Robert L. McGee, Jr.
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GULF POWER
A SOUTHERN COMPANY

September 26, 2016

Ms. Carlotta Stauffer, Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee FL 32399-0850

RE: Docket No. 160007-EI

Dear Ms. Stauffer:

Attached for official filing in the above-referenced docket is Gulf Power Company's Notice of Intent to Seek Official Recognition.

Sincerely,

C. Shane Boyett for

Robert L. McGee, Jr.
Regulatory and Pricing Manager

md

Attachments

cc: Beggs & Lane
Jeffrey A. Stone, Esq.
Parties of Record
Chairman Julie Imanuel Brown
Commissioner Lisa Polak Edgar
Commissioner Art Graham
Commissioner Ronald A. Brisé
Commissioner Jimmy Patronis
Keith Hetrick, General Counsel
Braulio L. Baez, Executive Director
Mark Futrell, Deputy Executive Director
Andrew Maurey, Director
Thomas Ballinger, Director
Mary Anne Helton, Deputy General Counsel

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: Environmental Cost Recovery Clause	)	
	)	Docket No. 160007-EI
	)	Filed: September 26, 2016
	)	

GULF POWER COMPANY'S
NOTICE OF INTENT TO SEEK OFFICIAL RECOGNITION

Gulf Power Company ("Gulf" or "the Company"), by and through its undersigned counsel, and pursuant to Section 120.569(2)(i), Florida Statutes and Paragraph VI.F of the Order Establishing Procedure (Order No. PSC-16-0102-PCO-EI), hereby gives notice of its intent to seek official recognition of the documents identified below related to the prior determination of need by the Florida Public Service Commission ("FPSC" or "Commission") for Gulf's ownership interest in Plant Scherer. Some of these documents were recently located in the Florida Department of Environmental Protection's ("FDEP") online OCULUS Document Management System and may not be readily available to all parties. Copies are therefore provided with this notification.

1. Document 1 consists of three submissions by the Commission comprising its report on the need for new generating units at Gulf's Caryville site ("Caryville") to the Florida Department of Environmental Regulation[1] ("FDER") pursuant to the Florida Electrical Power Plant Siting Act ("PPSA"), Sections 403.501 through 403.515, Florida Statutes. Document 1 is the entire Appendix A to the FDER Staff Report dated November 25, 1975, on Gulf's application for certification under the PPSA of the Caryville site and the first two 500 MW units

[1] The Florida Department of Environmental Regulation was the predecessor to the FDEP.

(known as R. F. Ellis Units 1 & 2) to be constructed on that site.[2] Appendix A consists of the three submissions by the Commission that comprise its report to the FDER on the need for the Caryville units as detailed below:

(a) The first submission in chronological order is a letter dated May 2, 1974, from the Executive Director of the FPSC to the Department of Pollution Control[3] pursuant to Section 403.507, Florida Statutes (1973). [Document 1, pp. 77-78] The letter concludes that "there is justification for the addition of the 2-500 MW units, as planned."

(b) The second submission is a letter dated July 16, 1975, from the Senior Electrical Engineer in the Commission's Engineering Department to the FDER resubmitting the recommendation of May 2, 1974. It states that the Commission has requested updated information from Gulf, and concludes that "we will update or supplement our recommendation if our review of such additional information indicates that a modification of our report is warranted." [Document 1, p. 76]

(c) The third submission is the FPSC's "Update of Evaluation of Electrical Need for R. F. Ellis Units No. 1 and No. 2" dated November 10, 1975. [Document 1, pp. 64-75] This document was provided to the FDER and constituted the Commission's final report pursuant to Section 403.507, Florida Statutes (1975). The report states that "it is still the conclusion of this Commission that additional generating capacity is needed to supply the projected electrical demands of Gulf Power Company's customers." [Document 1, p. 65]

2. <u>Document 2</u> is the "Proposed Findings of Fact, Conclusions of Law and Proposed Recommended Order" submitted by the Commission to the Division of Administrative Hearings

[2] This site certification application was processed as Division of Administrative Hearings Case No. 75-436N.
[3] The Department of Pollution control was the predecessor to the FDER.

(DOAH) on January 2, 1976, in connection with Gulf's application for certification of the Caryville units. The Commission's Proposed Conclusion of Law No. 4 states:

> As a matter of law, the uncontradicted evidence presented by the Applicant [Gulf] and the Commission's report requires the conclusion that the area to be served by the proposed plant is the entire service area of the Applicant and that there is a need for electrical generating capacity in that service area which can be met by the proposed plant.

3. Document 3 is Part II of Chapter 403, Florida Statutes (1975). This is the version of the PPSA in effect at the time of the Caryville site certification. Under Section 403.508(4)(a)2, the Commission was a statutory party to the certification hearing. The Commission's reports to FDER in connection with Caryville [Document 1] were submitted pursuant to Section 403.507(1)(a) which required the Commission to "prepare a report and recommendation as to the present and future needs for electrical generating capacity in the area to be served by the proposed site" and to submit its findings to FDER.[4]

4. Document 4 is the order of the Governor and Cabinet, dated May 7, 1976, granting certification for the first two 500 MW units at the Caryville site. There are seven exhibits attached to this order, including three recommended orders by the DOAH hearing officer—the final recommended order on site certification (Exhibit I), the initial recommended order relating to land use (Exhibit II), and an amendment to the initial land use order (Exhibit III). The recommended order on site certification (Exhibit I) notes that reports of the studies required by Section 403.507 were received into evidence. It also recites that one witness testified on behalf of the FPSC and makes a finding of fact that "[a]ll parties involved concurred that there is a necessity for expanded generating capacity to serve Gulf's customers and that the two initial units of 500mw each can meet this requirement." [Exhibit I, p. 2]

[4] Unlike the current version of Chapter 403, in 1975 there was no requirement for a formal determination of need.

5. Document 5 is Commission Order No. 9628 issued November 10, 1980, in Docket No. 800001-EU, Gulf's 1979 test year rate case. The order notes that due to continued decreases in load forecasts, Gulf notified the Commission in 1978 that it wished to obtain the Commission's approval to cancel the Caryville facility and instead purchase a portion of Georgia Power's Plant Scherer (Scherer). The primary issue at the time Gulf proposed to substitute Scherer for Caryville was whether the Commission would allow Gulf to recover the costs it would incur under the various Caryville construction contracts in order to cancel the planned construction ("cancellation charges"). Based on the economic advantage to Gulf's customers of the proposed Scherer purchase, the Commission approved Gulf's request to amortize the Caryville cancellation costs over five years, and to include the unamortized balance in rate base. However, since a contract had not yet been signed to acquire an interest in Scherer as the alternative to Caryville, the Commission required Gulf to hold these revenues subject to refund in the event the purchase of an interest in Scherer was not consummated, or the cancellation of Caryville was not otherwise justified, within one year of the date of the order. [Order No. 9628, pp. 6-7, 26] Thus, the Commission by its orders compelled Gulf to follow through on its plans to acquire an interest in Plant Scherer as the replacement for new generation at Caryville previously determined by the Commission in Document 1 to be needed to serve Gulf's customers in Northwest Florida.

6. Document 6 is Commission Order No. 10557 issued February 1, 1982, in Docket No. 810136-EU, Gulf's 1981 test year rate case. The order stated that in Gulf's last rate case, the Commission had 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." [Order 10557, p. 13] The Commission refused to revisit the issue regarding recovery of the cancellation charges, finding that the

Caryville cancellation had been "fully aired and resolved" in the prior rate case and "nothing of an evidentiary nature has been offered to persuade us to depart from our earlier findings." [Order 10557, p. 14] The Commission did continue the refund condition, pending consummation of the Scherer transaction. The deadline for Gulf to consummate the transaction and be relieved of the refund obligation was extended several times, and the purchase of an interest in Scherer was ultimately closed on October 18, 1984, following approval of the transaction by the Securities and Exchange Commission.

RESPECTFULLY SUBMITTED this 26th day of September, 2016.

JEFFREY A. STONE
Florida Bar No. 325953
RUSSELL A. BADDERS
Florida Bar No. 007455
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Pensacola, FL 32591
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Attorneys for Gulf Power Company

Document No. 1

Appendix A to the FDER Staff Report dated November 25, 1975

WITNESS: JENKINS
CASE NO. 75-07

APPLICATION FOR SITE CERTIFICATION
GULF POWER COMPANY
CAREYVILLE PLANT SITE
R. F. ELLIS ELECTRICAL GENERATING STATION

UPDATE OF
EVALUATION OF ELECTRICAL NEED FOR
R. F. ELLIS UNITS NO. 1 and NO. 2

FLORIDA PUBLIC SERVICE COMMISSION

November 10, 1975

Appendix A
C4

GENERAL

By letter dated July 16; 1975, in compliance with 403.507 F.S., the Florida Public Service Commission provided the Department of Environmental Regulation with the results of our analysis of electrical need for 2-500 megawatt (MW) generating units at the Careyville Plant Site. The actual rating is 518 MW. As explained in said letter, that report was originally submitted on May 2, 1974.

Four months have passed since our re-submittal and nineteen months have passed since the report was originally prepared. During that time the Commission has reviewed revised growth rate of both Gulf Power Company and its parent, the Southern Company. Although the latest growth rates are significantly lower than historical trends, it is still the conclusion of this Commission that additional generating capacity is needed to supply the projected electrical demands of Gulf Power Company's customers.

CONSIDERATION OF RECENT YEARS

In 1974, an abrupt change in the rate of growth in electrical power demands occurred nationwide as well as in Gulf Power Company's territory. Peak power demands generally did not increase in 1975. It is believed that the reduced rate of growth in electric energy consumption is a result of increased costs and the economic slowdown.

The following table clearly indicates the degree of difference between the historical growth rate for the ten-year period ending 1973, and the growth rates for 1974 and 1975:

GULF POWER COMPANY
COMPOUND ANNUAL GROWTH RATES

	1964-1974 10 yr. Average	1973-74	12 mos. ending Sept. 1975 over Sept. 1974
Total Area KWH	9.71%	0.59%	2.07%
Peak Summer Demand MW	9.78%	6.6%	-0.28%
No. Residential Customers	4.42%	5.49%	3.21%

SOURCE: COMPUTED FROM TEN YEAR PLANS AND DATA FURNISHED BY GULF POWER COMPANY

These figures tell an interesting story with conflicting conclusions. First, the growth in energy consumption was virtually nil in 1974 and increased slightly in 1975. Second, although the kilowatt-hour consumption growth rate did increase in 1975, peak megawatt demands showed a slight decrease. However the customer growth appears to be continuing, although at a rate some 25 to 30 percent less than the historical rate. Thus, should economic conditions improve to the point that average customer use returns to historical levels, there will potentially be enough customers to cause a substantial increase in peak power demands.

It should be noted that wide fluctuations and reductions in peak power demands from year to year is not as anomalous as is commonly believed. In this regard, a tabulation of the percent change in peak power demands over the previous year for the four members of the Southern Company is presented on the next page:

HISTORICAL MW PEAK DEMAND PERCENT CHANGE OVER PREVIOUS YEAR

	ALABAMA POWER COMPANY	GEORGIA POWER COMPANY	GULF POWER COMPANY	MISSISSIPPI POWER COMPANY
1965	9.14%	10.62%	6.12%	11.46%
1966	9.84	15.58	10.20	12.89
1967	(1.39)	2.41	5.23	10.03
1968	15.7	26.40	18.55	12.34
1969	8.87	7.53	14.68	18.23
1970	(2.15)	13.00	8.86	(0.42)
1971	5.98	2.26	8.79	2.44
1972	9.56	17.00	13.54	10.77
1973	7.90	7.14	6.07	4.67
1974	4.83	6.71	6.61	3.04
1975	3.45	(0.29)	(0.19)	0.69

(1) denotes negative ( )
(2) Source: Computed from data furnished by Gulf Power Company

Note that in 1968, Alabama and Georgia Power experienced a 15.7 and 26.4 percent increase in peak power demands respectively after a 1.39 percent decrease and a 2.41 percent increase was experienced the prior year. Marked increases were also experienced in 1968 and 1972 by all four companies, while significantly lower increases were experienced in 1967, 1970-71 and 1975. The apparent uniformity in year to year peak power demand increases between each of the companies suggests that underlying factors such as the economy and/or temperature are having a large affect.

The above tabulation also indicates that if generating units were built to meet peak power projections based on one or two years experience; deficiencies or excesses will result depending on which two years the projection was based. It should be emphasized, that within reasonable limits, a greater economic penalty is incurred from generating capacity deficiencies than from excesses.

CONSIDERATION OF GENERATION PLANNING

The question is raised, what significance should be attached to recent events that are contrary to historical trends. The answer involves an understanding of the electrical generation planning process and the characteristics of energy use.

The addition of generating plant is a long lead time process: for combustion turbines, 2-3 years are required; for conventional fossil plants, 4-6 years; for nuclear plants, 10 years is the average planning and construction period. Obviously, generation planning cannot react quickly to sudden changes in usage patterns. The need for increases in generating capability must therefore be based on reasonable forecasts with the realization that undue conservatism will result in shortages that cannot be readily compensated for while ultra liberal forecasts will result in uneconomic excesses. Faced with the inability of generation planning to respond quickly to changing economic patterns due to long lead time requirements, generating capability must be sufficient to meet the most probable peak power growth rate without either jeopardizing the reliability level or causing an unsupportable excess of generating plant.

RESERVE GENERATING MARGINS

Physical limitations on the ability to store appreciable amounts of electricity requires electric utilities to build generating plants to meet forecasted peak power demands with some reserve capability in case of malfunction.

The adequacy of a system's generating capability to provide service is the difference between the generating capability and the peak power demand, ususally expressed as a percent reserve margin. While an adequate reserve margin must be determined on a system by system basis, taking into account individual generating unit sizes, load factor, unit maturities, and forced outage rates, a 15 to 25 percent reserve margin has generally been found by the Federal Power Commission to be adequate for large systems. The desired reserve margin for any system changes as new units are added to the system and as older units are retired. Thus there is no magical number for a percent reserve margin which can be applied uniformly to each electric utility or even to the same electric utility each year.

Percent reserve margins also tend to increase as system size decreases because the outage of any one unit on a small system usually represents a larger percentage of its generating capability. For example, if the 15 to 25 reserve margin criteria were applied to Gulf Power's 1975 peak power demand of 1078 Megawatts, a 162 to 270 Megawatt generating reserve margin would result. However the customers of Gulf Power would be experiencing blackouts every time Crist Unit No. 6, 369.75 megawatts, or Unit No. 7, 578.00 megawatts, tripped off line during the summer months when peak or near peak power demands are experienced. It is common for generating units, particularly new units, to be forced out of service for extended periods. Thus smaller peak power systems such as Gulf Power, often have 50 percent or higher reserve generating margins.

GROWTH RATES IN PEAK POWER DEMANDS

A. Gulf Power Company

Gulf Power, in response to the decreased growth rates in all categories and their general economic outlook for the future, has reduced its projected rate of growth in peak power demands as follows;

	COMPOUND PEAK POWER GROWTH RATE PROJECTIONS
April, 1974 Ten-Year Site Plan	10.92%
April, 1975 Ten-Year Site Plan	9.67%
Recent Revision	8.45%

The latest 8.45% growth rate projection is a 22% reduction of the April, 1974 projection. However, even this reduction in the projected growth rate does not change the need for additional generating capability as indicated on the following page;

FALL 1975

GULF POWER COMPANY, MEGAWATT DEMAND, CAPACITY, AND RESERVE MARGIN PROJECTIONS

Year	Installed Capacity MW	Revised Peak Power Demands MW	Reserve Capacity MW	Reserve Capacity %	Reserve without Ellis Units #1 & #2 MW	Reserve without Ellis Units #1 & #2 %
1975	1567.9	1078(1)	489.9	45	489.9	45
1976	"	1185	382.9	32	382.9	32
1977	"	1297	270.9	21	270.9	21
1978	"	1419	148.9	10	148.9	10
1979	"	1553	14.9	00.9	14.9	00.9
1980	2086.3	1699	387.3	23	-130.7	-6.8
1981	2604.7	1859	745.7	40	-290.3	-13.8
1982	"	2033	571.7	28	-464.3	-20.2
1983	"	2226	378.7	17	-657.3	-26.3
1984	"	2434	170.7	07	-865.3	-31.8

(1) Actual
(2) Source: Gulf Power Company

Based on Gulf Power's current territorial load projections, reserve generating margins are anticipated to go negative in 1980 without the addition of R. F. Ellis Units No. 1 and No. 2.

