ORIGINAL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Review of Florida Power Corporation's Earnings, Including Effects of Proposed Acquisition of Florida Power Corporation by Carolina Power & Light

DOCKET NO. 000824-EI

Submitted for Filing:
March 18, 2002

FLORIDA POWER CORPORATION'S
REQUEST FOR OFFICIAL RECOGNITION
VOLUME V

44. *In re* increase in Gulf Power's rates and charges, Order No. 11498, Docket No. 820150-EU, 1983 Fla. PUC LEXIS 1065, 83 FPSC 59 (Fla. P.S.C. January 11, 1983).

45. *In re* Gulf Power authority to increase its rates and charges, Order No. 14030, Docket No. 840086-EI, 1985 Fla. PUC LEXIS 969, 85 FPSC 245 (Fla. P.S.C. January 25, 1985).

46. Bluefield Water Works, 262 U.S. 679 (1923).

47. Federal Power Comm'n v. Hope Natural Gas, 320 U.S. 591 (1944).

48. *In re* fuel adjustment clause of Electric Utilities, Order No. 12645, Docket No. 830001-EI, 1983 Fla. PUC LEXIS 163, 83 FPSC 12 (Fla. P.S.C. November 3, 1983).

49. *In re* proposed electrical power plant and related facilities, Polk County Units 1-4, Order No. 25805, Docket No. 910759-EI, 1992 Fla. PUC LEXIS 389, 92 FPSC 2:659, Fla. P.S.C. February 25, 1992).

In re: Petition of Gulf Power Company for an increase in its rates and charges

DOCKET NO. 820150-EU (CR); ORDER NO. 11498

Florida Public Service Commission

1983 Fla. PUC LEXIS 1065

83 FPSC 59

January 11, 1983

CORE TERMS: customer, rate base, plant, inventory, projected, coal, working capital, peak, capital structure, staff, rate case, ratepayer, retail, fuel, approve, energy, load, conservation, net operating income, operating expenses, rate of return, load factor, allowance, allocated, deferred, nameplate, revised, recommended, forecast, tariff

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[*1]

The following Commissioners participated in the disposition of this matter: GERALD L. GUNTER, JOHN R. MARKS, III, SUSAN W. LEISNER

Pursuant to duly given Notice, [*2] the Florida Public Service Commission held public hearings in Pensacola, Florida, on August 11, 1982; Fort Walton Beach, August 12, 1982; Panama City, Florida, August 13, 1982; and in Tallahassee, Florida, on October 5-8 and 11-14, 1982. Having considered the record herein, the Commission now enters its final order.

ORDER AUTHORIZING CERTAIN INCREASES

BY THE COMMISSION:

SUMMARY OF DECISION

In this Order, we have determined that Gulf Power Company, (Gulf, the utility or the Company) should be authorized an increase in gross revenues of $3,366,000 annually. Gulf did not request an attrition allowance in this proceeding and none was granted. An index to this order appears on Appendix A of this order and a summary of adjustments is set forth on Appendices B and C of this order.

BACKGROUND

This proceeding was commenced on June 4, 1982, by the filing of Gulf Power Company's Petition for a rate increase that would provide $36,944,000 of additional annual revenue. This Commission suspended the proposed rates on June 23, 1982, by Order No. 10919. Gulf did not request interim rate relief.

Extensive public hearings on Gulf Power Company's request have been held [*3] in this docket. These hearings extended over 11 days and resulted in a record comprising 2,952 pages of transcript and 267 exhibits. We have also had active participation by numerous parties, including representatives of the public, governmental agencies and large industrial customers.

THE PARTIES

Gulf Power Company

Gulf Power Company is a wholly owned subsidiary of the Southern Company and is subject to our jurisdiction under Chapter 366, Florida Statutes. The Company has been engaged in the electric utility business since 1925, operating in 10 counties in the State of Florida, serving approximately 217,000 customers.

The Company was last authorized to adjust its rates in 1982, (Order No. 10557, Docket No. 810136-EU, 2/1/82). At that time, we determined that the Company's fair rate of return fell within the range of 9.40%-9.94%. Gulf now asserts that to maintain its financial integrity and to provide reliable electric service, it must have additional gross annual revenues totalling $36,944,000. This increase, according to the Company, is required to provide the opportunity to earn an overall rate of return of 10.46%, which it alleges is fair and reasonable under [*4] prevailing conditions and which would allow for a rate of return on common equity of 18.0%.

Public Counsel

Pursuant to Section 350.061, Florida Statutes, the Public Counsel is appointed by the Joint Legislative Auditing Committee to represent the general public of Florida before the Florida Public Service Commission.

The Office of the Public Counsel (Public Counsel) presented the testimony of three witnesses during this proceeding. Public Counsel proposed that the Commission establish an average rate base of $688,690,000, a return on equity of 15.05%, and an overall rate of return of 9.61%. Among other things, Public Counsel objected to the use of 1983 as the test year and to the inclusion of CWIP in rate base. In addition, Public Counsel proposed that working capital should be established by the balance sheet approach, that industry association dues, charitable contributions, and all advertising expenses be disallowed from operating expenses. Public Counsel also advocated that Gulf's entire interest in Plant Daniel be included in the retail rate base.

Air Products, et al.

Air Products and Chemicals Company, American Cyanamid Company and Monsanto Textiles [*5] Company, customers of Gulf Power Company who are members of the Florida Industrial Power Users Group (FIPUG), intervened in this proceeding. These intervenors sponsored witnesses on the subject of rate design.

Federal Executive Agencies

The Federal Executive Agencies of the United States intervened in this proceeding, sponsoring witnesses on the subjects of accounting, cost of capital and rate design.

St. Regis Paper Company

St. Regis Paper Company presented testimony on the subject of rate design.

The Commission Staff

The Commission staff participated in the proceeding and presented the testimony of one witness dealing with the number and nature of consumer complaints against the Company.

REVENUE REQUIREMENTS DETERMINATION

The revenue requirements of a utility are derived by establishing its rate base, net operating income and fair rate of return. A test period of operations, traditionally based upon one year of operations, is used to derive these factors. Multiplying the rate base by the fair rate of return provides the net operating income the utility is permitted to earn. Comparing the permitted net operating income with the test year net operating [*6] income determines the net operating deficiency or excess. The total test year deficiency or excess is determined by expanding this deficiency or excess for taxes.

THE TEST YEAR

The function of a test year in a rate case is to provide a set period of utility operations that may be analyzed so as to allow the Commission to set reasonable rates for the period the rates will be in effect. A test period may be based upon an historic test year with such adjustments (often extensive) as will make it reflect typical conditions in the immediate future, and make it reasonably representative of expected future operations. Alternatively, a test period may be based upon a projected test year which, if appropriately developed and adjusted, may reasonably represent expected future operations.

In other recent major electric utility cases, 1982 was used as the test year. Thus, as the other cases progressed we could compare actual data with forecasted data as a check on the reasonableness of the forecasted data. However, in this case, Gulf proposed calendar year 1983 as the test year. Gulf argued that use of a 1983 test year is appropriate because it will recognize cost levels [*7] that will be in effect when the new rates are in effect. Both Public Counsel and the FEA vigorously opposed use of a 1983 test year on the ground that use of 1983 forecast data was too far removed from available actual data to be adequately reviewed. There is some merit in the arguments of both parties. We must therefore weigh the benefit of a more exact match between the test period examined and the period in which rates will be in effect against the disadvantage of increased reliance on forecast, as opposed to actual, data.

In this case only, we are persuaded that the merits of a fully projected test year outweigh its disadvantages. By the time hearings were held in this case, October, 1982, actual data for 1981 was available as was data through June, 1982. This allowed a thorough review of 1981 actual to 1982 forecast and 1982 actual data. We also thoroughly reviewed the link between 1982 forecast and 1983 forecast data. Extensive testimony was received concerning the budgeting process and forecasting methods used by the Company to substantiate the projected test year rate base and NOI. Mr. Scarbrough, adopting Mr. Gilbert's testimony, provided an overview of the planning [*8] process, discussing the planning and budgeting process, and the assumptions used in developing the financial forecast. He also discussed the operation and maintenance budget process. Mr. Parsons testified about the operation and maintenance expenses of the Company, the construction budget, the generation expansion plan, the fuel program and Gulf's relationship with Southern Company Services. Mr. Shearer presented testimony concerning the 1983 forecast of the number of customers and energy sales, and the 1982-1991 forecast of customer and energy sales. Mr. Oerting discussed the development of both the short-range and long-range forecasts of the peak hour demand requirements of the Company's service area. Mr. Ludwig addressed the Company's fossil fuel procurement policies and practices. Mr. Scarbrough presented the Company's revenue requirements, rate base and net operating income and explained the adjustments that were made in these areas. His testimony concerned the end result of the Company's financial forecasting process.

Mr. Bell, a partner in the firm of Arthur Andersen and Company, performed a review of the budget or forecasting system used by the Company to [*9] develop the projected rate base and NOI. He stated that the Company's financial forecasting system was evaluated using the professional standards outlined in the AICPA's Guidelines for Systems for the Preparation of Financial Forecasts. Based on his review, Mr. Bell concluded that the financial forecasting system and the procedures employed in the preparation of the forecasted data complied with the guidelines of the AICPA, except for the fact that the Company did not include economy energy transactions in the forecast.

Mr. Bell did note, however, several areas where there were significant variances between the assumptions used by the Company and conditions as they subsequently developed. These areas were the inflation rates, long term debt and the additional revenues allowed the Company after this rate case filing was made.

We find that the Company's rate base, net operating income and capital structure are generally based upon reasonable projections and assumptions and that the forecasting methodology employed by the Company is reasonable. There are, however, certain areas where we question the reasonableness of specific projections and assumptions. These areas will be [*10] identified and addressed as separate issues. Except for these specific areas, the evidence presented demonstrates that the assumptions and projections relied upon by the

Company in presenting its 1983 test year data are reasonable and may be relied upon as a basis for setting rates. As adjusted herein, we believe the test period reasonably represents expected operations during the period the rates will be in effect.

RATE BASE

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

Gulf Power has submitted a proposed jurisdictional rate base of $674,607,000. Evidence developed during the course of the proceeding has led us to reduce that amount to $636,896,000. [*11] Our adjustments are set forth as follows:

Rate Base Adjustments
$ (000)

		Per Company	Adjustments	As adjusted
A.	Utility Plant in Service	$751,035	$ 24,094	$775,129
B.	Accumulated Depreciation and Amortization	220,509		220,509
C.	Net Utility Plant in Service	530,526	24,094	554,620
D.	Construction Work in Progress	30,128	(24,094)	6,034
E.	Property Held For Future Use	2,291		2,291
F.	Net Utility Plant	562,945	0	562,945
G.	Working Capital	111,662	(37,711)	73,951
H.	Total Rate Base	$674,607	$ (37,711)	$636,896

A. Utility Plant In Service

The amount of plant in service originally proposed by the Company is $751,035,000. Utility plant in service should be increased to $775,129,000. Of the total amount of CWIP requested for inclusion in the rate base by the Company, $24,094,000 will begin commercial operation in 1983 and is more properly classified as plant in service in the test year.

B. Accumulated Depreciation and Amortization

The amount of accumulated depreciation and amortization originally proposed by the Company is $220,509,000. This is the proper amount and no adjustment is necessary. [*12]

C. Net Utility Plant In Service

Net plant in service is comprised of utility plant in service, less accumulated depreciation and amortization. We find that the appropriate amount of net utility plant in service for the test year is $554,620,000, based upon $775,129,000 of utility plant in service and $220,509,000 of accumulated depreciation and amortization.

D. Construction Work In Progress (CWIP)

In its original filing, the Company requested that $31,138,000 (juris.) of CWIP be included in its rate base. During cross-examination, Mr. Scarbrough indicated that of the $31,128,000 total, construction projects accounting for $24,094,000 will begin commercial operation in 1983. We think these projects are more properly classified as plant in service rather than CWIP. We must then determine whether the remaining $6,034,000 (including $3,918,000 of non-interest bearing CWIP) should be included in the rate base. In recent electric utility rate cases, we have articulated our policy of allowing some CWIP in rate base if it is necessary to establish or maintain the Company's financial integrity. It is our belief that including CWIP in the rate base increases [*13] cash flow and coverage ratios, and decreases the percentage of earnings comprised of AFUDC and that the resulting strengthened financial integrity of the utility leads to a lower cost of capital. Although financial integrity is a relative phenomena, it can best be measured by comparing significant fiancial indicators of Gulf with those of other electric utility companies with a bond rating of A. In this case, the significant financial indicators we used to assess Gulf's financial integrity are the coverage ratios showing the times interest earned (TIE) with and without AFUDC, which indicates the number of times a company's earnings (with and without AFUDC earnings) will cover its interest expense. In 1981, the TIE ratios for A rated companies are 2.9 (with AFUDC) and 2.4 (without AFUDC). Staff calculated that including all of the requested CWIP in rate base would result in TIE ratios for Gulf of 2.9 (with AFUDC) and 2.83 (without AFUDC). Staff indicated that classifiying a portion of the CWIP request as plant in service would have no effect on the TIE ratios. Because the majority of the CWIP projects included in the $6,034,000 are improvements or enhancements of existing plant, [*14] thus making irrelevant many of the arguments raised against the inclusion of CWIP in rate base, and because inclusion of that amount will allow the Company to maintain its financial integrity, we include $6,034,000 of CWIP in rate base.

E. The Caryville Site

Gulf included $2,291,000 of Plant Held for Future Use- related to the Caryville site in its proposed rate base. Public Counsel contended that the site should be removed from the rate base. The FEA proposed that the site be removed from the rate base, but that the Company be allowed to accrue an allowance on that property similar to AFUDC. As it was in the present proceeding, this issue was thoroughly aired in the Company's previous two rate cases. In the previous cases, we found that the site meets the criteria for property held for future use and included the full value of the site in the rate base.Based on the evidence submitted in this case, we will continue that policy and include the full value of the Caryville site in the rate base.

F. Total Net Utility Plant

Based upon a net utility plant in service amount of $554,620,000, inclusion of Construction Work In Progress of $6,034,000 and property held for [*15] future use of $2,291,000, the total net utility plant for the test year is $562,945,000.

G. Working Capital Allowance

A traditional component of rate base is the value of the working capital committed to utility operations. In recent cases we have applied the balance sheet approach to determining the working capital allowance, as opposed to the formula approach previously utilized. The balance sheet approach generally defines working capital as current assets and deferred debits that are utility related and do not already earn a return, less current liabilities, deferred credits and operating reserves that are utility related and upon which the Company does not already pay a return.

The Company has proposed a $111,662,000 working capital allowance. We have determined that the appropriate working capital allowance is $73,951,000. Our adjustments are set forth as follows:

Adjustments to Working Capital Allowance
$ (000)

Working Capital Allowance Per Company	$111,662
Adjustments:	
1. Fuel Inventory	(25,242)
2. Temporary Cash Investments	(13,453)
3. Nuclear Site PS&I	(1,752)
4. Property Ins. Res.	(1,147)
5. SCS Charges	(686)
6. Adj. for Inflation	(101)
7. Deferred O&M	4,683
Total Adjustments	(37,711)
Adjusted Working Capital	$ 73,951

[*16]

A discussion of these adjustments follows.

1. Fuel Inventory

Coal Inventory

Fuel inventory is an element of working capital and, as such, the Company should earn a return on its investment in fuel stocks that are reasonably and prudently included in fuel inventory. Determining the amount of fuel inventory to include in the rate base is not an easy task. On one hand, there is the overriding concern that fuel inventory be adequate to reasonably ensure the continuous generation of electricity to avoid, disruptions of service. On the other hand, is the desire to not require the ratepayers to support investment in fuel inventory beyond the amount necessary for the dependable operation of the generating system.

In this proceeding, Staff raised several issues concerning the Company's proposed coal inventory. Mr. Parsons and Mr. Ludwig testified extensively on the subject.

The first issue concerned the projected purchase prices and chargeout prices for coal during the test year. At the commencement of the case, all parties stipulated that the issue of the price paid for coal produced at the Alabama By-Products Company's Maxine Mine would be heard and decided in Docket [*17] No. 820001-EU. The parties further agreed to place subject to refund, that amount of the revenue increase awarded, if any, associated with the return on working capital, attributable to the Maxine coal, pending the outcome of Docket No. 820001-EU. We approve the stipulation and implement it by placing $13,442 of the Company's overall award subject to refund.

However, a question remains concerning the price paid for coal from other sources. In its original filing in MFR B-12, Gulf projected a 13-month average ending balance for system coal inventory of 1,496,714 tons valued at $94,614,317 or $63.2147 per ton. However, in Exhibit 240 Gulf indicated that it revised its forecast to 1,300,181 tons valued at $83,293,823 or $64.0633 per ton. This amounts to a reduction in total coal inventory as proposed by the Company, of $11,320,494. Although the Company settled on a system average price of $64 per ton, evidence adduced at the hearing showed that the average price for coal inventory for Plant Daniel is approximately $79 per ton. The delivered price per ton for the projected test year ranges from a low of $75.81 to a high of $85.58 or GEX coal and a low of $82.62 to a high [*18] of $92.38 for ARCO coal. While this issue was explored at the hearing, we conclude that the evidence presented to us raises a question but does not resolve it. We, therefore, make a carefully limited finding of fact that for the puposes of this rate case only, we will accept the purchase and charge out prices for coal proposed by the Company as reasonable. However, we intend to examine this issue in greater detail, either in Gulf's Fuel and Purchased Power Cost Recovery proceedings or in a separate investigation. Our acceptance of the Company's proposed costs does not preclude us from a prospective adjustment in a later, different docket, should we conclude that it is warranted on the basis of a complete record on this point.

Of its total inventory, the Company proposed to allocate $12,733,000 to its Unit Power Sales contract. It is the proper allocation and we approve it. If we were to make no further adjustments, the Company's proposed coal inventory, before application of the jurisdictional separation factor would be $70,560,823.

However, the next issue raised by Staff was whether the amount of coal in the Company's projected inventory is reasonable. Mr. Parsons testified [*19] that the Company has for many years followed a policy of maintaining its inventory at a 60-day nameplate capacity level. This means that assuming all of its coal fired generating plant operated at a 100% capacity factor, enough coal is on hand to operate the plants for 60 days. Assuming a more realistic capacity factor of 50%, this is roughly the equivalent of 120 days burn. Mr. Parsons further testified tht the projected test year inventory will exceed the 60-day nameplate target by 89,985 tons with a value of $5,759,059. Mr. Parsons stated it was not possible to precisely achieve the 60-day nameplate target and therefore the entire projected inventory should be included in working capital.

During his testimony, Mr. Parsons agreed that several different factors ought to be considered in developing a policy concerning the proper level of inventory. They include the demand for electricity based on historical and projected consumption, the reliability of coal suppliers and transportation including such things as labor contingencies, coal mining contingencies, supply versus demand for coal, supplier performance history, procurement leverage, the cost of maintaining alternative [*20] levels of coal, the cost of spot coal and the ability of the Company to purchase power from other sources and the cost of that power. Mr. Parsons testified that the 60-day nameplate policy has been continued not on the basis of any objective study weighing the importance and economic value of those factors; rather, the policy is based on the collective wisdom of the Company's management. He further testified that because all four operating companies of Southern follow the same 60-day nameplate policy, all have agreed to share their fuel supplies if one company experiences a fuel emergency. Mr. Parsons expressed concern that if Gulf unilaterally changed its policy, it might lose the perogative to call on members of the Southern system if it encountered a fuel shortage. Other than to say that the 60 day nameplate target was difficult to achieve with precision, Mr. Parsons offered no real defense of that portion of inventory in excess of the 60-day nameplate level. He agreed that the test year fluctuation above the 60-day nameplate level may not be representative of future conditions.

With all deference to Gulf's management, a policy followed by management that has such [*21] a tremendous financial impact on ratepayers must be substantiated with more than an assertion that it is the result of collective management wisdom. We do not wish to substitute our judgment for that of management. However, we insist that management's judgment be substantiated in a way that permits intelligent review of it. In this context, this can best be accomplished by performance of an analysis or study that identifies all of the major factors that influence development of a coal inventory policy, indicates the relative weight that should be attached to each factor, and evaluates the benefits and costs, in light of these factors, associated with a range of alternate coal inventory levels. The reasons why a particular factor is selected, why a particular weight is attached to it, and how it is included in a cost benefit analysis of alternative inventory levels should be clearly stated. In the absence of that kind of empirical support for its position, we find that the Company failed to carry its burden of proof with respect to the soundness of its 60-day nameplate policy.

Staff urged us to make two adjustments concerning the Company's proposed inventory level. The first [*22] adjustment would reduce inventory to the Company's stated 60-day nameplate level. We accept this adjustment. From the evidence, we conclude that the coal inventory fluctuates above and below the 60-day nameplate target from one year to the next. The Company presented no persuasive evidence as to why the ratepayers should bear the fortuity of a test year inventory in excess of the Company's stated policy. Therefore, the

Company's proposed inventory of $70,560,823 is reduced by $5,759,059 to $64,801,764, the 13 month average value of the coal inventory at a 60-day nameplate level.

Staff also urged us to reduce inventory by an amount necessary to bring it down to a 90-day projected burn level. A 90-day projected burn policy would require the Company to maintain sufficient coal on hand to meet the expected burn for the immediately succeeding 90 days. While the 60-day nameplate level is a relatively static target, a 90-day projected burn policy implies a rolling adjustment. Adoption of Staff's recommendation would reduce inventory to 756,649 tons with a value of $46,812,917. However, we reject Staff's recommendation for the same reason that we rejected the Company's 60-day nameplate [*23] policy, namely, that it is not supported in the record by the sort of objective evidence that would permit us to make an intelligent assessment of it. Staff must provide the same sort of analysis in support of its proposed inventory policy that we earlier required from the Company.

We are left then with two proposed inventory values, one of $64,801,764 based on a 60-day nameplate level, and the other of $46,812,917, based on a 90-day projected burn level, the difference between the two being $17,988,847.Neither of the two policies is supported by sufficient evidence to allow us to say it ought to be the policy followed by the Company. We, therefore, will reduce the Company's proposed 60-day nameplate value by one-half of the difference between it and the Staff's proposed 90-day projected burn value, $8,994,424. We are in effect reducing the Company's proposed inventory value because the Company failed to prove that its 60-day nameplate inventory policy was a reasonable and prudent policy. In so doing, we neither endorse nor reject any particular coal inventory policy; the record does not permit us to determine what the Company's coal inventory policy ought to be. However, [*24] we cannot permit the Company to benefit from its failure to carry its burden of proof. Therefore, we have reduced inventory to a level that we believe to be within a zone of reassonableness. We hope that we will receive a full evidentiary presentation, as outlined above, in the Company's next rate case so that we may lay this issue to rest.

The final issue raised with respect to the coal inventory was the proper accounting treatment of base coal in the various coal piles maintained by the Company. Base coal is the coal at the bottom of the pile that has been pulverized to the point that it cannot be used as fuel.The evidence shows that base coal in Gulf's generating plants in Florida was included in inventory while the base coal at Plant Daniel in Mississippe had been treated as a capitalized expense. The base coal in Gulf's Florida plants totals 53,000 tons with a weighted average original cost per ton of $6.0649, a total value of $321,440. However, including base coal in inventory with a test year projected cost of $64.0633 per ton gives the same coal a value of $3,395,355.Staff recommended that no adjustment be made and that this issue be thoroughly explored in the Company's [*25] fuel adjustment proceeding. We accept Staff's recommendation inasmuch as the accounting treatment of base coal varies among the investor-owned utilities and we can more easily establish a uniform policy with respect to this issue in the fuel adjustment proceedings.

Our adjustments to the Company's proposed coal inventory are summarized in the following table and, as shown there, we approve a test year coal inventory of $52,582,960.

Adjustments to Company's Proposed Coal Inventory

Co.'s original proposed coal inventory per MFR B-12	$94,614,037	(system)
Adjustment for revised forecast per Ex. 240	(11,320,494)	
	83,293,823	
Adjustment for UPS contract	(12,733,000)	
	70,560,823	
Adjustment to reduce to 60-day nameplate level	(5,759,059)	
13 month average 60-day nameplate level	64,801,764	
13 month average 90-day projected burn level	46,812,917	
Difference between 60-day nameplate level and 90-day projected burn level	17,988,847	
1/2 difference between 60-day nameplate and 90-day projected burn level	8,994,424	
60-day nameplate level	64,801,764	
Less adjustment	(8,994,424)	
Approved coal inventory level	55,807,340	(system)
Jurisdictional separation Factor	.94223	
Approved coal inventory level	$52,582,960	(juris)

[*26]

Heavy Oil Inventory

Mr. Parsons testified tht the Company maintains a heavy oil inventory of 88,000 barrels at a value of $1,182,720 for use at the Crist Units 1, 2 and 3 when natural gas is either unavailable or more costly than heavy oil. The oil inventory at Crist is approximately 27 days burn. The Company also maintains a heavy oil inventory of 126,000 barrels with a value of $1,753,222 (system) at Plant Daniel as Daniel has dual fuel capability. This level of inventory is approximately 10 days burn. Staff recommended that we include the heavy oil inventory at Crist in working capital but exclude the oil inventory at Plant Daniel. Staff contends that it is so unlikely that it will ever prove to be more economical to burn oil rather than coal at Plant Daniel that the oil inventory does not constitute property used and useful to serve retail customers. We reject Staff's recommendation as it is inconsistent with our policy of encouraging all new generating facilities as well as older facilities being converted from oil to coal to possess or retain dual fuel capability. Therefore, no adjustment will be made to the Company's proposed heavy oil fuel inventory. [*27]

No. 2 Oil Inventory

As with their coal inventory, the Company revised its forecast for its No. 2 fuel oil inventory, reducing its test year value by $144,361. We therefore have included the No. 2 fuel oil inventory in the test year rate base at a value of $938,647.

2. Temporary Cash Investments

Gulf included $13,453,000 related to temporary cash investments in working capital on the ground that they are a normal part of utility operations. However, inclusion of temporary cash investments in working capital will not affect the ratepayers only if the Company earns exactly the approved pretax rate of return on them, an unlikely event. If the temporary cash investments earn less than the approved rate of return, the ratepayers make up the difference; conversely, if the Company's return on temporary cash investment exceeds its approved rate of return, the ratepayers benefit. To prevent subsidization of the Company by the ratepayers or vice versa, temporary cash investments will be excluded from working capital. Therefore, working capital is decreased by a jurisdictional amount of $13,453,000. In a similar manner, earnings derived from temporary cash investments will [*28] be excluded from NOI.

3. Deferred Debits, Deferred Credits and Operating Reserves

In calculating its working capital allowance, the Company included $4,958,000 ($5,282,000 system) in deferred debits, deferred credits and operating revenues. This treatment is consistent with Gulf's last rate case and our recent decision in Docket No. 820007-EU and Docket No. 820097-EU. Public Counsel objected to inclusion of these items in Working Capital on the ground they are not used to meet day-to-day operating and maintenance expenses. However, we believe inclusion of these items in working capital provides a better match between rate base and capital structure and therefore will not depart from our established policy.

Having established the general principle of inclusion, we must review each item that falls within this categroy to determine whether on its own merits it is properly included in the Company's retail rate base. Staff recommended that we eliminate $1,752,000 from working capital, the amount included by the Company for the cost of evaluating a parcel of land for suitability as a nuclear plant generation site. We approve Staff's recommendation because the Company [*29] does not have any current plans to construct a nuclear facility at any time in the forseeable future.

Public Counsel urged us to exclude $1,039,000 from working capital, the amount included by the Company for the preliminary survey and investigation charges related to the Caryville site. Since the site is itself in rate base as plant held for future use, we will include the survey and investigation charges in working capital.

4. Property Insurance Reserve

The Company agreed with the Staff that the unfunded portion of the property insurance reserve represents a cost free liability to the Company that could be used to reduce working capital requirements. Public Counsel asserted that this item should be excluded from rate base. We think Staff's approach is correct; therefore, working capital is reduced by $1,147,000 so as to treat the unfunded portion of the property insurance reserve as a cost free liability.

5. Southern Company Services Charges

As a member of the Southern Company, Gulf purchases services at cost from the Southern Company Services, Inc. This arrangement gives Gulf access to the services of experts which Gulf, because of its size, cannot afford to [*30] retain in house. While we have no doubt that the services provided by Southern Company Services are valuable, we do question the reasonableness of the amount of payments to Southern Company Services budgeted by Gulf for the test year. In 1982, Gulf paid Southern a total of $13,282,135 while it has budgeted a total of $15,982,000 for 1983, an increase of 20.33%. When the Southern Company Services charges are differentiated into O&M expenses and capitalized expenses, the percentage increases are markedly different:

Southern Company Services Charges

	1982	1983	Increase	%Increase
O&M Expenses	$9,280,000	$10,136,991	$856,991	9.23%
Capitalized Expenses	4,004,135	5,845,009	1,842,874	46.05%
				20.33%

To analyze these increases, we first determined that Gulf's expected customer growth in 1983 is 3.63% and inflation is expected to be 6.1%; these numbers yield a compound growth rate of 9.95%. We use this as a standard of reasonableness against which to measure the anticipated increases in Southern Company Services charges. The expected increase in O&M expenses of 9.23% meets our standard but the 46.05% increase in capitalized expenses is far [*31] in excess of what can be accounted for by inflation and customer growth. The Company offered no adequate explanation of why services from SCS which would be treated as capitalized expenses are expected to increase by that amount. In the absence of an adequate explanation, we will disallow that portion of the increase that exceeds the 13 month average charge for 1982 for capitalized services plus 9.95%. The 13 month average for 1982 of $2,001,068 (assuming the expenses were incurred ratably over the period), plus 9.95% of that amount to account for inflation and customer growth is $2,200,174. The 13 month average for 1983 of $5,845,009, the amount budgeted by the Company, is $2,922,505. The jurisdictional difference is $686,000. We, therefore, reduce rate base by $686,000 to eliminate the excessive increase in test year SCS services which are treated as capitalized expenses.

6. Inflation and Escalation Rates

In another section of this Order, we set forth our reasons for reducing the 1982 and 1983 escalation rates used in projecting the test year rate base and operating expenses. The effect of using lower escalation rates is to reduce working capital by $101,000.

7. [*32] Employee Stock Ownership Plan - Accounts Payable

The Company contends that accounts payable related to its Employee Stock Ownership Plan (ESOP) should not be treated as cost free liabilities because they represent funds that have been set aside to purchase stock. Public Counsel asserts that the ESOP accounts payable are cost free liabilities. Having considered the record of this case, we find that we should consider ESOP accounts payable as cost free liabilities until such time as they are- converted to common stock. The accounts payable are the result of an accrual process and the Company does not have any identifiable cost that could be applied to the accounts payable. Working capital should be reduced by $13,000 to recognize ESOP accounts payable as cost free liabilities.

8. Unamortized Expense Balance

In another section of this Order we set forth our reasons for requiring the Company to amortize expenses related to boiler maintenance and turbine inspection over a three year period. The unamortized balance of these expenses should be included in working capital; therefore, we increase the Company's proposed working capital allowance by $4,683,000.

Unbilled Revenues [*33]

The Company has been accruing and recording unbilled revenues for book and financial reporting purposes since 1974. All of the parties agree that the related assets and liabilities should be included in the working capital allowance since the Company actually records unbilled revenues. Previously, we have included unbilled revenues if a Company actually records them for book and financial reporting purposes. We will continue that policy and include the assets and liabilities related to unbilled revenues in working capital because the Company actually records them.

Transition Adjustment

All parties agreed that no adjustment was necessary to remove the effects of the transition adjustment granted in Docket No. 820001-EU from working capital since the working capital allowance proposed by the Company does not include any amounts related to the transition adjustment.

Materials and Supplies

The Company proposed to include $12,41,000 for materials and supplies in working capital. On a jurisdictional basis, this constitutes an increase of .72% from 1981 to 1982 and 1.49% from 1982 to 1983. The Company's projected increases are conservative when compared to anticipated [*34] inflation rates of 5-7% for the same period of time. The amount proposed by the Company is approved.

Common Stock Dividends Payable

In calculating its working capital allowance, Gulf did not treat common stock dividends as cost free liabilities. Public Counsel asserts that the dividends should be treated as a cost free source of funds. According to Public Counsel, the nature of these funds changes when dividends are declared and they become an ordinary liability of the Company. The Company contends that the dividends represent common equity over which the stockholders still maintain control.

In our opinion, common stock dividends should earn a return because they represent stockholders' equity until such time as they are actually paid. Therefore no adjustment is necessary.

Caryville Cancellation Charges

The Company included $1,962,000, the amount of the unamortized Caryville cancellation charges, in its proposed rate base. Public Counsel believes these charges should be eliminated from the rate base as they do not constitute property used and useful in serving Gulf's retail customers.

This issue has also been thoroughly examined in the Company's previous two rate [*35] cases. In both of those cases we found that the Company's "decision to cancel its Caryville facility was prudently based upon an economic advantage to Gulf's customers associated with purchasing the Scherer capacity in lieu of constructing the Caryville facility". (Docket No. 810136-EU, Order No. 10557, p. 13.) Nothing of an evidentiary nature has been offered in this case to persuade us to reverse our earlier findings. Thus, the Caryville cancellation charges will continue to be amortized above the line over a five year period, with the unamortized balance included in the rate base. As in the past, the resulting revenue requirements will continue to be collected subject to refund, pending the consummation of Gulf's contract to purchase a portion of Plant Scherer.

II. Total Rate Base

Based upon total test year net utility plant of $562,945,000 and a working capital allowance of $73,951,000, the total test year rate base is $636,896,000.

NET OPERATING INCOME

Having established the Company's rate base, the next step in the revenue requirements formula is to determine the net operating income applicable to the test period.

The Company has proposed a test year [*36] net operating income of $51,908,000. Evidence developed during the course of the proceeding has led us to increase that amount to $60,015,000. Our adjustments are set forth as follows:

Adjustments to NOI
$ (000)

	Per Company	Adjustments	As Adjusted
A. Operating Revenues	$358,792	$9,142	$367,934
Operating Expenses			
B. Operating and Maintenance	240,644	(6,340)	234,304
C. Depreciation and Amortization	29,297	0	29,297
D. Taxes Other Than Income Taxes	14,251	18	14,269
E. Income Taxes Currently Payable	6,344	8,408	14,752
F. Deferred Income			

	Taxes (Net)	10,490	(1,051)	9,439
G.	Investment Tax Credit	5,858	0	5,858
H.	Gain on Sale of Plant	0	0	0
I.	Total Operating Expenses	306,884	1,035	307,919
J.	Net Operating Income	$ 51,908	8,107	$ 60,015

A. Operating Revenues

Customer Sales and Demand Forecast

Mr. Shearer and Mr. Oerting testified about the Company's projected test year peak demand, number of customers, and KWH sales. We find that the Company's forecasting methodology and the resulting projections are reasonable. Mr. Shearer, Mr. Haskins, and Mr. Scarbrough attempted to explain [*37] how the billing determinants are derived from the forecasts made by Mr. Shearer and Mr. Oerting. We find that the Company's proposed billing determinants are reasonable and may be used to design the rates approved as part of this proceeding.Most of the projected billing determinants are based on historical relationships, modified due to known facts. Although we cannot check the test year data in this fashion, comparison of 1982 actual data to 1982 projected data shows no significant variation. Because the same methodology was employed to forecast the 1983 billing determinants, we find the projections are reasonable.

Revenues from Present Rates

After the Company filed a petition initiating this docket, the Commission took final action in the Company's previous rate case, Docket No. 810136-EU. In Order No. 10963, we authorized the Company to revise its rate schedules to generate $1,374,277 in additional gross revenues effective June 17, 1982. During the hearing, the Company submitted Exhibit No. 17 P, which is revised MFR Schedule E-4(a), showing the additional revenues resulting from Order No. 10963.Based on this exhibit, we will increase the Company's test year [*38] operating revenues by $1,148,000 to reflect the rates currently in effect.

Schedule E and Economy Sales Revenues

The Company did not include two other sources of revenue in projecting test year operating revenues. First, the Company did not include the income it receives from economy energy sales. The Company contends one, that economy energy sales cannot be forecasted accurately, and two, since the plant out of which economy sales are made is always available to serve retail customers, that the profits of economy energy sales should go to the stockholders rather than to the ratepayers. We disagree sharply with the Company's second contention. Since the ratepayers are paying the full cost of the generating facilities out of which economy energy sales are made, any income derived from the use of those facilities should inure to the ratepayers' benefit. Therefore, income from economy energy sales will be included in test year operating revenues. The real question is what level of economy energy sales income to anticipate for 1983. While disavowing its accuracy, the Company projected 1983 economy energy sales revenue of $345,815. Public Counsel and the FEA urged us to examine [*39] the level of sales for the years 1976-1982 and anticipate economy energy sales of $2,685,000 and $1,018,000, respectively. However, the historical figures are somewhat misleading because they occurred before the Company sold off much of its unused capacity in unit power sales. We are therefore inclined to adopt the Company's estimate of $345,815 as the best available. Our review of this whole issue has led us to conclude that the Commission should institute a generic investigation to consider a true up of economy sales forecasts for all electric companies in the fuel adjustment clause docket.

Second, the Company also failed to include $4,905,000 of Schedule E capacity credits it receives from its Schedule E customers. Again the Company argues that since the ratepayers pay for service, not ownership, of the facilities, and since Schedule E sales do not affect the cost of serving retail customers, the stockholders should receive the benefit of Schedule E capacity payments. Again, we disagree with the Company. Since the ratepayers must provide a return on the generating facilities from which both retail and Schedule E sales are made, capacity payments made by Schedule E customers [*40] should offset the return provided by retail ratepayers. Otherwise, the Company would earn a double return on a portion of its generating facilities because the retail and Schedule E customers would be paying a return on the same facilities. For these reasons test year operating revenues are increased by $4,905,000 to reflect Schedule E capacity payments that will be received by the Company during the test year.

Temporary Cash Investments

Another adjustment that must be made to operating revenues is the result of our decision to exclude temporary cash investments from working capital. Earnings related to those investments must be removed from test year operating revenues. Therefore, test year operating revenues are reduced by $2,649,000.

Adjustments Related to Unused Capacity

In 1975, Gulf decided to purchase from Mississippi Power Company an undivided one-half interest in Daniel Units 1 and 2 located in Jackson County, Mississippi, thereby increasing its generating capacity by 511 MW. In 1976, it was agreed that Unit 2 would be deferred from 1979 to 1980 and that Mississippi Power Company would complete and own Unit 1 when it became commercial in 1977. Upon [*41] commercial operation of Unit 2, Gulf and Mississippi Power would then each own 50% of each unit. Unit 2 was deferred again, beginning commercial operation in June 1981.

Although this Commission never formally approved Gulf's purchase of Plant Daniel, we included it in the Company's rate base in the last rate case. In this proceeding, Mr. Earl Parsons, testifying for Gulf, presented testimony showing that the purchase of an interest in Plant Daniel and an interest in Plant Scherer, in lieu of constructing a plant on Gulf's Caryville site, is the most economic way to meet the expected long term growth in demand on Gulf's system. While we do agree that the purchase of Plant Daniel is in the long term best interest of Gulf's ratepayers, it is equally clear that the purchase of Plant Daniel created a short term over-supply of generating facilities on Gulf's system. In its last rate case, Gulf projected that, before the reserve margins of all the Southern operating companies were equalized, it would have a reserve margin of 66.2% in 1981. For system planning purposes, a reserve margin of 25% is considered adequate. In this rate case, before the reserve equalization process, and before [*42] all-system sales are considered, Gulf's reserve margin is projected to be 55.3% in 1983. Thus, our overriding concern is to ensure that the Company made every reasonable effort, in a timely fashion, to minimize, if not avoid, imposition of the revenue requirements associated with Plant Daniel on retail customers for that period of time when the Daniel capacity is not necessary to serve them.

In Gulf's last rate case we penalized the Company for failing to prudently identify and quantify the factors affecting load growth during the 1970's, because Gulf's failure in that regard meant that it did not begin to negotiate off-system sales of its unused capacity until 1980. We concluded that had the Company acted prudently it would have attempted to arrange off-system sales in the late 1970's.We therefore refused to impose the revenue requirements associated with the unsued capacity at Plant Daniel on the retail ratepayers and adjusted test year revenues by $3,099,000.

In this case, we are presented with a somewhat different factual situation. Gulf has entered into a Unit Power Sales contract (hereinafter referred to as the UPS contract) with Florida Power & Light Company and Jacksonville [*43] Electric Authority.Under the terms of the contract, FPL and JEA will own 238 MW of Gulf's share of Plant Daniel and thus be exclusively entitled to the output of that portion of the plant, through the mid 1990's. Unlike other off-system sales made by Gulf, the UPS contract is a firm sale of capacity. The 238 MW will not be available to serve Gulf's retail or other wholesale customers during the life of the contract. The UPS customers will pay all of the fixed and variable costs associated with the 238 MW, including a return on Gulf's investment. Because the UPS contract is a wholesale transaction, it is regulated by the FERC. Cur sole concern is whether Gulf has properly allocated all of the investment, operating costs, and revenues associated with UPS out of the retail jurisdiction. This issue was thoroughly explored during the cross-examination of the Company's witnesses, Mr. Carzoli and Mr. Parsons. Mr. Parsons testified that the fixed expenses were allocated between UPS and other customers on the basis of the ratio of 238 MW to 511 MW or 46.58%. The variable O&M expenses are allocated on the ratio of electricity provided to UPS and to other customers. Since the [*44] UPS customers are expected to receive 74.26% of the electricity expected to be produced in 1983 from Plant Daniel, they were allocated 74.26% of the variable costs of the unit.

In its original filing, the Company allocated $106,869,000 of rate base investment to the UPS contract as follows:

	System
Plant in Service	$105,131,000
Accumulated Depreciation	(15,197,000)
Net Plant	$ 89,934,000
Working Capital	
Fuel	12,162,000
Other	4,773,000

Total Working Capital	$16,935,000
Rate Base	$106,869,000

During his cross-examination, Mr. Carzoli agreed that as a result of the Company's revised coal inventory forecast, an additional $571,000 (system) should be allocated to the UPS contract, making the total fuel inventory allocation to UPS $12,733,000 (system). With that correction, we approve the Company's allocation of rate base to UPS. The Company's allocation of $88,663,000 (system) in operating revenues and $77,014,000 (system) in operating expenses as shown in the following table is also correct and we approve it:

Adjustment to Income Statement
for the UPS Contract

	System
Operating Revenues	$88,663
Operating Expenses	
Fuel	56,999
Variable O&M	3,114
Fixed O&M	3,149
Depreciation	3,985
Amortization of ITC	(310)
Income Taxes-Cum. Pay.	2,433
Deferred Inc. Taxes	3,062
Taxes Other Than Inc.	3,252
Gross Receipts Tax	1,330
Total Operating Expenses	$77,014
Net Operating Income	$11,649

[*45]

Public Counsel contends that Gulf erred in excluding the investment associated with the UPS contract from the retail rate base. Public Counsel argued that the unit power sales are an integral part of the Company's jurisdictional operations and should be included in the determination of the Company's revenue requirements. To do otherwise, would, in Public Counsel's opinion, force the retail ratepayers to subsidize unit power sales.

However, we have examined the UPS contract and the associated cost and allocation from all angles and we come to the opposite conclusion. If the proper amounts of investment, operating expenses and revenues are allocated to UPS customers, retail ratepayers will not only not subsidize UPS customers, but on the contrary, they will benefit handsomely from the sales, in the sense that they will not have to support the capacity sold in a UPS transaction for the life of the contract but the capacity will be available to serve them when they need it in the future, at a relatively reduced price when compared with the cost of future construction. Therefore, we reject Public Counsel's argument because the UPS contract is a wholesale transaction, not properly [*46] included in the retail jurisdiction and because we find that Gulf properly allocated investment, operating expenses and revenues between the UPS and retail customers. Thus, we find that retail customers are not subsidizing UPS customers, and that there has been a proper accounting of 238 of the 511 MW's and the dollars associated with that capacity.

We now turn our attention to the remaining 273 MW of Plant Daniel owned by Gulf. Under the Intercompany Interchange Contract (hereinafter referred to as the IIC) Gulf and the other operating companies on the Southern system buy and sell capacity from each other on an annual basis so that each company ends up with the same reserve margin, hovering around 25% from one year to the next. Under the terms of the IIC signed in November 1981, the contract which formed the basis for this rate case filing, Gulf is projected to sell 186 MW to the other members of Southern during the peak month of August in 1983. We assume that Gulf's projected sale of 186 MW to the pool was made possible by Gulf's purchase of a portion of Plant Daniel. We make this assumption because Plant Daniel was the incremental generating source added to Gulf's [*47] system, and by selling 238 MW off-system under the UPS contract and 186 MW to the Southern power pool, Gulf brings its projected reserve margin in 1983 down to the acceptable level of 23%. More importantly, Gulf's system average embedded capacity cost without Plant Daniel is $200 per KW, whereas the test year net investment in Plant Daniel is $371 per KW. If Gulf must make off-system sales to bring its reserve margin to an acceptable level, as it must during the test year, it ought, if at all possible, to sell its most expensive capacity off-system, retaining its lower cost capacity for the benefit of its retail ratepayers. In this proceeding, Gulf failed to prove that its only available option was to sell 186 MW of its unused capacity through the ICC.

Therefore, as we did with the UPS contract, we must assure ourselves that this sale of capacity to the Southern pool does not require the retail ratepayers to subsidize the purchasers of that capacity. The annual revenue requirements associated with 186 MW of Plant Daniel are $19,806,409. For the 186 MW it sells to the Southern pool, Gulf was projected to receive $12,260,555 over the course of the year in capacity payments. Also, [*48] we must consider the fact that if Gulf did not have capacity from Plant Daniel to sell to the pool, it would end up a net purchaser of capacity from the pool over the test year. Therefore, in addition to crediting capacity payments it received from the 186 MW sale against the revenue requirements associated with that capacity, we also credit against the revenue requirements the capacity payments Gulf would have made during the test year if it had not purchased a portion of Plant Daniel.

Another source of income which should be credited against the revenue requirements of the 186 MW comes from the Company's projected test year Schedule E and economy sales. The Company projects income of $5,206,000 from Schedule E capacity payments and $367,000 from economy sales in the test year. We will credit a portion of this income against the revenue requirements of the 186 MW. The amount credited is based on the ratio of 186 MW to the Company's total installed capacity available to make those sales of 1,793 MW (the Company's total installed capacity less the 238 MW allocated to the UPS contract). Thus, we credit $578,125 of Schedule E and economy sales against the revenue requirements of [*49] the 186 MW. We allocate only a portion of the Schedule E and economy sales income to the 186 MW because Mr. Parsons testified that these sales are made from all of the Company's installed generating facilities, with the exception of the 238 MW associated with the UPS contract, and refused to agree that the sales were made primarily from Plant Daniel.

Having credited all possible sources of income against the revenue requirements of the 186 MW, there is still a shortfall of $5,722,602 (system). During the test year, the Company would have the retail ratepayers support the revenue requirements of the 186 MW in the amount of $5,391,931, despite the fact that the 186 MW is above and beyond the capacity necessary to maintain an adequate reserve margin for Gulf. The shortfall comes about because the Company is selling its marginal capacity at average embedded cost rates. While the embedded cost rate provision of the IIC may, in the long run, benefit Gulf's ratepayers, it will cost them dearly in the test year. In effect Gulf's ratepayers are providing a reserve margin for other Southern companies's ratepayers at average embedded cost rates, supplying the difference between [*50] average and marginal capital costs themselves. Had the Company proved in this case that the short term costs associated with the oversupply of capacity due to the purchase of Plant Daniel were outweighed by the long term benefits associated with the acquisition, and had they proved that disposition of 186 MW via the IIC was the best because it was the only possible sale from that capacity, our decision today might be different. These issues would of course again raise the question of the timelines of the Company's efforts to bring about off-system sales on more favorable terms. However, the Company has consistently taken the position that the retail ratepayers are fully compensated for the capacity sold under the reserve equalization process contained in the IIC. We simply disagree with that proposition. Therefore, we will reduce the Company's revenue deficiency by $5,391,931 so as to avoid retail ratepayer subsidization of off-system sales. Our adjustment is summarized in the following table:

Adjustment for Off-System Sale
of Plant Daniel Capacity

Revenue requirement associated with 186 MW of Plant Daniel	$19,806,409
Net difference in ICC capacity payments for 186 MW of capacity	(13,505,682)
$12,260,555 capacity payments received 1,245,127 capacity payments avoided $13,505,682	
Revenue Requirements Associated with Sch. E and Economy Sales	(578,125)
(186 MW X ($5,206,000 + 367,000) 1793 MW)	
Net Annual Revenue Requirements associated with 186 MW of Plant Daniel	$5,722,602
Jurisdictional Separation Factor	.94221661
Jurisdictional Adjustment For Off-System Sale of Plant Daniel Capacity	$5,391,931

[*51]

Our adjustment may be somewhat conservative when the Company's position under the IIC signed in November 1982 is considered. The projected capacity sales by Gulf during the peak month in 1983 have been revised downward from 186 MW to

72.4 MW. With no change in the level of utilization of Plant Daniel for the retail ratepayers, this leaves Gulf a projected reserve margin of 37.1% in 1983 corresponding to 88.1 MW of plant that is neither necessary to serve retail customers in the test year or off-set by an off-system sale. The test year revenue requirements associated with the 88.1 MW of capacity in excess of a 25% reserve margin are $10,383,281. We would credit $258,011 of income from Sch. E and economy sales agasint the revenue requirements of the 88.1 MW. To this must be added the adjustment of $3,977,740 which is the revenue shortfall resulting from the sale of the 72.4 MW under the IIC. The calculation of these adjustments is set out in greater detail in Appendix D.Suffice to say that if we based our adjustment on the November 1982 IIC, the adjustment would be $14,103,010 rather than the $5,391,931 we approve today. We base our adjustment on the November 1981, [*52] rather than the November 1982 contract, only because the latter was received as a late filed exhibit after the close of the hearings held in this case and has not received the full review given the 1981 contract.

A portion of Plant Daniel will be used to serve retail customers during the test year. After accounting for UPS and IIC sales, 87 MW are available to serve retail customers. Mr. Parsons testified that of the 1878.5 GWH expected from Plant Daniel in 1983, 483.5 GWH would be sold to retail customers. This results in a capacity or utilization factor of the 87 MW of 63%. Thus, it is entirely appropriate for the retail rate customers to pay the revenue requirements associated with the remaining 87 MW Of Plant Daniel owned by Gulf.

Fuel and Conservation Revenues

Since the Company made an adjustment of $139,000 for the over-recovery of revenues in its Fuel and Purchase Power Cost Recover Factor, no further adjustments are necessary to make fuel costs equal fuel revenues in this proceeding. Public Counsel advocated the total exclusion of fuel expenses and revenues from the calculation of the Company's NOI. We decline to adopt their suggestion but note that since fuel [*53] expenses and revenues are equal, the effect on NOI is the same as excluding them.

The evidence shows that the Company's conservation costs and revenues are equal; therefore, no adjustment to NOI is necessary. Again, Public Counsel urged us to exclude conservation costs and revenues from the calculation of the Company's NOI. Again, we decline to adopt their suggestion with the observation that since conservation costs and revenues are equal, they will have no effect on the Company's NOI.

Test Year Operating Revenues

The effect of the adjustments described above is to increase test year operating revenues by $9,142,000. We therefore approve test year operating revenues of $367,934,000.

Operating Expenses

The Company has proposed test year operating and maintenance expense of $306,884,000. We have made several adjustments which have the effect of increasing test year operating expenses by $1,035,000 to $307,919,000. A discussion of our adjustments follows.

B. Operations and Maintenance Expense

The Company has proposed test year operating and maintenance expenses of $240,644,000. We have determined that this amount should be reduced to $234,304,000 as follows. [*54]

Adjustments to O&M Expenses
$ (000)

Per Company	$240,644
Adjustments	
1. Inflation	(2,334)
2. Non-recurring Maintenance	(3,831)
3. Rate Case Expense	(21)
4. Dues	(18)
5. Contributions	(27)
6. Advertising	(109)
Total Adjustments	$ (6,340)
Adjusted O&M Expense	$234,304

1. Inflation and Escalation Rates

In putting its rate case filing together, the Company assumed an inflation rate of 10.3% for 1982 and a 9% inflation rate for 1983. These assumptions were made during the second quarter of 1981. During his cross-examination, Mr. Scarbrough stated that the most current estimates for inflation are 5.2% for 1982 and 6.1% for 1983. Public Counsel recommended a 6% inflation rate for both years. We approve use of an inflation rate of 5.2% for 1982 and 6.1% for 1983.

In estimating the level of increase in rate base and operating expense it would experience in 1982 and 1983, the Company did not utilize simply an expected rate of inflation but instead used an escalation rate which is composed of an inflation rate and a 10.9% wage increase in 1982 and a 9% wage increase in 1983. The base figures to which these escalation rates were applied [*55] have been adjusted to account for expected customer growth. As the wage increase reflects expected operating conditions during 1982 and 1983, we approve their use. Public Counsel suggested that we place a portion of the rate increase we grant today under bond subject to refund until the exact amount of the test year wage increase is known. Public Counsel urges that the record contains no evidence as to the reasonableness or fairness of the projected wage increases. However, the Company is currently negotiating this issue with its employees' union. We will not hold the salary increases subject to refund. It is not consistent with the philosophy of a projected test year to select one from among many of the Company's projections and place it subject to refund until the amount of the actual expense incurred can be determined. Staff monitors the Company's return on a monthly basis. If test year actual operations differ markedly from the Company's projections and the Company has excessive earnings, we are fully empowered to order a reduction in rates if warranted.

As revised with the lower inflation rates, we approve of the use of escalation factors of 7.2% in 1982 and 7% in 1983. [*56] The combined effect of using a 7.2% escalation in 1982 and a 7% escalation in 1983 is to reduce test year operating expenses by $2,334,000 (juris.) and working capital by $101,000 (juris.)

2. Non-recurring Operating Expenses

Since we employ a test year approach to ratemaking, we must ensure that test year operating expenses are representative of the expenses the Company will incur during the period the rates will be in effect. However, to say that test year revenue requirements should not include any non-recurring expenses somewhat oversimplifies the issue because, given the nature of utility operations, every year will include some periodic expenses that will not be incurred the following year. Thus, what we really must determine is that the test year revenue requirements do not include excessive or unrepresentative non-recurring expenses.

In its filing, the Company included $10,145,000 of operating expenses for turbine inspections, boiler maintenance, and turbine blade replacements. All of these expenses are periodic in nature but they are not usually performed on an annual basis at every generating facility. Turbine inspections are performed on a cyclical [*57] basis over a period of years, and boiler maintenance is performed at the same time. Turbine blade replacements are done on an as-needed basis. Evidence adduced at the hearing showed that of $10,145,000, $6,050,000 are expenses which would not normally occur in the test year but which had been deferred to the test year due to financial constraints in previous years. While we do believe the maintenance associated with the $6,050,000 needs to be done, these expenses should not be considered normal test year operating expenses. Staff suggested that these expenses should be amortized over the maintenance cycle of five years. We think three years is more appropriate. Therefore, we will reduce test year operating expenses by $6,050,000 but allow $2,017,000 as the test year amortization expense. This results in a net decrease of $4,033,000 in test year operating expenses. The jurisdictional amount of this adjustment is $3,831,000.

The remaining $4,095,000 covers cyclical expenses which would normally occur in the test year. This amount compares favorably to the Company's four year average of all non-recurring expense items of $4,632,955. Therefore, $4,095,000 of non-recurring operating [*58] expenses is approved for the test year.

We caution the Company that both the funds provided on an amortized basis and the funds allowed as normal test year operating expenses are, in our mind, earmarked for the maintenance work for which the Company requested them. Any decision to delay or defer the maintenance and put the funds to other uses will be viewed with extreme skepticism in subsequent rate cases.

3. Rate Case Expense

The Company's total rate case expense for this proceeding is $409,005; the Company proposed to amortize this over a three year period. Public Counsel argued that the rate case expense should be divided evenly between the ratepayers and stockholders, amortized over a three year period. We disagree with both positions. Rate case expenses are a normal operating expense for a regulated utility and should be treated as such; it will not be split between ratepayers and stockholders. Additionally, the amortization period will be two years in view of the frequency of the Company's requests for rate relief. Therefore, we approve $293,835 as the rate case expense for the test year which includes $89,333 of expense from the Company's previous rate case and [*59] one half of the rate case expense of this proceeding.

4. Industry Dues

The Company budgeted $91,369 (system) for industry dues for the test year. Our established policy is to allow a company to recover industry dues above the line if membership in an organization contributes to and facilitates the operation of the company to the benefit of the ratepayers. However, we disallow dues if the organization is similar to a Chamber of Commerce or is a lobbying organization. Applying those criteria in this case, we will allow $65,125 of industry dues but disallow $17,617. The Company also included $1,108,542 (system) in Electric Power Research Institute (EPRI) dues. We will allow the entire jurisdictional amount to be recovered because through its contribution to EPRI, Gulf supports industry research and development. In the past, we have allowed the Company to recover Edison Electric Institute dues but in this case the Company did not budget any dues for the test year.

5. Charitable Contributions

Consistent with our decision on this issue in Gulf's last rate case, we remove from operating expenses $27,000 of charitable contributions. Gulf may, of course, continue [*60] to make contributions to charities; our decision merely requires the stockholders, rather than the ratepayers, to make the donations.

6. Advertising Expenses

In this case, as in Gulf's last rate case, we reduce advertising expense by $109,000 to disallow area development and institutional advertising expenses. This kind of advertising falls within the category of image building and promotional advertising as defined by the Commission in Order No. 6465. As such, it is disallowed for ratemaking purposes.

Injuries and Damages Reserve

In the Company's last rate case, we allowed the Company to increase its annual accrual to its injuries and damages reserve to $1.2 million. We also decided to remove the cap on this reserve. Our decision was based on an examination of claims paid from the reserve over the last five years. In this proceeding we again reviewed the claims made against the reserve over the last five years and we remain convinced that $1,200,000 is the proper annual accrual to the fund. We, therefore, approve a test year reseve fund of $1,581,000, which is the 13 month average of the fund, net of claims and accruals. The fund will remain uncapped, and we will [*61] continue to monitor its adequacy. No adjustment is necessary.

C. Depreciation and Amortization

The Company has proposed test year depreciation expense of $29,297,000. This is the proper amount and no adjustment is necessary.

D. Taxes Other Than Income Taxes

Effect of Other Adjustments

This adjustment is mechanical in nature and serves to show the effect on taxes other than income taxes of the various other adjustments that we have made to the Company's proposed net operating income. The effect is to increase taxes other than income taxes by $18,000.

E. Income Taxes Currently Payable

Changes in Florida Income Tax Law

The Florida Emergency Excise Tax (Ch. 221, F.S.) will be in effect during 1983. The tax paid is allowed as a credit five taxable years later. Generally accepted accounting principles would dictate deferral of the tax if material. Gulf's 1983 emergency excise tax is immaterial and should be expensed during 1983. Future tax expense should be reduced when the credit becomes available. Test year current income tax expense is, therefore, increased by $77,000.

Tax Credits Generated For Research and Development Expenditures [*62]

Public Counsel has raised for the first time in its post-hearing brief the issue of whether tax credits generated from research and development expenditures should be taken into consideration when arriving at forecasted net operating income.

The propriety of a party adding new issues after hearing is governed by Rule 25-22.38(5)(B) which states in part:

2. Any issue not raised by a party prior to the issuance of a prehearing order shall be waived by that party, except for good cause shown. A party seeking to raise a new issue after the issuance of the prehearing order shall demonstrate that: he or she was unable to identify the issue because of the complexity of the matter; discovery or other prehearing procedures were not adequate to fully develop the issues; due diligence was exercised to obtain facts touching on the issue; information obtained subsequent to the issuance of the prehearing order was not previously available to enable the party to identify the issue, and introduction of the issue could not be to the prejudice or surprise of any party. Specific reference shall be made to the information received, and how it enabled the party to identify the issue; . . .

Public [*63] Counsel has made no effort to demonstrate why the issue should not be considered waived. We decline to raise the issue on our own motion. The issue is accordingly considered waived and we will not dispose of it.

IRS Audit Adjustments

Gulf has proposed that IRS audit adjustments affecting the test year should be recognized. Public Counsel states that each audit adjustment must be analyzed to evaluate whether they conform to prudent utility regulation.

Any and all known facts that have a measurable effect on the test year should be recognized in setting rates. IRS audit adjustment affects only tax expense allowed. Since the IRS is the governing body determining actual taxes paid, the IRS audit adjustments should be recognized.

Income Tax True-Up

All parties have agreed that the debt component of the allowed rate of return should be trued-up with allowable interest expense used to determine income taxes. In order to true-up the allowed income tax expense, an adjustment to decrease allowable interest expense is necessary. The interest expense used by the Company to compute its income tax liability was $27,642,000, although it should have been $28,136,497. [*64] Allowable interest expense, based upon the approved rate base and capital structure is $26,494,110. Therefore, we increase income tax expense by $799,842.

Effective Tax Rate

Public Counsel asserts that the consolidated effective tax rate should be used in arriving at Gulf's revenue requirements. According to Gulf, the Company allocates the consolidated federal income tax liability in accordance with Security and Exchange Commission Rule 45 (c) which provides that a member of the group cannot be apportioned a tax liability greater than the liability based upon a separate return computed as if the Company has always filed a separate return. We find that the effect of filing a consolidated tax return should not be recognized. To do so would be in error in one or both of the following ways: 1) it would allow Gulf's ratepayers to enjoy the tax benefits of deductions for which they are not responsible; and 2) it would burden Gulf's ratepayers with responsibility for revenues they did not generate.

Gulf's entire tax liability will ultimately be paid to the IRS. The actual dollars allowed in a given period may be offset in the future by net operating loss carrybacks or various [*65] credits carrybacks. If these dollars are offset, future taxes allowed will be reduced by the associated refunds thereby recognizing equitable treatment. The appropriate tax rate to be used for purposes of computing Gulf's revenue requirements, including the revenue expansion factor, is the statutory rate of 48.7%. This treatment is consistent with the result in the two previous rate cases for Gulf.

Effect of Other Adjustments

This adjustment is mechanical in nature and serves to show the effect on income tax expense of the various other adjustments that we have made to the Company's proposed net operating income.The effect is to increase income taxes currently payable by $5,843,000.

F. Deferred Income Taxes (Net)

Unrecovered Deferred Taxes Arising Before 1975

Gulf has certain unrecovered deferred taxes that arose prior to 1975 when full normalization tax accounting was mandated by Order No. 6917.

The Company's amortization of these items, until this rate case, has been at the composite depreciation rate of the related assets at the time full normalization was implemented. Gulf now proposes to accelerate recovery of these unrecovered deferred taxes [*66] to provide for recovery over five years, relying on our requirement to flow back over collections resulting from tax rate changes over a five year period.

The Company's argument that Commission policy mandating a five year write-back of overfunded deferred taxes justifies a five-year recovery of items flowed-through to customers prior to normalization is unfounded. Amortization of the write-back over the remaining lives of the related assets is prescribed in APB No. 11 or FERC order 46 FR May 14, 1981, pg. 26613, 18 CFR2. We disagree with the rapid recovery of unfunded, unrecorded deferred taxes which arose from items that were flowed-through prior to I full normalization.

The Company's treatment since 1975 is congruent with FERC treatment (46 FR May 14, 1981, p. 26613:18CFR 2) of reverse flow-through and should continue. Therefore, we decreased deferred income tax expense $1,051,000.

Flow-Back of Deferred Taxes

The change in corporate income tax rate to a 46% rate requires a decision as to the proper amount of time over which to flow back deferred taxes which were created at 48%. In Order No. 10557, issued February 1, 1982, were required Gulf to flow back these deferred [*67] taxes over a five year period. Gulf again requests that the excess deferred taxes be flowed back over the life of the assets to which they relate. Public Counsel supports continued application of the period required in Order No. 10557. We find that we should continue to require the flow back over a five year period. This treatment is the same as required by Order No. 10557, conforms to our policy on this issue in other cases, and conforms to Rule 25-14.5, F.A.C. The Company's test year adjustment to reduce deferred taxes by $389,077 is in compliance with Rule 25-14.5, F.A.C.

Income Tax Effect of AFUDC

Public Counsel originally proposed that 100% of the income tax effect of AFUDC be recorded below-the-line in arriving at the Company's revenue requirements. In its post-hearing brief, Public Counsel states that the issue is moot, as the synchronization of income taxes for NOI purposes with the capital structure will properly account for the above-the-line deferred taxes associated with AFUDC.

The debt portion of AFUDC earnings is treated as an offset to interest expense, both recorded below-the-line. Since the tax effect of interest expense is recognized above-the-line, [*68] it follows that an offset to interest expense should also be recognized in tax expense above-the-line. The interest expense allowed for NOI purposes should be synchronized with that inherent in the capital structure.

Effect of Other Adjustments

This adjustment is mechanical in nature and serves to show the effect on deferred income tax expense of the various other adjustments that we have made to the Company's proposed net operating income. The effect is to increase deferred income taxes by $1,866,000.

G. Investment Tax Credit (Net)

Job Development Income Tax Credits

Public Counsel has proposed that the interest expense used to calculate the test year income tax expense include interest imputed to Job Development Investment Tax Credits (JDIC). This issue is essentially the same as that raised with regard to the rate of return to be assigned to JDIC as part of the capital structure. The issues should be resolved consistently. Interest expense will not be imputed to JDIC for purposes of calculating income tax expense.

The amortization of investment credit should match the depreciation of the asset that created the credit. IRC 46(f)(6) precludes a [*69] taxpayer from amortizing the credit prior to placing the asset which created the credit into service. Disallowance of the credit is possible if any other treatment is applied.

Public Counsel believes that to allow the qualified progress JDIC in the capital structure, at the overall rate of return after taxes, and not amortize the credit until construction is complete, and the property is placed in service, is unfair to the ratepayer. Public Counsel also contends this treatment is not the intent of Congress on the grounds that IRC Section 46(f) was written prior to the qualified progress expenditure section of the Code [IRC Section 46(d)] and, therefore, Congress could not consider its ramifications. We do not agree. Congress would have rewritten Section 46(f) if their intent was that different treatment be applied to qualified progress JDIC as opposed to other JDIC.

Public Counsel asserts that Gulf has failed to begin amortizing Qualified Progress Expenditure investment tax credits on the date that plant goes into service, the date those credits become available. Exhibit 2M, however, does not reflect the figures cited by Public Counsel. According to the record, Gulf begins [*70] amortizing investment tax credits in the year the plant is placed in service. No adjustment is necessary.

H. Gain or Loss on Sale of Plant

In Order No. 10306, we established a policy of requiring gains or losses from the disposition of utility property to be amortized over a five year period. However, the Company anticipates a loss of $21,917 on the sale of utility property in 1982 and no gains or losses of this nature in 1983. Therefore, no adjustment is necessary.

I. Total Operating Expenses

Total operating expenses for the test year, as adjusted herein, are $307,919,000.

J. Net Operating Income

The net operating income for the test year is derived by subtracting total operating expenses of $307,919,000 from operating revenues of $367,934,000. Thus we approve test year net operating income of $60,015,000.

Public Counsel raised the question of whether the Company had property accounted for non-utility operations conducted on utility property. Having reviewed the evidence on this point, we find that the Company has properly accounted for non-utility operations on utility property during the test year and no adjustment is necessary.

