers. Mr. Parsons testified that of the 1878.5 GWH expected from Plant Daniel in 1983, 483.5 GWH would be sold to retail customers. This results in a capacity or utilization factor of the 87 MW of 63%. Thus, it is entirely appropriate for the retail rate customers to pay the revenue requirements associated with the remaining 87 MW Of Plant Daniel owned by Gulf.

Fuel and Conservation Revenues

Since the Company made an adjustment of $139,000 for the over-recovery of revenues in its Fuel and Purchase Power Cost Recover Factor, no further adjustments are necessary to make fuel costs equal fuel revenues in this proceeding. Public Counsel advocated the total exclusion of fuel expenses and revenues from the calculation of the Company's NOI. We decline to adopt their suggestion but note that since fuel expenses and revenues are equal, the effect on NOI is the same as excluding them.

The evidence shows that the Company's conservation costs and revenues are equal; therefore, no adjustment to NOI is necessary. Again, Public Counsel urged us to exclude conservation costs and revenues from the calculation of the Company's NOI. Again, we decline to adopt their suggestion with the observation that since conservation costs and revenues are equal, they will have no effect on the Company's NOI.

Test Year Operating Revenues

The effect of the adjustments described above is to increase test year operating revenues by $9,142,000. We therefore approve test year operating revenues of $367,934,000.

Operating Expenses

The Company has proposed test year operating and maintenance expense of $306,884,000. We have made several adjustments which have the effect of increasing test year operating expenses by $1,035,000 to $307,919,000. A discussion of our adjustments follows.

B. Operations and Maintenance Expense

The Company has proposed test year operating and maintenance expenses of $240,644,000. We have determined that this amount should be reduced to $234,304,000 as follows.

Adjustments to O&M Expenses
$(000)

Per Company	$240,644
Adjustments	
1. Inflation	(2,334)
2. Non-recurring Maintenance	(3,831)
3. Rate Case Expense	(21)
4. Dues	(18)
5. Contributions	(27)
6. Advertising	(109)
Total Adjustments	$ (6,340)
Adjusted O&M Expense	$234,304

1. Inflation and Escalation Rates

In putting its rate case filing together, the Company assumed an inflation rate of 10.3% for 1982 and a 9% inflation rate for 1983. These assumptions were made during the second quarter of 1981. During his cross-examination, Mr. Scarbrough stated that the most current estimates for inflation are 5.2% for 1982 and 6.1% for 1983. Public Counsel recommended a 6% inflation rate for both years. We approve use of an inflation rate of 5.2% for 1982 and 6.1% for 1983.

In estimating the level of increase in rate base and operating expense it would experience in 1982 and 1983, the Company did not utilize simply an expected rate of inflation but instead used an escalation rate which is composed of an inflation rate and a 10.9% wage increase in 1982 and a 9% wage increase in 1983. The base figures to which these escalation rates were applied have been adjusted to account for expected customer growth. As the wage increase reflects expected operating conditions during 1982 and 1983, we approve their use. Public Counsel suggested that we place a portion of the rate increase we grant today under bond subject to refund until the exact amount of the test year wage increase is known. Public Counsel urges that the record contains no evidence as to the reasonableness or fairness of the projected wage increases. However, the Company is currently negotiating this issue with its employees' union. We will not hold the salary increases subject to refund. It is not consistent with the philosophy of a projected test year to select one from among many of the Company's projections and place it subject to refund until the amount of the actual expense incurred can be determined. Staff monitors the Company's return on a monthly basis. If test year actual operations differ markedly from the Company's projections and the Company has excessive earnings, we are fully empowered to order a reduction in rates if warranted.

As revised with the lower inflation rates, we approve of the use of escalation factors of 7.2% in 1982 and 7% in 1983. The combined effect of using a 7.2% escalation in 1982 and a 7% escalation in 1983 is to reduce test year operating expenses by $2,334,000 (juris.) and working capital by $101,000 (juris.)

2. Non-recurring Operating Expenses

Since we employ a test year approach to ratemaking, we must ensure that test year operating expenses are representative of the expenses the Company will incur during the period the rates will be in effect. However, to say that test year revenue requirements should not include any non-recurring expenses somewhat oversimplifies the issue because, given the nature of utility operations, every year will include some periodic expenses that will not be incurred the following year. Thus, what we really must determine is that the test year revenue requirements do not include excessive or unrepresentative non-recurring expenses.

In its filing, the Company included $10,145,000 of operating expenses for turbine inspections, boiler maintenance, and turbine blade replacements. All of these expenses are periodic in nature but they are not usually performed on an annual basis at every generating facility. Turbine inspections are performed on a cyclical basis over a period of years, and boiler maintenance is performed at the same time. Turbine blade replacements are done on an as-needed basis. Evidence adduced at the hearing showed that of $10,145,000, $6,050,000 are expenses which would not normally occur in the test year but which had been deferred to the test year due to financial constraints in previous years. While we do believe the maintenance associated with the $6,050,000 needs to be done, these expenses should not be considered normal test year operating expenses. Staff suggested that these expenses should be amortized over the maintenance cycle of five years. We think three years is more appropriate. Therefore, we will reduce test year operating expenses by $6,050,000 but allow $2,017,000 as the test year amortization expense. This results in a net decrease of $4,033,000 in test year operating expenses. The jurisdictional amount of this adjustment is $3,831,000.

The remaining $4,095,000 covers cyclical expenses which would normally occur in the test year. This amount compares favorably to the Company's four year average of all non-recurring expense items of $4,632,955. Therefore, $4,095,000 of non-recurring operating expenses is approved for the test year.

We caution the Company that both the funds provided on an amortized basis and the funds allowed as normal test year operating expenses are, in our mind, earmarked for the maintenance work for which the Company requested them. Any decision to delay or defer the maintenance and put the funds to other uses will be viewed with extreme skepticism in subsequent rate cases.

3. Rate Case Expense

The Company's total rate case expense for this proceeding is $409,005; the Company proposed to amortize this over a three year period. Public Counsel argued that the rate case expense should be divided evenly between the ratepayers and stockholders, amortized over a three year period. We disagree with both positions. Rate case expenses are a normal operating expense for a regulated utility and should be treated as such; it will not be split between ratepayers and stockholders. Additionally, the amortization period will be two years in view of the frequency of the Company's requests for rate relief. Therefore, we approve $293,835 as the rate case expense for the test year which includes $89,333 of expense from the Company's previous rate case and one half of the rate case expense of this proceeding.

4. Industry Dues

The Company budgeted $91,369 (system) for industry dues for the test year. Our established policy is to allow a company to recover industry dues above the line if membership in an organization contributes to and facilitates the operation of the company to the benefit of the ratepayers. However, we disallow dues if the organization is similar to a Chamber of Commerce or is a lobbying organization. Applying those criteria in this case, we will allow $65,125 of industry dues but disallow $17,617. The Company also included $1,108,542 (system) in Electric Power Research Institute (EPRI) dues. We will allow the entire jurisdictional amount to be recovered because through its contribution to EPRI, Gulf supports industry research and development. In the past, we have allowed the Company to recover Edison Electric Institute dues but in this case the Company did not budget any dues for the test year.

5. Charitable Contributions

Consistent with our decision on this issue in Gulf's last rate case, we remove from operating expenses $27,000 of charitable contributions. Gulf may, of course, continue to make contributions to charities; our decision merely requires the stockholders, rather than the ratepayers, to make the donations.

6. Advertising Expenses

In this case, as in Gulf's last rate case, we reduce advertising expense by $109,000 to disallow area development and institutional advertising expenses. This kind of advertising falls within the category of image building and promotional advertising as defined by the Commission in Order No. 6465. As such, it is disallowed for ratemaking purposes.

Injuries and Damages Reserve

In the Company's last rate case, we allowed the Company to increase its annual accrual to its injuries and damages reserve to $1.2 million. We also decided to remove the cap on this reserve. Our decision was based on an examination of claims paid from the reserve over the last five years. In this proceeding we again reviewed the claims made against the reserve over the last five years and we remain convinced that $1,200,000 is the proper annual accrual to the fund. We, therefore, approve a test year reseve fund of $1,581,000, which is the 13 month average of the fund, net of claims and accruals. The fund will remain uncapped, and we will continue to monitor its adequacy. No adjustment is necessary.

C. Depreciation and Amortization

The Company has proposed test year depreciation expense of $29,297,000. This is the proper amount and no adjustment is necessary.

D. Taxes Other Than Income Taxes

Effect of Other Adjustments

This adjustment is mechanical in nature and serves to show the effect on taxes other than income taxes of the various other adjustments that we have made to the Company's proposed net operating income. The effect is to increase taxes other than income taxes by $18,000.

E. Income Taxes Currently Payable

Changes in Florida Income Tax Law

The Florida Emergency Excise Tax (Ch. 221, F.S.) will be in effect during 1983. The tax paid is allowed as a credit five taxable years later. Generally accepted accounting principles would dictate deferral of the tax if material. Gulf's 1983 emergency excise tax is immaterial and should be expensed during 1983. Future tax expense should be reduced when the credit becomes available. Test year current income tax expense is, therefore, increased by $77,000.

Tax Credits Generated For Research and Development Expenditures

Public Counsel has raised for the first time in its post-hearing brief the issue of whether tax credits generated from research and development expenditures should be taken into consideration when arriving at forecasted net operating income.

The propriety of a party adding new issues after hearing is governed by Rule 25-22.38(5)(B) which states in part:

> 2. Any issue not raised by a party prior to the issuance of a prehearing order shall be waived by that party, except for good cause shown. A party seeking to raise a new issue after the issuance of the prehearing order shall demonstrate that: he or she was unable to identify the issue because of the complexity of the matter; discovery or other prehearing procedures were not adequate to fully develop the issues; due diligence was exercised to obtain facts touching on the issue; information obtained subsequent to the issuance of the prehearing order was not previously available to enable the party to identify the issue, and introduction of the issue could not be to the prejudice or surprise of any party. Specific reference shall be made to the information received, and how it enabled the party to identify the issue;. . .

Public Counsel has made no effort to demonstrate why the issue should not be considered waived. We decline to raise the issue on our own motion. The issue is accordingly considered waived and we will not dispose of it.

IRS Audit Adjustments

Gulf has proposed that IRS audit adjustments affecting the test year should be recognized. Public Counsel states that each audit adjustment must be analyzed to evaluate whether they conform to prudent utility regulation.

Any and all known facts that have a measurable effect on the test year should be recognized in setting rates. IRS audit adjustment affects only tax expense allowed. Since the IRS is the governing body determining actual taxes paid, the IRS audit adjustments should be recognized.

Income Tax True-Up

All parties have agreed that the debt component of the allowed rate of return should be trued-up with allowable interest expense used to determine income taxes. In order to true-up the allowed income tax expense, an adjustment to decrease allowable interest expense is necessary. The interest expense used by the Company to compute its income tax liability was $27,642,000, although it should have been $28,136,497. Allowable interest expense, based upon the approved rate base and capital structure is $26,494,110. Therefore, we increase income tax expense by $799,842.

Effective Tax Rate

Public Counsel asserts that the consolidated effective tax rate should be used in arriving at Gulf's revenue requirements. According to Gulf, the Company allocates the consolidated federal income tax liability in accordance with Security and Exchange Commission Rule 45 (c) which provides that a member of the group cannot be apportioned a tax liability greater than the liability based upon a separate return computed as if the Company has always filed a separate return. We find that the effect of filing a consolidated tax return should not be recognized. To do so would be in error in one or both of the following ways: 1) it would allow Gulf's ratepayers to enjoy the tax benefits of deductions for which they are not responsible; and 2) it would burden Gulf's ratepayers with responsibility for revenues they did not generate.

Gulf's entire tax liability will ultimately be paid to the IRS. The actual dollars allowed in a given period may be offset in the future by net operating loss carrybacks or various credits carrybacks. If these dollars are offset, future taxes allowed will be reduced by the associated refunds thereby recognizing equitable treatment. The appropriate tax rate to be used for purposes of computing Gulf's revenue requirements, including the revenue expansion factor, is the statutory rate of 48.7%. This treatment is consistent with the result in the two previous rate cases for Gulf.

Effect of Other Adjustments

This adjustment is mechanical in nature and serves to show the effect on income tax expense of the various other adjustments that we have made to the Company's proposed net operating income. The effect is to increase income taxes currently payable by $5,843,000.

F. Deferred Income Taxes (Net)

Unrecovered Deferred Taxes Arising Before 1975

Gulf has certain unrecovered deferred taxes that arose prior to 1975 when full normalization tax accounting was mandated by Order No. 6917.

The Company's amortization of these items, until this rate case, has been at the composite depreciation rate of the related assets at the time full normalization was implemented. Gulf now proposes to accelerate recovery of these unrecovered deferred taxes to provide for recovery over five years, relying on our requirement to flow back over collections resulting from tax rate changes over a five year period.

The Company's argument that Commission policy mandating a five year write-back of overfunded deferred taxes justifies a five-year recovery of items flowed-through to customers prior to normalization is unfounded. Amortization of the write-back over the remaining lives of the related assets is prescribed in APB No. 11 or FERC order 46 FR May 14, 1981, pg. 26613, 18 CFR2. We disagree with the rapid recovery of unfunded, unrecorded deferred taxes which arose from items that were flowed-through prior to full normalization.

The Company's treatment since 1975 is congruent with FERC treatment (46 FR May 14, 1981, p. 26613:18CFR 2) of reverse flow-through and should continue. Therefore, we decreased deferred income tax expense $1,051,000.

Flow-Back of Deferred Taxes

The change in corporate income tax rate to a 46% rate requires a decision as to the proper amount of time over which to flow back deferred taxes which were created at 48%. In Order No. 10557, issued February 1, 1982, were required Gulf to flow back these deferred taxes over a five year period. Gulf again requests that the excess deferred taxes be flowed back over the life of the assets to which they relate. Public Counsel supports continued application of the period required in Order No. 10557. We find that we should continue to require the flow back over a five year period. This treatment is the same as required by Order No. 10557, conforms to our policy on this issue in other cases, and conforms to Rule 25-14.5, F.A.C. The Company's test year adjustment to reduce deferred taxes by $389,077 is in compliance with Rule 25-14.5, F.A.C.

Income Tax Effect of AFUDC

Public Counsel originally proposed that 100% of the income tax effect of AFUDC be recorded below-the-line in arriving at the Company's revenue requirements. In its post-hearing brief, Public Counsel states that the issue is moot, as the synchronization of income taxes for NOI purposes with the capital structure will properly account for the above-the-line deferred taxes associated with AFUDC.

The debt portion of AFUDC earnings is treated as an offset to interest expense, both recorded below-the-line. Since the tax effect of interest expense is recognized above-the-line, it follows that an offset to interest expense should also be recognized in tax expense above-the-line. The interest expense allowed for NOI purposes should be synchronized with that inherent in the capital structure.

Effect of Other Adjustments

This adjustment is mechanical in nature and serves to show the effect on deferred income tax expense of the various other adjustments that we have made to the Company's proposed net operating income. The effect is to increase deferred income taxes by $1,866,000.

G. Investment Tax Credit (Net)

Job Development Income Tax Credits

Public Counsel has proposed that the interest expense used to calculate the test year income tax expense include interest imputed to Job Development Investment Tax Credits (JDIC). This issue is essentially the same as that raised with regard to the rate of return to be assigned to JDIC as part of the capital structure. The issues should be resolved consistently. Interest expense will not be imputed to JDIC for purposes of calculating income tax expense.

The amortization of investment credit should match the depreciation of the asset that created the credit. IRC 46(f)(6) precludes a taxpayer from amortizing the credit prior to placing the asset which created the credit into service. Disallowance of the credit is possible if any other treatment is applied.