B. Southern Company

Gulf Power Company is a wholly owned subsidiary of the Southern Company and is closely interconnected with the other subsidiaries - Alabama Power Company, Georgia Power Company and Mississippi Power Company in an integrated energy grid. Because of the physical integration of the facilities of all of these companies, consideration must also be given to the needs of the entire Southern Company system in the planning of additional generating capacity of any one member.

Southern Company is currently projecting a peak power growth rate of 7.96%. The corresponding projected peak power demand, generating capacity, and reserve generating margins with and without Ellis Units No. 1 and No. 2 are shown on the following page:

FALL 1975

SOUTHERN COMPANY, MEGAWATT DEMAND, CAPACITY, AND RESERVE MARGIN PROJECTIONS

Year	Installed Capacity MW	Peak Power Demands MW	Reserve Capacity MW	Reserve Capacity %	Reserve Without Ellis Units #1 & #2 MW	Reserve Without Ellis Units #1 & #2 %
1976	22003	17630	4373	24.8	4373	24.8
1977	23320	19120	4200	22.0	4200	22.0
1978	25182	20600	4582	22.2	4582	22.0
1979	27588	22350	5238	23.4	5238	23.4
1980	29475	24260	5215	21.5	4692	19.4
1981	31873	26130	5743	22.0	4707	18.0
1982	33564	28080	5484	19.5	4428	15.8
1983	35696	30210	5486	18.2	4430	14.7
1984	38129	32630	5499	16.8	4443	13.6
1985	40612	35150	5462	15.5	4406	12.5

(1) 1976 - 1985 compound growth rate equals 7.96%
(2) Source: Gulf Power Company

It should be emphasized that, because of construction delays and new-unit break-in difficulties, planned reserve margins seldom materialize. The required reserve generating margin for the Southern Company is also expected to increase as a result of adding sulfur dioxide scrubbers to an electrical generating unit, which like any major device is subject to malfunction.

C. Need in the Area to be Served

The Plant Siting Act requires the Public Service Commission to report on the need for electrical generating capacity in the area to be served. The Commission has been guided in its consideration of area to be served by its familiarity with the process of generation and transmission and the economics associated with them. Rather than adopting a general definition we have chosen to consider the merits of each case.

Several factors are considered; these include, but are not limited to, (1) the service area of the utility as specifically defined in a legal description or specified by law or as delineated by historical precedent, (2) whether the utility's area is indirectly defined by territorial agreements with neighboring utilities, (3) whether the plant is electrically isolated or integrated within the system of the utility, (4) the extent of interconnection with other utilities, (5) the responsibility for service as defined by statute, ordinance or related documents and (6) the responsibility of the utility in accordance with the intent of Laws of Florida, Chapter 74-196, the "grid bill". With regard to the "grid bill", the Florida Public Service Commission is prevented from abridging Gulf Power Company's relationship with the Southern Company. Indeed there appears to be no electrical justification for doing so.

After considering the previously mentioned factors, it is our judgement that the area to be served should be defined as Gulf Power Company's service area. This area is generally panhandle Florida, west of the Apalachicola River. Gulf Power has the responsibility to provide for the future power needs of its customers and defining the area to be served as Gulf's service area is consistent with this responsibility.

While it is the opinion of the Commission that additional generating capacity is needed in area to be served, the question arises as to just how this need should be satisfied - build R. F. Ellis Units No. 1 and No. 2 or purchase from the Southern Company. Because of its relationship to the Southern Company, Gulf has been able to delay construction of new generating units longer than if Gulf were an isolated system. Additionally, there do not appear to be any large blocks of firm power which can be purchased from Southern in lieu of these units.

CONCLUSIONS AND RECOMMENDATIONS

After due consideration of the factors previously discussed it is our conclusion that additional capacity is needed for the Gulf system. Just as recent trends cannot be ignored, neither can we ignore the historical trends. The continuation of customer growth provides the potential for increased peak demands to continue but at a lower rate of growth. To ignore this potential in light of the slow response of generation construction to changing patterns would seriously jeopardize the ability of the company to provide reliable service. To assume that recent trends are totally indicative of future trends would also require the additional assumptions that the economy will not recover and that people will significantly change their living habits and lose their incentive for improving their material well being.

While it is our conclusion that, based on the information available to us at this time, additional generating capacity is needed to provided for the future needs of Gulf Power's customers, it is our recommendation that Gulf should continue to explore and take advantage of all options for supplying the future power needs of its service area.

CERTIFICATE OF SERVICE

I DO HEREBY CERTIFY that the attached Update of Evaluation of Electrical Need for R. F. Ellis Units No. 1 and 2 was sent to Mr. William White, Department of Environmental Regulation, Koger Office Center, Tallahassee 32303; Mr. Tom Krilowicz, Division of State Planning, 660 Apalachee Parkway, Tallahassee 32304; Mr. Miles Davis, Attorney at Law, Beggs, Lane, Daniel, Gaines and Davis, Post Office Box 12950, Pensacola 32576; and, Mr. Fred T. Dunneman, Route One, Box 23A, Caryville 32427, on November 14th, 1975.

BARRETT G. JOHNSON
Office of General Counsel
Florida Public Service Commission
700 South Adams Street
Tallahassee, Florida 32304

Attorney for the Commission

FLORIDA PUBLIC SERVICE COMMISSION

COMMISSIONERS.
WILLIAM T. MAYO, CHAIRMAN
BILL BEVIS
MRS. PAULA F. HAWKINS

700 SOUTH ADAMS STREET
TALLAHASSEE 32304
TELEPHONE 904-488-1001

July 16, 1975

RECEIVED
JUL 16 1975

Mr. Hamilton S. Oven, Jr.
Administrator,
Power Plant Siting
Department of Environmental Regulation
2562 Executive Center Circle, East
Montgomery Building
Tallahassee, Florida 32301

Dear Mr. Oven:

As you are aware, Gulf Power Company filed a "preliminary application" for certification of the Careyville site on January 22, 1974. Pursuant to your notification of February 7, 1974 and in compliance with Chapter 403.507(1) F.S., the Commission provided a report and recommendation with regard to the site on May 2, 1974.

This office received notice of Gulf Power Company's revised application for certification of the above site on April 22, 1975. This will advise that at this point we have not modified our original assessment of the need for additional generating capacity in the area to be served by the proposed facility. Therefore, we are resubmitting the recommendation of May 2, 1974. However, we have, since receiving the revised application, requested Gulf Power to provide additional and more current data, which requests have not yet been met. As in previous applications, we will update or supplement our recommendation if our review of such additional information indicates that a modification of our report is warranted.

Very truly yours,

FRANCIS SEIDMAN
Senior Electrical Engineer
Engineering Department

FS/cd
CC: Commissioners
Executive Director

Appendix A

May 2, 1974

Mr. Hamilton S. Oven, Jr.
Deputy Executive Director
Department of Pollution Control
2562 Executive Center Circle, East
Montgomery Building
Tallahassee, Florida 32301

Re: Application for Site Certification
Gulf Power Company - Caryville Site

Dear Mr. Oven:

Pursuant to 403.507 F.S., the Florida Public Service Commission has analyzed the above referenced application. According to the cover letter of this application, Gulf Power Company initially contemplates the construction of 2-500 MW plants at the Caryville site. The long range potential capacity of the site is estimated to be 3,000 MWe. The first two units fall with the time frame of the initial ten year site plan and our comments are limited to these units.

It is our conclusion that there is justification for the addition of the 2-500 MW units, as planned. The first unit is expected to be on line to meet the 1979 summer peak. The second unit is expected to be on line to meet the 1981 summer peak.

In evaluating the need for the plants considered herein, consideration is given to the fact that Gulf Power Company operates under formal contractual arrangements as a part of the Southern Companies Power Pool. The purpose of this pool is to achieve economies for the customers of the respective companies through common planning, development and coordination of their operations. One of the advantages of this arrangement is the ability of the companies to stagger construction of the generating facilities necessary to serve their territorial loads so as to attain optimum sizing and the resulting economies of scale.

For the time frame under consideration in this application, the 2-500 MW units proposed to be built by Gulf Power Company will provide sufficient capacity within the system to meet the seasonal peak loads. It will, however, still be necessary for the company to purchase additional power through the pool to provide sufficient margin to maintain an adequate index of reliability. This relationship is illustrated by the following tabulations:

LOAD AND CAPABILITY DATA
(Megawatts)

Period	Peak Load	Gulf Power Company Generating Capability		Purchased Power	Total Capability	Reserve MW	Reserve % of Peak
	1748						
1979 Summer	1933	2114.0	(1)	206.3	2320.3	387.3	20.0
1980 Summer	2140 2068	2114		450.5	2564.5	424.5	19.8
1981 Summer	2374	2632.4	(2)	216.4	2848.8	474.8	20.0

Notes

(1) includes the first 500 MW unit at peak hour capability

(2) includes the first and second 500 MW unit at peak hour capability

The peak load forecast as shown above reflects a reasonable rate of annual growth as compared to historical trends.

If you have any questions regarding our analysis, please contact me.

Very truly yours,

T. MABRY ERVIN
Executive Director

TME/FS/cd

1748
1933
2068 2114

Document No. 2

Proposed Findings of Fact, Conclusions of Law and Proposed Recommended Order

STATE OF FLORIDA
DIVISION OF ADMINISTRATIVE HEARINGS

In re: Application by Gulf Power Company for Power Plant Site Certification, Caryville Steam Plant, Holmes/Washington County, Florida

CASE NO. 75-436

PROPOSED FINDINGS OF FACT, CONCLUSIONS OF LAW AND PROPOSED RECOMMENDED ORDER

The Florida Public Service Commission by and through its undersigned attorney, hereby submits its proposed findings of fact, conclusions of law and proposed recommended order:

FINDINGS OF FACT

1. Applicant Gulf Power Company, hereafter Applicant, submitted the application for site certification required by Section 403.506, Florida Statutes. Hereafter, references to section numbers shall refer to the Florida Statutes, which phrase shall be omitted. An initial public hearing as required by Section 403.508(2), was held which resulted in a favorable recommendation.

2. The Florida Public Service Commission, the Division of State Planning of the Department of Administration and the Department of Environmental Regulation, hereafter respectively the Commission, the Division and the Department, each conducted the study required by Section 403.507.

3. The Commission concluded, following thorough review of the study required by Section 507.507(1)(b), that the Applicant had an integrated system, so that the area to be served by the proposed plant constituted the entire service area of the Applicant and that a need for additional electrical generating capacity exists in that area which could be met by the proposed plant.

4. The Division found that the proposed plant is compatible with the Applicant's ten-year site plant, filed under the provisions of Section 403.505, and recommended certification.

5. The Department staff report concluded, following thorough review of the criteria specified in Section 403.507(2) as to both construction and operation, that the impact of the plant was acceptible, provided the Applicant complied with the conditions of certification

recommended by the Department staff, and accordingly recommended certification for the first two 500 MW units and for the 3,000 MW capacity of the site, subject to supplemental application for additional increments.

6. The Applicant presented testimony concerning the need for the electrical generating capacity of the proposed plant and the area to be served which was substantially in agreement with the findings of the Commission.

7. On the issues of need for additional generating capacity and the area to be served by the proposed plant, there was no evidence presented contrary to the findings of the Commission or the evidence of the Applicant.

8. The proposed power plant site certification proceeding includes five associated major transmission lines, with a total length of approximately 115 miles, of which approximately 33 miles will be routed through new corridors. The routings of these lines is shown fully in exhibit 1. The environmental impact of these lines is considered along with that of the plant itself, pursuant to Section 403.503(7), and is minimal.

9. The Applicant proposes to construct a service corridor to carry intake and discharge water lines and associated facilities from the Choctawhatchee River to the plant, generally along the route shown in Exhibits 12 and 13.

10. The Applicant proposes to construct its service corridor as a causeway costing approximately $216,000. The Department proposes other alternatives, of which the most acceptable is a concrete trestle structure estimated by the Applicant to cost approximately $899,000. Exhibit 15. Cost differentials between the types of structures were not specifically considered by the Department. (Tr. 308, 309, 410 and 411)

11. The Applicant proposes a biological monitoring program limited in time to the construction phase of the first two 500 MW units and of each increment and to the initial operating period. The Department proposes biological monitoring for the entire life of the site, whether or not the biological monitoring program reveals anything, except normal conditions. Needed to assure minimal adverse environ impact mandated by statute

12. The testimony on the cost differential between the two proposed monitoring programs was approximate but was not contradicted and suggests that the Applicant's proposal would cost approximately $100,000 for its total of two years operation as opposed to approximately $100,000 per year for the entire life of the site.

13. Cost differentials between proposals by the Applicant and the Department were not considered by the Department.

14. The Applicant will be required to meet emission and discharge standards set by both state and federal governments to protect the environment.

15. Cost of compliance with any standard or program will ultimately be borne by the customers of the Applicant.

CONCLUSIONS OF LAW

1. The Applicant's application is complete and fully complies with all requirements of law and rules adopted pursuant thereto.

2. Proper notice of all hearings and other proceedings was given to all apprpriate persons as required by law and rules adopted pursuant thereto.

3. The Commission, the Division and the Department performed all studies and made all recommendations in the manner required by law and rules adopted pursuant thereto.

4. As a matter of law, the uncontradicted evidence presented by the Applicant and the Commission's report requires the conclusion that the area to be served by the proposed plant is the entire service area of the Applicant and that there is a need for electrical generating capacity in that service area which can be met by the proposed plant.

5. As amatter of law, General Condition 11.2. proposed by the Department would operate to vary the rulemaking procedure prescribed by the Administrative Procedure Act and would operate to vary Section 403.511, since it could be construed to operate as a waiver of Applicant's rights under Chapter 120 and would appear to be on its face a waiver of the provisions of Section 403.511(1) inasmuch as the Department would not in fact be bound by the certification as that section requires.

RECOMMENDATIONS

From the foregoing and from the record and its exhibits and attachments as a whole, I conclude that the certification sought in this proceeding should be granted, subject to the following terms and conditions:

1. This certification shall be subject to the General and

Special Conditions of Certification as proposed by the Department except as modified herein.

2. Certification at this time shall issue for the first two 500 MW units and for the ultimate site capacity of 3,000 MW, provided that supplemental applications be filed for each subsequent increment in capacity to allow evaluation of each such increment.

3. General Condition 11.a. should be struck in its entirety, and General Condition 11.b. should be amended to read:

> After notice and hearing in accordance with the provisions of Section 120.57(1), Florida Statutes, unless such notice and hearing is waived in whole or in part by the Applicant, the Board may modify the conditions of this certification as required to meet the objectives of Chapter 403, Florida Statutes.

Since the Commission has no institutional expertise in the environmental aspects of this proceeding, the Commission has not proposed any conclusions of law or recommended any specific disposition of the issues raised with respect to construction of the service corridor, the type of biological monitoring program to be imposed, if any, or the use of herbicides as a minor component of weed control in transmission line corridors. However, the Commission would urge consideration of the Applicant's proposals, since they are considerably less expensive in each case, since the cost differentials, and therefore the cost-benefit ratio for each set of proposals, was not considered by the Department, and since all costs will ultimately be borne by the ratepayers of the Applicant, whom the Commission has a duty to protect.