FAIR [*71] RATE OF RETURN

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

Capital Structure

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

The establishment of a utility's capital structure serves to identify the sources of capital employed by a utility, together with the amounts and cost rates associated with each. After establishing the sources of capital, all capital costs, including the cost of equity capital, are weighted according to their relative proportion to total cost of capital. The weighted components are then added to provide a composite or overall cost of capital. The weighted cost of capital multiplied by the [*72] net utility rate base produces an appropriate return on rate base, including a return on equity capital in rate base. The return is also sufficient to recover the annual cost of other types of capital, including debt.

Since a return on all sources of capital is provided by this treatment, actual debt and similar capital costs are not included in test year operating expenses, but are treated "below the line." This assures that such capital costs are not double counted for ratemaking purposes.

An appropriate capital structure is both economical and safe. Such a capital structure should minimize the cost of capital by obtaining capital through an appropriate balance between debt and other components of capital. The capital structure used for ratemaking purposes for a particular company should bear an appropriate relationship to the actual sources of capital to the Company.

Consistent with our decision to employ a projected test period in this case, we have decided to utilize the capital structure projected by the Company to be in place through 1983. We have adjusted the system capital structure to remove capital that is not being utilized to fund the jurisdictional rate [*73] base. Such adjustments are necessary to reconcile rate base with capital structure.

We have determined to use a 13-month average capital structure with average cost rates. The parties initially disagreed on this issue; Gulf argued that year-end cost rates should be utilized, while the remaining parties maintained that average cost rates were appropriate. We believe that a 13-month average capital structure with average cost rates best represent the sources of funds used to finance Gulf's rate base. A 13-month average capital structure is a better representation of a utility's financing mix than a year end capital structure under most circumstances. Since capital must be raised in separate components, a single point in time may be too heavily weighted with one type of capital. A 13-month average capital structure smooths the effects of a particular incremental addition of capital. The utilization of average cost rates is especially appropriate in a case such as this one in which a fully projected test year is employed.

Gulf proposed that its capital structure be comprised of long-term debt, preferred stock, common equity, customer deposits, tax credits and deferred taxes. [*74] There is no short-term debt included because Gulf has no projected outstanding short-term debt for the 1983 test year.

Mr. Larkin, Public Counsel's witness, proposed the same components with the exclusion of Job Development Investment Tax Credits (JDIC), arguing that excluding JDIC would lower the weighted cost of debt and increase the weighted cost of equity. For the reasons that follow in the discussion on tax credits, we find that Gulf's capital structure should include JDIC as well as the other components proposed by Gulf.

Approved Capital Structure and Fair Rate of Return

Based on our review of the record, we approve and adopt the following capital structure and indicated capital costs:

GULF POWER COMPANY
Cost of Capital - 13-Month Average
Test Year Ending 12/31/83

Class of Capital	$ Amount	Percentage of Total Capital	Cost Rate	Weighted Cost Rate
1. Long term debt	281,146,610	44.14	9.21%	4.07%
2. Short term debt				
3. Preferred stock	53,770,592	8.44	8.31	.70
4. Customer Deposits	7,659,532	1.20	7.84	.09
5. Common Equity	169,277,229	26.58	15.85	4.21
6. Tax Credits - Zero Cost	1,548,454	.24		
7. Tax Credits-Weighted Cost	40,662,102	6.39	9.69	.62
8. Deferred Income Taxes	82,831,481	13.01		
TOTAL	$636,896,000	100.00		9.69%

[*75]

RANGE OF RETURN ON EQUITY 14.85% 16.85%
RANGE OF OVERALL RATE OF RETURN 9.41% 9.98%

Capital Structure Component Cost Rates and Amounts

To fully establish a capital structure, we must identify the sources of capital to be included and establish the amount and cost of each source.

Long-Term Debt

Gulf had originally proposed the use of an average balance of long-term debt of $393,187,000 on a system basis in conjunction with a year-end cost rate of 9.20%; however, Gulf in its brief, proposed the use of an average cost rate for long-term debt of 9.21%. Public Counsel's witness proposed an average balance for long-term debt of $271,986,000 on a jurisdictional basis with an average cost rate of 9.28%.

The FEA's position was that long-term debt should consist of $393,187,000 on a system basis at an average cost rate of 8.78%, utilizing a substitute Plant Daniel adjustment based upon recent debt and preferred costs, rather than the adjustment calculated by Mr. Scarbrough.

Included in Gulf's proposed capital structure was certain debt related to Gulf's Unit Power Sales from Plant Daniel. Consistent with our decision to remove Plant Daniel UPS from jurisdictional [*76] consideration in this case, we have removed $56,200,000 of long-term debt from Gulf's capital structure at the 10.43% rate provided for by the UPS contract.

Based upon our reconciliation of the utility's capital structure with its approved rate base, we find the appropriate long-term debt component to be a 13-month average balance of $281,146,610 with an average cost rate of 9.21%.

Preferred Stock

Gulf proposed that the preferred stock component of its capital structure consist of an average amount of $77,105,000 on a system basis at a year end cost rate of 8.29%. Public Counsel recommended that preferred stock consist of $53,927,000 on a jurisdictional basis at an average cost rate of 8.61%, which does not include an adjustment for UPS. The FEA recommended an amount of $77,105,000 on a system basis at an average cost rate of 8.08%.

Included in Gulf's proposed capital structure was certain preferred stock related to Gulf's Unit Power Sales from Plant Daniel. Consistent with our decision to remove Plant Daniel UPS from jurisdictional consideration, in this case, we have removed $12,321,000 of preferred stock from Gulf's capital structure at the 10.15% rate provided [*77] for by the UPS contract.

Consistent with our adjustments to the rate base, we find that the appropriate amount and cost rate for preferred stock are $53,770,592 and 8.31%, respectively.

Customer Deposits

Gulf proposed customer deposits in the average amount of $8,687,000 on a system basis at a cost rate of 7.84%, which is the effective cost rate when the deposits of inactive customer accounts are considered. Public Counsel proposed that $6,086,000 (jurisdictional basis) of customer deposits be included in capital structure at the same cost rate of 7.84%. The FEA also utilized the 7.84% cost rate with $8,687,000 (on a system basis) of customer deposits.

Consistent with our reconciliation of rate base to capital structure, we find that the appropriate amount of customer deposits to be included in the capital structure is $7,659,532. Recognizing that the utility pays no interest on customer deposits held in inactive accounts and that these funds are therefore cost-free, we find that the appropriate cost rate for customer deposits is the effective cost rate of 7.84%.

Short-Term Debt

As stated earlier, Gulf has no projected outstanding short-term debt for the test [*78] year.

Return on Equity Capital

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

Gulf's position was that it had $236,141,000 (system basis) of common equity at a cost rate of at least 17.5%. Public Counsel took the position that the utility had $159,909,000 (jurisdictional basis) of common equity and that a cost rate of 15.05% was appropriate. The FEA took the position that Gulf had $236,141,000 (system basis) of common equity and that 14.7% was a fair and reasonable return.

Amount of Common Equity

Consistent with our adjustments to the Company's proposed rate base, we find that the appropriate amount of equity capital is $169,277,229.

Cost of Equity Capital

Dr. Arthur T. Dietz, a witness for Gulf, relied on a discounted cash flow (DCF) model and a risk premium analysis in measuring the utility's cost of equity capital. He applied a modified DCF model to determine the cost rates for Gulf's two sources of equity capital: 1) capital contributions from the Southern Company and 2) retained earnings. Since Gulf is a wholly-owned subsidiary of the Southern [*79] Company, a publicly-traded holding company, Dr. Dietz relied on market data for the Southern Company in utilizing his DCF model. He testified that, including an allowance for issuance costs, his DCF calculation resulted in a cost of new common equity for the Southern Company of 18%.

Based on his two assumptions, Dr. Dietz concluded Gulf's cost of retained earnings was between 15.5%-18.4%. When he utilized these two components along with Gulf's projected 70%/30% split between new equity and retained earnings for acquiring new capital, Dr. Dietz concluded that Gulf's cost of common equity was at least 17.5%.

Mr. Charles A. Benore, another Gulf witness, calculated the Company's cost of common equity utilizing a DCF model, a risk premium analysis and a financial integrity test. Mr. Benore's DCF approach used the industrial companies represented by the Standard & Poors 400 Index as a proxy for measuring Southern Company's risk.He stated that this was a valid approach because he considered the Southern Company, and therefore Gulf, to be at least as risky as the average industrial company. Utilizing the current yield for the Standard & Poors 400 Index of 5.7% as the yield component [*80] for his DCF model along with the projected 1983 nominal growth in GNP of 10.5% as his growth component of his DCF model, Mr. Benore arrived at 16.2% as Gulf's appropriate cost of common equity before adjusting for issuance costs. After an adjustment of 5%-10% for issuance costs, Mr. Benore estimated a cost of common equity of 17.1%-18.0%.

In his risk premium analysis, Mr. Benore concluded a cost of common equity of 17.1% by adding his risk premium of 5.1% to the 12.0% projected yield for long-term U.S. Government bonds in 1983. In analyzing the return required by his financial integrity test, Mr. Benore first concluded that Gulf should increase its bond rating from its present A to an AA in order to enable it to raise capital more favorably in the future. After analyzing the several financial indicators associated with bond ratings and financial integrity, Mr. Benore concluded that Gulf would need to earn at least 18% on common equity if it were to have an opportunity to achieve an AA bond rating. Considering each of his tests and giving the greatest weight to his financial integrity test, Mr. Benore recommended that Gulf be allowed to earn at least 17.5% on common equity.

Mr. [*81] Miller, FEA's cost of capital witness, based his recommendation on the results of his DCF analysis. First, Mr. Miller compared Gulf with 94 other electric utility companies whese cost of capital he said represented a good approximation of the cost of common equity capital to Gulf. Mr. Miller found that the cost of equity capital for the 94 companies was 14.8%-15.6% based upon a dividend yield of 12.1% plus a growth rate of from 2.7%-3.5%.Based on his comparative regression analysis of these companies, Mr. Miller concluded that Gulf's cost of common equity was 0.3% below the 94 utility average and that, therefore, a reasonable range for the cost of common equity to Gulf was from

14.5%-15.3%. Mr. Miller's second DCF analysis was based on the utilization of the Southern Company as a proxy for Gulf. Finding a May-July, 1982 average Southern dividend yield of 13.2% and an expected growth rate of 1.8%-3.0%, Mr. Miller determined a cost of common equity in the range of 15.0%-16.2%. Because he considered Gulf less risky than the Southern Company, Mr. Miller concluded that Gulf's cost of equity should be 0.6% less than the cost to the Southern Company. When considering both [*82] of his DCF approaches, Mr. Miller recommended that the cost of common equity to Gulf, including an issuance allowance of 0.2%, was in the range of 14.7%-15.5%.

Mr. Parcell, Public Counsel's witness, relied upon a DCF analysis and a comparable earnings analysis in determining Gulf's cost of common equity. Utilizing a DCF analysis based upon a five-year historical period for both his yield (11.5%-12.5%) and growth (1.5%-2.5%) components and an issuance allowance of 4.3%, Mr. Parcell concluded that the cost of common equity to the Southern Company was 13.6%-15.6%. In his comparable earnings analysis, Mr. Parcell examined the return on common equity for the past five years for the Standard & Poors 400 Industrials. As a result of his analysis, Mr. Parcell determined that the industrial group has earned 15.0%-15.5% on common equity for the past five years. Based upon reported stock rankings, Mr. Parcell found that the electric utility industry in general was less risky than the industrial group and that, therefore, the appropriate cost of common equity for Gulf based on comparable earnings would be in the range of 14.0%-15.0%. Taking into consideration the results of both his DCF model [*83] and comparable earnings approach, Mr. Parcell concluded that a reasonable return on common equity for Gulf would be in the range of 14.5%-15.6% and that the midpoint of 15.05% be used to determine Gulf's overall cost of capital.

In this proceeding, we have heard expert testimony (all using variations of the DCF model) proposing returns on equity ranging from 14.5% to 18.0%.

From its analysis of the testimony and exhibits of each of the witnesses on this subject, as well as other record evidence, our Staff recommended that a reasonable cost of equity capital for Gulf lies within a range of 15.8% to 17.4%, with the futher recommendation that, giving greater weight to the somewhat lower returns produced by the witnesses' DCF models, we set 16.5% as the appropriate cost of equity capital for the purpose of calculating an overall rate of return.

We find the return on equity capital of 16.5% recommended by the Staff is slightly high in view of money markets at the time of our decision.

Lastly, we note that there has been a continuing downward trend in long-term interest rates and the rate of inflation over the some seven months that have elapsed from the filing of this case [*84] to the date of our decision. We note further, that there exists a strong relationship between the direction taken by these rates and the cost that investors demand for the use of their equity capital.

Considering the testimony and exhibits presented in this case, as impacted by the factors discussed above, we find that the appropriate and reasonable cost rate of common equity capital for Gulf Power Company is 15.85%, which, although slightly below the range recommended by our Staff, is well within the overall range of 14.5% to 18.0% testified to by the witnesses in this case.

Tax Credits - Weighted Cost

Gulf proposed that its capital structure be comprised of long-term debt, short-term debt, preferred stock, customer deposits, common equity, 3% Investment Tax Credits, Job Development Investment Tax Credits (JDIC) and deferred income taxes. Mr. Larkin, Public Counsel's witness, proposed the same components with the exclusion of JDIC, arguing that excluding JDIC will lower the weighted cost of debt and increase the weighted cost of equity. Mr. Larkin stated that were JDIC not available to Gulf, it would be required to raise an equivalent amount of capital from alternative [*85] sources, which, presumably, would include additional debt. Such debt capital, urges the Public Counsel, would require interest payments which would be deductible in determining above-the-line income taxes. Thus, Public Counsel asks that the Commission exclude JDIC from the capital structure and impute the hypothetical reduction in income tax expense in calculating the utility's above-the-line income taxes.

Mr. Larkin stated that were JDIC not available to Gulf, it would be required to raise an equivalent amount of capital from alternative sources, which, presumably, would include additional debt. Such debt capital, urges the Public Counsel, would require interest payments, which would be deductible in determining above-the-line income taxes. Thus, Public Counsel asks that the Commission exclude JDIC from the capital structure and impute the hypothetical reduction in income tax expense in calculating the Company's above-the-line income taxes.

Gulf asserts that $48,345,000 of JDIC, on a system basis, should be included in the capital structure at the Company's overall rate of return. Gulf states that the cost rate for JDIC is controlled by provisions of the Internal Revenue Code [*86] and the Internal Revenue Service (IRS) regulations, which require a return "not less than the taxpayer's overall cost of capital (determined without regard to the credit)." Gulf argues that the Public Counsel's hypothetical interest expense imputation is clearly improper and impermissible under the IRS regulations and would jeopardize Gulf's ability to continue to take the JDIC. Gulf submits that it has calculated the return on JDIC in the only manner consistent with the applicable statutes and IRS regulations and argues that placing the revenues associated with the "before tax" calculation of JDIC subject to refund would serve no useful purpose and would undermine the Company's financial integrity by placing a cloud over a portion of its revenues.

On the basis of the record in this case, we find that JDIC is presently required by Internal Revenue Service regulations to earn not less than the overall rate of return and be treated as if supplied by the common shareholders. In order to achieve a return equal to the overall rate of return, JDIC must earn an after tax return in the same manner as the funds supplied by common shareholders. However, under Public Counsel's proposed [*87] imputation of interest to JDIC supplied capital, JDIC capital would earn less than the overall rate of return and thereby subject the utility to the possible violation of Internal Revenue Service Regulations and therefore loss of JDIC.

According to the Public Counsel, the treatment of JDIC he has proposed has been followed by regulatory bodies with the JDIC adjustment being upheld on appeal to the Federal Courts. It also appears, though, that the IRS has not been a party to any of those actions and that no definitive decision on the issue has yet been reached. Ruling requests on the imputation of interest to JDIC capital have been filed with the IRS but, to date, no ruling on the issue by the IRS has been forthcoming. Should the IRS rule that the interest imputation on JDIC is consistent with its regulations, we believe that imputing such interest is the appropriate regulatory treatment and shall do so. Within 30 days after the date of this Order Gulf shall file with this Commission for approval a letter request for ruling on this issue to be subsequently submitted to the IRS. Accordingly, we shall hold the revenues associated with this proposed adjustment subject to refund [*88] for the period of twelve months. Should an IRS ruling approving the interest imputation be received a refund of the twelve months revenue, or $1,811,819, shall be ordered.

Tax Credits - Zero Cost

We have determined that it is appropriate to include zero cost investment tax credits in the capital structure. FEA is opposed to this treatment but we have included these tax credits since they are a source of funds to the Company.

Deferred Income Taxes

All parties except FEA agreed that deferred taxes are a source of funds to the Company and, as such, should be included in the capital structure.

Conservation Award

In Gulf's previous two rate cases we granted the Company 10 additional basis points on the overall rate of return reward for its superior efforts in conservation. Rather than consider it in this proceeding, all parties agreed to sever that issue from this case and consider it in the Company's Conservation Cost Recovery Proceedings.

REVENUE EXPANSION FACTOR

The purpose of the revenue expansion factor (NOI multiplier) is to gross up or expand the Company's net operating income deficiency to compensate for income taxes and revenue taxes that the [*89] Company will incur as the result of any revenue increase. We find that an NOI multiplier of 1.980261 should be used in this case. It is developed as follows:

Revenue Requirement	100.0000%
Gross Receipts	(1.5000)
Regulatory Assessment Fee	(.0625)
Net Before Income Taxes	98.4375
Income Taxes	(47.9391)
Revenue Expansion Factor	50.4984%
NOI Multiplier	1.980261

REVENUE DEFICIENCY

Having determined the Company's rate base, the test year NOI, and the overall fair rate of return, we can now calculate any excess or deficiency of revenues. Multiplying the rate base value of $636,896,000 by the fair overall rate of return of 9.69% yields an NOI requirement of $61,715,000. The adjusted NOI for the test year amounted to $60,015,000, resulting in an NOI deficiency of $1,700,000. Applying the appropriate NOI multiplier of 1.980261 to this figure yields a deficiency of $3,366,000 in gross annual revenues. We find and conclude that Gulf Power Company should increase its rates and charges so as to generate this amount of additional annual revenues. The Company is therefore authorized to do so.

RATE STRUCTURE AND RATE DESIGN

Having ascertained the Company's [*90] revenue requirement and the amount of revenue increase necessary, we now turn our attention to rate design. We must determine the rate of return currently earned by each rate class, the increase in revenue requirement allocated to each class, and how each class' revenue responsibility will be spread between the customer, energy, and demand charges. In this rate proceeding, we have also reviewed the continued appropriateness of several aspects of the Company's rate structure. We begin first with the cost of service studies presented in this case.

Cost of Service Methodology

In this rate case, several cost of service studies based on different demand allocations were presented to us for consideration: the 12 coincident peak method (12 CP), the 12 coincident peak and one-thirteenth weighted average method (12 CP & Avg.), a seasonally differentiated method whereby demand allocators are weighted to reflect utilization of facilities by season, an annual peak method, and a three summer peak method.

We continue to believe that the 12 CP & Avg. method is the best demand allocation methodology to use in Florida. Because Gulf buys and sells reserve capacity from other Southern [*91] operating companies based on the level of its monthly reserve margins, which, in turn, are the result of the size of Gulf's monthly system peaks, the size of all monthly peaks have an important impact on the cost of serving Gulf's retail customers. Thus the majority of production costs should be allocated on the basis of each class' contribution to all of the monthly peaks. Additionally, one-thirteenth of production costs should be allocated on the basis of each class' average demand so that each class will pay for some portion of the production plant it uses, even if the usage is not coincident with the system peak. This is consistent with our view that some of the production plant costs, such as coal handling equipment, while allocated on the basis of demand, vary more with the amount of KWH produced than with the demand placed on the system.

In designing rates, we have selected the Staff Requested cost of service study (Ex. 246) and the adjusted class rates of return that result from that study shown on Ex. 16G.The major differences between the Staff Requested and the Company's 12 CP & Avg. study are that the Staff Requested study does not recognize the concept of a minimum [*92] distribution system, allocates EPRI and other industry dues on the basis of energy, allocates conservation costs on the basis of energy, and allocates miscellaneous service charge revenues in the same manner that the costs associated with the service charges are allocated. The Staff's treatment of all of these items is correct.

Both the Company and Air Products objected to the allocation of conservation costs on the basis of energy, contending that these costs should be directly assigned to the customer classes for which the costs were incurred. However, on a number of occasions, we have stated our policy that since all customers benefit from conservation programs, the costs of approved conservation programs should be recovered from all customers based on KWH consumption. Mr. Carzoli acknowledged during his cross examination that if a group of conservation programs results in a reduction of of peak demand which, in turn, causes the avoidance or deferment of capacity related costs, all customers would benefit by lower demand or energy related costs. He agreed that if a group of conservation programs results in a lower monthly system peak than the Company would have had without [*93] the conservation programs, the payments Gulf would make or receive for reserve capacity to or from other Southern operating companies would be affected. He also agreed that to the extent that conservation programs result in decreased system peaks and thus a reduced need to purchase additional reserve capacity, all customers benefit from the conservation programs.

The Company and Air Products also argued that the Commission should select a cost of service study for use in designing rates that recognized the concept of the minimum distribution system. Mr. Pollock and Mr. Carzoli testified that certain portions of the distribution system must be in place so the utility can provide service if and when the customer desires it, and that this portion of the distribution system should be classified as customer rather than demand related. Public Counsel took the opposite position. In the last three electric utility rate cases, we have determined that only the meter and service drop portion of the distribution system are properly classified as customer related. The evidence presented by the Company and Air Products has not persuaded us to change our minds. For this reason, we [*94] selected the Staff Requested cost of service study, which does not recognize the minimum distribution system concept, for use in this proceeding.

The Staff Requested study shows a rate of return for the OS-III class of 32.97% at present rates. This class is composed of traffic signals, cable TV amplifiers, and other facilities with similar operating characteristics. Evidence adduced at the hearing tended to show that the return for this class is so high because of the way in which service drops were allocated in the cost of service study. Service drops were allocated based on the average number of customers; in the OS-III class, the customer is a municipality who has several traffic signals or numerous streetlights served by one bill. However, Mr. Carzoli agreed that some form of service drop is required for each light or signal, and that by using the average number of customers to allocate service drops, a much smaller number of drops than those actually installed for the class, was allocated to it. Mr. Carzoli stated that the return for the class was thereby significantly overstated. He did not attempt to adjust or recalculate the rate of return for this class because the [*95] Company needs to make an analysis to determine a more accurate allocation of service drops for the outdoor lighting classes. Because of this inaccuracy in the cost of service study, a rate decrease for this class is not warranted.

Allocation of the Revenue Increase

The results of the Staff Requested 12 CP and one-thirteenth weighted average demand cost of service study show the following rates of return (ROR) earned by the various customer classes:

Rate Code	Rate Schedule	Present ROR/Index
RS	Residential	8.71%/ .92
GS	General Service	16.01%/1.70
GSD	General Service Demand	10.55%/1.12
LP(GSLD)	General Service Large Demand	10.30%/1.09
PX	High Load Factor	7.63%/ .81
OS I-II	Street Lighting	9.01%/ .96
OS III	Outdoor Lighting	32.97%/3.50
Total Retail		9.42%/1.00

We have granted the Company an overall increase of $3,366,000. Staff recommended and we approve that miscellaneous service charges be increased to full cost, that the poultry farm transition rate be increased 25%, and that the remainder be allocated to the RS and PX classes whose present rates of return are the farthest below parity. The RS and PX classes receive increases of 1.01% and [*96] 3.79% (with fuel) as a result of this process.

The class rates of return with the revenue increase fully allocated are:

Rate Code	Rate Schedule	Approved ROR/Index
RS	Residential	8.99%/ .93
GS	General Service	16.13%/1.67
GSD	General Service Demand	10.57%/1.09
LP(GSLD)	General Service Large Demand	10.30%/1.07
PX	High Load Factor	8.99%/ .93
OS I-II	Street Lighting	9.04%/ .94
OS III	Outdoor Lighting	32.97%/3.41
Total Retail		9.69%/1.00

Load Research

Load research is used to estimate class contributions to monthly system coincident peak demands and class noncoincident demands for those classes of customers not equipped with magnetic tape meters. These estimates are used to develop allocation factors for demand-related items in the cost of service studies, such as generation, transmission and distribution plant, and related operation and maintenance expenses.

For this rate proceeding, Gulf found it necessary to conduct load research for the RS, GS, GSD and the LP rates classes. Gulf contends that the load research results are adequate for all classes. In its last rate case, Docket No. 810136-EU, we criticized Gulf for the poor quality of its [*97] load research. In this case, the quality of the load research for some clasess has been vastly improved.

Gulf selected probability samples for the RS, GS, GSD and a part of the LP class. We are therefore able to evaluate the statistical precision of the load research results. The precision of the load research for the classes at the 90% confidence level were +/- 10.79% for the RS class, +/- 11.1% for the GSD class, +/- 5.8% for the LP class and +/- 53% for the GS class. With the exception of the GS class, we find this level of precision acceptable at the present time. Testifying in support of the Company's position, Mr. Shearer stated that he considered +/- 53% at the 90% confidence level an acceptable level of precision for the GS class, in view of the small size of the class. In the absence of a cost benefit analysis demonstrating that the costs of attaining precision of +/- 10% at the 90% confidence level for the GS class clearly outweighs the benefits of doing so, we cannot accept his proposition.

However, we intend to open a generic investigation to determine what criteria for acceptable load research ought to be established by the Commission. In the meantime, we accept [*98] the load research proffered by Gulf with the realization that the precision of the class rates of return shown in the cost of service studies rises and falls with the accuracy of the load research performed for that class.

Customer Charges

The Company proposed to increase customer charges from those set in the previous rate case approximately one year ago. However, the Company did not carry its burden of proof with respect to the customer unit cost data filed in this case. In its original filing of customer unit costs, the Company included costs attributed to a minimum distribution system, EPRI and other industry dues, energy conservation costs, and the uncollectibles cost. When these items are removed from customer unit costs, as they should be, the unit costs for the GSD class and the GSLD class of $12.40 and $23.13 appear to be unreasonably low. Conversely, the GS class customer unit cost of $8.42 appears to be too high. In the absence of reliable customer unit cost data, customer charges will remain at their present levels. They are as follows:

Rate Code	Rate Schedule	Approved Customer Charge
RS	Residential	$ 5.00
GS	General Service	$ 7.00
GSD	General Service Demand	$19.50
LP(GSLD)	General Service Large Demand	$27.00
PX	High Load Factor	$60.00

[*99]

Demand Charges

At the present time, Gulf's three demand classes, GSD, LP (GSLD), and PX all have demand charges of $5.00 per KW per month.The Company proposed to increase them and inaugurate seasonally differentiated demand charges.

The demand unit costs for these classes are $8.13 for GSD, $9.11 for LP (GSLD), and $11.73 for PX. We believe demand charges should move in the direction of unit costs. When demand charges are set below unit costs, the difference is recovered through the energy charge with the result that high load factor customers subsidize low load factor customers. Because we have not increased the revenue requirements of the GSD and LP classes and have given a relatively small increase to the PX class, an increase in demand charges is a reallocation of revenue responsibility within each class. Therefore, to minimize the impact on low load factor customers, we will increase the demand charges to $6.25 per KW per month for the GSD and LP classes. On the other hand, rate PX is an optional rate for high load factor customers. Thus, we approve an increase of 50% of the PX demand charge to $7.50 per KW per month.

We reject the Company's proposal [*100] of seasonally differentiated demand charges. The cost of services submitted in this case showed that in 1981 two of the winter month system peaks were 87% of the annual system peak which occurred during the summer month, which implies that Gulf may well become a winter peaking system. To institute a lower demand charge in the winter months sends customers the wrong signal and we do not want customers to make long term decisions in anticipation of seasonally differentiated demand charges. Seasonal demand charges are also inconsistent with the 12 CP and Average cost allocation methodology we have endorsed.

Energy Charges

Air Products raised the issue of whether Gulf's proposed energy charges were properly calculated and took the position energy charges should recover only energy costs and should not be used to recover any fixed costs. While we agree in theory, we must be fair to both high and low load factor customers and move in a gradual fashion toward demand and energy charges set at full unit costs.

Service Charges

The Company proposed to increase service charges from $13.00 to $16.00 for initial connection, normal reconnection, and disconnection after cause, [*101] the collection charge from $4 to $6 and the meter tampering fee from $25.00 to $30.00. The Company submitted a cost analysis for each charge as part of the MFR's. Staff reviewed the analyses and recommended that the increases be approved. We agree that the proposed charges are cost based and the charges proposed by the Company are approved.

TOD Rates

Several issues were raised concerning TOD rates. Staff and Public Counsel proposed that mandatory TOD rates be established for customers with demands in excess of 2,000 KW per month. The Company stated that it was uneasy and wary of the idea but it did not think that it was improper to establish mandatory TOD rates for this group of customers. We approve the proposal with the proviso that no customer affected by it will pay more than 10% above the non-TOD rate in any month. We approve mandatory TOD rates because they are more cost based than standard rates and will provide a superior price signal to customers. TOD rates will encourage large customers to change their load patterns in a manner which may reduce the Company's peak capacity requirements. For large customers, additional metering costs are either zero [*102] because the meters are already in place, or small relative to the cost savings, due to the potential shifts in usage.

Air Products stated that while it had no theoretical objection to mandatory TOD rates, it was concerned that mandatory TOD rates for large customers only would result in interclass subsidies. The concern of Air Products is unfounded. The load factor method used to calculate TOD rates results in a revenue neutral rate. Class revenues under mandatory TOD rates will be exactly equal to what they would be with standard rates.

As in its last rate case, Gulf proposed several modifications of their summer and winter peak periods used for time of day rates. The Company wanted to shorten the summer peak period from April through October to June through October but lengthen daily summer peak periods which are now 12 AM through 10 PM to 10 AM through 10 PM. Gulf wanted to lengthen the months considered winter from the current November through March to November through May, but shorten the winter daily peak hours which are now 6 AM to 10 AM and 6 PM to 10 PM by eliminating the 6 PM to 10 PM peak period. The Company argued that the proposed peak periods more closely match [*103] its actual peak demand periods.

As we said in the last rate case, we made a deliberate decision to treat the state as one pooled system and therefore established uniform statewide peak periods in Docket No. 780793-EU. With sufficient interconnections between utilities, there is no question that treating the state as one system will lead to greater economic benefits than treating each individual utility as an island. Gulf introduced no evidence that contradicts our opinion that it should be given every encouragement to interconnect more strongly with the rest of Florida.

Gulf's proposed peak periods are inconsistent with our policy of statewide uniformity and therefore are rejected.

Public Counsel raised the question of whether the on peak/off peak price differentials proposed by the Company for rates RST and GST were so large as to discourage participation in these voluntary rates. Public Counsel need not fear that large on peak/off peak differentials will discourage participation in TOD rates. Customers whose usage is more on peak than that of the class as a whole, will never benefit from TOD rates, no matter what the differential. Customers whose usage is more off peak than [*104] the class as a whole, will benefit from TOD rates no matter what the differential. Thus increasing the differential will simply increase the amount of savings realized by customers who do benefit from TOD rates.

Using the load factor method and an estimate of the on peak/off peak ratios of the billing determinants for these classes, Staff calculated on peak/off peak differentials for rates RST and GST. When the Company submits its rates for final approval, it must also submit to Staff its working papers used to calculate the rates so that the estimated ratios of billing determinants may be checked.

The final issue with respect to TOD rates is the minimum term of service requirement. The Company is concerned that customers will opt for TOD rates for a few months when their off peak usage is greatest and then switch back to the standard rate when their percentage of consumption that is off peak declines. To prevent this, the Company proposed a minimum five-year term of service for rate PXT and a minimum one-year term of service for all other TOD rates.We believe that a one-year term of service for customers opting for TOD rates for the first time would unnecessarily [*105] discourage customers from trying TOD rates. Therefore no minimum term of service requirement may be imposed on customers opting for TOD rates for the first time. The Company may impose a minimum one-year term of service on customers the second time they opt for a TOD rate. Since we have decided to establish mandatory TOD rates for customers with demands in excess of 2,000 KW, all PX customers will now take service on a TOD rate. Therefore, the five year term of service requirement that is part of rate PX will also apply to PXT customers.

Outdoor Service Rates

The Company and Staff agreed that the street and outdoor lighting rates, OS-I and OS-II, are reasonably cost based, and Staff recommended no changes in the Company's proposed rates if the class was not allocated an increase. We find that the rates are reasonably cost based and approve them as proposed by the Company.For the sake of clarity, the charge currently known as the facilities charge will be designated as the fixture charge.

Deregulation of Outdoor Lighting

During the course of these proceedings, the Commission, on its own motion, raised the issue of whether the Company should continue to install outdoor [*106] lighting fixtures as part of its regulated enterprise. Several questions were raised concerning this issue: (1) Is it fair for an electric utility to provide this service at embedded cost rates if its competitor, a private electrical contractor, must offer the same service based on current costs? (2) Should an electric utility continue to devote some of its increasingly expensive capital to a service that is not essential to the provision of electricity to its customers? (3) If this service is deregulated and private contractors effectively compete with the Company, what steps can or should be taken to ensure that only energy efficient light fixtures are installed on the Company's system? (4) What, if any, adjustments should be made for those customers currently receiving outdoor lighting service on a nonmetered basis? While these questions were raised at the hearing, and the Company stated that it was not opposed to deregulation, the issues were not adequately explored, and since this issue affects all investor-owned utilities, we intend to open a generic docket on this subject.

Poultry Farm Transition Rate

Before Gulf's last rate case, poultry farm customers [*107] were billed on the residential rate.In the last rate case, we determined that these customers should ultimately be served on the GS rate and established a transition rate for them. The question in this case is whether to continue the transition rate or move the customers to the GS rate. The Company proposed to move them. However transferring these customers to the current GS rate would increase their bills by 36% with fuel and 58% without fuel. An increase of this magnitude is not warranted. A transition rate will be continued for this class; but the energy charge of the present transition rate will be increased by 25% over present revenues without fuel.

Minimum Bill Provision

For many years Gulf's tariffs that included a separately stated demand charge also included a ratchet provision that required a customer to pay a minimum level of demand charges every month regardless of whether his actual demand attained that level. In Gulf's last rate case, we eliminated these ratchet provisions because we believe they are a disincentive to conservation. The tariffs containing a separately stated demand charge filed for our approval in this case contain the following provision: [*108]

Minimum Monthly Bills- In consideration of the readiness of the Company to furnish such service, no monthly bill will be rendered for less than the Customer Charge plus the Demand Charge. For determination of Minimum Monthly Bills only, the billing demand shall not be less than seventy-five percent (75%) of the capacity required to be maintained.

At the hearing, Mr. Haskins testified that the effect of this provison is to require a customer to pay on a monthly basis his energy charges plus the highest of either his actual demand plus the customer charge, or the customer charge and the demand charge times 20 KW, or the customer charge and 75% of the capacity required to be maintained, the third provision applying only if the customer has signed a contract. The Company feels that it has the option to require a general services customer to sign a contract if it has to make an unusual investment to serve that customer and the Company believes it may not recover that investment through the normal course of operations. The Company's present policy is to require all customers with minimum monthly demands in excess of 500 KW to sign a contract. Although on its face the minimum [*109] monthly bill provision applies to all customers, in practice it is applied only to customers with large demands or customers who, in the opinion of the Company, require an unusual investment.We are troubled by this provision for two reasons. First, to those customers to whom it is actually applied, it functions as a ratchet, albeit a low one. The Company has available to it another means of ensuring that it recovers unusual investments it must make to serve a particular customer. It may require such a customer to make a Contribution in Aid of Construction. There is no support in the record for the proposition that every large customer imposes a risk of unrecovered investment such that a special contract or minimum bill provision must be applied to him.

Our second concern arises from the fact that this is a blanket provision contained on every demand tariff that is not uniformly applied to all customers. At best this gives the appearance of arbitrary treatment by the Company and it violates the principle of uniformity of tariff application.

For both of these reasons the minimum bill provision in its present form must be eliminated. However a minimum bill provision [*110] should be retained for those customers who, for economic reasons, opt for a rate for which they do not qualify. This will discourage customers from migrating to rate schedules designed for customers with dissimilar load characteristics, and thus preserve the homogeneity of the rate classes. The Company shall include a minimum bill provision of this type in the final tariffs it submits for approval as a result of this proceeding.

Transformer Ownership Discounts

Transformer ownership discounts are needed because the demand charge for each rate schedule includes costs associated with all the transformations necessary to provide service at the secondary distribution level. If a customer takes service at a voltage level higher than the secondary distribution level and thus provides his own transformation, a credit is warranted to cover those transformation costs not required to serve him. The current transformer ownership discounts are 25¢ per KW for - customers taking service at primary voltage and 70¢ per KW for those receiving service at transmission level. The Company proposed a uniform discount of 40¢ per KW. The method used by the Company to develop the uniform discount [*111] is not correct and we disagree with the concept of a uniform discount since there are differences in cost between service at primary voltage and transmission level. Because of this and because of the size of the revenue increase we have granted, the present transformer ownership discounts, which were developed less than a year ago, will be retained.

Voltage Level Discounts

At the present time, Gulf does not have voltage level discounts in its tariffs. Mr. Haskins acknowledged that customers who receive service above the primary distribution level absorb costs related to line and transformation losses that would otherwise be incurred by the Company, and the only reason the Company does not provide such discounts is a desire for tariff simplicity. However the difference in the costs of serving these customers should be recognized and we therefore approve discounts of 2% for customers served at transmission level and 1% for customers served at primary level.

Standby Service

St. Regis Paper Company intervened in this proceeding and offered the testimony of Mr. Harold Cook on the subject of standby and auxilliary rates for cogenerators and small power producers. [*112] Mr. Cook contended that because cogenerators do not require continuous firm service they should not be assessed the same demand charges required from firm customers. He recommended a special rate for cogenerators, the main feature of which is a percentage reduction of demand charges equivalent to the Company's percentage reserve margin used for system planning purposes.

In other recent rate cases (see Docket Nos. 820007-EU and 820097-EU), we achieved a similar result by removing all ratchets and minimum bill provisions from the demand tariffs and then establishing the otherwise applicable TOD rate as the standby rate for customers who produce their own power. We think this course preferable to Mr. Cook's proposal because it gives cogenerators an incentive to schedule maintenance during off peak periods, and if a cogenerator has a forced outage during a peak period he will be assessed the full cost of providing service to him. We will continue our policy in this case. As we have removed the generally applicable minimum bill provision, and since Gulf's present standby and auxiliary service rate is the otherwise applicable TOD rate, no further adjustment is necessary.

GS and [*113] GSD Breakpoint

At the present time the breakpoint between rates GS and GSD is 20 KW. This is the point at which a customer begins to incur a separately stated demand charge. There was some suggestion that perhaps the breakpoint should be raised to 50 KW. Staff recommended that the breakpoint not be changed at this time because of the lack of evidence as to what the breakpoint ought to be. We accept Staff's recommendation and accordingly make no change.

Elimination of Rate LP(GSLD)

Gulf has four rate schedules for commercial and industrial customers, GS, GSD, LP(GSLD), and PX, the latter an optional rate for high load factor customers. Gulf proposed to eliminate rate LP and place all General Service demand customers on GSD except those opting for rate PX. This proposal does not comport with sound rate design and we reject it.

The reason for having various General Service rate schedules is that the cost to serve customers varies depending on the customers' load characteristics. Mr. Pollock testified that the size, the delivery voltage, and the timing and rate of consumption are critical load characteristics. He agreed that in deciding whether to combine two groups [*114] of customers, the most important factors to consider are size, load factor, and coincidence factor. By definition, the demands of LP customers are greater than GSD customers, and it was Mr. Pollock's opinion that the load and coincidence factors of the two classes, as shown on Ex. 203 are significantly different for rate design purposes, and indicate that it would be unwise to combine the two rates.

The ratio of load to coincidence factor is the most important determinant of cost causation because it relates timing of demand to load factor. Ex. 203 shows that these ratios are 55.9 for rate GSD and 71.2 for rate LP. The coincidence factors for rate GSD and rate LP are 61.5% and 72.9% respectively;

the load factors for the two rates are 32.0% and 46.5%. In view of the large differences between the ratios of the two factors, as well as between the factors themselves, the two rates should not be combined. If the rates were combined, the result would be a much less homogeneous rate class with respect to the load characteristics critical for cost causation.

The Company wanted to eliminate rate LP because the it has moved closer to rate GSD in the last few rate cases. The [*115] Company contended that the analysis in Ex. 17G justified the elimination of the rate but we are unable to find anything in the exhibit that does so. There will always be some customers who will find it more economical to migrate to another rate schedule because of their particular load characteristics. It is not necessarily desirable to move these customers to another rate schedule as they may be more expensive to serve than the customers on the rate schedule to which they wish to move. For this reason we have retained a minimum bill provision for customers who opt for a rate for which they are not otherwise qualified.

Reactive Demand Charge

Gulf proposed to set the reactive demand charge at $1.40 per KVAR for KVAR's in excess of those which would have occurred if the customer had a 90% power factor. Currently the charge is $1.00 per KVAR. As we did in the last rate case, we reject the Company's proposal because it is based on the customer's, rather than the Company's, cost. Ex. 17R shows that it cost the Company approximately $1.00 per KVAR per month to correct a power factor by 10%. Mr. Haskins testified that the Company proposed a charge of $1.40 per KVAR because [*116] that is what it would cost a customer to buy and install the necessary capacitors to correct his power factor to 90%. In this context the customer's cost is irrelevant; we will continue to base the charge on the Company's cost and therefore there will be no change in the present charge of $1.00 per KVAR per month.

Qualifying Load Factor for PX

Rate PX is an optional high load factor tariff which presently requires a customer to contract for a demand of at least 7500 KW and maintain an annual load factor of 75%. Customers who opt for this rate would otherwise be served on rate LP.

The Company wanted to increase the qualifying load factor for this rate from 75% to 80%, on the ground that this was necessary to keep the qualifying load factor close to the economic breakeven load factor between rates LP and PX. The Company indicated that it has designed the PX rate with an economic breakeven load factor of 86-87%. However our goal in rate design is to achieve rate classes with homogeneous load characteristics so as to base rates as closely as possible on cost and avoid imposing costs on any customer for which he is not responsible. The average load factor of the [*117] LP class is 46.5%. If an LP customer has a load factor of 75%, he is closer in load characteristics to PX customers than LP customers and should be eligible for rate PX. Therefore the qualifying load factor of 75% will be retained.

Elimination of the Seasonal Service Rider

The Company has had an optional Seasonal Service Rider in effect for several years. The rider is designed to apply to a customer that is highly seasonal in nature, such as the hotels and motels along the beaches in the Company's service territory that operate only in the summer, and have essentially zero consumption during the winter months. Currently there are thirty-seven customers opting for service under this provision.

Essentially customers taking service on this rider agree to pay an additional $1.00 per KW of billing demand during the summer months, and in exchange, the Company waives the minimum billing demand provision of the customers' tariff. Because we have eliminated the minimum bill provision for all customers who qualify for a rate, this rider is no longer needed and therefore is eliminated.

Conservation Costs in Base Rates

In the recent FP&L rate case, Docket No. 820097-EU, [*118] we removed conservation costs from base rates and provided that all conservation costs be recovered through the Conservation Cost Recovery Clause. We did so to promote ease of identification of such costs, comparison of such costs between companies, and customer understanding. We will continue that policy in this case and thus all conservation costs will be removed from Gulf's base rates.

Legal Issues

Use of a Fully Projected Test Year

Public Counsel raised several legal issues during the course of this proceeding. The first was whether use of a fully projected test year is permissible under Florida law. As we have determined several times in the recent past, use of a fully projected test year is permissible under Florida law. The issue in this case differs slightly in that Gulf's case is based on a fully projected test year rather than a projected test year that is concurrent with the rate case. However, the purpose of setting rates for an electric utility is to provide an adequate return on equity and compensation for the reasonable costs of providing electrical service. Rates are set for the future, not for the past. To be adequate for the future, [*119] rates must be based on measures of investment and expense that will provide an adequate return during the time the rates will be in effect.

These principles have been clearly recognized by the Florida Supreme Court. In rejecting the use of a year-end rate base to offset attrition, the Court specifically authorized the use of an attrition allowance. Yet, measures of attrition inherently involve the use of projected data. The distinction between use of an attrition allowance in conjunction with a test year and the use of projected data is a difference in degree rather than kind. It is no more speculative to project changes in the factors that affect attrition than it is to assume that attrition in the future will precisely mirror attrition in the past.

The use of an historic test year with an attrition allowance, the use of a currently projected test year with an attrition allowance, or the use of a fully projected test year are different methods to produce the same result. Each is intended to provide a representation of the period in which the new rates, if any, will be in effect. We have determined in this case that Gulf's fully projected 1983 test year constitutes a valid [*120] basis for setting rates for 1983 and beyond. With the adjustments made herein, we conclude that Gulf's projected 1983 test year is based on reasonable projections and assumptions and thus permits us to set reasonable rates for the period in which they will be in effect.

Effective Date and Notice of New Rates

The next issue raised by Public Counsel was the effective date of the new rates. This issue was definitively settled by the Florida Supreme Court in Gulf Power Company v. Cresse, 410 So. 2d 492 (Fla. 1982), in which the Court ruled that the effective date of new rates is the date on which the issues were decided and the official vote was taken.

Public Counsel also urged us to require the Company to give ratepayers notice of the rate increase between the time the increase is granted and the new rates become effective. We find that the provisions of Sec. 366.04(1), F.S. permit us but do not require us to do so. At the present time, investor-owned utilities provide bill stuffers concerning the proposed rates and the service hearings when their application for a rate increase is filed with the Commission. They are also required to place quarter page legal [*121] notices in newspapers throughout their service territory. In addition, the Commission posts two legal notices, and issues press releases during the course of the proceeding. We find this to be sufficient notice and will not, as a matter of policy, require the Company to give additional notice of this proceeding

Payment of Previous Accounts Required

The next legal issue is whether, in light of Rule 25-6.105(8), F.A.C., the following provision contained in Gulf's tariff is valid:

Payment of Previous Accounts Required -Applications for service will not be accepted by the Company until the applicant has paid to the Company all sums at any time owing and then unpaid by him for service or bills rendered by the Company for any purpose, whether at the premises applied for or at any other premises (Eighth revised tariff sheet 4.13, paragraph 2.6; MFR Vol. II, page 724.)

Because the tariff provision states that service may be withheld until the applicant has paid all bills rendered by the Company for any purpose, it conflicts with sections (b) through (f) of Rule 25-6.105(8), Fla. Admin. Code. Mr. Haskins testified that the Company applied the tariff provision in [*122] conformity with the Commission's rule. However the tariff must be revised in the following manner so that on its' face it is consistent with the Commission's rule:

Payment of Previous Accounts Required -Applications for service will be accepted by the Company until the applicant has paid to the Company all sums at any time owing and then unpaid by him for service of the same class rendered by the Company, whether at the premises applied for or at any other premises (Eighth revised tariff sheet 4.13, paragraph 2.6; MFR Vol. II, page 724).

Rebuttal Testimony

The final legal issue raised by Public Counsel concerned the prefiled "rebuttal" testimony of Mr. Carzoli on the issue of recognizing a minimum distribution system in the cost of service study. No other witness had testified on the subject. Public Counsel objected to Mr. Carzoli's "rebuttal" as improper Gulf argued that it had the option to file the testimony either as revised direct testimony or as rebuttal. Public Counsel's objection was overruled.

In a major rate case, a utility files both its petition and its prefiled testimony well in advance of the scheduled hearing. After reviewing the company's filing [*123] and direct testimony, and conducting discovery, Staff and intervenors place watters at issue, and may present testimony on the issues they raise. In some cases the utility has filed revised direct testimony aimed more precisely at the issues raised by other parties or simply identified a witness as available to testify on an issue. In other cases, such as this one, the utility filed "rebuttal" testimony regardless of whether the witness of any other party testified on the issue.

This latter practice of filing "rebuttal" testimony when no other witness speaks to an issue is improper for two reasons. First, while Florida case law does not fully define rebuttal testimony, it is described as evidence responsive to that presented by another party, not testimony that should have been presented in the case-in-chief. See Driscoll v. Morris, 114 So. 2d 314 (Fla. 3rd DCA, 1959), Atlas v. Siso, 188 So. 2d 344 (Fla. 3rd DCA, 1966), and King Pest Control v. Binger, 379 So. 2d 660 (Fla. 4th DCA, 1980). In other words, a utility should file its direct case in its initial presentation and limit rebuttal to refuting evidence presented by other parties. Rebuttal testimony [*124] is not proper if another party does not present evidence on an issue nor should it be used to fill gaps in the utility's presentation of its case-in-chief.

Although rebuttal testimony should not be presented unless it is truly responsive to evidence offered by another party, the Commission has the discretion to allow it in any event. See Driscoll v. Morris, supra. But care must be taken to prevent prejudice to other parties in that situation. This may be accomplished by allowing surrebuttal to the rebuttal testimony. However this brings us to the second reason why rebuttal testimony should be carefully limited.By allowing a utility to bolster its direct case on rebuttal, rather than file revised direct testimony, the Commission should properly allow surrebuttal to other parties. Otherwise, no responsive testimony might ever be heard and the right to counter or rebut the Company's case would be frustrated. Surrebuttal, however, unduly extends the hearing process and we wish to avoid it wherever possible.

While Mr. Carzoli's "rebuttal" testimony appears improper, it does not prejudice the interests of any party to allow it to remain in the record. Public Counsel [*125] did not request an opportunity for surrebuttal. More importantly, Mr. Carzoli's "rebuttal" testimony was for naught as we rejected the substance of it, and adhered to our previous policy of not recognizing the concept of a minimum distribution system in a cost of service study. In this case, we will treat Gulf's actions as based on a misunderstanding of how to respond to the prehearing process and allow Mr. Carzoli's "rebuttal" testimony to remain in the record. In the future we intend to require utilities to file revised direct testimony if they wish to respond to an issue raised by another party and that party does not offer its own witness on the subject.

TVA Power

The final legal issue is one that we raised on our own motion. It has periodically been suggested that Gulf, through the Southern Company, purchase power from the TVA with a view towards reselling it to penisular Florida utilities and thereby reduce Florida's dependence on oil fired generation. Alternatively, it has been suggested that Florida utilities contract directly with TVA and that Gulf wheel the power from TVA to penisular Florida.

Neither of these options appears to be legally available. The TVA [*126] is organized and governed by a special act of Congress beginning at 16 U.S.C. Sec. 831 (1982 Supp.). Section 831 (n) (4) (A) states:

Unless otherwise specifically authorized by act of Congress the Corporation shall make no contracts for the sale or delivery of power which would have the effect of making the Corporation or its distributors, directly or indirectly, a source of power supply outside the area for which the Corporation or its distributors were the primary source of power supply on July 1, 1957.

Since the TVA was not a primary source of power supply to Florida in 1957, the statute clearly precludes the TVA from making a direct contract for the sale of power to a Florida utility with Southern merely wheeling the power from the TVA to Florida. As the statute also prohibits the TVA from becoming an indirect source of power supply beyond the 1957 boundary, any type of contractual link between the TVA, Southern, and a Florida utility would be suspect.

CONCLUSIONS OF LAW

In addition to the foregoing, we reach the following conclusions of law:

1. Gulf Power Company is a public utility within the meaning of Section 366.02, Florida Statutes, and is subject to [*127] the jurisdiction of the Commission.

2. This Commission has legal authority to approve and use a projected test period for ratemaking purposes. The calendar year 1983 is an appropriate test period for this proceeding.

3. The adjustments to rate base made herein are reasonable and proper. The value of the Company's rate base for ratemaking purposes is $636,896,000.

4. The adjustments made herein to the calculation of net operating income are reasonable and proper. For ratemaking purposes, Gulf's net operating income for the test period is $60,015,000.

5. The fair rate of return on equity capital for Gulf of 15.85% lies in a range of 14.85% to 16.85. A return of 15.85% should be used to determine revenue requirements.

6. The range of reasonableness for the overall fair rate of return for the Company is 9.41% to 9.98% with a midpoint of 9.69% to be used for ratemaking purposes.

7. Gulf Power Company should be authorized to increase its rates and charges by $3,366,000 in annual gross revenues to provide it an opportunity to earn a fair rate of return of 9.69%.

8. The rate schedules prescribed and approved herein are fair, just and reasonable within the meaning of Chapter [*128] 366, Florida Statutes.

9. The new rate schedules should be effective for billings rendered for meter readings taken on or after December 22, 1982, which is thirty (30) days after the date of the vote of the Commission upon the Company's petition.

10. Gulf Power Company should be ordered to file with the Commission for approval a letter request for a ruling on the imputation of interest to JDIC capital to be submitted to the IRS. Should an IRS ruling approving the imputation of interest to JDIC capital be received within twelve (12) months of the date of this Order, a refund of the revenue requirement associated with this matter should be ordered in the amount of $1,811,819. Accordingly, $1,811,819 of the total rate increase awarded by this Order should be subject to refund.

11. The return associated with that portion of working capital attributable to coal procurred from the Alabama By-Products Company's Maxine Mine should be subject to refund pending the outcome of a hearing on this matter in Docket No. 820001-EU. Accordingly, $13,442 of the total rate increase awarded by this Order should be subject to refund.

12. The refund condition established in Order No. [*129] 9628, applicable to revenues associated with the Caryville cancellation charges as a result of the ratemaking treatment afforded those charges in Order No. 9628, Order No. 10557, and this Order should be continued.

Accordingly, it is

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

ORDERED that the petition of Gulf Power Company for authority to increase its rates and charges is granted as set forth in this Order. It is further

ORDERED that Gulf Power Company is hereby authorized to submit revised rate schedules consistent herewith, designed to generate $3,366,000 in additional gross revenues annually. The Company shall include with the revised rate schedules all calculations and workpapers used in deriving the revised rates, including the workpapers that show the development of the billing determinants used to derive the TOD rates approved herein. It is further

ORDERED that the revised rate schedules authorized herein shall be reflected upon billings rendered for meter readings taken on or after December 22, 1982. It is further

ORDERED that the Company provide to each customer [*130] a bill stuffer describing the nature of the increase. It is further

ORDERED that Gulf Power Company file with the Commission for approval a letter request for a ruling on the imputation of interest to JDIC capital to be submitted to the IRS. The letter request shall be submitted to the Commission for approval within thirty (30) days of the date of this Order. Should an IRS ruling approving the imputation of interest to JDIC capital be received within twelve (12) months of the date of this Order, a refund of the revenue requirement associated with this matter shall be made in the amount of $1,811,819. Accordingly, $1,811,819 of the total rate increase awarded by this Order is subject to refund and the Company shall file a corporate undertaking. It is further

ORDERED that the return associated with that portion of working capital attributable to coal procurred from the Alabama By-Products Company's Maxine

Mine is subject to refund pending the outcome of a hearing on this matter in Docket No. 820001-EU. Accordingly, $13,442 of the total rate increase awarded by this Order is subject to refund and the Company shall file an appropriate corporate undertaking. It is further [*131]

ORDERED that the refund condition established in Order No. 9628, applicable to revenues associated with the Caryville cancellation charges as a result of the ratemaking treatment afforded those charges in Order No. 9628, Order No. 10557, and this Order is continued.

By ORDER of the Florida Public Service Commission, this 11th day of January 1983.

APPENDIX A

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APPENDIX B

SCHEDULE SUMMARIZING ADJUSTMENTS TO RATE BASE

$ (000)

	Company	Approved
Adjusted Rate Base Per MFR B-3b, Col. (80 p.31)	$674,607	$674,607
Adjustments		
Temp. Cash Investment	0	(13,453)
Clearing Accounts	0	0
Caryville Study & Equipment	0	0
Prel. Surv. & Investment	0	0
Inv. & Dam. Res.	0	0
Other Deferred Cr.	0	0
Common Stock Dividend	0	0
ESOP	0	(13)
Nuclear Site PS&I	0	(1,752)
Property Ins. Res.	0	(1,147)
Caryville PS&I	0	0
Coal Inventory	0	(13,901)
Oil Inventory	0	0
Deferred O&M Expense	0	4,683
CWIP	0	0
Caryville Plant Site	0	0
Caryville Cancel Chg.	0	0
Unit Power Sales	0	(538)
Inflation	0	(101)
Oil & Coal Inv.	0	(10,803)
SCS Charges	0	(686)
Total Adjustments	0	(37,711)
Adjusted Rate Base	$674,607	636,896

APPENDIX C

SCHEDULE SUMMARIZING NOI ADJUSTMENTS

$ (000)

	Company	Approved
Adjusted NOI Per MFR C-2d		
Col. (8) P. 190	$51,908	$51,908
Adjustments		
PX, RS & OS Rates	0	* 1,148
Taxes Other Than Income	0	* (18)
Inflation	0	* 2,334
Unit Power Sales	0	0
Schedule E	0	* 4,905
Economy Sales	0	* 346
Capacity	0	0
Temporary Cash Inv.	0	* (2,649)
Caryville Rev. & Exp.	0	0
Non Recur. Maint.	0	* 3,831
Rate Case Expenses	0	* 21
Dues	0	* 18
Contributions	0	* 27
Advertising	0	* 109
So. Co. Charges	0	0
1982 Tax Law	0	(77)
Amort. of ITC	0	0
Unfunded Def. Tax	0	1,051
Int. SYNCRHO	0	(800)
Adj. Related to Unused Capacity	0	5,392
Tax Effect of Above Adjustment		
Income Taxes Current	0	(7,531)
Total Adjustments	0	8,107
Adjusted Net Operating Income	$51,908	60,015

[*133]

* Tax Rate = 48.7%

APPENDIX D

Plant Daniel Adjustment Based on 1983 Contract

July 1983 Total Available Capacity		1820 MW
July 1983 Firm Peak Demand		1327.6 MW
Reserves		492.4 MW
% Reserve Margin		492.4/1327.6 = 37.1%
Maximum reasonable reserve margin:		25% X 1327.6 = 331.9
Projected reserves	492.4 MW	
less 25% reserve margin	-331.9 MW	
Excess Reserve: MW	160.5 MW	
less July 1983 equalization	-72.4 MW	
Unequalized Reserves above 25%	88.1 MW	

Summary of Alternative Plant Daniel Adjustment

88.1 MW Reserves above 25%	$10,383,281
Shedule E and Economy Sales Credit	
88.1/1793 X (4,905,000 + 346,000)	$ (258,011)
72.4 MW Equalization shortfall	$ 3,977,740
Total Daniel Adjustment	$14,103,010

1983 Revenue Requirements Associated with
88.1 MW of Plant Daniel

Investment - Plant Daniel		Revenue Requirements
Net Investment - Plant Daniel	$189,661,281	
Ratio of 88.1 MW to Total Daniel MW		
88.1 MW	.1724	
511 MW	$ 32,698,941	
238 MW Unit Power Sales (UPS)	$ 12,733,000	
Ratio of 88.1 MW to 238 MW UPS		
88.1 MW	.3702	
238 MW	$ 4,713,350	
1983 Net Investment Associated with		
88.1 MW of Plant Daniel	$ 37,412,291	
Equity Return (16.5% CE + 10.15% PS)	6.20%	
	$ 2,319,562	
X Revenue Expansion Factor	1.980261	$42,593,338
1983 Net Investment for 88.1 MW Daniel	$ 37,412,291	
Incremental Daniel weight Debt Return (10.43%)	5.49%	
	$ 2,053,935	
X Revenue Expansion Factor	1.015873	$ 2,086,537
Fixed Expenses		
Total Fixed O&N Expenses	$ 21,144,945	
X NOI Factor	51.3%	
	$ 10,847,357	
Ratio of 88.1 MW to Total Capcity of		
Daniel 88.1	.1724	
511	$ 1,870,161	
X Revenue Expansion Factor	1.980261	$ 3,703,406

Total Revenue Requirement for 88.1 MW Daniel	$10,383,281

[*134]

Adjustment for 72.4 MW Equalization Capacity Payment Shortfall

1.	Revenue Requirements Associated with 72.4 MW of Plant Daniel	$7,954,850
2.	1983 Interchange Contract Capacity Payments	(3,779,036)
3.	Revenue Requirements Associated with 1983 Schedule and Economy Sales	
	72.4/1793 X ($4,905,000 + $346,000)	(198,704)
4.	Net Jurisdictional Revenue Requirements	$3,977,740

In re: Petition of GULF POWER COMPANY for authority to increase its rates and charges

DOCKET NO. 840086-EI; ORDER NO. 14030

Florida Public Service Commission

1985 Fla. PUC LEXIS 969

85 FPSC 245

January 25, 1985

CORE TERMS: customer, rate base, plant, fuel, jurisdictional, revised, peak, load, rate case, inventory, working capital, energy, projected, methodology, discount, coincident, industrial, voltage, billing, capital structure, forecast, mandatory, net operating income, amortization, budgeted, earning, fair rate of return, future use, allocated, electric

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[*1]

The following Commissioners participated in the disposition of this matter: JOHN R. MARKS, III, Chairman; JOSEPH P. CRESSE, GERALD L. GUNTER

Pursuant to duly given Notice, the Florida Public Service Commission held public hearings in this docket on July 5, 1984 in Panama City, Florida; July 6, 1984 in Pensacola, Florida; and September 5, 1984, through September 14, 1984, in Tallahassee. Having considered the record herein, the Commission now enters its final order.

ORDER AUTHORIZING CERTAIN INCREASES

BY THE COMMISSION:

SUMMARY OF DECISION

In this order, we have determined that Gulf Power Company (Gulf, Gulf Power, the Utility, or the Company) should be authorized an increase in gross annual revenues of $4,659,000 based on the test year 1984. In reaching this decision, we have concluded that Gulf should have an opportunity to earn 15.6% on its common equity capital. We have disallowed in excess of $10 million of Gulf's 1984 Operating and Maintenance (O&M) expenses because the Company failed to carry its burden of proving the expenses projected [*3] were to be reasonably and prudently incurred and necessary to the provision of electric service to its customers. An index to this order appears on Appendix A and summary statements of our adjustments are set forth on Appendices B and C.

BACKGROUND

This proceeding was commenced on April 27, 1984 by the filing of Gulf's petition for a rate increase designed to produce $28,447,000 in additional annual revenues in 1984. Gulf requested that if the Commission suspended its permanent rate schedules that it be allowed to collect interim rates designed to increase its gross annual revenues by $21,503,000. This request was based upon a projected 1984 interim test year pursuant to the "File and Suspend" law, Section 366.06(3), Florida Statutes, instead of the "Interim Rate" statute at Section 366.071, Florida Statutes. As is more fully discussed in Order No. 13494, we declined to consider interim rate relief pursuant to Section 366.06(3), Florida Statutes, absent allegations and proof of "financial distress." Although Gulf did not request interim relief pursuant to Section 366.071, Florida Statutes, we did a check calculation based upon the year ended December 31, 1983, and found [*4] that Gulf was earning within its last authorized overall rate of return. No interim rate relief was granted.

As will be more fully discussed in the body of this order, Gulf, near the close of the formal hearings in this case, reduced its revenue increase request from the initial $28,447,000 to $18,759,000.

Extensive public hearings have been held on Gulf's rate request. These hearings extended over 8 days and resulted in a record comprising over 3,000 pages of transcript and over 150 exhibits. We have had the active participation of numerous parties, including the Public Counsel, governmental agencies and large industrial customers.

THE PARTIES

Gulf Power Company

Gulf Power Company is a wholly-owned subsidiary of the Southern Company. Gulf serves an area of approximately 7,400 square miles with an estimated population of 600,000. For the 12 months ended December 31, 1983, 39% of Gulf's operating revenues were derived from residential sales, 39% from commercial sales and 22% from other sources.

Gulf's last full rate case was in 1982 (Order No. 11498, Docket No. 820150-EU, issued January 11, 1983). In that case, we authorized a gross annual revenue increase of $3,366,000. [*5] Additionally, we determined that Gulf's fair rate of return on equity fell within the range of 14.85% and 16.85% and utilized 15.85% in establishing Gulf's overall rate of return of 9.69%.

Public Counsel

Pursuant to Section 350.061, Florida Statutes, the Public Counsel is appointed by the Joint Legislature Auditing Committee to represent the general public of Florida before the Florida Public Service Commission.

The Office of Public Counsel (Public Counsel or PC) presented the testimony of two witnesses during this proceeding. Public Counsel proposed that the Commission establish an average rate base of $560,131,000 and an overall rate of return of 9.21%. Public Counsel proposed that the Company receive a gross annual rate decrease of $17,040,000.

Federal Executive Agency

Federal Executive Agency (FEA) intervened in this proceeding on behalf of Eglin Air Force Base and Tyndall Air Force Base. FEA presented the testimony of three witnesses in the areas of accounting, cost of capital, cost of service, and rate design.

Monsanto Company, Air Products and Chemicals, Inc., and American Cyanamid Company

These three large industrial customers, hereinafter [*6] referred to as Monsanto, intervened in this proceeding. They presented two witnesses in the areas of cost of service and rate design. Monsanto advocated the use of the three summer coincident peak cost of service methodology.

The Commission Staff

The Commission Staff participated in the proceedings and presented the testimony of three witnesses dealing with cost of capital, customer complaints, and financial integrity indicators.

REVENUE REQUIREMENTS DETERMINATION

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

THE TEST YEAR

The function of a test year in a rate case is to provide a set [*7] 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 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 rate cases, this case is predicated on a projected test year. Specifically, Gulf initially sought authorization to collect additional- annual revenues of $28,447,000, based upon a 1984 test year but subsequently reduced this request to $18,759,000. Having considered the record in this case, we affirm the appropriateness of the 1984 test year for the purposes of this case. As will be discussed in greater detail in later portions of this order, we found that not all of Gulf's assumptions utilized in the projected test year were clear as to their underlying factors; however, as adjusted herein, we believe [*8] the test period reasonably represents expected operations during the period the approved 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 the investment on which the Company is entitled to earn a reasonable return. A utility's rate base is comprised of various components. These include: (1) net utility plant-in-service, which is comprised of plant-in-service less accumulated depreciation and amortization, (2) total net utility plant, which is comprised of net utility plant-in-service, CWIP (where appropriate), plant held for future use, and nuclear fuel where appropriate, and (3) working capital.

Gulf initially submitted a proposed jurisdictional rate base of $672,224,000, but subsequently reduced this amount to $629,709,000 in its revised filing. Evidence developed during the course of these proceedings has led us to reduce this amount to $625,602,000. Our rate base adjustments are set forth as follows:

GULF POWER COMPANY
1984 - RATE BASE - JURISDICTIONAL
000's
(from revised request)

	GULF	Adjustments	As Adjusted
A. Utility Plant in Service	$783,000	($154)	$782,846
B. Accumulated Depreciation & Amortization	(243,164)	4	(243,160)
C. Net Utility Plant in Service	539,836	(150)	539,686
D. Construction Work in Progress	10,538	(2,644)	7,894
E. Property Held for Future Use	1,734	2,235	3,969
F. Net Utility Plant	552,108	(559)	551,549
G. Working Capital	77,601	(3,548)	74,053
H. Total Rate Base	$629,709	(4,107)	625,602

[*9]

A. Utility Plant in Service

The amount of jurisdictional utility plant in service originally proposed by the Company for 1984 was $797,174,000. The revised request was for $783,000,000. We have made certain adjustments, described below, which reduce utility plant in service to $782,846,000.