Public Counsel believes that to allow the qualified progress JDIC in the capital structure, at the overall rate of return after taxes, and not amortize the credit until construction is complete, and the property is placed in service, is unfair to the ratepayer. Public Counsel also contends this treatment is not the intent of Congress on the grounds that IRC Section 46(f) was written prior to the qualified progress expenditure section of the Code [IRC Section 46(d)] and, therefore, Congress could not consider its ramifications. We do not agree. Congress would have rewritten Section 46(f) if their intent was that different treatment be applied to qualified progress JDIC as opposed to other JDIC.

Public Counsel asserts that Gulf has failed to begin amortizing Qualified Progress Expenditure investment tax credits on the date that plant goes into service, the date those credits become available. Exhibit 2M, however, does not reflect the figures cited by Public Counsel. According to the record, Gulf begins amortizing investment tax credits in the year the plant is placed in service. No adjustment is necessary.

H. Gain or Loss on Sale of Plant

In Order No. 10306, we established a policy of requiring gains or losses from the disposition of utility property to be amortized over a five year period. However, the Company anticipates a loss of $21,917 on the sale of utility property in 1982 and no gains or losses of this nature in 1983. Therefore, no adjustment is necessary.

I. Total Operating Expenses

Total operating expenses for the test year, as adjusted herein, are $307,919,000.

J. Net Operating Income

The net operating income for the test year is derived by subtracting total operating expenses of $307,919,000 from operating revenues of $367,934,000. Thus we approve test year net operating income of $60,015,000.

Public Counsel raised the question of whether the Company had property accounted for non-utility operations conducted on utility property. Having reviewed the evidence on this point, we find that the Company has properly accounted for non-utility operations on utility property during the test year and no adjustment is necessary.

FAIR RATE OF RETURN

The Commission must establish the fair rate of return which the Company should be authorized to receive on its investment in rate base. The fair rate of return should be established so as to maintain the Company's financial integrity and to enable it to acquire needed capital at reasonable costs.

Capital Structure

The ultimate goal of providing a fair return is to allow an appropriate return on equity investment in rate base. Because, as a general rule, sources of capital cannot be clearly associated with specific utility property, the Commission has traditionally considered all sources of capital (with appropriate adjustments) in establishing a fair rate of return.

The establishment of a utility's capital structure serves to identify the sources of capital employed by a utility, together with the amounts and cost rates associated with each. After establishing the sources of capital, all capital costs, including the cost of equity capital, are weighted according to their relative proportion to total cost of capital. The weighted components are then added to provide a composite or overall cost of capital. The weighted cost of capital multiplied by the net utility rate base produces an appropriate return on rate base, including a return on equity capital in rate base. The return is also sufficient to recover the annual cost of other types of capital, including debt.

Since a return on all sources of capital is provided by this treatment, actual debt and similar capital costs are not included in test year operating expenses, but are treated "below the line." This assures that such capital costs are not double counted for ratemaking purposes.

An appropriate capital structure is both economical and safe. Such a capital structure should minimize the cost of capital by obtaining capital through an appropriate balance between debt and other components of capital. The capital structure used for ratemaking purposes for a particular company should bear an appropriate relationship to the actual sources of capital to the Company.

Consistent with our decision to employ a projected test period in this case, we have decided to utilize the capital structure projected by the Company to be in place through 1983. We have adjusted the system capital structure to remove capital that is not being utilized to fund the jurisdictional rate base. Such adjustments are necessary to reconcile rate base with capital structure.

We have determined to use a 13-month average capital structure with average cost rates. The parties initially disagreed on this issue; Gulf argued that year-end cost rates should be utilized, while the remaining parties maintained that average cost rates were appropriate. We believe that a 13-month average capital structure with average cost rates best represent the sources of funds used to finance Gulf's rate base. A 13-month average capital structure is a better representation of a utility's financing mix than a year end capital structure under most circumstances. Since capital must be raised in separate components, a single point in time may be too heavily weighted with one type of capital. A 13-month average capital structure smooths the effects of a particular incremental addition of capital. The utilization of average cost rates is especially appropriate in a case such as this one in which a fully projected test year is employed.

Gulf proposed that its capital structure be comprised of long-term debt, preferred stock, common equity, customer deposits, tax credits and deferred taxes. There is no short-term debt included because Gulf has no projected outstanding short-term debt for the 1983 test year.

Mr. Larkin, Public Counsel's witness, proposed the same components with the exclusion of Job Development Investment Tax Credits (JDIC), arguing that excluding JDIC would lower the weighted cost of debt and increase the weighted cost of equity. For the reasons that follow in the discussion on tax credits, we find that Gulf's capital structure should include JDIC as well as the other components proposed by Gulf.

Approved Capital Structure and Fair Rate of Return

Based on our review of the record, we approve and adopt the following capital structure and indicated capital costs:

GULF POWER COMPANY

Cost of Capital - 13-Month Average

Test Year Ending 12/31/83

	Class of Capital	$Amount	Percentage of Total Capital	Cost Rate	Weighted Cost Rate
1.	Long term debt	281,146,610	44.14	9.21%	4.07%
2.	Short term debt	-0-	-0-	-0-	-0-
3.	Preferred stock	53,770,592	8.44	8.31	.70
4.	Customer Deposits	7,659,532	1.20	7.84	.09
5.	Common Equity	169,277,229	26.58	15.85	4.21
6.	Tax Credits - Zero Cost	1,548,454	.24	-0-	-0-
7.	Tax Credits-Weighted Cost	40,662,102	6.39	9.69	.62
8.	Deferred Income Taxes	82,831,481	13.01	-0-	-0-
	TOTAL	$636,896,000	100.00		9.69%

RANGE OF RETURN ON EQUITY 14.85% - 16.85%

RANGE OF OVERALL RATE OF RETURN 9.41% - 9.98%

Capital Structure Component Cost Rates and Amounts

To fully establish a capital structure, we must identify the sources of capital to be included and establish the amount and cost of each source.

Long-Term Debt

Gulf had originally proposed the use of an average balance of long-term debt of $393,187,000 on a system basis in conjunction with a year-end cost rate of 9.20%; however, Gulf in its brief, proposed the use of an average cost rate for long-term debt of 9.21%. Public Counsel's witness proposed an average balance for long-term debt of $271,986,000 on a jurisdictional basis with an average cost rate of 9.28%.

The FEA's position was that long-term debt should consist of $393,187,000 on a system basis at an average cost rate of 8.78%, utilizing a substitute Plant Daniel adjustment based upon recent debt and preferred costs, rather than the adjustment calculated by Mr. Scarbrough.

Included in Gulf's proposed capital structure was certain debt related to Gulf's Unit Power Sales from Plant Daniel. Consistent with our decision to remove Plant Daniel UPS from jurisdictional consideration in this case, we have removed $56,200,000 of long-term debt from Gulf's capital structure at the 10.43% rate provided for by the UPS contract.

Based upon our reconciliation of the utility's capital structure with its approved rate base, we find the appropriate long-term debt component to be a 13-month average balance of $281,146,610 with an average cost rate of 9.21%.

Preferred Stock

Gulf proposed that the preferred stock component of its capital structure consist of an average amount of $77,105,000 on a system basis at a year end cost rate of 8.29%. Public Counsel recommended that preferred stock consist of $53,927,000 on a jurisdictional basis at an average cost rate of 8.61%, which does not include an adjustment for UPS. The FEA recommended an amount of $77,105,000 on a system basis at an average cost rate of 8.08%.

Included in Gulf's proposed capital structure was certain preferred stock related to Gulf's Unit Power Sales from Plant Daniel. Consistent with our decision to remove Plant Daniel UPS from jurisdictional consideration, in this case, we have removed $12,321,000 of preferred stock from Gulf's capital structure at the 10.15% rate provided for by the UPS contract.

Consistent with our adjustments to the rate base, we find that the appropriate amount and cost rate for preferred stock are $53,770,592 and 8.31%, respectively.

Customer Deposits

Gulf proposed customer deposits in the average amount of $8,687,000 on a system basis at a cost rate of 7.84%, which is the effective cost rate when the deposits of inactive customer accounts are considered. Public Counsel proposed that $6,086,000 (jurisdictional basis) of customer deposits be included in capital structure at the same cost rate of 7.84%. The FEA also utilized the 7.84% cost rate with $8,687,000 (on a system basis) of customer deposits.

Consistent with our reconciliation of rate base to capital structure, we find that the appropriate amount of customer deposits to be included in the capital structure is $7,659,532. Recognizing that the utility pays no interest on customer deposits held in inactive accounts and that these funds are therefore cost-free, we find that the appropriate cost rate for customer deposits is the effective cost rate of 7.84%.

Short-Term Debt

As stated earlier, Gulf has no projected outstanding short-term debt for the test year.

Return on Equity Capital

To arrive at an overall fair rate of return, it is necessary that we utilize our judgment to establish an allowable return on common equity capital.

Gulf's position was that it had $236,141,000 (system basis) of common equity at a cost rate of at least 17.5%. Public Counsel took the position that the utility had $159,909,000 (jurisdictional basis) of common equity and that a cost rate of 15.05% was appropriate. The FEA took the position that Gulf had $236,141,000 (system basis) of common equity and that 14.7% was a fair and reasonable return.

Amount of Common Equity

Consistent with our adjustments to the Company's proposed rate base, we find that the appropriate amount of equity capital is $169,277,229.

Cost of Equity Capital

Dr. Arthur T. Dietz, a witness for Gulf, relied on a discounted cash flow (DCF) model and a risk premium analysis in measuring the utility's cost of equity capital. He applied a modified DCF model to determine the cost rates for Gulf's two sources of equity capital: 1) capital contributions from the Southern Company and 2) retained earnings. Since Gulf is a wholly-owned subsidiary of the Southern Company, a publicly-traded holding company, Dr. Dietz relied on market data for the Southern Company in utilizing his DCF model. He testified that, including an allowance for issuance costs, his DCF calculation resulted in a cost of new common equity for the Southern Company of 18%.

Based on his two assumptions, Dr. Dietz concluded Gulf's cost of retained earnings was between 15.5%-18.4%. When he utilized these two components along with Gulf's projected 70%/30% split between new equity and retained earnings for acquiring new capital, Dr. Dietz concluded that Gulf's cost of common equity was at least 17.5%.

Mr. Charles A. Benore, another Gulf witness, calculated the Company's cost of common equity utilizing a DCF model, a risk premium analysis and a financial integrity test. Mr. Benore's DCF approach used the industrial companies represented by the Standard & Poors 400 Index as a proxy for measuring Southern Company's risk. He stated that this was a valid approach because he considered the Southern Company, and therefore Gulf, to be at least as risky as the average industrial company. Utilizing the current yield for the Standard & Poors 400 Index of 5.7% as the yield component for his DCF model along with the projected 1983 nominal growth in GNP of 10.5% as his growth component of his DCF model, Mr. Benore arrived at 16.2% as Gulf's appropriate cost of common equity before adjusting for issuance costs. After an adjustment of 5%-10% for issuance costs, Mr. Benore estimated a cost of common equity of 17.1%-18.0%.

In his risk premium analysis, Mr. Benore concluded a cost of common equity of 17.1% by adding his risk premium of 5.1% to the 12.0% projected yield for long-term U.S. Government bonds in 1983. In analyzing the return required by his financial integrity test, Mr. Benore first concluded that Gulf should increase its bond rating from its present A to an AA in order to enable it to raise capital more favorably in the future. After analyzing the several financial indicators associated with bond ratings and financial integrity, Mr. Benore concluded that Gulf would need to earn at least 18% on common equity if it were to have an opportunity to achieve an AA bond rating. Considering each of his tests and giving the greatest weight to his financial integrity test, Mr. Benore recommended that Gulf be allowed to earn at least 17.5% on common equity.

Mr. Miller, FEA's cost of capital witness, based his recommendation on the results of his DCF analysis. First, Mr. Miller compared Gulf with 94 other electric utility companies whose cost of capital he said represented a good approximation of the cost of common equity capital to Gulf. Mr. Miller found that the cost of equity capital for the 94 companies was 14.8%-15.6% based upon a dividend yield of 12.1% plus a growth rate of from 2.7%-3.5%. Based on his comparative regression analysis of these companies, Mr. Miller concluded that Gulf's cost of common equity was 0.3% below the 94 utility average and that, therefore, a reasonable range for the cost of common equity to Gulf was from 14.5%-15.3%. Mr. Miller's second DCF analysis was based on the utilization of the Southern Company as a proxy for Gulf. Finding a May-July, 1982 average Southern dividend yield of 13.2% and an expected growth rate of 1.8%-3.0%, Mr. Miller determined a cost of common equity in the range of 15.0%-16.2%. Because he considered Gulf less risky than the Southern Company, Mr. Miller concluded that Gulf's cost of equity should be 0.6% less than the cost to the Southern Company. When considering both of his DCF approaches, Mr. Miller recommended that the cost of common equity to Gulf, including an issuance allowance of 0.2%, was in the range of 14.7%-15.5%.

Mr. Parcell, Public Counsel's witness, relied upon a DCF analysis and a comparable earnings analysis in determining Gulf's cost of common equity. Utilizing a DCF analysis based upon a five-year historical period for both his yield (11.5%-12.5%) and growth (1.5%-2.5%) components and an issuance allowance of 4.3%, Mr. Parcell concluded that the cost of common equity to the Southern Company was 13.6%-15.6%. In his comparable earnings analysis, Mr. Parcell examined the return on common equity for the past five years for the Standard & Poors 400 Industrials. As a result of his analysis, Mr. Parcell determined that the industrial group has earned 15.0%-15.5% on common equity for the past five years. Based upon reported stock rankings, Mr. Parcell found that the electric utility industry in general was less risky than the industrial group and that, therefore, the appropriate cost of common equity for Gulf based on comparable earnings would be in the range of 14.0%-15.0%. Taking into consideration the results of both his DCF model and comparable earnings approach, Mr. Parcell concluded that a reasonable return on common equity for Gulf would be in the range of 14.5%-15.6% and that the midpoint of 15.05% be used to determine Gulf's overall cost of capital.

In this proceeding, we have heard expert testimony (all using variations of the DCF model) proposing returns on equity ranging from 14.5% to 18.0%.

From its analysis of the testimony and exhibits of each of the witnesses on this subject, as well as other record evidence, our Staff recommended that a reasonable cost of equity capital for Gulf lies within a range of 15.8% to 17.4%, with the futher recommendation that, giving greater weight to the somewhat lower returns produced by the witnesses' DCF models, we set 16.5% as the appropriate cost of equity capital for the purpose of calculating an overall rate of return.

We find the return on equity capital of 16.5% recommended by the Staff is slightly high in view of money markets at the time of our decision.

Lastly, we note that there has been a continuing downward trend in long-term interest rates and the rate of inflation over the some seven months that have elapsed from the filing of this case to the date of our decision. We note further, that there exists a strong relationship between the direction taken by these rates and the cost that investors demand for the use of their equity capital.

Considering the testimony and exhibits presented in this case, as impacted by the factors discussed above, we find that the appropriate and reasonable cost rate of common equity capital for Gulf Power Company is 15.85%, which, although slightly below the range recommended by our Staff, is well within the overall range of 14.5% to 18.0% testified to by the witnesses in this case.

Tax Credits - Weighted Cost

Gulf proposed that its capital structure be comprised of long-term debt, short-term debt, preferred stock, customer deposits, common equity, 3% Investment Tax Credits, Job Development Investment Tax Credits (JDIC) and deferred income taxes. Mr. Larkin, Public Counsel's witness, proposed the same components with the exclusion of JDIC, arguing that excluding JDIC will lower the weighted cost of debt and increase the weighted cost of equity. Mr. Larkin stated that were JDIC not available to Gulf, it would be required to raise an equivalent amount of capital from alternative sources, which, presumably, would include additional debt. Such debt capital, urges the Public Counsel, would require interest payments which would be deductible in determining above-the-line income taxes. Thus, Public Counsel asks that the Commission exclude JDIC from the capital structure and impute the hypothetical reduction in income tax expense in calculating the utility's above-the-line income taxes.