Respectfully submitted,

BARRETT G. JOHNSON
Office of General Counsel
Florida Public Service Commission
700 South Adams Street
Tallahassee, Florida 32304

Attorney for the Commission

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a copy of the foregoing instrument was provided by U. S. Mail to Mr. William P. White, Jr., Department of Environmental Regulation, Koger Office Center, Tallahassee 32303; Mr. Tom Krilowicz, Division of State Planning, 660 Apalachee Parkway, Tallahassee 32304; Mr. Miles Davis, Attorney at Law, Beggs, Lane, Daniel, Gaines and Davis, Post Office Box 12950, Pensacola 32576; and Mr. Fred T. Dunneman, Route One, Box 23A, Caryville 32427, on January 2, 1976.

BARRETT G. JOHNSON

Document No. 3

Power Plant Siting Act (PPSA) - Part II of Chapter 403, Florida Statutes (1975)

which is not required to be licensed under the provisions of chapter 320.

History.—s. 7, ch. 74-110.

403.4152 Joint departmental study and report.—The Department of [1][Environmental Regulation] and the Department of Highway Safety and Motor Vehicles shall jointly undertake a study of the effectiveness of this act during the initial 2 years of its implementation and shall report the results of that study to the Legislature no later than 30 days prior to the convening of the 1977 regular session.

History.—s. 6; ch. 74-110.
[1]Note.—See Note 1, s. 403.415.

PART II

ELECTRICAL POWER PLANT SITING

403.501 Short title.—Sections 403.501-403.515 shall be known and cited as the "Florida Electrical Power Plant Siting Act."

History.—s. 1, ch. 73-33.

403.502 Legislative intent.—The legislature finds that the present and predicted growth in electric power demands in this state requires the development of a procedure for the selection and utilization of sites for electrical generating facilities and the identification of a state position with respect to each proposed site. The legislature recognizes that the selection of sites and the routing of associated transmission lines will have a significant impact upon the welfare of the population, the location and growth of industry, and the use of the natural resources of the state. The legislature finds that the efficiency of the permit application and review process at both the state and local level would be improved with the implementation of a process whereby a permit application would be centrally coordinated and all permit decisions could be reviewed on the basis of standards and recommendations of the deciding agencies. It is the policy of this state that, while recognizing the pressing need for increased power generation facilities, the state shall ensure through available and reasonable methods that the location and operation of electrical power plants will produce minimal adverse effects on human health, the environment, the ecology of the land and its wildlife, and the ecology of state waters and their aquatic life. It is the intent to seek courses of action that will fully balance the increasing demands for electrical power plant location and operation with the broad interests of the public. Such action will be based on these premises:

(1) To assure the citizens of Florida that operation safeguards are technically sufficient for their welfare and protection.

(2) To effect a reasonable balance between the need for the facility and the environmental impact resulting from construction and operation of the facility, including air and water quality, fish and wildlife, and the water resources and other natural resources of the state.

(3) To provide abundant, low-cost electrical energy.

History.—s. 1, ch. 73-33.

403.503 Definitions.—

(1) "Applicant" means any electric utility which makes application for a site location certification pursuant to the provisions of this act.

(2) "Application" means any request for approval of a particular site or sites filed in accordance with the procedures established pursuant to this act.

(3) "Person" means an individual, partnership, joint venture, private or public corporation, association, firm, public service company, political subdivision, municipal corporation, government agency, public utility district or any other entity, public or private, however organized.

(4) "Electric utility" means cities and towns, counties, public utility districts, regulated electric companies, electric cooperatives, and joint operating agencies, or combinations thereof, engaged in, or authorized to engage in, the business of generating, transmitting, or distributing electric energy.

(5) "Site" means any proposed location wherein a power plant, or power plant alteration or addition resulting in an increase in generating capacity, will be located, including offshore sites within state jurisdiction.

(6) "Certification" means the written order of the [1]board approving an application in whole or with such modification as the [1]board may deem appropriate, which order shall constitute a binding agreement between the applicant and the state requiring compliance with the provisions of the order as conditions to be met prior to, or concurrent with, the construction or operation of any electrical power plant coming under this act.

(7) "Electrical power plant" means, for the purpose of certification, any steam or solar electrical generating facility using any process or fuel, including nuclear materials, and shall include those directly associated transmission lines required to connect the electrical power plant to an existing transmission network.

(8) "Department" means the Department of [2][Environmental Regulation].

[1](9) "Board" means the Pollution Control Board.

(10) "Division" means the Division of State Plan-

ning of the Department of Administration.

(11) "State comprehensive plan" means that plan prepared in accordance with the provisions of part I of chapter 23.

History.—s. 1, ch. 73-33.

[1]**Note.**—The board was impliedly abolished by s. 26, ch. 75-22. Section 5(2), ch. 75-22, provides that the Governor and Cabinet shall perform the duties of the Pollution Control Board pursuant to the Florida Electrical Power Plant Siting Act, ss. 403.509, 403.511, 403.512, and 403.513.

[2]**Note.**—Bracketed words substituted by the editors for the words "Pollution Control." See s. 8, ch. 75-22.

403.504 Department of Environmental Regulation; powers enumerated.—The Department of [1][Environmental Regulation] shall have the following powers in relation to this act:

(1) To adopt, promulgate, or amend reasonable rules to carry out the provisions of this act, including rules setting forth environmental precautions to be followed in relation to the location and operation of electrical power plants.

(2) To prescribe the form, content, and necessary supporting documentation for site certification.

(3) To receive applications for final site locations and to investigate the sufficiency thereof.

(4) To make, and contract for when applicable, studies of electrical power plant sites proposed by the applicant.

(5) To conduct hearings on the proposed location of the electric power plant sites.

(6) To require an application fee not to exceed $25,000, such fee to be paid upon each application for certification.

(7) To prepare written reports which shall include:

(a) A statement indicating whether the application is in compliance with the department's rules.

(b) The report from the public service commission setting forth the need for electricity in the area to be served, as required by s. 403.507.

(c) The environmental effects of the construction and operation of the electrical power plant.

(d) A recommendation as to the disposition of the application.

(8) To give adequate public notice and to directly notify all concerned state or local agencies and report any comments received from said agencies to the [2]board and the applicant.

(9) To prescribe the means for monitoring the effects arising from the construction and operation of electrical power plants to assure continued compliance with terms of certification.

History.—s. 1, ch. 73-33.

[1]**Note.**—See Note 2, s. 403.503.

[2]**Note.**—See Note 1, s. 403.503.

403.505 Ten-year site plans.—

(1) Beginning January 1, 1974, each electric utility shall submit to the Division of State Planning a 10-year site plan which shall estimate its power generating needs and the general location of proposed power plant sites. The 10-year plan shall be reviewed and submitted not less frequently than every 2 years.

(2) Upon receipt of the plan, it shall be the duty of the division to make a preliminary study of each plan within 12 months and to classify each proposed plan as "suitable" or "unsuitable." The division may suggest alternate plans. All findings of the division shall be made available to the department for its consideration at any subsequent certification proceedings. It is recognized that 10-year site plans submitted by an electric utility are tentative information only and are subject to change at any time at the discretion of the utility. In its preliminary study of each site, the division shall consider:

(a) The need, including the need as determined by the Public Service Commission, for electrical power in the area to be served.

(b) The anticipated environmental impact of an electrical power plant on the area.

(c) Possible alternatives to the proposed plan.

(d) The views of appropriate local, state, and federal agencies.

(e) Whether there is conformance with the state comprehensive plan.

(3) To enable it to carry out its duties under this section, the division may, after hearing, establish a study fee which shall not exceed $1,000 for each proposed plan studied.

(4) Prior to October 1, 1973, the division shall adopt rules governing the method of submitting, processing and studying the 10-year plans as required by this section.

History.—s. 1, ch. 73-33.

403.506 Applicability and certification.—

(1) Provisions of this chapter shall apply to any electrical power plant as defined herein. No construction of any new electrical power plant or expansion in steam generating capacity of any existing electrical power plant may be undertaken after October 1, 1973, without first obtaining certification in the manner as herein provided, except that this act shall not apply to any such electrical power plant which is presently operating or under construction or which has, upon the effective date of this act, applied for a permit or certification under requirements in force prior to the effective date of this act.

(2) Applications for certification shall be upon forms prescribed by the department and shall be supported by such pertinent information and technical studies as the department may require.

History.—s. 1, ch. 73-33.

403.507 Detailed studies to be conducted.—

(1) It shall be the duty of the department to notify the Division of State Planning and the Public Service Commission within 10 days of receipt of an application for site certification.

(a) The division shall review and update the studies made under the provisions of s. 403.505 and shall present its recommendation to the department within 3 months of receipt of notification.

(b) The Public Service Commission shall prepare a report and recommendation as to the present and future needs for electrical generating capacity in the area to be served by the proposed site and shall submit its findings to the department within 3 months of receipt of notification.

The applicant, at its cost, shall furnish such information, studies, and data as the department, division, or Public Service Commission may direct.

(2) It shall be the duty of the department to conduct, or contract for, a study of the proposed power

generating facility, including, but not limited to, the following site criteria:

(a) Cooling system requirements;
(b) Proximity to load centers;
(c) Proximity to navigable water and other transportation systems;
(d) Soil and foundation conditions;
(e) Availability of water;
(f) Land use;
(g) Accessibility to transmission; and
(h) Environmental impact.

(3) All reasonable expenses associated with the studies required by subsections (1) and (2) shall be paid from the application fee required by s. 403.504(6).

History.—s. 1, ch. 73-33.

403.508 Public hearings.—

(1) The department shall conduct an initial public hearing in the county of the proposed site within sixty days of receipt of an application for site certification. The place of such public hearing shall be as close as possible to the proposed site.

(2) The department must determine at the initial public hearing whether or not the proposed site is consistent, and in compliance, with existing land use plans and zoning ordinances. If it is determined that the proposed site does conform with existing land use plans and zoning ordinances in effect as of the date of the application, the responsible zoning or planning authority shall not thereafter change such land use plans or zoning ordinances so as to affect the proposed site. If it is determined that the proposed site does not conform, it shall be the responsibility of the applicant to make the necessary application for rezoning. Should the application for rezoning be denied, the applicant may appeal this decision to the department, which may, if it determines after notice and hearing that it is in the public interest to authorize a nonconforming use of the land as a site for an electrical power plant, authorize a variance to the existing land use plans and zoning ordinances. [1][In the event no such variance is granted,] no further action may be taken by the department until the proposed site conforms to existing land use plans or zoning ordinances. The initial hearing may consider any other matter appropriate to consideration of the site.

(3) At least one additional public hearing shall be held by the department in the exercise of its functions under this chapter prior to acting upon the application.

(4)(a) The parties to a certification hearing shall include:

1. The applicant.
2. The Public Service Commission and the Division of State Planning.
3. Each county and municipal government and any other state agency which may have an interest in the proposed site, that has filed with the department, not less than 10 days prior to the date set for hearing, a notice of intent to be a party.
4. Any domestic nonprofit corporation or association formed in whole or in part to promote conservation or natural beauty, protect the environment, personal health, or other biological values, preserve historical sites, promote consumer interests, represent commercial or industrial groups, or promote orderly development of the area in which the site is located, that has filed with the department, not less than 10 days prior to the date set for hearing, a notice of intent to be a party.
5. Such other persons as the department or hearing officer may at any time deem appropriate.

(b) Any person may present written or oral testimony relative to the need for, or the effects of, the proposed electrical power plant.

History.—s. 1, ch. 73-33.
[1]Note.—The bracketed language was inserted by the editors.

[1]403.509 Recommendations to Pollution Control Board.—

(1) The department shall consider all evidence presented at the hearings as well as information gathered in any studies, and shall report to the board its recommendations for the disposition of an application for certification no later than 12 months after receipt of such an application, or such later time as is mutually agreed by the department and the applicant.

(2) Within 60 days of receipt of the department's report, the board shall act upon the application by written order, approving in whole, approving with such modification as the board may deem appropriate, or denying the issuance of a certificate and stating the reasons for issuance or denial. If the certificate is denied or approved with modifications, the board shall set forth in writing the action the applicant would have to take to secure the board's approval of the application.

(3) The issuance or denial of the certification by the board shall be the final administrative action required as to that application.

History.—s. 1, ch. 73-33.
[1]Note.—See Note 1, s. 403.508.

403.510 Superseded laws, regulations, and certification power.—

(1) If any provision of this act is in conflict with any other provision, limitation, or restriction which is now in effect under any law or ordinance of this state or any political subdivision or municipality, or any rule or regulation promulgated thereunder, this act shall govern and control, and such other law or ordinance or rule or regulation promulgated thereunder shall be deemed superseded for the purposes of this act.

(2) The state hereby preempts the regulation and certification of electrical power plant sites and electrical power plants as defined in this act.

History.—s. 1, ch. 73-33.

403.511 Effect of certification.—

(1) Subject to the conditions set forth therein, any certification agreement signed by the [1]chairman of the Pollution Control Board shall bind the state or any of its departments, agencies, divisions, bureaus, commissions, districts, or boards as to the approval of the site and the construction and operation of the proposed electrical power plant and major transmission lines.

(2) The certification agreement shall authorize the electric utility named therein to construct and operate the proposed electrical power plant subject

only to the conditions set forth in such certification. The certification agreement may include conditions which constitute variances from nonprocedural standards or regulations otherwise applicable to the construction and operation of the proposed electrical power plant.

(3) The issuance of a site certification shall be in lieu of any permit, certificate, or similar document required by any other department, agency, division, bureau, commission, district, or board of this state or any local agency, including, but not limited to, those documents, permits, or certificates which may be required under chapters 161, 253, 298, 370, 373, 378, 380, 381, and 387, but shall not affect in any way the rate-making powers of the Public Service Commission under chapter 366, nor shall this act in any way affect the right of any local government to charge appropriate fees or require that construction be in compliance with local building codes, standards, and regulations.

History.—s. 1, ch. 73-33; s. 2, ch. 74-170.

[1]Note.—Section 5(2), ch. 75-22, provides that the Governor shall perform the duties of the chairman of the Pollution Control Board as defined in s. 403.511.

403.5111 County and municipal authority unaffected by chapter 75-22, Laws of Florida.—Except as provided in ss. 403.510 and 403.511, nothing in chapter 75-22, Laws of Florida, shall be construed to have altered the authority of county and municipal governments as provided by law.

History.—s. 22, ch. 75-22.

403.512 Revocation or suspension of certification.—Any certification may be revoked or suspended:

(1) For any material false statement in the application or in the supplemental or additional statements of fact or studies required of the applicant when a true answer would have warranted the [1]board's refusal to recommend a certification in the first instance.

(2) For failure to comply with the terms or conditions of the original certification.

(3) For violation of the provisions of this chapter or regulations or orders issued hereunder.

History.—s. 1, ch. 73-33.

[1]Note.—See Note 1, s. 403.503.

403.513 Review.—

(1) The approval or rejection of an application for certification by the [1]Pollution Control Board shall be subject to judicial review.

(2) Any rules and regulations adopted pursuant to this act shall be subject to judicial review.

History.—s. 1, ch. 73-33.

[1]Note.—See Note 1, s. 403.503.

403.514 Enforcement of compliance.—Violations of this act shall be enforced as provided in ss. 403.121, 403.131, 403.141, and 403.161.

History.—s. 1, ch. 73-33.

403.515 Availability of information.—The department shall make available for public inspection and copying during regular office hours, at the expense of any person requesting copies, any information filed or submitted pursuant to this act.

History.—s. 1, ch. 73-33.

PART III

INTERSTATE ENVIRONMENTAL CONTROL COMPACT

403.60 Environmental Control Compact; execution authorized.—The Governor on behalf of this state is hereby authorized to execute a compact, in substantially the following form, with any one or more of the states of the United States, and the Legislature hereby signifies in advance its approval and ratification of such compact:

MEMBER JURISDICTION.—The environmental compact is entered into with all jurisdictions legally joining therein and enacted into law in the following form:

INTERSTATE ENVIRONMENTAL COMPACT

ARTICLE I

FINDINGS, PURPOSES AND RESERVATIONS OF POWERS.—

A. Findings.—Signatory states hereby find and declare:

1. The environment of every state is affected with local, state, regional and national interests and its protection, under appropriate arrangements for intergovernmental cooperation, is a public purpose of the respective signatories.