	(000's)
A. Plant-in-Service	
Amount Requested as Revised	$783,000
Adjustments:	
1. Unavailable Oil	(15)
2. Bonifay Building	(20)
2. Graceville Building	(23)
3. Leisure Lake	(201)
4. NIB-CWIP Reclassified Escambia Substation	105
Total Adjustments	(154)
Adjusted Plant-in-Service	$782,846

1. Unavailable Oil

Pursuant to Orders Nos. 12645 and 13902 entered in the fuel cost recovery clause docket, Gulf should have removed unavailable oil from fuel inventory and expensed the same. The Company's initial filing did not contain such an adjustment but Gulf subsequently agreed to the removal. In doing so, however, Gulf chose to amortize the unavailable oil amount of $97,000 over five years and, as a result, increased plant in service by $87,000, which represented the unamortized balance.

We have determined that a two-year amortization of the [*10] unavailable oil is more appropriate in this case. The resulting adjustment is to increase O&M by $29,000 and decrease plant in service by $15,000.

2. Bonifay and Graceville Offices

Included in Gulf's plant in service request were the jurisdictional construction costs of new branch office buildings in Bonifay and Graceville. The bonifay office, which will house two employees and serve some 1,980 customers cost, on a system basis, $265,862 and for the building and improvements $90 per square foot for the building alone, while the Graceville office, which will house three employees and serve some 1,403 customers, cost $246,184 for the building and improvements, on a system basis, and $95 per square foot for the building alone. Evidence taken during the hearing revealed that these two buildings and a third in Chipley were bid as a package, which had the effect of restricting the number of contractors available to bid. Additionally, it was revealed that the buildings contained special provisions, to include drive-in windows with bullet-proof glass.

We are not convinced that sufficient evidence has been introduced to justify the total cost of these buildings. We shall instruct [*11] our Staff to conduct an investigation into the prudence of the entire building project for Bonifay and Graceville. We shall, likewise, leave this issue open until the Company's next rate case at which time we shall allow a further opportunity to justify the entire cost of these projects. In the interim we shall disallow all construction costs in excess of $67 per square foot, which is a cost supported by the Means Survey provided by the Company. The necessary adjustments are to reduce plant in service by $20,000 for the Bonifay building and $23,000 for the Graceville building.

3. Leisure Lakes

In Docket No. 830484-EU, we determined that Gulf had imprudently constructed a substation and 2.2 miles of distribution line to serve the Leisure Lakes subdivision, which we determined was properly served by another utility. The necessary adjustment to remove this item from rate base is to reduce plant in service by $201,000 on a jurisdictional basis.

4. Reclassification of Non-interest Bearing (NIB) CWIP

Included in NIB-CWIP was $105,000 related to the Escambia Chemical Substation, which was actually completed and transferred to plant in service in February, 1984. Inasmuch [*12] as this substation is presently used and useful in the provision of electric service, we believe that it is more appropriately classified as plant in service. The necessary adjustment is to increase plant in service by $105,000.

B. Accumulated Depreciation and Amortization

The amount of accumulated depreciation and amortization originally proposed by Gulf was $240,709,000. The Company later revised this amount to $243,164,000. Our previously discussed adjustments to plant in service require a net reduction to accumulated depreciation and amortization of $4,000. Approved accumulated depreciation and amortization is $243,160,000.

C. Net Utility Plant-in-Service

Net utility plant-in-service is comprised of utility plant-in-service, less accumulated depreciation and amortization. We find that the appropriate amount of net utility plant-in-service for test year 1984 is $539,686,000.

D. Construction Work in Progress (CWIP)

The Company's investment in plant under construction 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 [*13] depreciation charges once the plant is placed in service. When this method is chosen, the financial statements of the Company reflect income "credits" associated with AFUDC, but the Utility realizes no current cash earnings from the investment in CWIP. Alternatively, CWIP may be included as a portion of rate base. Where the latter treatment is allowed, CWIP generates cash earnings, which provide cash flow and an increase in coverage ratios. No AFUDC is taken on that portion of CWIP which is included in rate base.

In recent cases, we have recognized that both proponents of the inclusion of CWIP in rate base and those who resist its 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, we have included what we deem to be an appropriate amount of CWIP in rate base for the purpose of maintaining the financial integrity of the Company on the conviction that the resulting financial ratings of the Utility would lead to a lower cost of capital. It follows, however, that normally only that amount of interest bearing CWIP needed [*14] 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 its original filing Gulf requested the inclusion of $30,207,000 of CWIP in its rate base. This amount was later revised to $10,538,000. As will be explained below, we have reduced this amount by $2,644,000 and approve for inclusion in rate base $7,894,000 of CWIP.

In its revised request, Gulf removed all interest bearing CWIP, while the remaining $10,538,000 requested for inclusion in rate base was non-interest bearing CWIP (CWIP-NIB). This amount of CWIP-NIB was due in large part to a new plant accounting system, which was installed by the Company in late-1983. In operation, this system accumulates all invoices for a given project and verifies their accuracy and payment before closing CWIP-NIB, to plant in service. The resulting delay may run from four to six months. All of the CWIP-NIB is construction of short duration (less than 30 days) or assets not needing construction, which are purchased on blanket work orders. Because of the nature of the asset or the short period [*15] of time involved in construction, CWIP-NIB is not eligible to earn AFUDC. Thus, if CWIP-NIB is not allowed in rate base, the Company will not earn a return on its investment in these assers, which are normally used and useful in the provision of electric service within 30 days of the beginning of construction.

We have conducted a Financial Integrity Study on this Company and have determined that it is not necessary to include any CWIP in rate base in order to maintain Gulf's financial integrity. However, because Gulf has provided sufficient evidence to document and justify its inability to earn either an AFUDC or rate base return on projects in service but not yet closed to plant accounts and short-term construction projects, we shall include in Gulf's rate base $7,894,000 of these projects.

Gulf included $2,539,000 of land for its planned general office building and additional land purchased at its Caryville site as CWIP-NIB. We believe this accounting treatment is not in conformance with the prescribed system of accounting and shall reclassify the $2,380,000 associated with the planned general office building as property held for future use. Our failure to reclassify [*16] this amount could result in double earnings on the investment if it was included in rate base as CWIP-NIB prior to the beginning of construction and was subsequently transferred to CWIP with the calculation of AFUDC once construction was begun. As is more fully discussed in the property held for future use section of this order, we have removed from rate base the $159,000 associated with the purchase of additional land at the Caryville site and shall allow the Company to capitalize AFUDC on this investment pending justification in its next rate case that the additional land is necessary and prudent. The remaining $105,000 reduction to CWIP is related to the Escambia Chemical substation, which, as discussed earlier, was reclassified as plant in service.

E. Property Held for Future Use

Gulf originally proposed to include $1,734,000 for property held for future use in 1984 and retained this amount in their revised filing. As was discussed in the previous section on CWIP, we reclassified $2,380,000 of land associated with the planned general office building from CWIP to property held for future use. We also removed $159,000 from CWIP-NIB that was related to the purchase of

[*17] additional land at Caryville. An additional $145,000 related to the purchase of land at Caryville had been classified by the Company as property held for future use. For the reasons stated below, we have reduced property held for future use by this $145,000.

Gulf currently has some 1,980 acres of land at the Caryville site in property held for future use. As evidenced by its filing in this case, Gulf is in the process of purchasing an additional 1,000 acres at a total projected cost of some $3,173,000. Of this amount, Gulf has requested the inclusion in this case of some $304,000 in two accounts ($159,000 in CWIP and $145,000 in Property Held for Future Use). Based upon our review of the evidence in this case, we find that Gulf has not adequately demonstrated that its plan to purchase another 1,000 acres for its Caryville site is necessary and prudent. We shall require our Staff to develop guidelines as to what amount of land should be allowed in property held for future use for proposed generating plant sites. The guidelines shall address, among other things, the amount of acreage necessary for plants of a certain generating capacity, their coal piles, and ash disposal areas, [*18] among others. While we remove the entire $304,000 requested for this additional land from any rate base treatment, we shall allow the Company to calculate an AFUDC return on its investments related to the new Caryville land purchases pending resolution of whether the purchase of an additional 1,000 acres is prudent. Whether the Company will be allowed to capitalize the AFUDC will, of course, depend upon whether they are ultimately allowed to place the additional land in property held for future use.

With the above adjustments, we approve property held for future use in the amount of $3,969,000 for 1984.

F. Net Utility Plant

Based upon the adjustments discussed above, total net utility plant for test year 1984 is $551,549,000.

G. Working Capital

A traditional component of rate base is the value of the working capital committed to utility operations. In recent cases we have applied the balance sheet approach to determine the working capital allowance, as opposed to the "formula" approach previously utilized. The balance sheet approach generally defines working capital as current assets and deferred debits that are utility related and do not already earn [*19] a return, less current liabilities, deferred credits and operating reserves that are utility related and upon which the Company does not already pay a return.

In its initial filing Gulf proposed a working capital allowance of $83,818,000, which was subsequently revised to $77,601,000. We have determined that the appropriate working capital allowance for 1984 is $74,053,000. Our adjustments are set forth as follows:

	(000's)
Revised Working Capital Per Company	$77,601
Adjustments:	
1. Fuel Inventory	(2,501)
2. Fuel & Conservation Overrecoveries	(344)
3. Unbilled Revenue	(202)
3. Billed Revenue	230

4. Nuclear Site Charges	(292)
5. Rate Case Expense	0
6. Unamortized Rate Case Expense	(439)
Total Adjustments	(3,548)
Adjusted Working Capital	$74,053

1. Fuel Inventory

Fuel inventory is an element of working capital and, as such, the Company should earn a return on its investment in fuel stocks that are reasonably and prudently included in the requested fuel inventory. Determining the amount of fuel inventory to be included in rate base involves a balancing process with many factors. On the one hand, there is an overriding concern that fuel [*20] inventory be adequate to reasonably insure the continuous generation of electricity and to avoid disruption of service. On the other hand, there is the desire that ratepayers not support investment in fuel inventory beyond the amount necessary for the dependable operation of the generating system. In making this determination as to the appropriate level of fuel inventory to be included in working capital, it is necessary to examine the fuel mix of the utility, historical consumption rates, potential consumption rates, sources-to-plant distances for each type of fuel, and potential bottlenecks that may impede the flow of fuel in the transportation system. Additionally, we must examine the potential for labor and weather-related disruptions at the source of the fuel as well as along the transportation chain.

In the Company's filing it made no adjustment to its fuel inventory for the removal of unavailable oil as required by Orders Nos. 12645 and 13902 in Dockets Nos. 830001-EI and 840001-EI. In its brief, the Company agreed such an adjustment was necessary and proper. We therefore have removed the following amounts associated with unavailable oil from working capital: [*21]

No. 6 Oil:	4,950 bbls at $13.452/bbl	= $ 66,587
No. 2 Oil:	989 bbls at $35.970/bbl	= $ 35,571
Total:		$102,158 System
	.9476478 X $102,158	= $ 96,810 Jurisdictional

We find that Gulf has attempted to comply with the requirements of Commission Order No. 11496 through its enlistment of the services of a fuel consultant (ICF, Inc.) and, through the use of the inventory model described and documented in the testimony and exhibits of G. W. Vicinus. While we consider the efforts of Gulf and ICF in developing a viable fuel inventory as a step in the right direction, we are not convinced by the record that the assumptions and factors utilized are sufficient to cause the Commission to place its stamp of approval on the inventory study developed by ICF. This is especially true since the Company did not use the inventory study to develop its fuel inventory request in this case. Instead, the Company requested a 60-day nameplate inventory, originally valued at $60,216,244, and later revised to $58,534,459, as shown in late filed Exhibit No. 8-N:

System 60-Day Nameplate	System Tons	Juris. Factor	Juris. $
$58,534,459	1,049,729	.9476478	$55,470,051

[*22]

The total system burn for coal for the 1984 test year excluding the burn for UPS sales is projected to be 3,416,222 tons. This equals an average daily burn of 9,333 tons for the test year. This means that, for coal, in terms of average daily burn, Gulf's request is equivalent to approximately 112 days supply on average at the end of each month.

In reaching our decision on the value of coal inventory to be included in working capital, we have used $55.76 per ton based upon the following calculation: $58,534,459/1,049,729 tons = $55,761/ton. This is the cost per ton as found in Exhibit 8-N.

Although our Staff used the ICF model to develop its recommendation, which we accept and will use as the bottom-line amount to be included in working capital, it did not use the same model inputs as those used by ICF in its recommendation. The Staff's recommendation is based on the results of model runs shown on late filed Exhibit 7-F, pages 6 of 7 and 7 of 7, cases 4 and 4(a) and cases 7 and 7(a). We find the Staff's recommendation to be more reasonable than the results obtained by ICF and adopt the same in determining a reasonable fuel inventory level.

Staff has used the following [*23] six steps which we adopt as our methodology to derive a reasonable inventory level for coal in this case:

Step 1

The results of the model runs depend on the initial inventory specified. Four runs are considered, two using 878,000 tons initial inventory [(cases 4(a) and 7(a)] and two using 973,000 tons initial inventory (cases 4 and 7). Since Gulf was allowed, in effect, roughly 900,000 tons in its last rate case, we find that this is the correct level to use as initial inventory. Therefore, we used the following interpolations to determine system inventory levels for 1984:

1291 + [900-878)/(973-878) X (1321 - 1291)] = 1298 for the appropriate level (000's tons) for 1984 with strike

951 + [(900-878)/(973-878) X (1093 - 951)] = 984 for the proper level (000's tons) for 1984 without strike

These fingures are converted from 12-month averages to 13-month averages by recalling that we used 900,000 tons as the initial inventory:

[900 + (12 X 1298)]/13 = 1267.4

[900 + (12 X 0984)]/13 = 977.5

Step 2

To convert these figures to days burn, we divided by the average daily burn of 9.98 (000's tons) used in the study, Appendix D, page D-2A (total consumption of 3,651.4 tons [*24] divided by 366).

1267.4/9.98 = 127.0 days burn with strike

977.5/9.98 = 98.0 days burn without strike

Step 3

We next made an adjustment for the fact that 47% of the burn at Plant Daniel is allocated for UPS sales. If this is removed for the strike case, the necessary inventory level decreases by 2% and if removed from the no-strike case, the necessary inventory level increases by 1%. Therefore, we adjust as follows:

127 X .98 = 124.5

98 X 1.01 = 99.0

Step 4

To properly weight the strike and no-strike cases, we averaged as follows:

124.5
99.0
99.0
322.5 = 107.5 days burn
/3

Step 5

Using the revised average daily burn of 9333.9 shown on Figure 17-1 (which excludes burn for UPS sales) we obtain 1,003,394 tons per month as the appropriate level.

Step 6

The average price of coal on Gulf's stockpiles is $55.761 (see Exhibit 8-N). Thus, the total dollars appropriate for coal inventory is $55.761 X 1,003,394 = $55,950,253 on a system basis, or $53,021,134 on a jurisdictional basis.

As a result of our modifications to the ICF Study we approve for inclusion in working capital a total fuel inventory component of $54,645,648 (jurisdictional) [*25] consisting of the following elements:

Fuel Type	System Units	System $ /Unit	System $	Juris. Factor	Juris. $
Coal	1,003,394 tons	55.761	55,950,253	.9476478	53,021,134
#2 Oil	736,882 gals	0.850	626,018	.9476478	593,245
#6 Oil	88,491 bbls	13.452	1,190,399	.9476478	1,128,079
Unavailable Oil			(102,158)	.9476478	(96,810)
Total			57,664,512		54,645,648

Note:

Figures in the above table exclude UPS.

We note that our modifications to the ICF Study are valid for only this rate case. Further acceptance of this study in future cases will require greater explanation of the study and its underlying assumptions by the Company.

2. Fuel and Conservation Overrecoveries

In this case, Gulf has excluded from its calculation of working capital some $344,000 of projected net overrecoveries associated with the fuel and conservation cost recovery clauses. Gulf contends that both overrecoveries and underrecoveries should be excluded from working capital because it receives interest on underrecoveries and pays interest on overrecoveries. We reject this argument. Consistent with our decisions in Florida Power and Light Company's and Florida [*26] Power Corporation's most recent rate cases and for the reasons stated in Order No. 13537, we shall include the fuel and conservation clause overrecoveries as a cost-free liability in the determination of working capital. The necessary adjustment is to reduce working capital by $344,000.

3. Billed and Unbilled Revenues Related to Changes in Industrial Class Revenue

As is more thoroughly discussed in a later portion of this order, we have determined that Gulf's projected customer and energy sales forecast for its industrial class were understated. As a result of this determination, we increased industrial class base revenues (adjusted for unbilled) by a net of $2,772,000, which consists of an increase in base revenue for the class of $3,176,000 and a decrease in unbilled revenues of $404,000. As a result of this change in revenues, we find that working capital should be reduced $202,000 for the change in unbilled revenues and increased $230,000 for the increase in billed revenues.

4. Nuclear Site Charges

In response to its rapid growth in demand during the early 1970's, Gulf commissioned an extensive engineering survey and site analysis to determine the feasibility [*27] of building a nuclear plant in Northwest Florida. In 1972, Gulf first placed an 1100 MW nuclear unit in its generation expansion plan. Subsequent reductions in load forecasts caused the unit's in-service date to be deferred until the unit was dropped from the plan in 1977. Gulf contends that it did not reject the construction of a nuclear plant until 1984. Gulf has proposed that it be allowed to write-off $1,462,000 ($353,000 per year) of the preliminary nuclear site engineering charges beginning Jnuary 1, 1984 and be allowed to include the unamortized balance of $1,316,000 in working capital.

In calculating the jurisdictional portion of this write-off, Gulf incorrectly utilized a retail component of .9476478 when it should have used the appropriate factor of .7855297. This reduces the annual amortization from $353,000 to $292,000.

We also find that Gulf should have known earlier than 1984 that it would no longer be planning the construction of a nuclear plant based upon these survey results. Based upon the Company's generation expansion plan and the projection that no new plant will be required prior to the year 2000 we find that the amortization of the nuclear site charges [*28] should begin effective January 1, 1983. The unamortized balance approved for inclusion in 1984 rate base is $1,024,000, which requires a reduction to working capital of $292,000.

5. Rate Case Expense

The Company proposed to include $418,331, later revised to $382,000 (Exhibit 6-DD), of rate case expense in this case. In addition, the Company requested that the amount be amortized over two years. Public Counsel, in its brief, contends that there should be no rate case expense allowed because there has been no showing of a need for additional revenues. We do not agree with Public Counsel. We find the amount of rate case expense incurred by Gulf to be reasonable in amount and a legitimate expenditure under the circumstances herein. We will therefore allow $764,000 of rate case expense to be amortized over two years at $382,000 per year.

6. Unamortized Rate Case Expense

The Company has included $439,000 in working capital which represents the unamortized portion of rate case expense. Since Commission policy is to exclude this item from working capital, we are reducing rate base $439,000.

Adjusted Working Capital

The net effect of our adjustments is to reduce [*29] the requested working capital allowance by a net of $3,548,000, which results in an approved 1984 working capital allowance of $74,053,000.

H. Total Rate Base

Based upon total test year net utility plant of $551,549,000, and working capital of $74,053,000, the total rate base for 1984 is $625,602,000.

FAIR RATE OF RETURN

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

Capital Structure

The ultimate goal of providing a fair rate of 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 the capital employed by a utility, as well as the amounts and costs [*30] rates associated with each. After establishing the sources of capital, all capital costs, including the cost of equity capital, are weighted according to their relative proportion to total capital. The weighted components are then added to provide a composite or overall cost of capital. The weighted cost of capital multiplied by the net utility rate base produces an appropriate return on rate base, including a return on equity capital invested in rate base. 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 the test year operating expenses, but are treated "below the line." This insures 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 costs of capital through an appropriate balance between debt and the 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 [*31] capital to the company.

Consistent with our decision to employ a projected test period in this case we have decided to utilize a capital structure projected by the Company to be in place through 1984. We have adjusted the system capital structure to remove capital that is not being utilized to fund the jurisdictional rate base. Such adjustments are necessary to reconcile rate base with capital structure. The types and proportions of capital will be developed in a following schedule.

All parties agreed to the use of a 13-month average capital structure. We believe that a 13-month capital structure best represents the source of funds used to finance Gulf's rate base. The 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, any single point in time may be too heavily weighted with one type of capital. The 13-month average capital structure smooths the effects of a particular increment of capital.

In the past, we have generally reconciled capital structure to rate base on a prorata basis, unless specific evidence indicates the need to adjust a particular [*32] capital structure component. In this proceeding, Public Counsel has proposed that, when an asset which did not generate deferred taxes or investment tax credits (ITC) is removed from rate base, the deferred taxes and the ITC balance should not be reduced on a prorata basis. Also, Public Counsel advocates that the customer deposits balance in the capital structure not be reduced when an asset is removed from rate base.

We find that any significant investment by the Company has a multitude of effects on the Company's financial position, and any attempt to trace each of these effects is impractical, and in many cases, impossible. Consequently, while it may be possible to implement Public Counsel's proposal, we find that singling out the tax benefits and customers deposits and sources of financing for specific identification is an incomplete solution to the problem. With the exception of investments in non-utility property, a non-regulated subsidiary, or any item that can be traced to a specific capital structure component, we will continue to find that a prorata reconciliation is the appropriate method to determine the Company's capital structure when we adjust rate base. [*33]

Capital Structure Component Cost Rate Amounts

To fully establish the capital structure, we must identify the sources of capital to be included and the amount and cost of each source. The amount and cost rates that we find appropriate to assign each of the components of the capital structure are as follows:

Class of Capital	Juris. Amount $	Percentage of Total Capital	Cost Rate	Weighted Average Cost Rate
Long Term Debt	269,191	43.0291%	9.24%	3.9759%
Short Term Debt	5,894	0.9421%	9.20%	0.0867%
Preferred Stock	54,242	8.6704%	8.65%	0.7500%
Customer Deposits	9,230	1.4754%	7.88%	0.1163%
Common Equity	173,641	27.7559%	15.60%	4.3299%
Tax Credits - 0 Cost	1,304	0.2084%	0.00%	0.0000%
Tax Credits - WTD Cost	31,241	4.9938%	9.75%	0.4867%
Def. Income Taxes	80,858	12.9249%	0.00%	0.0000%
Total	625,602	1		9.7454%

Return on Equity Capital

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

Although the Company did not ask for a change in its last authorized rate of return on equity, the Commission considers [*34] that it has a duty to review the appropriateness of a company's return on equity during a proceeding such as this.

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

Summary of Testimony

Dr. Arthur T. Dietz, testifying on behalf of the Company, relied exclusively on a variant of the discounted cash flow model in arriving at his recommended cost of common equity capital.

Dr. Dietz used the Southern Company's cost of common equity as a proxy for Gulf's cost of common equity since Gulf's common stock is not publicly traded. Dr. Dietz's methodology consisted of determining the discount rate that equated the market price of Southern Company common stock to the present value of the expected cash flows associated with the stock for five and ten year holding periods. The expected cash flows were estimated using a stock price of $15.94 (the midpoint of the 1984 trading range), a 1984 earnings per share estimate of $2.55, an earnings growth rate of 5.0% through 1988, a dividend growth rate of [*35] 3.5% through 1988, and an earnings and dividend growth rate of 4.0% for 1988-1993.

Using these assumptions, Dr. Dietz determined the cost of retained earnings to be 15.8% for a five year holding period and 15.4% for a ten year holding period. After making adjustments for market pressure, floatation costs, and dilution, Dr. Dietz determined the cost of new issues to be 17.5%. Weighting retained earnings 5/6ths and new issues 1/6th, Dr. Dietz concluded the cost of common equity to Gulf to be in the range of 15.8%-16.1% with a midpoint of 15.95%. (NOTE: The Company requested a 15.85% return on common equity which Dr. Dietz endorsed. As stated by Dr. Dietz, "I have used this figure because my analysis indicated that it is a reasonable request.")

Mr. James D. Rothschild, appearing on behalf of the Citizens of the State of Florida presented two equity costing methodologies: (1) a discounted cash flow analysis (DCF) and (2) a comparable earnings analysis.

Mr. Rothschild based his recommendation on the theory that the appropriate cost of equity for purposes of rate regulation is the earned rate of return which would make the marketplace valuation of a Company's used and useful net assets [*36] equal to the total book value of the common stock (i.e., the market-to-book ratio equals 1.0).

Mr. Rothschild performed his DCF analysis using companies in the Moody's 24 Electric Utilities Index that are not currently involved in nuclear construction. In arriving at his DCF cost of common equity Mr. Rothschild used a dividend yield of 10.0% (the actual dividend yield at March 31, 1984), an actual market-to-book ratio of 100.55% and an investor anticipated future earnings return rate of 13.5% to 14.5%. This produced a DCF cost of common equity range of 13.64%-14.94%. After making adjustments for financing costs and capital structure risk differentials, Mr. Rothschild concluded that Gulf's DCF cost of common equity was within the range of 14.22%-15.52% with a midpoint of 14.87%.

To support his DCF findings, Mr. Rothschild presented a comparable earnings analysis. The analysis was developed by examining the earnings of industrial companies (S&P 900) with achieved market-to-book ratios of approximately 1.0. Based on his analysis, Mr. Rothschild determined Gulf's cost of common equity to be in the range of 14.75%-15.25% with a midpoint of 15.00%.

Mr. Matthew I. Kahal, [*37] testifying on behalf of the Federal Executive Agencies, determined the cost of common equity to Gulf using a risk adjusted DCF model. The dividend yield used by Mr. Kahal was determined by dividing the most recent indicated dividend rate for the 85 companies (adjusted for one quarter's expected growth; assumed to be 1%) by the average stock price for each company for the three month period ended June 1984. This produced an average dividend yield of 11.57%

The expected dividend growth rate was calculated using the Earnings Retention Approach also known as the B times R method. Using historical financial information as the basis for his assumptions, Mr. Kahal projected a return on equity of 12.7% and a retention rate of 27.4% producing an expected dividend growth rate of 3.47%. After making adjustments for investor expected dilution (-.20), risk (-.14), and issuance expense (+.19), Mr. Kanal determined Gulf's cost of common equity to be 14.89%. (Exhibit 303, Schedule MIK - 2, page 1 of 1)

Mr. Steven F. Clinger, appearing on behalf of the Florida Public Service Commission Staff, presented four cost of equity analyses: (1) a discounted cash flow analysis (DCF), (2) a capital asset [*38] pricing model (CAPM), (3) an earnings/price (e/p) analysis, and (4) a risk premium regression analysis.

Using the DCF, CAPM, and E/P analyses, Mr. Clinger developed a quarterly interval weighted average cost of common equity for an index of high quality electric utilities for December, 1983; March, 1984; and June, 1984.

Mr. Clinger used two broad measures of overall investment risk in selecting his index of high quality electric utilities, S&P's Stock Ranking and Value Line's Stock Safety Ranking. In performing his DCF analysis, Mr. Clinger used a finite, variable growth rate DCF model.

The dividend yields used by Mr. Clinger were determined by dividing the next twelve months expected dividend payment by the then current stock price. The dividend growth rates for the initial non-constant growth period (years 1-4) were taken from Value Line. The expected long-term constant dividend growth rates for the years 5-30 were calculated by the b times r method using dividend, earnings, and book value information obtained from Value Line. By calculating the annual expected cas flows over the investment horizon, and solving for the investor required rate of return, Mr. Clinger concluded [*39] the Electric Utility Index's DCF cost of common equity to be 14.59%.

To support his DCF analysis, Mr. Clinger presented a capital asset pricing model. The risk free rates used were the then current yields of long term treasury bonds. The market return was estimated by adding an equity-debt risk premium to the risk free rate. The risk premium, representing the earned returns on long-term U.S. Treasury Bonds over the earned returns on common stock for the period 1926-1983, was obtained from Stocks, Bonds, Bills, and Inflation: The Past and Future by Ibbotson and Sinquefield. The beta values were obtained from Value Line. The CAPM indicated a cost of equity to the Electric Utility Index of 16.44%.

As a further check of his DCF analysis, Mr. Clinger presented an earnings/price analysis. Using an expected earnings per share amount (current earnings adjusted for one period's growth) and the then current market price, the model yielded a cost of common equity to the index of 14.73%.

In addition to the DCF, CAPM, and E/P analyses, Mr. Clinger presented an independently developed risk premium regression analysis. This approach assumes the cost of common equity is a [*40] function of the Company's cost of debt. As stated by Mr. Clinger:

". . . I first determined weighted costs of equity to Electric Utility Indices for the period March, 1982 - June 1984, at quarterly intervals, using the same risk filters, models, and methodology used to measure the index's current cost of equity. (Value Line, rather than IBES, was used prior to calendar year 1983 for EPS estimates in the earnings/price analysis.) I then calculated the index's cost of debt at these same discrete quarterly intervals and, through a regression analysis, developed an equation that estimated a company's cost of equity given a forecast of the company's bond yield."

Applying Eggert Economic Enterprises' consensus forecast of the general level of interest rates to his regression equation, Mr. Clinger determined Gulf's cost of common equity to be 16.3%.

After making an adjustment for risk, Mr. Clinger concluded the cost of common equity capital to be in the range of 15.3%-16.4% with a midpoint of 15.85%.

Commission Findings on Cost of Capital

The Company has requested a return on common equity of 15.85%, the same return on common equity granted in its last rate case, Docket No. 820150-EU. [*41] However, both Public Counsel and the Federal Executive Agencies point out that economic conditions have changed since the last rate case. In addition, market conditions have improved since the filing of testimoney in this case. We find it is important to consider current capital market information when setting the cost of common equity but we exercise caution when doing so.

We discount the use of Dr. Dietz's and Mr. Rothschild's DCF analyses due to the question of applicability to Gulf. We also discount the use of Mr. Kahal's DCF analysis due to his use of historical earned returns and retention rates as proxies for expected earned returns and retention rates. It is by no means clear that historical information accurately reflects investor expectations.

Based on the evidence in the record and a review of the equity costing methodologies presented, we find that a reasonable allowed rate of return on common equity capital for Gulf is 15.60%. Using Staff witness Clinger's regression risk premium model and the forecasted resultant interest coverage ratios as checks, we find a 15.60% return on common equity will allow Gulf the opportunity to raise capital on fair and reasonable [*42] terms and to maintain its financial integrity.

NET OPERATING INCOME (NOI)

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

The Company originally proposed a net operating income of $51,757,000, but later revised this figure to $52,576,000. Evidence developed during these proceedings has led us to increase this amount to $58,648,000. Our adjustments are set forth as follows:

(000's)

	1984		
	Adjusted Juris. Per Company	Commission Adjustments	Commission Adjusted
I. Operating Revenues	$373,582	$3,618	$377,200
Less Fuel and Conservation	(178,191)	0	(178,191)
Base Operating Revenues	195,391	3,618	199,009
II. Operating Expenses			
A. Operation and Maintenance	253,303	(8,029)	245,274
Less Fuel and Conservation	(175,647)	0	(175,647)
Base Operating and Maintenance	77,656	(8,029)	69,627
B. Depreciation and Amortization	29,542	(115)	29,427
C. Taxes Other Than Income Taxes	12,769	55	12,824
D. Income Taxes - Current	2,450	5,696	8,146
E. Deferred Income Taxes (Net)	12,951	0	12,951
F. Investment Tax Credit (Net)	7,447	(61)	7,386
Total Operating Expenses	142,815	(2,454)	140,361
III. Net Operating Income	$52,576	$6,072	$ 58,648

[*43]

I. Operating Revenues

The Company initially proposed a test year operating revenue for 1984 of $372,527,000. Gulf subsequently revised this figure to $195,391,000, which included the removal of $173,789,000 of fuel revenues and $4,402,000 of conservation revenues. We have made adjustments increasing operating revenues for 1984 by a total of $3,618,000 to $199,009,000. Our adjustments to revenue are as follows:

(000's)

	1984
Company Test Year Revenues	$195,391
Adjustments:	
A. Schedule E Capacity (20%)	1,322
B. Profit On Alternate & Supplemental Energy	161
C. Revenue Forecast	2,135
Total Adjustments	3,618

Adjusted Operating Revenue $199,009

A. Stockholder Retention of 20% of Schedule E Capacity Sales Revenues

Gulf has requested that its stockholders be allowed to retain 20% of the test year Schedule E capacity sales revenues in a manner similar to our recently approved decision (Order No. 12923) with respect to the treatment of economy energy sales profits. Gulf asserts that there are significant similarities between Schedule E and Economy Sales and argues that the incentives for making Economy Energy Sales and the resulting rewards [*44] to its customers should also be applicable to Schedule E Sales. We disagree and deny the requested stockholder retention of 20% of the Schedule E sales revenues.

Unlike Economy Energy Sales which are transacted on an hour-by-hour basis, Gulf's Schedule E sales are made pursuant to negotiated, long-term contracts, which require the purchasing utility to make capacity payments regardless of whether it elects to receive any of the associated energy. Gulf and the Southern Company have entered into Schedule E Sales contracts having an average 1654 MW of capacity during 1984. Under these contracts, Gulf received 6.31% of total revenues associated with these sales from January through May, 1984, and 6.12% during the remainder of the year. Gulf and the Southern Company have been offering Schedule E Sales since 1975 and we do not presently see the necessity of an incentive (20% or $1,322,000 in 1984 to the stockholders) to motivate Gulf to continue its existing Schedule E Sales and seek additional contracts. The necessary adjustment is to increase jurisdictional test year revenues by $1,322,000.

B. Stockholders Retention of 20% of Profits from Alternate and Supplemental Energy [*45] Sales

Alternate and Supplemental Energy Sales are related to Gulf's and the Southern Company's Unit Power Sales (UPS) contracts. Specifically, Supplemental Energy is energy which is sold to a utility when its contracted for generating unit is out of service. The energy price paid for Supplemental Energy is the greater of (1) the normal energy rate associated with the generating units contracted for, or (2) the incremental energy costs of the generating unit actually supplying the Supplemental Energy. Alternate Energy is energy which is sold out of less expensive units at the discretion of the Southern Company even though the contracted for capacity may be available for generation. By its Petition, Gulf seeks to retain for its stockholders 20% or $161,000 in 1984 of the profits associated with the sale of Alternate and Supplemental Energy.

The sale of Alternate and Supplemental Energy is integral to Gulf's and the Southern Company's UPS contracts on which the utilities' stockholders already earn a return on equity. Importantly, Gulf and the Southern Company are obligated by the UPS contracts to "use their best efforts" to provide Alternate and Supplemental Energy [*46] to the purchasing utility, when available. In view of the fact that Gulf already earns an equity return on the UPS contracts, plus the fact that it and the Southern Company are contractually obligated to provide Alternate and Supplemental Energy, when available, we do not find it necessary to further motivate them to do so by allowing the stockholders to retain 20% of the profits. The necessary adjustment is to increase test year revenues by $161,000 on a jurisdictional basis.

C. Revision to Industrial Class Revenue Forecast

As is more fully discussed in the Rate Section of this order, we found that Gulf's forecasted industrial revenues were too low. Gulf conceded that an adjustment to increase industrial revenues was appropriate and increased its revenue forecast by $637,000, but we found that the total amount of excess industrial sales during 1984 should be recognized for ratemaking purposes. The necessary correction is to increase test year revenues $2,135,000 on a jurisdictional basis in addition to the Company's adjustment increasing revenues $637,000.

II. Operating Expenses

Gulf initially requested total operating expenses of $320,770,000, which amount it [*47] subsequently reduced to $142,815,000. Included in the Company's revision were the removal of $171,314,000 in fuel expense and $4,333,000 in conservation expense. We have made additional adjustments reducing total operating expense by $2,454,000 to $140,361,000.

A. Operating and Maintenance Expense (O&M)

Gulf originally proposed total O&M expense of $254,825,000, including $171,314,000 of fuel expense and $4,333,000 of conservation expense. In its revised request, Gulf removed the fuel and conservation expenses and an additional $1,522,000 of other O&M expense leaving a total O&M request of $77,656,000. We have determined that this amount should be further reduced by $8,029,000 to $69,627,000 as follows:

(000's)

	1984
Operating and Maintenance Expenses Per Company	$77,656
Adjustments:	
1. Amortization of Unavailable Oil	29
2. Salaries - Increased Employees	(829)
3. Salary Levels	(1,560)
4. Bad Debt Expense	(153)
5. Updated C.P.I. Factor	(148)
6. Southern Company Services	(1,717)
7. Industry Dues	(3)
8. Boiler & Turbine Maintenance	(898)
9. O&M Reasonableness	(2,750)
Total Adjustments	(8,029)
Adjusted O&M Expenses	(69,627)

[*48]

1. Unavailable Oil

As was earlier discussed in the Rate Base section of this order, Gulf initially failed to remove unavailable oil and expense the same as required by Orders Nos. 12645 and 13902. Gulf subsequently agreed to the removal of the unavailable oil but chose to amortize it over five years. We have determined that a two-year amortization of the unavailable oil is more appropriate in this case. The resulting adjustment is to increase 1984 jurisdctional O&M by $29,000.

2. Salaries - Increased Employees

In its filing, Gulf projected that it would employ an average of 1172 non-construction employees for test year 1984, or 109 additional employees over its 1983 year-end level. Gulf's projection assumed that all 109 of the additional employees would be hired at the beginning of the year and the Company, agreeing that this assumption was not reasonable, made an adjustment reducing this expense $474,525 to spread the vacancies and new employees retably throughout the year. Notwithstanding the fact that Gulf continually stated that it needed all additional 109 employees so that it could continue to provide quality service, it had, through the first [*49] seven months of 1984, filled only 23 of the 109 budgeted positions. Gulf asserts that it has justified the need for all of the additional 109 employees but has not hired all of them in an effort to keep its return on equity within the approved range.

Analyzing projected test years is sufficiently challenging without gratuitous burdens. Gulf's strategy of intentionally not spending what it professes to need has only served to complicate our examination of what its true and legitimate needs are. It is not a strategy that should be repeated or adopted by others.

From the record in this case, we have ascertained that Gulf hired on the average of approximately 3.3 new employees per month during the first seven months of 1984. Accepting this as a reasonable rate that would continue throughout the remaining five months of 1984, we then annualized the effect on salaries and fringe benefits. The necessary adjustment is to reduce salaries and fringe benefits requested for the proposed 109 new employees by $1,094,000. When we recognize Gulf's $475,000 adjustment to this amount, our adjustment is to reduce jurisdictional O&M by $829,000.

3. Salary Levels

In its filing, Gulf charged [*50] $29,837,000 in salaries and $7,236,000 in fringe benefits to O&M expense. Gulf claims that these amounts are necessary to attract, motivate and retain qualified employees and to properly pay them for their performance. Since 1980, Gulf's salary program has been successful in reducing the employee turnover rate from 7.18% to slightly under 5% in 1983. Gross payroll and the average number of employees increased during the same period as reflected below:

Period	% Increase in Gross Payroll	% Increase in Average No. Employees
1980-81	18.37%	5.9%
1981-82	12.1%	1.8%
1982-83	8.9%	1.7%
1983-Projected 84	16.8%	9.1% Projected

As with the previous issue, the quality of Gulf's evidence leaves us unconvinced that the Company's budgeted salary levels are either reasonable or prudent. In fact, when we examined Gulf's actual experience for the first seven months of 1984, we found that its total gross payroll was under budget by 8.36%, while fringe benefits were 6.11% under budget for the same period. Under the circumstances of this case, we find that Gulf's actual experience during the first seven months of 1984 is the best evidence [*51] of its legitimate salary and fringe benefits requirements. Accordingly, we reduce Gulf's budgeted total gross payroll by 8.36% and its budgeted fringe benefit amount by 6.11% for a total 1984 jurisdictional reduction of O&M expense of $1,560,000.

4. Bad Debt Expense

In its original filing, Gulf equested in O&M its budgeted bad debt expense of $823,000. In its revised request, Gulf acknowledged that its original request was excessive and reduced its request by $147,000. We have agreed with Public Counsel and reduced Gulf's bad debt expense by an additional $153,000.

Gulf's originally budgeted bad debt expense of $823,000 equalled an increase of $147,000 or 22% over its actual bad debt experience for 1983. In 1983 the actual bad debt expense was $269,190 below the $937,000 we allowed the Company in its last rate case. Once again, we believe that Gulf's actual experience during the first half of 1984 is a better indicator of its needs than its projections. Specifically, Gulf's bad debt expense was $101,000 or 24% under budget at the end of June 1984, while actual uncollectible write-offs were $198,656 under budget for the same period and $219,751 under budget for the [*52] seven month period ended July 1984. As noted by Public Counsel, Gulf's 1984 actual accruals were running 36% or some $300,000 below the projected accruals. We agree with Public Counsel that the total adjustment required is $300,000 and reduce Gulf's revised request by an additional $153,000 to achieve that result.

5. Updated CPI Factor

When Gulf prepared its filing it inflated some $32,682,000 (system) 1983 O&M expenses by an assumed 1984 inflation rate of 4.8%. In view of the state of our economy and trends in inflation rates during the first seven months of 1984, we determined that a more recent forecast would more realistically represent the expected experience for 1984. Accordingly, the August, 1984 forecast, which projected average 1984 inflation to be 4.3% annually was substituted for Gulf's earlier-derived number of 4.8%. The necessary adjustment is to reduce 1984 O&M by a total of $329,000 on a system basis. Jurisdictionally we have removed $148,000 of the total from the Company's forecasted O&M, and as indicated later in the order, shall remove the remaining $151,000 from the benchmark calculation.

6. Southern Company Services

Gulf's O&M requests of [*53] $7,717,000 (jurisdictional) for 1984 payments for outside services represents a 24% increase over 1983's actual amount. A significant majority of these payments were projected to be to a sister corporation, Southern Company Services (SCS). Gulf takes the position that these budgeted charges, are reasonable and should be allowed. The utility says that SCS provides it with expertise in many areas of planning and opeations and at SCS's actual cost. Public Counsel, on the other hand, contends that Gulf's budgeted expenses for 1984 exceed the 1983 level by 24% and, further, that the Company's budgeted expenses through June, 1984 exceeded actual charges by 24%. Based upon this experience, Public Counsel recommended a reduction to O&M of $1,220,000.

Our review of Gulf's actual spending during 1984 revealed that Gulf had spent $991,446 less than it had budgeted for SCS during the first seven months of 1984. We find that Gulf has failed to prove that its budgeted amounts for SCS during 1984 are reasonable and prudent. Based upon our review of Exhibits 6-V and 8-W, we have determined that SCS expenses should be reduced $1,717,000 for 1984. This adjustment was calculated by [*54] taking the year-to-date percentage variances by function and applying those percentages to the budgeted amounts on Exhibit 8-W.

7. Industry Dues

Gulf originally proposed industry dues of $132,500 on a system basis. The Company subsequently revised its request to remove $19,600 of MFR Schedule C-2e dues and $10,890, or 30% of its Edison Electric Institute (EEI) dues. We have further reduced Gulf's request by $1,600 (system) for miscellaneous organizations that were not identified by the Company and an additional $1,210 necessary to make the EEI disallowance equal to 33 1/3% of the total dues as in other recent electric cases. The necessary adjustment is to reduce Gulf's revised request by an additional $3,000 on a jurisdictional basis.

8. Boiler and Turbine Maintenance

Gulf originally requested $3,820,000 on a system basis for boiler and turbine maintenance. In its revised request, the Company increased this amount by $1,274,000 to $5,094,000 (system), which included $4,194,000 for turbine inspections, $437,000 for Crist 4 and 5 rotor rewinds, plus $903,000 for boiler maintenance.

We have closely examined Gulf's proposed schedule for boiler and turbine maintenance [*55] and the projected costs and find that Gulf has failed to adequately justify the increased expense levels for the turbine inspections. Accordingly, we have determined that the Company should be allowed a total of $4,121,000 (system) based on the $2,781,000 turbine inspection cost provided by Gulf in its last rate case, plus $903,000 for related boiler inspections, plus a $437,000 annual allowance for the Crist 4 and 5 rotor rewinds. This is an increase of $301,000 (system) over the $3,820,000 requested in the Company's original filing and an amount we find will allow the Company a "normalized" allowance for turbine and boiler maintenance without any "catch up" allowance for any of this maintenance that may have been deferred in the past. The necessary adjustment is to reduce the Company's revised request by $898,000 on a jurisdictional basis.

9. O&M Reasonableness

Some of the most significant disallowances we have made in this case are those in which we have reduced Gulf's operating and maintenance expenses as a result of the Company's failure to either adequately control its O&M expenditures or to prove by competent substantial evidence that all of those projected expenses [*56] for the year 1984 are reasonable and prudent. The net effect of our adjustments on this major issue is to reduce the requested 1984 O&M by $3,835,000 on a jurisdictional basis. Because this adjustment is so significant and also represents a recurring problem, we think it especially important that the reader fully understand the nature of the problem, the facts bearing on this issue and the logic supporting our decision.

The basic problem is that Gulf's base electric rates, and the costs that comprise them, have for many years consistently grown at a rate in excess of that accounted for by a compound factor including the Utility's increases in new customers and general inflation as measured by the Consumer Price Index (CPI). Beginning in 1973 and throughout most of the 1970's, overall electric rates were impacted most dramatically by rising fuel costs. However, for a few years now fuel prices have generally stabilized and have contributed less to the continued rise in electric rates. In any event, the Commission has for a number of years provided for the full recovery of reasonably and prudently-incurred fuel costs through the Fuel and Purchased Power Cost Recovery [*57] Clause (presently Docket No. 850001-EI). As discussed previously, the revenues and expenses associated with fuel and purchased power, as well as the Company's conservation programs, have been removed from this case. However, even with these potentially volatile costs removed from consideration, Gulf's O&M expenses continued to outstrip a level of growth explained by customer growth and increases in the CPI.

In our most recent electric rate cases (Tampa Electric Company, Docket No. 830012-EU, Order No. 12663; Florida Power and Light Company, Docket No. 830465-EI, Order No. 13537; and Florida Power Corporation, Docket No. 830470-EI, Order No. 13771) we have compared each Utility's requested O&M to that of a previous period after expanding the latter by the CPI and the Utility's growth in customers. We continued the use of this comparison with Gulf, and at our request the Company prepared the following table, which was included at page 23 of the Prehearing Order:

Actual Non-Fuel O&M vs. Benchmark
(000's)

	1979 O&M Expense *	Compound Multiplier	1984 O&M Benchmark	1984 O&M Forecast	Difference from Benchmark
Power Production	$19,847	1.4385	$28,549	$41,181	$12,632
Transmission	1,444	1.7327	2,502	3,994	1,492
Distribution	4,536	1.7327	7,859	7,911	52
Customer Accounts	3,794	1.7327	6,574	6,763	189
Customer Svc & Info	907	1.7327	1,572	1,665	93
Sales	0	1.7327	0	0	0
Administrative & General	12,253	1.7327	21,231	28,047	6,816
Total O&M	$42,780		$68,287	$89,561	$21,274

[*58]

* These amounts have been adjusted to exclude ECR expenses, industry association dues related to Chamber of Commerce and lobbying, and area development and national advertising expenses.

Reference Data for Compound Multipler:

	Customers		Average CPI	
Year	Amount	% Increase	Amount	% Increase
1979 Actual	195,078	---	217.4	---

1980 Actual	202,851	3.98%	246.8	13.52%
1981 Actual	210,954	3.99%	272.4	10.37%
1982 Actual	218,419	3.54%	289.1	6.13%
1983 Actual	227,439	4.13%	298.4	3.22%
1984 Forecast	234,978	3.31%	312.7	4.80%

As may be seen from the above table, Gulf's forecast 1984 O&M expenditures of $89,561,000 were $21,274,000 in excess of the 1984 benchmark of $68,287,000. Gulf's revised request included $87,996,000 of O&M on a system basis, which was $19,709,000 in excess of the 1984 benchmark. As a result of our review of the record in this case, we have disallowed as either unreasonable or unproved a total of $10,364,000 of the revised request of $89,996,000, leaving an approved 1984 O&M budget of $79,197,000 on a system basis and $69,627,000 on a jurisdictional basis. In addition to the $5,967,000 (system) of specific [*59] adjustments described in items 1-8 above, we have made an additional $4,397,000 of adjustments based upon Gulf's failure to justify certain expenses in excess of the CPI and customer growth benchmark. Our net adjustments are set out in the table below and the rational for each follows:

Issue 38 (Benchmark Adjustments)

	Commission Vote System	Commission Vote Jurisdictional
1. Ash Disposal - Company	($ 810)	($ 767)
2. Production - Plant Daniel	(606)	(303)
3. Production - Engineering	(364)	(345)
4. Transmission - System Planning	(111)	(102)
5. CPI in Benchmark ($329-$163)	(166)	(151)
6. Transmission Line Rentals	(425)	(385)
7. A&G - Double Counting (Production)	(1,573)	(1,464)
8. UPS Allocation Error - Staff Audit Report Finding 10-Company	(342)	(319)
Subtotal - Issue 38 (Benchmark)	(4,397)	(3,835)
Total O&M Adjustments	($10,364)	($ 9,551)
Adjusted O&M Budget	$79,197	$69,627

1. Ash Disposal

In its initial request Gulf requested the inclusion in its 1984 O&M of $1,685,000 related to a new dry ash handling system that was constructed and placed in service in 1984 and for which it says there were no corresponding 1979 costs. [*60] However, in its revised request (Exhibit 6DD), Gulf acknowledged that $767,000 (jurisdictional) of the initial request for ash handling was non-recurring in nature and deleted this amount. Accordingly, we approve the adjustment removing $767,000 of 1984 O&M on a jurisdictional basis.

2. Production - Plant Daniel

Gulf acquired a 50% ownership in Plant Daniel in 1981 and, therefore, the unit has no 1979 base for expansion by the CPI. Gulf has requested 1984 O&M for Plant Daniel of $5,359,000; however, Exhibit 8aa reveals that as a part of its austerity program, Gulf reduced Plant Daniel O&M by $606,000 for 1984. Notwithstanding its deletion of the $606,000 from Plant Daniel's O&M budget in

1984, Gulf maintains that it still needs the entire $5,359,000 it originally projected. We disagree.

Although Gulf originally budgeted $5,359,000 for its portion of Daniel's 1984 O&M, it was able to reduce this amount by $606,000 (Exhibit 8aa) to protect its return on equity. While this reason, alone, may not be an adequate basis for disallowing the $606,000, we find that Gulf has failed in Exhibit 13 to justify its inclusion as necessary, reasonable and prudent. When the [*61] $606,000 is apportioned for the Company's UPS sales out of Plant Daniel, the appropriate adjustment is to reduce O&M by $303,000 on a jurisdictional basis.

3. Production - Engineering

In its 1984 budget, Gulf included $882,000 for Engineering within the larger function of "Production - Steam," while the 1979 amount for this category was $54,000. In seeking to justify the $804,000 differential between the $882,000 requested and the $78,000 accounted for by inflation and customer growth, Gulf explained that it had previously been improperly capitalizing certain operation and maintenance expenditures that should have been expensed in the year that they were incurred. After the Federal Energy Regulatory Commission (FERC) noted the improper capitalization in mid-1980, Gulf states it instituted tighter controls to ensure that only proper items were capitalized. Gulf argues that the improper capitalization resulted in the 1979 O&M expense for this function being understated and requests that the entire $804,000 differential be included in its approved O&M.

We have examined the limited evidence presented by the Company on this issue and have found that $345,000 on a jurisdictional [*62] basis is not supported by competent and substantial evidence and must be disallowed.

4. Transmission - System Planning

Gulf included in its 1984 budget $111,000 for system planning in the transmission area. There was no corresponding expense for this item in 1979 because Gulf said that it was (according to the FERC) inappropriately capitalizing these amounts.

We have examined the record on this issue and find no competent substantial evidence to support allowing this expense. The necessary adjustment is to reduce 1984 O&M by $102,000 on a jurisdictional basis.

5. CPI and Benchmark

As noted earlier, when Gulf prepared its filing it inflated its 1983 O&M expenses by an assumed inflation factor of 4.8%. Due to moderating trends in inflation, we substituted an inflation rate of 4.3% as being more realistic, which required a total reduction in O&M of $329,000 on a system basis. Of that amount we disallowed $148,000 (jurisdictionally) as a specific adjustment in forecasted O&M expenses, and here we disallow the remaining $151,000 (jurisdictionally) that the CPI and customer growth benchmark was increased by due to the 4.8% inflation rate.

6. Transmission Line [*63] Rentals

Gulf has a 50% ownership interest in Plant Daniel, which is located in Mississippi. Gulf investigated several options for transporting the Daniel power to Florida and concluded that renting transmission lines from Mississippi Power and Alabama Power was the most economical. The Company has included $1,381,000 of expense for these line rentals in its 1984 O&M budget, but states that it had no comparable expense in the 1979 base year. Gulf asserts that the entire $1,381,000 is reasonable and prudent and requests its inclusion in allowed O&M.

In Florida Power and Light Company's most recent rate case (Docket No. 830465-EI) we determined that it was not appropriate to allow for increases in both CPI and customer growth for all categories of expenses. Specifically, we found that production plant O&M should only be inflated for the CPI increases and not for customer growth. We made this determination because, unlike customer or line crew personnel whose numbers have a logical and fairly direct correlation to the number of customers served, generating plant is built to serve a certain maximum load and its non-fuel O&M expenses do not rise as a result of new customers [*64] being added to the system, but, rather, rise when new plant is built. Accordingly, in the FPL case, we inflated that Company's three major production functions by inflation alone when constructing a comparative benchmark.

In Gulf's case, we find the transmission line rentals to be comparable to new generating plant in purpose and shall disallow that portion of the requested expense that exceeds growth for inflation alone. The necessary adjustment corresponding to customer growth is to reduce the $1,381,000 requested by $385,000 on a jurisdictional basis.

7. Administrative and General - Double Counting

In its Administrative and General (A&G) expense, Gulf budgeted $28,047,000 for 1984 as compared to its 1979 O&M expense for this function of $12,253,000. The 1984 budgeted was $6,811,000 in excess of the $21,236,000 provided by the 1984 CPI and customer growth benchmark. Gulf attempted to justify $1,573,000 of this excess by saying that it was necessary to pay the Company's 50% share of Plant Daniel's administrative and general expenses.

We reject Gulf's attempted justification for this amount in excess of the CPI and customer growth benchmark. We reject it, not because [*65] we find the amount to be either unreasonable or imprudent, but because we find that Gulf has already included this amount in a previous justification. This is so because we find that A&G for new plant is accounted for in the base O&M and to accept it as additional justification would result in counting this expense twice. The necessary adjustment is to reduce jurisdictional O&M by $1,464,000.

8. UPS Allocation Error - Staff Audit Finding

Our Staff Auditors found an error in the Company's Unit Power Sales allocation method which required a reduction in O&M of $342,000 on a system basis. In its revised filing, Gulf agreed to this adjustment. The necessary jurisdictional adjustment is to reduce O&M $319,000.

Approved 1984 O&M Budget

As a result of our net adjustments to 1984 O&M, the approved 1984 non-fuel and non-conservation O&M for inclusion in this case is $69,627,000.

B. Depreciation and Amortization

The Company initially proposed test year depreciation expense of $29,478,000, which it increased in its revised request to $29,542,000. As a result of our adjustments we have reduced 1984 depreciation and amortization by $115,000 to an approved amount [*66] of $29,427,000.

C. Taxes Other Than Income Taxes

As was noted earlier and as is discussed more fully in the Rate Section of this order, we found Gulf's industrial class base revenue forecast to be low and increased the same by a total of $2,772,000. This increase in revenues necessitates a $55,000 (jurisdictional) increase in revenue taxes.

D. Income Taxes Currently Payable

This adjustment is mechanical in nature and serves to reflect the effect on income tax expense of the various other adjustments we have made to the Company's proposed operating income, including the adjustment made to the Company's proposed separations factors. This results in an increase to income tax expense of $5,696,000, and total income taxes currently payable of $8,146,000.

E. Deferred Federal Income Taxes (Net)

We make no adjustment to the Company's revised filing on this issue. The amount of deferred income taxes (net) is $12,951,000.

F. Investment Tax Credits (Net)

The Public Counsel and the Federal Executive Agencies once again urge us to treat the Investment Tax Credit (ITC) differently than we have done in the past. Once again, we decline to do so for fear that the proposed [*67] treatment may jeopardize the Company's ability to utilize the credit. We recognize that the treatment proposed by Public Counsel is more beneficial to the ratepayers, and we have directed this Company and another Florida utility to submit revenue ruling requests to the Internal Revenue Service (IRS) on this issue. As we have done in the past, we will treat the ITC as common equity for purposes of determining the Company's income tax expense allowed for ratemaking purposes. The revenue related to the increased taxes allowed on the debt portion of the ITC return are to be collected under bond or corporate undertaking, subject to refund with interest. Final resolution of this issue will wait until a response is received from the IRS or we decide to act without the IRS's response (see below). The revenues subject to refund are $1,336,000.

By this order, however, we give notice to all Florida utilities that our reluctance to follow the Public Counsel's proposal is based on the concern we have that the IRS may find the Public Counsel's method to be a violation of the Internal Revenue Code (IRC), thereby jeopardizing the utilities' ability to take investment tax credits. Because of [*68] this concern, we directed this company and United Telephone Company of Florida (United) to request rulings from the IRS on this issue. United's request was mailed to the IRS in August 1982. Gulf Power's request was mailed to the IRS in June 1983. More than two years have passed since United's request was sent to the IRS and, to date, no response from the IRS has been received.

It has come to our attention that American Telephone and Telegraph Company (AT&T) filed a ruling request with the IRS on May 9, 1983 and, after six amendments to the request, received a ruling from the IRS on December 29, 1983. The IRS was able to act on AT&T's request in a little over six months. It is our impression that most requests for rulings from the IRS are resolved in 6 to 8 months, and we are concerned that the failure of the IRS to act in United's and Gulf's request may be caused by the failure of the utilities involved to press for a final resolution of the issue.

We are tired of waiting for a response from the IRS and believe that this issue should have been resolved by now. Therefore, since we believe the treatment proposed by Public Counsel and the Federal Executive Agencies [*69] is the proper ratemaking treatment, in future cases we will apply this treatment, unless the IRS has issued a ruling on United and Gulf Power's requests indicating that the proposed treatment violates the I.R.C.

1. ITC Amortization Rate

In its filing, the Company has used a 31-year period to determine the amortization period for ITCs. The IRC requires that ITCs be amortized to cost of service no faster than ratably. The use of the composite depreciable life of the assets (after adjusting for net salvage) subject to the investment tax credit is a proper amortization rate under the IRC. The Company's composite depreciable life is 29 years.

The Company argues that the extra two years are added to the composite depreciable life as a safety margin to assure compliance with the IRC. We are unaware of other utilities using this safety margin. Also, if the Company's books and records are accurate the risk of faster-than-ratable amortization does not exist. Therefore, we find that the proper ITC amortization rate should be based on a 29-year life. This adjustment reduces income tax expense by $61,000.

Total Operating Expense

Total operating expense, as adjusted herein, [*70] is $140,361,000 for 1984.

III. Net Operating Income

The net operating income is derived by subtracting total operating expense from operating revenues. For 1984, Gulf's net operating income is $58,648,000 ($199,009,000 - $140,361,000).

REVENUE EXPANSION FACTOR

The purpose of the revenue expansion factor (NOI multiplier) is to gross up or expand the Company's net operating income deficiency to compensate for income taxes and revenue taxes that the Company will incur as the result of any revenue increase. The approved revenue expansion factor in this case is 1.984190, developed as follows:

Revenue Requirement	100.0000
Gross Receipts	1.5000
Reg. Assessment Fee	.1250
Uncollectible Accts.	.1325
Net Before Income Taxes	98.2425
Income Taxes	47.8441
Revenue Expansion Factor	50.3984

N.O.I. Multiplier	1.984190

REVENUE REQUIREMENTS

Having determined the Company's rate base, the net operating income applicable to the test period, and the overall fair rate of return, it is possible to calculate any excess/deficiency of revenues. Multiplying the rate base value for 1984 of $625,602,000 by the fair overall rate of return of 9.75% yields an NOI requirement [*71] for 1984 of $60,996,000. The adjusted net operating income for the test year amounted to $58,648,000 resulting in an NOI deficiency of $2,348,000. Applying the appropriate NOI multiplier of 1.984190 to this figure yields a deficiency of $4,659,000 in gross annual revenues, the calculation of which is detailed below:

(000's)

	1984
Rate Base	$625,602
Rate of Return	X 9.75%
Required NOI	$ 60,996
Adjusted NOI	- 58,648
NOI Deficiency	$ 2,348
NOI Multiplier	X 1.984190
Gross Revenue Increases	$ 4,659

In view of the above, we find and conclude that Gulf should be authorized to increase its rates and charged so as to generate $4,659,000 in additional revenues annually for the year 1984.

JURISDICTIONAL SEPARATION

Jurisdictional separation is the result of allocating the Company's total system costs for the test period between its retail and wholesale operations. Jurisdictional separation provides the basis for determining the Company's retail revenue deficiency. At issue is whether the jurisdictional separation performed by the Company properly reflects the jurisdictional NOI and rate base responsibility. The most important jurisdictional separation factors [*72] are those for energy and production plant. We have reviewed those separation factors used by the Company before FERC and this Commission over the last several rate cases and found no "double dipping" between jurisdictions.

Jurisdictional separation factors are the result of a cost of service study. As will be explained subsequently, we have rejected the Company-preferred cost of service study in favor of a Staff-requested study found in Exhibit 11B. Therefore, the separation factors resulting from Exhibit 11B shall be used in this case. We note that although we have found defects in the Company's overall forecast, we shall not adjust the separation factors for fear of creating larger errors than already exist in the Company's factors.

RATE STRUCTURE AND RATE DESIGN

Having ascertained the Company's revenue requirement and the amount of revenue increase necessary, we now turn our attention to rate design. We must determine the rate of return currently earned by each rate class, the increase in revenue requirement allocated to each class, and how each class's revenue responsibility will be spread between the customer, energy, and demand charges. In this rate proceeding, [*73] we have also reviewed the continued appropriateness of several aspects of the Company's rate structure. We begin first with the cost of service studies presented in this case.

Cost of Service Methodology

In this rate case, several cost of service studies based on various demand allocation methodologies were presented to us for consideration. The Company sponsored the average of the twelve monthly coincident peak (12 CP) demand allocation methodology to allocate production and transmission costs. Monsanto, APC, and ACC (hereinafter referred to as Monsanto) proposed the use of the summer coincident peak (3 CP) methodology. However, Monsanto's position was that if a 12 CP methodology were used, then the weighted twelve coincident peak approach would be more appropriate. FEA's position was that if a 12 CP and average cost of service study was chosen by the Commission, then fuel should also be included. Staff proposed the use of a 12 CP and 1/13th average demand (12 CP and average) cost of service study.

Mr. Carzoli, testifying on behalf of Gulf, advocated the use of the 12 CP method. Mr. Carzoli stated that his method was more appropriate because it recognizes the fact [*74] that Gulf Power plans and operates for the purpose of meeting season-to-season and month-to-month load requirements. This method also reflects the necessity for reserves and considers scheduled maintenance, unscheduled outages, and firm capacity commitments. Mr. Carzoli went further to state that distribution costs should be allocated to the customer and demand components utilizing the minimum distribution system methodology. Finally, Mr. Carzoli was opposed to recognizing an "average demand" component.

We disagree with the Company and find that a 12 CP and average demand cost of service study is appropriate. We believe it is appropriate to allocate part of production plant on average demand because the type of plant, and, therefore, the cost of capacity to be allocated, is partially dependent on the number of hours the capacity is needed. Moreover, we find that the portion of the production plant allocated on average demand should be classified as energy-related. Further, we find that only generation level accounts should be allocated on average demand. Staff requested, and the Company provided, a cost of service study consistent with our findings. Exhibit 11B, which is [*75] a 12 CP and average demand cost of service study, is the appropriate study to be used in this case. Our decision in this case is consistent with our decision in all electric rate cases over the past few years. This decision is especially appropriate in Gulf's case because the size of all of Gulf's monthly peaks is important in that Gulf receives from or makes payments to the Southern System on the basis of whether its monthly reserve margins, which are a function of the monthly peaks, are larger or smaller than Southern's margin. It is for this reason that we find Monsanto's proposed methodology to be particularly inappropriate.

Although we are adopting the 12 CP and average cost of service study for use in this case, we believe that even this study might not truly be the most appropriate study to use. The 12 CP and average methodology allocates all production and transmission plant based on twelve hours in the year. However, this study does not tell us how much capacity we need to serve off-peak load. Once we know that, we can determine how much additional capacity is needed to serve the peak load. This information will be invaluable in designing cost-based time [*76] of use rates. Therefore, we request that the Company perform such a study and that it be included in the Company's next rate case filing.

Staff raised the issue of whether the method used by Gulf to develop the twelve monthly coincident peaks for the 1984 test year for certain classes was appropriate. What Gulf did was to assume that the 1981 derived proportion of demand accounted for by the RS, GS, GSD rate classes and the secondary level portion of the LP rate class remained constant for the 1984 test year. However, it is clear that the GS class's demand cost responsibility was understated and its relative rate of return overstated because the class's MWH load grew tremendously during this period, as reflected in Exhibit 2G. We find the Company's methodology to be inappropriate. However, no adjustment is warranted because even with an adjustment GS remains significantly above parity. We caution the Company to change its methodology prior to its next rate case. The issue of the precision of the Company's load research will be discussed below.

FEA questioned whether it is appropriate for Gulf to have used load data derived from historic point estimates in developing its cost [*77] of service load allocators. In recent years we have stated that twelve monthly coincident peak hours are important in providing quality service to the State's electric customers, including those of Gulf Power Company. Thus, a 12 CP and average method has been ordered in the most recent seven rate cases for ratemaking purposes. FEA has suggested, albeit vaguely, that Gulf should provide data on all hours that have a 90% or better probability of being the monthly peak. The effect of using all hours having a 90% or better chance of including the monthly peak would result in something close to a 200 CP method. We find this proposal to be unnecessary and burdensome. However, we are open to reviewing more specific alternative methodologies once FEA provides them to this Commission.

The next cost of service issue relates to the treatment of conservation revenues and expenses in the cost of service study. Monsanto argued that conservation expenses should be assigned to those classes that caused the expenses to be incurred while the related revenues should be assigned to the classes that provided the revenues. In this case, conservation revenues and expenses were removed from the [*78] cost of service study. We find in this case, as we have in all recent electric rate cases, that this treatment is proper. All conservation dollars should be handled in the Energy Conservation Cost Recovery Clause. As we have stated previously, all customers benefit from these programs by the deferred need to add increasingly expensive capacity and by less expensive fuel charges. Therefore, all customers should pay toward the recovery of expenditures made to benefit them, including conservation costs.

The final cost of service issue relates to the Company's treatment of coal-by-wire sales in the cost of service study. The specific issue is how should the revenue received from these sales be credited back to the classes in the study. Revenues should be credited back as the related costs are allocated. The plant necessary to generate these sales was already allocated to rate classes using a 12 CP and average method. The basis for FP&L's or FPC's decision to purchase these coal-by-wire KWH's does not change the way Gulf's plant will be allocated among its rate classes. Having determined the appropriate allocation methodology, we find that the revenues collected through [*79] sales of this capacity should be credited to the classes in the same fashion that the costs associated with generating the KWH's were allocated to the classes. The Company has properly treated these revenues.