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Gulf asserts that $48,345,000 of JDIC, on a system basis, should be included in the capital structure at the Company's overall rate of return. Gulf states that the cost rate for JDIC is controlled by provisions of the Internal Revenue Code and the Internal Revenue Service (IRS) regulations, which require a return "not less than the taxpayer's overall cost of capital (determined without regard to the credit)." Gulf argues that the Public Counsel's hypothetical interest expense imputation is clearly improper and impermissible under the IRS regulations and would jeopardize Gulf's ability to continue to take the JDIC. Gulf submits that it has calculated the return on JDIC in the only manner consistent with the applicable statutes and IRS regulations and argues that placing the revenues associated with the "before tax" calculation of JDIC subject to refund would serve no useful purpose and would undermine the Company's financial integrity by placing a cloud over a portion of its revenues.

On the basis of the record in this case, we find that JDIC is presently required by Internal Revenue Service regulations to earn not less than the overall rate of return and be treated as if supplied by the common shareholders. In order to achieve a return equal to the overall rate of return, JDIC must earn an after tax return in the same manner as the funds supplied by common shareholders. However, under Public Counsel's proposed imputation of interest to JDIC supplied capital, JDIC capital would earn less than the overall rate of return and thereby subject the utility to the possible violation of Internal Revenue Service Regulations and therefore loss of JDIC.

According to the Public Counsel, the treatment of JDIC he has proposed has been followed by regulatory bodies with the JDIC adjustment being upheld on appeal to the Federal Courts. It also appears, though, that the IRS has not been a party to any of those actions and that no definitive decision on the issue has yet been reached. Ruling requests on the imputation of interest to JDIC capital have been filed with the IRS but, to date, no ruling on the issue by the IRS has been forthcoming. Should the IRS rule that the interest imputation on JDIC is consistent with its regulations, we believe that imputing such interest is the appropriate regulatory treatment and shall do so. Within 30 days after the date of this Order Gulf shall file with this Commission for approval a letter request for ruling on this issue to be subsequently submitted to the IRS. Accordingly, we shall hold the revenues associated with this proposed adjustment subject to refund for the period of twelve months. Should an IRS ruling approving the interest imputation be received a refund of the twelve months revenue, or $1,811,819, shall be ordered.

Tax Credits - Zero Cost

We have determined that it is appropriate to include zero cost investment tax credits in the capital structure. FEA is opposed to this treatment but we have included these tax credits since they are a source of funds to the Company.

Deferred Income Taxes

All parties except FEA agreed that deferred taxes are a source of funds to the Company and, as such, should be included in the capital structure.

Conservation Award

In Gulf's previous two rate cases we granted the Company 10 additional basis points on the overall rate of return reward for its superior efforts in conservation. Rather than consider it in this proceeding, all parties agreed to sever that issue from this case and consider it in the Company's Conservation Cost Recovery Proceedings.

REVENUE EXPANSION FACTOR

The purpose of the revenue expansion factor (NOI multiplier) is to gross up or expand the Company's net operating income deficiency to compensate for income taxes and revenue taxes that the Company will incur as the result of any revenue increase. We find that an NOI multiplier of 1.980261 should be used in this case. It is developed as follows:

Revenue Requirement	100.0000%
Gross Receipts	(1.5000)
Regulatory Assessment Fee	(.0625)
Net Before Income Taxes	98.4375
Income Taxes	(47.9391)
Revenue Expansion Factor	50.4984%
NOI Multiplier	1.980261

REVENUE DEFICIENCY

Having determined the Company's rate base, the test year NOI, and the overall fair rate of return, we can now calculate any excess or deficiency of revenues. Multiplying the rate base value of $636,896,000 by the fair overall rate of return of 9.69% yields an NOI requirement of $61,715,000. The adjusted NOI for the test year amounted to $60,015,000, resulting in an NOI deficiency of $1,700,000. Applying the appropriate NOI multiplier of 1.980261 to this figure yields a deficiency of $3,366,000 in gross annual revenues. We find and conclude that Gulf Power Company should increase its rates and charges so as to generate this amount of additional annual revenues. The Company is therefore authorized to do so.

RATE STRUCTURE AND RATE DESIGN

Having ascertained the Company's revenue requirement and the amount of revenue increase necessary, we now turn our attention to rate design. We must determine the rate of return currently earned by each rate class, the increase in revenue requirement allocated to each class, and how each class' revenue responsibility will be spread between the customer, energy, and demand charges. In this rate proceeding, we have also reviewed the continued appropriateness of several aspects of the Company's rate structure. We begin first with the cost of service studies presented in this case.

Cost of Service Methodology

In this rate case, several cost of service studies based on different demand allocations were presented to us for consideration: the 12 coincident peak method (12 CP), the 12 coincident peak and one-thirteenth weighted average method (12 CP & Avg.), a seasonally differentiated method whereby demand allocators are weighted to reflect utilization of facilities by season, an annual peak method, and a three summer peak method.

We continue to believe that the 12 CP & Avg. method is the best demand allocation methodology to use in Florida. Because Gulf buys and sells reserve capacity from other Southern operating companies based on the level of its monthly reserve margins, which, in turn, are the result of the size of Gulf's monthly system peaks, the size of all monthly peaks have an important impact on the cost of serving Gulf's retail customers. Thus the majority of production costs should be allocated on the basis of each class' contribution to all of the monthly peaks. Additionally, one-thirteenth of production costs should be allocated on the basis of each class' average demand so that each class will pay for some portion of the production plant it uses, even if the usage is not coincident with the system peak. This is consistent with our view that some of the production plant costs, such as coal handling equipment, while allocated on the basis of demand, vary more with the amount of KWH produced than with the demand placed on the system.

In designing rates, we have selected the Staff Requested cost of service study (Ex. 246) and the adjusted class rates of return that result from that study shown on Ex. 16G. The major differences between the Staff Requested and the Company's 12 CP & Avg. study are that the Staff Requested study does not recognize the concept of a minimum distribution system, allocates EPRI and other industry dues on the basis of energy, allocates conservation costs on the basis of energy, and allocates miscellaneous service charge revenues in the same manner that the costs associated with the service charges are allocated. The Staff's treatment of all of these items is correct.

Both the Company and Air Products objected to the allocation of conservation costs on the basis of energy, contending that these costs should be directly assigned to the customer classes for which the costs were incurred. However, on a number of occasions, we have stated our policy that since all customers benefit from conservation programs, the costs of approved conservation programs should be recovered from all customers based on KWH consumption. Mr. Carzoli acknowledged during his cross examination that if a group of conservation programs results in a reduction of of peak demand which, in turn, causes the avoidance or deferment of capacity related costs, all customers would benefit by lower demand or energy related costs. He agreed that if a group of conservation programs results in a lower monthly system peak than the Company would have had without the conservation programs, the payments Gulf would make or receive for reserve capacity to or from other Southern operating companies would be affected. He also agreed that to the extent that conservation programs result in decreased system peaks and thus a reduced need to purchase additional reserve capacity, all customers benefit from the conservation programs.

The Company and Air Products also argued that the Commission should select a cost of service study for use in designing rates that recognized the concept of the minimum distribution system. Mr. Pollock and Mr. Carzoli testified that certain portions of the distribution system must be in place so the utility can provide service if and when the customer desires it, and that this portion of the distribution system should be classified as customer rather than demand related. Public Counsel took the opposite position. In the last three electric utility rate cases, we have determined that only the meter and service drop portion of the distribution system are properly classified as customer related. The evidence presented by the Company and Air Products has not persuaded us to change our minds. For this reason, we selected the Staff Requested cost of service study, which does not recognize the minimum distribution system concept, for use in this proceeding.

The Staff Requested study shows a rate of return for the OS-III class of 32.97% at present rates. This class is composed of traffic signals, cable TV amplifiers, and other facilities with similar operating characteristics. Evidence adduced at the hearing tended to show that the return for this class is so high because of the way in which service drops were allocated in the cost of service study. Service drops were allocated based on the average number of customers; in the OS-III class, the customer is a municipality who has several traffic signals or numerous streetlights served by one bill. However, Mr. Carzoli agreed that some form of service drop is required for each light or signal, and that by using the average number of customers to allocate service drops, a much smaller number of drops than those actually installed for the class, was allocated to it. Mr. Carzoli stated that the return for the class was thereby significantly overstated. He did not attempt to adjust or recalculate the rate of return for this class because the Company needs to make an analysis to determine a more accurate allocation of service drops for the outdoor lighting classes. Because of this inaccuracy in the cost of service study, a rate decrease for this class is not warranted.

Allocation of the Revenue Increase

The results of the Staff Requested 12 CP and one-thirteenth weighted average demand cost of service study show the following rates of return (ROR) earned by the various customer classes:

Rate Code	Rate Schedule	Present ROR/Index
RS	Residential	8.71%/ .92
GS	General Service	16.01%/1.70
GSD	General Service Demand	10.55%/1.12
LP(GSLD)	General Service Large Demand	10.30%/1.09
PX	High Load Factor	7.63%/ .81
OS I-II	Street Lighting	9.01%/ .96
OS III	Outdoor Lighting	32.97%/3.50
Total Retail		9.42%/1.00

We have granted the Company an overall increase of $3,366,000. Staff recommended and we approve that miscellaneous service charges be increased to full cost, that the poultry farm transition rate be increased 25%, and that the remainder be allocated to the RS and PX classes whose present rates of return are the farthest below parity. The RS and PX classes receive increases of 1.01% and 3.79% (with fuel) as a result of this process.

The class rates of return with the revenue increase fully allocated are:

Rate Code	Rate Schedule	Approved ROR/Index
RS	Residential	8.99%/ .93
GS	General Service	16.13%/1.67
GSD	General Service Demand	10.57%/1.09
LP(GSLD)	General Service Large Demand	10.30%/1.07
PX	High Load Factor	8.99%/ .93
OS I-II	Street Lighting	9.04%/ .94
OS III	Outdoor Lighting	32.97%/3.41
Total Retail		9.69%/1.00

Load Research

Load research is used to estimate class contributions to monthly system coincident peak demands and class noncoincident demands for those classes of customers not equipped with magnetic tape meters. These estimates are used to develop allocation factors for demand-related items in the cost of service studies, such as generation, transmission and distribution plant, and related operation and maintenance expenses.

For this rate proceeding, Gulf found it necessary to conduct load research for the RS, GS, GSD and the LP rates classes. Gulf contends that the load research results are adequate for all classes. In its last rate case, Docket No. 810136-EU, we criticized Gulf for the poor quality of its load research. In this case, the quality of the load research for some clasess has been vastly improved.

Gulf selected probability samples for the RS, GS, GSD and a part of the LP class. We are therefore able to evaluate the statistical precision of the load research results. The precision of the load research for the classes at the 90% confidence level were ± 10.79% for the RS class, ± 11.1% for the GSD class, ± 5.8% for the LP class and ± 53% for the GS class. With the exception of the GS class, we find this level of precision acceptable at the present time. Testifying in support of the Company's position, Mr. Shearer stated that he considered ± 53% at the 90% confidence level an acceptable level of precision for the GS class, in view of the small size of the class. In the absence of a cost benefit analysis demonstrating that the costs of attaining precision of ± 10% at the 90% confidence level for the GS class clearly outweighs the benefits of doing so, we cannot accept his proposition.

However, we intend to open a generic investigation to determine what criteria for acceptable load research ought to be established by the Commission. In the meantime, we accept the load research proffered by Gulf with the realization that the precision of the class rates of return shown in the cost of service studies rises and falls with the accuracy of the load research performed for that class.

Customer Charges

The Company proposed to increase customer charges from those set in the previous rate case approximately one year ago. However, the Company did not carry its burden of proof with respect to the customer unit cost data filed in this case. In its original filing of customer unit costs, the Company included costs attributed to a minimum distribution system, EPRI and other industry dues, energy conservation costs, and the uncollectibles cost. When these items are removed from customer unit costs, as they should be, the unit costs for the GSD class and the GSLD class of $12.40 and $23.13 appear to be unreasonably low. Conversely, the GS class customer unit cost of $8.42 appears to be too high. In the absence of reliable customer unit cost data, customer charges will remain at their present levels. They are as follows:

Rate Code	Rate Schedule	Approved Customer Charge
RS	Residential	$ 5.00
GS	General Service	$7.00
GSD	General Service Demand	$19.50
LP(GSLD)	General Service Large Demand	$27.00
PX	High Load Factor	$60.00

Demand Charges

At the present time, Gulf's three demand classes, GSD, LP (GSLD), and PX all have demand charges of $5.00 per KW per month. The Company proposed to increase them and inaugurate seasonally differentiated demand charges.

The demand unit costs for these classes are $8.13 for GSD, $9.11 for LP (GSLD), and $11.73 for PX. We believe demand charges should move in the direction of unit costs. When demand charges are set below unit costs, the difference is recovered through the energy charge with the result that high load factor customers subsidize low load factor customers. Because we have not increased the revenue requirements of the GSD and LP classes and have given a relatively small increase to the PX class, an increase in demand charges is a reallocation of revenue responsibility within each class. Therefore, to minimize the impact on low load factor customers, we will increase the demand charges to $6.25 per KW per month for the GSD and LP classes. On the other hand, rate PX is an optional rate for high load factor customers. Thus, we approve an increase of 50% of the PX demand charge to $7.50 per KW per month.

We reject the Company's proposal of seasonally differentiated demand charges. The cost of services submitted in this case showed that in 1981 two of the winter month system peaks were 87% of the annual system peak which occurred during the summer month, which implies that Gulf may well become a winter peaking system. To institute a lower demand charge in the winter months sends customers the wrong signal and we do not want customers to make long term decisions in anticipation of seasonally differentiated demand charges. Seasonal demand charges are also inconsistent with the 12 CP and Average cost allocation methodology we have endorsed.

Energy Charges

Air Products raised the issue of whether Gulf's proposed energy charges were properly calculated and took the position energy charges should recover only energy costs and should not be used to recover any fixed costs. While we agree in theory, we must be fair to both high and low load factor customers and move in a gradual fashion toward demand and energy charges set at full unit costs.

Service Charges

The Company proposed to increase service charges from $13.00 to $16.00 for initial connection, normal reconnection, and disconnection after cause, the collection charge from $4 to $6 and the meter tampering fee from $25.00 to $30.00. The Company submitted a cost analysis for each charge as part of the MFR's. Staff reviewed the analyses and recommended that the increases be approved. We agree that the proposed charges are cost based and the charges proposed by the Company are approved.

TOD Rates

Several issues were raised concerning TOD rates. Staff and Public Counsel proposed that mandatory TOD rates be established for customers with demands in excess of 2,000 KW per month. The Company stated that it was uneasy and wary of the idea but it did not think that it was improper to establish mandatory TOD rates for this group of customers. We approve the proposal with the proviso that no customer affected by it will pay more than 10% above the non-TOD rate in any month. We approve mandatory TOD rates because they are more cost based than standard rates and will provide a superior price signal to customers. TOD rates will encourage large customers to change their load patterns in a manner which may reduce the Company's peak capacity requirements. For large customers, additional metering costs are either zero because the meters are already in place, or small relative to the cost savings, due to the potential shifts in usage.

Air Products stated that while it had no theoretical objection to mandatory TOD rates, it was concerned that mandatory TOD rates for large customers only would result in interclass subsidies. The concern of Air Products is unfounded. The load factor method used to calculate TOD rates results in a revenue neutral rate. Class revenues under mandatory TOD rates will be exactly equal to what they would be with standard rates.