2. Certain environmental pollution problems transcend state boundaries and thereby become common to adjacent states requiring cooperative efforts.

3. The environment of each state is subject to the effective control of the signatories, and coordinated, cooperative or joint exercise of control measures is in their common interests.

B. Purposes.—The purposes of the signatories in enacting this compact are:

1. To assist and participate in the national environment protection programs as set forth in federal legislation; to promote intergovernmental cooperation for multistate action relating to environmental protection through interstate agreements; and to encourage cooperative and coordinated environmental protection by the signatories and the federal government;

2. To preserve and utilize the functions, powers and duties of existing state agencies of government to the maximum extent possible consistent with the purposes of the compact.

C. Powers of the United States.—

1. Nothing contained in this compact shall impair, affect or extend the constitutional authority of the United States.

2. The signatories hereby recognize the power and right of the Congress of the United States at any time by any statute expressly enacted for that purpose to revise the terms and conditions of its consent.

D. Powers of the states.—Nothing contained in

Document No. 4

Order of the Governor and Cabinet, dated

May 7, 1976

BEFORE THE GOVERNOR AND CABINET
OF THE STATE OF FLORIDA

In re: Application of GULF POWER COMPANY for Power Plant Site Certification, Caryville Steam Plant, Holmes/Washington County, Florida	Division of Administrative Hearings Case No. 75-436N Application No. PS 75-07

The following persons were present and participated in the disposition of this matter:

Honorable Reubin O'D. Askew
Governor

Honorable Bruce A. Smathers
Secretary of State

Honorable Robert L. Shevin
Attorney General

Honorable Philip F. Ashler
Treasurer and Insurance Commissioner

Honorable Gerald A. Lewis
Comptroller

Honorable Doyle Conner
Commissioner of Agriculture

Honorable Ralph D. Turlington
Commissioner of Education

ORDER

THIS MATTER having come on to be heard by the Governor and the Florida Cabinet in exercising their functions under Sections 403.501 through 403.515, Florida Statutes, pursuant to Chapter 75-22, Laws of Florida, the Recommended Orders of the hearing officer, and the Stipulations between the Applicant and the Department having been considered and the parties and the public having been offered an opportunity to make comment and present arguments, it is therefore,

ORDERED, by the Governor and the Florida Cabinet that the Recommended Orders of the hearing officer (Exhibits I, II, and III) are approved and adopted except that they are hereby modified to be consistent with and to include, in the Conditions of Certification (Exhibits IV and V), the language indicated in the Stipulations between the Department and the Applicant (Exhibits VI and VII). Accordingly, Certification for the first two (2) five hundred (500) megawatt units of the proposed facility is hereby issued in accordance with said Recommended Orders as modified herein.

DONE the 4th day of May, 1976.

ENTERED this 7th day of May, 1976, at Tallahassee, Florida.

FOR THE GOVERNOR AND
FLORIDA CABINET:

Reubin O'D. Askew

REUBIN O'D. ASKEW
Governor

VOTE:

FOR:

Honorable Reubin O'D. Askew
Honorable Bruce A. Smathers
Honorable Robert L. Shevin
Honorable Philip F. Ashler
Honorable Gerald A. Lewis
Honorable Doyle Conner
Honorable Ralph D. Turlington

AGAINST:

Copies furnished to:

William P. White, Jr.
DEPARTMENT OF ENVIRONMENTAL REGULATION

Barrett G. Johnson
FLORIDA PUBLIC SERVICE COMMISSION

Louis F. Hubener
DIVISION OF STATE PLANNING

G. Miles Davis
GULF POWER COMPANY

Case File

STATE OF FLORIDA
DIVISION OF ADMINISTRATIVE HEARINGS

In re: Application of GULF POWER COMPANY for Power Plant Site Certification, Carryville Steam Plant, Holmes/Washington County, Florida	CASE NO. 75-436N

Pursuant to notice, the Division of Administrative Hearings, by its duly designated hearing officer, K. N. Ayers, held a public hearing in the above styled cause on December 3 and 4, 1975 at Caryville, Florida.

APPEARANCES:

G. Miles Davis, Esquire, Beggs & Lane, P. O. Box 12950, Pensacola, Florida 32576, representing Gulf Power Company

Barrett G. Johnson, Esquire, 700 South Adams Street, Tallahassee, Florida 32304, representing the Florida Public Service Commission and Division of State Planning

William P. White, Jr., Esquire, 2562 Executive Center Circle East, Montgomery Building, Tallahassee, Florida 32301, representing the Department of Environmental Regulation.

RECOMMENDED ORDER

By this Application, Gulf Power Company (Applicant or Gulf), who is duly authorized to serve customers in the panhandle portion of Florida west of the Apalachicola River, seeks certification as required by §403.501 et seq. F. S. to construct and operate an electrical power plant in the vicinity of Caryville, Florida. Gulf proposes to construct a steam plant capable of generating 3,000 megawatts (mw) of electricity commencing with an initial capacity of 500mw coming on line in 1980 and a second 500mw in 1981. Thereafter the additional capacity up to 3,000mw will be added incrementally as required to meet demand. Cooling water will be drawn from the Choctawhatchee River and after passing through condensers and heat exchangers pumped into 450 foot high cooling tanks where evaporation cooling will occur. Coal will be delivered by rail, unloaded from hopper cars at an unloading trestle and transported to the furnaces by a conveyer. Exhaust from furnaces will be transmitted to the atmosphere through a 700 foot high stack fitted with appropriate equipment to insure the discharge meets environmental standards.

At an original hearing held on June 23, 1975, evidence pertaining to existing land use plans and zoning was presented and on July 22, 1975 a Recommended Order was submitted in which the proposed site was found to conform with existing land use plans and zoning ordinances.

At the instant hearing, conducted pursuant to § 403.508(3) Florida Statutes and Chapter 17-17.11 FAC, evidence was received pertaining to the necessity for the expanded electrical generation, the expected environmental impact of the proposed power plant, the operational safeguards that should be required as a condition to certification, and other public interests to be considered in carrying out the legislative intent of the Florida Electrical Power Plant Siting Law. Detailed studies required by §403.507 F.S. were completed and reports of these studies were received into evidence at this hearing.

Six witnesses testified on behalf of Gulf, one witness testified on behalf of the Public Service Commission (PSC), two witnesses testified on behalf of the Department of Environmental

Regulations (DER) and twenty-three exhibits were admitted into evidence. There were no witnesses or intervenors from the general public or from municipal or county agencies.

FINDINGS OF FACT

All parties involved concurred that there is a necessity for expanded generating capacity to serve Gulf's customers and that the two initial units of 500mw each can meet this requirement.

The parties stipulated that the power plant site certification application submitted by Gulf (Exhibit 1) deals sufficiently with the issue of operational safeguards and further that DER's proposed conditions of certification contain a condition that adequately addresses that issue.

All agencies involved recommended certification; however, DER's recommendation was predicated upon Gulf complying with the general and special conditions or certifications contained in Exhibits 4 and 5. Gulf agreed to all those conditions but three, viz: 1. That the water intake and return lines to the river cross the wetlands on a trestle instead of the causeway proposed by Gulf; 2. A more extensive monitoring program and without termination date than the fixed period monitoring program proposed by Gulf; and 3. Restrictions upon use of herbicides to clear transmission line corridors in excess of those placed by federal and state authorities. In addition DER proposed in general conditions of certification 11(a) and (b) to modify in the future the conditions of certification by any new or more stringent department rule enacted pursuant to Chapter 120 F.S. Gulf objected to this condition of certification and submitted a brief in opposition thereto.

I

With respect to Item #1 above the proposed causeway will occupy some 8 acres of wetlands. It is proposed to commence the causeway at elevation + 58 feet (above MSL), which is the 25 year predicted high water flood level in the Choctawhatchee River flood plain, and continue the causeway some 2400 feet at this elevation to the river bank. The base of the proposed causeway will have a maximum width of 130 feet at a point near the river's edge where the causeway height will be 23 feet (T91). The top width is roughly 60 feet (T90) of which 18 feet will be paved surface. To the north of the access road will be a buried electrical service to carry electricity to the pumps. In the causeway to the south of the access road will be buried two intake lines of 30 inch diameter and one water discharge line. Near the river end of the causeway a vehicle turn-around area will be provided.

The causeway across the wetlands will run in a southwesterly direction from plant site parallel to the principal direction of flood water flow when the river is out of its banks. Five oval-shaped culverts will be placed in the causeway at the lowest points of natural contour and permit water to pass through the causeway to equalize levels on both sides of the causeway. These culverts will be 6 feet wide by 3 feet 8 inches high. During the wet season water will be standing in most of these culverts.

If the causeway were built in the same location, but without culverts, so as to block any flow normal to the causeway, the build up of water on the north side of the causeway would be only 1 or 2 inches at full flood stage of 57 feet (T146)* Accordingly the causeway would have little, if any, effect on the water flow in the wetlands over which this causeway passes; and, but for the 8 acres of wetlands eliminated by the construction of the causeway, the ecological function of these wetlands will be virtually unimpaired. As a collector of

*Although the witness said 60 feet this height would exceed the elevation of the causeway and no build up could result.

sediment from the flood waters the flood plain would also be unimpaired by the construction of the causeway (T154). The cost of constructing the causeway as proposed is $216,000.

As a condition of certification (Ex 5 D 1 b) DER prescribed "a trestle shall be used for access to the platform for all areas west of station 14 + 00." This includes the access across the wetlands and presumably it is DER's position that the intake and discharge pipes from the Choctawhatchee River shall be placed upon a trestle structure rather than upon a causeway. The only evidence presented with respect to the cost of the trestle structure was presented by Gulf that a concrete pile trestle to support the pipes and access road would cost some $900,000. A creosoted pile trestle to perform the same function would cost approximately $600,000 and to provide fire protection for the piling would cost another $250,000, which would place the cost of either type trestle some four times the cost of the causeway. No maintenance costs or useful life comparisons of the trestle and causeway were presented. Both trestle and causeway would require the same corridor to be cleared thus the construction of either would result in the same ecological damage. Thereafter, however, the vegetation and other indicia of wetlands could return under the trestle. While evidence was presented that the causeway would occupy 8 acres of former wetlands no evidence was presented of the area occupied by the piling of the trestle. It is obvious that this would be a small fraction of the area occupied by the causeway, but not necessarily insignificant.

Gulf opposed the trestle concept for two additional reasons. The exposed pipe on the trestle, if of steel, would require painting and would conduct heat from the sun to the water passing through the pipe.

Testimony was presented that ecologists not present had evaluated wetlands in general as having an ecological value of between $1,000 and $20,000 per acre per year. If these figures have economic reality all wetland should have a market value of at least $10,000 per acre. Regardless of this if we assume the values presented are real and the cost for the access corridors are correct, the following economic comparisons can be made. The difference in the cost of the causeway and trestle is approximately $700,000. If this money is borrowed by Gulf at 8 1/2% interest the interest cost is almost $60,000 per year. Since this would be a valid capital expense this interest cost will be reflected in the rates of Gulf's customers. If the wetlands are ecologically worth $7,500 per acre per year the 8 acres here involved would also have a value of $60,000 per year.

In this connection it should be noted that DER's condition of certification specifying trestle across wetlands was based solely on ecological factors and cost was not considered. (T308).

During the course of the hearing considerable evidence was presented regarding a third alternative for piping water to and from the river, viz. in pipes buried across the wetlands. This evidence was insufficient in numerous aspects to give it viability; however, several aspects of this proposal are worthy of note.

Any pipe that is used to carry cooling water requires some degree of slope to permit the pipe to be drained. From a position near SR 179 (where if underground pipes are used the pumps would have to be placed to provide access for maintenance) the pipe could be buried; but, at some point in the flood plain, the pipe would have to be placed upon a trestle to maintain slope to the river's edge (T287).

Burying pipes across the wetlands would have the least ecological impact upon the wetlands. Once the pipe path was trenched, suitable bearing material placed in the trench to support the pipe, the pipe laid and the trench back filled the wetlands would return to natural state and the area involved resume most of the characteristics of wetlands.

Problems associated with this proposal include providing all-weather access to the inside of the pipe; obtaining suction on pumps located 2400 feet laterally and 12 + feet above the level of the water to be pumped; long periods of shutdown in case a section of pipe required replacement; and routine engineering problems in obtaining a constant slope upon installation.

Regardless of the path taken by these pipes some difficulties with corbicula clams are expected. These creatures are endemic to the Choctawhatchee River and will be entrained in the pipe. There they will attach themselves and as they grow restrict the flow in the pipes. Although chlorination at the inlet is expected to help control this problem periodic cleaning of the intake pipes may be required. Accordingly access to these pipes at all stages of the water level in the flood plain is an important concern.

While testimony was presented that it was possible to obtain suction with pumps located 2400 feet laterally and 12 + feet higher than the level of the water to be pumped, it was also acknowledged that this 2400 feet of 30 inch pipe would "probably" have to be primed before the pumps could pick up suction. (T305-306). Cost and feasibility of providing all weather access to the buried pipes, and of providing capability to prime the remote pumps was not presented. Furthermore the cost associated with burying the pipes across the wetlands was not presented. Accordingly this concept should not be further considered.

II

With respect to the biological monitoring program to be carried out by Gulf to determine the effects of the power plant on river organisms, DER, as a condition of certification, proposes a program that will continue for the life of the plant regardless of the conclusions reached from such monitoring. Gulf, on the other hand, proposes a monitoring program to commence prior to the operation of Unit I to determine the base line conditions and continue for one year after commencement of operations of Unit I. Thereafter when Unit II comes on line the monitoring program would be re-instituted and continue for one more year. Since Unit II is scheduled to come on line one year after Unit I the monitoring program proposed by Gulf would actually be continuous for about 2 1/2 years.

All parties generally agreed that monitoring is required to ascertain the ecological effects of the plant on the aquatic life in the river. One type monitoring is needed to determine the effect of impingement and entrainment at the intake. The intake structure is designed so the plane of the intake screen is parallel to the current flow. This largely eliminates impingement of fish and other aquatic life on the intake screen as the current flow would tend to wash aquatic life off the screen. Since water is drawn into the intake at a speed of 1/2 foot per second those aquatic life in the volume of water entering which are small enough to pass through the screens will be entrained and killed in the filters. It is to determine the quantity and composition of the aquatic life so destroyed that this part of the monitoring program is intended. The second part of the monitoring program involves ascertaining the aquatic life in the river above the plant and below the point of discharge of the returned cooling water in order to ascertain the effect of the discharged water on the aquatic organisms.

With respect to the entrainment monitoring there was considerable confusion in the testimony regarding anticipated findings. Gulf's witness stated that at low river and low flow conditions the greatest number of organisms would be entrained. While it is obvious that the greatest percentage of available water will be removed from the river during low flow conditions (since the same quantity or volume of water will be withdrawn as at high flow conditions) it is not obvious that there will be a higher density of aquatic organisms in the river at this same time; and no one so testified. In fact the testimony was that various organisms in the water may change radically (of a magnitude of 1,000 to 1) at various times throughout the year. It would appear that whatever concentration of aquatic organisms that exist in the thalweg of the river would exist in the water withdrawn through the intake pipes and be entrained. Those organisms that exist in slack water portions of the river, swim or otherwise remain out of the current passing near the intake would not be entrained. Thus a sampling point in the current near the intake would provide adequate information on the effects of entrainment. The program proposed by Gulf and contained in Exhibit 21 appears adequate for this determination.