Allocation of Revenue Increase

We have granted the Company an overall increase of $4,659,000. Staff recommended that we allocate the entire revenue increase to the RS class in order to move that class closer to parity. However, we disagree with Staff based on problems that are apparent in the cost of service study. Due to the size of the rate increase, we believe it would be more fair to have the revenue increase absorbed primarily by the increase in customer charges and the implementation of a temporary service charge. The balance of the increase, if there is any, shall be collected from all customer classes proportionate to each class's present base revenues, through the KWH charge. The class rates of return with the revenue increase fully allocated are:

Rate Code	Rate Schedule	Approved ROR/Index
RS	Residential	8.73/ .89
GS	General Service	18.96/1.95
GSD	General Service Demand	10.66/1.09
LP(GSLD)	General Service Large Demand	10.43/1.07
PX	High Load Factor	10.00/1.03
OS I-II	Street Lighting	9.10/ .93
OS III	Outdoor Lighting	30.16/3.09
Total Retail		9.75/1.00

[*80]

Load Research

Load research is used to estimate class contributions to monthly system coincident peak demands and class non-coincident demands for those classes of customers not equipped with magnetic tape meters. Historic load research is used to develop projected test year billing determinants and allocation factors for demand-related items in the cost of service studies, such as generation, transmission and distribution plant, and related operation and maintenance expenses. For this rate proceeding, the Company provided load research data for the RS, GS, GSD, and LP rate classes. The load research data utilized by the Company in developing cost of service study allocation factors was collected in 1981, which was the most recent historical period for which the Company had complete data. The Company maintains that the historic load research data is adequate for purposes of this rate case.

Statistical accuracy or precision refers to the measurement of the difference between a sample result and the result from a complete measurement under the same conditions. In early 1984, the Commission adopted Rule 25-6.437, Florida Administrative Code, regarding cost of service load [*81] research. This Rule requires the four large investor-owned utilities to design samples to provide estimates of the historic summer and winter peak demands and the average of the 12 monthly coincident peaks for each class that accounts for more than 1% of a utility's annual retail sales within plus or minus 10% at the 90% confidence level. This Rule does not apply to Gulf's 1981 load research data since 1986 is the first year for which the utilities are required to report data collected from samples designed to provide estimates with the specified accuracy. However, in 1981, Gulf was subject to the PURPA guidelines requiring estimates for the system and class peaks within plus or minus 10% at the 90% confidence level for those classes accounting for more than 10% or more of the utility's annual retail sales. MFR Schedule E-14a shows that none of the class estimates meet PURPA standards. Therefore, we find that the estimates are not adequately precise and agree with Staff that, although the load research is inadequate, it is the best data that we have and should, therefore, be used.

Gulf collected load data in 1983 which is providing more precise estimates of coincident [*82] and non-coincident demands. Furthermore, Gulf has filed a sampling plan pursuant to Rule 25-6.437, Florida Administrative Code, which has been approved by Staff as being in conformance with this Rule. Therefore, we should see a substantial improvement in Gulf's load research data in the future.

Forecast by Revenue Class

The Company prepared a forecast of customers, energy sales, and peak demand by revenue class for the test year 1984. The issue in this case is whether the forecast was reasonable. Having compared the July 1984 year to date actual energy sales and customers with the corresponding forecasted levels, we have found that forecasted industrial revenues are too low. The Company conceded that an adjustment to increase industrial revenues by $637,000 is appropriate. However, the Company maintained that 106,774,000 KWH of 1984 industrial sales and revenues are attributable solely to "non-recurring" sales made on a short term basis, and that a proforma adjustment should be made to ignore the revenues from these sales in the test year. Exhibit 2V was prepared by the Company and shows a three year history of actual "non-recurring" industrial sales. Exhibit 2V reveals [*83] that the Company experienced significant amounts of "non-recurring" industrial sales during 1982 and 1983. In fact, the 1982 level of 108,608,000 KWH exceeds the estimated actual level for 1984 of 106,774,000. The 1983 level of "non-recurring" industrial sales was 50,070,000 KWH. Since "non-recurring" sales have occurred in each of the past three years and the 1982 actual "non-recurring" sales exceeded the estimated actual 1984 "non-recurring", we find that the Company's proposed proforma adjustment should not be made. Therefore, the total amount of excess industrial sales during 1984 should be recognized for ratemaking purposes and revenues should be increased $2,135,000, in addition to the Company's adjustment of $637,000, for a total increase of $2,772,000.

Finally, the Company made an adjustment reducing revenue taxes $10,000 related to its erroneous $637,000 adjustment increasing revenues described above. Revenue taxes should have been increased. We have corrected this adjustment and we increased revenue taxes $35,000 related to our revenue adjustment. The net effect is to increase other taxes by $55,000.

Billing Determinants

Billing determinants are the estimates, [*84] by rate class, of the number of bills, KWH consumption, and billed KW. The Company's proposed billing determinants were based on the overall forecast discussed previously. Based on our conclusion as to the appropriateness of the overall forecast by revenue class, we find that the billing determinants for those rate classes that include industrial customers are understated, as are the base revenues. This affects rate schedules GSD, LP, and PX.

The Company has agreed to an annual adjustment of $636,576 in base revenues attributed to higher KWH usage than was forecasted in the industrial revenue class. Schedule 4 of Exhibit 6DD illustrates how the Company calculated this revenue adjustment. However, the Company included unbilled revenue and excluded the "non-recurring sales" in its estimate of the annual base revenue effect. We have recalculated the revenue adjustment to include the "non-recurring sales" and to separate unbilled and billed revenue pursuant to the Company's methodology in Exhibit 6DD. We, therefore, came up with the following correction factors for rate schedules GSD, LP and PX:

Rate Classes	Correction Factor
GSD	.99583047
LP	.91575788
PX	.92634393

[*85]

The correction factor is the ratio of the original forecast base revenue over the revised forecast base revenue. These factors shall be applied to the revenue increase allocated to these classes prior to calculating rates.

Customer Charges

In recent rate cases we have stated that customer charges should reflect customer-related costs, as determined in the cost of service study. However, as discussed previously, we are hesitant to fully rely on unit costs from the cost of service study because of the problems noted with the Company's forecast. Specifically, we shall not raise the GS customer charge to the cost of service study indicated level and instead shall hold that charge constant. We are increasing the RS customer charge by 25% to $6.25, to reflect the amount by which costs have increased. Finally, with the elimination of mandatory TOU rates, we are adopting an average customer charge for the LP rate class of $51.00. The approved customer charges are as follows:

Rate Code	Rate Schedule	Present	Unit Cost W/O Minimum Distribution System(a)	Approved Customer Charges
RS	Residential	$5.00	$8.36	n1 $6.25
GS	General Service Nondemand	7.00	21.23	n1 7.00
GSD	General Service Demand (21 KW-499 KW)	19.50	26.81	n2 27.00
LP (GSLD)	General Service Large Demand (500 KW & Up)	27.00	30.98	51.00
PXT	High Load Factor Power (7500 KW & Up - 75% Load Factor)	60.00	145.83	146.00

[*86]

n1 Plus $3.00 time-of-use meter charge where applicable.

n2 Plus $5.40 time-of-use meter charge where applicable.

Standard Demand Charges

We find that standard demand charges should remain at their presently for Gulf's demand classes, KWH's are as highly correlated with coincident demand as billing demand. Plant costs are for the most part allocated on coincident demand. However, because coincident demand is not measured for most customers, demand-related costs have been collected or recovered on the basis of billing demand and KWH's. Presently, most of the demand-related costs are collected on billing demand. Since at this time KWH's are as highly correlated with coincident demand as billing demand, we are opposed to collecting more of the demand-related costs through demand charges. Based on the evidence in this case, a rate design which collects part of the demand-related costs through the KWH charge is just as cost based as one which collects all of the demand-related costs through the demand charge. Furthermore, Exhibit 2Q shows that there is considerable variation in coincidence factors within the GSD and LP classes. We acknowledge that demand [*87] charges are needed to protect against unwarranted growth in peak coincident demands, but increasing the proportion of demand-related costs recovered through demand charges is inequitable to low load factor customers when KWH's are as highly correlated with coincident demand as billing demand and when there is a wide variation of coincidence factors in a class. We, therefore, approve the following standard demand charges:

Rate Class	Approved Standard Demand Charges
GSD	$6.25
LP	6.25
PX	7.50

Time Of Use Rates

In the Company's last rate case, time of use (TOU) rates were made mandatory for customers with monthly demands in excess of 2000 KW. At issue in this case is whether TOU rates should remain mandatory for these customers. We decline to continue mandatory TOU rates because we feel that it is unfair to eliminate a customer's freedom of choice. Moreover, we want to be especially cautious not to mandate TOU rates where we are not satisfied that the rate structure is reasonable. At this point, we cannot conclude that the TOU rates are cost-based. Further, if the rate structure is designed properly and based on the cost to serve those customers, it should [*88] then be providing the necessary incentives to obviate the need to mandate TOU rates for any customers. Therefore, we are discontinuing mandatory TOU rates for specific customers and are allowing optional TOU rates for all customers.

The next question is how should the optional TOU rates be designed. The Company's present TOU rates were designed under the load factor method, which incorporates on-peak and maximum demand charges and separate charges for on-peak and off-peak KWH usage. The Company proposed to continue designing its TOU rates under this method. Monsanto proposed a method for PXT customers whereby all demand costs are collected in an on-peak demand charge and time-differentiated energy charges are abolished. The FEA sponsored method uses the ratio of marginal peak to off-peak energy costs to divide embedded energy costs into peak and off-peak charges. Staff recommends that the methodology approved in the recent FP&L and FPC cases be used because Gulf's off-peak system lambda is less than the average off-peak fuel cost. Under this method there is only an on-peak demand charge which is set equal to the class's standard demand charge. The off-peak KWH charge is set [*89] at the energy unit cost at the approved class rate of return. The on-peak KWH charge will then recover the energy unit cost as well as the remaining revenue requirement assigned to the class that is not being recovered in any other charge.

Having reviewed all of the testimony on the proper design of TOU rates, we find that it would be inappropriate to change to another rate design method when we are not convinced that it would be beneficial. As we discussed previously, it would make more sense to charge the amount of plant that is required to meet off-peak load to both on and off-peak and to charge the plant needed just to serve the peak load to the on-peak rate. However, the currently approved cost of service methodology does not effectuate that goal. Therefore, the resulting TOU rate design will necessarily be inadequate. For this reason, we are reluctant to move to a new TOU rate design at this time. We approve the continued use of the load factor method for designing Gulf's optional rates and will continue to look at the question of TOU rate design on a generic basis.

Having eliminated mandatory TOU rates and having chosen a TOU rate design, we now must address [*90] the issue of the revenue shortfall that will occur when those customers who would gain from TOU rates opt for them and those who would lose opt for the non-TOU rate. The Company, Monsanto, and Staff agree that if a revenue shortfall can be quantified, it should be recovered from the class in which the shortfall occurred. Standard non-time differentiated rates are based on average cost. With the elimination of mandatory TOU rates, those customers who consume more on-peak and who are more costly to serve than average will not opt for the TOU rate. Additionally, those customers who will save by remaining on TOU rates will do so. In order to properly reflect the costs of the standard and TOU customers, the revenue shortfall from those customers who will opt for TOU rates shall be added back to the standard rate for that class.

The question remains as to how to calculate the revenue shortfall from the elimination of mandatory TOU rates. The billing determinants for any class reflect those customers on TOU rates and those on standard rates. These billing determinants are shown in MFR Schedule E-4D. However, the MFR Schedule as filed was prepared under the assumption that mandatory [*91] TOU rates would be continued for certain customers. With the abolition of mandatory TOU rates, it is inappropriate to use this MFR to calculate revenue from those rate classes which contain customers on mandatory TOU rates because the mix of TOU and standard customers will change. However, the Company has the computer capability to calculate the impact on test year billing determinants and revenue for any given rate design. We find that this calculated shortfall shall be added to the standard KWH rate and this rate shall remain in effect until the next rate change.

The final issue related to TOU rates is the rate design for the LP class. The Company proposed to have two LP TOU rates, an optional TOU rate for LP customers with demands between 500 KW and 1999 KW and a mandatory TOU rate for those customers with demands of 2000 KW and above. Given the fact that we have abolished all mandatory TOU rates, there should be only one LP TOU rate.

Service Charges

The Company proposed no change in service charges in this rate case. At the present time, the Company does not have a separate charge for temporary service. The Company presently charges $16.00 for temporary service, [*92] which is the standard connection charge. The present charge of $16.00 does not cover the cost of the installation and removal of the temporary pole and service drop. Exhibit 12H provides the cost data associated with establishing temporary service and shows a total cost of $47.81. We find that the Company should institute a temporary service charge of $48.00. We further find that the Company's other service charges are cost-based and should be continued. The approved service charges are as follows:

	Approved Service Charges
Initial Connection	$16.00
Reconnection of Existing Service	$16.00
Reconnect for Nonpayment	$16.00
Temporary Service - Underground	
Single Phase/Three Phase	$48.00
Temporary Service - Overhead	
Single Phase/Three Phase	$48.00

Street and Outdoor Lighting Rates

The Company agrees that charges for each of the various lighting services should recover the costs associated with such service. However, the present composite energy charge, which recovers non-fuel energy-related, demand-related and customer-related costs other than those related to the fixture and maintenance of the fixture, is above cost and is subsidizing the cost [*93] of the Company-owned fixtures and the maintenance of those fixtures. The present energy charge for OS-I and OS-II is 2.51¢ per KWH while the unit cost from the approved cost of service study is 1.819¢ at the classes' present rate of return. It is inequitable that customers who own their fixtures should share in the cost of Company-owned fixtures through the energy charge they pay. Furthermore, having the energy charge above the unit cost at the class rate of return gives the Company a competitive edge in providing fixtures. We have determined that the non-fuel energy charge shall be set at Unit cost at the class approved rate of return in order to eliminate subsidization of either customer or Company-owned fixtures.

Maintenance charges should recover those costs associated with maintenance of lights, shown to be $700,000 in Exhibit 11E. The Company's proposed maintenance charges are not high enough to recover all allocated lighting maintenance expense. Mr. Haskins, testifying on behalf of the Company, agreed that the most appropriate way to design maintenance charges is to apply a ratio to the estimated maintenance charges in Exhibit 12J to develop maintenance charges which [*94] will produce $700,000. We find that the maintenance charges in Mr. Haskins' Exhibit 12K, which were developed pursuant to this methodology, are the appropriate maintenance charges for use in this rate case.

The Company provided updated pole costs of $4.47 and $2.03 for concrete and wood poles, respectively, in Exhibit 12L. We find that the charge for concrete poles should be raised from $3.70 to $4.50. Wood poles should remain at their present level of $2.00.

The remainder of the revenue requirement for the lighting classes will come from fixture charges. Fixture charges shall be priced at whatever fixed carrying charge is necessary to produce the remaining revenue requirement.

The final issue related to outdoor lights is whether it is appropriate for the Company to charge the OS-II energy charge to customers who own their own general area lights. OS-I, street lighting, and OS-II, general area lighting (outdoor lighting), have non-fuel energy and fuel charges based on usage during hours when lights controlled by photocells would be on. OS-III has an energy charge based on constant usage 24 hours a day. The fuel charge for OS-I and OS-II is based on 79% off-peak [*95] consumption while OS-III is charged the RS-GS-GSD fuel charge. Presently, customer-owned streetlights pay the OS-I energy of 2.510¢ and the OS-I fuel charge. However, customer-owned general area lights must take service on OS-III and pay an energy charge of 4.562¢ per KWH. We find that the Company's current practice is discriminatory and that because customer-owned general area lights have the same usage pattern as lights served on OS-I and OS-II, they should be billed the OS-II energy and fuel charge.

Minimum Bill Provision

The Company currently has a minimum bill provision for the GSD and LP rate classes equal to the customer charge for those customers who qualify for the rate schedule. The Company proposes a revision to the minimum bill provision of the demand rate schedules GSD, GSDT, LP, LPT and PXT. This revision provides for a minimum charge of $2.35 per KW of contract capacity for customers served at secondary voltage, $1.25 per KW for service at primary voltage, and $ .65 per KW for service at transmission voltage. The minimum bill amount is designed to assure the Company recovery of the average carrying costs on the average investment in "local facilities" [*96] which serve customers at their specific voltage levels. "Local facilities" is defined as that investment needed to serve the average customer which requires an addition of facilities to the Company's existing electric system grid. This includes such things as substation costs and transmission and distribution line costs. Thus, the minimum bill provision is not designed to recover any production costs. The provision would be imposed when the customer's total bill does not equal or exceed the minimum charge times the contract capacity. Mr. Haskins, testifying on behalf of Gulf, stated that the benefit of this provision is that customers who are providing sufficient revenue to pay for the carrying cost on the Company's local facilities will be protected from those who would not otherwise be paying for these facilities.

Although we are sympathetic to the Company's position, we find that the Company projects a total of only $8,111 in revenue from this provision from the GSD class and $5,002 from the LP class. We do not feel that this amount shows that there is a significant inequity to correct. Further, the Commission's rules allow the Company to collect CIAC or file a special contract [*97] in cases where the Company finds it necessary to deviate from approved rate schedules. For these reasons, we find that the proposed revision to the minimum monthly bill is unnecessary and should be denied.

Reactive Demand Charge

The power produced by generating plants is measured in KVA's (kilovolt-amperes) and is known as apparent power. It is comprised of both real and reactive power. Power is real when it is consumed to do work and to generate heat and light, for example for lights, stoves, or water heaters. Power is reactive when the ingredients for power are present but no useful work is being done. Reactive power must be supplied to most types of magnetic equipment, such as motors, refrigerators and air conditioners. Any electric device incorporating coiled wire wound on metal core material will strongly evidence reactive power characteristics.

Real power is measured in KW's. The ratio of real power (KW's) to apparent power (KVA's) is known as the power factor. It is usually expressed as a percent. Thus, if the power factor were 100%, KW's equal KVA's and there is no reactive power produced.

Power factor is of concern to a utility because the utility [*98] must have the ability to provide enough power to supply both the real and reactive power needs of the system. To meet these needs the utility either has to generate or purchase power or install capacitors on its system to supply its reactive power needs. Capacitors are much cheaper than generator capacity and, because they are installed closer to the load areas, eliminate the need to transport reactive power long distances. Reactive power supplied from capacitors reduces the net load which must be supported by the system.

The issue in this rate case relates to the appropriate charge or penalty imposed on certain customers with power factors below 90%. The disagreement between the parties lies in whether the charge should be based on the customer's, rather than the Company's, cost of correcting his power factor to 90%. The Company maintains that the charge should be based on the customer's cost because the customer gains certain localized benefits if the capacitors are installed on his premises which he could not gain if Gulf puts the capacitors on its system. Basically, putting capacitors on the customer's premises will reduce line losses, improve voltage conditions and release [*99] capacity on the customer's side of the meter. Thus, the customer benefits through improved operating efficiency of his equipment and by not buying power which is wasted internally in line losses.

Staff's position is that Company charges should be based on Company costs. Gulf's proposed charge is admittedly a value of service rate; its stated intention is to give "the customer an economically balanced incentive for making the investment in power factor correction equipment." We agree with Staff that, for purposes of establishing the charge, it is irrelevant if the customer could derive other benefits from placing capacitors on his premises. It makes no sense to charge a customer $1.50 per KVAR to correct something the Company can correct for $1.00. If it is true that the customer could benefit from putting capacitors on his side of the meter, he should do so. However, we do not believe that Gulf should attempt to force the customer to do so. Gulf's duty is to charge customers according to the costs those customers impose on the utility system. Therefore, we reject Gulf's proposed reactive demand charge of $1.50 and approve a continuation of the current charge of $1.00 per KVAR. [*100]

Transformer Ownership Discounts

Transformer ownership discounts are needed because demand charges include costs associated with all the transformation necessary to provide service from the production plant down to the secondary distribution level. If a customer takes service at a voltage higher than secondary and thus provides his own transformation, a credit is warranted to cover those transformation costs not required to service him. We find that this discount should be referred to in the tariff as a transformer ownership discount to avoid confusion with the metering voltage discount discussed later.

The current ownership discounts are 25¢ per KW for primary voltage and 70¢ per KW for transmission level. The Company is proposing to set the discount at 47¢ per KW for primary and 82¢ per KW for transmission level. Staff recommended that the billing units used to determine the appropriate credits should be adjusted for losses and that we should look to Exhibit 11G in determining the proper credit. Exhibit 11G provides the embedded cost for transformation from transmission voltage to primary and from primary to secondary. The Staff recommended level of these [*101] credits is based on the amount of transformation costs included in the rate. The Company proposed to reduce the calculated avoided cost to reflect the fact that demand charges are set below unit cost and because it determined that the transformer ownership discount should bear the same relationship to unit cost as the demand charge. FEA has proposed an intermediate transformer ownership discount at level 3, sub-transmission based on its misunderstanding of MFR E11.

We disagree with all parties on this issue and find that it is inappropriate to have the discounts based on the amount of transformation costs included in the rates. We feel that it is more appropriate to pay the customer for what he puts in, as opposed to removing the average embedded cost. Therefore, the transformer ownership credits should remain at their present levels, 25¢ per KW for primary voltage and 70¢ per KW for transmission voltage.

Voltage Level Discounts

In the Company's last rate case, we implemented a voltage level discount for KWH of 2% for transmission level and 1% for customers served at primary level. This discount represents costs related to losses which occur during transformation that [*102] the Company avoids for customers who take service above the secondary distribution level. However, we find that a discount should be applied to the demand charge as well as the energy charge because the KW reading on the meter is also affected. Although the Company maintained that its proposed transformer ownership credit includes compensation for demand losses occurring during transformation, we conclude that Gulf witness Carzoli's testimony established that this is not the case. Therefore, a demand metering voltage discount shall be established, which is separate from the discount for transformer ownership. However, due to the fact that the Company was unable to provide separate information on line and transformer losses, we are unable to quantify the exact discount. Therefore, we shall approve a 2% transmission discount for both demand and energy and a 1% primary metering voltage discount for both charges.

FEA has proposed an intermediate metering voltage discount for level 3, sub-transmission. MFR E11 appears to indicate there is an additional level of transformation cost avoided by the Company. In actuality, the 14 customers shown at level 3 receive service at primary [*103] level, but are shown separately because no primary line investment is given to these customers. For the purpose of the voltage discount they should be listed as primary distribution voltage customers, level 4, and should get only the primary transformation credit.

Poultry Farm Transition Rate

The Commission voted two rate cases ago to close the Poultry Farm service rate schedule. At that time a transition rate, GS-1, was established to avoid an excessive increase for these customers. All parties agreed that the GS-1 rate should now be discontinued because these customers have been given ample time to prepare for the move to the GS rate. We agree and accept this stipulation.

Interruptible Service Rider

The Company filed a proposed Interruptible Service Rider on April 23, 1984. In Docket No. 840188-EI, the Commission voted to consider the rider in this rate case. The issue in this case is whether the rider should be approved. Gulf's Interruptible Service Rider has a number of features which make it different from the interruptible rate schedules of FPC or TECO. It was designed by Gulf to apply only to new customers or to new load of existing customers. [*104] The rider contains a maximum interruptible capacity of 20% of the total contract capacity of the customer. It was also designed to contain, what the Company terms, an "economic switch" rather than an electrical switch to cause the interruption. This "economic switch" is a severe penalty for non-compliance which includes a pay-back of all credits paid for the prior 11 months or all months since the last compliance, whichever is greater, plus a non-compliance charge of 25% of this amount. Thus, in reality, this is more like a curtailable rate rather than an interruptible rate. However, unlike the curtailable rates of FPL and FPC, Gulf will treat this load as non-firm in its generation planning process.

The credit is designed assuming mandatory TOU rates for these customers and using the load factor rate design. Under this proposal, when a curtailment is called, the credit will be equal to the on-peak demand charge times the contracted interruptible capacity. In months when no curtailment is invoked, the credit will equal one-third of the on-peak demand charge times the contracted interruptible capacity plus two-thirds of the on-peak demand charge times the maximum demand [*105] in excess of the contracted firm capacity. Gulf has limited the number of curtailments that can be called to 15 per year with a maximum number of hours of interruption per calendar year of 300. The rider also provides for a six hour advance notice of curtailment.

There are several aspects of this rider with which we are concerned. Specifically, we find that it is discriminatory to limit the rider to new customers or new load. We also find that it is inappropriate for the rider to contain limitations on the percentage of a customer's load that can be curtailable and the number of curtailments or hours of curtailment. Moreover, because the credit is designed assuming mandatory TOU rates and because mandatory TOU rates have been abolished, the credit will have to be redesigned. We also question whether the level of the credit is too great, given the limitation on the number of curtailments.

During cross-examination, Company witness Haskins stated that if the Commission proposed to make any changes to the rider, the Company would prefer to withdraw and refile it later. Based on the specific concerns we have stated, we do not believe the Interruptible. Service Rider should be [*106] approved as filed. However, we shall leave it to the Company to propose a revised rider. We emphasize to Gulf that it would be beneficial to the Company to have interruptible rates because they could help the Company avoid the construction of new plant. Yet we recognize the fact that Gulf is not planning for any new plant. Therefore, we shall request that Gulf develop a plan for instituting interruptible service prior to any plans for Gulf to construct new plant or prior to the planning of new plant on the Southern Company, system. Moreover, we note that if we approve interruptible rates, there would have to be a revision to the Intercompany Interexchange Contract to reflect Gulf's ability to interrupt customers.

Customer Migration

Gulf has four rate schedules for commercial and industrial customers: GS, GSD, LP (GSLD) and PX (an optional rate for high load factor customers). The reason for having various general service rate schedules is that the cost to serve customers varies depending on the customers' load characteristics. The rates for each class reflect the difference in cost to serve. The Company has proposed no change to the parameters which establish [*107] the applicability of each rate schedule.

FEA raised the issue of whether customers should be allowed to migrate between rate classes. Specifically, FEA would prefer that LP customers be able to switch to the GSD rate schedule because they would get a lower bill.

Monsanto witness Pollock testified that size, voltage level, coincidence factor, and load factor are critical characteristics for forming rate classes. He concluded that the relationship between load factor and coincidence factor is particularly crucial. This issue has to do with customers having different coincidence factors, load factors, voltage levels and size. The point is best explained by a comparison of GSD and LP rates. The demand unit cost for LP is higher than GSD's because the LP class has a considerably higher coincidence factor. In other words, for each coincident KW, LP has 1.5 billing KW over which to collect demand-related costs while GSD has 2.0 billing KW per coincidence KW. Exhibit 202A demonstrates how the coincidence factor affects the demand unit costs. GSD's energy charge is lower than LP's because the demand charges have been set equal, resulting in more demand-related costs being recovered [*108] in LP's energy charge than GSD's. However, if all demand-related costs and all customer-related costs were collected through the demand and customer charges, respectively, all LP customers would still want to migrate to GSD because the considerably higher coincidence factor results in a higher demand unit cost which is not offset by a lower energy unit cost. For a 100% load factor customer, the lower LP energy unit cost amounts to a 7¢ energy savings per billing KW which is much less than the $1.08 difference in demand unit cost. The energy savings per billing KW would decrease as load factor decreases. Thus, based on the present load characteristics of GSD and LP and the costs associated with each class, the LP rates will always be higher than the GSD rates if the rates are cost based. Until an inexpensive demand meter is invented which measures coincident demand, rather than noncoincident demand, so that customers can be billed on coincident demand, differences in coincidence factors between these classes will dictate different rates by class.

Witness Pollock testified that the GSD and LP classes differ enough in load factor and coincidence factor, based on Exhibit 2Q, that [*109] if rates are to track costs, they should remain two separate rate classes, given the present flat customer, energy and demand rate design. We agree and find that migration downward to lower demand rate schedules should not be allowed unless the customer can hold demand down for a year to qualify. We further find that the parameters established for different rate classes are proper and should be continued. We find that allowing unqualified migration will destroy the homogeneity of the classes and some customers will not be paying the costs they impose on the system for which they should be responsible.

Seasonal Rates

Gulf currently has seasonal rates for the RS and GS rate classes. Gulf has had seasonal rates for over twenty years because historically the Company's summer peaks have been higher than its winter peaks, resulting in a higher cost of providing service in the summer. However, RS and GS customers were notified two rate cases ago, in Docket No. 810136, that the summer-winter differential might be eliminated in the future.

Gulf prepared a series of graphs of the historical monthly coincident loads or system peaks. An examination of these graphs shows [*110] how dramatically Gulf's monthly peaks have changed over time and that within the last few years winter peaks have become very close to summer peaks in magnitude. In 1981, the maximum winter peak was 90% of the maximum summer peak; the 1982 winter peak was 98% of the summer peak; and in 1983 the winter peak was 96% of the summer peak. Moreover, Exhibit 2P establishes that seasonal rates make more sense for the GSD rate class than for the GS class.

Staff has recommended that seasonal rates be eliminated because they are no longer justified. The Company maintains that seasonal rates are appropriate and should be continued. We agree with Staff that there is a question as to the justification supplied for the continuation of seasonal rates, but are reluctant to make any change at this time due to the inadequate data that we have. Therefore, we caution the Company that we shall consider the elimination of seasonal rates in the Company's next rate case.

CONCLUSIONS OF LAW

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

2. This Commission has the legal authority to approve [*111] and use a projected test period for ratemaking purposes. Calendar year 1984 is an appropriate base test period.

3. The adjustments to rate base made herein are reasonable and proper. The value of the Company's 1984 rate base for ratemaking purposes is $625,602,000.

4. The adjustments made to the calculation of net operating income are proper and appropriate. For ratemaking purposes, Gulf's net operating income for 1984 is $58,648,000.

5. The fair rate of return on the equity capital of Gulf lies in a range of 14.6% to 16.6% for 1984. A return of 15.6% should be used to determine revenue requirements.

6. The range of reasonableness for the overall fair rate of return for the Company is 9.46% to 10.04%, with a focus upon 9.75% for ratemaking purposes in 1984.

7. Gulf Power Company should be authorized to increase its rates and charges by $4,659,000 in annual gross revenues in 1984 to provide it with an opportunity to earn a fair rate of return of 9.75%.

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

9. The new rate schedules shall be reflected upon billings rendered for meter [*112] readings taken on or after December 17, 1984.

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 $4,659,000 in additional gross revenues annually. The Company shall include with the revised rate schedules all calculations and workpapers used in deriving the revised rates and charges. It is further

ORDERED that the revised schedules authorized herein for the revenue increase shall be reflected upon billings rendered for meter readings taken on or after December 17, 1984. It is further

ORDERED that the Company shall perform a cost of service study that will determine how much additional capacity is needed beyond the peak load to serve the Company's territorial needs. This study shall be included in the Company's next rate case filing. It is further

ORDERED that Gulf Power Company [*113] shall perform a study and develop a plan for implementing interruptible service, as described herein. It is further

ORDERED that Gulf Power Company provide to each of its customers a bill stuffer describing the nature of the base rate increase, as well as, the basis for the revised fuel clause factor. A copy of the bill stuffer shall be provided to the Commission's Electric and Gas Department for review prior to its use. It is further

ORDERED that any party adversely affected by the Commission's final action in this matter is entitled to request: 1) reconsideration of the decision by filing a motion for reconsideration with the Commission Clerk within 15 days of the issuance of this order in the form prescribed by Rule 25-22.60, Florida Administrative Code, or 2) judicial review by the Florida Supreme Court by the filing of a notice of appeal with the Commission Clerk and the filing of a copy of the notice and the filing fee with the Supreme Court. This filing must be completed within 30 days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate [*114] Procedure.

BY ORDER of the Florida Public Service Commission, this 25th day of January, 1985.

APPENDIX B

GULF POWER COMPANY
COMPARATIVE AVERAGE RATE BASES
1984 TEST YEAR
$ (000)

COMPANY

	SYSTEM PER BOOKS AS FILED	JURIS. PER BOOKS AS FILED	JURIS. ADJSTMNIS. AS FILED	ADJUSTED JURIS. AS FILED	ADDITIONAL ADJSTMNIS. EXH. 6-DD	REVISED JURIS.
PLANT IN SERVICE	944128	808235				
C APPLIANCE SALES			-1811		0	
C DANIEL COAL CARS			-9524		0	
95 BASE COAL			274		0	
3 REVISED PLANT DATA			0		-11924	
C SMITH ASH STRG.			0		-603	
C AFUDC - LAST ORDER			0		-1734	
24 UNAVAIL. OIL			0		87	
7 BONIFAY BLDG.			0		0	
7 GRACLVILLE BLDG.			0		0	
9 LEISURE LAKE			0		0	
10 CWIP - NIB RECLASS.			0		0	
63 UPS SALES			0		0	
4 DISTRIBUTION PLANT			0		0	
5 STEAM PLANT			0		0	
38 C&M EXPENSE			0		0	
TOTAL	944128	808235	-11061	797174	-14174	783000
ACOUM. DEPRACIATION	-271970	-243152				
C APPLIANCE SALES			375		0	
C DANIEL CARS			2068		0	
8 REVISED PLANT DATA			0		-2246	
94 LBW DEPREL. RATES			0		-215	
C SMITH ASH STORACE			0		6	
7, 9, 10 STAFF ADUSTMNIS.			0		0	
4 DISTRIBUTION PLANT			0		0	
63 UPS SALES			0		0	
5 STEAM PLANT			0		0	
8 DEPREC. AMOUNT			0		0	
TOTAL	-271970	-243152	2443	-240709	-2455	-243164
NET PLANT IN SERVICE	672158	565083	-8618	556465	-16629	539836
CONST. WORK IN PROG.	82574	78842				
C PLANT SCHERER			-48635		0	
10 CWIP INTEREST BRNG.			0		-26987	
10 CWIP - NIB			0		7318	
10, 11, 12 AMT. OF						

CWIP			0		0	
TOTAL	82574	78842	-48635	30207	-19669	10538
PROP. HELD FOR FUT. USE	1830	1734				
10 CWIP - NIB RECIASS.			0		0	
13 CARYVILLE SITE			0		0	
14 CARYVILLE SITE			0		0	
15 MILTON OFFICE			0		0	
TOTAL	1830	1734	0	1734	0	1734
NET UTILITY PLANT	756562	645659	-57253	588406	-36298	552108

[*115]

GULF POWER COMPANY
COMPARATIVE AVERAGE RATE BASES
1984 TEST YEAR
$ (000)

	COMM. VOTE		EEA	
	JURIS. ADJSTMNIS.	ADJUSTED JURIS.	JURIS. ADJSTMNIS.	ADJUSTED JURIS.
PLANT IN SERVICE				
C APPLIANCE SALES	0		0	
C DANIEL COAL CARS	0		0	
95 BASE COAL	0		0	
3 REVISED PLANT DATA	0		0	
C SMITH ASH STRG.	0		0	
C AFUDC - LAST ORDER	0		0	
24 UNAVAIL. OIL	-15		0	
7 BONIFAY BLDG.	-20		0	
7 GRACLVILLE BLDG.	-23		0	
9 LEISURE LAKE	-201		0	
10 CWIP - NIB RECLASS.	105		0	
63 UPS SALES	0		0	
4 DISTRIBUTION PLANT	0		0	
5 STEAM PLANT	0		0	
38 C&M EXPENSE	0		0	
TOTAL	-154	7828469	0	783000
ACOUM. DEPRECIATION				
C APPLIANCE SALES	0		0	
C DANIEL COAL CARS	0		0	
8 REVISED PLANT DATA	0		0	
94 LBW DEPREC. RATES	0		0	
C SMITH ASH STORAGE	0		0	
7, 9, 10 STAFF ADJSTMNIS.	4		0	
4 DISTRIBUTION PLANT	0		0	

63 UPS SALES	0		0	
5 STEAM PLANT	0		0	
8 DEPREC. AMOUNT	0		0	
TOTAL	4	-2431601	0	-243164
NET PLANT IN SERVICE	-150	5396861	0	539836
CONST. WORK IN PROG.				
C PLANT SCHERER	0		0	
10 CWIP INTEREST BRNG.	0		0	
10 CWIP - NIB	-2644		0	
10, 11, 12 AMT. OF CWIP	0		0	
TOTAL	-2644	7894	0	10538
PROP. HELD FOR FUT. USE				
10 CWIP - NIB RECIASS.	2380		0	
13 CARYVILLE SITE	-145		-145	
14 CARYVILLE SITE	0		-1364	
15 MILTON OFFICE	0		0	
TOTAL	2235	3969	-1509	225
NET UTILITY PLANT	-559	551549	-1509	550599

[*116]

GULF POWER COMPANY
COMPARATIVE AVERAGE RATE BASES
TEST YEAR ENDED 12/31/84
(000)
PAGE 2 OF 2

	SYSTEM PER BOOKS AS FILED	JURIS. PER BOOKS AS FILED	COMPANY JURIS. ADJSTD. AS FILED	ADJSTD. JURIS. AS FILED	ADDITIONAL ADJSTMNIS. EXH. 6-DD
WORKING CAPITAL	119411	125094			
C NUCLEAR SITE			-146		0
C UNAMORT. DEF. C&M			3024		0
C FUEL INVENTORY			-22084		0
C EMPLOYEE LOANS			-902		0
C MERCHANDISE			-1404		0
C INTEREST & DIV. REC.			-140		0
C A/R APPLIANCE SALES			-5498		0
C TEMPORARY CASH			-33185		0
C SERCIAL DEPOSITS			-1394		0
C COMMON DIV. DECL.			3919		0
C CUSTOMER DEPOSITS			9815		0
C A/R APPLIANCE SALES			218		0
C SHORT TERM DEBT			6501		0
24 UNAVAILABLE OIL			0		-97
18 FUEL INV. $ ADJ.			0		-1541
20 CASH			0		-723
27 CONDENSATE PUMPS			0		-354

29 DEFERRED C&M			0		-3285
93 NOTES REC.			0		-217
17 FUEL INV.			0		0
23 FUEL & CONS. OVERREC.			0		0
58 UNBILLED REVEIS			0		0
58A/R Billed Revenue			0		0
20 NUCLEAR SITE CHARCES			0		0
46 Unamortized Rate Case Exp.			0		0
63 UPS - PRT & SUPP.			0		0
63 UPC - INJ. & CHCE.			0		0
TOTAL	119511	125094	-41276	83818	-6217
TOTAL RATE BASE	876073	770753	-96529	672224	-42515

[*117]

GULF POWER COMPANY
COMPARATIVE AVERAGE RATE BASES
TEST YEAR ENDED 12/31/84
(000)

	COMPANY REVISED JURIS.	COMM. VOTE JURIS. ADJUSTMENT	COMM. VOTE ADJUSTED JURIS.	EEA JURIS. ADJUSTMENT	EEA ADJUSTED JURIS.
WORKING CAPITAL					
C NUCLEAR SITE		0		0	
C UNAMORT. DEF. C&M		0		0	
C FUEL INVENTORY		0		0	
C EMPLOYEE LOANS		0		0	
C MERCHANDISE		0		0	
C INTEREST & DIV. REC.		0		0	
C A/R APPLIANCE SALES		0		0	
C TEMPORARY CASH		0		0	
C SPECIAL DEPOSITS		0		0	
C COMMON DIV. DECL.		0		0	
C CUSTOMER DEPOSITS		0		0	
C A/R APPLIANCE SALES		0		0	
C SHORT TERM DEBT		0		0	
24 UNAVAILABLE OIL		0		0	
18 FUEL INV. $ ADJ.		0		0	
20 CASH		0		0	
27 CONDENSATE PUMPS		0		0	
29 DEFERRED C&M		0		0	
93 NOTES REC.		0		0	
17 FUEL INV.		-2501		0	
23 FUEL & CONS. OVERREC.		-344		0	
58 UNBILLED REVENUE		-202		0	
58A/R Billed Revenue		230		0	
20 NUCLEAR SITE CHARGES		-292		-1316	
46 Unamortized Rate Case Exp.		-439		-1455	
63 UPS - PRT & SUPP.		0		0	
63 UPS - INJ. & CHCE.		0		0	
TOTAL	77601	-3548	74053	-2771	74830

TOTAL RATE BASE	629709	-4107	625602	-4280	625429

APPENDIX C [*118]

GULF POWER COMPANY
COMPARATIVE NET OPERATING INCOME
YEAR ENDED 12/31/84

	JURIS. NOI PER BOOKS	COMPANY JURIS. PER BOOKS	ADJUSTED JURIS.	ADD'L. ADJ.
OPERATING REVENUES	374875			
C FRANCHISE FEE		-4083		0
C FUEL OVER RECOVERY		-342		0
C CONSERV. OVER RECOV.		-47		0
C DANIEL COAL CARS		-706		0
33 SCHED. E CAPAC. (20%)		-1322		0
36 PROF. ON ALT.&SUPP. ENERGY		646		0
58 BASE RATE REV.-REV. FRCST.		3506		637
34 SCHED. E CAPAC.		0		418
44 FUEL REVENUE		0		-173789
45 CONSERV. REVENUE		0		-4402
TOTAL	374875	-2348	372527	-177136
OPERATING EXPENSES				
OPERATION & MAINT.	255113			
C ADVERTISING		-269		0
21 LINE OF CREDIT		0		0
24 AMORT. UNAVAIL. OIL		0		19
35 CAPAC. PAYMENTS		0		-673
38 BUDGETED O & M				
PRODUCTION		0		-767
TRANSMISSION		0		0
DISTRIBUTION		0		0
CUSTOMER ACTS.		0		0
CUSTOMER SERV. & INFORM.		0		0
ADMIN. & GENERAL		0		-319
CPI IN BENCHMARK		0		0
39 INCREASED NO. OF EMPLS. - SALARY		0		-475
40 SALARY LEVEL		0		0
41 TREE TRIMMING		0		0
42 BAD DEBT EXPENSE		0		-147
43 UPDATED CPI FACTOR		0		0
44 FUEL INPENSE		0		-171314
45 CONSERVATION EXPENSE		0		-4333
46 RATE CASE EXPENSE		0		-36
47 SOUTHERN COMP. SERVICES		0		0
48 INDUSTRY DUES		-19		-11
59 BOILER & TURBINE MAINT.		0		1175
96 MON+ECUR. MAINT. EXP.		0		-288
63 UNIT POWER SALES		0		0

TOTAL	255113	-288	254825	-177169

[*119]

GULF POWER COMPANY
COMPARATIVE NET OPERATING INCOME
YEAR ENDED 12/31/84

	COMPANY REVISED JURIS.	COMMISSION JURIS. ADJUSTS.	VOTE+ ADJUSTED JURIS.
OPERATING REVENUES			
C FRANCHISE FEE		0	
C FUEL OVER RECOVERY		0	
C CONSERV. OVER RECOV.		0	
C DANIEL COAL CARS		0	
33 SCHED. E CAPAC. (20%)		1322	
36 PROF. ON ALT.&SUPP. ENERGY		161	
58 BASE RATE REV.-REV. FRCST.		2135	
34 SCHED. E CAPAC.		0	
44 FUEL REVENUE		0	
45 CONSERV. REVENUE		0	
TOTAL	195391	3618	199009
OPERATING EXPENSES			
OPERATION & MAINT.			
C ADVERTISING		0	
21 LINE OF CREDIT		0	
24 AMORT. UNAVAIL. OIL		29	
35 CAPAC. PAYMENTS		0	
38 BUDGETED O & M			
PRODUCTION		-648	
TRANSMISSION		-487	
DISTRIBUTION		0	
CUSTOMER ACCTS.		0	
CUSTOMER SERV. & INFORM.		0	
ADMIN. & GENERAL		-1464	
CPI IN BENCHMARK		-151	
39 INCREASED NO. OF EMPLS. - SALARY		-829	
40 SALARY LEVEL		-1560	
41 TREE TRIMMING		0	
42 BAD DEBT EXPENSE		-153	
43 UPDATED CPI FACTOR		-148	
44 FUEL EXPENSE		0	
45 CONSERVATION EXPENSE		0	
46 RATE CASE EXPENSE		0	
47 SOUTHERN COMP. SERVICES		-1717	
48 INDUSTRY DUES		-3	
59 BOILER & TURBINE MAINT.		-898	
96 MON+ECUR. MAINT. EXP.		0	
63 UNIT POWER SALES		0	
TOTAL	77656	-8029	69627

[*120]

GULF POWER COMPANY
COMPARATIVE N.O.I.

	COMPANY					COMMISSION VOTE+	
	PER BOOKS	JURIS. ADJ.	ADJUSTED JURIS.	ADD'L. ADJ.	REVISED JURIS.	JURIS. ADJ.	ADJUSTED JURIS.
DEPRECIATION & AMORT.	29874						
C BASE COAL		61		0		0	
3 DEPREC. - PLANT ADUS.		0		-474		0	
3 SMITH ASH STORACE		0		24		-48	
4 DISTRIBUTION PLANT		0		0		0	
5 PRODUCTION PLANT		0		0		0	
7 BONIFAY AND CRACEVILLE		0		0		-1	
9 LEASURE LAKES		0		0		-9	
10 ESCAMBIA CHEM. SUB.		0		0		4	
27 CARYVILLE		-810		0		0	
37 NUC. STTE		353		0		-61	
63 UPS		0		0		0	
94 NEW DEPREC. RATES		0		514		0	
TOTAL	29874	-396	29478	64	29542	-115	29427
AMORTIZATION OF ITC	-1477						
51 AMORT. RATE		0		0		-61	
94 NEW DEPREC. RATE		0		28		0	
TOTAL	-1477	0	-1477	28	-1449	-61	-1510
TAXES OTHER THAN INCOME	19300						
C FRANCHISE FEE		-4083		0		0	
C FPSC ASSESSMENT FEE		127		0		0	
44 FUEL TAXES		0		-2475		0	
45 CONSERVATION TAXES		0		-69		0	
58 REVENUE ADJ.		-21		-10		55	
TOTAL	19300	-3977	15323	-2554	12769	55	12824
INCOME TAXES - CURRENT	-1932						
49 TAX EFFECT OF ADUS.		2706		1922		5701	
50 JDIC INT. IMPUTATION		0		0		0	
C UPS ALLOCATION		0		-246		0	
INT. SYNCH		0		0		-5	
TOTAL	-1932	2706	774	1676	2450	5696	8146
DEFERRED INCOME TAXES	12951	0	12951	0	12951	0	12951
INVESTMENT TAX CREDIT	8896	0	8896	0	8896	0	8896
TOTAL OPERATING EXPENSES	322725	-1955	320770	-177955	142815	-2454	140361
NET OPERATING INCOME	52150	-393	51757	819	52576	6072	58648

[*121]

Supreme Court of the United States

BLUEFIELD WATERWORKS & IMPROVEMENT CO.
v.
PUBLIC SERVICE COMMISSION OF WEST VIRGINIA et al.

No. 256.

Argued January 22, 1923.
Decided June 11, 1923.

In Error to the Supreme Court of Appeals of West Virginia.

Proceedings by the Bluefield Waterworks & Improvement Company against the Public Service Commission of the State of West Virginia and others to suspend and set aside an order of the Commission fixing rates. From a judgment of the Supreme Court of West Virginia, dismissing the petition, and denying the relief (89 W. Va. 736, 110 S. E. 205), the Waterworks Company bring error. Reversed.

West Headnotes

Constitutional Law ⚷298(1.5)
92k298(1.5) Most Cited Cases

Rates which are not sufficient to yield a reasonable return on the value of the property used in public service at the time it is being so used to render the service are unjust, unreasonable, and confiscatory, and their enforcement deprives the public utility company of its property, in violation of the Fourteenth Amendment of the Constitution.

Constitutional Law ⚷298(3)
92k298(3) Most Cited Cases

Under the due process clause of the Fourteenth Amendment of the Constitution, U.S.C.A., a waterworks company is entitled to the independent judgment of the court as to both law and facts, where the question is whether the rates fixed by a public service commission are confiscatory.

Waters and Water Courses ⚷203(10)
405k203(10) Most Cited Cases

It was error for a state public service commission, in arriving at the value of the property used in public service, for the purpose of fixing the rates, to fail to give proper weight to the greatly increased cost of construction since the war.

Waters and Water Courses ⚷203(10)
405k203(10) Most Cited Cases

A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties, but it has no constitutional right to such profits as are realized or anticipated in highly profitable enterprises or speculative ventures.

Waters and Water Courses ⚷203(10)
405k203(10) Most Cited Cases

Since the investors take into account the result of past operations as well as present rates in determining whether they will invest, a waterworks company which had been earning a low rate of returns through a long period up to the time of the inquiry is entitled to return of more than 6 per cent. on the value of its property used in the public service, in order to justly compensate it for the use of its property.

Federal Courts ⚷504.1
170Bk504.1 Most Cited Cases
(Formerly 106k394(6))

A proceeding in a state court attacking an order of a public service commission fixing rates, on the ground that the rates were confiscatory and the order void under the federal Constitution, is one where there is drawn in question the validity of authority exercised under the state, on the ground of repugnancy to the federal Constitution, and therefore is reviewable by writ of error.

****675 *680** Messrs. Alfred G. Fox and Jos. M. Sanders, both of Bluefield, W. Va., for plaintiff in error.

Mr. Russell S. Ritz, of Bluefield, W. Va., for defendants in error.

*683 Mr. Justice BUTLER delivered the opinion of the Court.

Plaintiff in error is a corporation furnishing water to the city of Bluefield, W. Va., **676 and its inhabitants. September 27, 1920, the Public Service Commission of the state, being authorized by statute to fix just and reasonable rates, made its order prescribing rates. In accordance with the laws of the state (section 16, c. 15-O, Code of West Virginia [sec. 651]), the company instituted proceedings in the Supreme Court of Appeals to suspend and set aside the order. The petition alleges that the order is repugnant to the Fourteenth Amendment, and deprives the company of its property without just compensation and without due process of law, and denies it equal protection of the laws. A final judgment was entered, denying the company relief and dismissing its petition. The case is here on writ of error.

[1] 1. The city moves to dismiss the writ of error for the reason, as it asserts, that there was not drawn in question the validity of a statute or an authority exercised under the state, on the ground of repugnancy to the federal Constitution.

The validity of the order prescribing the rates was directly challenged on constitutional grounds, and it was held valid by the highest court of the state. The prescribing of rates is a legislative act. The commission is an instrumentality of the state, exercising delegated powers. Its order is of the same force as would be a like enactment by the Legislature. If, as alleged, the prescribed rates are confiscatory, the order is void. Plaintiff in error is entitled to bring the case here on writ of error and to have that question decided by this court. The motion to dismiss will be denied. See Oklahoma Natural Gas Co. v. *684 Russell, 261 U. S. 290, 43 Sup. Ct. 353, 67 L. Ed. 659, decided March 5, 1923, and cases cited; also Ohio Valley Co. v. Ben Avon Borough, 253 U. S. 287, 40 Sup. Ct. 527, 64 L. Ed. 908.

2. The commission fixed $460,000 as the amount on which the company is entitled to a return. It found that under existing rates, assuming some increase of business, gross earnings for 1921 would be $80,000 and operating expenses $53,000 leaving $27,000, the equivalent of 5.87 per cent., or 3.87 per cent. after deducting 2 per cent. allowed for depreciation. It held existing rates insufficient to the extent of 10,000. Its order allowed the company to add 16 per cent. to all bills, excepting those for public and private fire protection. The total of the bills so to be increased amounted to $64,000; that is, 80 per cent. of the revenue was authorized to be increased 16 per cent., equal to an increase of 12.8 per cent. on the total, amountingto $10,240.

As to value: The company claims that the value of the property is greatly in excess of $460,000. Reference to the evidence is necessary. There was submitted to the commission evidence of value which it summarized substantially as follows:

a.	Estimate by company's engineer on basis of reproduction new, less depreciation, at prewar prices	$ 624,548 00
b.	Estimate by company's engineer on basis of reproduction new, less depreciation, at 1920 prices	1,194,663 00
c.	Testimony of company's engineer fixing present fair value for rate making purposes	900,000 00
d.	Estimate by commissioner's engineer on basis of reproduction new, less depreciation at 1915 prices, plus additions since December 31, 1915, at actual cost, excluding Bluefield Valley waterworks, water rights, and going value	397,964 38
e.	Report of commission's statistician showing investment cost less depreciation	365,445 13

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f.  Commission's valuation, as fixed in
     case No. 368 ($360,000), plus gross
     additions to capital since made
     ($92,520.53) ............................ 452,520 53
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***685** It was shown that the prices prevailing in 1920 were nearly double those in 1915 and pre-war time. The company did not claim value as high as its estimate of cost of construction in 1920. Its valuation engineer testified that in his opinion the value of the property was $900,000--a figure between the cost of construction in 1920, less depreciation, and the cost of construction in 1915 and before the war, less depreciation.

The commission's application of the evidence may be stated briefly as follows:

As to 'a,' supra: The commission deducted $204,000 from the estimate (details printed in the margin), [FN1] leaving approximately $421,000, which it contrasted with the estimate of its own engineer, $397,964.38 (see 'd,' supra). It found that there should be included $25,000 for the Bluefield Valley waterworks plant in Virginia, 10 per cent. for going value, and $10,000 for working capital. If these be added to $421,000, there results $500,600. This may be compared with the commission's final figure, $460,000.

FN1

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Difference in depreciation allowed ........ $ 49,000
Preliminary organization and development
 cost ..................................... 14,500
Bluefield Valley waterworks plant .......... 25,000
Water rights ............................... 50,000
Excess overhead costs ...................... 39,000
Paving over mains .......................... 28,500
                                            --------
                                            $204,000
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***686** As to 'b' and 'c,' supra: These were given no weight by the commission in arriving at its final figure, $460,000. It said:

> 'Applicant's plant was originally constructed more than twenty years ago, and has been added to from time to time as the progress and development of the community required. For this reason, it would be unfair toits consumers to use as a basis for present fair value the abnormal prices prevailing during the recent war period; but, when, as in this case, a part of the plant has been constructed or added to during that period, in fairness to the applicant, consideration must be given to the cost of such expenditures made to meet the demands of the public.'

****677** As to 'd,' supra: The commission, taking $400,000 (round figures), added $25,000 for Bluefield Valley waterworks plant in Virginia, 10 per cent. for going value, and $10,000 for working capital, making $477,500. This may be compared with its final figure, $460,000.

As to 'e,' supra: The commission, on the report of its statistician, found gross investment to be $500,402.53. Its engineer, applying the straight line method, found 19 per cent. depreciation. It applied 81 per cent. to gross investment and added 10 per cent. for going value and $10,000 for working capital, producing $455,500. [FN2] This may be compared with its final figure, $460,000.

FN2 As to 'e': $365,445.13 represents investment cost less depreciation. The gross investment was found to be $500,402.53, indicating a deduction on account of depreciation of $134,957.40, about 27 per cent., as against 19 per cent. found by the commission's engineer.

As to 'f,' supra: It is necessary briefly to explain how this figure, $452,520.53, was arrived at. Case No. 368 was a proceeding initiated by the application of the company for higher rates, April 24, 1915. The commission made a valuation as of January 1, 1915. There were presented two estimates of reproduction cost less depreciation, one by a valuation engineer engaged by the company, ***687** and the other by a valuation engineer engaged by the city, both 'using the same method.' An inventory made by the company's engineer was accepted as correct by the city and by the commission. The method 'was that generally employed by courts and commissions in arriving at the value of public utility properties under this method.' and in both estimates 'five year average unit prices' were applied. The estimate of the company's engineer was $540,000 and of the city's engineer, $392,000. The principal differences as given by the commission are shown in the margin. [FN3] The commission disregarded both estimates and arrived at $360,000. It held that the best basis of valuation was the net investment, i. e., the total cost of the property less depreciation. It said:

FN3

		Company Engineer.	City Engineer.
1.	Preliminary costs	$14,455	$1,000
2.	Water rights	50,000	Nothing
3.	Cutting pavements over mains	27,744	233
4.	Pipe lines from gravity springs	22,072	15,442
5.	Laying cast iron street mains	19,252	15,212
6.	Reproducing Ada springs	18,558	13,027
7.	Superintendence and engineering	20,515	13,621
8.	General contingent cost	16,415	5,448
		$189,011	$63,983

'The books of the company show a total gross investment, since its organization, of $407,882, and that there has been charged off for depreciation from year to year the total sum of $83,445, leaving a net investment of $324,427. * * * From an examination of the books * * * it appears that the records of the company have been remarkably well kept and preserved. It therefore seems that, when a plant is developed under these conditions, the net investment, which, of course, means the total gross investment less depreciation, is the very best basis of valuation for rate making purposes and that the other methods above referred to should ***688** be used only when it is impossible to arrive at the true investment. Therefore, after making due allowance for capital necessary for the conduct of the business and considering the plant as a going concern, it is the opinion of the commission that the fair value for the purpose of determining reasonable and just rates in this case of the property of the applicant company, used by it in the public service of supplying water to the city of Bluefield and its citizens, is the sum of $360,000, which sum is hereby fixed and determined by the commission to be the fair present value for the said purpose of determining the reasonable and just rates in this case.'

In its report in No. 368, the commission did not indicate the amounts respectively allowed for going value or working capital. If 10 per cent. be added for the former, and $10,000 for the latter (as fixed by the commission in the present case), there is produced $366,870, to be compared with $360,000, found by the commission in its valuation as of January 1, 1915. To this it added $92,520.53, expended since, producing $452,520.53. This may be compared with its final figure, $460,000.

The state Supreme Court of Appeals holds that the valuing of the property of a public utility corporation and prescribing rates are purely legislative acts, not subject to judicial review, except in so far as may be necessary to determine whether such rates are void on constitutional or other grounds, and that findings of fact by the commission based on evidence to support them will not be reviewed by the court. City of Bluefield v. Waterworks, 81 W. Va. 201, 204, 94 S. E. 121; Coal & Coke Co. v. Public Service Commission, 84 W. Va. 662, 678, 100 S. E. 557, 7 A. L. R. 108; Charleston v. Public Service Commission, 86 W. Va. 536, 103 S. E. 673.

In this case (89 W. Va. 736, 738, 110 S. E. 205, 206) it said:

'From the written opinion of the commission we find that it ascertained the value of the petitioner's property for rate making [then quoting the commission] 'after ***689** maturely and carefully considering the various methods presented for the ascertainment of fair value and giving such weight as seems proper to every element involved and all the facts and circumstances disclosed by the record.''

[2][3] The record clearly shows that the commission, in arriving at its final figure, did not accord proper, if any, weight to the greatly enhanced costs of construction in 1920 over those prevailing about 1915 and before the war, as established by uncontradicted ****678** evidence; and the company's detailed estimated cost of reproduction new, less depreciation, at 1920 prices, appears to have been wholly disregarded. This was erroneous. Missouri ex rel. Southwestern Bell Telephone Co. v. Public Service Commission of Missouri, 262 U. S. 276, 43 Sup. Ct. 544, 67 L. Ed. 981, decided May 21, 1923. Plaintiff in error is entitled under the due process clause of the Fourteenth Amendment to the independent judgment of the court as to both law and facts. Ohio Valley Co. v. Ben Avon Borough, 253 U. S. 287, 289, 40 Sup. Ct. 527, 64 L. Ed. 908, and cases cited.

We quote further from the court's opinion (89 W. Va. 739, 740, 110 S. E. 206):

'In our opinion the commission was justified by the law and by the facts in finding as a basis for rate making the sum of $460,000.00. * * * In our case of Coal & Coke Ry. Co. v. Conley, 67 W. Va. 129, it is said: 'It seems to be generally held that, in the absence of peculiar and extraordinary conditions, such as a more costly plant than the public service of the community requires, or the erection of a plant at an actual, though extravagant, cost, or the purchase of one at an exorbitant or inflated price, the actual amount of money invested is to be taken as the basis, and upon this a return must be allowed equivalent to that which is ordinarily received in the locality in which the business is done, upon capital invested in similar enterprises. In addition to this, consideration must be given to the nature of the investment, a higher rate ***690** being regarded as justified by the risk incident to a hazardous investment.'

'That the original cost considered in connection with the history and growth of the utility and the value of the services rendered constitute the principal elements to be considered in connection with rate making, seems to be supported by nearly all the authorities.'

[4] The question in the case is whether the rates prescribed in the commission's order are confiscatory and therefore beyond legislative power. Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the service are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment. This is so well settled by numerous decisions of this court that citation of the cases is scarcely necessary:

'What the company is entitled to ask is a fair return upon the value of that which it employs for the public convenience.' Smyth v. Ames (1898) 169 U. S. 467, 547, 18 Sup. Ct. 418, 434 (42 L. Ed. 819).

'There must be a fair return upon the reasonable value of the property at the time it is being used for the public. * * * And we concur with the court below in holding that the value of the property is to be determined as of the time when the inquiry is made regarding the rates. If the property, which legally enters into the consideration of the question of rates, has increased in value since it was acquired, the company is entitled to the benefit of such increase.' Willcox v. Consolidated Gas Co. (1909) 212 U. S. 19, 41, 52, 29 Sup. Ct. 192, 200 (53 L. Ed. 382, 15 Ann. Cas. 1034, 48 L. R. A. [N. S.] 1134).

'The ascertainment of that value is not controlled by artificial rules. It is not a matter of formulas, but there must be a reasonable judgment having its basis in a proper consideration of all relevant facts.' Minnesota Rate Cases (1913) 230 U. S. 352, 434, 33 Sup. Ct. 729, 754 (57 L. Ed. 1511, 48 L. R. A. [N. S.] 1151, Ann. Cas. 1916A, 18).

***691** 'And in order to ascertain that value, the original cost of construction, the amount expended

in permanent improvements, the amount and market value of its bonds and stock, the present as compared with the original cost of construction, the probable earning capacity of the property under particular rates prescribed by statute, and the sum required to meet operating expenses, are all matters for consideration, and are to be given such weight as may be just and right in each case. We do not say that there may not be other matters to be regarded in estimating the value of the property.' Smyth v. Ames, 169 U. S., 546, 547, 18 Sup. Ct. 434, 42 L. Ed. 819.
'* * * The making of a just return for the use of the property involves the recognition of its fair value if it be more than its cost. The property is held in private ownership and it is that property, and not the original cost of it, of which the owner may not be deprived without due process of law.'

Minnesota Rate Cases, 230 U. S. 454, 33 Sup. Ct. 762, 57 L. Ed. 1511, 48 L. R. A. (N. S.) 1151, Ann. Cas. 1916A, 18.

In Missouri ex rel. Southwestern Bell Telephone Co., v. Public Service Commission of Missouri, supra, applying the principles of the cases above cited and others, this court said:

'Obviously, the commission undertook to value the property without according any weight to the greatly enhanced costs of material, labor, supplies, etc., over those prevailing in 1913, 1914, and 1916. As matter of common knowledge, these increases were large. Competent witnesses estimated them as 45 to 50 per centum. * * * It is impossible to ascertain what will amount to a fair return upon properties devoted to public service, without giving consideration to the cost of labor, supplies, etc., at the time the investigation is made. An honest and intelligent forecast of probable future values, made upon a view of all the relevant circumstances, is essential. If the highly important element of present costs is wholly disregarded, such a forecast becomes impossible. Estimates for to-morrow cannot ignore prices of to-day.'

[5] ***692** It is clear that the court also failed to give proper consideration to the higher cost of construction in 1920 over that in 1915 and before the war, and failed to give weight to cost of reproduction less depreciation on the basis of 1920 prices, or to the testimony of the company's valuation engineer, based on present and past costs of construction, that the property in his opinion, was worth $900,000. The final figure, $460,000, was arrived ****679** at substantially on the basis of actual cost, less depreciation, plus 10 per cent. for going value and $10,000 for working capital. This resulted in a valuation considerably and materially less than would have been reached by a fair and just consideration of all the facts. The valuation cannot be sustained. Other objections to the valuation need not be considered.

3. Rate of return: The state commission found that the company's net annual income should be approximately $37,000, in order to enable it to earn 8 per cent. for return and depreciation upon the value of its property as fixed by it. Deducting 2 per cent. for depreciation, there remains 6 per cent. on $460,000, amounting to $27,600 for return. This was approved by the state court.

[6] The company contends that the rate of return is too low and confiscatory. What annual rate will constitute just compensation depeds upon many circumstances, and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding, risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in ***693** highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.

In 1909, this court, in Willcox v. Consolidated Gas Co., 212 U. S. 19, 48- 50, 29 Sup. Ct. 192, 53 L. Ed. 382, 15 Ann. Cas. 1034, 48 L. R. A. (N. S.) 1134, held that the question whether a rate yields such a return as not to be confiscatory depends upon circumstances, locality and risk, and that no proper rate can be established for all cases; and that, under the circumstances of that case, 6 per cent. was a fair return on the value of the property employed in supplying gas to the city of New York, and that a rate yielding that return was not confiscatory. In that case the investment was held to be safe, returns certain and risk reduced almost to a minimum--as nearly a safe and secure investment as could be imagined in regard to any private manufacturing enterprise.

In 1912, in Cedar Rapids Gas Co. v. Cedar Rapids, 223 U. S. 655, 670, 32 Sup. Ct. 389, 56 L. Ed. 594, this court declined to reverse the state court where the value of the plant considerably exceeded its cost, and the estimated return was over 6 per cent.

In 1915, in Des Moines Gas Co. v. Des Moines, 238 U. S. 153, 172, 35 Sup. Ct. 811, 59 L. Ed. 1244, this court declined to reverse the United States District Court in refusing an injunction upon the conclusion reached that a return of 6 per cent. per annum upon the value would not be confiscatory.

In 1919, this court in Lincoln Gas Co. v. Lincoln, 250 U. S. 256, 268, 39 Sup. Ct. 454, 458 (63 L. Ed. 968), declined on the facts of that case to approve a finding that no rate yielding as much as 6 per cent. ***694** on the invested capital could be regarded as confiscatory. Speaking for the court, Mr. Justice Pitney said:

> 'It is a matter of common knowledge that, owing principally to the World War, the costs of labor and supplies of every kind have greatly advanced since the ordinance was adopted, and largely since this cause was last heard in the court below. And it is equally well known that annual returns upon capital and enterprise the world over have materially increased, so that what would have been a proper rate of return for capital invested in gas plants and similar public utilities a few years ago furnishes no safe criterion for the present or for the future.'

In 1921, in Brush Electric Co. v. Galveston, the United States District Court held 8 per cent. a fair rate of return. [FN4]

FN4 This case was affirmed by this court June 4, 1923, 262 U. S. 443, 43 Sup. Ct. 606, 67 L. Ed. 1076.

In January, 1923, in City of Minneapolis v. Rand, the Circuit Court of Appeals of the Eighth Circuit (285 Fed. 818, 830) sustained, as against the attack of the city on the ground that it was excessive, 7 1/2 per cent., found by a special master and approved by the District Court as a fair and reasonable return on the capital investment--the value of the property.

[7] Investors take into account the result of past operations, especially in recent years, when determining the terms upon which they will invest in such an undertaking. Low, uncertain, or irregular income makes for low prices for the securities of the utility and higher rates of interest to be demanded by investors. The fact that the company may not insist as a matter of constitutional right that past losses be made up by rates to be applied in the present and future tends to weaken credit, and the fact that the utility is protected against being compelled to serve for confiscatory rates tends to support it. In ***695** this case the record shows that the rate of return has been low through a long period up to the time of the inquiry by the commission here involved. For example, the average rate of return on the total cost of the property from 1895 to 1915, inclusive, was less than 5 per cent.; from 1911 to 1915, inclusive, ****680** about 4.4 per cent., without allowance for depreciation. In 1919 the net operating income was approximately $24,700, leaving $15,500, approximately, or 3.4 per cent. on $460,000 fixed by the commission, after deducting 2 per cent. for depreciation. In 1920, the net operating income was approximately $25,465, leaving $16,265 for return, after allowing for depreciation. Under the facts and circumstances indicated by the record, we think that a rate of return of 6 per cent. upon the value of the property is substantially too low to constitute just compensation for the use of the property employed to render the service.

The judgment of the Supreme Court of Appeals of West Virginia is reversed.

Mr. Justice BRANDEIS concurs in the judgment of reversal, for the reasons stated by him in Missouri ex rel. Southwestern Bell Telephone Co. v. Public Service Commission of Missouri, supra.