As in its last rate case, Gulf proposed several modifications of their summer and winter peak periods used for time of day rates. The Company wanted to shorten the summer peak period from April through October to June through October but lengthen daily summer peak periods which are now 12 AM through 10 PM to 10 AM through 10 PM. Gulf wanted to lengthen the months considered winter from the current November through March to November through May, but shorten the winter daily peak hours which are now 6 AM to 10 AM and 6 PM to 10 PM by eliminating the 6 PM to 10 PM peak period. The Company argued that the proposed peak periods more closely match its actual peak demand periods.

As we said in the last rate case, we made a deliberate decision to treat the state as one pooled system and therefore established uniform statewide peak periods in Docket No. 780793-EU. With sufficient interconnections between utilities, there is no question that treating the state as one system will lead to greater economic benefits than treating each individual utility as an island. Gulf introduced no evidence that contradicts our opinion that it should be given every encouragement to interconnect more strongly with the rest of Florida. Gulf's proposed peak periods are inconsistent with our policy of statewide uniformity and therefore are rejected.

Public Counsel raised the question of whether the on peak/off peak price differentials proposed by the Company for rates RST and GST were so large as to discourage participation in these voluntary rates. Public Counsel need not fear that large on peak/off peak differentials will discourage participation in TOD rates. Customers whose usage is more on peak than that of the class as a whole, will never benefit from TOD rates, no matter what the differential. Customers whose usage is more off peak than the class as a whole, will benefit from TOD rates no matter what the differential. Thus increasing the differential will simply increase the amount of savings realized by customers who do benefit from TOD rates.

Using the load factor method and an estimate of the on peak/off peak ratios of the billing determinants for these classes, Staff calculated on peak/off peak differentials for rates RST and GST. When the Company submits its rates for final approval, it must also submit to Staff its working papers used to calculate the rates so that the estimated ratios of billing determinants may be checked.

The final issue with respect to TOD rates is the minimum term of service requirement. The Company is concerned that customers will opt for TOD rates for a few months when their off peak usage is greatest and then switch back to the standard rate when their percentage of consumption that is off peak declines. To prevent this, the Company proposed a minimum five-year term of service for rate PXT and a minimum one-year term of service for all other TOD rates. We believe that a one-year term of service for customers opting for TOD rates for the first time would unnecessarily discourage customers from trying TOD rates. Therefore no minimum term of service requirement may be imposed on customers opting for TOD rates for the first time. The Company may impose a minimum one-year term of service on customers the second time they opt for a TOD rate. Since we have decided to establish mandatory TOD rates for customers with demands in excess of 2,000 KW, all PX customers will now take service on a TOD rate. Therefore, the five year term of service requirement that is part of rate PX will also apply to PXT customers.

Outdoor Service Rates

The Company and Staff agreed that the street and outdoor lighting rates, OS-I and OS-II, are reasonably cost based, and Staff recommended no changes in the Company's proposed rates if the class was not allocated an increase. We find that the rates are reasonably cost based and approve them as proposed by the Company. For the sake of clarity, the charge currently known as the facilities charge will be designated as the fixture charge.

Deregulation of Outdoor Lighting

During the course of these proceedings, the Commission, on its own motion, raised the issue of whether the Company should continue to install outdoor lighting fixtures as part of its regulated enterprise. Several questions were raised concerning this issue: (1) Is it fair for an electric utility to provide this service at embedded cost rates if its competitor, a private electrical contractor, must offer the same service based on current costs? (2) Should an electric utility continue to devote some of its increasingly expensive capital to a service that is not essential to the provision of electricity to its customers? (3) If this service is deregulated and private contractors effectively compete with the Company, what steps can or should be taken to ensure that only energy efficient light fixtures are installed on the Company's system? (4) What, if any, adjustments should be made for those customers currently receiving outdoor lighting service on a nonmetered basis? While these questions were raised at the hearing, and the Company stated that it was not opposed to deregulation, the issues were not adequately explored, and since this issue affects all investor-owned utilities, we intend to open a generic docket on this subject.

Poultry Farm Transition Rate

Before Gulf's last rate case, poultry farm customers were billed on the residential rate. In the last rate case, we determined that these customers should ultimately be served on the GS rate and established a transition rate for them. The question in this case is whether to continue the transition rate or move the customers to the GS rate. The Company proposed to move them. However transferring these customers to the current GS rate would increase their bills by 36% with fuel and 58% without fuel. An increase of this magnitude is not warranted. A transition rate will be continued for this class; but the energy charge of the present transition rate will be increased by 25% over present revenues without fuel.

Minimum Bill Provision

For many years Gulf's tariffs that included a separately stated demand charge also included a ratchet provision that required a customer to pay a minimum level of demand charges every month regardless of whether his actual demand attained that level. In Gulf's last rate case, we eliminated these ratchet provisions because we believe they are a disincentive to conservation. The tariffs containing a separately stated demand charge filed for our approval in this case contain the following provision:

> Minimium Monthly Bills- In consideration of the readiness of the Company to furnish such service, no monthly bill will be rendered for less than the Customer Charge plus the Demand Charge. For determination of Minimum Monthly Bills only, the billing demand shall not be less than seventy-five percent (75%) of the capacity required to be maintained.

At the hearing, Mr. Haskins testified that the effect of this provison is to require a customer to pay on a monthly basis his energy charges plus the highest of either his actual demand plus the customer charge, or the customer charge and the demand charge times 20 KW, or the customer charge and 75% of the capacity required to be maintained, the third provision applying only if the customer has signed a contract. The Company feels that it has the option to require a general services customer to sign a contract if it has to make an unusual investment to serve that customer and the Company believes it may not recover that investment through the normal course of operations. The Company's present policy is to require all customers with minimum monthly demands in excess of 500 KW to sign a contract. Although on its face the minimum monthly bill provision applies to all customers, in practice it is applied only to customers with large demands or customers who, in the opinion of the Company, require an unusual investment. We are troubled by this provision for two reasons. First, to those customers to whom it is actually applied, it functions as a ratchet, albeit a low one. The Company has available to it another means of ensuring that it recovers unusual investments it must make to serve a particular customer. It may require such a customer to make a Contribution in Aid of Construction. There is no support in the record for the proposition that every large customer imposes a risk of unrecovered investment such that a special contract or mininmum bill provision must be applied to him.

Our second concern arises from the fact that this is a blanket provision contained on every demand tariff that is not uniformly applied to all customers. At best this gives the appearance of arbitrary treatment by the Company and it violates the principle of uniformity of tariff application.

For both of these reasons the minimum bill provision in its present form must be eliminated. However a minimum bill provision should be retained for those customers who, for economic reasons, opt for a rate for which they do not qualify. This will discourage customers from migrating to rate schedules designed for customers with dissimilar load characteristics, and thus preserve the homogeneity of the rate classes. The Company shall include a minimum bill provision of this type in the final tariffs it submits for approval as a result of this proceeding.

Transformer Ownership Discounts

Transformer ownership discounts are needed because the demand charge for each rate schedule includes costs associated with all the transformations necessary to provide service at the secondary distribution level. If a customer takes service at a voltage level higher than the secondary distribution level and thus provides his own transformation, a credit is warranted to cover those transformation costs not required to serve him. The current transformer ownership discounts are 25¢ per KW for customers taking service at primary voltage and 70¢ per KW for those receiving service at transmission level. The Company proposed a uniform discount of 40¢ per KW. The method used by the Company to develop the uniform discount is not correct and we disagree with the concept of a uniform discount since there are differences in cost between service at primary voltage and transmission level. Because of this and because of the size of the revenue increase we have granted, the present transformer ownership discounts, which were developed less than a year ago, will be retained.

Voltage Level Discounts

At the present time, Gulf does not have voltage level discounts in its tariffs. Mr. Haskins acknowledged that customers who receive service above the primary distribution level absorb costs related to line and transformation losses that would otherwise be incurred by the Company, and the only reason the Company does not provide such discounts is a desire for tariff simplicity. However the difference in the costs of serving these customers should be recognized and we therefore approve discounts of 2% for customers served at transmission level and 1% for customers served at primary level.

Standby Service

St. Regis Paper Company intervened in this proceeding and offered the testimony of Mr. Harold Cook on the subject of standby and auxilliary rates for cogenerators and small power producers. Mr. Cook contended that because cogenerators do not require continuous firm service they should not be assessed the same demand charges required from firm customers. He recommended a special rate for cogenerators, the main feature of which is a percentage reduction of demand charges equivalent to the Company's percentage reserve margin used for system planning purposes.

In other recent rate cases (see Docket Nos. 820007-EU and 820097-EU), we achieved a similar result by removing all ratchets and minimum bill provisions from the demand tariffs and then establishing the otherwise applicable TOD rate as the standby rate for customers who produce their own power. We think this course preferable to Mr. Cook's proposal because it gives cogenerators an incentive to schedule maintenance during off peak periods, and if a cogenerator has a forced outage during a peak period he will be assessed the full cost of providing service to him. We will continue our policy in this case. As we have removed the generally applicable minimum bill provision, and since Gulf's present standby and auxiliary service rate is the otherwise applicable TOD rate, no further adjustment is necessary.

GS and GSD Breakpoint

At the present time the breakpoint between rates GS and GSD is 20 KW. This is the point at which a customer begins to incur a separately stated demand charge. There was some suggestion that perhaps the breakpoint should be raised to 50 KW. Staff recommended that the breakpoint not be changed at this time because of the lack of evidence as to what the breakpoint ought to be. We accept Staff's recommendation and accordingly make no change.

Elimination of Rate LP(GSLD)

Gulf has four rate schedules for commercial and industrial customers, GS, GSD, LP(GSLD), and PX, the latter an optional rate for high load factor customers. Gulf proposed to eliminate rate LP and place all General Service demand customers on GSD except those opting for rate PX. This proposal does not comport with sound rate design and we reject it.

The reason for having various General Service rate schedules is that the cost to serve customers varies depending on the customers' load characteristics. Mr. Pollock testified that the size, the delivery voltage, and the timing and rate of consumption are critical load characteristics. He agreed that in deciding whether to combine two groups of customers, the most important factors to consider are size, load factor, and coincidence factor. By definition, the demands of LP customers are greater than GSD customers, and it was Mr. Pollock's opinion that the load and coincidence factors of the two classes, as shown on Ex. 203 are significantly different for rate design purposes, and indicate that it would be unwise to combine the two rates.

The ratio of load to coincidence factor is the most important determinant of cost causation because it relates timing of demand to load factor. Ex. 203 shows that these ratios are 55.9 for rate GSD and 71.2 for rate LP. The coincidence factors for rate GSD and rate LP are 61.5% and 72.9% respectively; the load factors for the two rates are 32.0% and 46.5%. In view of the large differences between the ratios of the two factors, as well as between the factors themselves, the two rates should not be combined. If the rates were combined, the result would be a much less homogeneous rate class with respect to the load characteristics critical for cost causation.

The Company wanted to eliminate rate LP because the it has moved closer to rate GSD in the last few rate cases. The Company contended that the analysis in Ex. 17G justified the elimination of the rate but we are unable to find anything in the exhibit that does so. There will always be some customers who will find it more economical to migrate to another rate schedule because of their particular load characteristics. It is not necessarily desirable to move these customers to another rate schedule as they may be more expensive to serve than the customers on the rate schedule to which they wish to move. For this reason we have retained a minimum bill provision for customers who opt for a rate for which they are not otherwise qualified.

Reactive Demand Charge

Gulf proposed to set the reactive demand charge at $1.40 per KVAR for KVAR's in excess of those which would have occurred if the customer had a 90% power factor. Currently the charge is $1.00 per KVAR. As we did in the last rate case, we reject the Company's proposal because it is based on the customer's, rather than the Company's, cost. Ex. 17R shows that it cost the Company approximately $1.00 per KVAR per month to correct a power factor by 10%. Mr. Haskins testified that the Company proposed a charge of $1.40 per KVAR because that is what it would cost a customer to buy and install the necessary capacitors to correct his power factor to 90%. In this context the customer's cost is irrelevant; we will continue to base the charge on the Company's cost and therefore there will be no change in the present charge of $1.00 per KVAR per month.

Qualifying Load Factor for PX

Rate PX is an optional high load factor tariff which presently requires a customer to contract for a demand of at least 7500 KW and maintain an annual load factor of 75%. Customers who opt for this rate would otherwise be served on rate LP.

The Company wanted to increase the qualifying load factor for this rate from 75% to 80%, on the ground that this was necessary to keep the qualifying load factor close to the economic breakeven load factor between rates LP and PX. The Company indicated that it has designed the PX rate with an economic breakeven load factor of 86-87%. However our goal in rate design is to achieve rate classes with homogeneous load characteristics so as to base rates as closely as possible on cost and avoid imposing costs on any customer for which he is not responsible. The average load factor of the LP class is 46.5%. If an LP customer has a load factor of 75%, he is closer in load characteristics to PX customers than LP customers and should be eligible for rate PX. Therefore the qualifying load factor of 75% will be retained.

Elimination of the Seasonal Service Rider

The Company has had an optional Seasonal Service Rider in effect for several years. The rider is designed to apply to a customer that is highly seasonal in nature, such as the hotels and motels along the beaches in the Company's service territory that operate only in the summer, and have essentially zero consumption during the winter months. Currently there are thirty-seven customers opting for service under this provision.

Essentially customers taking service on this rider agree to pay an additional $1.00 per KW of billing demand during the summer months, and in exchange, the Company waives the minimum billing demand provision of the customers' tariff. Because we have eliminated the minimum bill provision for all customers who qualify for a rate, this rider is no longer needed and therefore is eliminated.

Conservation Costs in Base Rates

In the recent FP&L rate case, Docket No. 820097-EU, we removed conservation costs from base rates and provided that all conservation costs be recovered through the Conservation Cost Recovery Clause. We did so to promote ease of identification of such costs, comparison of such costs between companies, and customer understanding. We will continue that policy in this case and thus all conservation costs will be removed from Gulf's base rates.

Legal Issues

Use of a Fully Projected Test Year

Public Counsel raised several legal issues during the course of this proceeding. The first was whether use of a fully projected test year is permissible under Florida law. As we have determined several times in the recent past, use of a fully projected test year is permissible under Florida law. The issue in this case differs slightly in that Gulf's case is based on a fully projected test year rather than a projected test year that is concurrent with the rate case. However, the purpose of setting rates for an electric utility is to provide an adequate return on equity and compensation for the reasonable costs of providing electrical service. Rates are set for the future, not for the past. To be adequate for the future, rates must be based on measures of investment and expense that will provide an adequate return during the time the rates will be in effect.

These principles have been clearly recognized by the Florida Supreme Court. In rejecting the use of a year-end rate base to offset attrition, the Court specifically authorized the use of an attrition allowance. Yet, measures of attrition inherently involve the use of projected data. The distinction between use of an attrition allowance in conjunction with a test year and the use of projected data is a difference in degree rather than kind. It is no more speculative to project changes in the factors that affect attrition than it is to assume that attrition in the future will precisely mirror attrition in the past.

The use of an historic test year with an attrition allowance, the use of a currently projected test year with an attrition allowance, or the use of a fully projected test year are different methods to produce the same result. Each is intended to provide a representation of the period in which the new rates, if any, will be in effect. We have determined in this case that Gulf's fully projected 1983 test year constitutes a valid basis for setting rates for 1983 and beyond. With the adjustments made herein, we conclude that Gulf's projected 1983 test year is based on reasonable projections and assumptions and thus permits us to set reasonable rates for the period in which they will be in effect.

Effective Date and Notice of New Rates

The next issue raised by Public Counsel was the effective date of the new rates. This issue was definitively settled by the Florida Supreme Court in Gulf Power Company v. Cresse, 410 So. 2d 492 (Fla. 1982), in which the Court ruled that the effective date of new rates is the date on which the issues were decided and the official vote was taken.