With respect to the monitoring required to ascertain the effects of the plant operation on the river eco-systems Gulf proposed sampling only periphyton while DER's condition of certification (Exhibit 5) provides for a sampling to include phytoplankton, zoo plankton, ichthyoplankton, nutrient analysis, benthos and fish. These samples would be taken at points above and below the plant intake and discharge for the obvious determination of the effects on the river ecological system resulting from the discharge of the used cooling water back into the system. In this regard it should be pointed out that the water to be discharged will be treated to remove heat, solids, and other concentrations that would affect compliance with the EPA standards.

No valid cost estimates for the monitoring program proposed by either Gulf or DER was presented. One witness upon cross examination gave a ball park "guesstimate" of $50,000 per year for Gulf's proposed program and $100,000 per year for DER's program. The witness expressly disallowed any credit for the accuracy of these figures and accordingly they are disregarded. They are inserted here simply because cost of the end product, electricity, is a factor to be considered in determining under what conditions this certification should be granted.

As noted above Gulf proposes to continue the monitoring program for approximately 30 months (until one year after Unit II has come on line) while DER proposes a monitoring program that will continue for the life of the plant. The biological community sampling program contained in Exhibit 5, part II C should be followed. The time during which these programs should be continued will be discussed under Conclusions.

III

All parties generally agreed that the use of herbicides was required to clear vegetation from transmission line corridors in wet areas where mechanical equipment cannot operate. Gulf proposes to use Kuron, a herbicide approved by both state and federal authorities. It will be used in wet areas only at a frequency not to exceed once per year and in accordance with manufacturer's instructions admitted into evidence as Exhibit 22. At the hearing DER appeared to take the position that approval by DER should be obtained prior to each time the herbicide is used. The evidence presented clearly shows that Kuron is a safe non-persistent herbicide which, when applied in accordance with instructions, will cause no harm to untargeted vegetation. All of the transmission line routes were not finalized at the time of the hearing but when the remainder of these corridors are finalized there appears to be no reason that Gulf should not provide DER with a map of these corridors indicating thereon those areas in which herbicides will be used.

IV

No factual evidence regarding general conditions of certification 11(a) and (b) was presented. Accordingly these will be treated solely as a matter of law.

CONCLUSIONS OF LAW

In part II of Chapter 403 Florida Statutes the legislative intent of the Florida Electrical Power Plant Siting Law provides in Section 403.502 in pertinent part:

> "...the state shall insure through available and reasonable methods that the location and operation of electrical power plants will produce minimal adverse effects on human health, the environment, the ecology of the land and its wildlife, and the ecology of state waters and their aquatic life. It is the intent to seek courses of action that will fully balance the increasing demands for electrical power plant location and operation with the broad interest of the public. Such action will be based on these premises:
>
> (1) To assure the citizens of Florida that operation safeguards are technically sufficient for their welfare and protection.
>
> (2) To effect a reasonable balance between the need for the facility and the environmental impact resulting from construction and operation of the facility, including air and water quality, fish and wildlife, and the water resources and other natural resources of the state.
>
> (3) To provide abundant, low cost electrical energy."

Since there is no question of the need for the proposed facility the primary interest that must be balanced are the environmental impact of various courses of action and the cost of these various options.

The first area where such balance must be applied is in the water intake and return corridor between the plant and the river. Although trestle-like structures have been required across other wetlands where power plant sitings were involved, here the only evidence of ecological damage is that resulting from the loss of wetlands area due to the construction of the causeway. The only evidence of cost differential between causeway and trestle was that the trestle would cost some $700,000 more than the causeway. It is the balance of this cost against the loss of 8 acres of wetland that must be made. Based upon findings noted earlier, it is concluded that the causeway construction should be approved.

The principal issue regarding biological monitoring of the water of the Choctawhatchee River is the duration of the program. Insufficient evidence was presented to support DER's position that such monitoring should continue for the life of the plant. On the other hand insufficient evidence was presented regarding the cost of the programs proposed from which a cost benefit analysis and determination can be made. It is therefore concluded that this issue should be reconsidered at a future date.

Whether or not general conditions of certification 11(a) and (b) should be approved presents a serious question of law. These sections provide:

> "(a) upon the adoption by the department of a rule pursuant to Chapter 120, Florida Statutes, containing limitations or requirements applicable to any then continuing or future activities under this certification,

which rule provisions are new or more stringent than the requirements contained herein, the conditions of this certification shall be automatically modified consistent with such rule.

(b) After review of such information as the department deems appropriate, the department may, by order of the Secretary or his designee, modify the conditions of this certification as it deems necessary to attain the objectives of Chapter 403, Florida Statutes. The department shall provide notice and an opportunity for hearing in accordance with Chapter 403 and Chapter 120, Florida Statutes, and rules and regulations adopted pursuant thereto."

Section 403.511(1), Florida Statutes provides:

"The certification agreement shall authorize the electric utility named therein to construct and operate the proposed electrical power plant subject only to the conditions set forth in such certification." (underlining added).

If conditions 11(a) and (b) are included in the certificate this would have the effect of removing all finality from the certification agreement and thereby make it subject to future conditions imposed by an agency. This appears to be in direct conflict with the provisions of the statute above quoted and therefore an unauthorized condition. This is not to say the legislature cannot, at any future date, impose more onerous conditions of operation or restrictions upon Gulf; only that the law now extant militates strongly against an agency retaining such powers as a condition to site certification. Other reasons these conditions should be stricken were submitted by Gulf in its brief in opposition to these conditions. Since I consider the above to be dispositive of the issue those reasons advanced by Gulf are not reached.

From the foregoing it is concluded that Gulf Power Company should be issued a certificate to construct and operate an electrical power plant in Holmes and Washington counties as proposed in its application (Exhibit 1). It is further concluded that the conditions of certification (Exhibits 4 and 5) are valid conditions and should be made a condition of certification except for those conditions requiring trestle across wetlands, water monitoring for the life of the plant, prior approval before using Kuron in transmission line corridors and special conditions 11(a) and (b).

RECOMMENDATIONS

It is RECOMMENDED that the application of Gulf Power Company for a power plant site certificate be granted so as to authorize the construction and operation of a coal-fired steam generating electrical power plant near Caryville, Florida in accordance with Exhibit 1. It is further

RECOMMENDED that this approval be conditioned upon compliance by Gulf with the conditions of certification contained in Exhibits 4 and 5 except conditions II D 1 (b)(Exhibit 5), general conditions 11(a) and (b), (Exhibit 4), and that condition II C (Exhibit 5) be modified to provide such monitoring shall commence not less than six months prior to completion of Unit I and continue for a period of three years after completion of Unit II. At this time Gulf may petition DER for authority to discontinue said monitoring or to modify same and if such request is not approved Gulf shall be entitled to a hearing at which evidence shall be presented from which a determination can be made whether the benefits of said monitoring program justify the costs involved.

DONE and ENTERED this 19th day of January, 1976, in Tallahassee, Florida.

K. N. AYERS
Hearing Officer
Division of Administrative Hearings
Room 530, Carlton Building
Tallahassee, Florida

Copy furnished:

G. Miles Davis, Esquire
Beggs & Lane
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Pensacola, Florida 32576

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Caryville

STATE OF FLORIDA
DIVISION OF ADMINISTRATIVE HEARINGS

IN RE: Application by Gulf Power Company for Power Plant Site Certification Caryville Steam Plant, Holmes/ Washington County, Florida

CASE NO. 75-436N

Pursuant to notice, the Division of Administrative Hearings by its duly designated hearing officer, K. N. Ayers, held a public hearing in the above style cause on June 23, 1975 at Caryville, Florida.

APPEARANCES: G. Miles Davis, P. O. Box 12950, Pensacola, Florida representing the applicant.

Vance W. Kidder, 2562 Executive Center Circle, Tallahassee, Florida, representing the Department of Pollution Control.

RECOMMENDED ORDER

By this application Gulf Power Company (hereinafter referred to as Gulf Power or Applicant) seeks a power plant siting certification in accordance with Section 403.506 et seq. Florida Statutes. The purpose of the hearing, which was conducted pursuant to Section 403.508 Florida Statutes, was to determine whether or not the proposed site is consistent, and in compliance with, existing land use plans and zoning ordinances.

Four witnesses testified in behalf of the application and six exhibits were admitted into evidence. There were no protestants.

The proposed site consists of approximately 1500 acres. It is proposed to construct a coal fired plant consisting of one 500 megawatt unit to put into operation by June 1, 1980. A second 500 megawatt generator is planned for completion no later than June 1, 1981. To meet future power needs, Gulf Power is planning the site to allow potential expansion to a generating capacity of 3,000 megawatts. The intake and discharge will be into the Choctawhatchee River.

Exhibit 1, a plat plan of the site, Exhibit 2, Notices of Publication, Exhibit 3, News release dated June 12, 1975, Exhibit 4, Resolution of Board of County Commissioners of Holmes County, Exhibit 5, Resolution of Board of County Commissioners of Washington County, and Exhibit 6, Resolution of the City of Caryville, were admitted into evidence. The proposed site is partly in the city of Caryville and part of it is in Holmes County, and part in Washington County. By resolution of the Board of County Commissioners of Holmes County (Exhibit 4) the Board of County Commissioners approved the proposed site. That site is consistent with the planning requirements of Holmes County. By resolution of the Board of County Commissioners of Washington County, (Exhibit 5) those county commissioners also approved the proposed site and the resolution stated that the use of the proposed site is in accord with zoning and land use requirements of Washington County. They do not have any zoning laws for the unincorporated area of the county. By resolution of the city of Caryville (Exhibit 6) the city of Caryville approved the proposed use of the site. Caryville does not have any zoning requirements for that part of the land in question which is within the city limits of Caryville.

In view of the absence of protest, the evidence need not be further delineated except to say that the proposed site conforms with existing land use plans and zoning ordinances in effect as of the date of the application. From the foregoing it is concluded that the granting of the application will not be inconsistent with the land use plans and zoning ordinances for the proposed site. It is therefore,

RECOMMENDED that the application of Gulf Power Company for a land use siting certificate be approved so as to authorize the use of a 1500 acre tract of land in Holmes/Washington counties and City of Caryville for a proposed power plant site.

DONE and ENTERED this 22nd day of July, 1975 in Tallahassee, Florida.

K N Ayers

K. N. AYERS
Hearing Officer
Division of Administrative Hearings
Room 530, Carlton Building
Tallahassee, Florida

STATE OF FLORIDA
DIVISION OF ADMINISTRATIVE HEARINGS

In re: Application by Gulf Power Company for Power Plant Site Certification Caryville Steam Plant, Holmes/ Washington County, Florida

CASE NO. 75-436N

AMENDED RECOMMENDED ORDER

By stipulation entered at the final hearing on Gulf Power Company application for certification of the proposed Caryville Steam Plant on December 3, 1975, the applicant, Gulf Power Company and the Division of Environmental Regulations, requested the Hearing Officer modify the initial Recommended Order in this case filed July 22, 1975. At the land use portion of the hearing held on June 23, 1975 the legal description of the site and plats of the area involved were not presented. All parties to this proceeding concur that the plat plan of the site and the legal description of the site should be included in the record in this case. The stipulation and five plat plans having been received by the hearing officer on December 3, 1975, such stipulation is accepted and the hearing officer concurs that the record in this case will be more complete and accurate if the Recommended Order dated July 22, 1975 is amended to reflect the legal description of the site. It is therefore,

ORDERED that the Recommended Order entered July 22, 1975 be amended to reflect the area of the site to be approximately 1900 acres described in accordance with the legal description included on Gulf Power Company Plats B-3877 dated January 27, 1975; B-3878 dated January 14, 1975; C-3863 dated October 26, 1974; E-2744 dated May 18, 1961; and E-3879 dated January 13, 1975 which are attached hereto and incorporated herein.

DONE and ORDERED this 5th day of December, 1975, in Tallahassee, Florida.

K. N. Ayers
K. N. AYERS
Hearing Officer
Division of Administrative Hearings
Room 530, Carlton Building
Tallahassee, Florida

Copy furnished:

William P. White, Jr., Esq.
G. Miles Davis, Esq.
Barrett G. Johnson, Esq.

EXHIBIT III

State of Florida Department of Environmental Regulation
Gulf Power Company
R. F. Ellis, Jr. Generating Station (Caryville Steam Plant)
Case No. PA-76-07
CONDITIONS OF CERTIFICATION

GENERAL (Proposed 11-25-75)

Table of Contents

1. Change in Discharges or Emissions

a. All discharges or emissions which result from the construction or operation of the proposed electrical power plant shall be consistent with the terms of this certification when any operation or construction activity is not specifically described in the certification or regulated by the laws or regulations of the State of Florida, the description in the application shall govern.

b. Causation, in connection with construction or operation, of pollution, as defined in Section 403.031, Florida Statutes, which is not specified in the application or which is more frequent or at levels or in amounts in excess of that authorized herein shall constitute a violation of the certification.

c. Any facility expansions or production increases must be approved, after submission of a supplemental application, prior to any such expansions or increases. Prior to any process modification which will result in new or increased discharges or emissions, the permittee shall obtain appropriate modification of the conditions of certification.

2. Noncompliance Notification

If, for any reason, the permittee does not comply with or will be unable to comply with any condition specified in this certification, the permittee shall notify the appropriate District Manager or District Office of the Department by telephone as soon as it becomes aware that such noncompliance may be anticipated or that it has occurred. The permittee shall confirm such notification in writing as soon as possible but not more than five (5) days after becoming aware of the actual or anticipated noncompliance.

The permittee shall provide, in both instances, the following information:

a. A description of the noncompliance, its cause and effect; and,

b. The period of noncompliance, including exact dates and times; or, if not corrected, the anticipated time the noncompliance is expected to continue, and steps being taken to reduce, eliminate and prevent recurrence of the noncompliance and any impact that might have occurred or may occur from such noncompliance.

3. Facilities Operation

The permittee shall at all times take all actions, deemed necessary by the Department, necessary to maintain in good working order and to operate as efficiently as possible all treatment or control facilities or systems installed or used by the permittee to achieve compliance with the terms and conditions of this certification.

4. Adverse Impact

The permittee shall take all actions deemed necessary by the Department necessary to minimize any adverse impact resulting from noncompliance with any limitation specified in this certification.

5. Right of Entry

The permittee shall immediately allow any authorized representative of the Department, upon the presentation of credentials:

a. To enter upon the permittee's premises where an effluent source is located or in which records are required to be kept under the terms and conditions of this certification; and,

b. To have access to and to copy any records required to be kept under the conditions of this certification or any records or documents relating to or documenting any activity which is controlled by this certification; and,

c. To inspect any monitoring equipment or monitoring method required in this certification and to sample any discharge or pollutants.

6. Revocation or Suspension.

This certification may be suspended or revoked in whole or in part pursuant to Section 403.512 and Chapter 120, Florida Statutes, and any rules or regulations adopted pursuant thereto.

7. Civil and Criminal Liability

Nothing in this certification shall be construed to relieve the permittee from civil or criminal liability for noncompliance with any condition of this certification, applicable rules or regulations of the Department or Chapter 403, Florida Statutes, except for variance granted.

Nothing in this certification shall be construed to preclude the institution of any legal action or relieve the permittee from any responsibilities, liabilities, or penalties established pursuant to any applicable state statutes, or regulations not superceded by the Florida Electrical Power Plant Siting Act.

8. Property Rights

The issuance of this certification does not convey any property rights in either real or personal property, or any exclusive privileges, nor does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of Federal, State or local laws or regulations. The applicant shall obtain necessary authorization from the appropriate agency of the State of Florida to use any state-owned lands occupied by the intake and discharge structures and river access corridors, or any other portion of the electrical power plant, specifically including transmission line facilities.

9. Severability

The provisions of this certification are severable, and if any provision of this certification or the application of any provision of this certification to any circumstances, is held invalid, the application of such provision to other circumstances and the remainder of the certification shall not be affected thereby.