END OF DOCUMENT

Supreme Court of the United States

FEDERAL POWER COMMISSION et al.
v.
HOPE NATURAL GAS CO.
CITY OF CLEVELAND
v.
SAME.

Nos. 34 and 35.

Argued Oct. 20, 21, 1943.
Decided Jan. 3, 1944.

Separate proceedings before the Federal Power Commission by such Commission, by the City of Cleveland and the City of Akron, and by Pennsylvania Public Utility Commission wherein the State of West Virginia and its Public Service Commission were permitted to intervene concerning rates charged by Hope Natural Gas Company which were consolidated for hearing. An order fixing rates was reversed and remanded with directions by the Circuit Court of Appeals, 134 F.2d 287, and Federal Power Commission, City of Akron and Pennsylvania Public Utility Commission in one case and the City of Cleveland in another bring certiorari.

Reversed.

Mr. Justice REED, Mr. Justice FRANKFURTER and Mr. Justice JACKSON, dissenting.

On Writs of Certiorari to the United States Circuit Court of Appeals for the Fourth Circuit.

West Headnotes

[1] Public Utilities 120
317Ak120 Most Cited Cases
(Formerly 317Ak7.1, 317Ak7)

Rate-making is only one species of price-fixing which, like other applications of the police power, may reduce the value of the property regulated, but that does not render the regulation invalid.

[2] Public Utilities 123
317Ak123 Most Cited Cases
(Formerly 317Ak7.4, 317Ak7)

Rates cannot be made to depend upon fair value, which is the end product of the process of rate-making and not the starting point, when the value of the going enterprise depends on earnings under whatever rates may be anticipated.

[3] Gas 14.3(2)
190k14.3(2) Most Cited Cases
(Formerly 190k14(1))

The rate-making function of the Federal Power Commission under the Natural Gas Act involves the making of pragmatic adjustments, and the Commission is not bound to the use of any single formula or combination of formulae in determining rates. Natural Gas Act, § § 4(a), 5(a), 6, 15 U.S.C.A. §§ 717c(a), 717d(a), 717e.

[4] Gas 14.5(6)
190k14.5(6) Most Cited Cases
(Formerly 190k14(1))

When order of Federal Power Commission fixing natural gas rates is challenged in the courts, the question is whether order viewed in its entirety meets the requirements of the Natural Gas Act. Natural Gas Act, § § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. §§ 717c(a),717d(a), 717e, 717r(b).

[5] Gas 14.4(1)
190k14.4(1) Most Cited Cases
(Formerly 190k14(1))

Under the statutory standard that natural gas rates shall be "just and reasonable" it is the result reached and not the method employed that is controlling. Natural Gas Act § § 4(a), 5(a), 15 U.S.C.A. § § 717c(a), 717d(a).

[6] Gas 14.5(6)
190k14.5(6) Most Cited Cases
(Formerly 190k14(1))

If the total effect of natural gas rates fixed by Federal Power Commission cannot be said to be unjust and unreasonable, judicial inquiry under the Natural Gas Act is at an end. Natural Gas Act, § § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[7] Gas ⚷14.5(7)
190k14.5(7) Most Cited Cases
(Formerly 190k14(1))

An order of the Federal Power Commission fixing rates for natural gas is the product of expert judgment, which carries a presumption of validity, and one who would upset the rate must make a convincing showing that it is invalid because it is unjust and unreasonable in its consequences. Natural Gas Act, § § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. §§ 717c(a), 717d(a), 717e, 717r(b).

[8] Gas ⚷14.4(1)
190k14.4(1) Most Cited Cases
(Formerly 190k14(1))

The fixing of just and reasonable rates for natural gas by the Federal Power Commission involves a balancing of the investor and the consumer interests. Natural Gas Act, § § 4(a), 5(a), 15 U.S.C.A. § § 717c(a), 717d(a).

[9] Gas ⚷14.4(9)
190k14.4(9) Most Cited Cases
(Formerly 190k14(1))

As respects rates for natural gas, from the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business, which includes service on the debt and dividends on stock, and by such standard the return to the equity owner should be commensurate with the terms on investments in other enterprises having corresponding risks, and such returns should be sufficient to assure confidence in the financial integrity of the enterprise so as to maintain its credit and to attract capital. Natural Gas Act, § § 4(a), 5(a), 15 U.S.C.A. §§ 717c(a), 717d(a).

[10] Gas ⚷14.4(9)
190k14.4(9) Most Cited Cases
(Formerly 190k14(1))

The fixing by the Federal Power Commission of a rate of return that permitted a natural gas company to earn $2,191,314 annually was supported by substantial evidence. Natural Gas Act, § § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[11] Gas ⚷14.4(9)
190k14.4(9) Most Cited Cases
(Formerly 190k14(1))

Rates which enable a natural gas company to operate successfully, to maintain its financial integrity, to attract capital and to compensate its investors for the risks assumed cannot be condemned as invalid, even though they might produce only a meager return on the so-called "fair value" rate base. Natural Gas Act, § § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[12] Gas ⚷14.4(4)
190k14.4(4) Most Cited Cases
(Formerly 190k14(1))

A return of only 3 27/100 per cent. on alleged rate base computed on reproduction cost new to natural gas company earning an annual average return of about 9 per cent. on average investment and satisfied with existing gas rates suggests an inflation of the base on which the rate had been computed, and justified Federal Power Commission in rejecting reproduction cost as the measure of the rate base. Natural Gas Act, § § 4(a), 5(a), 15 U.S.C.A. § § 717c(a), 717d(a).

[13] Gas ⚷14.4(9)
190k14.4(9) Most Cited Cases
(Formerly 190k14(1))

There is no constitutional requirement that owner who engages in a wasting- asset business of limited life shall receive at the end more than he has put into it, and such rule is applicable to a natural gas company since the ultimate exhaustion of its supply of gas is inevitable. Natural Gas Act, §§ 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[14] Gas ⚷14.4(9)
190k14.4(9) Most Cited Cases
(Formerly 190k14(1))

In fixing natural gas rate the basing of annual depreciation on cost is proper since by such procedure the utility is made whole and the integrity of its investment is maintained, and no more is required. Natural Gas Act, §§ 4(a), 5(a), 6, 19(b), 15 U.S.C.A. §§ 717c(a), 717d(a), 717e, 717r(b).

[15] Gas ⚷14.3(4)
190k14.3(4) Most Cited Cases
(Formerly 190k14(1))

There are no constitutional requirements more exacting than the standards of the Natural Gas Act which are that gas rates shall be just and reasonable, and a rate order which conforms with the act is valid. Natural Gas Act, §§ 4(a), 5(a), 6, 19(b), 15 U.S.C.A. §§ 717c(a), 717d(a), 717e, 717r(b).

[16] Commerce ⚷62.2
83k62.2 Most Cited Cases
(Formerly 83k13)

The purpose of the Natural Gas Act was to provide through the exercise of the national power over interstate commerce an agency for regulating the wholesale distribution to public service companies of natural gas moving in interstate commerce not subject to certain types of state regulation, and the act was not intended to take any authority from state commissions or to usurp state regulatory authority. Natural Gas Act, § 1 et seq., 15 U.S.C.A. § 717 et seq.

[17] Mines and Minerals ⚷92.5(3)
260k92.5(3) Most Cited Cases
(Formerly 260k92.7, 260k92)

Under the Natural Gas Act, the Federal Power Commission has no authority over the production or gathering of natural gas. Natural Gas Act, § 1(b), 15 U.S.C.A. § 717(b).

[18] Gas ⚷14.1(1)
190k14.1(1) Most Cited Cases
(Formerly 190k14(1))

The primary aim of the Natural Gas Act was to protect consumers against exploitation at the hands of natural gas companies and holding companies owning a majority of the pipe-line mileage which moved gas in interstate commerce and against which state commissions, independent producers and communities were growing quite helpless. Natural Gas Act, §§ 4, 6-10, 14, 15 U.S.C.A. §§ 717c, 717e-717i, 717m.

[19] Gas ⚷14.1(1)
190k14.1(1) Most Cited Cases
(Formerly 190k14(1))

Apart from the express exemptions contained in § 7 of the Natural Gas Act considerations of conservation are material where abandonment or extensions of facilities or service by natural gas companies are involved, but exploitation of consumers by private operators through maintenance of high rates cannot be continued because of the indirect benefits derived therefrom by a state containing natural gas deposits. Natural Gas Act, §§ 4, 5, and § 7 as amended 15 U.S.C.A. §§ 717c, 717d, 717f.

[20] Commerce ⚷62.2
83k62.2 Most Cited Cases
(Formerly 83k13)

A limitation on the net earnings of a natural gas company from its interstate business is not a limitation on the power of the producing state, either to safeguard its tax revenues from such industry, or to protect the interests of those who sell their gas to the interstate operator, particularly where the return allowed the company by the Federal Power Commission was a net return after all such charges. Natural Gas Act, §§ 4, 5, and § 7, as amended, 15 U.S.C.A. §§ 717c, 717d, 717f.

[21] Gas ⚷14.4(1)
190k14.4(1) Most Cited Cases
(Formerly 190k14(1))

The Natural Gas Act granting Federal Power Commission power to fix "just and reasonable rates" does not include the power to fix rates which will disallow or discourage resales for industrial use. Natural Gas Act, §§ 4(a), 5(a), 15 U.S.C.A. §§ 717c(a), 717d(a).

[22] Gas ⚷14.4(1)
190k14.4(1) Most Cited Cases
(Formerly 190k14(1))

The wasting-asset nature of the natural gas industry does not require the maintenance of the level of rates so that natural gas companies can make a greater profit on each unit of gas sold. Natural Gas Act, §§ 4(a), 5(a), 15 U.S.C.A. §§ 717c(a), 717d(a)
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[23] Federal Courts 🔑452
170Bk452 Most Cited Cases
(Formerly 106k383(1))

Where the Federal Power Commission made no findings as to any discrimination or unreasonable differences in rates, and its failure was not challenged in the petition to review, and had not been raised or argued by any party, the problem of discrimination was not open to review by the Supreme Court on certiorari. Natural Gas Act, § 4(b), 15 U.S.C.A. § 717c(b).

[24] Constitutional Law 🔑74
92k74 Most Cited Cases
(Formerly 15Ak226)

Congress has entrusted the administration of the Natural Gas Act to the Federal Power Commission and not to the courts, and apart from the requirements of judicial review, it is not for the Supreme Court to advise the Commission how to discharge its functions. Natural Gas Act, § § 1 et seq., 19(b), 15 U.S.C.A. §§ 717 et seq., 717r(b).

[25] Gas 🔑14.5(3)
190k14.5(3) Most Cited Cases
(Formerly 190k14(1))

Under the Natural Gas Act, where order sought to be reviewed does not of itself adversely affect complainant but only affects his rights adversely on the contingency of future administrative action, the order is not reviewable, and resort to the courts in such situation is either premature or wholly beyond the province of such courts. Natural Gas Act, § 19(b), 15 U.S.C.A. § 717r(b).

[26] Gas 🔑14.5(4)
190k14.5(4) Most Cited Cases
(Formerly 190k14(1))

Findings of the Federal Power Commission on lawfulness of past natural gas rates, which the Commission was without power to enforce, were not reviewable under the Natural Gas Act giving any "party aggrieved" by an order of the Commission the right of review. Natural Gas Act, § 19(b), 15 U.S.C.A. § 717r(b).

****283** ***592** Mr. Francis M. Shea, Asst. Atty. Gen., for petitioners Federal Power Com'n and others.

***593** Mr. Spencer W. Reeder, of Cleveland, Ohio, for petitioner City of cleveland.

Mr. William B. Cockley, of Cleveland, Ohio, for respondent.

Mr. M. M. Neeley, of Charleston, W. Va., for State of West Virginia, as amicus curiae by special leave of Court.

Mr. Justice DOUGLAS delivered the opinion of the Court.

The primary issue in these cases concerns the validity under the Natural Gas Act of 1938, 52 Stat. 821, 15 U.S.C. s 717 et seq., 15 U.S.C.A. s 717 et seq., of a rate order issued by the Federal Power Commission reducing the rates chargeable by Hope Natural Gas Co., 44 P.U.R.,N.S., 1. On a petition for review of the order made pursuant to s 19(b) of the Act, the ***594** Circuit Court of Appeals set it aside, one judge dissenting. 4 Cir., 134 F.2d 287. The cases ****284** are here on petitions for writs of certiorari which we granted because of the public importance of the questions presented. City of Cleveland v. Hope Natural Gas Co., 319 U.S. 735, 63 S.Ct. 1165.

Hope is a West Virginia corporation organized in 1898. It is a wholly owned subsidiary of Standard Oil Co. (N.J.). Since the date of its organization, it has been in the business of producing, purchasing and marketing natural gas in that state. [FN1] It sells some of that gas to local consumers in West Virginia. But the great bulk of it goes to five customer companies which receive it at the West Virginia line and distribute it in Ohio and in Pennsylvania. [FN2] In July, 1938, the cities of Cleveland and Akron filed complaints with the Commission charging that the rates collected by Hope from East Ohio Gas Co. (an affiliate of Hope which distributes gas in Ohio) were excessive and unreasonable. Later in 1938 the Commission on its own motion instituted an investigation to determine the reasonableness of all of Hope's interstate rates. In March ***595** 1939 the Public Utility Commission of Pennsylvania filed a complaint with the Commission charging that the rates collected by Hope from Peoples Natural Gas Co. (an affiliate of Hope distributing gas in Pennsylvania) and two non-affiliated companies were unreasonable. The City of Cleveland asked that the challenged rates be declared unlawful and that just and reasonable rates be determined from June 30, 1939 to the date of the Commission's order. The latter finding was requested in aid of state regulation and to afford the Public Utilities Commission of Ohio a proper basic for disposition of a fund collected by East Ohio under bond from Ohio consumers since June 30, 1939. The cases were consolidated and hearings were held.

FN1 Hope produces about one-third of its annual gas requirements and purchases the rest under some 300 contracts.

FN2 These five companies are the East Ohio Gas Co., the Peoples Natural Gas Co., the River Gas Co., the Fayette County Gas Co., and the Manufacturers Light & Heat Co. The first three of these companies are, like Hope, subsidiaries of Standard Oil Co. (N.J.). East Ohio and River distribute gas in Ohio, the other three in Pennsylvania. Hope's approximate sales in m.c.f. for 1940 may be classified as follows:

Local West Virginia sales	11,000,000
East Ohio	40,000,000
Peoples	10,000,000
River	400,000
Fayette	860,000
Manufacturers	2,000,000

Local West Virginia
Hope's natural gas is processed by Hope Construction & Refining Co., an affiliate, for the extraction of gasoline and butane. Domestic Coke Corp., another affiliate, sells coke-oven gas to Hope for boiler fuel.

On May 26, 1942, the Commission entered its order and made its findings. Its order required Hope to decrease its future interstate rates so as to reflect a reduction, on an annual basis of not less than $3,609,857 in operating revenues. And it established 'just and reasonable' average rates per m.c.f. for each of the five customer companies. [FN3] In response to the prayer of the City of Cleveland the Commission also made findings as to the lawfulness of past rates, although concededly it had no authority under the Act to fix past rates or to award reparations. 44 P.U.R.,U.S., at page 34. It found that the rates collected by Hope from East Ohio were unjust, unreasonable, excessive and therefore unlawful, by $830,892 during 1939, $3,219,551 during 1940, and $2,815,789 on an annual basis since 1940. It further found that just, reasonable, and lawful rates for gas sold by Hope to East Ohio for resale for ultimate public consumption were those required *596 to produce $11,528,608 for 1939, $11,507,185 for 1940 and $11.910,947 annually since 1940.

FN3 These required minimum reductions of 7 ¢ per m.c.f. from the 36.5 ¢ and 35.5 ¢ rates previously charged East Ohio and Peoples, respectively, and 3 ¢ per m.c.f. from the 31.5 ¢ rate previously charged Fayette and Manufacturers.

The Commission established an interstate rate base of $33,712,526 which, it found, represented the 'actual legitimate cost' of the company's interstate property less depletion and depreciation and plus unoperated acreage, working capital and future net capital additions. The Commission, beginning with book cost, made **285 certain adjustments not necessary to relate here and found the 'actual legitimate cost' of the plant in interstate service to be $51,957,416, as of December 31, 1940. It deducted accrued depletion and depreciation, which it found to be $22,328,016 on an 'economic-service-life' basis. And it added $1,392,021 for future net capital additions, $566,105 for useful unoperated acreage, and $2,125,000 for working capital. It used 1940 as a test year to estimate future revenues and expenses. It allowed over $16,000,000 as annual operating expenses--about $1,300,000 for taxes, $1,460,000 for depletion and depreciation, $600,000 for exploration and development costs, $8,500,000 for gas purchased. The Commission allowed a net increase of $421,160 over 1940 operating expenses, which amount was to take care of future increase in wages, in West Virginia property taxes, and in exploration and development costs. The total amount of deductions allowed from interstate revenues was $13,495,584.

Hope introduced evidence from which it estimated reproduction cost of the property at $97,000,000. It also presented a so-called trended 'original cost' estimate which exceeded $105,000,000. The latter was designed 'to indicate what the original cost of the property would have been if 1938 material and labor prices had prevailed throughout the whole period of the piece-meal construction of the company's property since 1898.' 44 P.U.R.,N.S., at pages 8, 9. Hope estimated by the 'percent condition' method accrued depreciation at about 35% of ***597** reproduction cost new. On that basis Hope contended for a rate base of $66,000,000. The Commission refused to place any reliance on reproduction cost new, saying that it was 'not predicated upon facts' and was 'too conjectural and illusory to be given any weight in these proceedings.' Id., 44 P.U.R.,U.S., at page 8. It likewise refused to give any 'probative value' to trended 'original cost' since it was 'not founded in fact' but was 'basically erroneous' and produced 'irrational results.' Id., 44 P.U.R., N.S., at page 9. In determining the amount of accrued depletion and depreciation the Commission, following Lindheimer v. Illinois Bell Telephone Co., 292 U.S. 151, 167-169, 54 S.Ct. 658, 664--666, 78 L.Ed. 1182; Federal Power Commission v. Natural Gas Pipeline Co., 315 U.S. 575, 592, 593, 62 S.Ct. 736, 745, 746, 86 L.Ed. 1037, based its computation on 'actual legitimate cost'. It found that Hope during the years when its business was not under regulation did not observe 'sound depreciation and depletion practices' but 'actually accumulated an excessive reserve' [FN4] of about $46,000,000. Id., 44 P.U.R.,N.S., at page 18. One member of the Commission thought that the entire amount of the reserve should be deducted from 'actual legitimate cost' in determining the rate base. [FN5] The majority of the ***598** Commission concluded, however, that where, as here, a business is brought under regulation for the first time and where incorrect depreciationand depletion practices have prevailed, the deduction of the reserve requirement (actual existing depreciation and depletion) rather than the excessive reserve should be made so as to ****286** lay 'a sound basis for future regulation and control of rates.' Id., 44 P.U.R.,N.S., at page 18. As we have pointed out, it determined accrued depletion and depreciation to be $22,328,016; and it allowed approximately $1,460,000 as the annual operating expense for depletion and depreciation. [FN6]

FN4 The book reserve for interstate plant amounted at the end of 1938 to about $18,000,000 more than the amount determined by the Commission as the proper reserve requirement. The Commission also noted that 'twice in the past the company has transferred amounts aggregating $7,500,000 from the depreciation and depletion reserve to surplus. When these latter adjustments are taken into account, the excess becomes $25,500,000, which has been exacted from the ratepayers over and above the amount required to cover the consumption of property in the service rendered and thus to keep the investment unimpaired.' 44 P.U.R.,N.S., at page 22.

FN5 That contention was based on the fact that 'every single dollar in the depreciation and depletion reserves' was taken 'from gross operating revenues whose only source was the amounts charged customers in the past for natural gas. It is, therefore, a fact that the depreciation and depletion reserves have been contributed by the customers and do not represent any investment by Hope.' Id., 44 P.U.R.,N.S., at page 40. And see Railroad Commission v. Cumberland Tel. & T. Co., 212 U.S. 414, 424, 425, 29 S.Ct. 357, 361, 362, 53 L.Ed. 577; 2 Bonbright, Valuation of Property (1937), p. 1139.

FN6 The Commission noted that the case was 'free from the usual complexities involved in the estimate of gas reserves because the geologists for the company and the Commission presented estimates of the remaining recoverable gas reserves which were about one per cent apart.' 44 P.U.R.,N.S., at pages 19, 20.
The Commission utilized the 'straight-line-basis' for determining the depreciation and depletion reserve requirements. It used estimates of the average service lives of the property by classes based in part on an inspection of the physical condition of the property. And studies were made of Hope's retirement experience and maintenance policies over the years. The average service lives of the various classes of property were converted into depreciation rates and then applied to the cost of the property to ascertain the portion of the cost which had expired in rendering the service.
The record in the present case shows that Hope is on the lookout for new sources of supply of natural gas and is contemplating an extension of its pipe line into Louisiana for that purpose. The Commission recognized in fixing the rates of depreciation that much material may be used again

when various present sources of gas supply are exhausted, thus giving that property more than scrap value at the end of its present use.

Hope's estimate of original cost was about $69,735,000--approximately $17,000,000 more than the amount found by the Commission. The item of $17,000,000 was made up largely of expenditures which prior to December 31, 1938, were charged to operating expenses. Chief among those expenditures was some $12,600,000 expended ***599** in well-drilling prior to 1923. Most of that sum was expended by Hope for labor, use of drilling-rigs, hauling, and similar costs of well-drilling. Prior to 1923 Hope followed the general practice of the natural gas industry and charged the cost of drilling wells to operating expenses. Hope continued that practice until the Public Service Commission of West Virginia in 1923 required it to capitalize such expenditures, as does the Commission under its present Uniform System of Accounts. [FN7] The Commission refused to add such items to the rate base stating that 'No greater injustice to consumers could be done than to allow items as operating expenses and at a later date include them in the rate base, thereby placing multiple charges upon the consumers.' Id., 44 P.U.R.,N.S., at page 12. For the same reason the Commission excluded from the rate base about $1,600,000 of expenditures on properties which Hope acquired from other utilities, the latter having charged those payments to operating expenses. The Commission disallowed certain other overhead items amounting to over $3,000,000 which also had been previously charged to operating expenses. And it refused to add some $632,000 as interest during construction since no interest was in fact paid.

FN7 See Uniform System of Accounts prescribed for Natural Gas Companies effective January 1, 1940, Account No. 332.1.

Hope contended that it should be allowed a return of not less than 8%. The Commission found that an 8% return would be unreasonable but that 6 1/2% was a fair rate of return. That rate of return, applied to the rate base of $33,712,526, would produce $2,191,314 annually, as compared with the present income of not less than $5,801,171.

The Circuit Court of Appeals set aside the order of the Commission for the following reasons. (1) It held that the rate base should reflect the 'present fair value' of the ***600** property, that the Commission in determining the 'value' should have considered reproduction cost and trended original cost, and that 'actual legitimate cost' (prudent investment) was not the proper measure of 'fair value' where price levels had changed since the investment. (2) It concluded that the well-drilling costs and overhead items in the amount of some $17,000,000 should have been included in the rate base. (3) It held that accrued depletion and depreciation and the annual allowance for that expense should be computed on the basis of 'present fair value' of the property not on the basis of 'actual legitimate cost'.

****287** The Circuit Court of Appeals also held that the Commission had no power to make findings as to past rates in aid of state regulation. But it concluded that those findings were proper as a step in the process of fixing future rates. Viewed in that light, however, the findings were deemed to be invalidated by the same errors which vitiated the findings on which the rate order was based.

Order Reducing Rates. Congress has provided in s 4(a) of the Natural Gas Act that all natural gas rates subject to the jurisdiction of the Commission 'shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful.' Sec. 5(a) gives the Commission the power, after hearing, to determine the 'just and reasonable rate' to be thereafter observed and to fix the rate by order. Sec. 5(a) also empowers the Commission to order a 'decrease where existing rates are unjust * * * unlawful, or are not the lowest reasonable rates.' And Congress has provided in s 19(b) that on review of these rate orders the 'finding of the Commission as to the facts, if supported by substantial evidence, shall be conclusive.' Congress, however, has provided no formula by which the 'just and reasonable' rate is to be determined. It has not filled in the ***601** details of the general prescription [FN8] of s 4(a) and s 5(a). It has not expressed in a specific rule the fixed principle of 'just and reasonable'.

FN8. Sec. 6 of the Act comes the closest to supplying any definite criteria for rate making. It provides in subsection (a) that, 'The Commission may investigate the ascertain the actual legitimate cost of the property of every natural-gas company, the depreciation therein, and, when found necessary for rate-making purposes, other facts which bear on the determination of such cost or depreciation and the fair value of such property.' Subsection (b) provides that every natural-gas company on request shall file with the Commission a statement of the 'original cost' of its property and shall keep the Commission informed regarding the 'cost' of all additions, etc.

[1][2] When we sustained the constitutionality of the Natural Gas Act in the Natural Gas Pipeline Co. case, we stated that the 'authority of Congress to regulate the prices of commodities in interstate commerce is at least as great under the Fifth Amendment as is that of the states under the Fourteenth to regulate the prices of commodities in intrastate commerce.' 315 U.S. at page 582, 62 S.Ct. at page 741, 86 L.Ed. 1037. Rate-making is indeed but one species of price-fixing. Munn v. Illinois, 94 U.S. 113, 134, 24 L.Ed. 77. The fixing of prices, like other applications of the police power, may reduce the value of the property which is being regulated. But the fact that the value is reduced does not mean that the regulation is invalid. Block v. Hirsh, 256 U.S. 135, 155--157, 41 S.Ct. 458, 459, 460, 65 L.Ed. 865, 16 A.L.R. 165; Nebbia v. New York, 291 U.S. 502, 523--539, 54 S.Ct. 505, 509--517, 78 L.Ed. 940, 89 A.L.R. 1469, and cases cited. It does, however, indicate that 'fair value' is the end product of the process of rate-making not the starting point as the Circuit Court of Appeals held. The heart of the matter is that rates cannot be made to depend upon 'fair value' when the value of the going enterprise depends on earnings under whatever rates may be anticipated. [FN9]

FN9 We recently stated that the meaning of the word 'value' is to be gathered 'from the purpose for which a valuation is being made. Thus the question in a valuation for rate making is how much a utility will be allowed to earn. The basic question in a valuation for reorganization purposes is how much the enterprise in all probability can earn.' Institutional Investors v. Chicago, M., St. P. & P.R. Co., 318 U.S. 523, 540, 63 S.Ct. 727, 738.

***602** [3][4][5][6][7] We held in Federal Power Commission v. Natural Gas Pipeline Co., supra, that the Commission was not bound to the use of any single formula or combination of formulae in determining rates. Its rate-making function, moreover, involves the making of 'pragmatic adjustments.' Id., 315 U.S. at page 586, 62 S.Ct. at page 743, 86 L.Ed. 1037. And when the Commission's order is challenged in the courts, the question is whether that order 'viewed in its entirety' meets the requirements of the Act. Id., 315 U.S. at page 586, 62 S.Ct. at page 743, 86 L.Ed. 1037. Under the statutory standard of 'just and reasonable' it is the result reached not the method employed which is controlling. Cf. Los Angeles Gas & Electric Corp. v. Railroad ****288** Commission, 289 U.S. 287, 304, 305, 314, 53 S.Ct. 637, 643, 644, 647, 77 L.Ed. 1180; West Ohio Gas Co. v. Public Utilities Commission (No. 1), 294 U.S. 63, 70, 55 S.Ct. 316, 320, 79 L.Ed. 761; West v. Chesapeake & Potomac Tel. Co., 295 U.S. 662, 692, 693, 55 S.Ct. 894, 906, 907, 79 L.Ed. 1640 (dissenting opinion). It is not theory but the impact of the rate order which counts. If the total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry under the Act is at an end. The fact that the method employed to reach that result may contain infirmities is not then important. Moreover, the Commission's order does not become suspect by reason of the fact that it is challenged. It is the product of expert judgment which carries a presumption of validity. And he who would upset the rate order under the Act carries the heavy burden of making a convincing showing that it is invalid because it is unjust and unreasonable in its consequences. Cf. Railroad Commission v. Cumberland Tel. & T. Co., 212 U.S. 414, 29 S.Ct. 357, 53 L.Ed. 577; Lindheimer v. Illinois Bell Tel. Co., supra, 292 U.S. at pages 164, 169, 54 S.Ct. at pages 663, 665, 78 L.Ed. 1182; Railroad Commission v. Pacific Gas & E. Co., 302 U.S. 388, 401, 58 S.Ct. 334, 341, 82 L.Ed. 319.

***603** [8][9] The rate-making process under the Act, i.e., the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests. Thus we stated in the Natural Gas Pipeline Co. case that 'regulation does not insure that the business shall produce net revenues.' 315 U.S. at page 590, 62 S.Ct. at page 745, 86 L.Ed. 1037. But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. Cf. Chicago & Grand Trunk R. Co. v. Wellman, 143 U.S. 339, 345, 346, 12 S.Ct. 400, 402, 36 L.Ed. 176. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. See State of Missouri ex rel. South-western Bell Tel. Co. v. Public Service Commission, 262 U.S. 276, 291, 43 S.Ct. 544, 547, 67 L.Ed. 981, 31 A.L.R. 807 (Mr. Justice Brandeis concurring). The conditions under which more or less might be allowed are not important here. Nor is it important to this case to determine the various permissible ways in which any rate base on which the return is computed might be arrived at. For we are of the view that the end result in this case cannot be condemned under the Act as unjust and unreasonable from the investor or company viewpoint.

We have already noted that Hope is a wholly owned subsidiary of the Standard Oil Co. (N.J.). It has no securities outstanding except stock. All of that stock has been owned by Standard since 1908. The par amount presently outstanding is approximately $28,000,000 as compared with the rate base of $33,712,526 established by *604 the Commission. Of the total outstanding stock $11,000,000 was issued in stock dividends. The balance, or about $17,000,000, was issued for cash or other assets. During the four decades of its operations Hope has paid over $97,000,000 in cash dividends. It had, moreover, accumulated by 1940 an earned surplus of about $8,000,000. It had thus earned the total investment in the company nearly seven times. Down to 1940 it earned over 20% per year on the average annual amount of its capital stock issued for cash or other assets. On an average invested capital of some $23,000,000 Hope's average earnings have been about 12% a year. And during this period it had accumulated in addition reserves for depletion and depreciation of about $46,000,000. Furthermore, during 1939, 1940 and 1941, Hope paid dividends of 10% on its stock. And in the year 1942, during about half of which the lower rates were in effect, it paid dividends of 7 1/2%. From 1939-1942 its earned surplus increased from $5,250,000 to about $13,700,000, i.e., to almost half the par value of its outstanding stock.

As we have noted, the Commission fixed a rate of return which permits Hope to earn $2,191,314 annually. In determining that amount it stressed the importance of maintaining the financial integrity of the **289 company. It considered the financial history of Hope and a vast array of data bearing on the natural gas industry, related businesses, and general economic conditions. It noted that the yields on better issues of bonds of natural gas companies sold in the last few years were 'close to 3 per cent', 44 P.U.R.,N.S., at page 33. It stated that the company was a 'seasoned enterprise whose risks have been minimized' by adequate provisions for depletion and depreciation (past and present) with 'concurrent high profits', by 'protected established markets, through affiliated distribution companies, in populous and industralized areas', and by a supply of gas locally to meet all requirements, *605 'except on certain peak days in the winter, which it is feasible to supplement in the future with gas from other sources.' Id., 44 P.U.R.,N.S., at page 33. The Commission concluded, 'The company's efficient management, established markets, financial record, affiliations, and its prospective business place it in a strong position to attract capital upon favorable terms when it is required.' Id., 44 P.U.R.,N.S., at page 33.

[10][11][12] In view of these various considerations we cannot say that an annual return of $2,191,314 is not 'just and reasonable' within the meaning of the Act. Rates which enable the company to operate successfully, to maintain its financial integrity, to attract capital, and to compensate its investors for the risks assumed certainly cannot be condemned as invalid, even though they might produce only a meager return on the so-called 'fair value' rate base. In that connection it will be recalled that Hope contended for a rate base of $66,000,000 computed on reproduction cost new. The Commission points out that if that rate base were accepted, Hope's average rate of return for the four-year period from 1937-1940 would amount to 3.27%. During that period Hope earned an annual average return of about 9% on the average investment. It asked for no rate increases. Its properties were well maintained and operated. As the Commission says such a modest rate of 3.27% suggests an 'inflation of the base on which the rate has been computed.' Dayton Power & Light Co. v. Public Utilities Commission, 292 U.S. 290, 312, 54 S.Ct. 647, 657, 78 L.Ed. 1267. Cf. Lindheimer v. Illinois Bell Tel. Co., supra, 292 U.S. at page 164, 54 S.Ct. at page 663, 78 L.Ed. 1182. The incongruity between the actual

operations and the return computed on the basis of reproduction cost suggests that the Commission was wholly justified in rejecting the latter as the measure of the rate base.

In view of this disposition of the controversy we need not stop to inquire whether the failure of the Commission to add the $17,000,000 of well-drilling and other costs to ***606** the rate base was consistent with the prudent investment theory as developed and applied in particular cases.

[13][14][15] Only a word need be added respecting depletion and depreciation. We held in the Natural Gas Pipeline Co. case that there was no constitutional requirement 'that the owner who embarks in a wasting-asset business of limited life shall receive at the end more than he has put into it.' 315 U.S. at page 593, 62 S.C. at page 746, 86 L.Ed. 1037. The Circuit Court of Appeals did not think that that rule was applicable here because Hope was a utility required to continue its service to the public and not scheduled to end its business on a day certain as was stipulated to be true of the Natural Gas Pipeline Co. But that distinction is quite immaterial. The ultimate exhaustion of the supply is inevitable in the case of all natural gas companies. Moreover, this Court recognized in Lindheimer v. Illinois Bell Tel. Co., supra, the propriety of basing annual depreciation on cost. [FN10] By such a procedure the ****290** utility is made whole and the integrity of its investment maintained. [FN11] No more is required. [FN12] We cannot approve the contrary holding ***607** of United Railways & Electric Co. v. West, 280 U.S. 234, 253, 254, 50 S.Ct. 123, 126, 127, 74 L.Ed. 390. Since there are no constitutional requirements more exacting than the standards of the Act, a rate order which conforms to the latter does not run afoul of the former.

FN10 Chief Justice Hughes said in that case (292 U.S. at pages 168, 169, 54 S.Ct. at page 665, 78 L.Ed. 1182): 'If the predictions of service life were entirely accurate and retirements were made when and as these predictions were precisely fulfilled, the depreciation reserve would represent the consumption of capital, on a cost basis, according to the method which spreads that loss over the respective service periods. But if the amounts charged to operating expenses and credited to the account for depreciation reserve are excessive, to that extent subscribers for the telephone service are required to provide, in effect, capital contributions, not to make good losses incurred by the utility in the service rendered and thus to keep its investment unimpaired, but to secure additional plant and equipment upon which the utility expects a return.'

FN11 See Mr. Justice Brandeis (dissenting) in United Railways & Electric Co. v. West, 280 U.S. 234, 259--288, 50 S.Ct. 123, 128--138, 74 L.Ed. 390, for an extended analysis of the problem.

FN12 It should be noted that the Act provides no specific rule governing depletion and depreciation. Sec. 9(a) merely states that the Commission 'may from time to time ascertain and determine, and by order fix, the proper and adequate rates of depreciation and amortization of the several classes of property of each natural-gas company used or useful in the production, transportation, or sale of natural gas.'

The Position of West Virginia. The State of West Virginia, as well as its Public Service Commission, intervened in the proceedings before the Commission and participated in the hearings before it. They have also filed a brief amicus curiae here and have participated in the argument at the bar. Their contention is that the result achieved by the rate order 'brings consequences which are unjust to West Virginia and its citizens' and which 'unfairly depress the value of gas, gas lands and gas leaseholds, unduly restrict development of their natural resources, and arbitrarily transfer their properties to the residents of other states without just compensation therefor.'

West Virginia points out that the Hope Natural Gas Co. holds a large number of leases on both producing and unoperated properties. The owner or grantor receives from the operator or grantee delay rentals as compensation for postponed drilling. When a producing well is successfully brought in, the gas lease customarily continues indefinitely for the life of the field. In that case the operator pays a stipulated gas-well rental or in some cases a gas royalty equivalent to one-eighth of the gas marketed. [FN13] Both the owner and operator have valuable property interests in the gas which are separately taxable under West Virginia law. The contention is that the reversionary interests in the leaseholds should be represented in the rate proceedings since it is their gas which is being sold in interstate ***608** commerce. It is argued, moreover, that the owners of the reversionary interests should have the benefit of the 'discovery value' of the gas leaseholds, not the interstate consumers. Furthermore, West Virginia contends that the Commission in fixing a rate for natural gas produced in that State should consider the effect of the rate order on the economy of West Virginia. It is pointed out that gas is a wasting asset with a rapidly diminishing supply. As a result West Virginia's gas deposits are becoming increasingly valuable. Nevertheless the rate fixed by the Commission reduces that value. And that reduction, it is said, has severe repercussions on the economy ofthe State. It is argued in the first place that as a result of this rate reduction Hope's West Virginia property taxes may be decreased in view of the relevance which earnings have under West Virginia law in the assessment of property for tax purposes. [FN14] Secondly, it is pointed out that West Virginia has a production tax [FN15] on the 'value' of the gas exported from the State. And we are told that for purposes of that tax 'value' becomes under West Virginia law 'practically the substantial equivalent of market value.' Thus West Virginia argues that undervaluation of Hope's gas leaseholds will cost the State many thousands of dollars in taxes. The effect, it is urged, is to impair West Virginia's tax structure for the benefit of Ohio and Pennsylvania consumers. West Virginia emphasizes, moreover, its deep interest in the conservation of its natural resources including its natural gas. It says that a reduction of the value of these leasehold values will jeopardize these conservation policies in three respects: (1) **291 exploratory development of new fields will be discouraged; (2) abandonment of lowyield high-cost marginal wells will be hastened; and (3) secondary recovery of oil will be hampered. *609 Furthermore, West Virginia contends that the reduced valuation will harm one of the great industries of the State and that harm to that industry must inevitably affect the welfare of the citizens of the State. It is also pointed out that West Virginia has a large interest in coal and oil as well as in gas and that these forms of fuel are competitive. When the price of gas is materially cheapened, consumers turn to that fuel in preference to the others. As a result this lowering of the price of natural gas will have the effect of depreciating the price of West Virginia coal and oil.

FN13 See Simonton, The Nature of the Interest of the Grantee Under an Oil and Gas Lease (1918), 25 W.Va.L.Quar. 295.

FN14 West Penn Power Co. v. Board of Review, 112 W.Va. 442, 164 S.E. 862.

FN15 W.Va.Rev.Code of 1943, ch. 11. Art. 13, ss 2a, 3a.

West Virginia insists that in neglecting this aspect of the problem the Commission failed to perform the function which Congress entrusted to it and that the case should be remanded to the Commission for a modification of its order. [FN16]

FN16 West Virginia suggests as a possible solution (1) that a 'going concern value' of the company's tangible assets be included in the rate base and (2) that the fair market value of gas delivered to customers be added to the outlay for operating expenses and taxes.

We have considered these contentions at length in view of the earnestness with which they have been urged upon us. We have searched the legislative history of the Natural Gas Act for any indication that Congress entrusted to the Commission the various considerations which West Virginia has advanced here. And our conclusion is that Congress did not.

[16][17] We pointed out in Illinois Natural Gas Co. v. Central Illinois Public Service Co., 314 U.S. 498, 506, 62 S.Ct. 384, 387, 86 L.Ed. 371, that the purpose of the Natural Gas Act was to provide, 'through the exercise of the national power over interstate commerce, an agency for regulating the wholesale distribution to public service companies of natural gas moving interstate, which this Court had declared to be interstate commerce not subject to certain types of state regulation.' As stated in the House Report the 'basic purpose' of this legislation was 'to occupy' the field in which such cases as State of Missouri v. *610 Kansas Natural Gas Co., 265 U.S. 298, 44 S.Ct. 544, 68 L.Ed. 1027, and Public Utilities Commission v. Attleboro Steam & Electric Co., 273 U.S. 83, 47 S.Ct. 294, 71 L.Ed. 549, had held the States might not act. H.Rep. No. 709, 75th Cong., 1st Sess., p. 2. In accomplishing that purpose the bill was designed to take 'no authority from State commissions' and was 'so drawn as to complement and in no manner usurp State regulatory authority.' Id., p. 2. And the Federal Power Commission was given no authority over the 'production or gathering of natural gas.' s

1(b).

[18] The primary aim of this legislation was to protect consumers against exploitation at the lands of natural gas companies. Due to the hiatus in regulation which resulted from the Kansas Natural Gas Co. case and related decisions state commissions found it difficult or impossible to discover what it cost interstate pipe-line companies to deliver gas within the consuming states; and thus they were thwarted in local regulation. H.Rep., No. 709, supra, p. 3. Moreover, the investigations of the Federal Trade Commission had disclosed that the majority of the pipe-line mileage in the country used to transport natural gas, together with an increasing percentage of the natural gas supply for pipe-line transportation, had been acquired by a handful of holding companies. [FN17] State commissions, independent producers, and communities having or seeking the service were growing quite helpless against these combinations. [FN18] These were the types of problems with which those participating in the hearings were pre-occupied. [FN19] Congress addressed itself to those specific evils.

FN17 S.Doc. 92, Pt. 84-A, ch. XII, Final Report, Federal Trade Commission to the Senate pursuant to S.Res.No. 83, 70th Cong., 1st Sess.

FN18 S.Doc. 92, Pt. 84-A, chs. XII, XIII, op. cit., supra, note 17.

FN19 See Hearings on H.R. 11662, Subcommittee of House Committee on Interstate & Foreign Commerce, 74th Cong., 2d Sess.; Hearings on H.R. 4008, House Committee on Interstate & Foreign Commerce, 75th Cong., 1st Sess.

***611** The Federal Power Commission was given ****292** broad powers of regulation. The fixing of 'just and reasonable' rates (s 4) with the powers attendant thereto [FN20] was the heart of the new regulatory system. Moreover, the Commission was given certain authority by s 7(a), on a finding that the action was necessary or desirable 'in the public interest,' to require natural gas companies to extend or improve their transportation facilities and to sell gas to any authorized local distributor. By s 7(b) it was given control over the abandonment of facilities or of service. And by s 7(c), as originally enacted, no natural gas company could undertake the construction or extension of any facilities for the transportation of natural gas to a market in which natural gas was already being served by another company, or sell any natural gas in such a market, without obtaining a certificate of public convenience and necessity from the Commission. In passing on such applications for certificates of convenience and necessity the Commission was told by s 7(c), as originally enacted, that it was 'the intention of Congress that natural gas shall be sold in interstate commerce for resale for ultimate public consumption for domestic, commercial, industrial, or any other use at the lowest possible reasonable rate consistent with the maintenance of adequate service in the public interest.' The latter provision was deleted from s 7(c) when that subsection was amended by the Act of February 7, 1942, 56 Stat. 83. By that amendment limited grandfather rights were granted companies desiring to extend their facilities and services over the routes or within the area which they were already serving. Moreover, s 7(c) was broadened so as to require certificates ***612** of public convenience and necessity not only where the extensions were being made to markets in which natural gas was already being sold by another company but in other situations as well.

FN20 The power to investigate and ascertain the 'actual legitimate cost' of property (s 6), the requirement as to books and records (s 8), control over rates of depreciation (s 9), the requirements for periodic and special reports (s 10), the broad powers of investigation (s 14) are among the chief powers supporting the rate making function.

[19] These provisions were plainly designed to protect the consumer interests against exploitation at the hands of private natural gas companies. When it comes to cases of abandonment or of extensions of facilities or service, we may assume that, apart from the express exemptions [FN21] contained in s 7, considerations of conservation are material to the issuance of certificates of public convenience and necessity. But the Commission was not asked here for a certificate of public convenience and necessity under s 7 for any proposed construction or extension. It was faced with a determination of the amount which a private operator should be allowed to earn from the sale of natural gas across state lines through an established distribution system. Secs. 4 and 5, not s 7, provide the standards for that determination. We cannot find in the words of the Act or in its history the slightest intimation or suggestion that the exploitation of consumers by private operators through the maintenance of high

rates should be allowed to continue provided the producing states obtain indirect benefits from it. That apparently was the Commission's view of the matter, for the same arguments advanced here were presented to the Commission and not adopted by it.

FN21 Apart from the grandfather clause contained in s 7(c), there is the provision of s 7(f) that a natural gas company may enlarge or extend its facilities with the 'service area' determined by the Commission without any further authorization.

We do not mean to suggest that Congress was unmindful of the interests of the producing states in their natural gas supplies when it drafted the Natural Gas Act. As we have said, the Act does not intrude on the domain traditionally reserved for control by state commissions; and the Federal Power Commission was given no authority over *613 'the production or gathering of natural gas.' s 1(b). In addition, Congress recognized the legitimate interests of the States in the conservation of natural gas. By s 11 Congress instructed the Commission to make reports on compacts between two or more States dealing with the conservation, production and transportation of natural gas. [FN22] The Commission was also **293 directed to recommend further legislation appropriate or necessary to carry out any proposed compact and 'to aid in the conservation of natural-gas resources within the United States and in the orderly, equitable, and economic production, transportation, and distribution of natural gas.' s 11(a). Thus Congress was quite aware of the interests of the producing states in their natural gas supplies. [FN23] But it left the protection of *614 those interests to measures other than the maintenance of high rates to private companies. If the Commission is to be compelled to let the stockholders of natural gas companies have a feast so that the producing states may receive crumbs from that table, the present Act must be redesigned. Such a project raises questions of policy which go beyond our province.

FN22 See P.L. 117, approved July 7, 1943, 57 Stat. 383 containing an 'Interstate Compact to Conserve Oil and Gas' between Oklahoma, Texas, New Mexico, Illinois, Colorado, and Kansas.

FN23 As we have pointed out, s 7(c) was amended by the Act of February 7, 1942, 56 Stat. 83, so as to require certificates of public convenience and necessity not only where the extensions were being made to markets in which natural gas was already being sold by another company but to other situations as well. Considerations of conservation entered into the proposal to give the Act that broader scope. H.Rep.No. 1290, 77th Cong. 1st Sess., pp. 2, 3. And see Annual Report, Federal Power Commission (1940) pp. 79, 80; Baum, The Federal Power Commission and State Utility Regulation (1942), p. 261.
The bill amending s 7(c) originally contained a subsection (h) reading as follows: 'Nothing contained in this section shall be construed to affect the authority of a State within which natural gas is produced to authorize or require the construction or extension of facilities for the transportation and sale of such gas within such State: Provided, however, That the Commission, after a hearing upon complaint or upon its own motion, may by order forbid any intrastate construction or extension by any natural-gas company which it shall find will prevent such company from rendering adequate service to its customers in interstate or foreign commerce in territory already being served.' See Hearings on H.R. 5249, House Committee on Interstate & Foreign Commerce, 77th Cong., 1st Sess., pp. 7, 11, 21, 29, 32, 33. In explanation of its deletion the House Committee Report stated, pp. 4, 5: 'The increasingly important problems raised by the desire of several States to regulate the use of the natural gas produced therein in the interest of consumers within such States, as against the Federal power to regulate interstate commerce in the interest of both interstate and intrastate consumers, are deemed by the committee to warrant further intensive study and probably a more retailed and comprehensive plan for the handling thereof than that which would have been provided by the stricken subsection.'

[20] It is hardly necessary to add that a limitation on the net earnings of a natural gas company from its interstate business is not a limitation on the power of the producing state either to safeguard its tax revenues from that industry [FN24] or to protect the interests of those who sell their gas to the interstate operator. [FN25] The return which **294 the Commission *615 allowed was the net return after all such charges.

FN24 We have noted that in the annual operating expenses of some $16,000.000 the Commission included West Virginia and federal taxes. And in the net increase of $421,160 over 1940 operating expenses allowed by the Commission was some $80,000 for increased West Virginia property taxes. The adequacy of these amounts has not been challenged here.

FN25 The Commission included in the aggregate annual operating expenses which it allowed some $8,500,000 for gas purchased. It also allowed about $1,400,000 for natural gas production and about $600,000 for exploration and development. It is suggested, however, that the Commission in ascertaining the cost of Hope's natural gas production plant proceeded contrary to s 1(b) which provides that the Act shall not apply to 'the production or gathering of natural gas'. But such valuation, like the provisions for operating expenses, is essential to the rate-making function as customarily performed in this country. Cf. Smith, The Control of Power Rates in the United States and England (1932), 159 The Annals 101. Indeed s 14(b) of the Act gives the Commission the power to 'determine the propriety and reasonableness of the inclusion in operating expenses, capital, or surplus of all delay rentals or other forms of rental or compensation for unoperated lands and leases.'

It is suggested that the Commission has failed to perform its duty under the Act in that it has not allowed a return for gas production that will be enough to induce private enterprise to perform completely and efficiently its functions for the public. The Commission, however, was not oblivious of those matters. It considered them. It allowed, for example, delay rentals and exploration and development costs in operating expenses. [FN26] No serious attempt has been made here to show that they are inadequate. We certainly cannot say that they are, unless we are to substitute our opinions for the expert judgment of the administrators to whom Congress entrusted the decision. Moreover, if in light of experience they turn out to be inadequate for development of new sources of supply, the doors of the Commission are open for increased allowances. This is not an order for all time. The Act contains machinery for obtaining rate adjustments. s 4.

FN26 See note 25, supra.

[21][22] But it is said that the Commission placed too low a rate on gas for industrial purposes as compared with gas for domestic purposes and that industrial uses should be discouraged. It should be noted in the first place that the rates which the Commission has fixed are Hope's interstate wholesale rates to distributors not interstate rates to industrial users [FN27] and domestic consumers. We hardly *616 can assume, in view of the history of the Act and its provisions, that the resales intrastate by the customer companies which distribute the gas to ultimate consumers in Ohio and Pennsylvania are subject to the rate-making powers of the Commission. [FN28] But in any event those rates are not in issue here. Moreover, we fail to find in the power to fix 'just and reasonable' rates the power to fix rates which will disallow or discourage resales for industrial use. The Committee Report stated that the Act provided 'for regulation along recognized and more or less standardized lines' and that there was 'nothing novel in its provisions'. H.Rep.No.709, supra, p. 3. Yet if we are now to tell the Commission to fix the rates so as to discourage particular uses, we would indeed be injecting into a rate case a 'novel' doctrine which has no express statutory sanction. The same would be true if we were to hold that the wasting-asset nature of the industry required the maintenance of the level of rates so that natural gas companies could make a greater profit on each unit of gas sold. Such theories of rate-making for this industry may or may not be desirable. The difficulty is that s 4(a) and s 5(a) contain only the conventional standards of rate-making for natural gas companies. [FN29] The *617 Act of February 7, 1942, by broadening s 7 gave the Commission some additional authority to deal with the conservation aspects of the problem. [FN30] But s 4(a) and s 5(a) were not changed. If the standard **295 of 'just and reasonable' is to sanction the maintenance of high rates by a natural gas company because they restrict the use of natural gas for certain purposes, the Act must be further amended.

FN27 The Commission has expressed doubts over its power to fix rates on 'direct sales to industries' from interstate pipelines as distinguished from 'sales for resale to the industrial customers of distributing companies.' Annual Report, Federal Power Commission (1940), p. 11.

FN28. Sec. 1(b) of the Act provides: 'The provisions of this Act shall apply to the transportation of natural gas in interstate commerce, to the sale in interstate commerce of natural gas for resale for ultimate public consumption for domestic, commercial, industrial, or any other use, and to natural-gas companies engaged in such transportation or sale, but shall not apply to any other transportation or sale of natural gas or to the local distribution of natural gas or to the facilities used for such distribution or to the production or gathering of natural gas.' And see s 2(6), defining a 'natural-gas company', and H.Rep.No. 709, supra, pp. 2, 3.

FN29 The wasting-asset characteristic of the industry was recognized prior to the Act as requiring the inclusion of a depletion allowance among operating expenses. See Columbus Gas & Fuel Co. v. Public Utilities Commission, 292 U.S. 398, 404, 405, 54 S.Ct. 763, 766, 767, 78 L.Ed. 1327, 91 A.L.R. 1403. But no such theory of rate-making for natural gas companies as is now suggested emerged from the cases arising during the earlier period of regulation.

FN30 The Commission has been alert to the problems of conservation in its administration of the Act. It has indeed suggested that it might be wise to restrict the use of natural gas 'byfunctions rather than by areas.' Annual Report (1940) p. 79. The Commission stated in that connection that natural gas was particularly adapted to certain industrial uses. But it added that the general use of such gas 'under boilers for the production of steam' is 'under most circumstances of very questionable social economy.' Ibid.

[23][24] It is finally suggested that the rates charged by Hope are discriminatory as against domestic users and in favor of industrial users. That charge is apparently based on s 4(b) of the Act which forbids natural gas companies from maintaining 'any unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service.' The power of the Commission to eliminate any such unreasonable differences or discriminations is plain. s 5(a). The Commission, however, made no findings under s 4(b). Its failure in that regard was not challenged in the petition to review. And it has not been raised or argued here by any party. Hence the problem of discrimination has no proper place in the present decision. It will be time enough to pass on that issue when it is presented to us. Congress has entrusted the administration of the Act to the Commission not to the courts. Apart from the requirements of judicial review it is not ***618** for us to advise the Commission how to discharge its functions.

Findings as to the Lawfulness of Past Rates. As we have noted, the Commission made certain findings as to the lawfulness of past rates which Hope had charged its interstate customers. Those findings were made on the complaint of the City of Cleveland and in aid of state regulation. It is conceded that under the Act the Commission has no power to make reparation orders. And its power to fix rates admittedly is limited to those 'to be thereafter observed and in force.' s 5(a). But the Commission maintains that it has the power to make findings as to the lawfulness of past rates even though it has no power to fix those rates. [FN31] However that may be, we do not think that these findings were reviewable under s 19(b) of the Act. That section gives any party 'aggrieved by an order' of the Commission a review 'of such order' in the circuit court of appeals for the circuit where the natural gas company is located or has its principal place of business or in the United States Court of Appeals for the District of Columbia. We do not think that the findings in question fall within that category.

FN31 The argument is that s 4(a) makes 'unlawful' the charging of any rate that is not just and reasonable. And s 14(a) gives the Commission power to investigate any matter 'which it may find necessary or proper in order to determine whether any person has violated' any provision of the Act. Moreover, s 5(b) gives the Commission power to investigate and determine the cost of production or transportation of natural gas in cases where it has 'no authority to establish a rate governing the transportation or sale of such natural gas.' And s 17(c) directs the Commission to 'make available to the several State commissions such information and reports as may be of assistance in State regulation of natural-gas companies.' For a discussion of these points by the Commission see 44 P.U.R.,N.S., at pages 34, 35.

[25][26] The Court recently summarized the various types of administrative action or determination reviewable as orders under the Urgent Deficiencies Act of October 22, ***619** 1913, 28 U.S.C. ss 45, 47a, 28 U.S.C.A. ss 45, 47a, and kindred statutory provisions. Rochester Tel. Corp. v. United States, 307 U.S. 125, 59 S.Ct. 754, 83 L.Ed. 1147. It was there pointed out that where 'the order sought to be reviewed does not of itself adversely affect complainant but only affects his rights adversely on the contingency of future administrative action', it is not reviewable. Id., 307 U.S. at page 130, 59 S.Ct. at page 757, 83 L.Ed. 1147. The Court said, 'In view of traditional conceptions of federal judicial power, resort to the courts in these situations is either premature or wholly beyond their province.' Id., 307 ****296** U.S. at page 130, 59 S.Ct. at page 757, 83 L.Ed. 1147. And see United States v. Los Angeles s.l.r. c/o., 273 U.S. 299, 309, 310, 47 S.Ct. 413, 414, 415, 71 L.Ed. 651; Shannahan v.

United States, 303 U.S. 596, 58 S.Ct. 732, 82 L.Ed. 1039. These considerations are apposite here. The Commission has no authority to enforce these findings. They are 'the exercise solely of the function of investigation.' United States v. Los Angeles & S.L.R. Co., supra, 273 U.S. at page 310, 47 S.Ct. at page 414, 71 L.Ed. 651. They are only a preliminary, interim step towards possible future action--action not by the Commission but by wholly independent agencies. The outcome of those proceedings may turn on factors other than these findings. These findings may never result in the respondent feeling the pinch of administrative action.

Reversed.

Mr. Justice ROBERTS took no part in the consideration or decision of this case.

Opinion of Mr. Justice BLACK and Mr. Justice MURPHY.

We agree with the Court's opinion and would add nothing to what has been said but for what is patently a wholly gratuitous assertion as to Constitutional law in the dissent of Mr. Justice FRANKFURTER. We refer to the statement that 'Congressional acquiescence to date in the doctrine of Chicago, etc., R. Co. v. Minnesota, supra (134 U.S. 418, 10 S.Ct. 462, 702, 33 L.Ed. 970), may fairly be claimed.' That was the case in which a majority of this Court was finally induced to expand the meaning ***620** of 'due process' so as to give courts power to block efforts of the state and national governments to regulate economic affairs. The present case does not afford a proper occasion to discuss the soundness of that doctrine because, as stated in Mr. Justice FRANKFURTER'S dissent, 'That issue is not here in controversy.' The salutary practice whereby courts do not discuss issues in the abstract applies with peculiar force to Constitutional questions. Since, however, the dissent adverts to a highly controversial due process doctrine and implies its acceptance by Congress, we feel compelled to say that we do not understand that Congress voluntarily has acquiesced in a Constitutional principle of government that courts, rather than legislative bodies, possess final authority over regulation of economic affairs. Even this Court has not always fully embraced that principle, and we wish to repeat that we have never acquiesced in it, and do not now. See Federal Power Commission v. Natural Gas Pipeline Co., 315 U.S. 575, 599-601, 62 S.Ct. 736, 749, 750, 86 L.Ed. 1037.

Mr. Justice REED, dissenting.

This case involves the problem of rate making under the Natural Gas Act. Added importance arises from the obvious fact that the principles stated are generally applicable to all federal agencies which are entrusted with the determination of rates for utilities. Because my views differ somewhat from those of my brethren, it may be of some value to set them out in a summary form.

The Congress may fix utility rates in situations subject to federal control without regard to any standard except the constitutional standards of due process and for taking private property for public use without just compensation. Wilson v. New, 243 U.S. 332, 350, 37 S.Ct. 298, 302, 61 L.Ed. 755, L.R.A.1917E, 938, Ann.Cas.1918A, 1024. A Commission, however, does not have this freedom of action. Its powers are limited not only by the constitutional standards but also by the standards of the delegation. Here the standard added by the Natural Gas Act is that the rate be 'just ***621** and reasonable.' [FN1] Section 6 [FN2] ****297** throws additional light on the meaning of these words.

FN1 Natural Gas Act, s 4(a), 52 Stat. 821, 822, 15 U.S.C. s 717c(a), 15 U.S.C.A. s 717c(a).

FN2 52 Stat. 821, 824, 15 U.S.C. s 717e, 15 U.S.C.A. s 717e:
'(a) The Commission may investigate and ascertain the actual legitimate cost of the property of every natural-gas company, the depreciation therein, and, when found necessary for rate-making purposes, other facts which bear on the determination of such cost or depreciation and the fair value of such property.
'(b) Every natural-gas company upon request shall file with the Commission an inventory of all or any part of its property and a statement of the original cost thereof, and shall keep the Commission informed regarding the cost of all additions, betterments, extensions, and new construction.'

When the phrase was used by Congress to describe allowable rates, it had relation to something ascertainable. The rates were not left to the whim of the Commission. The rates fixed would produce an annual return and that annual return was to be compared with a theoretical just and reasonable return, all risks considered, on the fair value of the property used and useful in the public service at the time of the determination.

Such an abstract test is not precise. The agency charged with its determination has a wide range before it could properly be said by a court that the agency had disregarded statutory standards or had confiscated the property of the utility for public use. Cf. Chicago, M. & St. P.R. Co. v. Minnesota, 134 U.S. 418, 461--466, 10 S.Ct. 462, 702, 703--705, 33 L.Ed. 970, dissent. This is as Congress intends. Rates are left to an experienced agency particularly competent by training to appraise the amount required.

The decision as to a reasonable return had not been a source of great difficulty, for borrowers and lenders reached such agreements daily in a multitude of situations; and although the determination of fair value had been troublesome, its essentials had been worked out in fairness to investor and consumer by the time of the enactment ***622** of this Act. Cf. Los Angeles G. & E. Corp. v. Railroad Comm., 289 U.S. 287, 304 et seq., 53 S.Ct. 637, 643 et seq., 77 L.Ed. 1180. The results were well known to Congress and had that body desired to depart from the traditional concepts of fair value and earnings, it would have stated its intention plainly. Helvering v. Griffiths, 318 U.S. 371, 63 S.Ct. 636.

It was already clear that when rates are in dispute, 'earnings produced by rates do not afford a standard for decision.' 289 U.S. at page 305, 53 S.Ct. at page 644, 77 L.Ed. 1180. Historical cost, prudent investment and reproduction cost [FN3] were all relevant factors in determining fair value. Indeed, disregarding the pioneer investor's risk, if prudent investment and reproduction cost were not distorted by changes in price levels or technology, each of them would produce the same result. The realization from the risk of an investment in a speculative field, such as natural gas utilities, should be reflected in the present fair value. [FN4] The amount of evidence to be admitted on any point was of course in the agency's reasonable discretion, and it was free to give its own weight to these or other factors and to determine from all the evidence its own judgment as to the necessary rates.

FN3 'Reproduction cost' has been variously defined, but for rate making purposes the most useful sense seems to be, the minimum amount necessary to create at the time of the inquiry a modern plant capable of rendering equivalent service. See I Bonbright, Valuation of Property (1937) 152. Reproduction cost as the cost of building a replica of an obsolescent plant is not of real significance. 'Prudent investment' is not defined by the Court. It may mean the sum originally put in the enterprise, either with or without additional amounts from excess earnings reinvested in the business.

FN4 It is of no more than bookkeeping significance whether the Commission allows a rate of return commensurate with the risk of the original investment or the lower rate based on current risk and a capitalization reflecting the established earning power of a successful company and the probable cost of duplicating its services. Cf. American T. & T. Co. v. United States, 299 U.S. 232, 57 S.Ct. 170, 81 L.Ed. 142. But the latter is the traditional method.

***623** I agree with the Court in not imposing a rule of prudent investment alone in determining the rate base. This leaves the Commission free, as I understand it, to use any available evidence for its finding of fair value, including both prudent investment and the cost of installing at the present time an efficient system for furnishing the needed utility service.

My disagreement with the Court arises primarily from its view that it makes no ****298** difference how the Commission reached the rate fixed so long as theresult is fair and reasonable. For me the statutory command to the Commission is more explicit. Entirely aside from the constitutional problem of whether the Congress could validly delegate its rate making power to the Commission, in toto and without standards, it did legislate in the light of the relation of fair and reasonable to fair value and reasonable return. The Commission must therefore make its findings in observance of that relationship.

The Federal Power Commission did not, as I construe their action, disregard its statutory duty. They heard the evidence relating to historical and reproduction cost and to the reasonable rate of return and they appraised its weight. The evidence of reproduction cost was rejected as unpersuasive, but from the other evidence they found a rate base, which is to me a determination of fair value. On that base the earnings allowed seem fair and reasonable. So far as the Commission went in appraising the property employed in the service, I find nothing in the result which indicates confiscation, unfairness or unreasonableness. Good administration of rate making agencies under this method would avoid undue delay and render revaluations unnecessary except after violent fluctuations of price levels. Rate making under this method has been subjected to criticism. But until Congress changes the standards for the agencies, these rate making bodies should continue the conventional theory of rate ***624** making. It will probably be simpler to improve present methods than to devise new ones.

But a major error, I think was committed in the disregard by the Commission of the investment in exploratory operations and other recognized capital costs. These were not considered by the Commission because they were charged to operating expenses by the company at a time when it was unregulated. Congress did not direct the Commission in rate making to deduct from the rate base capital investment which had been recovered during the unregulated period through excess earnings. In my view this part of the investment should no more have been disregarded in the rate base than any other capital investment which previously had been recovered and paid out in dividends or placed to surplus. Even if prudent investment throughout the life of the property is accepted as the formula for figuring the rate base, it seems to me illogical to throw out the admittedly prudent cost of part of the property because the earnings in the unregulated period had been sufficient to return the prudent cost to the investors over and above a reasonable return. What would the answer be under the theory of the Commission and the Court, if the only prudent investment in this utility had been the seventeen million capital charges which are now disallowed?

For the reasons heretofore stated, I should affirm the action of the Circuit Court of Appeals in returning the proceeding to the Commission for further consideration and should direct the Commission to accept the disallowed capital investment in determining the fair value for rate making purposes.

Mr. Justice FRANKFURTER, dissenting.

My brother JACKSON has analyzed with particularity the economic and social aspects of natural gas as well as ***625** the difficulties which led to the enactment of the Natural Gas Act, especially those arising out of the abortive attempts of States to regulate natural gas utilities. The Natural Gas Act of 1938 should receive application in the light of this analysis, and Mr. Justice JACKSON has, I believe, drawn relevant inferences regarding the duty of the Federal Power Commission in fixing natural gas rates. His exposition seems to me unanswered, and I shall say only afew words to emphasize my basic agreement with him.

For our society the needs that are met by public utilities are as truly public services as the traditional governmental functions of police and justice. They are not less so when these services are rendered by private enterprise under governmental regulation. Who ultimately determines the ways of regulation, is the decisive aspect in the public supervision of privately-owned utilities. Foreshadowed nearly sixty years ago, Railroad Commission Cases (Stone v. Farmers' Loan & Trust Co.), 116 U.S. 307, 331, 6 S.Ct. 334, 344, 388, 1191, 29 L.Ed. 636, it was decided more than fifty ****299** years ago that the final say under the Constitution lies with the judiciary and not the legislature. Chicago, etc., R. Co. v. Minnesota , 134 U.S. 418, 10 S.Ct. 462, 702, 33 L.Ed. 970.

While legal issues touching the proper distribution of governmental powers under the Constitution may always be raised, Congressional acquiescence to date in the doctrine of Chicago, etc., R. Co. v. Minnesota, supra, may fairly be claimed. But in any event that issue is not here in controversy. As pointed out in the opinions of my brethren, Congress has given only limited authority to the Federal Power Commission and made the exercise of that authority subject to judicial review. The Commission is authorized to fix rates chargeable for natural gas. But the rates that it can fix must be 'just and reasonable'. s 5 of the Natural Gas Act, 15 U.S.C. s 717d, 15 U.S.C.A. s 717d. Instead of making the Commission's rate determinations final, Congress***626** specifically provided for court review of such orders. To be sure, 'the finding of the

Commission as to the facts, if supported by substantial evidence' was made 'conclusive', s 19 of the Act, 15 U.S.C. s 717r; 15 U.S.C.A. s 717r. But obedience of the requirement of Congress that rates be 'just and reasonable' is not an issue of fact of which the Commission's own determination is conclusive. Otherwise, there would be nothing for a court to review except questions of compliance with the procedural provisions of the Natural Gas Act. Congress might have seen fit so to cast its legislation. But it has not done so. It has committed to the administration of the Federal Power Commission the duty of applying standards of fair dealing and of reasonableness relevant to the purposes expressed by the Natural Gas Act. The requirement that rates must be 'just and reasonable' means just and reasonable in relation to appropriate standards. Otherwise Congress would have directed the Commission to fix such rates as in the judgment of the Commission are just and reasonable; it would not have also provided that such determinations by the Commission are subject to court review.