Public Counsel also urged us to require the Company to give ratepayers notice of the rate increase between the time the increase is granted and the new rates become effective. We find that the provisions of Sec. 366.04(1), F.S. permit us but do not require us to do so. At the present time, investor-owned utilities provide bill stuffers concerning the proposed rates and the service hearings when their application for a rate increase is filed with the Commission. They are also required to place quarter page legal notices in newspapers throughout their service territory. In addition, the Commission posts two legal notices, and issues press releases during the course of the proceeding. We find this to be sufficient notice and will not, as a matter of policy, require the Company to give additional notice of this proceeding

Payment of Previous Accounts Required

The next legal issue is whether, in light of Rule 25-6.105(8), F.A.C., the following provision contained in Gulf's tariff is valid:

> Payment of Previous Accounts Required -Applications for service will not be accepted by the Company until the applicant has paid to the Company all sums at any time owing and then unpaid by him for service or bills rendered by the Company for any purpose, whether at the premises applied for or at any other premises (Eighth revised tariff sheet 4.13, paragraph 2.6; MFR Vol. II, page 724.)

Because the tariff provision states that service may be withheld until the applicant has paid all bills rendered by the Company for any purpose, it conflicts with sections (b) through (f) of Rule 25-6.105(8), Fla. Admin. Code. Mr. Haskins testified that the Company applied the tariff provision in conformity with the Commission's rule. However the tariff must be revised in the following manner so that on its' face it is consistent with the Commission's rule:

> Payment of Previous Accounts Required -Applications for service will be accepted by the Company until the applicant has paid to the Company all sums at any time owing and then unpaid by him for service ~~or bills~~ of the same class rendered by the Company ~~for any purposes~~, whether at the premises applied for or at any other premises (Eighth revised tariff sheet 4.13, paragraph 2.6; MFR Vol. II, page 724).

Rebuttal Testimony

The final legal issue raised by Public Counsel concerned the prefiled "rebuttal" testimony of Mr. Carzoli on the issue of recognizing a minimum distribution system in the cost of service study. No other witness had testified on the subject. Public Counsel objected to Mr. Carzoli's "rebuttal" as improper Gulf argued that it had the option to file the testimony either as revised direct testimony or as rebuttal. Public Counsel's objection was overruled.

In a major rate case, a utility files both its petition and its prefiled testimony well in advance of the scheduled hearing. After reviewing the company's filing and direct testimony, and conducting discovery, Staff and intervenors place matters at issue, and may present testimony on the issues they raise. In some cases the utility has filed revised direct testimony aimed more precisely at the issues raised by other parties or simply identified a witness as available to testify on an issue. In other cases, such as this one, the utility filed "rebuttal" testimony regardless of whether the witness of any other party testified on the issue.

This latter practice of filing "rebuttal" testimony when no other witness speaks to an issue is improper for two reasons. First, while Florida case law does not fully define rebuttal testimony, it is described as evidence responsive to that presented by another party, not testimony that should have been presented in the case-in-chief. See Driscoll v. Morris, 114 So. 2d 314 (Fla. 3rd DCA, 1959), Atlas v. Siso, 188 So. 2d 344 (Fla. 3rd DCA, 1966), and King Pest Control v. Binger, 379 So. 2d 660 (Fla. 4th DCA, 1980). In other words, a utility should file its direct case in its initial presentation and limit rebuttal to refuting evidence presented by other parties. Rebuttal testimony is not proper if another party does not present evidence on an issue nor should it be used to fill gaps in the utility's presentation of its case-in-chief.

Although rebuttal testimony should not be presented unless it is truly responsive to evidence offered by another party, the Commission has the discretion to allow it in any event. See Driscoll v. Morris, supra. But care must be taken to prevent prejudice to other parties in that situation. This may be accomplished by allowing surrebuttal to the rebuttal testimony. However this brings us to the second reason why rebuttal testimony should be carefully limited. By allowing a utility to bolster its direct case on rebuttal, rather than file revised direct testimony, the Commission should properly allow surrebuttal to other parties. Otherwise, no responsive testimony might ever be heard and the right to counter or rebut the Company's case would be frustrated. Surrebuttal, however, unduly extends the hearing process and we wish to avoid it wherever possible.

While Mr. Carzoli's "rebuttal" testimony appears improper, it does not prejudice the interests of any party to allow it to remain in the record. Public Counsel did not request an opportunity for surrebuttal. More importantly, Mr. Carzoli's "rebuttal" testimony was for naught as we rejected the substance of it, and adhered to our previous policy of not recognizing the concept of a minimum distribution system in a cost of service study. In this case, we will treat Gulf's actions as based on a misunderstanding of how to respond to the prehearing process and allow Mr. Carzoli's "rebuttal" testimony to remain in the record. In the future we intend to require utilities to file revised direct testimony if they wish to respond to an issue raised by another party and that party does not offer its own witness on the subject.

TVA Power

The final legal issue is one that we raised on our own motion. It has periodically been suggested that Gulf, through the Southern Company, purchase power from the TVA with a view towards reselling it to penisular Florida utilities and thereby reduce Florida's dependence on oil fired generation. Alternatively, it has been suggested that Florida utilities contract directly with TVA and that Gulf wheel the power from TVA to penisular Florida.

Neither of these options appears to be legally available. The TVA is organized and governed by a special act of Congress beginning at 16 U.S.C. Sec. 831 (1982 Supp.). Section 831 (n) (4) (A) states:

> Unless otherwise specifically authorized by act of Congress the Corporation shall make no contracts for the sale or delivery of power which would have the effect of making the Corporation or its distributors, directly or indirectly, a source of power supply outside the area for which the Corporation or its distributors were the primary source of power supply on July 1, 1957.

Since the TVA was not a primary source of power supply to Florida in 1957, the statute clearly precludes the TVA from making a direct contract for the sale of power to a Florida utility with Southern merely wheeling the power from the TVA to Florida. As the statute also prohibits the TVA from becoming an indirect source of power supply beyond the 1957 boundary, any type of contractual link between the TVA, Southern, and a Florida utility would be suspect.

CONCLUSIONS OF LAW

In addition to the foregoing, we reach the following conclusions of law:

1. Gulf Power Company is a public utility within the meaning of Section 366.02, Florida Statutes, and is subject to the jurisdiction of the Commission.

2. This Commission has legal authority to approve and use a projected test period for ratemaking purposes. The calendar year 1983 is an appropriate test period for this proceeding.

3. The adjustments to rate base made herein are reasonable and proper. The value of the Company's rate base for ratemaking purposes is $636,896,000.

4. The adjustments made herein to the calculation of net operating income are reasonable and proper. For ratemaking purposes, Gulf's net operating income for the test period is $60,015,000.

5. The fair rate of return on equity capital for Gulf of 15.85% lies in a range of 14.85% to 16.85. A return of 15.85% should be used to determine revenue requirements.

6. The range of reasonableness for the overall fair rate of return for the Company is 9.41% to 9.98% with a midpoint of 9.69% to be used for ratemaking purposes.

7. Gulf Power Company should be authorized to increase its rates and charges by $3,366,000 in annual gross revenues to provide it an opportunity to earn a fair rate of return of 9.69%.

8. The rate schedules prescribed and approved herein are fair, just and reasonable within the meaning of Chapter 366, Florida Statutes.

9. The new rate schedules should be effective for billings rendered for meter readings taken on or after December 22, 1983, which is thirty (30) days after the date of the vote of the Commission upon the Company's petition.

10. Gulf Power Company should be ordered to file with the Commission for approval a letter request for a ruling on the imputation of interest to JDIC capital to be submitted to the IRS. Should an IRS ruling approving the imputation of interest to JDIC capital be received within twelve (12) months of the date of this Order, a refund of the revenue requirement associated with this matter should be ordered in the amount of $1,811,819. Accordingly, $1,811,819 of the total rate increase awarded by this Order should be subject to refund.

11. The return associated with that portion of working capital attributable to coal procurred from the Alabama By-Products Company's Maxine Mine should be subject to refund pending the outcome of a hearing on this matter in Docket No. 820001-EU. Accordingly, $13,442 of the total rate increase awarded by this Order should be subject to refund.

12. The refund condition established in Order No. 9628, applicable to revenues associated with the Caryville cancellation charges as a result of the ratemaking treatment afforded those charges in Order No. 9628, Order No. 10557, and this Order should be continued.

Accordingly, it is

ORDERED by the Florida Public Service Commission that the findings of fact and conclusions of law set forth herein are approved. It is further

ORDERED that the petition of Gulf Power Company for authority to increase its rates and charges is granted as set forth in this Order. It is further

ORDERED that Gulf Power Company is hereby authorized to submit revised rate schedules consistent herewith, designed to generate $3,366,000 in additional gross revenues annually. The Company shall include with the revised rate schedules all calculations and workpapers used in deriving the revised rates, including the workpapers that show the development of the billing determinants used to derive the TOD rates approved herein. It is further

ORDERED that the revised rate schedules authorized herein shall be reflected upon billings rendered for meter readings taken on or after December 22, 1982. It is further

ORDERED that the Company provide to each customer a bill stuffer describing the nature of the increase. It is further

ORDERED that Gulf Power Company file with the Commission for approval a letter request for a ruling on the imputation of interest to JDIC capital to be submitted to the IRS. The letter request shall be submitted to the Commission for approval within thirty (30) days of the date of this Order. Should an IRS ruling approving the imputation of interest to JDIC capital be received within twelve (12) months of the date of this Order, a refund of the revenue requirement associated with this matter shall be made in the amount of $1,811,819. Accordingly, $1,811,819 of the total rate increase awarded by this Order is subject to refund and the Company shall file a corporate undertaking. It is further

ORDERED that the return associated with that portion of working capital attributable to coal procurred from the Alabama By-Products Company's Maxine Mine is subject to refund pending the outcome of a hearing on this matter in Docket No. 820001-EU. Accordingly, $13,442 of the total rate increase awarded by this Order is subject to refund and the Company shall file an appropriate corporate undertaking. It is further

ORDERED that the refund condition established in Order No. 9628, applicable to revenues associated with the Caryville cancellation charges as a result of the ratemaking treatment afforded those charges in Order No. 9628, Order No. 10557, and this Order is continued.

By ORDER of the Florida Public Service Commission, this 11th day of January 1983.

Steve Tribble

Steve Tribble
COMMISSION CLERK

(S E A L)

BED
PS
MBT

APPENDIX A

INDEX OF ORDER

APPENDIX B

SCHEDULE SUMMARIZING ADJUSTMENTS TO RATE BASE

$(000)

	Company	Approved
Adjusted Rate Base Per MFR B-3b, Col. (80 p.31)	$674,607	$674,607
Adjustments		
Temp. Cash Investment	0	(13,453)
Clearing Accounts	0	0
Caryville Study & Equipment	0	0
Prel. Surv. & Investment	0	0
Inv. & Dam. Res.	0	0
Other Deferred Cr.	0	0
Common Stock Dividend	0	0
ESOP	0	(13)
Nuclear Site PS&I	0	(1,752)
Property Ins. Res.	0	(1,147)
Caryville PS&I	0	0
Coal Inventory	0	(13,901)
Oil Inventory	0	0
Deferred O&M Expense	0	4,683
CWIP	0	0
Caryville Plant Site	0	0
Caryville Cancel Chg.	0	0
Unit Power Sales	0	(538)
Inflation	0	(101)
Oil & Coal Inv.	0	(10,803)
SCS Charges	0	(686)
Total Adjustments	0	(37,711)
Adjusted Rate Base	$674,607	636,896

APPENDIX C

SCHEDULE SUMMARIZING NOI ADJUSTMENTS

$(000)

	Company	Approved
Adjusted NOI Per MFR C-2d Col. (8) P. 190	$51,908	$51,908
Adjustments		
PX, RS & OS Rates	0	1,148*
Taxes Other Than Income	0	(18)*
Inflation	0	2,334*
Unit Power Sales	0	0
Schedule E	0	4,905*
Economy Sales	0	346*
Capacity	0	0
Temporary Cash Inv.	0	(2,649)*
Caryville Rev. & Exp.	0	0
Non Recur. Maint.	0	3,831*
Rate Case Expenses	0	21*
Dues	0	18*
Contributions	0	27*
Advertising	0	109*
So. Co. Charges	0	0
1982 Tax Law	0	(77)
Amort. of ITC	0	0
Unfunded Def. Tax	0	1,051
Int. SYNCRHO	0	(800)
Adj. Related to Unused Capacity	0	5,392
Tax Effect of Above Adjustment		
Income Taxes Current	0	(7,531)
Total Adjustments	0	8,107
Adjusted Net Operating Income	$51,908	60,015

*Tax Rate = 48.7%

Plant Daniel Adjustment Based on 1983 Contract

July 1983 Total Available Capacity	1820 MW
July 1983 Firm Peak Demand	1327.6 MW
Reserves	492.4 MW
% Reserve Margin	492.4/1327.6 = 37.1%

Maximum reasonable reserve margin: 25% X 1327.6 = 331.9

Projected reserves	492.4 MW
less 25% reserve margin	-331.9 MW
Excess Reserve: MW	160.5 MW
less July 1983 equalization	-72.4 MW
Unequalized Reserves above 25%	88.1 MW

Summary of Alternative Plant Daniel Adjustment

88.1 MW Reserves above 25%	$ 10,383,281
Shedule E and Economy Sales Credit	
$\frac{88.1}{1793}$ X (4,905,000 + 346,000)	$ (258,011)
72.4 MW Equalization shortfall	$ 3,977,740
Total Daniel Adjustment	$ 14,103,010

12/20/82

1983 Revenue Requirements Associated with 88.1 MW of Plant Daniel

	Investment - Plant Daniel	Revenue Requirements
Net Investment - Plant Daniel	$ 189,661,281	
Ratio of 88.1 MW to Total Daniel MW		
$\frac{88.1 \text{ MW}}{511 \text{ MW}}$	.1724	
	$ 32,698,941	
238 MW Unit Power Sales (UPS)	$ 12,733,000	
Ratio of 88.1 MW to 238 MW UPS		
$\frac{88.1 \text{ MW}}{238 \text{ MW}}$	.3702	
	$ 4,713,350	
1983 Net Investment Associated with 88.1 MW of Plant Daniel	$ 37,412,291	
Equity Return (16.5% CE + 10.15% PS)	6.20%	
	$ 2,319,562	
X Revenue Expansion Factor	1.980261	$ 42,593,338
1983 Net Investment for 88.1 MW Daniel	$ 37,412,291	
Incremental Daniel weighted Debt Return (10.43%)	5.49%	
	$ 2,053,935	
X Revenue Expansion Factor	1.015873	$ 2,086,537

Fixed Expenses

Total Fixed O&M Expesnes	$ 21,144,945	
X NOI Factor	51.3%	
	$ 10,847,357	
Ratio of 88.1 MW to Total Capcity of Daniel $\frac{88.1}{511}$	.1724	
	$ 1,870,161	
X Revenue Expansion Factor	1.980261	$ 3,703,406
Total Revenue Requirement for 88.1 RC-355niel		$ 10,383,281

Adjustment for 72.4 MW Equalization Capcity Payment Shortfall

1.	Revenue Requirements Associated with 72.4 MW of Plant Daniel	$ 7,954,850
2.	1983 Interchange Contract Capacity Payments	(3,779,036)
3.	Revenue Requirements Associated with 1983 Schedule and Economy Sales $\frac{72.4}{1793}$ X (\$4,905,000 + \$346,000)	(198,704)
4.	Net Jurisdictional Revenue Requirements	$ 3,977,740

Gulf Power Company
75 North Pace Boulevard
Post Office Box 1151
Pensacola FL 32520-1151
Telephone 904 434-8381

Douglas L. McCrary
President

the southern electric system

December 9, 1983

Mr. R. W. Scherer, President
Georgia Power Company
Post Office Box 4545
Atlanta GA 30302

Dear Bob:

Re: Gulf Ownership in Plant Scherer

As you know, after we received the inadequate rate increase from the Florida Public Service Commission late last year, we discussed with you and members of your staff the possibility of Gulf modifying or withdrawing altogether from its contract with Georgia Power Company to purchase a 25% interest in Units 3 and 4 at Plant Scherer. We knew that with the level of rates granted in that case Gulf's interest coverages could be below the minimum level required in the indenture, thus prohibiting us from issuing bonds in amounts necessary to finance our portion of the project to completion. In addition, our load growth projections have declined significantly from the time we initially committed to the purchase of an interest in both Units 3 and 4. Consequently, we felt that we must conduct additional economic analyses before making a final decision.