10. Review of Site Certification

a. This certification shall be final unless modified, revoked or suspended pursuant to law. Five years from the date of issuance, the Department shall initiate a review of all monitoring data that has been submitted to it, and any other data which the Department determines to be advisable, for the purpose of determining the extent of the permittee's compliance with the conditions of this certification and the environmental impact of this facility. The Department shall submit the results of its review and recommendations to the permittee. Such review shall be repeated every five years thereafter. This in no way prohibits the Department's undertaking a review of the certification and the permittee's compliance therewith at any other time.

b. One year after commencement of operation of the two 500 MW units certified herein, the Department shall review the monitoring program to determine the necessity for its continuance, supplementation or alteration, if any.

11. Modification of Conditions

The conditions of this certification may be modified in the following manner:

a. Upon the adoption by the Department of a rule pursuant to Chapter 120, Florida Statutes, containing limitations or requirements applicable to any then continuing or future activities under this certification, which rule provisions are new or more stringent than the requirements contained herein, the conditions of this certification shall be automatically modified consistent with such rule.

b. After review of such information as the Department deems appropriate, the Department may, by order of the Secretary or his designee, modify the conditions of this certification as it deems necessary to attain the objectives of Chapter 403, Florida Statutes. The Department shall provide notice and an opportunity for hearing in accordance with Chapter 403 and Chapter 120, Florida Statutes and rules or regulations adopted pursuant thereto.

12. Definitions

The meaning of terms used herein shall be governed by the definitions contained in Chapter 403, Florida Statutes and any regulations adopted pursuant thereto. In the event of any dispute over the meaning of a term used herein which is not defined in such statutes or regulations, such dispute shall be resolved by reference to the most relevant definitions contained in any other statute or regulation or, in the alternate, by the use of the commonly accepted meaning as determined by the Department.

13. Site Certification

These General Conditions and the succeeding Special Conditions apply to Units No. 1 and 2 of 500 MW each of the proposed R. F. Ellis, Jr. Generating Station. Although the site is certified as suitable for an ultimate capacity of 3000 MW, the General and Special Conditions shall be reconsidered and may be modified upon approval of supplemental applications.

State of Florida Department of Environmental Regulation
Gulf Power Company
R. F. Ellis, Jr. Generating Station (Caryville Steam Plant)
Case No. PA 75-07
CONDITIONS OF CERTIFICATION (Proposed 11-26-75)

SPECIAL

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EXHIBIT V 72

State of Florida Department of Environmental Regulation
Gulf Power Company
R. F. Ellis, Jr. Generating Station (Caryville Steam Plant)
Case No. PA-75-07
<u>CONDITIONS OF CERTIFICATION</u> (Proposed 11-26-75)

SPECIAL

I. Air

The construction and operation of the R. F. Ellis, Jr., Generating Station shall be in accordance with all applicable provisions of Chapters 17-2, 17-5, and 17-7, Florida Administrative Code. The permittee shall comply with the following specific conditions of certification:

A. Emission Limitations

1. Stack emissions shall not exceed those specified in Chapter 17-2.04(6)(e)1., FAC.

2. The permittee shall not burn a fuel containing more than an average of 0.7% sulfur unless it can be demonstrated that either, a) heat efficiency is such as to insure compliance with above emission limitations or, b) that a flue gas desulfurization unit is installed that will insure compliance with the above emission limitations.

3. The height of the boiler exhaust stack for Units 1 and 2 shall not be less than 700 feet above grade. The height of stacks for future units shall be determined after review of supplemental applications.

4. The permittee shall provide proof of a contract for low sulfur coal or provide proof of a contract for purchase of a flue gas desulfurization system to meet the above limitations for sulfur dioxide emissions not less than 42 months prior to startup of the power boilers.

B. Air Monitoring Program

1. The permittee shall install and operate continuously monitoring devices for each boiler exhaust for sulfur dioxide, nitrogen dioxide and opacity. The monitoring devices shall meet the applicable requirements of 40 CFR, Part 60, as published in the Federal Register of October 6, 1975. Calculation of SO_2 emissions in accordance with Section 60.45 of 40 CFR, Part 60, may be utilized in lieu of SO_2 exhaust monitoring.

2. The permittee shall provide two continuous ambient monitoring devices for SO_2, one continuous ambient monitoring device for nitrogen oxides, and two ambient monitoring devices for suspended particulates. These devices shall be as described in Table 1-1 and located as shown on Figure 1-1 of these conditions unless the Department and permittee should agree otherwise.

3. The permittee shall maintain a log of fuels used and copies of fuel analyses containing information of sulfur content, ash content and heating values to facilitate calculations of emissions.

4. The permittee shall maintain and operate the meteorological monitoring system described in Table 1-1 of these conditions unless the Department and permittee should agree otherwise.

5. The permittee shall provide sampling ports into each stack and shall provide access to the sampling ports in order that stack sampling may be accomplished. The Department shall approve the location and configuration of the stack sampling ports.

6. The ambient monitoring program shall be reviewed annually by the Department and permittee beginning two years after start-up of Unit No. 1. The monitoring program may be modified by mutual consent of permittee and the Department.

C. Reporting

1. Stack monitoring, fuel usage and fuel analysis data shall be furnished to the Department on a quarterly basis in accordance with 40 CFR, Part 60, Section 60.7.

2. Ambient air monitoring data shall be reported to the Department quarterly by the last day of the month following the quarterly reporting period utilizing the SAROAD or mutually acceptable format. The reporting schedule may be revised upon mutual consent of the permittee and the Department.

II. Water

Discharges during construction and operation of the R. F. Ellis Generating Station shall be in compliance with all applicable provisions of Chapter 17-3, Florida Administrative Code and 40 CFR 423, Effluent Guidelines and Standards for Steam Electric Power Generating Point Source Category. Also the permittee shall comply with the following conditions of certification:

A. Effluent Limitations

1. The zone of reasonable mixing for cooling tower blowdown shall not exceed that area within the 5°F. isotherm produced by a discharge of 19,941 gpm at a daily average temperature of 96°F. at the POD (Monitoring point 002).

2. The blowdown from the cooling towers shall be withdrawn at the point of lowest temperature of the recirculating cooling water prior to the addition of make-up water. Free chlorine and chlorine residual shall be monitored at monitoring point 003 as shown on figure 3.5-7, as attached.

3. Sanitary wastewater shall be collected and treated in an appropriately designed wastewater treatment system that will comply with the applicable sections of Chapter 17-3, Florida Administrative Code. The plant shall be so designed as to provide proper treatment efficiency. Gulf Power Company shall provide the Northwest Florida District Manager of the Department of Environmental Regulation with detailed plans and specifications of the sanitary wastewater treatment system prior to construction of that system. The District Manager shall indicate his approval or disapproval thereof within 60 days of receipt. Gulf Power shall not construct a sanitary wastewater treatment plant until approval has been granted by the Department.

4. Low Volume Waste Sources - (Including but not limited to wastewaters from wet scrubber air pollution control systems, ion exchange water treatment systems, water treatment evaporator blowdown, laboratory and sampling streams, blowdown from recirculating house service water systems) shall not discharge water containing more than the following concentrations of contaminants:

Contaminants	Daily Maximum	30-Day Average
Total Suspended Solids	100 mg/l	30 mg/l
Oil and Grease	20 mg/l	15 mg/l

These sources shall be monitored at the discharge from the wastewater basin prior to the juncture with the cooling tower blowdown line as shown in Figure 3.5-7 as monitoring point 007.

5. Ash Transport Water

The quantity of Total Suspended Solids (TSS) and Oil and Grease discharged in water bleed-off from the bottom ash disposal pond and the fly ash disposal pond shall not exceed the quantity calculated by multiplying the flow of water in the bottom ash transport system times the following factors and dividing the product by 20:

Contaminants	Daily Maximum	30-Day Average
TSS	100 mg/l	30 mg/l
Oil and Grease	20 mg/l	15 mg/l

These contaminants shall be monitored at monitoring point 006 as shown on attached Figure 3.5-7.

6. Boiler Blowdown

The quantity of contaminants discharged in boiler blowdown shall not exceed the following concentrations:

Contaminants	Daily Maximum	30-Day average
Copper	1.0 mg/l	1.0 mg/l
Iron	1.0 mg/l	1.0 mg/l

Iron and copper shall be monitored prior to discharge into the wastewater basin as shown on Figure 3.5-7 at monitoring point 004.

7. Metal Cleaning Wastes

The quantity of contaminants discharged in metal cleaning wastes including preoperational cleaning wastes shall not exceed the following concentrations:

Contaminants	Daily Maximum	30-Day Average
Total Suspended Solids	100 mg/l	30 mg/l
Oil and Grease	20 mg/l	15 mg/l
Copper	1.0 mg/l	1.0 mg/l
Iron	1.0 mg/l	1.0 mg/l
Phosphate	1.0 mg/l	1.0 mg/l

These wastes shall be monitored prior to discharge into the wastewater basin as shown on Figure 3.5-7 and monitoring point 005.

8. Chlorine

The quantity of free available chlorine discharged in the blowdown from the cooling towers shall not exceed 0.5 mg/l at any one time and shall not exceed 0.2 mg/l as an average daily concentration for any thirty consecutive days. Neither free available chlorine nor total residual chlorine may be discharged from any unit for more than two hours in any one day and not more than one unit in any plant may discharge chlorine at any one time, unless it can be demonstrated to the Department that the units at this plant cannot operate under the restriction of this condition.

9. Combined Discharges

Since the waste streams from the various sources are to be combined prior to discharge, the quantity of each contaminant listed in paragraphs II.A.4 thru II.A.7 of this section attributable to each waste source shall not exceed the specific limitation for that waste source.

10. Leachate

Leachate from coal storage piles and ash disposal ponds shall not contaminate the waters of the State (including both surface and groundwaters) in excess of the limitations of Chapter 17-3.

11. Temperature

The maximum 24-hour average temperature of the cooling tower blowdown shall not exceed 96^{o}F. at the end of the discharge pipe at monitoring point 002.

12. Polychlorinated Biphenyl Compounds

There shall be no discharge of polychlorinated biphenyl compounds such as those commonly used for transformer fluid.

13. Ash Pond Collector Wells

The effluent from wells utilized to intercept ash pond leachate shall be returned to the ash sluicing systems as makeup water and shall not be discharged without meeting the limitations of Chapter 17-3, FAC, or condition II.A.5.

B. Water Consumption

1. River Water

The amount of water withdrawn from the Choctawhatchee River shall not exceed 45,000 gallons per minute (gpm) or 7500 gpm per unit for Units No. 1 and 2.

2. Well Water

The amount of water withdrawn from wells shall not exceed 3000 gallons per minute except in case of fire.

C. Water Monitoring and Reporting

The permittee shall monitor and report to the Department the listed parameters on the basis specified. The methods and procedures utilized in the monitoring program shall be approved by the Department. The Department will review the monitoring program annually and determine the necessity and extent of any necessary continuation of the monitoring program.

1. Surface Water

a. The permittee shall monitor and report to the Department on a quarterly basis the following parameters from the following sources during plant operation:

Parameters	Sampling Location	Sample Type	Frequency of Samplers
Flow	Intake/002	Recorder or Pump log	Continuous
Temperature	Intake/002	Recorder	Continuous
pH	" 002	Multiple grabs	1/week
TDS	" 002	grab	1/week
Dissolved Oxygen	002	grab	1/week
Conductivity	002	recorder	Continuous
Free Chlorine Residual	003/008	Multiple grabs	1/week
Total Chlorine Residual	003	Multiple grabs	1/week
Copper	004, 005	grab	1/month
Iron	004, 005	grab	1/month
Arsenic	006	grab	1/month
Chromium	006	grab	1/month
Lead	006	grab	1/month
Oil and Grease	001, 006, 007	grab	1/week
Mercury	006	grab	1/month
Total Phosphorus as PO_4	005	grab	during discharge

b. Ambient Water Monitoring

The permittee shall conduct an ambient water monitoring program for one year after start of operation of each unit. The ambient water monitoring program shall include both surface and ground water and shall include both quality and quantity. The results of the water monitoring program will be submitted to the Department quarterly.

c. Biological Monitoring

1. Entrainment and Impingement

Entrainment and impingement of aquatic organisms and effects due to the cooling water intake system will be monitored and reported. Samples will be collected from the intake screens and water filters at two month intervals to identify species involved and to quantify how many of each species is affected. At the end of each year's collection of data, a report will be prepared in which the significance of the information will be evaluated. Pre-operational background studies may be utilized to estimate the proportion of the total available organisms subjected to impingement and/or entrainment.

2. Methodology

The extent of impingement or entrainment of aquatic organisms will be determined as follows:

a) The screen or filter will be examined for a consecutive 24-hour period once every two months. The collection obtained will be analyzed for:

1) Species present;
2) Number of each individual species caught;
3) Total biomass of each species; and
4) Average size of the individuals caught.

b) Semi-annual Analysis - A qualified biologist will analyze these figures (a, above) every six months to determine the significance in terms of:

1) Stage of development of the organisms;
2) Percent reduction this represents when compared to the total population of the area as determined from background data; and
3) Protection and propagation of the species of the area.

3. Biological Communities

Changes in the aquatic biological communities due to plant operation will be detected by continuation of the biological program. The background biological program that has been conducted for the environmental report will form the basis of this program, with modifications as outlined:

a) Field Sampling

Sampling at different levels of biological organismal complexity will be performed according to the following schedule:

Community	Sampling Frequency
Phytoplankton	Every four months
Zoo plankton	" " "
Ichthyoplankton	" " "
Nutrient Analysis	Every two months
Benthos	" " "
Fish	" " "

b) Cataloging

A cataloging of other developments in the area will be performed. Changes in the area since the background data were collected may influence any biological alternatives, noted.

c) Report

A report will be prepared at the end of each year. It will include a bibliography of literature pertinent to effects of specific chemical and/or physical stresses on species indigenous to the region. Any significant change from the background levels noted in the communities sampled should be detected by the above program. Conclusions will be drawn as to whether or not any changes observed are the result of operation of the power plant.

2. Ground Water Monitoring

a. General

The permittee shall implement and continue after commencement of plant operation of Unit 1, a groundwater monitoring program, as described in Section 6.4 of the application. A ground water monitoring program shall be reviewed annually by the Department, the Northwest Florida Water Management District and Gulf Power Company. The Department will determine the necessity and extent of continuation of the monitoring program, after the first year. The Department may require periodic monitoring as each new unit in placed in operation to assess the impact of the new units.

Quarterly reports on the quality of water in samples collected from the monitoring wells, the ash pond and interceptor wells shall be provided to the Department and the Northwest Florida Water Management District.

b. Ash Pond Monitoring

i. The permittee shall locate the two initial portions of ash pond "A" and the monitoring/interceptor wells where the overburden is hydrologically distinct from the underlying limestone foundation.

ii. If the monthly reports on the monitoring wells indicate significant contamination of the shallow or Floridan aquifer system, then the initial ash disposal ponds shall be sealed, relocated or closed, or the operation of these ash disposal ponds shall be altered in such a manner as to assure the Department that no significant contamination of groundwater will occur. Expansion of ash pond "A" to its ultimate size shall be constructed and/or operated to assure the Department that no significant contamination of ground water will occur.

iii. Gulf Power shall notify the Department and Water Management District of the number and location of interceptor wells to be located around the ash pond areas.

c. Supply Wells

i. Gulf Power Company shall include the Water Management District at the testing and logging of the first production well. Testing for timelevel and distance-drawdown at this first well should be conducted for at least a 36-hour time frame.

ii. Gulf Power shall supply the District with pertinent data on transmissivity and storage values for the shallow aquifer and the Floridan aquifer system when available.