To what sources then are the Commission and the courts to go for ascertaining the standards relevant to the regulation of natural gas rates? It is at this point that Mr. Justice JACKSON'S analysis seems to me pertinent. There appear to be two alternatives. Either the fixing of natural gas rates must be left to the unguided discretion of the Commission so long as the rates it fixes do not reveal a glaringly had prophecy of the ability of a regulated utility to continue its service in the future. Or the Commission's rate orders must be founded on due consideration of all the elements of the public interest which the production and distribution of natural gas involve just because it is natural gas. These elements are reflected in the Natural Gas Act, if that Act be applied as an entirety. See, for ***627** instance, ss 4(a)(b)(c)(d), 6, and 11, 15 U.S.C. ss 717c(a)(b)(c)(d), 717e, and 717j, 15 U.S.C.A. ss 717c(a--d), 717e, 717j. Of course the statute is not concerned with abstract theories of ratemaking. But its very foundation is the 'public interest', and the public interest is a texture of multiple strands. It includes more than contemporary investors and contemporary consumers. The needs to be served are not restricted to immediacy, and social as well as economic costs must be counted.

It will not do to say that it must all be left to the skill of experts. Expertise is a rational process and a rational process implies expressed reasons for judgment. It will little advance the public interest to substitute for the hodge-podge of the rule in Smyth v. Ames, 169 U.S. 466, 18 S.Ct. 418, 42 L.Ed. 819, an encouragement of conscious obscurity or confusion in reaching a result, on the assumption that so long as the result appears harmless its basis is irrelevant. That may be an appropriate attitude when state action is challenged as unconstitutional. Cf. Driscoll v. Edison Light & Power Co., 307 U.S. 104, 59 S.Ct. 715, 83 L.Ed. 1134. But it is not to be assumed that it was the design of Congress to make the accommodation of the conflicting interests exposed in Mr. Justice JACKSON'S opinion the occasion for a blind clash of forces or a partial assessment of relevant factors, either before the Commission or here.

The objection to the Commission's action is not that the rates it granted were too low but that the range of its vision was too narrow. And since the issues before the Commission involved no less than the ****300** total public interest, the proceedings before it should not be judged by narrow conceptions of common law pleading. And so I conclude that the case should be returned to the Commission. In order to enable this Court to discharge its duty of reviewing the Commission's order, the Commission should set forth with explicitness the criteria by which it is guided ***628** in determining that rates are 'just and reasonable', and it should determine the public interest that is in its keeping in the perspective of the considerations set forth by Mr. Justice JACKSON.

By Mr. Justice JACKSON.

Certainly the theory of the court below that ties rate-making to the fair- value-reproduction-cost formula should be overruled as in conflict with Federal Power Commission v. Natural Gas Pipeline Co. [FN1] But the case should, I think, be the occasion for reconsideration of our rate-making doctrine as applied to natural gas and should be returned to the Commission for further consideration in the light thereof.

FN1 315 U.S. 575, 62 S.Ct. 736, 86 L.Ed. 1037.

The Commission appears to have understood the effect of the two opinions in the Pipeline case to be at least authority and perhaps direction to fix natural gas rates by exclusive application of the 'prudent investment' rate base theory. This has no warrant in the opinion of the Chief Justice for the Court, however, which released the Commission from subservience to 'any single formula or combination of formulas' provided its order, 'viewed in its entirety, produces no arbitrary result.' 315 U.S. at page 586, 62 S.Ct. at page 743, 86 L.Ed. 1037. The minority opinion I understood to advocate the 'prudent investment' theory as a sufficient guide in a natural gas case. The view was expressed in the court below that since this opinion was not expressly controverted it must have been approved. [FN2] I disclaim this imputed ***629** approval with some particularity, because I attach importance at the very beginning of federal regulation of the natural gas industry to approaching it as the performance of economic functions, not as the performance of legalistic rituals.

FN2 Judge Dobie, dissenting below, pointed out that the majority opinion in the Pipeline case 'contains no express discussion of the Prudent Investment Theory' and that the concurring opinion contained a clear one, and said, 'It is difficult for me to believe that the majority of the Supreme Court, believing otherwise, would leave such a statement unchallenged.' (134 F.2d 287, 312.) The fact that two other Justices had as matter of record in our books long opposed the reproduction cost theory of rate bases and had commented favorably on the prudent investment theory may have influenced that conclusion. See opinion of Mr. Justice Frankfurter in Driscoll v. Edison Light & Power Co., 307 U.S. 104, 122, 59 S.Ct. 715, 724, 83 L.Ed. 1134, and my brief as Solicitor General in that case. It should be noted, however, that these statements were made, not in a natural gas case, but in an electric power case--a very important distinction, as I shall try to make plain.

I.

Solutions of these cases must consider eccentricities of the industry which gives rise to them and also to the Act of Congress by which they are governed.

The heart of this problem is the elusive, exhaustible, and irreplaceable nature of natural gas itself. Given sufficient money, we can produce any desired amount of railroad, bus, or steamship transportation, or communications facilities, or capacity for generation of electric energy, or for the manufacture of gas of a kind. In the service of such utilities one customer has little concern with the amount taken by another, one's waste will not deprive another, a volume of service and be created equal to demand, and today's demands will not exhaust or lessen capacity to serve tomorrow. But the wealth of Midas and the wit of man cannot produce or reproduce a natural gas field. We cannot even reproduce the gas, for our manufactured product has only about half the heating value per unit of nature's own. [FN3]

FN3 Natural gas from the Appalachian field averages about 1050 to 1150 B.T.U. content, while by-product manufactured gas is about 530 to 540. Moody's Manual of Public Utilities (1943) 1350; Youngberg, Natural Gas (1930) 7.

****301** Natural gas in some quantity is produced in twenty-four states. It is consumed in only thirty-five states, and is ***630** available only to about 7,600,000 consumers. [FN4] Its availability has been more localized than that of any other utility service because it has depended more on the caprice of nature.

FN4 Sen.Rep. No. 1162, 75th Cong., 1st Sess., 2.

The supply of the Hope Company is drawn from that old and rich and vanishing field that flanks the Appalachian mountains. Its center of production is Pennsylvania and West Virginia, with a fringe of lesser production in New York, Ohio, Kentucky, Tennessee, and the north end of Alabama. Oil was discovered in commercial quantities at a depth of only 69 1/2 feet near Titusville, Pennsylvania, in 1859. Its value then was about $16 per barrel. [FN5] The oil branch of the petroleum industry went forward at once, and with unprecedented speed. The area productive of oil and gas was roughed out by the drilling of over 19,000 'wildcat' wells, estimated to have cost over $222,000,000. Of these, over 18,000 or 94.9 per cent, were 'dry holes.' About five per cent, or 990 wells, made discoveries of commercial importance, 767 of them resulting chiefly in oil and 223 in gas only. [FN6] Prospecting for many years was a search for oil, and to strike gas was a misfortune. Waste during this period and even later is appalling. Gas was regarded as having no commercial value until about 1882, in which year the total yield was valued only at about $75,000. [FN7] Since then, contrary to oil, which has become cheaper gas in this field has pretty steadily advanced in price.

FN5 Arnold and Kemnitzer, Petroleum in the United States and Possessions (1931) 78.

FN6. Id. at 62-63.

FN7. Id. at 61.

While for many years natural gas had been distributed on a small scale for lighting, [FN8] its acceptance was slow, ***631** facilities for its utilization were primitive, and not until 1885 did it take on the appearance of a substantial industry. [FN9] Soon monopoly of production or markets developed. [FN10] To get gas from the mountain country, where it was largely found, to centers of population, where it was in demand, required very large investment. By ownership of such facilities a few corporate systems, each including several companies, controlled access to markets. Their purchases became the dominating factor in giving a market value to gas produced by many small operators. Hope is the market for over 300 such operators. By 1928 natural gas in the Appalachian field commanded an average price of 21.1 cents per m.c.f. at points of production and was bringing 45.7 cents at points of consumption. [FN11] The companies which controlled markets, however, did not rely on gas purchases alone. They acquired and held in fee or leasehold great acreage in territory proved by 'wildcat' drilling. These large marketing system companies as well as many small independent owners and operators have carried on the commercial development of proved territory. The development risks appear from the estimate that up to 1928, 312,318 proved area wells had been sunk in the Appalachian field of which 48,962, or 15.7 per cent, failed to produce oil or gas in commercial quantity. [FN12]

FN8 At Fredonia, New York, in 1821, natural gas was conveyed from a shallow well to some thirty people. The lighthouse at Barcelona Harbor, near what is now Westfield, New York, was at about that time and for many years afterward lighted by gas that issued from a crevice. Report on Utility Corporations by Federal Trade Commission, Sen.Doc. 92, Pt. 84-A, 70th Cong., 1st Sess., 8-9.

FN9 In that year Pennsylvania enacted 'An Act to provide for the incorporation and regulation of natural gas companies.' Penn.Laws 1885, No. 32, 15 P.S. s 1981 et seq.

FN10 See Steptoe and Hoffheimer's Memorandum for Governor Cornwell of West Virginia (1917) 25 West Virginia Law Quarterly 257; see also Report on Utility Corporations by Federal Trade Commission, Sen.Doc. No. 92, Pt. 84- A, 70th Cong., 1st Sess.

FN11 Arnold and Kemnitzer, Petroleum in the United States and Possessions (1931) 73.

FN12. Id. at 63.

***632** With the source of supply thus tapped to serve centers of large demand, like Pittsburgh, Buffalo, Cleveland, Youngstown, Akron, and other industrial communities, the distribution of natural gas fast became big business. Its advantages as a ****302** fuel and its price commended it, and the business yielded a handsome return. All was merry and the goose hung high for consumers and gas companies alike until about the time of the first. World War. Almost unnoticed by the consuming public, the whole Appalachian field passed its peak of production and started to decline. Pennsylvania, which to 1928 had given off about 38 per cent of the natural gas from this field, had its peak in 1905; Ohio, which had produced 14 per cent, had its peak in 1915; and West Virginia, greatest producer of all, with 45 per cent to its credit, reached its peak in 1917. [FN13]

FN13. Id. at 64.

Western New York and Eastern Ohio, on the fringe of the field, had some production but relied heavily on imports from Pennsylvania and West Virginia. Pennsylvania, a producing and exporting state, was a heavy consumer and supplemented her production with imports from West Virginia. West Virginia was a consuming state, but the lion's share of her production was exported. Thus the interest of the states in the North Appalachian supply was in conflict.

Competition among localities to share in the failing supply and the helplessness of state and local authorities in the presence of state lines and corporate complexities is a part of the background of federal intervention in the industry. [FN14] West Virginia took the boldest measure. It legislated a priority in its entire production in favor of its own inhabitants. That was frustrated by an injunction ***633** from this Court. [FN15] Throughout the region clashes in the courts and conflicting decisions evidenced public anxiety and confusion. It was held that the New York Public Service Commission did not have power to classify consumers and restrict their use of gas. [FN16] That Commission held that a company could not abandon a part of its territory and still serve the rest. [FN17] Some courts admonished the companies to take action to protect consumers. [FN18] Several courts held that companies, regardless of failing supply, must continue to take on customers, but such compulsory additions were finally held to be within the Public Service Commission's discretion. [FN19] There were attempts to throw up franchises and quit the service, and municipalities resorted to the courts with conflicting results. [FN20] Public service commissions of consuming states were handicapped, for they had no control of the supply. [FN21]

FN14 See Report on Utility Corporations by Federal Trade Commission, Sen.Doc. No. 92, Pt. 84-A, 70th Cong., 1st Sess.

FN15 Commonwealth of Pennsylvania v. West Virginia, 262 U.S. 553, 43 S.Ct. 658, 67 L.Ed. 1117, 32 A.L.R. 300. For conditions there which provoked this legislation, see 25 West Virginia Law Quarterly 257.

FN16 People ex rel. Pavilion Natural Gas Co. v. Public Service Commission, 188 App.Div. 36, 176 N.Y.S. 163.

FN17 Village of Falconer v. Pennsylvania Gas Company, 17 State Department Reports, N.Y., 407.

FN18 See, for example, Public Service Commission v. Iroquois Natural Gas Co., 108 Misc. 696, 178 N.Y.S. 24; Park Abbott Realty Co. v. Iroquois Natural Gas Co., 102 Misc. 266, 168 N.Y.S. 673; Public Service Commission v. Iroquois Natural Gas Co., 189 App.Div. 545, 179 N.Y.S. 230.

FN19 People ex rel. Pennsylvania Gas Co. v. Public Service Commission, 196 App.Div. 514, 189 N.Y.S. 478.

FN20 East Ohio Gas Co. v. Akron, 81 Ohio St. 33, 90 N.E. 40, 26 L.R.A., N.S., 92, 18 Ann.Cas. 332; Village of New-comerstown v. Consolidated Gas Co., 100 Ohio St. 494, 127 N.E. 414; Gress v. Village of Ft. Laramie, 100 Ohio St. 35, 125 N.E. 112, 8 A.L.R. 242; City of Jamestown v. Pennsylvania Gas Co., D.C., 263 F. 437; Id., D.C., 264 F. 1009. See, also, United Fuel Gas Co. v. Railroad Commission, 278 U.S. 300, 308, 49 S.Ct. 150, 152, 73 L.Ed. 390.

FN21 The New York Public Service Commission said: 'While the transportation of natural gas through pipe lines from one state to another state is interstate commerce * * *, Congress has not taken over the regulation of that particular industry. Indeed, it has expressly excepted it from the operation of the Interstate Commerce Commissions Law (Interstate Commerce Commissions Law, section 1). It is quite clear, therefore, that this Commission can not require a Pennsylvania corporation producing gas in Pennsylvania to transport it and deliver it in the State of New York, and that the Interstate Commerce Commission is likewise powerless. If there exists such a power, and it seems that there does, it is a power vested in Congress and by it not yet exercised. There is no available source of supply for the Crystal City Company at present except through purchasing from the Porter Gas Company. It is possible that this Commission might fix a price at which the Potter Gas Company should sell if it sold at all, but as the Commission can not require it to supply gas in the State of New York, the exercise of such a power to fix the price, if such power exists, would merely say, sell at this price or keep out of the State.' Lane v. Crystal City Gas Co., 8 New York Public Service Comm.Reports, Second District, 210, 212.

**303 *634 Shortages during World War I occasioned the first intervention in the natural gas industry by the Federal Government. Under Proclamation of President Wilson the United States Fuel Administrator took control, stopped extensions, classified consumers and established a priority for domestic over industrial use. [FN22] After the war federal control was abandoned. Some cities once served with natural gas became dependent upon mixed gas of reduced heating value and relatively higher price. [FN23]

FN22 Proclamation by the President of September 16, 1918; Rules and Regulations of H. A. Garfield, Fuel Administrator, September 24, 1918.

FN23 For example, the Iroquois Gas Corporation which formerly served Buffalo, New York, with natural gas ranging from 1050 to 1150 b.t.u. per cu. ft., now mixes a by-product gas of between 530 and 540 b.t.u. in proportions to provide a mixed gas of about 900 b.t.u. per cu. ft. For space heating or water heating its charges range from 65 cents for the first m.c.f. per month to 55 cents for all above 25 m.c.f. per month. Moody's Manual of Public Utilities (1943) 1350.

Utilization of natural gas of highest social as well as economic return is domestic use for cooking and water ***635** heating, followed closely by use for space heating in homes. This is the true public utility aspect of the enterprise, and its preservation should be the first concern of regulation. Gas does the family cooking cheaper than any other fuel. [FN24] But its advantages do not end with dollars and cents cost. It is delivered without interruption at the meter as needed and is paid for after it is used. No money is tied up in a supply, and no space is used for storage. It requires no handling, creates no dust, and leaves no ash. It responds to thermostatic control. It ignites easily and immediately develops its maximum heating capacity. These incidental advantages make domestic life more liveable.

FN24 The United States Fuel Administration made the following cooking value comparisons, based on tests made in the Department of Home Economics of Ohio State University:
Natural gas at 1.12 per M. is equivalent to coal at $6.50 per ton.
Natural gas at 2.00 per M. is equivalent to gasoline at 27¢ per gal.
Natural gas at 2.20 per M. is equivalent to electricity at 3¢ per k.w.h.
Natural gas at 2.40 per M. is equivalent to coal oil at 15¢ per gal.
Use and Conservation of Natural Gas, issued by U.S. Fuel Administration (1918) 5.

Industrial use is induced less by these qualities than by low cost in competition with other fuels. Of the gas exported from West Virginia by the Hope Company a very substantial part is used by industries. This wholesale use speeds exhaustion of supply and displaces other fuels. Coal miners and the coal industry, a large part of whose costs are wages, have complained of unfair competition from low-priced industrial gas produced with relatively little labor cost. [FN25]

FN25 See Brief on Behalf jof Legislation Imposing an Excise Tax on Natural Gas, submitted to N.R.A. by the United Mine Workers of America and the National Coal Association.

Gas rate structures generally have favored industrial users. In 1932, in Ohio, the average yield on gas for domestic consumption was 62.1 cents per m.c.f. and on industrial, ***636** 38.7. In Pennsylvania, the figures were 62.9 against 31.7. West Virginia showed the least spread, domestic consumers paying 36.6 cents; and industrial, 27.7. [FN26] Although this spread is less than ****304** in other parts of the United States, [FN27] it can hardly be said to be self-justifying. It certainly is a very great factor in hastening decline of the natural gas supply.

FN26 Brief of National Gas Association and United Mine Workers, supra, note 26, pp. 35, 36, compiled from Bureau of Mines Reports.

FN27 From the source quoted in the preceding note the spread elsewhere is shown to be:

State	Industrial	Domestic
Illinois	29.2	1.678
Louisiana	10.4	59.7
Oklahoma	11.2	41.5
Texas	13.1	59.7
Alabama	17.8	1.227
Georgia	22.9	1.043

About the time of World War I there were occasional and short-lived efforts by some hard-pressed companies to reverse this discrimination and adopt graduated rates, giving a low rate to quantities adequate for domestic use and graduating it upward to discourage industrial use. [FN28] ***637** These rates met opposition from industrial sources, of course, and since diminished revenues from industrial sources tended to increase the domestic price, they met little popular or commission favor. The fact is that neither the gas companies nor the consumers nor local regulatory bodies can be depended upon to conserve gas. Unless federal regulation will take account of conservation, its efforts seem, as in this case, actually to constitute a new threat to the life of the Appalachian supply.

FN28 In Corning, New York, rates were initiated by the Crystal City Gas Company as follows: 70 ¢ for the first 5,000 cu. ft. per month; 80 ¢ from 5,000 to 12,000; $1 for all over 12,000. The Public Service Commission rejected these rates and fixed a flat rate of 58 ¢ per m.c.f. Lane v. Crystal City Gas Co., 8 New York Public Service Comm. Reports, Second District, 210.
The Pennsylvania Gas Company (National Fuel Gas Company group) also attempted a sliding scale rate for New York consumers, net per month as follows: First 5,000 feet, 35 ¢; second 5,000 feet, 45¢; third 5,000 feet, 50 ¢; all above 15,000, 55 ¢. This was eventually abandoned, however. The company's present scale in Pennsylvania appears to be reversed to the following net monthly rate; first 3 m.c.f., 75 ¢; next 4 m.c.f., 60 ¢; next 8 m.c.f., 55¢; over 15 m.c.f., 50 ¢ . Moody's Manual of Public Utilities (1943) 1350. In New York it now serves a mixed gas.
For a study of effect of sliding scale rates in reducing consumption see 11 Proceedings of Natural Gas Association of America (1919) 287.

II.

Congress in 1938 decided upon federal regulation of the industry. It did so after an exhaustive investigation of all aspects including failing supply and competition for the use of natural gas intensified by growing scarcity. [FN29] Pipelines from the Appalachian area to markets were in the control of a handful of holding company systems. [FN30] This created a highly concentrated control of the producers' market and of the consumers' supplies. While holding companies dominated both production and distribution they segregated those activities in separate *638 subsidiaries, [FN31] the effect of which, if not the purpose, was to isolate **305 some end of the business from the reach of any one state commission. The cost of natural gas to consumers moved steadily upwards over the years, out of proportion to prices of oil, which, except for the element of competition, is produced under somewhat comparable conditions. The public came to feel that the companies were exploiting the growing scarcity of local gas. The problems of this region had much to do with creating the demand for federal regulation.

FN29 See Report on Utility Corporations by Federal Trade Commission, Sen. Doc. 92, Pt. 84-A, 70th Cong., 1st Sess.

FN30 Four holding company systems control over 55 per cent of all natural gas transmission lines in the United States. They are Columbia Gas and Electric Corporation, Cities Service Co., Electric Bond and Share Co., and Standard Oil Co. of New Jersey. Columbia alone controls nearly 25 per cent, and fifteen companies account for over 80 per cent of the total. Report on Utility Corporations by Federal Trade Commission, Sen. Doc. 92, Pt. 84-A, 70th Cong., 1st Sess., 28.
In 1915, so it was reported to the Governor of West Virginia, 87 per cent of the total gas production of that state was under control of eight companies. Steptoe and Hoffheimer, Legislative Regulation of Natural Gas Supply in West Virginia, 17 West Virginia Law Quarterly 257, 260. Of these, three were subsidiaries of the Columbia system and others were subsidiaries of larger systems. In view of inter-system sales and interlocking interests it may be doubted whether there is much real competition among these companies.

FN31 This pattern with its effects on local regulatory efforts will be observed in our decisions. See United Fuel Gas Co. v. Railroad Commission, 278 U.S. 300, 49 S.Ct. 150, 73 L.Ed. 390; United Fuel Gas Co. v. Public Service Commission, 278 U.S. 322, 49 S.Ct. 157, 73 L.Ed. 402; Dayton Power & Light v. Public Utilities Commission, 292 U.S. 290, 54 S.Ct. 647, 78 L.Ed. 1267; Columbus Gas & Fuel Co. v. Public Utilities Commission, 292 U.S. 398, 54 S.Ct. 763, 78 L.Ed. 1327, 91 A.L.R. 1403, and the present case.

The Natural Gas Act declared the natural gas business to be 'affected with a public interest,' and its regulation 'necessary in the public interest.' [FN32] Originally, and at the time this proceeding was commenced and tried, it also declared 'the intention of Congress that natural gas shall be sold in interstate commerce for resale for ultimate public consumption for domestic, commercial, industrial, or any other use at the lowest possible reasonable rate consistent with the maintenance of adequate service in the public interest.' [FN33] While this was later dropped, there is nothing to indicate that it was not and is not still an accurate statement of purpose of the Act. Extension or improvement of facilities may be ordered when 'necessary or desirable in the public interest,' abandonment of facilities may be ordered when the supply is 'depleted to the extent that the continuance of service is unwarranted, or that the present or future public convenience or necessity ***639** permit' abandonment and certain extensions can only be made on finding of 'the present or future public convenience and necessity.' [FN34] The Commission is required to take account of the ultimate use of the gas. Thus it is given power to suspend new schedules as to rates, charges, and classification of services except where the schedules are for the sale of gas 'for resale for industrial use only,' [FN35] which gives the companies greater freedom to increase rates on industrial gas than on domestic gas. More particularly, the Act expressly forbids any undue preference or advantage to any person or 'any unreasonable difference in rates * * * either as between localities or as between classes of service.' [FN36] And the power of the Commission expressly includes that to determine the 'just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force.' [FN37]

FN32 15 U.S.C. s 717(a), 15 U.S.C.A. s 717(a). (Italics supplied throughout this paragraph.)

FN33 s 7(c), 52 Stat. 825, 15 U.S.C.A. s 717f(c).

FN34 15 U.S.C. s 717f, 15 U.S.C.A. s 717f.

FN35 Id., s 717c(e).

FN36 Id., s 717c(b).

FN37 Id., s 717d(a).

In view of the Court's opinion that the Commission in administering the Act may ignore discrimination, it is interesting that in reporting this Bill both the Senate and the House Committees on Interstate Commerce pointed out that in 1934, on a nationwide average the price of natural gas per m.c.f. was 74.6 cents for domestic use, 49.6 cents for commercial use, and 16.9 for industrial use. [FN38] I am not ready to think that supporters of a bill called attention to the striking fact that householders were being charged five times as much for their gas as industrial users only as a situation which the Bill would do nothing to remedy. On the other hand the Act gave to the Commission what the Court aptly describes as 'broad powers of regulation.'

FN38 Sen. Rep. No. 1162, 75th Cong., 1st Sess. 2.

***640** III.

This proceeding was initiated by the Cities of Cleveland and Akron. They alleged that the price charged by Hope for natural gas 'for resale to domestic, commercial and small industrial consumers in Cleveland and elsewhere is excessive, unjust, unreasonable, greatly in excess of the price charged by Hope to nonaffiliated companies at wholesale for resale to domestic, commercial and small industrial consumers, and greatly in excess of the price charged by Hope to East Ohio for resale to certain favored industrial consumers in Ohio, and therefore is further unduly discriminatory between consumers and between classes of service' (italics supplied). The company answered admitting differences in prices to affiliated and nonaffiliated companies and justifying them by differences in conditions of delivery. ****306** As to the allegation that the contract price is 'greatly in excess of the price charged by Hope to East Ohio for resale to certain favored industrial consumers in Ohio,' Hope did not deny a price differential, but alleged that industrial gas was not sold to 'favored consumers' but was sold under contract and schedules filed with and approved by the Public Utilities Commission of Ohio, and that certain conditions of delivery made it not 'unduly discriminatory.'

The record shows that in 1940 Hope delivered for industrial consumption 36,523,792 m.c.f. and for domestic and commercial consumption, 50,343,652 m.c.f. I find no separate figure for domestic consumption. It served 43,767 domestic consumers directly, 511,521 through the East Ohio Gas Company, and 154,043 through the Peoples Natural Gas Company, both affiliates owned by the same parent. Its special contracts for industrial consumption, so far as appear, are confined to about a dozen big industries.

***641** Hope is responsible for discrimination as exists in favor of these few industrial consumers. It controls both the resale price and use of industrial gas by virtue of the very interstate sales contracts over which the Commission is exercising its jurisdiction.

Hope's contract with East Ohio Company is an example. Hope agrees to deliver, and the Ohio

Company to take, '(a) all natural gas requisite for the supply of the domestic consumers of the Ohio Company; (b) such amounts of natural gas as may be requisite to fulfill contracts made with the consent and approval of the Hope Company by the Ohio Company, or companies which it supplies with natural gas, for the sale of gas upon special terms and conditions for manufacturing purposes.' The Ohio company is required to read domestic customers' meters once a month and meters of industrial customers daily and to furnish all meter readings to Hope. The Hope Company is to have access to meters of all consumers and to all of the Ohio Company's accounts. The domestic consumers of the Ohio Company are to be fully supplied in preference to consumers purchasing for manufacturing purposes and 'Hope Company can be required to supply gas to be used for manufacturing purposes only where the same is sold under special contracts which have first been submitted to and approved in writing by the Hope Company and which expressly provide that natural gas will be supplied thereunder only in so far as the same is not necessary to meet the requirements of domestic consumers supplied through pipe lines of the Ohio Company.' This basic contract was supplemented from time to time, chiefly as to price. The last amendment was in a letter from Hope to East Ohio in 1937. It contained a special discount on industrial gas and a schedule of special industrial contracts, Hope reserving the right to make eliminations therefrom and agreeing that others might be added from time to *642 time with its approval in writing. It said, 'It is believed that the price concessions contained in this letter, while not based on our costs, are under certain conditions, to our mutual advantage in maintaining and building up the volumes of gas sold by us (italics supplied).' [FN39]

FN39 The list of East Ohio Gas Company's special industrial contracts thus expressly under Hope's control and their demands are as follows:

**307 The Commission took no note of the charges of discrimination and made no disposition of the issue tendered on this point. It ordered a flat reduction in the price per m.c.f. of all gas delivered by Hope in interstate commerce. It made no limitation, condition, or provision as to what classes of consumers should get the benefit of the reduction. While the cities have accepted and are defending the reduction, it is my view that the discrimination of which they have complained is perpetuated and increased by the order of the Commission and that it violates the Act in so doing.

The Commission's opinion aptly characterizes its entire objective by saying that 'bona fide investment figures now become all-important in the regulation of rates.' It should be noted that the all-importance of this theory is not the result of any instruction from Congress. When the Bill to regulate gas was first before Congress it contained *643 the following: 'In determining just and reasonable rates the Commission shall fix such rate as will allow a fair return upon the actual legitimate prudent cost of the property used and useful for the service in question.' H.R. 5423, 74th Cong., 1st Sess. Title III, s 312(c). Congress rejected this language. See H.R. 5423, s 213 (211(c)), and H.R. Rep. No. 1318, 74th Cong., 1st Sess. 30.

The Commission contends nevertheless that the 'all important' formula for finding a rate base is that of prudent investment. But it excluded fromthe investment base an amount actually and admittedly invested of some $17,000,000. It did so because it says that the Company recouped these expenditures from customers before the days of regulation from earnings above a fair return. But it would not apply all of such 'excess earnings' to reduce the rate base as one of the Commissioners suggested. The reason for applying excess earnings to reduce the investment base roughly from $69,000,000 to $52,000,000 but refusing to apply them to reduce it from that to some $18,000,000 is not found in a difference in the character of the earnings or in their reinvestment. The reason assigned is a difference in bookkeeping treatment many years before the Company was subject to regulation. The $17,000,000, reinvested chiefly in well drilling, was treated on the books as expense. (The Commission now requires that drilling costs be carried to capital account.) The allowed rate base thus actually was determined by the Company's bookkeeping, not its investment. This attributes a significance to formal classification in account keeping that seems inconsistent with rational rate regulation. [FN40] Of *644 course, the **308 Commission would not and should not allow a rate base to be inflated by bookkeeping which had improperly capitalized expenses. I have doubts about resting public regulation upon any rule that is to be used or not depending on which side it favors.

FN40 To make a fetish of mere accounting is to shield from examination the deeper causes, forces, movements, and conditions which should govern rates. Even as a recording of current transactions, bookkeeping is hardly an exact science. As a representation of the condition and trend of a business, it uses symbols of certainty to express values that actually are in constant flux. It may be said that in commercial or investment banking or any business extending credit success depends on knowing what not to believe in accounting. Few concerns go into bankruptcy or reorganization whose books do not show them solvent and often even profitable. If one cannot rely on accountancy accurately to disclose past or current conditions of a business, the fallacy of using it as a sole guide to future price policy ought to be apparent. However, our quest for certitude is so ardent that we pay an irrational reverence to a technique which uses symbols of certainty, even though experience again and again warns us that they are delusive. Few writers have ventured to challenge this American idolatry, but see Hamilton, Cost as a standard for Price, 4 Law and Contemporary Problems 321, 323-25. He observes that 'As the apostle would put it, accountancy is all things to all men. * * * Its purpose determines the character of a system of accounts.' He analyzes the hypothetical character of accounting and says 'It was no eternal mold for pecuniary verities handed down from on high. It was--like logic or algebra, or the device of analogy in the law--an ingenious contrivance of the human mind to serve a limited and practical purpose.' 'Accountancy is far from being a pecuniary expression of all that is industrial reality. It is an instrument, highly selective in its application, in the service of the institution of money making.' As to capital account he observes 'In an enterprise in lusty competition with others of its kind, survival is the thing and the system of accounts has its focus in solvency. * * * Accordingly depreciation, obsolescence, and other factors which carry no immediate threat are matters of lesser concern and the capital account is likely to be regarded as a secondary phenomenon. * * * But in an enterprise, such as a public utility, where continued survival seems assured, solvency is likely to be taken for granted. * * * A persistent and ingenious attention is likely to be directed not so much to securing the upkeep of the physical property as to making it certain that capitalization fails in not one whit to give full recognition to every item that should go into the account.'

***645** The Company on the other hand, has not put its gas fields into its calculations on the present-value basis, although that, it contends, is the only lawful rule for finding a rate base. To do so would result in a rate higher than it has charged or proposes as a matter of good business to charge.

The case before us demonstrates the lack of rational relationship between conventional rate-base formulas and natural gas production and the extremities to which regulating bodies are brought by the effort to rationalize them. The Commission and the Company each stands on a different theory, and neither ventures to carry its theory to logical conclusion as applied to gas fields.

IV.

This order is under judicial review not because we interpose constitutional theories between a State and the business it seeks to regulate, but because Congress put upon the federal courts a duty toward administration of a new federal regulatory Act. If we are to hold that a given rate is reasonable just because the Commission has said it was reasonable, review becomes a costly, time-consuming pageant of no practical value to anyone. If on the other hand we are to bring judgment of our own to the task, we should for the guidance of the regulators and the regulated reveal something of the philosophy, be it legal or economic or social, which guides us. We need not be slaves to a formula but unless we can point out a rational way of reaching our conclusions they can only be accepted as resting on intuition or predilection. I must admit that I possess no instinct jby which to know the 'reasonable' from the 'unreasonable' in prices and must seek some conscious design for decision.

The Court sustains this order as reasonable, but what makes it so or what could possibly make it otherwise, ***646** I cannot learn. It holds that: 'it is the result reached not the method employed which is controlling'; 'the fact that the method employed to reach that result may contain infirmities is not then important' and it is not 'important to this case to determine the various permissible ways in which any rate base on which the return is computed might be arrived at.' The Court does lean somewhat on considerations of capitalization and dividend history and requirements for dividends on outstanding stock. But I can give no real weight to that for it is generally and I think deservedly in discredit as any guide in rate cases. [FN41]

FN41 See 2 Bonbright, Valuation of Property

(1937) 1112.

Our books already contain so much talk of methods of rationalizing rates that we must appear ambiguous if we announce results without our working methods. We are confronted with regulation of a unique type of enterprise which I think requires considered rejection of much conventional utility doctrine and adoption of concepts of 'just and reasonable' rates and practices and of the 'public interest' that will take account of the peculiarities of the business.

The Court rejects the suggestions of this opinion. It says that the Committees in reporting the bill which became the Act said it provided 'for regulation along recognized and more or less standardized lines' and that there was 'nothing novel in its provisions.' So saying it sustains a rate calculated on a novel variation of a rate base theory which itself had at the time of enactment of the legislation been recognized only in dissenting opinions. Our difference seems to be between unconscious innovation, [FN42] and the purposeful ****309** and deliberate innovation I ***647** would make to meet the necessities of regulating the industry before us.

FN42 Bonbright says, '* * * the vice of traditional law lies, not in its adoption of excessively rigid concepts of value and rules of valuation, but rather in its tendency to permit shifts in meaning that are inept, or else that are ill-defined because the judges that make them will not openly admit that they are doing so.' Id., 1170.

Hope's business has two components of quite divergent character. One, while not a conventional common-carrier undertaking, is essentially a transportation enterprise consisting of conveying gas from where it is produced to point of delivery to the buyer. This is a relatively routine operation not differing substantially from many other utility operations. The service is produced by an investment in compression and transmission facilities. Its risks are those of investing in a tested means of conveying a discovered supply of gas to a known market. A rate base calculated on the prudent investment formula would seem a reasonably satisfactory measure for fixing a return from that branch of the business whose service is roughly proportionate to the capital invested. But it has other consequences which must not be overlooked. It gives marketability and hence 'value' to gas owned by the company and gives the pipeline company a large power over the marketability and hence 'value' of the production of others.

The other part of the business--to reduce to possession an adequate supply of natural gas--is of opposite character, being more erratic and irregular and unpredictable in relation to investment than any phase of any other utility business. A thousand feet of gas captured and severed from real estate for delivery to consumers is recognized under our law as property of much the same nature as a ton of coal, a barrel of oil, or a yard of sand. The value to be allowed for it is the real battleground between the investor and consumer. It is from this part of the business that the chief difference between the parties as to a proper rate base arises.

It is necessary to a 'reasonable' price for gas that it be anchored to a rate base of any kind? Why did courts in the first place begin valuing 'rate bases' in order to 'value' something else? The method came into vogue ***648** in fixing rates for transportation service which the public obtained from common carriers. The public received none of the carriers' physical property but did make some use of it. The carriage was often a monopoly so there were no open market criteria as to reasonableness. The 'value' or 'cost' of what was put to use in the service by the carrier was not a remote or irrelevant consideration in making such rates. Moreover the difficulty of appraising an intangible service was thought to be simplified if it could be related to physical property which was visible and measurable and the items of which might have market value. The court hoped to reason from the known to the unknown. But gas fields turn this method topsy turvy. Gas itself is tangible, possessible, and does have a market and a price in the field. The value of the rate base is more elusive than that of gas. It consists of intangibles-- leaseholds and freeholds--operated and unoperated--of little use in themselves except as rights to reach and capture gas. Their value lies almost wholly in predictions of discovery, and of price of gas when captured, and bears little relation to cost of tools and supplies and labor to develop it. Gas is what Hope sells and it can be directly priced more reasonably and easily and accurately than the components of a rate base can be valued. Hence the reason for resort to a roundabout way of rate base price fixing does not exist in the case of gas in the field.

But if found, and by whatever method found, a rate base is little help in determining reasonableness of the price of gas. Appraisal of present value of these intangible rights to pursue fugitive gas depends on the value assigned to the gas when captured. The 'present fair value' rate base, generally in ill repute, [FN43] is not even **310 urged by the gas company for valuing its fields.

FN43 'The attempt to regulate rates by reference to a periodic or occasional reappraisal of the properties has now been tested long enough to confirm the worst fears of its critics. Unless its place is taken by some more promising scheme of rate control, the days of private ownership under government regulation may be numbered.' 2 Bonbright, Valuation of Property (1937) 1190.

*649 The prudent investment theory has relative merits in fixing rates for a utility which creates its service merely by its investment. The amount and quality of service rendered by the usual utility will, at least roughly, be measured by the amount of capital it puts into the enterprise. But it has no rational application where there is no such relationship between investment and capacity to serve. There is no such relationship between investment and amount of gas produced. Let us assume that Doe and Roe each produces in West Virginia for delivery to Cleveland the same quantity of natural gas per day. Doe, however, through luck or foresight or whatever it takes, gets his gas from investing $50,000 in leases and drilling. Roe drilled poorer territory, got smaller wells, and has invested $250,000. Does anybody imagine that Roe can get or ought to get for his gas five times as much as Doe because he has spent five times as much? The service one renders to society in the gas business is measured by what he gets out of the ground, not by what he puts into it, and there is little more relation between the investment and the results than in a game of poker.

Two-thirds of the gas Hope handles it buys from about 340 independent producers. It is obvious that the principle of rate-making applied to Hope's own gas cannot be applied, and has not been applied, to the bulk of the gas Hope delivers. It is not probable that the investment of any two of these producers will bear the same ratio to their investments. The gas, however, all goes to the same use, has the same utilization value and the same ultimate price.

To regulate such an enterprise by undiscriminatingly transplanting any body of rate doctrine conceived and *650 adapted to the ordinary utility business can serve the 'public interest' as the Natural Gas Act requires, if at all, only by accident. Mr. Justice Brandeis, the pioneer juristic advocate of the prudent investment theory for man-made utilities, never, so far as I am able to discover, proposed its application to a natural gas case. On the other hand, dissenting in Commonwealth of Pennsylvania v. West Virginia, he reviewed the problems of gas supply and said, 'In no other field of public service regulation is the controlling body confronted with factors so baffling as in the natural gas industry, and in none is continuous supervision and control required in so high a degree.' 262 U.S. 553, 621, 43 S.Ct. 658, 674, 67 L.Ed. 1117, 32 A.L.R. 300. If natural gas rates are intelligently to be regulated we must fit our legal principles to the economy of the industry and not try to fit the industry to our books.

As our decisions stand the Commission was justified in believing that it was required to proceed by the rate base method even as to gas in the field. For this reason the Court may not merely wash its hands of the method and rationale of rate making. The fact is that this Court, with no discussion of its fitness, simply transferred the rate base method to the natural gas industry. It happened in Newark Natural Gas & Fuel Co. v. City of Newark, Ohio, 1917, 242 U.S. 405, 37 S.Ct. 156, 157, 61 L.Ed. 393, Ann.Cas.1917B, 1025, in which the company wanted 25 cents per m.c.f., and under the Fourteenth Amendment challenged the reduction to 18 cents by ordinance. This Court sustained the reduction because the court below 'gave careful consideration to the questions of the value of the property * * * at the time of the inquiry,' and whether the rate 'would be sufficient to provide a fair return on the value of the property.' The Court said this method was 'based upon principles thoroughly established by repeated secisions of this court,' citing many cases, not one of which involved natural gas or a comparable wasting natural resource. Then came issues as to state power to *651 regulate as affected by the commerce clause. Public Utilities Commission v. Landon, 1919, 249 U.S. 236, 39 S.Ct. 268, 63 L.Ed. 577; Pennsylvania Gas Co. v. Public Service Commission, 1920, 252 U.S. 23, 40 S.Ct. 279, 64 L.Ed. 434. These questions settled, the Court again was called upon in natural gas cases to consider state rate-making claimed to be invalid under the Fourteenth Amendment. United Fuel Gas Co. v. Railroad Commission of Kentucky, 1929, 278 U.S. 300, 49 S.Ct. 150, 73 L.Ed. 390; United Fuel Gas Company v. Public Service Commission of West Virginia, 1929, 278 U.S. 322, 49 S.Ct. 157, 73 L.Ed. 402. Then, as now, the differences were 'due **311 chiefly to the difference in value ascribed by each to the gas rights and leaseholds.' 278 U.S. 300, 311, 49 S.Ct. 150, 153, 73 L.Ed. 390. No one seems to have questioned that the rate base method must be pursued and the controversy was at what rate base must be used. Later the 'value' of gas in the field was questioned in determining the amount a regulated company should be allowed to pay an affiliate therefor--a state determination also reviewed under the Fourteenth Amendment. Dayton Power & Light Co. v. Public Utilities Commission of Ohio, 1934, 292 U.S. 290, 54 S.Ct. 647, 78 L.Ed. 1267; Columbus Gas & Fuel Co. v. Public Utilities Commission of Ohio, 1934, 292 U.S. 398, 54 S.Ct. 763, 78 L.Ed. 1327, 91 A.L.R. 1403. In both cases, one of which sustained, and one of which struck down a fixed rate the Court assumed the rate base method, as the legal way of testingreasonableness of natural gas prices fixed by public authority, without examining its real relevancy to the inquiry.

Under the weight of such precedents we cannot expect the Commission to initiate economically intelligent methods of fixing gas prices. But the Court now faces a new plan of federal regulation based on the power to fix the price at which gas shall be allowed to move in interstate commerce. I should now consider whether these rules devised under the Fourteenth Amendment are the exclusive tests of a just and reasonable rate under the federal statute, inviting reargument directed to that point *652 if necessary. As I see it now I would be prepared to hold that these rules do not apply to a natural gas case arising under the Natural Gas Act.

Such a holding would leave the Commission to fix the price of gas in the field as one would fix maximum prices of oil or milk or coal, or any other commodity. Such a price is not calculated to produce a fair return on the synthetic value of a rate base of any individual producer, and would not undertake to assure a fair return to any producer. The emphasis would shift from the producer to the product, which would be regulated with an eye to average or typical producing conditions in the field.

Such a price fixing process on economic lines would offer little temptation to the judiciary to become back seat drivers of the price fixing machine. The unfortunate effect of judicial intervention in this field is to divert the attention of those engaged in the process from what is economically wise to what is legally permissible. It is probable that price reductions would reach economically unwise and self-defeating limits before they would reach constitutional ones. Any constitutional problems growing out of price fixing are quite different than those that have heretofore been considered to inhere in rate making. A producer would have difficulty showing the invalidity of such a fixed price so long as he voluntarily continued to sell his product in interstate commerce. Should he withdraw and other authority be invoked to compel him to part with his property, a different problem would be presented.

Allowance in a rate to compensate for gas removed from gas lands, whether fixed as of point of production or as of point of delivery, probably best can be measured by a functional test applied to the whole industry. For good or ill we depend upon private enterprise to exploit these natural resources for public consumption. The function which an allowance for gas in the field should perform *653 for society in such circumstances is to be enough and no more than enough to induce private enterprise completely and efficiently to utilize gas resources, to acquire for public service any available gas or gas rights and to deliver gas at a rate and for uses which will be in the future as well as in the present public interest.

The Court fears that 'if we are now to tell the Commission to fix the rates so as to discourage particular uses, we would indeed be injecting into a rate case a 'novel' doctrine * * *.' With due deference I suggest that there is nothing novel in the idea that any change in price of a service or commodity reacts to encourage or discourage its use. The question is not whether such consequences will or will not follow; the question is whether effects must be suffered blindly or may be intelligently selected, whether price control shall have targets at which it deliberately aims or shall be handled like a gun in the hands of one who does not know it is loaded.

We should recognize 'price' for what it is--a tool, a means, an expedient. In public **312 hands it has much the same economic effects as in private hands. Hope knew that a concession in industrial price would tend to build up its volume of sales. It used price as an expedient to that end. The Commission makes another cut in that same price but the Court thinks we should ignore the effect that it will have on exhaustion of supply. The fact is that in natural gas regulation price must be used to reconcile the private property right society has permitted to vest in an important natural resource with the claims of society upon it--price must draw a balance between wealth and welfare.

To carry this into techniques of inquiry is the task of the Commissioner rather than of the judge, and it certainly is no task to be solved by mere bookkeeping but requires the best economic talent available. There would doubtless be inquiry into the price gas is bringing in the *654 field, how far that price is established by arms' length bargaining and how far it may be influenced by agreements in restraint of trade or monopolistic influences. What must Hope really pay to get and to replace gas it delivers under this order? If it should get more or less than that for its own, how much and why? How far are such prices influenced by pipe line access to markets and if the consumers pay returns on the pipe lines how far should the increment they cause go to gas producers? East Ohio is itself a producer in Ohio. [FN44] What do Ohio authorities require Ohio consumers to pay for gas in the field? Perhaps these are reasons why the Federal Government should put West Virginia gas at lower or at higher rates. If so what are they? Should East Ohio be required to exploit its half million acres of unoperated reserve in Ohio before West Virginia resources shall be supplied on a devalued basis of which that State complains and for which she threatens measures of self keep? What is gas worth in terms of other fuels it displaces?

FN44 East Ohio itself owns natural gas rights in 550,600 acres, 518,526 of which are reserved and 32,074 operated, by 375 wells. Moody's Manual of Public Utilities (1943) 5.

A price cannot be fixed without considering its effect on the production of gas. Is it an incentive to continue to exploit vast unoperated reserves? Is it conducive to deep drilling tests the result of which we may know only after trial? Will it induce bringing gas from afar to supplement or even to substitute for Appalachian gas? [FN45] Can it be had from distant fields as cheap or cheaper? If so, that competitive potentiality is certainly a relevant consideration. Wise regulation must also consider, as a private buyer would, what alternatives the producer has *655 if the price is not acceptable. Hope has intrastate business and domestic and industrial customers. What can it do by way of diverting its supply to intrastate sales? What can it do by way of disposing of its operated or reserve acreage to industrial concerns or other buyers? What can West Virginia do by way of conservation laws, severance or other taxation, if the regulated rate offends? It must be borne in mind that while West Virginia was prohibited from giving her own inhabitants a priority that discriminated against interstate commerce, we have never yet held that a good faith conservation act, applicable to her own, as well as to others, is not valid. In considering alternatives, it must be noted that federal regulation is very incomplete, expressly excluding regulation of 'production or gathering of natural gas,' and that the only present way to get the gas seems to be to call it forth by price inducements. It is plain that there is a downward economic limit on a safe and wise price.

FN45 Hope has asked a certificate of convenience and necessity to lay 1140 miles of 22-inch pipeline from Hugoton gas fields in southwest Kansas to West Virginia to carry 285 million cu. ft. of natural gas per day. The cost was estimated at $51,000,000. Moody's Manual of Public Utilities (1943) 1760.

But there is nothing in the law which compels a commission to fix a price at that 'value' which a company might give to its product by taking advantage of scarcity, or monopoly of supply. The very purpose of fixing maximum prices is to take away from the seller his opportunity to get all that otherwise the market would award him for his goods. This is a constitutional use of the power to fix maximum prices, Block **313 v. Hirsh, 256 U.S. 135, 41 S.Ct. 458, 65 L.Ed. 865, 16 A.L.R. 165; Marcus Brown Holding Co. v. Feldman, 256 U.S. 170, 41 S.Ct. 465, 65 L.Ed. 877; International Harvester Co. v. Kentucky, 234 U.S. 216, 34 S.Ct. 853, 58 L.Ed. 1284; Highland v. Russell Car & Snow Plow Co., 279 U.S. 253, 49 S.Ct. 314, 73

L.Ed. 688, just as the fixing of minimum prices of goods in interstate commerce is constitutional although it takes away from the buyer the advantage in bargaining which market conditions would give him. United States v. Darby, 312 U.S. 100, 657, 61 S.Ct. 451, 85 L.Ed. 609, 132 A.L.R. 1430; Mulford v. Smith, 307 U.S. 38, 59 S.Ct. 648, 83 L.Ed. 1092; United States v. Rock Royal Co-operative, Inc., 307 U.S. 533, 59 S.Ct. 993, 83 L.Ed. 1446; Sunshine Anthracite Coal Co. v. Adkins, 310 U.S. 381, 60 S.Ct. 907, 84 L.Ed. 1263. The Commission has power to fix ***656** a price that will be both maximum and minimum and it has the incidental right, and I think the duty, to choose the economic consequences it will promote or retard in production and also more importantly in consumption, to which I now turn.

If we assume that the reduction in company revenues is warranted we then come to the question of translating the allowed return into rates for consumers or classes of consumers. Here the Commission fixed a single rate for all gas delivered irrespective of its use despite the fact that Hope has established what amounts to two rates--a high one for domestic use and a lower one for industrial contracts. [FN46] The Commission can fix two prices for interstate gas as readily as one--a price for resale to domestic users and another for resale to industrial users. This is the pattern Hope itself has established in the very contracts over which the Commission is expressly given jurisdiction. Certainly the Act is broad enough to permit two prices to be fixed instead of one, if the concept of the 'public interest' is not unduly narrowed.

FN46 I find little information as to the rates for industries in the record and none at all in such usual sources as Moody's Manual.

The Commission's concept of the public interest in natural gas cases which is carried today into the Court's opinion was first announced in the opinion of the minority in the Pipeline case. It enumerated only two 'phases of thepublic interest: (1) the investor interest; (2) the consumer interest,' which it emphasized to the exclusion of all others. 315 U.S. 575, 606, 62 S.Ct. 736, 753, 86 L.Ed. 1037. This will do well enough in dealing with railroads or utilities supplying manufactured gas, electric, power, a communications service or transportation, where utilization of facilities does not impair their future usefulness. Limitation of supply, however, brings into a natural gas case another phase of the public interest that to my mind overrides both the owner ***657** and the consumer of that interest. Both producers and industrial consumers have served their immediate private interests at the expense of the long-range public interest. The public interest, of course, requires stopping unjust enrichment of the owner. But it also requires stopping unjust impoverishment of future generations. The public interest in the use by Hope's half million domestic consumers is quite a different one from the public interest in use by a baker's dozen of industries.

Prudent price fixing it seems to me must at the very threshold determine whether any part of an allowed return shall be permitted to be realized from sales of gas for resale for industrial use. Such use does tend to level out daily and seasonal peaks of domestic demand and to some extent permits a lower charge for domestic service. But is that a wise way of making gas cheaper when, in comparison with any substitute, gas is already a cheap fuel? The interstate sales contracts provide that at times when demand is so great that there is not enough gas to go around domestic users shall first be served. Should the operation of this preference await the day of actual shortage? Since the propriety of a preference seems conceded, should it not operate to prevent the coming of a shortage as well as to mitigate its effects? Should industrial use jeopardize tomorrow's service to householders any more than today's? If, however, it is decided to cheapen domestic use by resort to industrial sales, should they be limited to the few uses ****314** for which gas has special values or extend also to those who use it only because it is cheaper than competitive fuels? [FN47] And how much cheaper should industrial ***658** gas sell than domestic gas, and how much advantage should it have over competitive fuels? If industrial gas is to contribute at all to lowering domestic rates, should it not be made to contribute the very maximum of which it is capable, that is, should not its price be the highest at which the desired volume of sales can be realized?

FN47 The Federal Power Commission has touched upon the problem of conservation in connection with an application for a certificate permitting construction of a 1500-mile pipeline from southern Texas to New York City and says: 'The Natural Gas Act as presently drafted does not enable the Commission to treat fully the serious implications

> of such a problem. The question should be raised as to whether the proposed use of natural gas would not result in displacing a less valuable fuel and create hardships in the industry already supplying the market, while at the same time rapidly depleting the country's natural-gas reserves. Although, for a period of perhaps 20 years, the natural gas could be so priced as to appear to offer an apparent saving in fuel costs, this would mean simply that social costs which must eventually be paid had been ignored.
> 'Careful study of the entire problem may lead to the conclusion that use of natural gas should be restricted by functions rather than by areas. Thus, it is especially adapted to space and water heating in urban homes and other buildings and to the various industrial heat processes which require concentration of heat, flexibility of control, and uniformity of results. Industrial uses to which it appears particularly adapted include the treating and annealing of metals, the operation of kilns in the ceramic, cement, and lime industries, the manufacture of glass in its various forms, and use as a raw material in the chemical industry. General use of natural gas under boilers for the production of steam is, however, under most circumstances of very questionable social economy.' Twentieth Annual Report of the Federal Power Commission (1940) 79.

If I were to answer I should say that the household rate should be the lowest that can be fixed under commercial conditions that will conserve the supply for that use. The lowest probable rate for that purpose is not likely to speed exhaustion much, for it still will be high enough to induce economy, and use for that purpose has more nearly reached the saturation point. On the other hand the demand for industrial gas at present rates already appears to be increasing. To lower further the industrial rate is merely further to subsidize industrial consumption and speed depletion. The impact of the flat reduction ***659** of rates ordered here admittedly will be to increase the industrial advantages of gas over competing fuels and to increase its use. I think this is not, and there is no finding by the Commission that it is, in the public interest.

There is no justification in this record for the present discrimination against domestic users of gas in favor of industrial users. It is one of the evils against which the Natural Gas Act was aimed by Congress and one of the evils complained of here by Cleveland and Akron. If Hope's revenues should be cut by some $3,600,000 the whole reduction is owing to domestic users. If it be considered wise to raise part of Hope's revenues by industrial purpose sales, the utmost possible revenue should be raised from the least consumption of gas. If competitive relationships to other fuels will permit, the industrial price should be substantially advanced, not for the benefit of the Company, but the increased revenues from the advance should be applied to reduce domestic rates. For in my opinion the 'public interest' requires that the great volume of gas now being put to uneconomic industrial use should either be saved for its more important future domestic use or the present domestic user should have the full benefit of its exchange value in reducing his present rates.

Of course the Commission's power directly to regulate does not extend to the fixing of rates at which the local company shall sell to consumers. Nor is such power required to accomplish the purpose. As already pointed out, the very contract the Commission is altering classifies the gas according to the purposes for which it is to be resold and provides differentials between the two classifications. It would only be necessary for the Commission to order ****315** that all gas supplied under paragraph (a) of Hope's contract with the East Ohio Company shall be ***660** at a stated price fixed to give to domestic service the entire reduction herein and any further reductions that may prove possible by increasing industrial rates. It might further provide that gas delivered under paragraph (b) of the contract for industrial purposes to those industrial customers Hope has approved in writing shall be at such other figure as might be found consistent with the public interest as herein defined. It is too late in the day to contend that the authority of a regulatory commission does not extend to a consideration of public interests which it may not directly regulate and a conditioning of its orders for their protection. Interstate Commerce Commission v. Railway Labor Executives Ass'n, 315 U.S. 373, 62 S.Ct. 717, 86 L.Ed. 904; United States v. Lowden, 308 U.S. 225, 60 S.Ct. 248, 84 L.Ed. 208
.

Whether the Commission will assert its apparently broad statutory authorization over prices and discriminations is, of course, its own affair, not ours. It is entitled to its own notion of the 'public interest' and its judgment of policy must prevail. However, where there is ground for thinking that views of this Court may have constrained the Commission to accept the rate-base method of decision and a particular single formula as 'all important' for a rate base, it is appropriate to make clear the reasons why I, at least, would not be so understood. The Commission is free to face up realistically to the nature and peculiarity of the resources in its control, to foster their duration in fixing price, and to consider future interests in addition to those of investors and present consumers. If we return this case it may accept or decline the proffered freedom. This problem presents the Commission an unprecedented opportunity if it will boldly make sound economic considerations, instead of legal and accounting theories, the foundation of federal policy. I would return the case to the Commission and thereby be clearly quit of what now may appear to be some responsibility for perpetrating a shortsighted pattern of natural gas regulation.

END OF DOCUMENT

In re: Investigation of Fuel Adjustment Clauses of Electric Utilities

DOCKET NO. 830001-EU; ORDER NO. 12645

Florida Public Service Commission

1983 Fla. PUC LEXIS 163

83 FPSC 12

November 3, 1983; Partial Publication Only

CORE TERMS: fuel, staff, true-up, inventory, prudence, oil, coal, guidelines, procurement, generic, nonrecoverable, transportation, long-term, monthly, supplier, plant, expenditure, recommends, rate case, audit, tank, confidential, retroactive, expensed, reporting, subject to refund, ratepayer, normally, invoice, fuel oil

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[*1]

The following Commissioners participated in the disposition of this matter: Gerald L. Gunter, Chairman; Joseph P. Cresse, Susan W. Leisner, John R. Marks, III, Katie Nichols

Pursuant to notice, a public hearing on the above matter was held before the Florida Public Service Commission on June 1, 2, 3 and 24, 1983, in Tallahassee, Florida.

ORDER CONCERNING GENERIC ISSUES

BY THE COMMISSION:

Background

During the June, 1983, true-up hearings certain "generic" issues were raised for consideration. The time alotted for hearing was insufficient and a second hearing on these issues was

Issues Presented

The following issues were raised in this proceeding: n1

1. Whether the Commission should require that all company inventory policies be supported and justified to the Commission's satisfaction by a comprehensive and systematic inventory study?

2. Whether or not a generic inventory policy should be adopted by the Commission on a standby basis and be applied by the Commission for ratemaking purposes in cases where a utility fails the justify an alternative inventory [*3] policy?

3. Whether fuel oil that cannot be burned for generation should be maintained in inventory and, if not, how should it be taken off the books.

4. Whether base coals that are nonrecoverable for operating purposes should remain a component of coal inventory?

5. When should a transfer of nonrecoverable base coal to Account 312 be effectuated and what ratemaking treatment should be used to recognize the transfer?

6. Should the Commission adopt specific standards for new long-term fuel contracts?

7. What, if any, should be the Commission standards for new long-term fuel contracts?

8. Should compliance with Commission standards be a prerequisite to recovery of new long-term fuel contract costs?

9. Whether affiliates and subsidiaries of utilities or utility holding companies engaged in procurement of fuel or services for a utility should be required to conduct such activities under the same standard as a utility would be required to meet had it purchased the same fuel or service.

10. Whether the Commission should require that all ulilities file a monthly report detailing all purchases of fuel, transportation and/or fuel handling services as proposed by staff.

11. [*4] Whether the proposed monthly reporting forms should be accorded specified confidential treatment.

12. Whether the Commission should change the operation of the clause to place a jurisdictional limitation on the review of prudence rather than treat prudence at the end of each six month period and explicitly make revenues subject to refund.

13. What is the Commission's current power to review expenditures during prior true-up periods?

14. What is the proper legal procedure for the Commission to adopt a conservation reward/penalty methodology and to grant a reward or impose a penalty?

15. Would the Commission deny due process if it were to grant conservation rewards or impose conservation penalties during the June true-up hearings.

16. Whether costs to be recovered by FPL should be calculated using the original or the current version of the rule. (This issue is being preserved pending appeal by Public Counsel)

17. Are net savings to be calculated on a monthly or six month basis? (This issue is being preserved pending a petition for reconsideration by Public Counsel)?

n1 These issues were commingled with other issues in the Prehearing Order (Order No. 11999) and are not numbered the same as in that order. [*5]

Of these seventeen issues, the first twelve involve questions of fact and policy, while the last five involve questions of law.

Findings of Fact

Fuel Inventory Policies (Issues 1 and 2)

In recent rate cases we have reviewed the inventory policies of each of the four large generating utilities as part of our analysis of working capital requirements. Each utility's inventory policy effects the level of fuel held in inventory, which effects in turn the utility's working capital requirements under the balance sheet approach. In each case we encountered difficulties in analyzing each company's policy and in Order No. 11498 and we found that Gulf Power Company's inventory policy was not justified.

The staff has proposed that we require each utility to support and justify its inventory policy by a comprehensive and systematic study. The staff envisions a proceeding separate from a rate case wherein we would review the results of each utility's study and rule on the reasonableness of its inventory policy. FPL and FPC agree that further study of inventory policies is appropriate. TECO and Gulf, however, maintain that any review of inventory policy should fall within a rate [*6] case.

We agree that further study of fuel inventory policies is needed. However, we will not order special studies to be performed for approval separate from rate cases. Instead, we expect each utility to fully document its inventory policy in its next rate case.

The staff has proposed a "generic" fuel inventory policy to be applied in a rate case if a utility fails to fully justify its own policy. The staff's proposed policy is as follows:

1. Heavy Oil - 45 days projected burn plus normally unavailable oil.

2. Light Oil - 30 days burn at the lighest average monthly rate during the most current and five year period plus normally unavailable oil.

3. Coal - 90 days projected burn plus base coal volumes.

All other parties objected to the adoption of a generic policy. Each utility proposed that we rely on the record of each case to identify the proper inventory level if the utility's policy is not justified. Public Counsel also preferred a case-by-case analysis.

If a utility fails to justify its own inventory policy in a rate proceeding the Commission should have a generic policy available in order to evaluate the reasonableness of the dollar amount of inventory requested [*7] in working capital. The generic policy will not be used automatically in the event that the utility's policy is not justified, rather, we will strive to determine an optimum policy from the evidence presented in the rate case. If we cannot determine an optimum policy from the record, we would have the option of using the generic policy, or the generic policy modified by evidence of record. In such a case, the utility would be free to demonstrate that the generic policy would not provide acceptable inventory levels for its operation or the utility could build an alternative inventory based on the generic policy with modification to meet its operational requirements.

The generic policy recommended by staff is not represented to be the most optimal policy. Staff witness Foxx stated that it is not possible to create one generic inventory policy which is equally fair to all utilities. This is due to the differences in the system generating characteristics of the utilities.However, staff's proposed generic policy was shown to be reasonable by Mr. Foxx's testimony, which showed utility inventory levels throughout the nation in relation to burn levels.Although the levels specified [*8] by staff's generic policy are not equal to the national averages, we find the proposed generic policy to be reasonable. We therefore adopt the staff's proposed generic inventory policy for the purposes set forth above.

Nonrecoverable Oil (Issue 3)

Each utility that maintains an oil inventory holds a certain amount of "nonrecoverable oil" in inventory. The point of discharge in an oil storage tank is above the bottom, allowing water and sediment to fall below the level from which oil is pumped. Nonrecoverable oil represents the volume of oil below the discharge pipes at the bottom of oil storage tanks. This nonrecoverable oil typically contains a certain amount of noncombustible oil which must be processed before use as fuel oil. It also contains a certain amount of combustible oil, but this oil cannot be removed for use without special equipment.

The staff had originally proposed that each company estimate the amount of combustible oil when filling its tanks and expense that oil at the then current price of oil.The staff has modified that approach and now proposes that the value of all nonrecoverable oil below the discharge value be expensed at average unit cost at the [*9] next fuel adjustment true-up and thereafter expensed after each tank cleaning and refill at the then prevailing cost. FPL and TECO propose to retain all nonrecoverable oil in inventory and expense it out at tank cleaning. Public Counsel proposes that all nonrecoverable oil be removed from inventory and be amortized over the expected period between tank cleanings.

We find that the value of all heavy and light oil which normally resides in the storage tanks below the normal operating intake pipe and is normally unavailable should be expensed at the end of the next fuel adjustment true-up hearing. This oil should be expensed at the average unit cost of oil residing in the tanks on the day expensed. If a tank is emptied and refilled, the nonrecoverable oil should be expensed when the tank is refilled.

In recent rate cases nonavailable oil has been included in working capital for utilities and those utilities' rates currently allow a recovery on the investment in that nonrecoverable oil. If that oil is expensed off the utility should no longer receive a return on it. Therefore, when each utility calculates the expense of its nonrecoverable oil it should likewise calculate the revenue [*10] effect of removing that oil from rate base. The adjustment to the fuel adjustment clause to expense the oil would reflect the offset of the rate base reduction. After the nonrecoverable oil has been expensed through the fuel adjustment clause the clause would thereafter reflect an adjustment to recognize the rate base reduction until the utility's next rate case.

Base Coal (Issues 4 and 5)

Each coal pile maintained by a utility contains a certain amount of "base coal" used to support the pile. This coal is normally low grade coal and is not expected to be burned as part of normal utility operations. Except for TECO, this coal is maintained in inventory in spite of the fact that it is not expected to be burned. All parties (except FPL, which uses no coal) have agreed that base coal should be capitalized in Account 312 and depreciated over the life of the plant. TECO currently accounts for its base coal in this manner. We find that the proper treatment of investment in base coal is to capitalize it in account 312 as proposed. Normally, plant items such as base coal would be depreciated over the life of the plant to which it relates. However, we find that a [*11] shorter period of five years is more appropriate for the depreciation of base coal.

The staff proposes that we require the transfer of base coal to account 312 in the next true-up and allow recovery of depreciation through the fuel adjustment until each company's next rate case. FPC, Gulf and Public Counsel propose that no change occur until the next rate case. We agree with FPC, Gulf and Public Counsel. There is no need for extraordinary measures in correcting the accounting for base coal. A delay until each company's next rate case is appropriate.

Commission Standards for New Long Term Fuel Contracts (Issues 6-9)

The staff had proposed that we adopt specific detailed guidelines for new long-term contracts. The original staff proposal envisioned a set of specific guidelines that a utility should meet in obtaining new contracts. These guidelines would cover solicitation and negotiation of new contracts. FPL, FPC, TECO and GULF all opposed the adoption of detailed standards governing fuel contracts. Each expressed a concern that detailed standards would not be flexible enough to encompass all reasonable procurement decisions. In response to the positions of the other [*12] parties, the staff modified its proposal to involve a set of broad guidelines to be adopted by the Commission. More detailed guidelines would be approved for use by the staff, but would not be adopted for direct application by the Commission to each utility. We agree that we should adopt broad guidelines, as proposed by staff. Utilities will then be placed on notice as to the basic procurement standards we intend to apply.

We next must determine what broad guidelines should be adopted. The staff, in its final recommendation, broadened the standards that it has originally proposed. We view these revised standards as appropriate and adopt them as our central policy on new long term fuel contracts. The approved guidelines are set forth on Appendix A of this Order. These broad guidelines will be augmented by more specific guidelines that we will approve for internal staff use.

The staff proposed that compliance with the broadened guidelines be a prerequisite to cost recovery through the fuel adjustment. Again, the four utilities opposed the application of preset criteria as a condition for cost recovery. We find that compliance with our central guidelines should not be a prerequisite [*13] to fuel cost recovery. However, should a utility fail to comply with the our central guidelines it would have a special burden to show that non-compliance was justified.In addition, staff's detailed guidelines would be considered in any fuel adjustment proceeding where staff sought to apply them to utility's purchases. We would then formally determine whether compliance with staff's guidelines is also appropriate.