We have completed our analyses which continue to show that the Scherer capacity is overwhelmingly the lowest cost alternative for providing the future electrical requirements of our customers. Due to these significant cost advantages and because of several workshops, hearings, and orders in which the Florida Public Service Commission has clearly supported our participation in the Scherer capacity, we strongly believe and trust that the Commission will grant Gulf sufficient revenues to finance our part of the Scherer project and maintain our financial integrity.

However, due to the decline in Gulf's load growth projections, the management of Gulf Power Company has decided to limit Gulf's participation in Plant Scherer to 25% of Unit 3 only, if this arrangement is agreeable to Georgia Power Company. Our studies show that our present estimates of future demand on Gulf's system do not support our participation in Unit 4 at Plant Scherer.

If you are agreeable to this modification in our agreement, please signify your approval on the enclosed copy and return to us for our files. We stand ready to consummate the agreement as soon as we receive your approval and the Securities and Exchange Commission grants its final approval of the amended contract calling for Gulf's participation in 25% of Unit 3 only, rather than 25% of Units 3 and 4 at Plant Scherer.

Your kind consideration and cooperation in this matter is greatly appreciated.

Sincerely,

D. L. McCrary

D. L. McCrary

Agreed:

R. W. Scherer, President
Georgia Power Company

Date

dbm

Enclosure

cc: Georgia Power Company
J. H. Miller, Jr.
H. G. Baker, Jr.
A. W. Dahlberg
W. Y. Jobe
Gulf Power Company
E. B. Parsons, Jr.
A. E. Scarbrough

bc: The Southern Company
E. L. Addison
Florida Public Service Commission
J. P. Cresse
G. L. Gunter
S. Leisner
J. R. Marks, III
K. Nichols

Atlanta, Georgia 30308
Telephone 404 526-6526

Mailing Address
Post Office Box 4545
Atlanta, Georgia 30302

R. W. Scherer
Chairman of the Board
Chief Executive Officer

the southern electric system

December 13, 1983

Mr. D. L. McCrary
President and Chief
Executive Officer
Gulf Power Company
P. O. Box 1151
Pensacola, Florida 32520

Dear Doug:

Georgia Power Company agrees to modify our contract with Gulf Power Company to provide for the purchase by Gulf of 25% of Plant Scherer Unit Number 3 only, rather than 25% of both Unit Numbers 3 and 4. This sale, of course, is contingent on receipt of all requisite regulatory approvals.

Yours truly,

RWScherer

R. W. Scherer

RWS:vn

cc: Mr. J. H. Miller, Jr.
Mr. H. G. Baker, Jr.
Mr. G. W. Edwards
Mr. W. I. Jobe
Mr. R. J. Kelly
Mr. A. W. Dahlberg
Mr. M. A. Carlton, Jr.

Release No. 23448 (S.E.C. Release No.), Release No. 35-23448, 31 S.E.C. Docket 621, 1984 WL 472458

Securities and Exchange Commission (S.E.C.)
PUBLIC UTILITY HOLDING COMPANY ACT OF 1935

SECURITIES AND EXCHANGE COMMISSION (S.E.C.)

In the Matter of
GEORGIA POWER COMPANY
Atlanta, Georgia
GULF POWER COMPANY
Pensacola, Florida

(70–6573)
October 10, 1984

MEMORANDUM OPINION AND ORDER AUTHORIZING SALE AND ACQUISITION OF UTILITY ASSETS AND DENYING REQUESTS FOR HEARING

I. Introduction

*1 Gulf Power Company ('Gulf') proposes to purchase from Georgia Power Company ('Georgia') a 25% interest in Unit 3 of the Robert W. Scherer coal-fired generating plant now under construction in Monroe County, Georgia. The electric utility unit includes a 50% undivided interest in the property and facilities to be used in common by Units 3 and 4. [1] Gulf and Georgia are subsidiaries of The Southern Company, a registered holding company.

Gulf's contract with Georgia is for a sale at cost, including carrying charges based upon a weighted incremental monthly cost of Georgia's capital. The cost of the 25% at April 18, 1984 was estimated to be $67,047,000. After closing, Gulf will pay currently 25% of the construction costs incurred by Georgia in completing Unit 3. Gulf estimates that the total cost of acquiring and constructing its 25% of Unit 3 (including estimated allowance for Gulf funds used during construction) will be approximately $182 million.

Georgia would credit to Gulf 25% of investment tax credits earned by Georgia prior to such closing with respect to Unit 3, or about $3.3 million. Gulf also will assume enough of Georgia's federal and state income tax liability on the proposed transaction, so that Georgia will have no after-tax book gain as a result of the proposed transaction. This allocation is estimated at $2.5 million.

Excluding combustion turbines, Georgia owned, at the end of 1983, about 10,000 megawatts (mw), of generating capacity in service. [2] Georgia is not the sole owner of all its generating facilities. In the case of the newer plants in service, 91.6% of Units 1 and 2 of Scherer, 45.7% of Wansley and 49.9% of the nuclear Hatch plant are owned, in specified percentages, by others. They are Oglethorpe Power Corporation, Municipal Electric Authority of Georgia, and the City of Dalton, nonprofit companies serving Georgia's rural cooperatives and municipalities that acquired from Georgia their interests in these units, at cost, when under construction. [3] They are also 54.3% co-owners of the two units of the nuclear Vogtle plant, which Georgia is constructing.

The Vogtle nuclear units total about 2,300 mw capacity, of which Georgia will own 1,060 mw. Scherer Units 3 and 4, also under construction, are each of 818 mw capacity, of which, as noted, 204.5 mw in Unit 3 is under contract to Gulf. Georgia is sole owner of projects under construction consisting of two hydroelectric facilities of 175 mw capacity and a large pumped storage unit. [4] Its 1984 budget of $1.5 billion for plant additions includes $830 million for generating facilities.

Georgia is the agent for the co-owners to construct and, on completion, to operate the jointly owned plants. Its sales of interests in these plants included an obligation by Georgia to purchase declining fractions of energy from the co-owners after operation is commenced until such time as the co-owners are expected to require the energy for their own needs. As Georgia does not now need the energy so purchased, nor its own entitlement, it has by contracts arranged to sell, also in declining fractions, the energy output from these plants to non-affiliated utility companies (described as nonterritorial sales). The same arrangements have been made with respect to Scherer Unit 3, in which Gulf is to purchase a 25% interest. In 1983, Georgia generated 53.3 billion kwh and purchased 3.5 billion. It sold 53.4 billion kwh, of which 7.1 billion represented nonterritorial sales.

*2 Excluding a combustion turbine, Gulf owned, at the end of 1983, 1,430 mw of generating plants in Florida, and half, 500 mw, of a new plant of its associate, Mississippi Power Company. It generated 7.7 billion kwh in 1983 and sold or interchanged about 7.4 billion kwh, of which about 1.3 billion were in nonterritorial sales. It has no other generation under construction. Gulf's Florida plants are small and aging. In 1978, it deferred indefinitely a proposed new generating plant in Florida, in favor of participating in Scherer.[5]

Gulf had, at the end of 1983, net utility plant of $685 million and its capital structure consisted of:

	(In millions)	
Long-term debt	$382	53.7%
Preferred stock	76	10.8%
Common stock	253	35.5%
	$711	100.0%

and no short-term debt.[6] Its revenues were $433 million and net income, after preferred dividends, of $35.5 million. Its bond coverage ratio was 2.9 times, with a Moody's rating of A, compared to Georgia's Baa. Gulf is capable of financing the purchase and construction.

The application-declaration was filed March 3, 1981 and was duly noticed (HCAR No. 22030, 22 SEC Docket 919, April 27, 1981). The record has been supplemented and the proposal has been amended. Initially, the agreement of February 19, 1981, provided for Georgia to sell to Gulf 25% of Units 3 and 4 of the Scherer plant. The amendment cancelled its proposed purchase in Unit No. 4. In the meantime, construction of Unit No. 3 continued. When filed, the cost of 25% of both units was less than $5 million. By April of this year, as noted, the cost of a 25% interest in Unit 3 totaled about $67 million.

Objections to the proposal were filed by Ratewatch,[7] which contends that the price is not adequate, and raises other issues. The Georgia Consumers' Utility Counsel ('CUC') also filed an appearance and objections. CUC states that the proposed transaction need not be 'at cost' as a matter of law, and urges that Georgia should earn a profit on the sale, which, it is stated, would or may benefit consumers under a 1981 Georgia statue.[8] Both Ratewatch and CUC request a hearing.

They raise no material issues of fact relevant to the requirements under the Act. A hearing will therefore be denied.[9] Their objections are without merit, all as indicated below.

2. Statutory standards

The sale of an undivided interest in the plant under construction makes Gulf a party to a construction contract, whereby Georgia will complete the plant and be reimbursed currently by Gulf for 25% of the construction costs, after transfer. This construction contract is subject to Section 13(b) of the Act, which requires that the construction be performed at cost. However, Section 13(b) does not apply, as such, to the price for the transfer of the property. Rule 80(b), adopted in 1936 [10], excluded 'utility assets' from Section 13.

*3 We note that the agreement of sale signed February 19, 1981, was subject only to approval by this Commission. Very little had then been spent by Georgia on Unit 3. Georgia continued with construction as required by the agreement. Georgia advanced the necessary funds, and under the contract it will be compensated by Gulf for all costs, including its capital charges. These construction costs of Georgia thus may be considered subject to Section 13(b), as having been incurred for Gulf's account, subject to reimbursement after our approval.

To the extent that the contract with Gulf is deemed not for services but a transfer of utility assets, the acquisition by Gulf is subject to Section 10. The principal issue is related to price, as to which Section 10(b) provides that we approve the acquisition unless:

> '(2) in case of the acquisition of securities or utility assets, the consideration, including all fees, commissions, and other remuneration, to whomever paid, to be given, directly or indirectly, in connection with such acquisition is not reasonable or does not bear a fair relation to the sums invested in or the earning capacity of the utility assets to be acquired or the utility assets underlying the securities to be acquired;'

The provisions of Section 10 apply to all acquisitions, from non-affiliates as well as associate companies in a system. But in the case of an acquisition from an associate company, the Act has been interpreted not to permit a sale at a profit. The price is limited to cost. This interpretation has long been followed in the administration of the Act. [11] This is not the type of case that suggests that a reexamination is appropriate. [12] It was, as applied to current transfer, merely a corollary of one of the reforms imposed on utility companies by the Act and related legislation to eliminate past inter-company profits from the plant accounts of substantially all utility companies in the United States. [13] This requirement was directed to operating companies, under Section 208 of the Federal Power Act, Title II of the statute of which the Holding Company Act is Title I. It was included in the list of abuses in Section 1(b)(1) of the Act, characterized as 'paper profits from inter-company transactions.' This Commission's authority under Section 15 of the Act of require utility subsidiaries of registered holding companies to eliminate past intercompany profits was affirmed in American Power & Light Company v. SEC, supra. [14] Such major writedowns also required corresponding adjustments of capitalization under the Act. They were considered in the Commission's orders on financing and reorganizations under the Act. Georgia wrote off 12% of its plant and Gulf 61%. [15] There is no basis for the contention or suggestion that the transfer to Gulf should be at a price that reflects a 'profit' above cost.

Ratewatch makes the alternative suggestion that the application be denied in the expectation that Gulf would purchase equivalent capacity from Georgia in another plant under construction. Aside from the two small hydroelectric facilities, Georgia has under construction the two coal-fired Units 3 and 4 of Scherer and the two nuclear Vogtle units. One cannot seriously expect that Gulf would take an interest in Georgia's nuclear plant under construction. The decision to replace its coal-fired project in Florida by participation in Scherer was made in 1978. [16] Unit 3 of the Scherer plant is scheduled to be completed in 1987 at an estimated cost of about $802 million. Unit 4 is scheduled for service two years later at a cost of 6% higher, largely because of additional carrying charges. Total investment in Unit 4 is currently about $20 million or 2.3% of its estimated cost; it is now $270 million for Unit 3, or about 33% of its estimated cost. Ratewatch, disagreeing with the proposed agreement, is urging, in effect, that by our disapproval Gulf may be compelled to accept a 25% interest in the higher cost Unit 4. Ratewatch considers a sale to Gulf of a 25% interest in Unit 4 of greater advantage to ratepayers of Georgia. It is fair to assume for like reasons that Florida consumers served by Gulf would prefer Gulf's choice of Unit 3.

*4 We have no such regional preference, and, above all, the Act does not give us a dispensation to favor Georgia over Gulf, as Ratewatch would have us do. We have no authority to review the merits of Georgia's construction program, [17] nor which generating facilities under construction Georgia should retain and which or how much it shall sell. In the present case the choice has been made by agreement between Georgia and Gulf, and our function is to review the transaction to determine whether the terms comply with the standards of the Act, and they do. [18] We note also that in a recent decision the Georgia Commission stated that in the next financing it will review Georgia's construction program, [19] and our decision today does not limit the extent of that review nor what Ratewatch may submit to the Georgia Commission.

Ratewatch argues that we cannot grant our approval without an environmental impact statement under the National Environmental Policy Act of 1969 (NEPA). [20] As we have previously determined, our limited authority with respect to financings subject to Sections 6 and 7 [21] and acquisitions subject to Section 10 [22] does not make NEPA applicable. We have no licensing authority over generating facilities, where they are to be built or the adequacy and need for the facilities. Georgia has chosen the construction site for all four Scherer units, located in Monroe County in Central Georgia, with total capacity of 3272 mw, of which Gulf is acquiring 204.5 mw. Georgia determined the type of units to be built and their priority, and construction will continue as planned, unaffected by the transfer to Gulf or to other co-owners. All units will be operated by Georgia and all the electricity generated will enter the transmission network in central Georgia. The transfer of ownership to Gulf, as proposed, divides responsibility for providing capital for Unit 3 between Georgia and Gulf, in accordance with present estimates of their relative needs in the 1990's. [23] It has no bearing on the environmental effects of the Scherer units either in construction or when in operation, and our approval of the transer is not the kind of 'Federal actions' involving NEPA, as heretofore decided.

Finally, CUC has called our attention to a Georgia statute, [24] passed in 1981, which provides recovery for Georgia ratepayers of their cash contribution to the cost of construction and a portion of the profits on a transfer of ownership of any electric utility plant. He requests that we identify what part of the transaction is a transfer of a utility asset subject to Section 10(b)(2) and what part is a 'construction contract' subject to Section 13(b). It is stated that such identification might be helpful in determining 'profit' under the Georgia statute.

As we said before, Georgia's obligation to complete the plant for Gulf's account is a construction contract within Section 13(b) of the Act, and the transfer of the constructed part of the facility must also be made, as proposed, at cost. The computation of the transfer price, which is consistent with the Act, includes the incremental cost of capital employed by Georgia and certain tax adjustments, involving both investment tax credits and other income tax effects. The price will exceed Georgia's tax basis for the property, which creates the need for tax adjustments, and will differ in some respects from Georgia's book value. The certificate under Rule 24, which will be filed after the transfer, will provide a detailed price computation as of the closing date, which will be available to the Georgia Commission for any assistance it may provide in the application of the Georgia statute.