D. Control Measures During Construction

1. River Intake Access Corridor

The river intake access corridor shall be constructed in such a manner as to minimize the environmental impact in the following manner:

a. The access corridor shall be the minimum width necessary to construct the intake/discharge systems.

b. In order to minimize alteration to the natural drainage characteristics, sedimentation patterns, flushing characteristics, and current patterns of the wetlands affected, culverts shall be utilized upland of station 14+00 on the topographic survey. A trestle shall be utilized for access to the platform for all areas west of station 14+00.

c. In excavating for the intake pipes or causeway any material excavated and permanently moved during construction may be utilized as backfill, causeway fill or shall be deposited on an upland area. A peripheral dike berm or other control device shall be constructed, as warranted, around all construction and spoil areas to insure against spillage or discharge of excavated material that may cause turbidity in excess of 50 Jackson Turbidity Units above background in waters of the State.

d. The number, size and specific placement of the culverts along the corride shall be mutually agreed upon by the DER staff and the permittee.

e. Turbidity Control - Turbidity control devices shall be installed as warranted prior to construction or maintenance dredging to insure that turbidity of State waters is not increased more than 50 Jackson Turbidity Units.

2. Stormwater Runoff

During construction and plant operation, necessary measures shall be employed to settle, filter, treat or absorb silt containing or pollutant loaded stormwater runoff to prevent contamination of waters of the State during periods not exceeding a 10 year, 24 hour rainfall event. Such measures may include sediment traps, barriers and use of berms and vegetation. Exposed or disturbed soil shall be protected as soon as possible to minimize silt and sediment runoff into waters of the State. The effluent from detention pond "B" shall be monitored at monitoring point 001 as shown on Figure 3.5-7, as attached, to determine concentrations of suspended solids, oil and grease and that effluent shall not contain suspended solids in excess of 50 mg/l nor shall the pH exceed the range of 6.0 to 8.5 standard units.

3. pH

Chemical releases will be treated if necessary prior to discharge to waters of the State to prevent violations of pH water quality standards.

4. Environmental Control Program

The permittee shall designate a person to implement an environmental control program. A control program shall be established to provide for a periodic review of all construction activities to assure those activities conform to the environmental conditions set forth in the conditions of certification. If unexpected harmful effects or evidence of irreversible damage are detected during facility construction, the applicant shall provide to the Department an analysis of the problem and a plan for action to eliminate or significantly reduce the harmful effects or damage.

III. Operation Safeguards

The overall design and layout of the plant must be such as to minimize hazards to humans and the environment. Security control measures will be utilized to prevent public exposure to hazardous conditions. OSHA standards will be complied with to protect employees and the public.

IV. Solid Wastes

Solid wastes generated by the construction or operation of the certified facility shall be handled and disposed of in accordance with all applicable regulations of Chapters 17-5 and 17-7, Florida Administrative Code. If open burning of refuse or construction wastes is performed in accordance with Chapter

17-5, FAC, no additional permits are required, but the District Forester of the Florida Department of Agriculture and Consumer Services shall be notified. Open burning shall not occur if the Division of Forestry has issued a ban on burning due to fire hazard conditions.

V. Vegetative Screening

The permittee is encouraged to utilize existing vegetation or plantings of indigenous vegetation to screen the coal pile, ash pond and river intake from public view.

VI. Ash Disposal Pond B

The permittee shall continue groundwater hydrologic investigations of the area in which ash disposal pond "B" is located. Prior to construction of ash pond "B", the permittee shall provide evidence to the Department and NWFWMD that said pond is located where the overburden is hydrologically distinct from the underlying limestone formation, or that said pond will be sealed with impervious materials to prevent contamination of the Floridan aquifer from ash pond leachate, or that said ash disposal pond can be operated so as to preclude significant contamination of groundwater.

VII. Potable Water Supply System

The potable water supply system shall be designated and operated in conformance with Chapter 17-22, FAC. Information as required in 17-22.05 shall be submitted to the Department prior to construction and operation. The operator of the potable water supply system shall be certified in accordance with Chapter 17-23, FAC.

VIII. Sanitary Wastewater Disposal System

The sanitary wastewater disposal system shall be operated in conformance with Chapters 17-3, 17-16, and 17-19, FAC.

IX. Disposal of Sanitary Wastes During Construction

Disposal of sanitary wastes from portable chemical toilets during construction shall be handled in conformance with applicable regulations of the Department of Environmental Regulation and with the consent and approval of the appropriate County Health Department. Such wastes may be disposed of in an approved sewage treatment plant or as approved by the Northwest District Manager or the local county health Department.

X. Applicability of Conditions

The preceeding special conditions shall apply to Units 1 and 2 at the Ellis Steam Plant. The applicability of the above conditions to future units at this site will be dependent on review of the supplemental application material and the applicable rules of the Department at the time of application.

XI. Roadway Connections and Crossings

The permittee shall contact and provide details of all connections to or crossings of State and Federal roadways to Mr. E. W. Lee, District Engineer of the Florida Department of Transportation, in the Chipley District office prior to initiation of construction.

XII. Biocides and Herbicides

The use of biocides or herbicides in the cooling towers or on transmission line right-of-ways shall be minimized to the greatest extent practicable. Before any herbicide or biocide not specified in the application is used, the permittee shall notify the Department of the type of chemical compound, location and frequency of use, and concentration to be used. The Department shall indicate approval or disapproval of such biocide or herbicide in writing within 30 days of such notification.

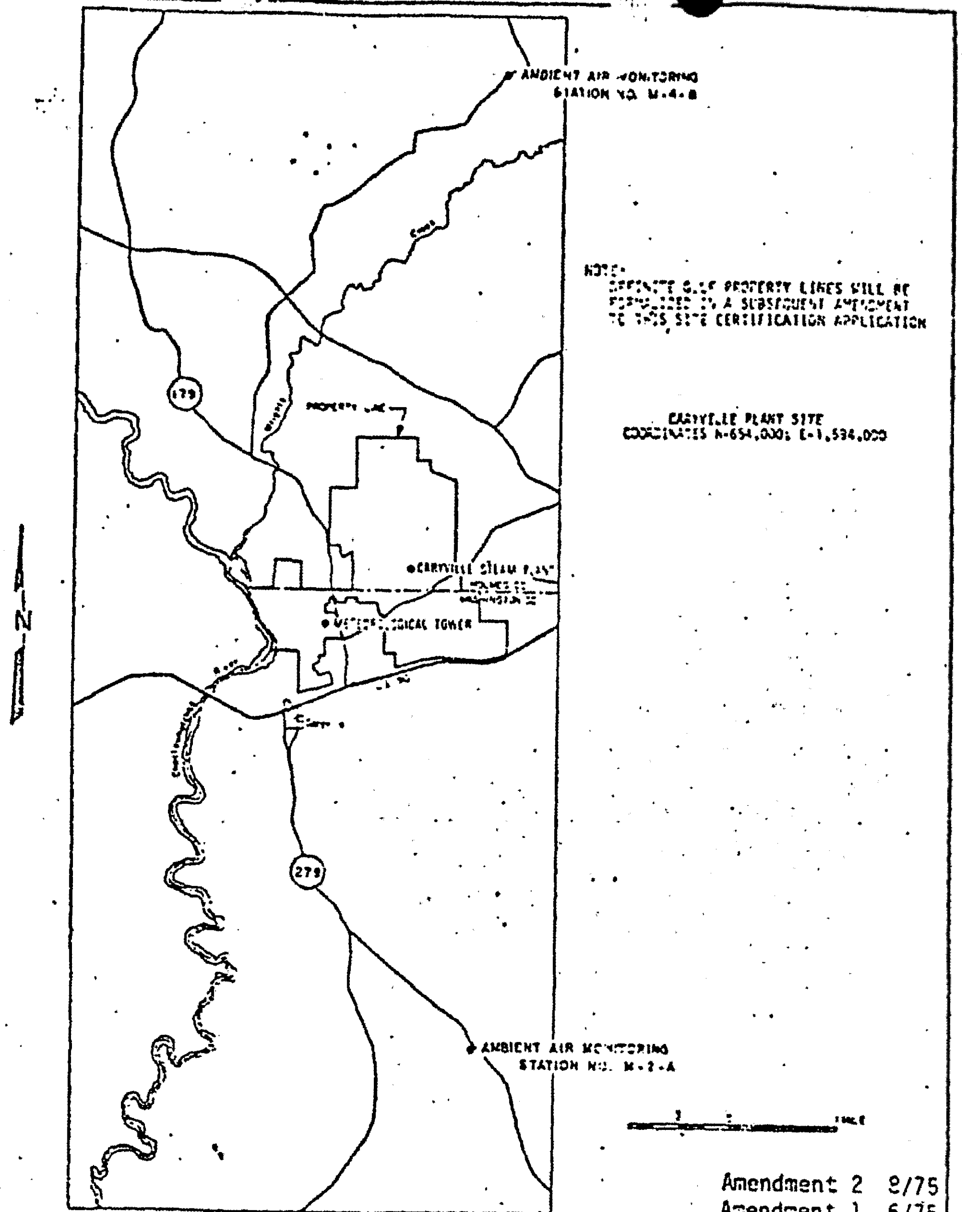
TABLE 1-1

METEOROLOGICAL INSTRUMENTATION AT CARYVILLE SITE

Measured Parameter	Approximate Height Above Tower Base	Range	Accuracy
Wind Speed	195 feet & 33 feet	0-25, 50, 100 mph	±1 percent
Horizontal Wind Direction	195 feet & 33 feet	0 to 540°	±3°
Vertical Wind Direction	195 feet	±60°	±3°
Ambient Air Temperature	33 feet	-5 to +45°C	±0.5°C
Temperature Gradient	195 feet & 33 feet	-5 to +10°C	±0.1°C
Dewpoint Temperature	33 feet	-5 to +45°C	±0.3°C
Wind Direction Sigma	195 feet	0 to 40°C	±1.2°C
Precipitation	Ground	0 to 1"	±0.01"
Solar Radiation	Ground	0 to 2gm-cal/cm^2/min	±1.5 percent
Barometric Pressure	Ground	28.0 to 32.0" Hg	±0.5 percent

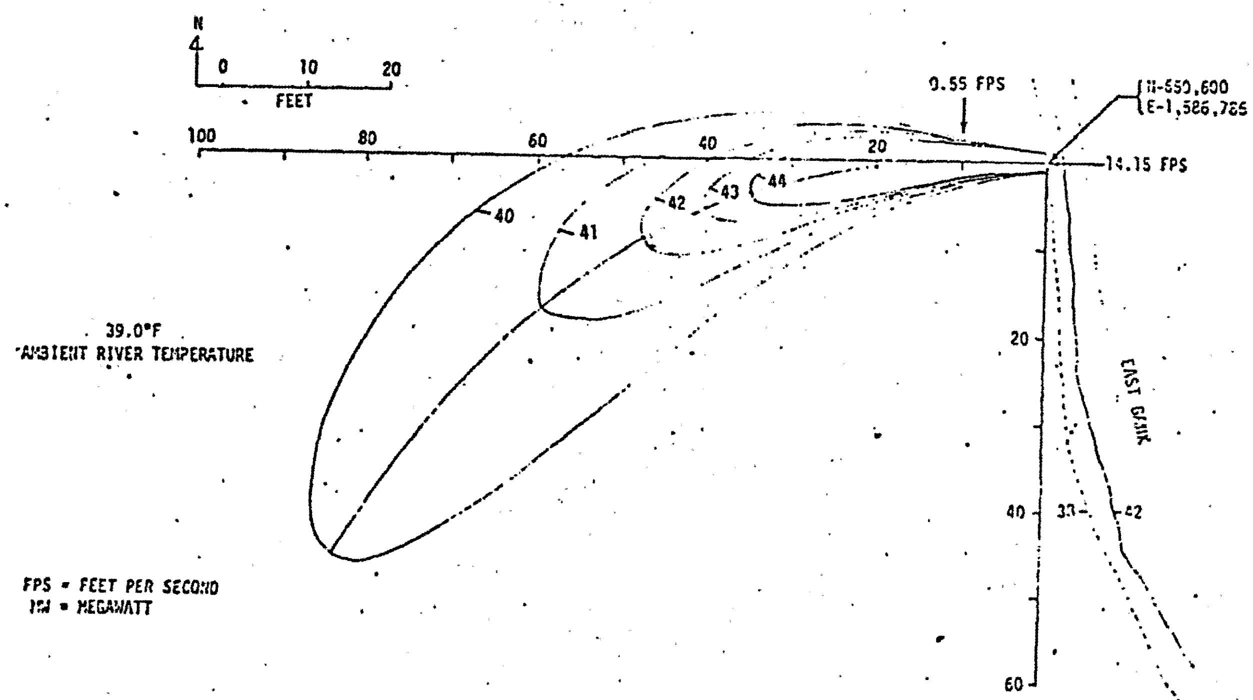
Gulf has installed equipment for onsite measurements in a cleared area west of the plant location as shown in figure 1-1. Sensors for monitoring wind characteristics including wind speed and direction, temperature, and dew point are mounted on a 199-foot tower located near the center of the cleared area. There are no large structures near the tower that could affect meteorological measurements. Equipment for monitoring precipitation, solar radiation, and barometric pressure is located at ground level near the tower. The meteorological instrumentation is described in detail in Table 1-1.

The system that will be used to monitor air quality in the vicinity of the plant is in the final stages of installation, and consists of two ambient air monitoring stations located north and south of the plant as shown in figure 1-1. Ambient air monitoring station No. M-4-B contains a Meloy SA-185-2 sulfur dioxide analyzer, a high-vol participate sampler, and support equipment. Ambient air monitoring station No. M-2-A contains a Meloy SA-185-2 sulfur dioxide analyzer, a Thermo Electron 14D oxides-of-nitrogen analyzer, a high-vol particulate sampler, and support equipment.