The staff has also proposed that our guidelines be applied to affiliates and subsidiaries of utilties or utility holding companies engaged in the procurement of fuel or services for a utility. Public Counsel agrees with the staff, stating that a utility should show that its affiliated companies are the most cost-effective providers of fuel and services.

We agree with the staff and Public Counsel. Given the broad standards that we have adopted, we consider it reasonable to expect purchases by affiliated companies for a utility to meet the same standards as purchases by the utility itself.

Monthly Fuel Reports (issues 10 and 11)

The staff has proposed that we reguire all utilities to file a monthly report detailing all purchases of fuel, transportation [*14] and fuel handling services and has recommended the form and content of the report.

FPL is willing to provide the information but suggests that guality adjustments need not be included because they are not made on an invoice by invoice basis. FPC has no objection to providing the information if we determine that the information cannot be adequately reviewed by our monthly field audits. TECO states that the requested information is being compiled and submitted at the audit staff's request. Gulf has no objection to filing the information, as long as it is done concurrently with the filing of FERC's Form 423. All of the utilities stressed the need to protect the confidentiality of information filed on the forms. Public Counsel supports the staff's proposed reporting forms.

We agree with the staff and Public Counsel that the information requested by the proposed forms is a valuable and useful tool in analyzing the prudence of utility fuel purchases and related transactions.We find that the information requested by staff should be provided on a monthly basis, to be filed with the Commission Clerk within 30 days after the end of the reporting month unless the utility demonstrates [*15] a need for an extension. The monthly reporting forms are to be completed on a plant specific and supplies specific basis.

The first form proposed by staff is the Coal Receipt Analysis form. One form would be completed for each plant. This form includes information on the delivered price and quality of coal received in each month from each supplier for each plant. The point of receipt is usually at a river loading facility or rail tipple where the coal is loaded into river barges or rail cars. Separate invoices from a given supplier may be combined into one entry if the coal was purchased under the same contract and invoiced at the same price. Any retroactive or quality adjustments known at the time of filing should be included in the appropriate columns. Retroactive and quality adjustments for coal from previous reporting periods would be attached as an addendum to this form which already documents the time period involved, the specific previously reported entries to revise, the revision (in total dollars and in dollars per ton) to each previously reported entry, and the nature or cause of the revision. If quality reports are not available at the time of filing, they would [*16] be updated in a similar fashion.

The second form proposed by staff is the Fuel Oil Receipt Analysis which reflects the invoice information of oil delivered to generating facilities or terminals. One form would be completed for each plant or terminal. One entry would be made for each supplier for each grade of fuel. Residual fuel oil of different sulfur grades must be reported separately.Multiple invoices may be reported as one entry so long as the above criteria are met. In the event multiple invoices are reported as one entry, the weighted average price would be reported. Retroactive price changes and quality adjustments would be reported as an attachment which documents the previously reported entry to revise, the nature of the revision, ad the revision in total dollars and dollars per barrel.

The third form proposed by staff is the Coal Rail Transportation Cost Analysis form which documents the rail transportation costs for coal shipped from each supplier to each plant. One form would be completed for each plant. Retroactive adjustments to this form would be reported in a similar manner as above. The entries would be on a date shipped basis.

The fourth form [*17] proposed by staff is the Coal Waterborne Transportation Cost Analysis form which documents the costs of the various components in the waterborne coal transportation network. One form would be completed for each plant. The entries would be on a date shipped basis. Retroactive adjustments would be made in a similar manner as the first two forms.

The staff proposed that retroactive revisions or adjustments to transactions previously reported would be included in the form of an addendum which would be specific enough in nature to enable the staff to revise the original filing of the form. The forms would be required to be filed in a timely manner. We find that the content of the forms proposed by the staff is reasonable and except for reformatting to isolate confidential material (see below), we approve the format of the forms as well.

Next, we must determine whether any portion of the monthly reports should be accorded confidential treatment. We agree that certain portions of the monthly reports will contain proprietary confidential business information. However, many portions of the monthly reports will not. The proprietary information for all types of fuel is transportation. [*18] Any breakout of transportation costs must be treated confidentially. In addition, F.O.B. mine prices for coal is proprietary in nature as is the price of fuel oil. Disclosure of separate transportation or F.O.B. mine prices would have a direct impact on a utility's future fuel and transportation contracts by informing potential bidders of current prices paid for services. Disclosure of fuel oil prices would have an indirect effect upon bidding suppliers. Suppliers would be reluctant to provide significant price concessions to an individual utility if prices were disclosed because other purchasers would seek similar concessions.

As proposed, staff's reporting forms commingle confidential and non confidential information.By segregating transportation and base fuel price information to separate parts of the form, confidential material can be separate from non confidential material. Revised forms to accomplish this purpose are shown on Appendix B of this order. Each utility participating in the fuel adjustment clause should file these forms monthly. Forms 423-1 and 423-2 would be public record. Forms 423-1(a), 423-2(a) and 423-2(b) would be confidential and exempt from public [*19] access.

Change in the Operation of the Fuel Adjustment Clause (Issue 12)

The staff has proposed that we change the operation of the fuel adjustment clause so as to clarify the nature of our jurisdiction over amounts passed through the clause. As proposed by the staff, this change is to be prospective in nature. We will discuss our jurisdiction over amounts previously passed through the clause as currently structured at a later point in this order.

As currently structured, the clause provides that utilities are to justify their expenditures at a true-up hearing immediately following each six month period. The staff proposed that we change the clause so that, instead of requiring proof of prudence at the true-up immediately following a six month period, we simply limit our jurisdiction over all transactions passed through the fuel clause for a period of three years from the date we approve the amount at the true-up hearing. Under the staff proposal, if before the end of the three year period the Commission indicates a need for further review for any specific transaction, the Commission would explicitly retain jurisdiction over amounts passed through the fuel clause [*20] relating to that transaction. The Commission may then continue jurisdiction over those amounts until a final order is issued. Once a specific transaction which has been explicitly set aside for review has been ruled upon by the Commission, the Commission would lose jurisdiction over that transaction for the period reviewed by the Commission. The above jurisdictional limitations would not apply for transactions when fraud or other such irregularities can be shown.

Each of the parties responded to the staff proposal in different ways.

FPL proposed that unless a utility has fraudulently or through error provided incorrect or incomplete information, or the amounts paid have changed due to litigation or dispute, Commission jurisdiction should cease after one year from the date of the transaction, unless the Commission identifies a problem and retains jurisdiction over a specific transaction.

FPC agreed that the current six month may not be adequate for proper review, but stated that the Commission may not lawfully extend its jurisdiction beyond a reasonably determined review period in order to provide a catch-all for the possibility that it may have overlooked something.

According [*21] to TECO, the Commission should first enter a provisional true-up order within sixty days of the end of the six month period under review. The Commission should then provide for a further true-up followed by a final order after a reasonable length of time. TECO submits that such final order should be entered within one year of the end of the six month period under review.

Gulf's position is that unless the Commission specifically reserves jurisdiction to allow further study of expenditures, jurisdiction lapses on approval of the true-up. The exception to this limitation of jurisdiction are instances of fraud or misrepresentations.

Public Counsel supported staff's approach.

The current structure of the clause creates two problems. First, although under the current clause prudence is to be reviewed at the true-up hearing after each six-month period, varying positions have been stated as to our jurisdiction to look at the prudence of transactions after a true-up order has been issued. Although we have now resolved the issue, a second problem was caused by our prior practice of identifying questionable transactions and placing the associated revenues subject to refund. In recent [*22] periods, utilities have preferred to stipulate to continuing jurisdiction rather than have their revenues explicitly made subject to refund. According to the utilities, making revenues subject to refund creates a financial uncertainty about those revenues, adversely affecting a utility's financial position.

The staff's proposal achieves two goals. It resolves all uncertainty as to our jurisdiction over amounts passed through the clause by explicitly retaining the power to review prior transactions. Thus, the complex factual and legal problem engendered by the structure of the current clause is avoided. It also obviates any desire or need to explicitly declare revenues subject to refund, as jurisdiction continues without question. The financial uncertainty that arises when revenues are declared subject to refund is avoided. We therefore agree with the staff's proposal that the operation of the clause should be changed.

Staff's proposal to place a time limit on our jurisdiction, however, is inappropriate. We see no justification in limiting our ability to scrutinize past transactions. We fully intend to review a utility's procurement decisions solely in light of the [*23] facts known or knowable at the time a decision was made. The appropriate limitation of our jurisdiction is based on whatever statute of limitations or other jurisdictional limitations applies to our actions as a matter of law.

Under the new structure, rather than explicitly considering prudence at the end of each six month period, we will consider only the question of comparing projected to actual results.Questions of prudence require careful and often prolonged study. When a question arises as to the prudence of a utility's expenditures, proper time should be taken to fully analyze the question and resolve the matter on all of the facts available. Often, a full staff analysis should be made before the matter is formally included within the fuel adjustment proceeding.

From now on, each utility will be required at true-up only to demonstrate how the amounts actually expended for fuel and purchased power compare with the amounts projected for the prior six month period. The true-up approved at that time will reflect the reconciliation of projected to actual results (with the appropriate calculation of interest, other true-up amounts, etc.). Although the burden of proving the [*24] prudence of its actions will remain with the utility, the question of prudence will arise only as facts regarding fuel procurement justify scrutiny. Hopefully, we will be presented with complete analyses of procurement decisions in a timely manner.

At the true-up hearing that follows a six month period a utility will still be free to present whatever evidence of prudence it chooses to provide. We note that certain utilities have periodically presented broad statements as to the prudence of their fuel procurement activities.Such prsentations are not inappropriate, but they hardly elucidate the subject matter. Fuel procurement is an exceedingly complex matter and a determination of the prudence of procurement decisions requires a complex analysis.

While a utility may feel satisfied that it has properly met its burden by such a presentation, we expect the quality and quantity of evidence to be presented in support of the prudence of fuel procurement decisions to match the complexity of the subject matter. We will therefore accept any relevant proof a utility chooses to present a true-up, but we will not adjudicate the question of prudence, nor consider ourselves bound to do so until [*25] all relevant facts are analyzed an placed before us. We will be free to revisit any transaction until we explicitly determine the matter to be fully and finally adjudicated.

Although this order is being issued after the true-up order for the October, 1982 - March 1983 period, the restructuring of the clause is effective as of that true-up hearing. Except for the delay engendered by an extended hearing on the generic issues, we would have decided this issue in conjunction with the final true-up decision for that period. Therefore, all fuel transactions, beginning October 1, 1982, are subject to the newly structured clause and Order No. 12172, the true-up order for the October, 1982 - March, 1983 period is the first true-up order under the new structure.

Future Rulemaking

Having resolved the above policy issues within an adjudicatory framework, we consider it appropriate to move toward rulemaking and codify our policy. The staff is directed to begin drafting rules to encompass the policy decisions made in this order.

Conclusions of Law

Review of Prior True-up Periods (Issue 13)

Periodically, we find it necessary to review the prudence of certain utility [*26] fuel procurement actions. Often the transactions in question extend into prior six-month periods. From time to time questions have arisen as to our authority to review transactions in prior true-up periods. We find it appropriate to fully resolve the issue at this time.

According to the staff, absent an allegation of prudence, evidence of record thereon and an order making a finding of prudence, the Commission may review expenditures made during prior true-up periods. According to staff, however, where a particular transaction has been called into question by the Commission, evidence in support of its reasonableness has been presented by the utility, and the expense has not been disallowed, the Commission should consider the prudence of that transaction to have been ruled on, even if the order did not make an explicit finding of prudence. In addition, the staff asserts that the nature of the six-month clause and the manner in which costs flow through the clause shows that a true-up order is not truly final as to prudence.

FPL, FPC, Gulf and TECO all assert that Commission jurisdiction over fuel transactions lapses at true-up unless the Commission explicitly reserves jurisdiction [*27] to allow further study.

Public Counsel's position is that the Commission may review any expenditure that has previously passed through the clause and disallow those costs that were imprudently incurred. According to Public Counsel, the utilities are relieved of regulatory lag by the operation of the clause and, in exchange, the Commission and ratepayers must have assurances that the costs collected are proper.

We conclude that the staff's view is proper. The question of whether we may review the prudence of expenditures made during prior true-up periods is governed by whether the prudence regarding of expenditures has been adjudicated. The issuance of a true-up order does not adjudicate the question of prudence per se. As pointed out by staff, the true-up hearings have never been relied upon by the Commission or any other party as the point at which prudence is actually reviewed. With rare exception, prudence has not been alleged, proven nor ruled upon during those proceedings. An actual adjudication of prudence depends on whether an allegation of prudence was made, evidence was presented thereon and a ruling made. Where an expenditure has been disputed and its prudence examined [*28] on the record, a ruling in favor of prudence should be inferred even if none is explicitly made.

This approach to jurisdiction over prior true-up periods naturally involves a review of the record of prior proceedings. Since several hearings are held each year, this process is necessarily complex. We will defer such a review until such time as we must face the question for a particular utility.

Staff is also correct in stating that the nature of the clause and the way costs are passed through it belies any finality to a true-up order. As stated in Order No. 11572, the effect of expenditures during any six month period extend beyond that period and utilities frequently pass retroactive price adjustments through the clause.

The nature of the fuel adjustment is continuous and the segregation of charges to fuel cost into 6-month periods is for ease of administration only.Indeed, fuel purchases in any one period will affect future periods, as fuel cost is charged on an "as burned" basis at weighted average inventory cost. Thus, instead of fuel costs collected in any one period reflecting only fuel purchased during that period, those costs reflect the weighted average cost [*29] of purchases during and prior to that period. In addition, it is quite common for utilities to receive retroactive adjustments to fuel price and transportation costs well after the close of the original transaction to which they relates.

Conservation Penalty/Reward (Issues 27 and 28)

Since we have declined to adopt any penalties or rewards at this time these issues are moot.

Proper Version of Oil Backout Rule (Issue 29)

Public Counsel has raised this issue in order to preserve its pending appeal. No ruling is necessary.

Calculation of Net Savings on Six-Month or Monthly Basis (Issue 30)

Public Counsel has raised this issue in order to preserve it pending a motion for reconsideration. No ruling is necessary.

Other Conclusions of Law

The findings of fact and policy decisions made in this order are supported by the weight of the evidence of record and are within the range of the discretion granted to the Commission by the legislature under Chapter 366, Florida Statutes.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that the issues of fact and law set forth on pages 2 and 3 of this order be and the same are resolved [*30] as set forth in the body of this order. It is further

ORDERED that each electric utility seeking to recover the cost of fuel through the fuel adjustment clause shall file monthly reports in the form of Appendix B to this order, each report to be submitted within 30 days after the end of the reporting month.

By Order of the Florida Public Service Commission this 3rd day of November, 1983.

APPENDIX A

FLORIDA PUBLIC SERVICE COMMISSION FUEL PROCUREMENT POLICY

I. General

A. The Public Service Commission requires that all expense associated with the procurement of fuel, fuel related handling services and fuel transportation which are recovered through the Fuel Adjustment Clause be prudently incurred, result from competitive procurement procedures, be reasonably competitive in cost or value relative to what other buyers are paying under similar terms and conditions for fuel or services of comparable quality or specifications and result from sound administration of fuel supply agreements.

B. To accomplish the objectives expressed in (A), the Commission establishes the following guidelines that it recommends to electric utilities seeking fuel expense recovery through [*31] the Fuel Adjustment Clause. The Commission fully recognizes that differing fuel mixes and plant locations will necessarily result in vastly different fuel procurement strategies. However, the Commission also believes that there are certain fundamental, common procedures which, when employed, will result in the lowest, long run overall fuel expense to the companies and their ratepayers.

C. While the Commission believes that compliance with the guidelines expressed in this policy will achieve the lowest system fuel cost, the utility's management has sole responsibility to procure fuel in the most cost efficient manner possible and therefore it should have the flexibility to employ any means to achieve this result. In consideration of the above, departures from Commission policy are authorized when such departures can be justified and shown to be in the best interest of the utility and its ratepayers.

D. Departures from Commission policy which through Commission audit, investigation and hearing can be shown to have resulted in unjustified additional fuel expense are inappropriate for recovery through the Fuel Adjustment Clause and such expense will be disallowed.

E. If the Commission [*32] determines, based upon Staff audit and/or investigation, that a utility's unjustified departure from recommended Commission policy has resulted in unnecessary fuel expense, then the utility shall be required to apply credits against the clause or to make refunds to its customers.

F. The Commission's guidelines are intentionally broad to allow utility management the flexibility to tailor procurement procedures to fit a broad range of contingencies and adapt to changes in fuel markets.

G. The burden of proof rests solely with the utility to document the reasonableness of its procurement practices and the resultant expenses from such practices.

H. General overall compliance with Commission policy in no way removes the responsibility of a utility to justify andy particular transaction the Commission may require the specifically justified.

II. Long-Term Agreements for Fuel, Fuel Handling Services, Fuel Transportation, Spot Purchases and Affiliate Transaction.

A. The Commission recommends that the majority of a utility's requirements for fuel, fuel handling services and/or transportation be procured under the terms of a long-term contract. Primary reliance upon long-term [*33] contracts will ensure that fuel or services will be available when required at reasonable, stable costs to the utility and its ratepayers.

B. The Commission recommends that, to the extent practicable, such long-term contracts be negotiated in a competitive environment. It is recommended that the primary method employed should be an open competitive bidding process or some comparable alternative which produces the same result.

C. All aspects of the procurement process employed in acquiring a long-term fuel or services supply contract should be documented and available to the Commission upon request.

D. Vendors should be selected on the basis of a formal evaluation system which is neutral in its application and capable of producing quantifiable ratings of individual suppliers. Considerations other than delivered price, fuel quality and vendor performance should be thoroughly documented.

E. The Commission recommends that all fuel agreements incorporate clear specification for the fuel or service to be provided and bonus/penalty provisions to ensure that the fuel or services contracted for are provided in accordance with contract terms.

F. The Commission recommends that the [*34] utility arrange for adequate fuel sampling techniques and equipment to be deployed at the point of receipt from the fuel supplier and the point of delivery, if different. Such a procedure will ensure that the quality of the fuel received at the unloading facility is consistent with that of the fuel as loaded, the invoiced priced and the contract specifications.To the extent possible, all such arrangements should be clearly written in the contract.

G. Utilities subject to the Commission's jurisdiction should not pay for or agree to pay for fuel or services at prices in excess of that dictated by the negotiated price terms of executed contracts existing between such utilities and providers of such fuel or services.

H. The Commission recommends that long term fuel or service contracts be based upon a base price plus well defined escalators, public tariffs or public postings unless a benefit to the ratepayer can be demonstrated by using some other pricing arrangement.

I. The Commission recommends that all utilities seek to incorporate a "right to audit" clause in any contract which utilizes escalators. The right to audit clause should give the utility the authority to audit specific [*35] records of the supplier.

J. The Commission recommends that all utilities enforce the right to audit through the annual use of its own audit staff or an independent accounting firm. Any refunds or adjustments due, as identified by audit, should be promptly resolved and credited to fuel expense.

K. The Commission recommends that any escalation methodology to be employed in a long-term contract be tied as closely as possible to actual changes in a suppliers verifiable costs.

L. The Commission recommends that all utilities seek to incorporate adequate well defined remedies in all long-term contracts for substandard quality performance unreliable volume or quality performance and unacceptable high price over protracted periods of time.

N. It is recommended that all contracts and the individual terms of each contract be reviewed and approved by the legal office of the utility.

O. All utility personnel having any interest in a particular firm seeking a long term fuel or services contract with a utility should be removed from any selection process, contract negotiation or administration of a contract with the firm. All personnel having any potential conflict of interest [*36] should be prevented from having any impact upon the contracting process.

P. All utility transaction with affiliated companies which provide fuel or fuel related services should be based on costs which are consistent with or lower than the costs a utility would incur if the utility received the fuel or services from an independent supplier in the competitive market obtained through competitive bidding.

Q. All spot transactions should be priced at, or below, the market price at the time of purchase and should not exceed the normal contract price for similar fuel or fuel related services unless required for reliability purposes.

R.The Commission expects, to the extent possible, that each utility utilize the terms of their long-term contracts relating to minimum and maximum volumes of fuel required to be delivered in order to take advantage of lower prices in the spot market when they exist.

S. The Commission expects that any utility which has a contract with an affiliated organization shall administer that contract in a manner identical to the administration of a contract with an independent organization.

T. Any fuel or fuel related transaction which does not meet the above [*37] criteria shall be denied recovery through the fuel clause by the Commission, unless the utility, which has the full burden of proof, can demonstrate that the transaction is in the best interest of the ratepayer.

z

In re: Petition For Determination of Need for a Proposed Electrical Power Plant and Related Facilities, Polk County Units 1-4, by Florida Power Corporation

DOCKET NO. 910759-EI; ORDER NO. 25805

Florida Public Service Commission

1992 Fla. PUC LEXIS 389

92 FPSC 2:659

February 25, 1992

CORE TERMS: pipeline, polk county, site, fuel, natural gas, load, plant, cycle, combined, forecast, customer, winter, generation, energy, ultimate decision, conservation, reliability, anchor, generating, peak, combustion, ratio, turbine, margin, cost-effective, transportation, long-term, rating, coal, modification

[*1]

The following Commissioners participated in the disposition of this matter: THOMAS M. BEARD, Chairman; SUSAN F. CLARK; J. TERRY DEASON; BETTY EASLEY; LUIS J. LAUREDO

ORDER DETERMINING THE NEED FOR A PROPOSED POWER PLANT

BY THE COMMISSION:

Pursuant to Notice, a formal hearing was held in this docket on November 20 and 21, 1991, in Tallahassee, Florida by the duly designated hearing officer of the Florida Public Service Commission, Commissioner Betty Easley. Upon consideration of the record in this proceeding, the Commission now enters its Final Order.

Background

On July 8, 1991, Florida Power Corporation (FPC or Florida Power) filed with the Commission its Notice of Intent to file a Petition for Determination of Need for a proposed electrical power plant and related facilities at a site located in Polk County, Florida. FPC filed its petition on August 16, 1991, in which it requested that the Commission determine the need for the construction of four advanced combined cycle units fired primarily with natural gas, with the capability of being converted to burn coal gas in the future. FPC estimated that the four proposed units would produce 940 MW of electricity. FPC expected [*2] its proposed units to come on line in the 1998-2000 time frame, with 235 MW of capacity to be available in 1998, 2 units of 235 MW each in 1999, and 235 MW to become available in 2000.

Destec Energy, Inc., Panda Energy, Inc., the Florida Industrial Cogenerator's Association (FICA), the Floridians for Responsible Utility Growth (FRG), and the Florida Division of Chesapeake Utilities, Inc. were granted leave to intervene in this proceeding. The day of the hearing Hillsborough County filed a petition to intervene and cross examine witnesses. Florida Power Corporation objected to Hillsborough County's intervention on the grounds that it had not shown that it had a substantial interest in the outcome of the proceeding, that its petition was not timely filed, and that Florida Power's interests would be prejudiced by such a tardy intervention. Because Hillsborough County had not timely filed its petition at least five days before the hearing, as Commission Rule 25-22.039, Florida Administrative Code requires, Hillsborough County's request to cross examine witnesses at the hearing was denied, but the county was permitted to intervene to file a post-hearing brief in the case.

After the [*3] November 21-22, 1991 hearing Florida Power Corporation (FPC), the Florida Industrial Cogenerator's Association (FICA), The Floridians for Responsible Utility Growth (FRG), and Destec Energy, Inc. (Destec) filed briefs, post hearing statements, and/or proposed findings of fact. The Hearing Officer issued her Recommended Order and Responses to Proposed Findings of Fact on December 30, 1991. They are included in this order as Attachments A and B, respectively. FICA, FRG and Destec filed exceptions to the Hearing Officer's Recommended Order, and FRG requested oral argument on its exceptions. That oral argument was held on February 3, 1992. Our responses to the exceptions are included in this order as Attachment C.

Upon consideration of the record and the exceptions filed, we find that the Hearing Officer's Findings of Fact and Responses to Proposed Findings of Fact should be adopted as this agency's Findings of Fact and Responses, with one minor change to Finding of Fact 132. In order to recognize, as FICA and Destec pointed out in their exceptions, that allowing utilities to earn a return on investment in non-utility purchases is another way utilities can compensate for the financial [*4] consequences of increased purchased power obligations, we adopted this rewording for Finding of Fact 132:

Credit rating agencies recognize that, without compensating factors, increased reliance on purchased power obligations may lower coverage ratios. A utility can compensate for the financial consequences of increased purchased power obligations by increasing its equity ratio (reducing its debt leverage), increasing its earnings, or petitioning for modified regulatory treatment that allows the utility an opportunity to earn a return on this capacity.

Also, a typographical error was made in transcribing FPC's Proposed Finding 72. The word "reductions" should be replaced with the word "improvements" to read: "opportunities for efficiency improvements are first identified in energy audits . . ."

Upon consideration of the record and the exceptions filed, we also find that the Hearing Officer's Conclusions of Law should be adopted as this agency's Conclusions of Law. We conclude that the Recommended Order in its entirety is supported by competent substantial evidence in the record and comports with the essential requirements of law.

Based on the foregoing, it is

ORDERED by the [*5] Florida Public Service Commission that the Hearing Officer's Findings of Fact as modified above are accepted and adopted as this agency's Findings of Fact. It is further

ORDERED that the Hearing Officer's Conclusions of Law are accepted and adopted as this agency's Conclusions of Law. It is further

ORDERED that for the reasons set out in the Recommended Order, Florida Power Corporation's Petition for Determination of Need for Proposed Electrical Power Plant and Related Facilities is hereby APPROVED for the first two proposed units. It is further

ORDERED that this Docket be closed.

By ORDER of the Florida Public Service Commission, this 25th day of FEBRUARY, 1992.

ATTACHMENT A

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Need for Proposed Electrical Power Plant and related facilities Polk County Units 1-4, by Florida Power Corporation

DOCKET NO. 910759-EI

ORDER NO. 25550

ISSUED:

RECOMMENDED ORDER

Pursuant to Notice, a formal hearing was held in this docket on November 20 and 21, 1991, in Tallahassee, Florida by its duly designated hearing officer, Commissioner Betty Easley.

A. APPEARANCES:

CHERYL G. STUART, Esquire [*6] and CARLOS ALVAREZ, Esquire, Hopping, Boyd, Green and Sams, Post Office Box 6526, 123 South Calhoun Street, Tallahassee, Florida 32314

On behalf of Florida Power Corporation.

James P. Fama, Esquire, Post Office Box 14042, 3201 Thirty-fourth Street, South, St. Petersburg, Florida 33733

On behalf of Florida Power Corporation.

Wayne L. Schiefelbein, Esquire, Gatlin, Woods, Carlson & Cowdery, 1709-D Mahan Drive, Tallahassee, Florida 32308

On behalf of Chesapeake Utilities Corporation.

Suzanne Brownless, Esquire and Ken Irwin, Esquire, Oertel, Hoffman, Fernandez & Cole, P.A., 2700 Blair Stone Road, Suite C, Tallahassee, Florida 32301

On behalf of Destec Energy, Inc.

Paul Sexton, Esquire, Richard A. Zambo, P.A., 211 South Gadsden Street, Tallahassee, Florida 32301.

On behalf of Florida Industrial Cogeneration Association.

Terry R. Black, Esquire, Pace University Energy Project, Center for Environmental Legal Studies, 78 N. Broadway, White Plains, New York 10603

On behalf of Floridians for Responsible Utility Growth.

Edward Gwynn, Esquire, 4100 Spring Valley, Suite 1001, Dallas, Texas 75244

On behalf of Panda Energy Corporation.

John J. Dingfelder, [*7] Esquire

Post Office Box 1110

Tampa, Florida 33601

On behalf of Hillsborough County

MARTHA C. BROWN, MICHAEL A. PALECKI, Esquire, and MARY ANNE BIRCHFIELD, Esquire, 101 East Gaines Street, Suite 216, Tallahassee, Florida 32399-0863

On behalf of the Commission Staff.

PRENTICE PRUITT, Esquire, the Office of the General Counsel, 101 East Gaines Street, Suite 212, Tallahassee, Florida 32399-0861

Counsel to the Commissioners.

BACKGROUND

On July 8, 1991, Florida Power Corporation (FPC or Florida Power) filed with the Commission its Notice of Intent to file a Petition for Determination of Need for a proposed electrical power plant and related facilities at a site located in Polk County, Florida. FPC filed its petition on August 16, 1991, in which it requested that the Commission determine the need for the construction of four advanced combined cycle units fired primarily with natural gas, with the capability of being converted to burn coal gas in the future. FPC estimates that the four proposed units will produce 940 MW of electricity. FPC's expects its proposed units to come on line in the 1998-2000 time frame, with 235 MW of capacity to be available in 1998, [*8] 470 MW in 1999, and 235 MW to become available in 2000.

Destec Energy, Inc., Panda Energy, Inc., the Florida Industrial Cogenerator's Association (FICA), the Floridians for Responsible Utility Growth (FRG), and the Florida Division of Chesapeake Utilities, Inc. were granted leave to intervene in this proceeding. The day of the hearing Hillsborough County filed a petition to intervene and cross examine witnesses. Florida Power Corporation objected to Hillsborough County's intervention on the grounds that it had not shown that it had a substantial interest in the outcome of the proceeding, that its petition was not timely filed, and that Florida Power's interests would be prejudiced by such a tardy intervention. Because Hillsborough County had not timely filed its petition at least five days before the hearing, as Commission Rule 25-22.039, Florida Administrative Code requires, Hillsborough County's request to cross examine witnesses at the hearing was denied, but the county was permitted to intervene to file a post-hearing brief in the case.

FICA and FRG filed several motions in this docket which were addressed and disposed of by the prehearing officer in Order No. 25221 granting [*9] intervention, granting partial extension of time to file testimony, denying motion regarding discovery, denying motion for continuance, and granting admission to practice before the commission. FICA petitioned the full

Commission to reconsider the prehearing officer's decision on its motion to extend the time to file testimony and its motion regarding discovery. That petition for reconsideration was reviewed and denied by the full Commission at its November 5, 1991 Agenda Conference.

The transcripts of the two-day hearing were received on November 26, 1991. Post hearing briefs were filed on December 16, 1991. Florida Power Corporation and the Floridians for Responsible Utility Growth filed proposed findings of fact, and a ruling on each proposed finding is includes in the Appendix to this recommended order.

The substantive aspects of this case are governed by Section 403.519, and Chapter 366, Florida Statutes. The procedural aspects of the case are governed by the provisions of Chapter 120, Florida Statutes, and Chapter 25-22, Florida Administrative Code.

ISSUES

The ultimate issue in this case is whether the Petition for a Determination of Need meets the statutory requirements [*10] of Section 403.519, Florida Statutes, as amended by Chapter 90-331, Laws of Florida. Section 403.519, Florida Statutes, enumerates five major areas for consideration by the Florida Public Service Commission in determining the need for an electrical power plant:

(1) the need for electric system reliability and integrity;

(2) the need for adequate electricity at reasonable cost;

(3) whether the proposed plant is the most cost effective alternative available;

(4) conservation measures taken by or reasonably available to the applicant which might mitigate the need for the proposed power plant, and

(5) other matters within the Commission's jurisdiction which it deems relevant.

The Florida Public Service Commission is the sole forum to determine the need for the proposed power plant, and only issues relating to that need, as prescribed by section 403.519, Florida Statutes, were heard in this proceeding. Separate public hearings will be held by the Department of Environmental Regulation before the Division of Administrative Hearings to consider the environmental and other impacts of the proposed plant and associated facilities.

At the Prehearing Conference on November 4, 1991, the [*11] parties identified thirty-three issues for resolution in this proceeding. They are:

Need for Electric System Reliability

ISSUE 1: Are the reliability criteria used by FPC to determine its need for 940 MW of combined cycle units reasonable for planning purposes?

ISSUE 2: Is the load forecast used by FPC to determine its need for 940 MW of combined cycle units reasonably adequate for planning purposes?

ISSUE 3: Does FPC, as a utility interconnected with the statewide grid, exhibit a need for 235 MW of capacity in 1998, 470 MW of capacity in 1999, and 235 MW of capacity in 2000?

ISSUE 4: Are the proposed 940 MW of combined cycle units needed to contribute to electric system reliability and integrity to FPC and to the State of Florida?

ISSUE 5: Are there any adverse consequences to FPC and its customers if all four of its proposed combined cycle units are not completed in the approximate time frame requested by FPC?

ISSUE 6: Is the timing of FPC's petition to determine the need for its proposed combined cycle units appropriate?

Fuel Issues

ISSUE 7: Is the fuel price forecast used by FPC reasonably adequate for planning purposes?

ISSUE 8: [*12] Have adequate assurances been provided regarding: A) the sufficiency of supplies of natural gas; B) the commitment of natural gas supplies to FPC, and C) the availability either of gas transportation capacity or of commitments to build sufficient capacity; to serve the needs of the proposed Polk County units?

ISSUE 9: Will the Polk County Project contribute to fuel diversity for FPC's system, and for peninsular Florida?

ISSUE 10: If FPC is not authorized to construct all four of its proposed combined cycle units will FPC be able to secure an economical gas supply?

Reasonable Cost

ISSUE 11: Did FPC reasonably consider the costs of environmental compliance associated with the Clean Air Act when it evaluated its future generation needs?

ISSUE 12: Have the reasonably anticipated costs to FPC of environmental compliance of the proposed units been properly considered by FPC?

ISSUE 13: Has FPC provided sufficient information on the site, design and engineering characteristics of its 940 MW of combined cycle units to evaluate its proposal?

ISSUE 14: Do FPC's proposed combined cycle units contribute to the provision of adequate electricity to FPC and the State [*13] of Florida at a reasonable cost?

ISSUE 15: Assuming that the construction of a natural gas pipeline would be beneficial to the state, could natural gas-fired QFs provide the "anchor" demand which FPC indicates is so important?

Most Cost-effective Alternative

ISSUE 16: What would be the anticipated effect on FPC's credit rating if FPC constructs its proposed capacity?

ISSUE 16a: What would be the anticipated effect on FPC's credit rating if FPC constructs its proposed capacity in conjunction with the construction of a potential gas pipeline by FPC or others?

ISSUE 16b: What would be the anticipated effect on FPC's credit rating if FPC relies on self-service generation, including self-service wheeling, in lieu of capacity purchases, conservation and load management?

ISSUE 17: What would be the anticipated effect on FPC's credit rating if all or part of the proposed capacity were replaced by purchased power?

ISSUE 18: What would be the general effect on FPC's revenue requirements if its proposed capacity was replaced in whole or in part by purchased power and the effects of credit ratings are considered?

ISSUE 19: Has the availability of purchased [*14] power from other utilities been adequately explored and evaluated by FPC?

ISSUE 20: Has the availability of non utility generation, including firm capacity purchases and self-service generation, been adequately explored and evaluated by FPC?

ISSUE 21: Has FPC demonstrated that it has adequately considered conservation or other non-generating alternatives, including the end use of natural gas, reasonably available to it that could mitigate the need for all or part of FPC's proposed 940 MW of combined cycle units?

ISSUE 22: STIPULATED Has FPC adequately explored other reasonably available generating technologies for utility construction in lieu of the proposed project?

ISSUE 23: Are FPC's planned unit retirements in 1999 and 2000 cost-effective compared to the refurbishment and continued operation of those units?

ISSUE 24: Will the proposed combined cycle units constructed by FPC be the most cost-effective alternative to FPC and Peninsular Florida?

Miscellaneous

ISSUE 25: What associated facilities are required in conjunction with the Polk County project?

ISSUE 26: Do purchases from QFs limit FPC's planning and operating flexibility?

ISSUE [*15] 27: Based on the resolution of the previous factual and legal issues, should FPC's petition for determination of need for 940 MW of combined cycle units, with 235 MW on-line in 1998, 470 MW on-line in 1999, and 235 MW on-line in 2000, be granted?

LEGAL ISSUES

ISSUE 28: Based on the resolution of ISSUE 8, should the Commission grant or deny FPC's Petition for Determination of Need?

ISSUE 29: Under Florida law, may the Commission impose upon new FPC constructed generating capacity the same cost and performance obligations and requirements that FPC places upon QFs, so that its stockholders bear the risk of construction and operation, rather than the ratepayers?

ISSUE 30: Is FPC obligated as a matter of law to purchase QF capacity in lieu of constructing the proposed units?

ISSUE 31: Under Florida law, may the Commission, in making a determination of need for FPC's proposed units, consider the benefits of a potential natural gas pipeline to persons other than FPC?

ISSUE 32: Under Section 403.519, Florida Statutes, does the term "most cost-effective alternative available" mean the same thing as "least cost option or combination of options available"? [*16]

ISSUE 33: Does Florida law require the company to examine and use all reasonably available conservation measures that might mitigate the need for the proposed plant? If not, what standard is appropriate to determine that the company has fulfilled its obligations under section 403.519, Florida Statutes.

In addressing these issues at the hearing, the parties have provided the Hearing Officer with substantial competent evidence to make the following material Findings of Fact.

FINDINGS OF FACT

FLORIDA POWER'S REQUEST

1. Florida Power Corporation ("Florida Power") is an investor-owned public utility regulated by the Public Service Commission. Florida Power provides electrical power to more than one million customers in thirty-two (32) counties in the state of Florida. (Tr. 72; Ex. 2, pp. 5, 32).

2. Florida Power has proposed the addition of 940 MW to be produced by four separate and distinct 235 MW combined cycle units. (Tr. 71, Ex. 1, p. 9).

3. Florida Power has proposed that one unit will be added in November, 1998; two in November, 1999; and one in November, 2000. (Ex. 1, p. 10).

4. Florida Power's proposed plan to construct the four 235 MW combined cycle [*17] units is identified as Alternative 3 in Florida Power's Integrated Resource Study. (Tr. 934, Ex. 105).

INTEGRATED RESOURCE PLANNING METHODOLOGY

5. The 1991 Integrated Resource Plan (IRP) was designed to provide reliability, cost effectiveness, environmental responsibility, and financial stability for Florida Power. Florida Power plans to meet these goals with a diversified set of demand- and supply-side resources. (Tr. 71).

6. The Integrated Resource Plan is based on the principle of diversified resources. The plan includes demand-side management (DSM), cogeneration, tie-line construction, peaking capacity, interruptible load, and combined cycle units. (Tr. 941).

7. Florida Power's planning process combines DSM programs, QF and utility purchases, new transmission and generating plants, and interruptible load. (Tr. 1079; Tr. 920).

8. Florida Power's integrated planning process requires Florida Power to first determine the optimum amount of DSM programs and then evaluate alternative capacity plans to meet any further capacity needs. (Tr. 915).

9. Florida Power uses two reliability criteria - a winter 15-percent reserve margin and 0.1 days per year Loss of Load [*18] Probability (LOLP) - to evaluate system reliability. The LOLP calculation provides a probabilistic evaluation that takes into account the uncertain nature of generator forced-outage rates and tie-line assistance from other areas. (Tr. 917; Ex. 2, p. 113).

10. Florida Power's methodology for calculating LOLP is generally accepted by the Florida Public Service Commission and the utility industry. The calculation of reserve margin provides a determination of total system capacity compared to the system peak load. (Tr. 917).

11. Ten alternative resource combinations were formulated and modeled using the PROSCREEN II production costing and economic model. These alternatives were evaluated using 27 sets of input-assumptions. (Tr. 932-33; Tr. 1090).

12. The primary output of the PROSCREEN II model is the Cumulative Present Worth of Revenue Requirement (CPWRR). The CPWRR from each model run was weighted by its probability of occurrence, and the expected (or average) CPWRR values for each alternative were compared. (Tr. 933; Tr. 1089; Ex. 72-73).

13. Florida Power developed a high, medium, and low forecast for each of the primary input assumptions: demand and energy, fuel prices, [*19] and capital cost of technologies. The analysis evaluated the 27 possible combinations of these assumptions. (Tr. 918).

14. The assigned probabilities for the fuel forecast were 20 percent for the high scenario, 55 percent for the medium scenario, and 25 percent for the low scenario. The assigned probabilities for the demand-and-energy and the cost-of-technology forecasts were 25 percent for the high scenario, 50 percent for the medium scenario, and 25 percent for the low scenario. (Tr. 932; Ex. 2, p. 137).

LOAD FORECAST

Methodology/Assumptions

15. The Florida Power forecasting procedure is the same as that used by the Load Forecasting Working Group of the North American Electric Reliability Council (NERC). (Tr. 648).

16. The Florida Power long-term load forecast seeks to project trends in Florida Power's customer base, energy sales, and peak seasonal demands over the next 20 years. The results indicate the future electricity demands that are likely to come from each of its customer classes. (Tr. 631).

17. The following are key assumptions of the Florida Power load forecast:

* Normal weather conditions are characterized by the 1981-1990 average of service [*20] area conditions. (Tr. 634).

* The long-term customer forecast is developed from the Bureau of Economic and Business Research's "medium-case" population projections. (Tr. 634).

* The forecast accounts for the addition of a new partial-requirements wholesale customer (New Smyrna Beach) in 1992, but it otherwise assumes that there will be no major changes in the company's wholesale load or energy service. (Tr. 634).

* The energy and demand forecast subtracts the load impacts of Florida Power's DSM programs and self-service cogeneration, but for reporting purposes, it does not subtract interruptible/curtailable loads. It assumes that all interruptible/curtailable customers will be served at the time of peak. (Tr. 634).

* Florida Power forecasts that its rates will not increase in real terms over the period 1991-2000. (Tr. 302, Ex. 2, p. 219).

18. Since 1983, residential use per customer exhibited an exceptionally high rate of growth that was driven by several factors. These include: (a) a strong Florida economic expansion; (b) larger, more energy intensive homes; (c) a greater percentage of new single-family home construction compared to multifamily homes; (d) strong population [*21] growth in Florida Power's high-

use Eastern and Mid-Florida divisions; and (e) a declining real price of electricity since 1986. (Tr. 649).

19. Interruptible load is not included in the peak demand used for calculating the winter reserve margin. This margin is calculated using only firm peak load. The interruptible load is not considered to be firm for the purpose of calculating LOLP. (Tr. 923).

20. Self-service generation has been addressed in the Integrated Resource Study, Docket No. 910759-EI, in the forecast of future demand and energy. The forecast assumes that self-service generation will not increase. (Tr. 301).

21. Historically, Florida Power has tended to underforecast its load. (Tr. 660-664; Ex. 38). Attempts to correct underforecasting have focused on factors affecting the short-term (1991-1995) forecast. (Tr. 666, Ex. 2, p. 208).

Results

22. Florida Power forecasts the compound average annual growth rate in customers through 2010 to be approximately 2.17 percent, with the customer base increasing from roughly 1.14 million to 1.75 million over that time. (Tr. 648).

23. Florida Power forecasts total energy sales to grow at an annual rate of 3.41 percent [*22] for the period 1991 through 2010. (Tr. 650).

24. Florida Power forecasts winter and summer peak demands to increase at compound average annual growth rates of 2.15 percent and 2.55 percent, respectively, for the period 1991 through 2010. (Tr. 650). Florida Power forecasts peak summer demand for 2001 to be 7,716 MW, and winter peak demand for 2001 to be 8,301 MW. (Ex. 2, p. 263).

25. Florida Power forecasts residential energy-use per customer for 2001 to be 13,205 kWh. (Ex. 2, p. 259). The average kWh per residential customer growth rate from 1991-2000 is forecasted to be approximately 1 percent per year. (Ex. 2, p. 259).

26. Florida Power forecasts the average annual growth in energy use by its commercial customers to be 1.4 percent per year for 1991-2000. In addition, energy use per commercial customer is forecasted to be 75,299 kWh in 2001. (Ex. 2, p. 259).

27. Florida Power forecasts energy use per industrial customer in 2001 to be 1,146 kWh. (Ex. 64).

28. The further in the future, the load forecast becomes a broader range of possible values, and more uncertain. (Tr. 666-667).

CONSERVATION

Assumptions

29. In Florida Power's review prior to filing [*23] its conservation plan with the Commission in February 1990, 199 potential programs were identified that met all end uses. A broad set of criteria were applied to reduce these to 40 programs that were likely to be feasible for Florida Power and its customers. These 40 were then analyzed in terms of cost effectiveness, and 22 were accepted. (Tr. 834).

30. Florida Power's DSM projections represent an expansion of previously approved cost-effective DSM programs. These programs, referred to as M.A.C.S.

(Maximum Avoidable Capacity Scenario), offer an expanded menu of conservation and load management services. (Tr. 677).

31. Florida Power did not consider natural gas use as an end use in developing M.A.C.S. The Florida Public Service Commission stated in its February 1990 order in Docket 890737 that electric utilities are not compelled to pursue end-use gas programs. (Tr. 848).

32. Florida Power's marketing strategy is to start with low, but reasonable financial incentives and raise them to increase market penetration. (Tr. 719).

33. Florida Power's Energy Efficiency and Conservation filing, submitted on February 12, 1990, included cost-effectiveness analyses for all programs [*24] currently included in M.A.C.S. All programs were in conformance with Florida Public Service Commission's Rule 25-17.008 as it pertains to cost effectiveness. (Tr. 682).

Conservation Impacts

34. Florida Power forecasts DSM programs under M.A.C.S. will reduce winter peak demand by 1,445 MW, or nearly 30 percent of Florida Power's new resource needs between 1992-2001. (Tr. 72, Tr. 73, Ex. 3).

35. Florida Power forecasts to obtain over 1,000 MW in incremental dispatchable load management capacity for the period 1992-2001. In total, load management programs are expected to reduce winter peak demand by 1,814 MW in 2001. (Tr. 689).

36. Florida Power forecasts that energy efficiency programs implemented under M.A.C.S. will reduce winter peak demand by an additional 334 MW in 2001. Combining the contributions of the energy efficiency programs implemented prior to M.A.C.S. with the projected contributions from M.A.C.S. would result in a total winter peak reduction of 568 MW in 2001. (Tr. 689).

37. Florida Power forecasts that energy efficiency programs implemented under M.A.C.S. will reduce energy consumption in 2001 by 391 GWh. The combined results from efficiency programs [*25] implemented from 1980 through 2001 will have reduced consumption in 2001 by 779 GWh. (Tr. 689).

38. In 1990, Florida Power allocated more than $ 50 million to its DSM programs. (Tr. 676; Ex. 43). Florida Power's 1990 DSM budget was 2.9 percent of total operating revenue. (Tr. 676; Ex. 43). Annual expenditures on Florida Power's DSM programs are forecasted to be nearly $ 75 million in 1992, and nearly $ 1.4 billion by 2001. (Ex. 55).

39. Florida Power forecasts costs for those DSM programs in which Florida Power does not control the load, and primarily reduce energy, to be 20 percent of total DSM program costs for the period 1992-2001. Costs for those programs which allow Florida Power to control the load, and primarily reduce peak demand, are forecasted to be 80 percent of total DSM program costs for the period 1992-2001. (Ex. 55).

40. Increasing participation, in those programs projected to have participation rates below 10 percent, to 10 percent in 1996 would provide 792 MW of additional savings. However, Florida Power contends that increasing participation to 10 percent is not supported by Florida Power's data. (Tr. 852, Ex. 60).

41. Florida Power has recently [*26] established a Conservation Monitoring, Evaluation and Planning Department. This department will have lead responsibility for developing and implementing a framework for determining the kW and kWh reductions associated with each Florida Power conservation program. (Tr. 692).

EXISTING AND PLANNED SUPPLY-SIDE AND TRANSMISSION ALTERNATIVES

Generation

42. For the Integrated Resource Study, all of Florida Power's generation is assumed to be available for operation, including all units that were returned from Extended Cold Shutdown (ECS). Turner Unit 2 has been retired, and Avon Park Unit 2 will be leased to an independent power producer to be rebuilt to burn peat as a fuel. (Tr. 919; Ex. 65).

43. The total existing Florida Power winter generating capacity is 6,621 MW. Of this capacity, 4,912 MW is steam generation and 1,709 MW is from combustion turbines. (Tr. 919; Ex. 65).

44. Additional units currently under construction or planned for construction were also included as assumptions for the Integrated Resource Study. Four distillate-fired combustion turbines with total winter capacity of 364 MW are scheduled to be in service at the DeBary site in November 1992. [*27] Four more identical units with a total winter capacity of 364 MW also are scheduled to be in-service at the Intercession City site by November 1993. (Tr. 920).

45. Florida Power is planning to locate a 40 MW gas-fired combustion turbine with a waste-heat boiler at the University of Florida. This unit will add 40 MW of capacity to the Florida Power system and will provide a steam source for the University. (Tr. 920).

46. The Higgins Plant site was retired in 1999 for the Study. This retirement included the three oil-fired steam units with a total winter capacity of 123 MW and four distillate-fired combustion turbines with a total winter capacity of 126 MW. (Tr. 919). Two distillate-fired combustion turbines at Avon Park were assumed retired in the year 2000 for the study. They have a total winter capacity of 60 MW. (Tr. 919).

Purchased Power

47. Purchased power will account for approximately 15 percent of Florida Power's 1998 total generation resources. Florida Power is the state's largest purchaser of QF capacity. Florida Power also purchases capacity from Southern Company. (Tr. 1096; Tr. 864; Tr. 72; Ex. 3; Ex. 2, pp. 94-5).

48. Florida Power contracted 43 [*28] MW of new QF capacity in 1991 and more than 800 MW between 1992 and 1996. If all of the capacity under contract comes on line, more than 11 percent (over 1,000 MW) of supply-side resources in 1996 will come from QF generating capacity. (Tr. 864-865).

49. In Florida Power's previous solicitation for QF capacity, the bids received were only 1 to 2 percent below the avoided costs that Florida Power published. (Tr. 1177)

50. Florida Power's Integrated Resource Plan incorporates over 900 MW of future purchased capacity from the QF developers. Most of this QF capacity is not on line, but is expected to be in service by 1997. (Tr. 1081; Tr. 918).

51. Florida Power has contracted for more capacity than reliability studies indicate is needed. In other words, by assuming a 75-percent probability of performance, Florida Power contracted for 844 MW of capacity, but it assumed for planning purposes that only 633 MW will ultimately be available. (Tr. 869).

52. If all contracted QF capacity performs, Florida Power will have 211 MW more capacity than it expected when it developed its Integrated Resource Plan. (Tr. 869).

53. Florida Power signed an agreement in 1988 to buy up to 400 [*29] MW of coal-fired UPS from Southern Company. The UPS portion of the sale begins in 1994 with a 200 MW purchase and increases to 400 MW by 1995. The contract expires in 2010 and also has provisions for early options in 1993 and 1994 for UPS purchases or firm economy purchases called "Schedule E." (Tr. 920; Tr. 72; Ex. 2, p. 85).

54. Florida Power intends to buy economy energy from Southern Company or other utilities interconnected with Southern Company. This economy energy will come into the Florida Power system on the 500 kV line scheduled to be in service by January 1997. For the Integrated Resource Study, it was assumed that Florida Power will buy up to 500 MW at a time, with a total of 1,000 GWh for each year. (Tr. 921; Tr. 72; Ex. 67; Ex. 2, pp. 85-7). The power purchases over the new 500 kV intertie with Southern Company are expected to represent about 10 percent or at least 500 MW of winter peak demand. (Ex. 3).

Transmission Line

55. The addition of the 500 kV tie-line is expected to improve the loss-of-load probability to between .02 and .03. The line is also expected to improve the reliability of other utilities in the state, which in turn further improves [*30] Florida Power's reliability. (Tr. 976). The tie-line does not affect Florida Power's reserve margin since Florida Power plans to use it for economy and emergency purchases. (Tr. 924).

56. With the construction of the 500 kV line from Florida to Southern Company, the First Contingency Total Transfer Capability (FCTTC) will be increased by 1,300 MW to 4,900 MW. The existing facilities will account for 3,600 MW of transfer capability and the new 500 kV line will account for 1,300 MW. (Ex. 2, p. 117).

57. From the new 500 kV line, as well as other facility additions on Florida Power's system, Florida Power's tie capacity to the Florida assistance area is expected to increase to 2,200 MW. (Ex. 2, p. 117).

58. The negotiations and logistics involved in building the 500 kV line are extensive. The January 1997 completion date was the best estimate at the time the IRP study began. There are distinct possibilities that the actual completion date (sic.) could be later. (Tr. 948).

59. If the 1997 500 kV line were not constructed, the number of megawatts that Florida Power would have to add to the proposed Polk County units in order to keep its LOLP at 0.1 days per year would be [*31] 225 MW for 1997. If the 500 kV line is not built, Florida Power would have to add more than 500 MW to keep its LOLP as low as it would be if the tie-line were built. (Ex. 88, pp. 1-2).

INTEGRATED RESOURCE PLANNING INPUT TECHNOLOGIES

60. Five generation technologies were considered viable alternatives in the Integrated Resource Study: pulverized coal, combined cycle, combustion turbine, fluidized bed combustion, and integrated gasification combined cycle. (Tr. 1000).

61. Significant experience exists with both combustion turbines and steam cycles, which are the primary components of combined cycle units. The combined cycle is a well developed, efficient technology with a relatively short construction schedule. (Tr. 1007).

62. Florida Power considered the following 10 alternative plans:

* Alternative 1: two 165 MW combustion turbines on distillate and one 700 MW pulverized coal unit.

* Alternative 2: three 165 MW combustion turbines on distillate and one 450 MW pulverized coal unit.

* Alternative 3: four 235 MW combined cycle on gas.

* Alternative 4: four 235 MW combined cycle on distillate.

* Alternative 5: twenty-four 40 MW small combustion turbines on gas.

* [*32] Alternative 6: 110 MW purchase from Orlando Utilities and four 235 MW combined cycle on gas.

* Alternative 7: one 165 MW combustion turbine on distillate and 870 MW of integrated gasification on coal.

* Alternative 8: one 165 MW combustion turbine on distillate and 750 MW of fluidized bed combustion on coal.

* Alternative 9: 593 MW from orimulsion gasification combined cycle and two 165 MW combustion turbines on distillate.

* Alternative 10: two 165 MW of combustion turbine on gas, one 376 MW pulverized coal purchase from Cajun, and one combined cycle on gas for 235 MW. (Ex. 104).

63. It was stipulated by all parties that Florida Power Corporation adequately explored other reasonably available generating technologies for utility construction in lieu of the proposed project. (Tr. 1011)

STRATEGIC CONSIDERATIONS, (Including Clean Air Act Compliance Strategy)

64. Strategic analysis refers to systematic consideration of issues such as fuel choices, environmental and siting benefits, and operational flexibility. Some of these issues are long term in nature and/or difficult to quantify. (Tr. 1081, Ex. 2, pp. 175-76).

65. There are three ways for a utility to comply with [*33] the Clean Air Act. One is to reduce loads so that fewer kWh need to be produced. A second way is to reduce emissions at existing plants by switching fuels or putting on scrubbers. The third is to build new plants so that existing plants are used less. (Tr. 1411-1412).

66. Florida Power evaluated the long-term factors affecting Florida Power's Clean Air compliance strategy after 2000 for potential resource additions. (Tr. 916-17).

67. Florida Power's proposed generation expansion plan was designed to be operated on an economic dispatch basis and to also meet Clean Air Act regulations. For this reason, Florida Power plans to switch the Bartow plant and Crystal River 1 and 2 plants from burning high-sulfur fuel to a lower-sulfur fuel. (Ex. 85).

68. The Polk County units' natural gas fuel supply, which produces no sulfur emissions when burned, plays a critical role in Florida Power's compliance with the Clean Air Act under Phase II. Also, since the units are operated as intermediates, they can be base loaded to reduce sulfur emissions further at an incremental dispatch cost. (Ex. 2, p. 84).

RESULTS OF FLORIDA POWER'S INTEGRATED RESOURCE PLANNING

69. The cumulative [*34] present worth risk analysis graphs extended until 2030 also shows that Alternative 3, the four combined cycle units, is projected to be the lowest cost option for adding new capacity to Florida Power's system, when compared to the 10 alternatives. (Ex. 83, pp. 1-5).

70. The purchased power alternatives, 10 and 6, were not projected to be as cost effective as the proposed Polk County units. When compared to Alternative 3 in present value dollars, Alternative 6 is projected to cost approximately $ 17.5 million more, and Alternative 10 is projected to cost approximately $ 80 million more. (Tr. 1089; Ex. 105).

71. Alternative 6 was projected to be the second best option. Alternative 6 included a short-term purchase of 110 MW of coal-fired capacity from the Orlando Utilities Commission (OUC). (Tr. 1086; Tr. 935-6; Ex. 105).

72. Florida Power expects a life extension of the Higgins Plant and the two Avon Park combustion turbines planned for retirement in 1999 and 2000 respectfully to cost Florida Power's customers approximately $ 37 million more in present value terms than building the Polk County units. These costs are predominantly due to Clean Air Act compliance measures [*35] that Florida Power would have to undertake if the units were not retired (Tr. 1112-1113).

73. In 1991 dollars, Alternative 3 is expected to be the best option, at approximately $ 20.4 to $ 20.6 billion over a 30-year period. (Ex. 105, 87).

74. Without the addition of the Polk County units, Florida Power expects its winter reserve margin will range from 13.9 percent for winter 1998/99 to 5.6 percent in winter 2000/01. (Tr. 924; Ex. 68)

75. Florida Power projects that it must add a minimum of 83 MW in November, 1998, 381 MW in November, 1999, and 276 MW in November, 2000 in order to meet Florida Power's forecasted 1998/99. 1999/00, and 2000/01 winter peak load, respectfully. (Ex. 81).

76. The second combined cycle unit in 1999 is not needed to meet Florida Power's reliability criteria. (Ex. 86).

77. Florida Power's analysis shows that deferring one 1999 unit to the year 2000 is expected to increase the cost by $ 1.3 million over a 30-year period. This represents an expected increase of 0.007 percent. Sulfur dioxide emissions would be higher if the second unit were deferred by one year. (Ex. 87)

78. Florida Power expects that the accuracy of the total cost of each [*36] alternative plan over 30 years is plus or minus 20 percent and the accuracy of

the differences between the alternative plans is plus or minus 5 percent. (Tr. 955)

STATEWIDE NEED FOR GENERATION

79. To assist in determining the consistency of the proposed Polk County Units with peninsular Florida's system reliability and need, an update of the Florida Electric Power Coordinating Group's (FCG) 1989 Planning Hearing Generation Expansion Planning Studies document (1989 APH) was provided. The 1989 APH showed an accumulated addition of 5,930 MW, 6,990 MW, and 7,785 MW of generating capacity would be required in the winters of 1998/99, 1999/00, and 2000/01, respectively, to meet the reliability criteria. (Tr. 622; Ex. 36).

80. Adjustments were made to that information for known changes, including the removal of Florida Power's previously identified coal units. (Ex. 36). After these adjustments, the reserve margins for the winters of 1998/99 through 2000/01, excluding Florida Power's Polk County Units, are less than the amount necessary to maintain adequate peninsular Florida reliability. (Tr. 623-624; Ex. 36). Florida Power's proposed capacity additions will provide only a [*37] portion of the additional generating capacity that is needed for peninsular Florida to maintain an adequate level of reliability. (Tr. 621).

GAS SUPPLY AND TRANSPORTATION

81. Florida Power currently uses very small volumes of natural gas on its system. (Tr. 1091). Florida Power's Bartow, Higgins, Turner, and Avon Park plants all have natural gas capability and are served by FGT on an interruptible basis. (Ex. 2, p. 170). The Suwannee plant is served by SGNG, also on an interruptible basis. Id. Florida Power plans to use about 8.8 MMCFD of natural gas at its planned facility at the University of Florida. Id.

82. Florida Power is considering a possible conversion of its Anclote plant as supported by testimony of the witnesses and the Letter of Intent (Late filed Ex. 28). As shown in the December 3, 1991 letter of intent, Anclote will require approximately 120 MMCFD of natural gas beginning in 1995. The Anclote units are expected to have less than a 50-percent capacity factor for a number of years.

83. The four Polk County units (940 MW) will require about 100 MMCFD on average, and will have a peak demand of between 200 and 216 MMCFD. (Tr. 449; Ex. 2, p. 172) [*38]

84. The Polk County units will contribute to fuel diversity on Florida Power's system and in peninsular Florida. (Tr. 1091-1092; Ex. 2, p. 126). The Polk county units will increase the percentage of installed gas-fired combined cycle generating capacity in peninsular Florida to about 6 percent in 1998/1999 and about 9 percent in 2000/2001. (Tr. 1092; Ex. 106, p. 2).

Fuel Forecast

85. The fuel price forecast uses the same basic methodology as that used previously by Florida Power and reviewed by the Florida Public Service Commission as recently as the 1991 Annual Planning Hearing. (Tr. 536). Florida Power's natural gas price forecast is conservative and may show a relative price disadvantage for gas as compared to other fuels. (Tr. 587, 595).

86. Florida Power's forecast of natural gas price trends is well within the range of projections compiled by other recognized sources. (Tr. 575, 577).

Such sources include Data Resources, Inc., the Gas Research Institute, the American Gas Association, and the United States Department of Energy's Energy Information Administration. (Tr. 576-77).

87. In Florida Power's base- and low-case fuel forecasts, natural gas is expected [*39] to be priced at or below the price of low sulfur oil and well below the price of distillate oil. (Tr. 532,538; Ex. 2, pp. 71-73). Florida Power expects that natural gas prices will remain below oil competition levels through most of the 1990s. (Tr. 576).

Gas Supply

88. Natural gas reserves and resources in the United States are vast and well documented. (Tr. 579; Tr. 497). Recent studies estimate the nation's gas resource base to be in excess of 1 quadrillion cubic feet. (Tr. 579; Ex. 34, pp. 1-2; Ex. 2, pp. 163, 167). In 1990, less gas was consumed than was added to the reserve base. (Tr. 497; Ex. 2, p. 163). In relation to these vast resources, Florida Power's expected natural gas requirements are quite small. (Tr. 578).

89. Florida is relatively close to significant potential onshore gas reserves in Louisiana, Mississippi, and Alabama, as well as the offshore Gulf Coast gas-producing regions and some of the country's largest coalbed methane deposits. (Tr. 580; Tr. 502; Ex. 2, p. 162-164).

90. Florida Power has not entered into any contracts or letters of intent for gas supply for the Polk county units. (Tr. 391). Florida Power's strategy is to defer entering [*40] into fuel supply contracts until a time closer to the in-service date of the Polk county units. (Tr. 391, 394-395; Ex. 2, p. 169). Florida Power does not expect to enter into contracts until after the Florida Public Service Commission and the Department of Environmental Regulation have authorized the Polk County units. (Tr. 394-395).

Gas Transmission

91. Florida represents the only major demand growth area in the United States that is served by only one natural gas pipeline. (Tr. 396). FGT is the only major natural gas pipeline currently serving peninsular Florida. (Ex. 2, pp. 170-171). The FGT system has been expanded recently in two stages. Id. The second stage is expected to be complete late in 1991 or early in 1992. Id. Virtually all of FGT's resulting delivery capability (925 MMCFD) has been reserved on a firm basis. Id. Florida Power has reserved 8.8 MMCFD of transportation capacity from the Phase II expansion to serve Florida Power's planned University of Florida plant. (Ex. 2, p. 170).

92. FGT currently is planning a Phase III expansion to be completed in 1994 or 1995. Id. The capacity expected to be available from this expansion has been [*41] heavily oversubscribed by potential shippers. Id. Florida Power has not executed a contract with FGT, but it has placed an initial request for Phase III capacity in the following amounts: (a) May-September - 140 MMCFD; (b) October-April 55 MMCFD. (Id.; Tr. 431-432). This capacity could accommodate a conversion of the Anclote units in the mid-1990's, but is not expected to accommodate the needs of the Polk County units. (Tr. 431, 396).

93. Florida Power initially identified three gas transportation options. (Tr. 397; Ex. 2, pp. 172-173). Option A was the development of a new independent pipeline owned by Florida Power and others. (Tr. 397; Ex. 2, p.

172). Option B was a subsequent expansion of FGT's system (beyond Phase III) to accommodate the Polk county units, while committing the Anclote gas requirements to FGT's Phase III expansion. (Tr. 397; Ex. 2, 172). Option C was to commit to capacity on a new, competitive pipeline to be constructed by a party or parties other than Florida Power or FGT. (Tr. 397; Ex. 2, pp. 172-173).

94. Florida Power has been negotiating with a newly-formed joint venture consisting of United Gas Pipeline Company (United) and the ANR [*42] Pipeline Company (ANR) (a division of Coastal Corporation). (Tr. 427, 443-444). The Suncoast Venture has been formed for the purpose of building a new pipeline in Florida. (Tr. 443-444; Ex. 28).

95. Florida Power has executed a December 4, 1991 non-binding Letter of Intent (the Letter) with respect to the SunCoast Venture. The Suncoast venture involves the construction of a new intrastate pipeline approximately 560 miles in length with an initial capacity of 400 MMCFD. The pipeline is expected to have a delivery point to the Polk County units as well as delivery points both upstream and downstream of the Polk County site. (Ex. 28)

96. As of the signing of the Letter of Intent, FGT has not presented Florida Power with any proposal that would be more advantageous to Florida Power than the SunCoast proposal. (Ex. 28)

97. In assessing pipeline options, Florida Power must consider both short-run fuel savings and the long-term benefits of developing competitive pipeline capacity in Florida. (Tr. 415-16, 435-38). It is not necessarily in the long-run best interests of Florida Power's customers for Florida Power to capture short-term fuel savings by foregoing the cost savings [*43] or strategic benefits that competitive gas transportation can generate. Id.

98. The absence of pipeline competition has hampered Florida Power's ability to obtain desired terms and conditions of transportation service. (Tr. 441). The introduction of competition could help facilitate more attractive terms of service and prices. (Tr. 437, 441; Tr. 500).

99. The initiation of every major pipeline project in the nation in recent years has been based on the advance gas transportation commitments of one or more key shippers, or, in other words, an "anchor load." (Tr. 480-481; Ex. 24).

100. An anchor load ensures that a pipeline will be built in sufficiently large diameter to achieve economies of scale. (Tr. 476-477). Such economies is expected to allow transportation rates to be held to levels that will attract shippers and allow the gas transported on the new system to remain competitive with alternative fuels. Id. Firm contracts with credit-worthy shippers typically are required for the pipeline sponsor to obtain financing. (Tr. 477).

101. An anchor load must be sufficiently large to justify the several million dollar expenditure necessary to do preliminary analyses [*44] and get a pipeline project to the stage of the required regulatory findings. (Tr. 479-80). Ideally, project development would not begin without firm commitments for all of the pipeline's capacity. (Tr. 477).

102. Generally, an anchor load represents a volumetric commitment of between one-third and one-half of the pipeline's capacity. (Tr. 483). More committed load at the outset translates to an increased likelihood that a competitively sized pipeline will be constructed. (Tr. 503).

103. Since the proposed pipeline (Suncoast) has an initial capacity of 400 MMCFD, a sufficient anchor need only require between 133 and 200 MMCFD. (Tr. 483, Ex. 28).

104. The proposed pipeline construction configuration shows a lateral to Anclote and Peoples Gas System, and laterals to Orlando, Kissimmee, Lakeland, Teco-Hardee, Seminole-Tocala, and Teco-Power Park. (Ex. 28).