*5 The fees and expenses to be incurred in this transaction are expected not to exceed $175,000 for Georgia and not to exceed $2,500 for Gulf. No state or federal commission, other than this Commission, has jurisdiction over the proposed transaction.

IT IS ORDERED, accordingly, that the application, as amended be, and it hereby is, granted effective forthwith, subject to the terms and conditions prescribed in Rule 24 promulgated under the Act; and

IT IS FURTHER ORDERED that the requests for hearing be, and they hereby are, denied.

By the Commission.
Shirley E. Hollis
Acting Secretary

Footnotes

1 Ownership of common facilities will be adjusted among the co-owners on completion so that the common facilities will be owned in the same proportion as the generating units, the adjustment to be based on cost.

2 Including its half interest in an Alabama generating subsidiary, jointly owned by it and Alabama Power Company, also an associate company in the Southern System.

3 Georgia Power Company, HCAR No. 21709, 20 SEC Docket 1441 (September 5, 1980); Georgia Power Company, HCAR No. 19751, 10 SEC Docket 909 (November 9, 1976); and Georgia Power Company, HCAR No. 18750, 6 SEC Docket 24 (December 31, 1974).

4 The pumped storage project is for 847.8 mw. That is not additional capacity. It provides only additional peaking capacity.

5 See Gulf Power Company, Fla. Comm. Docket No. 800001–EU(CR), Order No. 9628 (November 10, 1980), at 6.

6 Its current short term borrowing authorization is $70 million. The Southern Company, HCAR No. 23253, 30 SEC Docket 102 (March 21, 1984).

7 Ratewatch is an unincorporated organization of Georgia citizens organized to promote just and reasonable utility rates.

8 Georgia Code Annotated, § 46–2–26.1(c) (1984).

9 See Heering v. SEC, 673 F.2d 1191, 1192–93 (11th Cir. 1982); The Southern Company, HCAR No. 21766, 21 SEC Docket 380 (October 29, 1980), aff'd without opinion, Herring v. SEC, 672 F.2d 894 (D.C. Cir. 1981); Assoc. of Mass. Consumers, Inc. v. SEC, 516 F.2d 711, 714–16 (D.C. Cir. 1975) Bell Telephone Company of Pennsylvania v. FCC, 503 F.2d 1250, 1267–68 (3rd Cir. 1974); See also Gulf States Utilities Company v. FPC, 411 U.S. 747, 754–55 (1973); City of Lafayette La. v. SEC, 454 F.2d 941, 954–56 (D.C. Cir. 1971).

10 Rule U–13–1, HCAR No. 125 (March 30, 1936), redesignated Rule 80, HCAR No. 2694 (April 18, 1941).

11 See Consolidated Gas Supply Corp., HCAR No. 22910, 27 Docket 1114, 1115 (April 12, 1983); Central and South West Corp., HCAR No. 22635, 26 SEC Docket 174, 180–81 (September 16, 1982); Kentucky Power Company, HCAR No. 22392, 24 SEC Docket 1099 (February 18, 1982); New Jersey Power & Light Co., HCAR No. 14566 (January 30, 1962); Philadelphia Co. 31 SEC 793, 801–02 (1950); Cambridge Electric Light Company, HCAR No. 7406 (May 13, 1947); West Texas Utilities Co., 21 SEC 566, 573 (1945); The Twin State Gas & Electric Co., 14 SEC 732, 741–744 (1943); Interborough Gas Co., 11 SEC 918, 921–922 (1942); Public Service Company of Indiana, 11 SEC 298, 302–303 (1942); and New England Power Co., 3 SEC 366 (1938).

12 In Cambridge Electric Light Company, id. at 2, the Commission said:

> '. . . viewing the system as a whole, the proposed transfer at a profit must be regarded in the nature of a write-up which would be properly classified in Account 107 of the Uniform System of Accounts prescribed for electric utility companies by the Federal Power Commission and recommended by the National Association of Railroad and Utilities Commissioners. Under the circumstances and considering the potentialities of abuse present in the intra-system profits of the nature involved here (cf. Section 1(b) of the Act), we are of the opinion that the proposed transaction should be so modified as to eliminate its inflationary aspects.'

13 American Power & Light Co. v. SEC., 158 F.2d 771, (1st Cir. 1946), cert. denied, 331 U.S. 827 (1947); Northwestern Electric Co. v. FPC, 321 U.S. 119 (1944); California-Oregon Power Co. v. FPC, 150 F.2d 25 (9th Cir. 1945), cert. denied, 326 U.S. 781 (1946). The latter case includes a concise review of earlier decisions and the legislative background. The Federal Communications Act and the National Gas Act contained parallel provisions. United States v. New York Telephone Co., 326 U.S. 638 (1946), involved a transfer of property to a subsidiary. The subsidiary was ordered to write off the profit to its parent (AT&T), and the Supreme Court affirmed, noting, 'the Federal Power Commission, the Securities and Exchange Commission, and some state Commissions (see the opinion of the New York Public Service Commission in the instant case) have taken the same position concerning interaffiliate transactions as has the Federal Communications Commission.' Id. at 655 n.23.

14 See also Florida Power & Light Co., HCAR No. 2874 (July 11, 1941), Florida Power & Light Co., 15 SEC 85 (1943), and Florida Power & Light Co, 30 SEC 408 (1949).

15 Georgia Power Company, 8 SEC 656, 664–66 (1941) and Gulf Power Company, 10 SEC 151, 156–58 (1941). Commonwealth and Southern Corporation, the parent of both, and the other party in these proceedings, made the capital contributions needed to maintain a minimum common equity, and dividend restrictions were imposed to assure that equity would increase.

16 See letter of Gulf Power Company to Florida Public Service Commission dated August 25, 1978 and noted in Gulf Power Company, Florida Commission Docket No. 800001–EU(CR), Order No. 9628 (November 10, 1980), at 6.

17 See The Southern Company, HCAR No. 21766, 21 SEC Docket 380 (October 10, 1980), aff'd without opinion, Herring v. SEC, 672 F.2d 894 (D.C. Cir. 1981). Having concluded that we have no authority to review the merits of Georgia's construction program, we deny Ratewatch's Motion for Production of Documents, the subject-matter of which was limited solely to soliciting information about Georgia's construction program.

18 We note that the arrangement with Gulf is not unlike that extended to non-affiliated co-owners. Georgia had sold 16.5% of Scherer Units 3 and 4, which in 1980 it reacquired at cost, and sold the co-owners 15.5% of Units 1 and 2, also at cost. Georgia Power Company, HCAR No. 21709, 20 SEC Docket 1441 (September 5, 1980).

19 Georgia Power Company, Ga. Pub. Serv. Comm. Docket No. 3457–U Order (June 1, 1984), at 13.

20 Section 102(2)(C) of NEPA requires the statement in case of 'major Federal actions significantly affecting the quality of the human environment.'

21 See The Southern Company, HCAR No. 21665, 20 SEC Docket 799, 801–02 (July 24, 1980); The Southern Company, HCAR No. 21766, 21 SEC Docket 380–82 (October 29, 1980), aff'd without opinion, Herring v. SEC, 672 F.2d 894 (D.C. Cir. 1981).

22 Northern States Power Co., HCAR No. 22334, 24 SEC Docket 486, 494–95 (December 23, 1981).

23 Georgia and Gulf have already contracted to sell about 88% of the capacity of Unit 3 to non-affiliates through 1992, with sales phasing out over the following three years. The effect is to postpone the availability of the generation to Gulf until needed.

24 Georgia Code Annotated, § 46-2-26.1(c) (1984).

Release No. 23448 (S.E.C. Release No.), Release No. 35-23448, 31 S.E.C. Docket 621, 1984 WL 472458

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BEFORE THE PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.	DOCKET NO. 050001-EI ORDER NO. PSC-05-0084-FOF-EI ISSUED: January 24, 2005

The following Commissioners participated in the disposition of this matter:

BRAULIO L. BAEZ, Chairman
J. TERRY DEASON
RUDOLPH "RUDY" BRADLEY
CHARLES M. DAVIDSON

APPEARANCES:

JOHN T. BUTLER, ESQUIRE, Steel, Hector & Davis LLP, 200 South Biscayne Blvd., Suite 4000, Miami, Florida 33131-2398 and R. WADE LITCHFIELD, ESQUIRE, and NATALIE F. SMITH, ESQUIRE, 700 Universe Boulevard, Juno Beach, Florida 33408
On behalf of Florida Power & Light Company (FPL).

NORMAN H. HORTON, JR., ESQUIRE, Messer, Caparello & Self, P.A., Post Office Box 1876, Tallahassee, Florida 32302-1876
On behalf of Florida Public Utilities Company (FPUC).

RUSSELL A. BADDERS, ESQUIRE, Beggs & Lane, Post Office Box 12950, Pensacola, Florida 32591-2950
On behalf of Gulf Power Company (GULF).

JAMES A. MCGEE, ESQUIRE, Progress Energy Florida, Post Office Box 14042 St. Petersburg, Florida 33733 and BONNIE E. DAVIS, ESQUIRE, Progress Energy Florida, 106 East College Avenue, Suite 800, Tallahassee, Florida 32301
On behalf of Progress Energy Florida (PEF).

JAMES D. BEASLEY, ESQUIRE, Ausley & McMullen, Post Office Box 391, Tallahassee, Florida 32302
On behalf of Tampa Electric Company (TECO).

JON C. MOYLE, JR., ESQUIRE, and WILLIAM H. HOLLIMON, ESQUIRE, Moyle, Flanigan, Katz, Raymond and Sheehan, P.A., The Perkins House, 118 North Gadsden Street, Tallahassee, Florida 32301
On behalf of Thomas K. Churbuck (CHURBUCK).

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JOSEPH A. MCGLOTHLIN, ESQUIRE, VICKI GORDON KAUFMAN, ESQUIRE, and TIMOTHY J. PERRY, ESQUIRE, McWhirter, Reeves, McGlothlin, Davidson, Kaufman & Arnold, P.A., 117 South Gadsden Street, Tallahassee, Florida 32301
On behalf of Florida Industrial Power Users Group (FIPUG).

PATRICIA A. CHRISTENSEN, ESQUIRE, Associate Public Counsel, Office of Public Counsel, c/o The Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400
On behalf of the Citizens of the State of Florida (OPC).

ADRIENNE E. VINING, ESQUIRE, WM. COCHRAN KEATING, IV, ESQUIRE, and JENNIFER RODAN, ESQUIRE, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850
On behalf of the Florida Public Service Commission.

FINAL ORDER APPROVING UNIT POWER SALES AGREEMENTS BETWEEN FLORIDA POWER & LIGHT COMPANY AND SOUTHERN COMPANY FOR COST RECOVERY PURPOSES

BY THE COMMISSION:

Case Background

Florida Power & Light Company (FPL) currently purchases 955 MW of capacity from Southern Company (Southern) via unit power sales (UPS) agreements set to expire on May 31, 2010. The existing UPS agreements are for coal-fired generation from Southern's Scherer and Miller units in Georgia. After adjusting for losses on Southern's side of the interface, FPL receives 930 MW of capacity. Three new UPS agreements between FPL and Southern are scheduled to take effect on June 1, 2010, and continue to December 31, 2015. The new UPS agreements would also provide 955 MW of firm capacity, with FPL receiving 930 MW at the interface. The new UPS agreements would provide 165 MW of coal-fired capacity from the Scherer unit, with the remaining 790 MW of capacity from Southern's natural gas-fired Harris and Franklin units in Georgia.

FPL requested our approval for cost recovery of the new UPS agreements as part of its annual fuel adjustment filing with the Commission. At the conclusion of the hearing held in this docket on November 8 and 9, 2004, we rendered a bench decision on all issues with the exception of Issue 14C, which addresses approval of the new UPS agreements. We requested a written recommendation on Issue 14C and the parties were provided the opportunity to file briefs supporting their positions on that issue by December 1, 2004. Based on the evidence presented at the hearing and in consideration of the parties' post-hearing briefs, we addressed Issue 14C at our January 4, 2005 Agenda Conference. This Order memorializes our decision regarding FPL's request for approval of its new UPS agreements with Southern. We have jurisdiction over this matter pursuant to Sections 366.04, 366.05, and 366.06, Florida Statutes.

FPL's New UPS Agreements

According to FPL, the purpose of the new UPS agreements is to retain as many of the benefits of the existing contracts as possible. While FPL may not have been able to retain all of the benefits of the existing UPS agreements, the new UPS agreements do provide some fuel diversity, enhanced reliability, and opportunities for economy energy purchases. Specifically, the new UPS agreements provide for: (1) the purchase of 165 MW of coal-fired and 790 MW of gas-fired capacity and energy, with the right of first refusal to purchase additional coal-fired energy if made available; (2) a short-term commitment which allows FPL to further explore ownership of new solid fuel generation; (3) enhanced reliability through geographic and fuel supply differences; and, (4) the retention of firm transmission rights within the Southern system.

FPL states that the benefits of the new UPS agreements, such as fuel diversity, enhanced reliability, and opportunities for economy energy purchases, are difficult to quantify. We agree. A pure dollar and cents cost-effectiveness comparison suggests that a self-build option would be more cost-effective by approximately \$69-\$93 million. Therefore, we are faced with the decision of how much of a premium should be paid for the types of benefits provided by the new UPS agreements. The concept is similar to that of purchasing car insurance. You pay a premium for something you hope to never use, but are glad you have it if needed. We estimate that the "premium" would equate to approximately 0.02 cents/kwh, or about 20 cents/month per residential customer over the 5.5 year term of the UPS agreements.

Since the 1990's, the majority of new generation additions in Florida and the nation have been natural gas-fired units. No new coal-fired generating units have been constructed for quite some time, either in Florida or in the Southern system. FPL's reliance on natural gas for future generation additions is the highest of any Florida investor-owned utility. The coal units that support the existing UPS agreements, the Scherer and Miller units, are being retained for use by the original owners for their native load customers. This fact is supported by the testimony of FPL's witness Hartman who stated that going into negotiations, FPL wanted to buy all coal-fired energy, but Southern only wanted to sell gas-fired energy. In essence, while the amount of coal-fired capacity is reduced from 930 MW to 165 MW, some fuel diversity is preserved for FPL at a time when Florida's utilities are highly dependent on natural gas-fired generation. When compared to the self-build alternative, the new UPS agreements increase fuel diversity on FPL's system. In addition, the right of first refusal for additional coal-fired capacity provides additional fuel diversity opportunities. FPL is currently studying the feasibility of adding coal-fired generation to its system and has committed to provide a report on that subject to the Commission by March 2005. The short term nature of the new UPS agreements allows a window of time for FPL to more fully analyze the potential for constructing coal-fired generation during the 2010-2015 timeframe.

Both the existing and the new UPS agreements enhance reliability through geographic and fuel supply differences. FPL has been allocated a share of the Florida/Georgia transmission interface and is currently utilizing this transmission capacity to import power under the existing

UPS agreements. This amount of transmission import capacity will not change with the new UPS agreements. Under the new UPS agreements, 930 MW of power will be imported from the Southern region, just like the existing UPS agreements. If FPL did not extend the contracts, the 500 kV lines would remain in place, but FPL would be required to make its share of the interface capacity available for purchase by third parties. The existing UPS agreements are based entirely on coal-fired- energy. As discussed above, fuel diversity is enhanced by the new UPS agreements. While the new UPS agreements have a significant portion of capacity that is gas-fired, the fuel is delivered via a gas transportation network that is outside of Florida, providing enhanced fuel supply reliability.