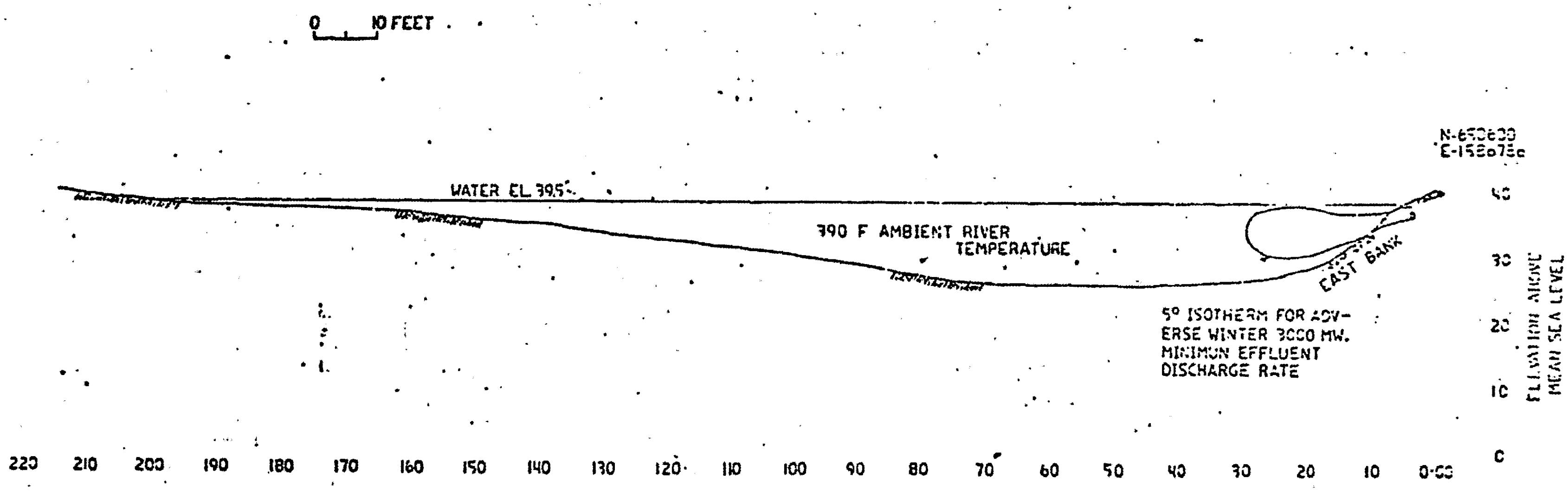
Amendment 2 8/75
Amendment 1 6/75

Gulf Power	GULF POWER CO CARYVILLE STEAM PLANT	LOCATION OF METEOROLOGICAL AND AIR QUALITY MEASUREMENT STATIONS
		FIGURE ~~6.6-1~~ 1-1

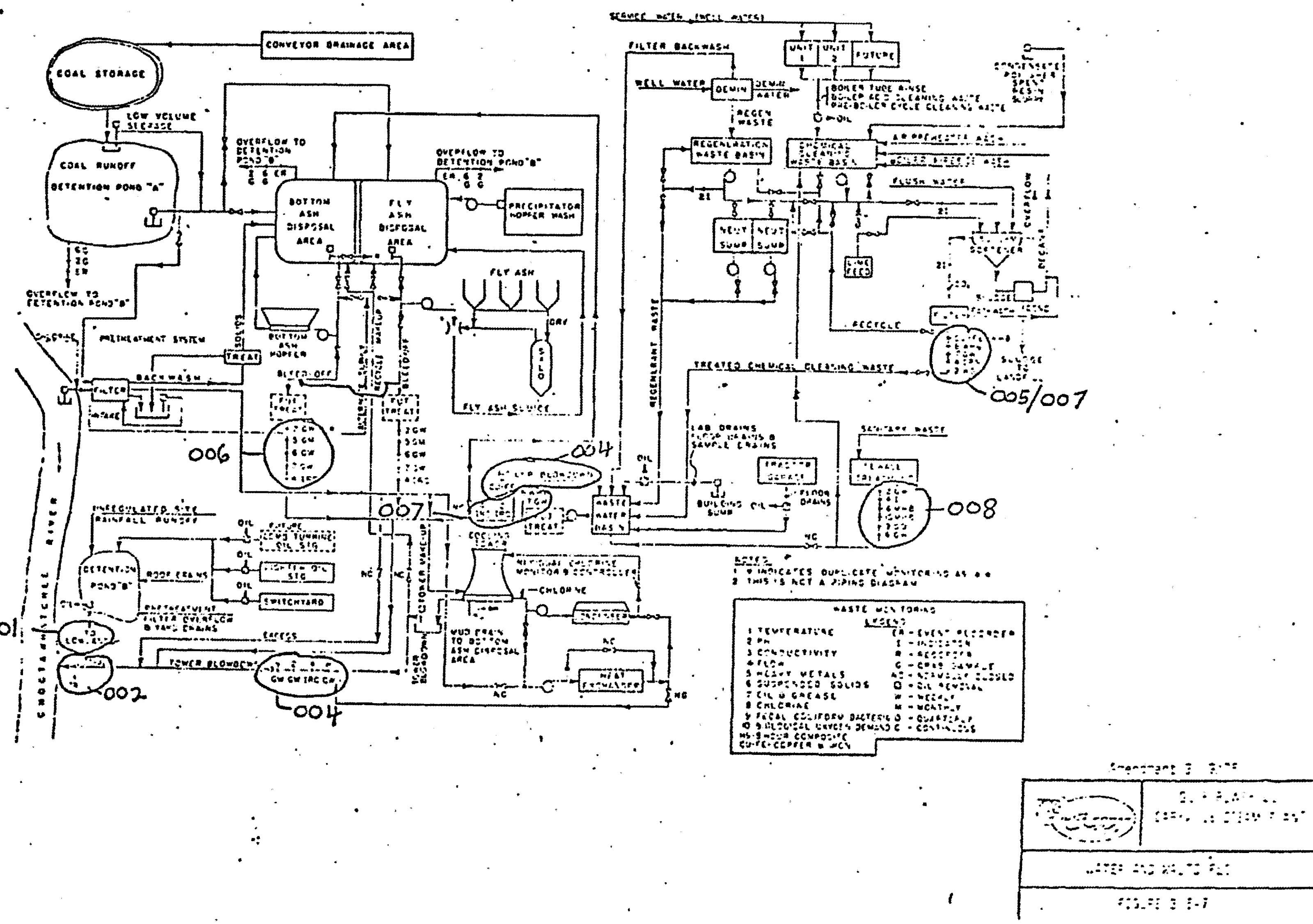


Amendment 3 9/75

[illegible logo]	GULF POWER CO CARY[illegible]LE STEAM PLANT
TEMPERATURE ISOTHERMS [illegible] 3,000 MW CAPACITY, [illegible] AND MAXIMUM PLANT EFFLUENT RATE	
FIGURE 2-1	



RIVER CROSS SECTION AT THE DISCHARGE STRUCTURE


CHOCTAWHATCHEE RIVER
COAL STORAGE
CONVEYOR DRAINAGE AREA
LOW VOLUME SEEPAGE
COAL RUNOFF DETENTION POND "A"
OVERFLOW TO DETENTION POND "B"
BOTTOM ASH DISPOSAL AREA
FLY ASH DISPOSAL AREA
PRECIPITATOR HOPPER WASH
FLY ASH
DRY
SILO
FLY ASH SLUICE
BOTTOM ASH HOPPER
BLEED-OFF
RECYCLE MAKEUP
PRETREATMENT SYSTEM
SOLIDS
TREAT
BACKWASH
FILTER
INTAKE
DISCHARGE
UNREGULATED SITE RAINFALL RUNOFF
DETENTION POND "B"
ROOF DRAINS
PRETREATMENT FILTER OVERFLOW & TANK DRAINS
SWITCHYARD
OIL
EXCESS
TOWER BLOWDOWN
COOLING TOWER
TOWER MAKE-UP
CHLORINE
MUD DRAIN TO BOTTOM ASH DISPOSAL AREA
HEAT EXCHANGER
NC
WASTE WATER BASIN
LAB DRAINS FLOOR DRAINS & SAMPLE DRAINS
BUILDING SUMP
FLOOR DRAINS
SANITARY WASTE
SERVICE WATER (WELL WATER)
FILTER BACKWASH
WELL WATER
DEMIN
DEMIN WATER
REGEN WASTE
REGENERATION WASTE BASIN
REGENERANT WASTE
NEUT SUMP
UNIT 1
UNIT 2
FUTURE
BOILER TUBE RINSE
CHEMICAL CLEANING WASTE BASIN
FLUSH WATER
OVERFLOW
RECYCLE
LIME FEED
TREATED CHEMICAL CLEANING WASTE
001
002
004
005/007
006
007
008
NOTES
1 * INDICATES DUPLICATE MONITORING AS
2 THIS IS NOT A PIPING DIAGRAM
WASTE MONITORING
LEGEND
1 TEMPERATURE
2 PH
3 CONDUCTIVITY
4 FLOW
5 HEAVY METALS
6 SUSPENDED SOLIDS
7 OIL & GREASE
8 CHLORINE
9 FECAL COLIFORM BACTERIA
10 BIOLOGICAL OXYGEN DEMAND
ER - EVENT RECORDER
I - INDICATOR
R - RECORDER
G - GRAB SAMPLE
NC - NORMALLY CLOSED
W - WEEKLY
M - MONTHLY
Q - QUARTERLY
C - CONTINUOUS

BEFORE THE STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL REGULATION

In re: Application of GULF POWER COMPANY for Power Plant Site Certification, Caryville Steam Plant, Holmes/Washington County, Florida	Division of Administrative Hearings Case No. 75-436N Application No. PA 75-07

STIPULATION OF APPLICANT AND DEPARTMENT

COMES NOW, the State of Florida Department of Environmental Regulation and the Applicant, Gulf Power Company, and hereby show that they are in agreement as to the appropriate resolution of three of the issues dealt with at the final hearing before the hearing officer in this matter, to wit: the use of herbicides along transmission line corridors, biological monitoring of the effects of the intake from and discharge into the Choctawhatchee River and modification of certification conditions.

WHEREFORE, the Department and the Applicant agree and hereby request that the conditions and certification contained in Exhibits 4 and 5 entered at the final hearing should be as set forth below:

I. Condition II.C.1.c. of Exhibit 5 (Special Conditions) should be amended to read:

c. Biological Monitoring

1. Entrainment

Entrainment of aquatic organisms and effects of the cooling intake system shall be monitored and reported.

a) Methodology

A composite sample of Choctawhatchee River water shall be collected over a 24 hour period near the intake structure. Mid-depth samples shall

EXHIBIT VI

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be collected every six hours. These aliquots shall form the complete 24 hour composite. Composite samples shall be collected not less than once every two months beginning at least one year prior to startup of the first 500 MW unit.

b) Sample Analysis

(1) Sample analysis shall include: population enumeration; species identification to the lowest practical taxon; biomass estimates; stage of development of fish and macroinvertebrates.

(2) A qualified biologist shall analyze the collected data to determine their significance in terms of: stage of development of the organisms; percent reduction represented when compared to total population of the area as determined from background data; protection and propagation of species in the area.

c) Report

The Applicant shall submit a written report to the department within 45 days of the end of each yearly period of entrainment sampling. Such reports shall include the data derived from the sampling and the analysis of such data.

2. Biological Communities

Changes in the aquatic biological communities due to plant operation shall be monitored and reported.

a) Methodology

The biological program conducted by the Applicant for the environmental report which forms a part of its application shall be utilized for the purpose of supplementing baseline data. Additional

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pre-operational and post-operational data shall be acquired by procedures set forth below:

(1) Field Sampling

Two sampling stations shall be established, the first upstream of the intake structure, the second downstream from the discharge point. Such stations shall be located so as to reflect, as nearly as practicable, whole river conditions prior to intake and subsequent to discharge respectively. Sampling at different levels of biological complexity shall, commencing at least one year prior to startup of the first 500 MW unit, be performed for the communities listed below at, at least, the sampling frequencies specified.

Community	Sampling Frequency
Phytoplankton	Every four months
Zooplankton	Every four months
Ichthyoplankton	Every four months
Nutrient Analysis	Every two months
Benthos (including Periphyton)	Every two months
Fish	Every two months

(2) Cataloging

The Applicant shall catalog other developments in the area affecting the Choctawhatchee River's biological communities which may influence the biological data acquired by sampling.

b) Report

The Applicant shall submit a written report to the department at the end of each year of biological community monitoring. Such reports, prepared by a qualified biologist, shall be submitted within 45 days of the completion of each monitoring period and shall contain: a tabulation of data derived from sampling; an analysis of the data; conclusions as to whether detected changes are the result of operation of the power plant; and, a bibliography of literature pertinent to the effects of specific chemical and/or physical stresses on species naturally occurring in the area sampled which relate or may relate to the Applicant's activities.

II. Conditions 10.b. and c. of Exhibit 4 (General Conditions) should be amended to read:

b. One year after commencement of operation of each unit certified herein, and every three years thereafter, the department shall review the monitoring programs required to be conducted by the Applicant to determine the necessity for their continuance, supplementation or alteration, if any.

c. The monitoring requirements of condition II.C.1.c. of Exhibit 5 (Special Conditions) shall continue for a period of at least one year after startup of Unit II. At any time after one year of operation of Unit I, the Applicant may petition the department for authority to discontinue said monitoring or to modify same and if such request is not approved Applicant shall be entitled to a hearing at which evidence shall be presented from which a determination can be made whether the benefits of said monitoring program justify the costs involved. Submission and response to such a request shall be subject to the provisions of Chapters 403 and 120, Florida

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Statutes, and the rules and regulations adopted pursuant thereto.

III. Condition XII. of Exhibit 5 (Special Conditions) should be altered to read:

XII. Biocides and Herbicides

A. The use of biocides or herbicides in the cooling towers or on transmission line right-of-ways shall be minimized to the greatest extent practicable.

B. Application of the herbicide "Kuron" in transmission line corridors shall be used only upon the following conditions:

1. Application shall be made only at wind speeds of 5 miles per hour or less;
2. Application shall be made only in marsh or other areas not susceptible to mechanical clearing;
3. Application in any given location shall not be made more frequently than once per year; and,
4. Application shall be made only in areas previously identified on maps provided to the department.

IV. Condition 11 of Exhibit 4 (General Conditions) should be amended to read:

11. Modification of Conditions

The conditions of this certification may be modified in the following manner:

A. Upon the adoption by the Department of a rule pursuant to Chapter 120, Florida Statutes, containing limitations or requirements applicable to any then continuing or future activities under this certification, which rule provisions are new or more stringent than the requirements contained

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herein, the conditions of this certification shall be automatically modified consistent with such rule. If such requirements are less stringent than the requirements contained herein, the conditions of this certification which are not referred to by [illegible] reference to the Florida Administrative Code, shall be automatically modified consistent with such rule. In the application of such later adopted rule, this paragraph shall not be construed to mean that the R. F. Ellis, Jr. plant is a new source if a distinction between new and existing sources is made within the later adopted rule.

B. On its own motion or on petition of the applicant and, after review of such information as the Department deems appropriate, the Department may, by order of the Secretary or his designee, modify the conditions of this certification as it deems necessary to attain the objectives of Chapter 403, Florida Statutes. The Department shall provide notice and an opportunity for hearing in accordance with Chapter 403 and Chapter 120, Florida Statutes and rules or regulations adopted pursuant thereto.

STIPULATED to on behalf of the Department and Gulf Power Company this 28th day of April, 1976.

[signature]
Attorney for Gulf Power Company

[signature]
Attorney for the Department

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BEFORE THE STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL REGULATION

In re: Application of GULF POWER COMPANY for Power Plant Site Certification, Caryville Steam Plant, Holmes/Washington Counties, Florida	Division of Administrative Hearings Case No. 75-436N Application No. PA 75-07

STIPULATION OF DEPARTMENT AND APPLICANT

COME NOW the State of Florida Department of Environmental Regulation and the Applicant, Gulf Power Company, and hereby show that they are in agreement as to the appropriate resolution of one of the issues dealt with at the final hearing before the hearing officer in this matter, to wit: the method of construction to be utilized in the corridor of the cooling water intake and discharge lines.

WHEREFORE, the Department and the Applicant agree and hereby request that the conditions of certification contained in Exhibit 5 entered at the hearing should be as set forth below:

I. Condition II.D.1.b. of Exhibit 5 (Special Conditions) should be amended to read:

b. In order to minimize alteration of the natural drainage characteristics, sedimentation patterns, flushing characteristics, and current patterns of the wetlands affected, culverts shall be utilized.

II. A new subpart "f." should be added to Condition II.D.1. after the existing subpart "e." which should read as follows:

f. The causeway side slopes shall be vegetated to prevent erosion. Riprap shall be placed on areas of the causeway which will be subjected to water velocities greater than three (3) feet per second. If severe erosion of the causeway results from water velocities less than

EXHIBIT XII   47

three feet per second, riprap shall be put in place to prevent future erosion.

STIPULATED to on behalf of the Department and Gulf Power Company this 28th day of April, 1976.

Attorney for Gulf Power Company

Attorney for the Department

Document No. 5

Commission Order No. 9628 issued

November 10, 1980

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 Process

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 $1,255,585 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 heen 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 $16,617 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 94.13298%	(286,707)
Consolidated Tax Return Adjustment $199,872 x 100%	199,872
Advertising Expenses $79,822 x .513 x 94.13298%	38,546
Industry Association Dues $8,662 x .513 x 94.13298%	4,183
Charitable Contributions $(267) x .513 x 94.13298%	(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 14.85% 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
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%	
Adjusted 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

Document No. 6

Commission Order No. 10557 issued

February 1, 1982

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:

Construction Work In Progress

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.

<u>Working Capital Allowance</u>

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 pericd 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:

Bank Service Charges

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

	1981
With Plant Daniel	
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:

Rate Base

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.

Income Statement

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.

Seasonal Rates

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: **Environmental Cost**)
Recovery Clause) Docket No.: **160007-EI**

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy of the foregoing was furnished by electronic mail this 26th day of September, 2016 to the following:

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