The benefits associated with the firm transmission rights should improve compared to the existing UPS agreements. According to witness Hartman, the transmission rights associated with the existing UPS agreements are bundled with the capacity payments and are not transferable within the Southern system. The new "roll-over" transmission rights, if approved, would be billed separately pursuant to Southern's Open Access Transmission Tariff (OATT). FPL may request alternate transmission paths that allow additional economy energy transactions. Alternate firm transmission paths could be requested with 24 hours notice and non-firm requests with only a one hour notice. The additional economy purchases are estimated to provide between $36 to $83 million dollars in savings to FPL's ratepayers. Witness Hartman did acknowledge that the maximum level of savings assumed, $83 million, was substantially greater than FPL's recent history of out-of-state economy energy purchases and that the minimum level of $36 million is more in line with FPL's recent historical experience. Witness Hartman used the maximum and the <u>average</u> values of economy energy savings to arrive at the range of $69 to $93 million dollar net cost figures. Using the maximum and the minimum figures for economy energy purchases would result in a range of net cost of $69 to $117 million, respectively, when compared to the self-build option. However, if natural gas prices were to rise significantly during the 2010 to 2015 time frame, the savings from economy energy purchases could surpass the estimated maximum level and possibly mitigate the additional costs of the contracts. The table below summarizes the three scenarios:

Cost above self-build	153	153	153
Economy energy purchases	83	60	36
Net total cost*	**69**	**93**	**117**

Witness Hartman also stated that he was doubtful that FPL would be able to secure equivalent firm transmission rights if the roll-over rights were not granted because FPL would be at the end of the line behind several other entities requesting transmission access. If this were to happen, even the minimum amount of economy energy purchases would be in jeopardy. The reverse would also be true. Without firm transmission rights, FPL may not be in a position to make economy sales to Southern. Therefore, it appears that the primary benefit of the new UPS agreements is the retention of firm transmission rights within the Southern system. Witness Hartman testified several times that whoever owns the transmission rights receives all of the benefits of economy energy transactions and that "[i]f we own the transmission rights, how much we share with our customer is a matter of the fact that they get all of it . . . [a]ll of the benefits of the transmission rights."

One additional benefit of the new UPS agreements is the fact that all three contracts are fully dispatchable by FPL. We are unsure if this same provision is contained in the existing UPS agreements. In essence, the generating units defined in the contracts are under the direct control of FPL, as if FPL owned the units. As such, FPL can even make sales from these units when it is economic to do so. FPL stated in response to Staff Interrogatory No. 43 that "[i]f the dispatch cost of the plants under contract is lower than the market price, but higher than our own system marginal costs, we would dispatch the plants under contract to the extent we can sell the output into the market." It is unusual for a purchased power contract to also provide for the opportunity to produce revenues for the original buyer; however, the ability to dispatch the units is worthless unless FPL has the transmission rights to deliver the power.

FPL stated many times that the benefits of the UPS agreements should flow to the customers. Therefore, we find that, as a condition of approval, any gain on sales to third parties that utilize the transmission rights associated with the UPS agreements shall be credited 100% to FPL's ratepayers. If FPL negotiates the purchase of additional coal capacity and energy from either the Miller or Scherer units, the same conditions shall apply. In order to not penalize FPL, the gains on such sales shall not be included in FPL's calculation of a three year rolling average for purposes of establishing the threshold for other economy sales pursuant to Order No. PSC-00-1744-PAA-EI, issued September 26, 2000, in Docket No. 991779-EI, In re: Review of the appropriate application of incentives to wholesale power sales by investor-owned electric utilities. Such a conditional approval will ensure that the value of all of the benefits that are not quantifiable today will flow to FPL's ratepayers in the future.

Other parties to the proceeding, Churbuck, OPC, and FIPUG, contend that FPL did not provide sufficient evidence to justify approval of the new UPS agreements. We disagree and believe that the record is sufficient for us to render such a decision. No matter how long or in what detail one considers the evidence, we are faced with the decision of how much of a premium should be paid for the types of benefits provided by the new UPS agreements. We have the information and expertise needed to make a decision based upon the economic impact of the new UPS agreements and a description of the benefits they will bring to FPL's ratepayers.

In summary, the new UPS agreements continue many of the benefits associated with the current UPS agreements. Access to coal-fired energy via firm transmission rights appears to be the greatest benefit to FPL's ratepayers. Therefore, based upon the evidence presented at the hearing and in consideration of the parties' post-hearing briefs, we find that the new UPS agreements between FPL and Southern shall be approved for cost recovery purposes, subject to the conditions set forth above.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that the Unit Power Sales Agreements between Florida Power & Light Company and Southern Company, which are scheduled to take effect on June 1, 2010, and continue to December 31, 2015, are hereby approved for cost recovery purposes, subject to the conditions set forth in the body of this Order. It is further

ORDERED that this is an ongoing docket that shall remain open.

By ORDER of the Florida Public Service Commission this 24th day of January, 2005.

BLANCA S. BAYÓ, Director
Division of the Commission Clerk
and Administrative Services

By: Kay Flynn
Kay Flynn, Chief
Bureau of Records

(S E A L)

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NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Director, Division of the Commission Clerk and Administrative Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Director, Division of the Commission Clerk and Administrative Services and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

BEFORE THE PUBLIC SERVICE COMMISSION

In re: Petition for approval of two unit power sales agreements with Southern Company Services, Inc. for purposes of cost recovery through capacity and fuel cost recovery clauses, by Progress Energy Florida, Inc.	DOCKET NO. 041393-EI ORDER NO. PSC-05-0272-PAA-EI ISSUED: March 14, 2005

The following Commissioners participated in the disposition of this matter:

BRAULIO L. BAEZ, Chairman
J. TERRY DEASON
RUDOLPH "RUDY" BRADLEY
CHARLES M. DAVIDSON
LISA POLAK EDGAR

NOTICE OF PROPOSED AGENCY ACTION
ORDER APPROVING UNIT POWER SALES AGREEMENTS BETWEEN PROGRESS ENERGY FLORIDA, INC. AND SOUTHERN COMPANY SERVICES, INC. FOR COST RECOVERY PURPOSES

BY THE COMMISSION:

NOTICE is hereby given by the Florida Public Service Commission that the action discussed herein is preliminary in nature and will become final unless a person whose interests are substantially affected files a petition for a formal proceeding, pursuant to Rule 25-22.029, Florida Administrative Code.

CASE BACKGROUND

Progress Energy Florida, Inc. (Progress) currently purchases 414 MW of capacity and the associated energy from the Southern Company (Southern) under two unit power sales (UPS) agreements. These agreements were executed in 1988, and are set to expire in May 2010. The existing UPS agreements consist of coal-fired generation from Southern's Scherer and Miller units, located in Georgia.

As a part of its annual fuel adjustment filing in Docket No. 040001-EI, Progress requested Commission approval for cost recovery of the anticipated extension of the existing UPS agreements with Southern. At the time, Progress had not yet finalized the agreements with Southern, but rather filed a Letter of Intent with Southern to extend the existing 1988 UPS agreements. At the prehearing conference for Docket No. 040001-EI, held on October 25, 2004, the Prehearing Officer ruled that the Commission would not address the issue until an agreement was finalized and filed with the Commission.

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On November 24, 2004, Progress signed two new UPS agreements with Southern, which will replace the existing agreements upon their expiration. The two new UPS agreements consist of 424 MW of capacity, including 74 MW of coal-fired capacity from the Scherer unit. The remaining 350 MW of capacity will be provided by Southern's natural gas-fired combined cycle unit, Franklin 1, also located in Georgia. The term for each agreement is June 1, 2010 through December 31, 2015.

On December 13, 2005, Progress filed a petition requesting a finding from the Commission that entering into the UPS agreements is a reasonable and prudent action by Progress to maintain its 20 percent reserve margin. Progress also requested recovery of the energy and capacity costs associated with the agreements, subject to Commission review of the actual expenses in the annual Capacity and Fuel Cost Recovery Clause proceedings. We have jurisdiction over this subject matter pursuant to Sections 366.04, 366.05, and 366.06, Florida Statutes.

UPS AGREEMENTS BETWEEN PROGRESS AND SOUTHERN

Progress currently purchases 414 MW of capacity from the Southern Company (Southern) under two UPS agreements which will expire on May 31, 2010. The capacity consists of coal-fired generation from Southern's Miller and Scherer units, located in Georgia. In order to maintain its 20 percent reserve margin, Progress has entered into two new UPS agreements with Southern, scheduled to take effect June 1, 2010, and expire December 31, 2015. These agreements would provide 424 MW of capacity, including 74 MW of coal-fired capacity from the Scherer unit, and the remaining 350 MW provided by the natural gas-fired Franklin 1 combined cycle unit, also located in Georgia. Progress has also obtained a right-of-first refusal for additional coal-fired capacity to replace all or part of the natural-gas fired capacity, should additional coal-fired capacity become available.

The UPS agreements specify different levelized capacity charges for the coal-fired and natural gas-fired capacity. These charges include: capital costs, costs of non-environmental capital additions, fixed O&M, and allocated overhead expenses. Any applicable changes in law which impact environmental costs will be borne by Progress. Progress will also be charged fixed gas transportation costs to deliver gas to the Franklin unit, and transmission costs to the Florida-Georgia interface. Energy charges under the agreements are set based on delivered fuel costs multiplied by the actual heat rate at the Scherer unit (heat rate varies according to the coal mix burned) and a guaranteed heat rate at the Franklin unit.

As a condition precedent for the UPS agreements, Progress must obtain firm transmission service to the Florida-Georgia interface. Transmission under the existing 1988 UPS agreements was provided under bundled service, which included roll-over rights to the transmission access. In November 2004, Progress requested firm transmission service from Southern under the terms of Southern's Open Access Transmission Tariff (OATT). A transmission agreement must be reached by February 2006, unless both parties agree to extend the deadline. Progress has the right to terminate both UPS agreements if transmission access is not granted under acceptable terms.

Cost-Effectiveness

Progress provided a cost-effectiveness analysis of the new UPS agreements, which compares expansion plans with and without the UPS agreements, from year 2010 until 2055. Progress used a 45-year analysis to represent the five year term of the contract, followed by the assumed 40-year life of a coal-fired generating unit added to the plan following the expiration of the agreements in 2015. The UPS agreements defer the need for one combined cycle unit from 2010 to 2011, defer a second combined cycle from 2012 to 2018, and change the timing of subsequent units. Progress' analysis included the cost savings benefit of economy purchases made possible by the transmission access on Southern's system associated with the UPS agreements. Through the five year UPS contract term, 2010 through 2015, the net present value (NPV) analysis shows a significant savings of $133 million, even if economy sales are not taken into account, due to the deferral of two generating units. Progress stated that this savings would increase to a NPV of $145 million with the inclusion of savings from economy purchases. Progress' 45-year comparison of the two expansion plans resulted in a negative $5 million NPV, with a base case economy energy purchase assumption. Progress performed a sensitivity analysis assuming a fifty percent economy purchase reduction, which resulted in a negative $11 million NPV over 45 years.

We have reviewed Progress' cost-effectiveness analysis and believe it is based on reasonable assumptions. We note that the NPV outcome of the analysis is highly dependent on the time period used in the analysis, because the timing of several units is altered by the inclusion of the UPS agreements in Progress' expansion plan. The benefits projection for the years 2010 through 2015 is more certain than the potential costs based on a 45-year analysis. Therefore, we place more credence on the short-term benefits of the contracts.

Non-Price Benefits

We agree with Progress that the UPS agreements have several non-price benefits, which are difficult to quantify, including:

- *Transmission Access and Economy Energy*: The UPS agreements allow Progress to exercise its roll-over rights and maintain transmission access to the Southern system and beyond. This provides access to potential economy energy purchases and sales, and increases reliability. Progress believes that the UPS agreements will provide the opportunity for increased economy purchases because a portion of the capacity is natural-gas fired. The Franklin unit will not be dispatched over as many hours as a coal-fired unit, providing Progress with excess transmission capacity that may be used to transport economy energy in the hours when Progress is not taking energy from Franklin.

- *Fuel Diversity*: Although the UPS agreements provide less coal capacity than the existing agreements, more coal capacity is provided than under the self-build option. Placing this coal-fired capacity under contract will reduce the exposure of Progress' ratepayers to fuel price volatility. Progress has also obtained a right-of-first refusal on additional coal capacity to replace all or part of the Franklin natural-gas fired capacity.

- *Planning Flexibility*: The UPS agreements offer planning flexibility compared to a self-build option. Progress has obtained a right to extend a portion of the contracted capacity to 2017, or it can let the agreement expire. The contracts also give Progress additional time to study the cost-effectiveness and feasibility of adding coal-fired capacity. Progress provided information on two recent internal and external analyses of the impact of adding coal-fired capacity to Progress' system. Progress assumed that the in-service date of a coal-fired unit would be moved up from year 2017 to 2015 in its expansion plan with the UPS agreements.

- *Reliability*: The UPS agreements increase reliability by: 1) adding an outside source for natural gas transportation; and, 2) providing access to energy from Southern's system and beyond. The Franklin agreement allows Southern to provide energy from alternate units in case of a forced outage or if Southern chooses not to dispatch the Franklin unit. If Southern provides energy from an alternate source, Progress will receive a discount on the energy charge.

In summary, the UPS agreements provide a NPV savings of between \$133 million to \$145 million over the life of the contracts, due to the deferral of two natural gas-fired combined cycle units. Further, the agreements provide several non-price benefits, including: 1) access to transmission on Southern's system; 2) the potential for savings from economy energy purchases; 3) fuel diversity; 4) increased reliability; and, 5) planning flexibility. We believe that the fuel diversity and planning flexibility afforded by the agreements are of particular importance due to the volatility and forecasting uncertainty of natural gas prices. The coal-fired capacity from Southern's Scherer unit will reduce Progress' ratepayers exposure to fuel price volatility, while the timing of the contracts will give Progress the flexibility to defer several natural gas-fired plants and potentially move up the in-service date of a coal-fired unit. Given the more certain up-front NPV benefits and additional non-price benefits, we believe the UPS agreements are worth the risk that an expansion plan that includes the agreements may have a negative NPV of between \$5 to \$11 million through 2055. Accordingly, we find that entering into the UPS agreements is a reasonable and prudent action by Progress to maintain its 20 percent reserve margin. Therefore, we hereby approve cost recovery of the energy and capacity costs associated with the UPS agreements between Progress and Southern, subject to our review of the actual expenses in the annual Capacity and Fuel Cost Recovery Clause proceedings.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that the Unit Power Sales Agreements between Progress Energy Florida, Inc. and Southern Company Services, Inc., which are scheduled to take effect June 1, 2010, and expire December 31, 2015, are hereby approved for cost recovery purposes as set forth in the body of this Order. It is further

ORDERED that the provisions of this Order, issued as proposed agency action, shall become final and effective upon the issuance of a Consummating Order unless an appropriate petition, in the form provided by Rule 28-106.201, Florida Administrative Code, is received by the Director, Division of the Commission Clerk and Administrative Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, by the close of business on the date set forth in the "Notice of Further Proceedings" attached hereto. It is further

ORDERED that in the event this Order becomes final, this docket shall be closed.

By ORDER of the Florida Public Service Commission this 14th day of March, 2005.

BLANCA S. BAYÓ, Director
Division of the Commission Clerk
and Administrative Services

By: Kay Flynn
Kay Flynn, Chief
Bureau of Records

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NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing that is available under Section 120.57, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing will be granted or result in the relief sought.

Mediation may be available on a case-by-case basis. If mediation is conducted, it does not affect a substantially interested person's right to a hearing.

The action proposed herein is preliminary in nature. Any person whose substantial interests are affected by the action proposed by this order may file a petition for a formal proceeding, in the form provided by Rule 28-106.201, Florida Administrative Code. This petition must be received by the Director, Division of the Commission Clerk and Administrative Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, by the close of business on April 4, 2005.

In the absence of such a petition, this order shall become final and effective upon the issuance of a Consummating Order.

Any objection or protest filed in this/these docket(s) before the issuance date of this order is considered abandoned unless it satisfies the foregoing conditions and is renewed within the specified protest period.