105. The contractual arrangements and design for the engineering, permitting, certification, construction, and testing of a major natural gas pipeline can require a lead time of six to seven years. (Tr. 403-04, 407; Tr. 483-93; Tr. 590-92; Ex. 21). This lead time is approximately the same under any of the identified [*45] pipeline options. (Tr. 484-85; Tr. 592). The tentative pipeline schedule shown in Exhibit 21 is reasonable because of the following factors:

* After a need for new gas pipeline capacity has been established, the contractual arrangements required to bring about such a development can take a year or more to finalize. (Tr. 590; Tr. 407).

* Before required filings are made for regulatory approvals of the pipeline, it can take 12 to 18 months (some of this time can overlap the contracting phase) to conduct the design and engineering work, the right-of-way evaluation and acquisition, and the development of cost estimates, pro forma rates, and a proposed tariff. (Tr. 487-89).

* Obtaining state, federal and local approvals for major natural gas pipeline construction can take four to five years, as evidenced by recent pipeline proceedings at FERC. (Tr. 490; Tr. 591; Tr. 403). Unexpected environmental issues or other complications will tend to draw out the process. (Tr. 489).

* Following regulatory approvals of a new natural gas pipeline, construction may be delayed by approximately six months to account for such factors as the final redesign necessary to comply with regulatory requirements, [*46] the finalization of the construction contract, the mobilization of construction forces, and the completion of financing. (Tr. 491-92). Thereafter, construction can be expected to take up to two years. (Tr. 492; Tr. 592; Tr. 407; Ex. 21).

106. To ensure that sufficient new natural gas pipeline capacity will be available for the Polk County units, there can be no material delay in initiating significant pipeline development activities. (Tr. 407, 421; Tr. 589, 596). Pipeline capacity can be constructed between now and the 1998 in-service date for the Polk County units, but not if there is an initial delay in commencing the development process. (Tr. 407; Tr. 589).

FINANCIAL IMPACTS

Impact of the Construction of the Polk County Units

107. Florida Power has conducted analyses to ensure that the Polk units will not adversely affect its financial portfolio. (Tr. 1083; Tr. 197; Tr. 277-78; (Ex. 2, pp. 150-55).

108. Florida Power has determined that it can finance the investments included in its Integrated Resource Study, Docket No. 910759-EI, through conventional means without threatening its AA bond rating. (Tr. 307).

Impacts of Purchased Power on Credit Rating [*47]

109. Increased utility industry reliance on purchased power has received attention from ratings analysts and the financial community, who are reassessing the consequences of this development. The legal and financial complexities of purchased power transactions have outstripped conventional analytical tools, resulting in divided opinions regarding the specific degree of consequences from having significant levels of purchased power. (Tr. 193).

110. Power purchase agreements have been recognized as an issue by all major credit agencies. The financial community gives purchased power policy close scrutiny when the amount of purchase capacity reaches 10 to 15 percent of the utility's total available resources. (Ex. 12, p. 3).

111. No clear-cut formula can be followed in assessing the impact of third-party generation on an investor-owned utility's credit profile. The financial community's understanding of the implications of utility purchases is still evolving. But increased reliance on this source of power does not have to portend lower credit ratings. (Ex. 7, p. 5)

112. Quantifying the financial impacts of the reduced planning and operating flexibility caused by power purchases [*48] is difficult. In addition, there is no agreed-on method for calculating increases in risks that result from them. (Tr. 296, 299; Ex. 16).

113. To a degree, purchased power obligations can be absorbed in the credit quality assessment. Purchased power obligations are only one factor in credit quality assessment. Coverage and capitalization ratios may move somewhat within ranges without impacting the credit rating of a utility. (Tr. 182)

114. Qualitatively, determining credit quality includes a judgmental assessment of any and all circumstances that bear on risk exposure. Such circumstances include the outlook for sales, competition, management quality, the regulatory environment, the quality of reported earnings, and the quality of the balance sheet. (Tr. 167; Ex. 6, p. 2).

115. Quantitatively, utility credit quality is based on a number of financial ratios. Three of the primary ratios are debt leverage, interest coverage, and the internal funds ratio. A lower value for the first and higher values for the (second and) third of these ratios indicate - all other things being equal - lower risk to bondholders and higher credit quality. (Tr. 166-67; Ex. 6, p. 3).

116. [*49] What enhances a utility's credit quality after a purchased power contract or a construction option has been exercised is the total qualitative and quantitative posture of the utility. (Tr. 232-3)

117. Capacity payments can contribute to the overall utility credit risk because these payments increase the utility's aggregate fixed-charge obligations. (Tr. 188) However, the qualitative factors associated with the terms of purchased power contracts can reduce the financial risk of these types of payments. (E. 11, p. 4).

118. Depending on the financial condition of the utility, third-party purchases can be beneficial to a utility. Furthermore, a utility's credit rating could be upgraded despite the fact that its purchased power commitments have increased. (Tr. 233, 248)

119. In measuring the financial impact of purchased power contracts, Duff and Phelps converts the fixed obligations for the contracts into debt

equivalents on a utility's income statement and balance sheet. Duff and Phelps reclassifies one-third of the total capacity charges associated with purchased power as the equivalent of interest expense on the income statement. The approximate value of the assets that [*50] provide the capacity are added to the balance sheet as the equivalent of additional debt. (Tr. 175).

120. Standard & Poors (S&P) will balance the risks with the benefits in assessing the impact on a utility's creditworthiness. The analysis will cover all aspects of the utility's credit profile including financial, operating, and regulatory segments. (Ex. 7, p. 5)

121. Moody's recognizes that there are a number of clear benefits a utility can gain by entering into purchased power commitments. However, Moody's also believes that there are risks inherent in a utility's use of purchased power. Therefore, in assessing the impact of purchased power commitments on a utility's credit quality, Moody's will focus on the specific terms and conditions of the underlying contracts, the financial and operating strength of the power providers, and the unique characteristics of the utility. (Ex. 8, p. 9)

Duff and Phelps' Downgrades of Other Utilities

122. Increased financial pressure expected to accrue from generating capacity purchases contributed to several Duff and Phelps rating actions in 1989 and 1990. Credit downgrades for Consolidated Edison Company (Ex. 10), the Delaware [*51] Economic Development Authority (a project of Delmarva Power and Light Company), Orange and Rockland Utilities, Inc., Eastern Edison Company, Public Service Electric and Gas Company, and Potomac Electric Power Company all cited the impact of both purchased power and construction as contributing to the downgrade action. (Tr. 176-7, 243-4; Ex. 10, Ex. 13).

123. The news release from D&P concerning the credit downgrade of Public Service Electric and Gas Company states that the utility plans to rely primarily on independent power producers and cogenerators to meet its future generation needs over the next several years. (Ex. 13) The fact that Florida Power is contesting even the exercise of soliciting bids for purchased power confirms that the company has no intention of relying primarily on these sources for its future generation needs.

124. All of the news releases from D&P cite declining interest coverage ratios, declining equity ratios, and a general deterioration in financial protection measures that have been occurring in some cases over the past several years. (Tr. 243-4; Ex. 10; Ex. 13)

125. Since its last heavy construction cycle in 1982, Florida Power has taken great [*52] strides to improve its financial protection measures and put itself in a strong financial position for the start of this growth cycle. (Tr. 236) Florida Power has increased its equity position from 44.6% of investor capital in 1982 to 56% in 1990 and has improved its interest coverage ratio from 2.42x to 3.89x over the same period. (Tr. 375)

126. Florida Power is currently rated AA- by Duff and Phelps, representing an upgrade from its 1986 rating of A+. Florida Power has similar lower tier AA class credit quality ratings from the other major credit-rating agencies. (Tr. 168; Ex. 2, p. 150).

Florida Power's Level of Purchased Power

127. Florida Power has contracted for significant amounts of power as measured by methods recognized and used by credit-rating agencies in the financial community. Purchased power is projected to represent 15 percent of Florida Power's total generation resources by 1998. (Tr. 165, 182; Ex. 2, p. 157).

128. Total purchased power capacity charges are projected to reach 178 percent of interest expense in 1997, based on the Integrated Resource Study, which assumes a 75-percent success rate for contracts of future purchased power delivery (exclusive [*53] of the Southern UPS contract). (Tr. 182; Ex. 2, p. 157).

Financial Affect of Building versus Buying

129. When a utility builds a plant and then places it in its rate base, the utility obtains revenue to cover operating costs and capital costs. The operating costs include depreciation, return on equity, and sometimes deferred taxes. The revenues covering each of the costs are available to the utility to reinvest in the utility system as customer needs require. (Tr. 270; Ex. 2, p. 156). In contrast, when a utility purchases capacity, the revenues obtained flow through to another party to cover its debt and pay dividends to its shareholders. (Tr. 270).

130. Excluding variable costs such as fuel, interest payments are the only fixed long-term financial obligation associated with a utility-owned power plant. Other revenue requirement components associated with a utility-owned generating plant include the equity return and depreciation. These funds ensure that the utility can meet its interest obligations at all times, which is the primary concern of credit-rating agencies. (Tr. 308-09).

131. Relying on a NUG purchase, as opposed to a generation asset constructed and [*54] owned by the utility, reduces depreciation cost recovery as a source of cash to the utility. Depreciation cost recovery is the single largest source of cash flow available for investing in new facilities to serve customers. (Tr. 180; Ex. 2, p. 156).

132. There are two ways of compensating for the financial consequences of increased purchased power obligations. One is to increase the proportion of equity used to finance other utility assets. The second is to increase the rate of return on equity. Both represent real costs of purchased capacity. (Tr. 181).

THE POLK COUNTY UNITS

Site Description

133. Florida Power undertook a comprehensive and exhaustive selection study to identify a site capable of accommodating a wide range of fossil-fuel technologies, including combined cycle units fueled by natural gas. (Ex. 2., pp. 187-190). The site selection process considered environmental, socioeconomic, and engineering criteria, including fuel delivery facilities and the location of existing transmission. (Ex. 2, pp. 187-190). Florida Power received considerable assistance in this effort from an independent group of environmentalists, educators, and community leaders [*55] called the Environmental Advisory Group (EAG). The EAG met regularly to review Florida Power's siting criteria and helped to identify issues of public concern. (Tr. 1025).

134. The site chosen as a result of the selection process is the 8,000 acre Polk County site, located in southwest Polk County, approximately 40 miles east of Tampa and 3.5 miles northwest of Ft. Meade. (Tr. 1027).

135. The site represents a rare opportunity to make beneficial use of land that has already been disturbed by the activities associated with on-going phosphate mining. Unlike more "traditional" site preparation and development activities, approximately two years of activity on the site will be required before actual construction of the generating units can begin. (Tr. 1033, 1053).

136. The location identified as the power block site is presently highly irregular and under water. As Mr. Major described in his testimony, approximately 8 million cubic yards of fill material will be required to develop the power block area - the equivalent of stacking 100 football fields 60 feet high. This fill will come from an existing pond on site which has not yet had clay deposited in it. (Tr. 1041).

137. [*56] One of the reasons it is necessary to proceed with the licensing activities at this time is to ensure that the required fill material remains suitable for fill. This will involve the relocation of some on-going mining activities to ensure that clay is not deposited in the settling pond that will be the source of the fill material. (Tr. 1060-1061).

Associated Facilities

138. The 1998 Polk County unit is expected to require the looping of the existing Barcola-Ft. Meade 230 kV transmission line into a new 230 kV switchyard at the plant site. This line passes through the site. (Tr. 1029-1030).

139. For the remaining three units, Florida Power expects that it will be necessary to rebuild a portion of the existing line from Barcola to the plant site with double-circuit structures to support two 230 kV circuits. The portion of the line from the plant site to Ft. Meade is expected to require the addition of a new 230 kV circuit and is expected to use existing structures. In using the existing structures, Florida Power expects it to be necessary to relocate approximately 2.7 miles of the existing Ft. Meade-Rockland 115 kV circuit, parallel to SR 630 west of the Ft. Meade substation. [*57] (Tr. 1029-1030).

140. The associated transmission facilities required will depend ultimately on the number of units certified. For certification of only the first two Polk County units, the associated transmission facilities required are expected to be those stated in finding 138 and a portion or all of those stated in finding 139. (Tr. 1029).

141. Florida Power expects a natural gas lateral will be needed. The exact dimensions of the lateral will depend on the ultimate placement of the natural gas pipeline. (Tr. 1030).

142. A facility for storage of up to 3 days of distillate oil as a backup fuel for natural gas will be necessary for the Polk County Units. (Tr. 1030)

Cost of the Units

143. Florida Power has refined its site-specific cost estimate for the Polk County Units as the project has developed. As preliminary engineering is completed, this estimate will be further refined. Florida Power's current estimate of $ 566/kW (1991 dollars) includes site development, associated transmission, and a potential gas lateral. (Ex. 97).

144. The current site-specific cost estimate of $ 566/kW (1991 dollars) for the Polk County units compares favorably with the non-site-specific [*58] cost estimate of $ 599/kW (1991 dollars) used by Mr. Niekum in the evaluation of the alternative plans for planning purposes. (Tr. 1034-35; Ex. 97).

145. The units will be constructed by Florida Power using the traditional approach to utility construction contracting as described in Mr. Ruisch's testimony. (Tr. 102). Florida Power will use an architect/engineer to design the plant and to assist Florida Power with construction management. Multiple fixed-price bid solicitations with well-defined work scopes will be used for equipment manufacturers and other subcontractors. (Tr. 1033).

146. Environmental compliance measures are included in Florida Power Corporation's estimates of costs for such items as equipment, construction, spare parts and inventory, indirect costs, contingencies, land and site development, transmission and switchyard, and gas lateral and metering. (Tr. 1063).

147. The capital cost of the combined cycle units is expected to be half the capital cost of a pulverized coal plant. (Ex. 2, p. 108). The combined cycle technology provides operational flexibility, moderate construction time, and fuel diversity. (Ex. 2, p. 108).

148. The total installed cost [*59] for all four Polk County units is expected be approximately $ 862 million. This estimate includes escalation and AFUDC. The land and development cost for the Polk County site is approximately $ 64 million (1991 dollars). The cost of the four combined cycle units is approximately $ 448 million (1991 dollars). (Ex. 97).

149. Florida Power employs competitive bidding in its power plant construction and in its fuel procurement. (Tr. 1177-78).

Operational Specifications

150. The Polk County units are designed to operate on natural gas with distillate as a backup fuel. The Polk County site can accommodate all necessary on-site gas facilities such as compressors and metering that may be required. (Tr. 1030).

151. Following the installation of the Polk County units, Florida Power's natural gas use is projected to change from nearly zero to 11 percent. (Ex. 2, p. 179)

152. The Polk County units are extremely efficient, having an expected heat rate of 7,960 Btu/kWh. As a result, these efficient plants use smaller amounts of fuel per unit of electric service delivered, and when combined with the use of a clean fuel, these units can reduce the exposure of Florida Power's [*60] system to new environmental rules or taxes. (Ex. 2, p. 180, Ex. 1, p. 111).

153. The Polk County units are expected to have a Scheduled Maintenance Rate of 5% and a Forced Outage Rate of 4% (Ex. 1, p. 111).

154. The Polk County site is capable of future conversion to coal gasification. The site layout is designed to allow coal delivery, storage and handling, as well as allowing space for gasifiers and solid waste disposal areas for gasification byproducts. Preliminary air quality analyses for coal gasification emissions indicate the site is suitable. Two industrial-grade rail lines are adjacent to the site to facilitate future coal delivery. (Tr. 1029).

155. The four combined cycle units are expected to operate as intermediate (55-percent capacity factor) units on Florida Power's system. However, these units have the ability to run base load (continuous duty) as required. (Ex. 2, p. 84).

TIMING OF NEED DETERMINATION

156. A one-year delay in the in-service date of the all four of the proposed units will cause Florida Power's winter reserve margin to drop below its minimum level of 15 percent. With this one-year delay, the projected reserve margins will range from [*61] a low of 12 percent in the winter of 1999/2000 to 14.5 percent the following winter. Further delays will have a more dramatic effect. (Ex. 2, pp. 199-200).

157. Florida Power's proposed schedule preserves the ability to bring the combined cycles on line early to meet any contingencies that might affect system reliability. If the units are delayed, strategic flexibility to mitigate problems such as a delay in QF capacity, a greater anticipated load, or a delay in the 500 kV line, would be unavailable. (Ex. 2, p. 201).

158. Denying or delaying the entire Determination of Need for all four could cause increased site development costs; however, denying or delaying the Determination of Need for the 1999 or 2000 combined cycle units need not cause increased site development costs. (Tr. 1060, 1061)

159. The determination of how much capacity is needed and the cost-effectiveness of a capacity choice becomes more accurate the closer it is to the date the capacity is needed. (Tr. 666, 667).

160. Florida Power's proposed construction time for the combined cycle unit is approximately three years. (Tr. 1050, Ex. 1, p. 195)

CONCLUSIONS OF LAW

The Florida Public Service Commission [*62] has jurisdiction over the parties and the subject matter of this docket pursuant to Chapters 120 and 366, Florida Statutes, section 403.519, Florida Statutes, and Chapter 25-22, Florida Administrative Code.

The information provided in this record satisfies the informational requirements of Rule 25-22.081, Florida Administrative Code. Florida Power Corporation has provided sufficient information on the site, design and engineering characteristics of its four proposed 235 MW combined cycle units to evaluate its proposal. On the basis of the competent substantial evidence contained in the record, I have evaluated the proposed Polk County units, and I hold that, for the reasons stated below, at this time Florida Power Corporation has a need to construct two of the four proposed units to meet its future capacity needs. I propose that Florida Power's petition for a determination of the need to construct the first two Polk County units be granted. Further I hold that Florida Power Corporation's petition for a determination of the need to construct the last two units to meet projected capacity needs for the years 1999-2000 is premature, and I propose that the petition for the last two [*63] units not be granted at this time.

Section 403.519, Florida Statutes, provides that in considering the need for a proposed electrical power plant, the Commission must take into account:

. . . the need for electric system reliability and integrity, the need for adequate electricity at a reasonable cost, and whether the proposed plant is the most cost-effective alternative available. The commission shall also expressly consider the conservation measures taken by or reasonably available to the applicant or its members which might mitigate the need for the proposed plant and other matters within its jurisdiction which it deems relevant.

Reliability and the Need for Adequate Electricity at a Reasonable Cost

The record in this case supports the conclusion that the first two proposed combined cycle units on Florida Power's proposed Polk County site will contribute to electric system reliability and integrity. I find that Florida Power's reliability criteria - a LOLP of 0.1 days per year and a winter reserve margin of 15% - are reasonable for planning purposes. I also find that the addition of the first two units will enable Florida Power to meet that winter reserve margin criteria [*64] and to withstand the outage of its largest unit at time of system peak. The combined cycle technology chosen is a sufficiently mature and reliable generating option for Florida Power's system. The first two Polk County units will contribute to diversifying Florida Power's system fuel mix, and thus contribute to the integrity of Florida Power's system.

I find that Florida Power's load forecast is reasonable for planning purposes, and it supports the conclusion that the first two proposed Polk County units will contribute to, and are in fact needed to ensure, electric system integrity and reliability. Additions of 5,930 and 6,990 MW of generating capacity are projected to be required in the winters of 1998/99 and 1999/00 for peninsular Florida (Finding of Fact 79 (FF79)) and the first two Polk County units are needed to provide a portion of that required generating capacity.

At this time, however, I cannot find with certainty that Florida Power's load forecast supports the conclusion that Florida Power's last two proposed units are needed to provide adequate electricity to Florida Power's customers, because the need is identified in the long term, far in the future. Too much uncertainty [*65] remains with respect to Florida Power's planned resources in the 1999-2000 time frame. For example, to ensure against the possibility that some QF's may default in their obligations, Florida Power has contracted for more capacity than reliability studies indicate is needed. (FF51) If all of Florida Power's contracted QFs perform, Florida Power will have 211 MW more capacity than projected. All other things being equal, the additional 211 MW of capacity would be sufficient to avoid or delay construction of one of the Polk County units. (FF52) On the other hand, if Florida Power's proposed 500 kV transmission line is not constructed, this event would push the need forward, and Florida Power would have to advance the construction of one of its combined cycle units. (FF59)

It is reasonable and beneficial to wait to grant a Determination of Need for the construction of the last two Polk County units, because the load, fuel, and conservation forecasts will be more certain. In addition, Florida Power will know in approximately four years, by 1996, how much of the 800 MW of contracted QF capacity will materialize, and whether the 500 kV line will be completed as planned.

Florida Power [*66] can defer its third combined cycle unit from 1999 to 2000 without violating its reliability criteria. (FF76) It appears that the deferral of this unit would cause virtually no difference in cost. (FF77 &

FF78) While construction of this unit in 1999 would likely produce Clean Air Act benefits, those benefits are not quantifiable at this time.

Through a thorougheconomic analysis of a variety of generating alternatives, Florida Power Corporation has shown that the first two proposed Polk County units will contribute to the provision of adequate electricity to Florida Power and the State of Florida at a reasonable cost. The design of the units is based on the use of modern, high-efficiency gas-fired combustion turbines and steam turbines configured in a "combined cycle." As a result, these efficient plants use smaller amounts of fuel per unit of electric service delivered. (FF152) The units take approximately three years to construct. (FF160)

The associated facilities that will be required by Florida Power in conjunction with the two recommended 235 MW units at the Polk County Site, including transmission facilities, oil storage facilities, and a natural gas lateral, are reasonable. [*67] Furthermore, the reasonably anticipated costs of environmental compliance of the first two Polk County units have been adequately considered. Florida Power included the costs of environmental compliance in its estimates for equipment, construction, spare parts and inventory, indirect costs, contingencies, land and site development, transmission and switchyard, and gas lateral and metering costs (FF146).

The fuel forecasts submitted by Florida Power in this proceeding are reasonable and appropriate for planning purposes, and the record demonstrates that adding two 235 MW gas burning combined cycle units will contribute to fuel diversity for Florida Power and for the State. (FF84)

With respect to the issues of natural gas supply that arose during the course of this proceeding, it appears that Florida Power's natural gas requirements are quite small relative to present natural gas reserves in the United States (FF88) and sufficient gas reserves exist to fuel the first two Polk County units.

While the issues of gas transportation to the Polk County site are somewhat more complex, I also conclude that adequate assurances have been provided in this proceeding that gas transportation [*68] capacity will be available to serve the needs of the first two Polk County units. Florida Power contends, and I agree, that construction of a second natural gas pipeline into peninsular Florida will provide a variety of strategic benefits for the state. While the strategic benefits alone cannot lead to a determination of the need for the proposed power plants, certainly the Commission may consider them in this proceeding. I have so considered them in light of the new pipeline's contribution to fuel diversity for Florida Power and the State, and in light of the lead times associated with construction of the pipeline and the plants.

A commitment of one or more key shippers to use approximately one-third to one-half of the pipeline capacity is necessary to anchor the new pipeline. (FF102) While it is theoretically possible, the facts of this case do not demonstrate a clear probability that QFs would "anchor" the pipeline at this time, and no QFs claimed in this proceeding that they were presently willing to commit to a gas supply for the new pipeline.

Florida Power's Letter of Intent with SunCoast Venture indicates that Suncoast would construct a pipeline with an initial capacity [*69] of 400 MMCFD. (FF95) Because six or seven years are typically needed to bring a new pipeline of this size into service, it is necessary to make the decision of the units necessary to "anchor" the pipeline now. (FF105) Anclote plus two Polk

Units will use approximately half the pipeline capacity, and, therefore, they should act as a strong anchor load. (FF103) The facts do not support the conclusion that all four Polk County units are necessary to anchor the pipeline, and in view of the present uncertainty of the need for the last two Polk County units, I see no reason to change my conclusion that the petition for approval of the last two units should not be granted at this time.

Florida Power selected the Polk County site, a site to be developed on mined-out phosphate land, with the assistance of a group of educators, environmentalists, and community leaders known as the Environmental Advisory Group (EAG) (FF133 & FF135). The site preparation will be predominantly the same for two units as it would be for four units, and will take approximately two years of preparation before construction can begin. (FF135) I conclude that it is important for Florida Power to secure a site to [*70] meet its future generation needs, and approval of the first two Polk County units will be sufficient to that end.

A one-year delay in the completion of the first unit will cause Florida Power's winter reserve margin to fall below its minimum level of 15 percent. There are also adverse consequences associated with not starting now to prepare the site and secure the gas supply; however, there are no adverse consequences associated with waiting to certify the last units. In fact, it would be beneficial to wait to certify the last two units because more will be known about when they are needed and whether there would be a more cost-effective manner to meet the need.

Most Cost-Effective Alternative Available

Florida Power evaluated ten alternative generating plans in its Integrated Resource Study. These plans included various generating technologies, as well as purchased power options from other utilities. It was stipulated by all parties that Florida Power Corporation adequately explored other reasonably available generating technologies for its construction in lieu of the proposed project. I approve that stipulation, and I conclude that Florida Power's Integrated Resource [*71] Plan (IRP) developed from the Study is reasonable for planning purposes.

The record demonstrates that, for the purposes of planning, the planned unit retirements in 1999 and 2000 are cost-effective when compared to the refurbishment and continued operation of those units. Florida Power expects a life extension of the units to cost Florida Power customers $ 37 million more than constructing the four proposed Polk County units. These costs are predominantly due to Clean Air Act compliance measures that Florida Power would have to undertake if the units were not retired (FF72).

With respect to the effects of self-service generation on Florida Power's credit rating, I conclude that there is not competent substantial evidence in this record to determine what effect, if any, reliance on self-service generation would have on Florida Power's credit rating.

Florida Power's contention that further purchased power will have a negative effect upon its planning and operating flexibility did not impact my decision regarding the "buy vs. build" issues in this case. I am also not persuaded by the contention that further purchased power creates a substantial risk of a negative impact on Florida [*72] Power's credit rating. Florida Power has not demonstrated that it will experience a downgrade in its credit rating if it purchases more power.

While increased utility industry reliance on purchased power has received attention from ratings analysts and the financial community, these analysts have divided opinions regarding the specific degree of consequences from having significant levels of purchased power. (Tr. 193). There is no one method of evaluating purchased power that is widely accepted. (Tr. 296) The analysts agree, however, that there are risks in both purchasing power and constructing one's own plant. (Ex. 12, p. 7)

I find that increased reliance on this source of power does not have to portend lower credit ratings. (Ex. 7, p. 5) Just because a utility increases its reliance on purchased power does not mean that debt protection measures will deteriorate and a downgrade is imminent. In many cases, various qualitative factors may outweigh the quantitative factors. (Tr. 236-7; Ex. 12, p. 7)

I recognize that purchased power is not without its risks, just as constructing one's own plant contains risks. However, I also recognize that it is generally not possible to [*73] point to an increased reliance on purchased power as the sole reason for a change in credit rating. (Tr. 176) Similarly, I cannot conclude that Florida Power's credit rating would be downgraded solely because it constructs the needed generating capacity and participates in the construction of a pipeline. Each of the utilities downgraded by Duff and Phelps had demonstrated a pattern of deterioration in its financial ratios over a period of time preceding the downgrade action. The possibility of a credit downgrade exists for any utility that allows its financial protection measures to fall outside the ranges prescribed by the rating agencies, regardless of its level of purchased power. In light of the fact that Florida Power has steadily improved its financial protection measures since its last growth cycle, I find Florida Power's claim that additional purchased power commitments would result in a credit downgrade to be exaggerated.

Florida Power has demonstrated that it reasonably considered capacity purchases from other utilities and nonutility generators to meet future generation needs. In the past, Florida Power has purchased significant amounts of QF capacity (without any [*74] demonstrated loss of planning and operating flexibility). If all of Florida Power's contracted QF capacity comes on-line, it will have over 1,000 MW of QFs -- over 11 percent of supply-side resources. (FF48) Furthermore, in terms of the immediate need, the record in this case contains no formal proposals for a project capable of deferring the first two units.

I am reluctant to require Florida Power to bid for power to avoid construction of the first two units. Since no non-utility projects were proposed in this docket, I have no assurance that a bid would be successful. Power is needed in 1998 and, because of the delay associated with bidding, Florida Power would not have time to meet this need, should the bid be unsuccessful. If the bid is successful, it would jeopardize the construction of a second pipeline into peninsular Florida and Florida Power would likely lose its site for future generation. Therefore, whether successful or unsuccessful, requiring bidding for Florida Power's first two units would be detrimental.

Approval of Florida Power's first two proposed generating units and deferral of a decision on the last two gives non-utility generators ample time to negotiate [*75] with Florida Power for a power purchase contract to displace the third and fourth units. If those negotiations are not fruitful, non-utility generators will have the opportunity to intervene in Florida Power's future certification petition and to demonstrate why their non-utility power is less costly. Also, at that time the status of a new pipeline to transport natural gas for utility and non-utility generators alike will be more certain. Deferral of a decision on the third and fourth units gives non-utility generators time to develop and propose tangible projects. Failure of non-utility generators to come forward with a site specific alternative to Florida Power's third and fourth units will cast doubt on the availability of non-utility generators to supply this need.

At this time, I will not make a finding on how Florida Power should meet the needs of its third and fourth units. I will not require bidding for purchased power to avoid construction of these units for two reasons: the need for the third unit is not mature, and we have no policy or rules requiring bidding. However, Florida Power should reevaluate all of the options for meeting the needs of the third and fourth [*76] units before requesting certification in order to ensure that it chooses the most cost-effective option.

Furthermore, I conclude that consideration of whether to impose upon new Florida Power constructed generating capacity the same cost and performance obligations that Florida Power Corporation imposes upon QFs is beyond the scope of this proceeding, as is the question of whether Florida Power is obligated as a matter of law to purchase QF capacity in lieu of constructing the proposed units. Those issues are more properly addressed in a generic rulemaking docket or ratemaking proceeding. In fact, the obligation to purchase issue will be resolved in such a proceeding, specifically Docket No. 910603-EQ, the negotiated QF contracts docket. In addition, if Florida Power's construction, non-fuel operating, and maintenance costs are substantially higher than what they are claiming they will be in this docket, the increase in costs will have to be justified in some future rate case to obtain cost-recovery. This is the risk the company assumes by constructing its own units.

Conservation or other non-generating alternatives

As mentioned above, section 403.519, Florida Statutes [*77] requires the Commission to consider "whether the proposed plant is the most cost-effective alternative available" for meeting the need for additional generating capacity. FRG has raised the issue of whether this phrase means the same thing as "least cost option." I conclude that it does not. The term "least cost" does not appear in the statute or Commission rules. Had the legislature intended those terms to be synonymous, it would have so indicated. The evidence shows that the first two Polk County Units have the lowest cost on a cumulative present worth revenue requirements basis. Regardless of the resolution of this question, the record contains no competent substantial evidence that the requisite amount of capacity is or will be available elsewhere at a cheaper cost.

FRG has questioned whether Florida law requires Florida Power to examine and use all reasonably available conservation measures that might mitigate the need for the proposed plant. I conclude that Florida law imposes no such requirement on a utility. Section 403.519 imposes a requirement on the Commission to consider the conservation measures taken by or reasonably available to the utility which might [*78] mitigate the need for the proposed plant. As described in the findings of fact above, I have taken these matters into account, and I conclude that, based on the information available in this record, Florida Power has adequately considered the conservation measures that are reasonably available to it to avoid the need for capacity as required by section 403.519, Florida Statutes.

Florida Power examined 199 potential conservation programs prior to filing its conservation plan containing 22 cost effective programs with the Commission in February 1990. Florida Power's Maximum Avoidable Capacity Scenario (M.A.C.S.) submitted in this proceeding expands upon those programs, and allows for the development of additional programs. (FF29 & FF30). I conclude that Florida Power is taking the conservation measures that are reasonably available to it at this time, but the market penetration rates for some of Florida Power's conservation programs appear to be low. (Tr. 1320, 1361, 1414-17) For example, its residential air conditioning service program is planned to have a market penetration of only 1.0 percent by 1996. In addition, the market penetrations of the company's commercial/industrial [*79] conservation programs also appear low. At this time, however, there are no conclusive facts available to determine that additional conservation could be achieved by expanding participation in those programs projected to have a participation rate less than 10 percent by 1996. By increasing participation to 10 percent in those programs, 792 MW could be saved. (FF40) Ten percent is arbitrarily chosen to demonstrate how it appears on paper that conservation can displace the proposed units. However, there is scant evidence in the record about how difficult or easy it is to increase conservation market penetration even a few percent. Florida Power's load management and load shifting programs have performed well, but those programs primarily save peak demand and peaking units, with little savings in energy generated by base load units.

Delay of approval of the third and fourth units gives the Commission further time to analyze Florida Power's conservation market penetrations. To this end, Florida Power shall resubmit its conservation plan and programs to the Commission for approval one year prior to filing its petition for determination of need for the third and fourth Polk County [*80] units. Included in its conservation plan shall be a definitive explanation of why its conservation programs are not projected to achieve higher participation rates.

It is my recommendation that the Florida Public Service Commission enter a final order:

(a) incorporating the foregoing Findings of Fact and Conclusions of Law;

(b) granting the Petition for Determination of Need for the first two proposed Polk County Units only; and

(c) that the Final Order be submitted to the Department of Environmental Regulation as required by and in accordance with the date specified by Section 403.507(2) (a)2, Florida Statutes.

Respectfully submitted,

BETTY EASLEY, Commissioner and Hearing Officer

APPENDIX

RESPONSES TO PROPOSED FINDINGS OF FACT

FLORIDA POWER CORPORATION

THE PARTIES

1. Florida Power Corporation ("Florida Power") is an investor-owned public utility regulated by the Public Service Commission. Florida Power provides electrical power to more than one million customers in thirty-two (32) counties in the state of Florida. (Keesler, Tr. 72; Ex. 2, pp. 5, 32).

We accept the above proposed finding of fact.

2. Florida Industrial Cogeneration Association ("FICA") is [*81] an association whose members own or operate cogeneration facilities in Florida. (Seelke, Tr. 1189).

We accept the above proposed finding of fact. See Background.

3. Destec Energy, Inc. ("Destec") is a Delaware corporation whose principal place of business is in Houston, Texas. Destec is engaged in the development, operation and ownership of cogeneration facilities and coal gasification projects.

We accept the above proposed finding of fact. See Background.

4. Floridians for Responsible Utility Growth ("FRG") is an informal ad hoc coalition of individual utility customers and organizations doing business in the state of Florida. Members of the coalition include Legal Environmental Assistance Foundation ("LEAF"), a public interest advocacy organization located in Tallahassee; Florida Solar Energy Industries Association, an industry association, an industry trade association located in Homestead; Timothy Steorts, an individual utility customer residing in Lake Wales; and John O. Blackburn, an individual utility customer who resides in Maitland.

We accept the above proposed finding of fact. See Background.

5. The Florida Division of Chesapeake Utilities Corporation is an [*82] operating division of Chesapeake Utilities Corporation which distributes natural gas at retail in Hillsborough, Polk and Osceola Counties, having a principal place of business in Winter Haven.

We accept the above proposed finding of fact. See Background.

6. Panda Energy Corporation of Dallas, Texas is a corporation engaged in the development and operation of cogeneration facilities. (Lindloff, Tr. 1425).

We accept the above proposed finding of fact. See Background.

7. Hillsborough County is a political subdivision of the state of Florida.

We accept the above proposed finding of fact. See Background.

INTEGRATED RESOURCE PLAN

Key Planning Criteria

8. The 1991 Integrated Resource Plan (IRP) was designed to provide reliability, cost effectiveness, environmental responsibility, and financial stability for Florida Power. Florida Power plans to meet these goals with a diversified set of demand- and supply-side resources. (Keesler, Tr. 71).

We accept the above proposed finding of fact.

9. The Integrated Resource Plan is based on the principle of diversified resources. The plan includes demand-side management (DSM), cogeneration, tie-line construction, peaking capacity, [*83] interruptible load, and combined cycle units. (Niekum, Tr. 941).

We accept the above proposed finding of fact.

10. The total addition of all resources must satisfy Florida Power's dual reliability of 0.1 days per year Loss of Load Probability (LOLP) and a 15-percent reserve margin. (Niekum, Tr. 916; Ex. 2, p. 120).

We reject the above proposed finding of fact because no statute or regulatory provision requires utilities to use an LOLP of 0.1 days per year or a reserve margin of 15 percent. The Commission as a matter of policy only requires that utilities use reliability criteria which are reasonable.

11. The selection of resources must consider fuel diversity, schedule flexibility and modularity, generation type, and system needs. (Niekum, Tr. 916-917).

We reject the above proposed finding of fact because no statute or regulatory provision requires utilities to specifically consider the above-mentioned items.

12. Any long-term factors affecting Florida Power's Clean Air compliance strategy after 2000 must be evaluated for any potential resource addition. (Niekum, Tr. 916-17; Ex. 70; Ex. 84; Ex. 2, pp. 124-126).

We reject the above proposed finding of fact because no [*84] statute or regulatory provision requires utilities to specifically consider the above-mentioned items.

Integrated Resource Planning Methodology

13. Florida Power's planning process combines DSM programs, QF and utility purchases, new transmission and generating plants, and interruptible load. (Foley, Tr. 1079; Niekum, Tr. 920).

We accept the above proposed finding of fact.

14. Florida Power's integrated planning process requires Florida Power to first determine the optimum amount of DSM programs and then evaluate alternative capacity plans to meet any further capacity needs. (Niekum, Tr. 915).

We accept the above proposed finding of fact.

15. Ten alternative resource combinations were formulated and modeled using the PROSCREEN II production costing and economic model. These alternatives were evaluated using 27 sets of input assumptions. (Niekum, Tr. 932-33; Foley, Tr. 1090).

We accept the above proposed finding of fact.

16. The primary output of the PROSCREEN II model is the Cumulative Present Worth of Revenue Requirement (CPWRR). The CPWRR from each model run was weighted by its probability of occurrence, and the expected (or average) CPWRR values for each alternative [*85] were compared. (Niekum, Tr. 933; Foley, Tr. 1089; Ex. 72-73).

We accept the above proposed finding of fact.

Load Forecast

General Approach

17. The Florida Power forecasting procedure is the same as that used by the Load Forecasting Working Group of the North American Electric Reliability Council (NERC). (Jacob, Tr. 648).

We accept the above proposed finding of fact.

18. The Florida Power long-term load forecast seeks to project trends in Florida Power's customer base, energy sales, and peak seasonal demands over the next 20 years. The results indicate the future electricity demands that are likely to come from each of its customer classes. (Jacob, Tr. 631).

We accept the above proposed finding of fact.

19. The load reductions resulting from the maximum feasible DSM were removed from the demand and energy forecast. (Niekum, Tr. 918; Jacob, Tr. 634).

We accept the above proposed finding of fact; however, the finding is duplicative in substance to Finding 17 in Recommended Order.

20. The load forecast accounts for projected self-service generation. Florida Power's projected demand would be higher if not for the fact that self-service generators are assumed to serve [*86] some of their own load. (Wieland, Tr. 302).

We accept the above proposed finding of fact; however, the finding is duplicative in substance to Finding 17 in Recommended Order.

21. A base case is developed using a set of assumptions designed to identify the important factors affecting the forecast. This establishes a "most-probable" scenario. (Jacob, Tr. 632).

We reject the above proposed finding of fact because the finding is vague.

22. Interruptible load is not included in the peak demand used for calculating the winter reserve margin. This margin is calculated using only firm peak load. The interruptible load is not considered to be firm for the purpose of calculating LOLP. (Niekum, Tr. 923).

We accept the above proposed finding of fact.

Assumptions

23. The following are the key assumptions of the Florida Power load forecast:

* Normal weather conditions are characterized by a 10-year average of service area conditions.

* The long-term customer forecast is developed from the Bureau of Economic and Business Research's "medium-case" population projections.

* The forecast accounts for the addition of a new partial-requirements wholesale customer (New Smyrna Beach) [*87] in 1992, but it otherwise assumes that there will be no major changes in the company's wholesale load or energy service.

* The energy and demand forecast subtracts the load impacts of Florida Power's DSM programs and self-service cogeneration, but for reporting purposes, it does not subtract interruptible/curtailable loads. It assumes that all interruptible/curtailable customers will be served at the time of peak. (Jacob, Tr. 634).

* Florida Power forecasts that its rates will not increase in real terms over the next 10 years. (Wieland, Tr. 302).

We accept the above proposed finding of fact with modification, see Finding 17 in Recommended Order.

Inherent Forecasting Uncertainties

24. Historically, Florida Power has tended to underforecast its load. One of the reasons for this is the inability of a long-term forecast to predict volatile business cycles. A second reason is that the Bureau of Economic and Business Research's forecasts have tended to underestimate population growth. (Jacob, Tr. 660-664; Ex. 38).

We accept the above proposed finding of fact with clarification. See Finding 21 in Recommended Order.

25. Differences between the normalized and forecast peak demands [*88] may be substantial because actual peak conditions and those assumed in the forecast for controllable resources (such as load management) may vary considerably. For example, during the summer of 1990, peak-hour load management and voltage load reduction were not used. As a result, if one adjusted the actual peak to match forecast assumptions, the variance would fall from 11.9 to 1.3 percent. (Ex. 37, p. 3).

We accept the above proposed finding of fact; however, the finding is not material to the ultimate decision in this case.

System-wide Energy Forecast Results

26. Florida Power total energy sales are projected to grow at an annual rate of 3.41 percent through 2010 (as compared to a rate of 3.46 percent during the 1980s). (Jacob, Tr. 650).

We accept the above proposed finding of fact with modification. See Finding 23 in Recommended Order.

27. Winter and summer peak demands are expected to increase at compound average annual growth rates of 2.15 percent and 2.55 percent, respectively, for the period ending 2010. (Jacob, Tr. 650).

We accept the above proposed finding of fact with modification. See Finding 24 in Recommended Order.

28. Florida Power expects that its customer [*89] base, energy sales, and peak demand will continue to grow significantly, but at somewhat more modest rates than in the recent past. This growth will occur at varying rates across customer classes. (Jacob, Tr. 631).

We reject the above proposed finding of fact because the finding is vague.

29. Florida Power expects continued customer growth over the 20-year forecast period, primarily the result of population in-migrations. The compound average annual growth rate in customers through 2010 is expected to be approximately 2.17 percent, with the customer bases increasing from roughly 1.14 million to 1.75 million over that time. (Jacob, Tr. 648).

We accept the above proposed finding of fact with modification. See Finding 22 in Recommended Order.

30. The total peak summer demand for 1990 was 5,946 MW, and the total winter peak demand for 1989/1990 was 6,056 MW. (Ex. 2, p. 263).

We accept the above proposed finding of fact; however, the finding is not material to the ultimate decision in this case.

31. The forecasted peak summer demand for 2001 is 7,716 MW, and the total forecasted winter peak demand for 2001 is 8,301 MW. This 2001 forecast is 30 percent higher than the 1990 [*90] summer peak demand and 37 percent higher than the 1990 winter peak demand. (Ex. 2, p. 263).

We accept the above proposed finding of fact. However, the first sentence is included in Finding 24 in Recommended Order and, the second sentence is not material to the ultimate decision in this case.

Residential Sector Methods and Results

32. Florida Power is projecting significant increases in residential customers. The results of the load forecast show compound average annual growth rates for total customers of 2.17 percent through 2010. (Jacob, Tr. 648).

We reject the above proposed finding because the first sentence is vague, and the second sentence is restated in Finding 22 in Recommended Order.

33. Growth is also expected in residential use per customer at a more moderate pace than the 1980s. (Jacob, Tr. 649). Florida Power's residential energy-use per customer for 2001 is expected to be 13,205 kWh. (Ex. 2, p. 259). The average kWh growth rate for residential customers from 1991-2000 is approximately 1 percent per year. (Ex. 2, p. 259).

We accept the above proposed finding of fact with modification. See Finding 25 in Recommended Order.

34. Since 1983, residential [*91] use per customer exhibited an exceptionally high rate of growth that was driven by several factors. These include: (a) a strong Florida economic expansion; (b) larger, more energy intensive homes; (c) a greater percentage of new single-family home construction compared to multifamily homes; (d) strong population growth in Florida Power's high-use Eastern and Mid-Florida divisions; and (e) a declining real price of electricity since 1986. (Jacob, Tr. 649).

We accept the above proposed finding of fact.

35. Forecasts indicate that the recent upward trend in residential energy sales will moderate, but generally continue well into the 21st century. (Jacob, Tr. 649).

We accept the above proposed finding of fact; however, the finding is duplicative in substance to Finding 25 in Recommended Order.

Methods and Results for Non-Residential Sectors

36. From 1991-2000, Florida Power's commercial customers have an average annual growth in energy use of 1.4 percent per year. In addition, their expected 2001 energy use per customer is 75,299 kWh. (Ex. 2, p. 259).

We accept the above proposed finding of fact with modification. See Finding 26 in Recommended Order.

37. For Florida Power's [*92] industrial customers, their average annual growth rate in energy-use will be about one percent per year. The 2001 energy-use per industrial customer for Florida Power is expected to be 1,146 kWh per year. (Ex. 2, pp. 246, 255).

We accept the above proposed finding of fact with modification. See Finding 27 in Recommended Order.

38. This recent decline in energy sales is expected to reach a low in 1991 and begin a moderate rebound. (Jacob, Tr. 641). Sales to the phosphate industry have been depressed since the late 1980s. New phosphate mines, however, are expected to begin operations in the mid-1990s, initiating a surge in phosphate energy sales. (Jacob, Tr. 641).

We accept the above proposed finding of fact; however, the finding is not material to the ultimate decision in this case.

39. Florida Power's retail forecasts for the street-and-highway lighting and public authority classes are tied to population growth within the service area. The street-and-highway lighting forecast is adjusted to reflect reduction attributable to luminaire changeouts, a specific energy efficiency program undertaken by Florida Power. (Jacob, Tr. 642).

We accept the above proposed finding [*93] of fact; however, the finding is not material to the ultimate decision in this case.

40. Florida Power also must compile sales forecasts for two wholesale customer classes. The first is the Rural Electric Authority revenue class, which consists of only one partial-requirements customer, Seminole Electric Cooperative, Incorporated (SECI). SECI provides Florida Power with a forecast of its energy requirements above those it expects to supply itself. The second category is the municipal revenue class. (Jacob, Tr. 642). Energy sales to Seminole Electric Cooperative are expected to be constant through the 1991-2000 time period. However, energy sales from Florida Power to municipals is forecasted to increase by 0.7 percent per year from 1991-2000. (Ex. 2, p. 246).

We accept the above proposed finding of fact; however, the finding is not material to the ultimate decision in this case.

Existing and Planned Demand-Side Management

Role of DSM in Florida Power's Integrated Resource Plan

41. As a result of its DSM analyses in the Integrated Resource Plan, Florida Power has determined that DSM will be the largest resource category used to meet new needs. During the period 1991-2000, [*94] DSM programs will provide nearly 30 percent of all Florida Power's new resource needs. (Keesler, Tr. 73; Ex. 3).

We accept the above proposed finding of fact with modification. See Finding 34 in Recommended Order.

42. In 1990, Florida Power allocated more than $ 50 million to its DSM programs. (Gelvin, Tr. 676; Ex. 43). Florida Power's 1990 DSM budget was 2.9 percent of total operating revenue. (Gelvin, Tr. 676; Ex. 43). By 1992, annual expenditures on Florida Power's DSM programs are expected to climb to nearly $ 75 million; they will exceed $ 1.4 billion by 2001. Florida Power DSM costs within this time period will have increased almost 200 percent. (Ex. 55).

We accept the above proposed finding of fact with modification. See Finding 38 in Recommended Order.

Maximum Avoidable Capacity Scenario (M.A.C.S.)

43. Florida Power's DSM projections represent an expansion of previously approved cost-effective DSM programs. These programs, referred to as M.A.C.S. (Maximum Avoidable Capacity Scenario), offer a significantly expanded menu of conservation and load management services. (Gelvin, Tr. 677).

We accept the above proposed finding of fact with modifications. See Finding [*95] 30 in Recommended Order.

44. The individual M.A.C.S. DSM programs are described below:

* Home Energy Check -- examination of the home structure and energy-using equipment.

* Home Energy Analysis -- computer analysis of the building structure, insulation, caulking and weather stripping, heating and air-conditioning systems, and water heating.

* Home Energy Fixup Program -- customer assistance for minor weatherization energy improvements to the home, including weather stripping, caulking, water heater insulation, and installing low-flow devices in showers.

* Residential Energy Management -- voluntary program that allows Florida Power to turn off selected energy-using equipment (electric central heating and/or air-conditioning, water heaters, and pool pumps) for short intervals during periods of peak electrical usage.

* Comfort Cash Loan Program -- program can fund items such as heat pumps or other high efficiency central air-conditioning systems, and heat recovery or heat-pump water heating equipment at subsidized interest rates

* Air-Conditioning Duct Test and Repair -- pressure test on the home's central duct work system.

* Insulation Upgrade -- customer assistance for upgrading [*96] ceiling/attic insulation to reduce energy losses for heating and air conditioning the home.

* Residential HVAC Service -- $ 5 certificate toward air-conditioning or heat pump service.

* HEATWORKS Heating Storage System -- system where during periods of high demand when the domestic heating system is interrupted by Florida Power, heating from HEATWORKS is available to replace it (water is heated in a dedicated storage thermal tank during off-peak hours).

* High Efficiency Air Conditioning Promotion -- incentive program for dealers to sell high efficiency central air-conditioning systems, heat pumps, and heat recovery or heat-pump water heating equipment.

* Low-Income Programs -- programs designed for low-income customers.

* Trade Efficiency -- seminars on the Florida Energy Efficiency Building Code, how to build an energy-efficient home, and energy-saving equipment.

* Business Energy Check -- inspection of a commercial/industrial facilities' lighting, building envelope, water heating system, heating, ventilating, air-conditioning and other energy-using systems.

* Business Energy Analysis -- in-depth study of a commercial/industrial customer's facility.

* Air Conditioning Duct [*97] Test and Repair -- pressure test performed on the central duct work system.

* Interior Lighting and Conversion -- rebates to business customers who install preapproved lighting products designed to reduce energy consumption and demand.

* Commercial/Industrial HVAC Service -- $ 5 certificate for air-conditioning service.

* Business Energy Fixup -- program provides minor weatherization repairs such as caulking, weather stripping, door sweeps and thresholds, window film, water heater insulation, faucet aerators, lamp replacement, and HVAC filter replacement.

* Commercial/Industrial HVAC Promotion -- incentive program for air-conditioning dealers to sell high-efficiency central air conditioning, heat pumps, and heat recovery or heat pump water heating equipment.

* Motor Replacement Rebate -- incentive for customers to replace inefficient motors with high efficiency types.

* Heat Pipe Development -- analysis of the energy savings resulting from installing heat pipes to control humidity and reduce energy use.

* Demand Reduction Capital Offset (DRCO) -- program designed to encourage significant conservation efforts that are not addressed by other Florida Power incentive programs. [*98]

(Ex 2., pp. 54-59).

We accept the above proposed finding of fact; however, the finding is not material to the ultimate decision in this case.

45. In Florida Power's initial review, 199 potential programs were identified that met all end uses. A broad set of criteria were applied to reduce these to 40 programs that were likely to be feasible for Florida Power and its customers. These 40 were then analyzed in terms of cost effectiveness, and 22 were accepted. (Gelvin, Tr. 835).

We accept the above proposed finding of fact with modification. See Finding 29 in Recommended Order.

46. The M.A.C.S. plan assumes that Florida Power will receive the Florida Public Service Commission's approval in 1992 to increase DSM incentives as markets become saturated at their current levels. (Gelvin, Tr. 802).

We accept the above proposed finding of fact; however, the finding is not material to the ultimate decision in this case.

47. It has been standing Florida Public Service Commission policy since 1986 that DSM opportunities for new construction should be sought through modifications to the building code as opposed to cost-recoverable utility actions. (Gelvin, Tr. 789).

We accept the [*99] above proposed finding of fact; however, the finding is not material to the ultimate decision in this case.

48. Florida Power did not consider natural gas use as an end use in developing M.A.C.S. The Florida Public Service Commission stated in its

February 1990 order in Docket 890737 that electric utilities are not compelled to pursue end-use gas programs. (Gelvin, Tr. 848).

We accept the above proposed finding of fact.

49. In order to adapt to changing customer needs, economic conditions, and technology improvements, M.A.C.S. has a procedure to allow for the development and evaluation of new conservation programs. This process, "New Program Development," ensures that new DSM will be pursued if it is prudent and cost effective. (Gelvin, Tr. 708).

We accept the above proposed finding of fact; however, the finding is not material to the ultimate decision in this case.

50. M.A.C.S. addresses every major customer class and type of energy use. (Gelvin, Tr. 705). Every sector has at least one conservation program addressing each significant end use. Florida Power also has several programs that target both an end use and a customer class. (Gelvin, Tr. 706).

We reject the [*100] above proposed finding of fact because the finding is vague.

Overall DSM Impacts

51. In total, DSM programs under M.A.C.S. will reduce winter peak demand by 1,445 MW in 2001. (Keesler, Tr. 72).

We accept the above proposed finding of fact with modification. See Finding 34 in Recommended Order.

52. Some DSM programs will perform better than expected. Others will not perform as well as expected. The overall M.A.C.S. projections take this program's under- and overperformance into account. (Gelvin, Tr. 763).

We reject the above proposed finding of fact because the finding is not a fact.

Load Management

53. Under M.A.C.S., Florida Power plans to obtain over 1,000 MW in incremental dispatchable load management capacity over the next decade. In total, load management programs will reduce winter peak demand by 1,814 MW in 2001. (Gelvin, Tr. 689).

We accept the above proposed finding of fact with modification. See Finding 35 in Recommended Order.

54. Florida Power's load management program represents 86 percent of the total current DSM budget because there are an extremely large number of customers in it. As participation rates rise in other conservation programs, their [*101] share of the budget will increase accordingly. (Gelvin, Tr. 712).

We reject the above proposed finding of fact because the finding is not a fact.

55. Florida Power's interruptible load program will alleviate the need for new capacity by contributing an additional 84 MW, almost 2 percent. (Ex. 3).

We accept the above proposed finding of fact; however, the finding is not material to the ultimate decision in this case.

Efficiency Improvements

56. Energy efficiency programs implemented under M.A.C.S. will reduce winter peak demand by an additional 334 MW in 2001. Combining the contributions of the energy efficiency programs implemented prior to M.A.C.S. with the contributions from M.A.C.S. will result in a total winter peak reduction of 568 MW in 2001. (Gelvin, Tr. 689).

We accept the above proposed finding of fact with modification. See Finding 36 in Recommended Order.

57. Energy efficiency programs implemented under M.A.C.S. will reduce energy consumption in 2001 by 391 GWh. The combined results from efficiency programs implemented from 1980 through 2001 will have reduced consumption in 2001 by 779 GWh. (Gelvin, Tr. 689).

We accept the above proposed finding of fact [*102] with modification. See Finding 37 in Recommended Order.

58. Efficiency programs that create long-term peak savings are also vital to Florida Power's resource portfolio. These programs can effectively reduce the need for generation and will not increase rates. (Gelvin, Tr. 712).

We reject the above proposed finding of fact because the finding is not a fact.

Cost Effectiveness

59. Florida Power's Energy Efficiency and Conservation filing, submitted on February 12, 1990, included cost-effectiveness analyses for all programs currently included in M.A.C.S. All programs were in conformance with Florida Public Service Commission's Rule 25-17.008 as it pertains to cost effectiveness. (Gelvin, Tr. 682).

We accept the above proposed finding of fact.

60. Florida Power uses three economic tests to evaluate the cost effectiveness of its DSM programs:

* The total resource cost test measures the net costs of a DSM program based on the total program costs, including both participants' costs and those borne by the utility.

* The participant test measures the program's impact on participating customers, taking into account participant costs, bill reductions, and any utility [*103] incentives or tax credits received.

* The rate impact test is an indirect measure of a DSM program's effect on customer rates. This test compares the respective changes in utility revenue and utility costs. (Gelvin, Tr. 681-82).

We accept the above proposed finding of fact; however, it is not material to the ultimate decision in this case.

61. The Florida Public Service Commission, after nine months of investigation, mandated the use of the rate impact test, the participant test, and the total resource test to characterize the full range of benefits, costs, and economic perspectives affected by DSM programs. (Gelvin, Tr. 734).

We accept the above proposed finding of fact; however, the finding is not material to the ultimate decision in this case.

Difficulties in Extrapolating Results from Other Utilities to Florida Power

62. Many characteristics specific to an individual utility affect DSM potential. These include economic climate, annual load profile, manufacturing, services, agricultural activities, and tourism. (Gelvin, Tr. 814).

We reject the above proposed finding of fact because the finding is vague.

63. Climatic differences between Florida and the Northeast [*104] are substantial. For example, Boston and New York have at least 10 times as many heating degree days as St. Petersburg. Conversely, St. Petersburg has about four times as many cooling degree days as Boston and about three times as many as New York City. (Gelvin, Tr. 726-27; Ex. 50).

We accept the above proposed finding of fact; however, the finding is not material to the ultimate decision in this case.

64. Florida Power has low loads during the winter, except for a few days in January when there is a chill or frost, causing a large winter load "spike." During the summer when air conditioning is universal, Florida Power's peak load rises and then falls through the summer season. However the summer load never rises to the height of the winter spike. (Gelvin, Tr. 728; Ex. 52).

We accept the above proposed finding of fact; however, the finding is not material to the ultimate decision in this case.

65. Significantly different weather patterns combined with varying electric and central air conditioner saturations cause energy use patterns and related DSM savings to vary between Florida Power and the Northeastern utilities. (Gelvin, Tr. 727).

We accept the above proposed finding [*105] of fact; however, the finding is not material to the ultimate decision in this case.

66. Economic conditions in the Northeast and Florida are very different. New England utilities serve mixed rural and urban areas with a balanced mixture of manufacturing, services, agriculture, and tourism. In contrast, Florida has less tourism and more economic activity in retirement housing, business services, high-tech, and light-to-medium industry. (Gelvin, Tr. 727).

We reject the above proposed finding of fact because the finding is not a fact.

DSM Market Penetration

67. There is considerable national debate about both the relative rate of increase and the absolute levels of market penetration that can be achieved by increasing DSM incentive levels. (Gelvin, Tr. 782).

We reject the above proposed finding of fact because the finding is not a fact.

68. Florida Power starts with reasonable financial incentives and raises them to increase market penetration. Since Florida Power is not paying the maximum incentive to all customer groups, this payment method is economical. (Gelvin, Tr. 719).

We accept the above proposed finding of fact with modification. See Finding 32 in Recommended [*106] Order. We reject the last sentence because it is not a fact supported in the record.

69. Conservation program participation is affected by issues other than the size of financial incentives. Customers join programs where the conservation measure is identified, installed, described, serviced, and financed. (Gelvin, Tr. 714-15).

We reject the above proposed finding of fact because the finding is not a fact and is vague.

70. Achieving 10-percent penetration across the board for all Florida Power DSM programs is not supported by Florida Power's data. Planning on such penetration levels would impose risks in view of the lack of historical experience for utilities with similar system requirements and a similar customer base. (Gelvin, Tr. 852).

We accept the above proposed finding of fact with modification. See Finding 40 in Recommended Order.

Florida Power's DSM Implementation Approach

71. Florida Power uses a variety of market research techniques to support M.A.C.S.'s development and implementation. Surveys, focus groups, and information from Florida Power customer databases are used to identify barriers to participation, determine customer satisfaction with programs, refine [*107] program designs, and provide input for developing new programs. Market research activities are used in conjunction with other methods to quantify program impacts. (Gelvin, Tr. 683).

We accept the above proposed finding of fact; however, the finding is not material to the ultimate decision in this case.

72. Opportunities for efficiency reductions are first identified in energy audits performed by certified Florida Power representatives. These audits can be done in the form of a relatively simple on-site inspection or a more detailed analysis, and they are available to all Florida Power residential, commercial, industrial, and agricultural customers. (Gelvin, Tr. 688).

We accept the above proposed finding of fact; however, the finding is not material to the ultimate decision in this case.

73. In order to tailor programs for varying customer needs, Florida Power performs thorough site analyses done by trained auditors. These auditors generate detailed recommendations to maximize each customer's energy-saving potential. (Gelvin, Tr. 718).

We accept the above proposed finding of fact; however, the finding is not material to the ultimate decision in this case.

74. For all [*108] conservation programs, Florida Power targets the decisionmaker for each account. For example, for chain store accounts, Florida Power approaches the chain's national headquarters. (Gelvin, Tr. 719). Air-conditioning and water-heating programs are directed toward equipment dealers to minimize the number of free riders. (Gelvin, Tr. 719). Florida Power also coordinates with architects and engineers to develop new construction and retrofit programs. (Gelvin, Tr. 720).

We accept the above proposed finding of fact; however, the finding is not material to the ultimate decision in this case.

Monitoring and Evaluation

75. Florida Power has employed a wide range of monitoring techniques to evaluate DSM program impacts. These include engineering studies, customer surveys, analyses of implementation data, comparative usage analyses, and end-use metering. (Gelvin, Tr. 691-92).

We accept the above proposed finding of fact; however, the finding is not material to the ultimate decision in this case.

76. Florida Power has recently established a Conservation Monitoring, Evaluation and Planning Department. This department will have lead responsibility for developing and implementing [*109] a framework for determining the kW and kWh reductions associated with each Florida Power conservation program. (Gelvin, Tr. 692).

We accept the above proposed finding of fact.

Existing and Planned Generation

77. For the Integrated Resource Study, all of Florida Power's generation is assumed to be available for operation, including all units that were returned from Extended Cold Shutdown (ECS). Turner Unit 2 has been retired, and Avon Park Unit 2 will be leased to an independent power producer to be rebuilt to burn peat as a fuel. (Niekum, Tr. 919; Ex. 65).

We accept the above proposed finding of fact.

78. The total existing Florida Power winter generating capacity is 6,621 MW. Of this capacity, 4,912 MW is steam generation and 1,709 MW is from combustion turbines. (Niekum, Tr. 919; Ex. 65).

We accept the above proposed finding of fact.

79. Florida Power plans on meeting 768 MW or 16 percent of winter load through new peaking capacity. (Ex. 3). Additional units currently under construction or planned for construction were also included as assumptions for the Integrated Resource Study. Four distillate-fired combustion turbines with total winter capacity are scheduled [*110] to be in service at the DeBary site in November 1992. Four more identical units are scheduled to be in-service at the Intercession City site by November 1993. (Niekum, Tr. 920).

We accept the above proposed finding of fact with the deletion of the first sentence and changes providing additional detail. The first sentence is vague in that it does not describe in which year the 768 MW of peaking capacity will meet 16% of winter load. Additionally, the amount of megawatts expected at each site has been added to the finding. See Finding 44 in Recommended Order.

80. Florida Power is planning to locate a 40 MW gas-fired combustion turbine with a waste-heat boiler at the University of Florida. This unit will add 40 MW of capacity to the Florida Power system and will provide a steam source for the University. (Niekum, Tr. 920).

We accept the above proposed finding of fact.

81. The Higgins Plant site was retired in 1999 for the Study. This retirement included the three oil-fired steam units with a total winter capacity of 123 MW and four distillate-fired combustion turbines with a total winter capacity of 126 MW. (Niekum, Tr. 919). In 2000, two distillate-fired combustion turbines [*111] at Avon Park also will be retired. They have a total winter capacity of 60 MW. (Niekum, Tr. 919).

We accept the above proposed finding of fact with a clarification that what is understood is that in 2000, the two distillate-fired combustion turbines at Avon Park were retired for the study. It is not found as fact that the two units will be retired in 2000. See Finding 46 in Recommended Order.

Power Purchases

82. Purchased power will account for approximately 15 percent of Florida Power's 1998 total generation resources. Florida Power is the state's largest purchaser of QF capacity. Florida Power also purchases capacity from Southern Company. (Foley, Tr. 1096; Dolan, Tr. 864; Keesler, Tr. 72; Ex. 3; Ex. 2, pp. 94-5).

We accept the above proposed finding of fact.

Existing and Planned Qualifying Facilities (QFs)

83. Florida Power has contracted to purchase more QF capacity than all other Florida investor-owned utilities combined. (Dolan, Tr. 864-865; Foley, Tr. 1079; Keesler, Tr. 72).

We accept the above proposed finding of fact; however, the finding is duplicative in substance to Finding 47 in Recommended Order.

84. Florida Power contracted 43 MW of new QF capacity [*112] in 1991 and more than 800 MW between 1992 and 1996. If all of the capacity under contract comes on line, more than 11 percent (over 1,000 MW) of supply-side resources in 1996 will come from QF generating capacity. (Dolan, Tr. 864-865).

We accept the above proposed finding of fact.

85. Florida Power's Integrated Resource Plan incorporates over 900 MW of future purchased capacity from the QF developers. Most of this QF capacity is not online, but is expected to be in service by 1997. (Foley, Tr. 1081; Niekum, Tr. 918).

We accept the above proposed finding of fact.

86. To account for the risks of non-availability of planned non-utility projects, Florida Power has contracted for more capacity than reliability studies indicate is needed. In other words, by assuming a 75-percent probability of performance, Florida Power contracted for 844 MW of capacity, but it assumes for planning purposes that only 633 MW will ultimately be available. (Dolan, Tr. 869). The 75-percent probability assumption for available capacity as contracted has been recently reviewed by the Florida Public Service Commission. (Dolan, Tr. 870).

We accept the above proposed finding of fact with the following [*113] exception: While it is true that the 75-percent probability assumption was reviewed by the Commission in approving negotiated contracts submitted by Florida Power, it is important to note that the Commission did not endorse the 75-percent probability assumption as a general policy. Rather, it specifically stated that utilities should not sign up more QF capacity than they need as a general rule (Order No. 24923). See Finding 51 in Recommended Order.

87. Florida Power also has a number of self-service cogenerators online and able to make small amounts of energy sales under Florida Power's as-available tariff. (Dolan, Tr. 865).

We accept the above proposed finding of fact; however, the finding is not material to the ultimate decision in this case.

88. The status of capacity under contract by Florida Power has been resubmitted under a late-file exhibit. The update of Florida Power's existing QF contracts is as of November 20, 1991. This exhibit is not representative of the QF assumptions used in the Integrated Resource Study. (Ex. 62). The status of contracts between September 13 and November 20 has not changed substantially. (Ex. 61; Ex. 62).

We accept the above proposed [*114] finding of fact; however, the finding is not material to the ultimate decision in this case.

Utility Purchases

89. Existing purchases from other utilities were included as a base assumption for the Integrated Resource Study. (Niekum, Tr. 920; Keesler, Tr. 72).

We accept the above proposed finding of fact; however, the finding is duplicative in substance to Findings 53 and 54 in Recommended Order.

90. Florida Power signed an agreement in 1988 to buy up to 400 MW of coal-fired UPS from Southern Company. The UPS portion of the sale begins in 1994 with a 200 MW purchase and increases to 400 MW by 1995. The contract expires in 2010 and also has provisions for early options in 1993 and 1994 for UPS purchases or firm economy purchases called "Schedule E." (Niekum, Tr. 920; Keesler, Tr. 72; Ex. 2, p. 85).

We accept the above proposed finding of fact.

91. Florida Power will buy economy energy from Southern Company or other utilities interconnected with Southern Company. This economy energy will come into the Florida Power system on the 500 kV line scheduled to be in service by January 1997. For the Integrated Resource Study, it was assumed that Florida Power will buy up to 500 [*115] MW at a time, with a total of 1,000 GWh for each year. (Niekum, Tr. 921; Keesler, Tr. 72; Ex. 67; Ex. 2, pp. 85-7). The power purchases over the new 500 kV intertie with Southern Company will represent about 10 percent or at least 500 MW of winter peak demand. (Ex. 3).

We accept the above proposed finding of fact with modification: See Finding 54 in Recommended Order. We are unwilling to accept as a fact that Florida Power will buy.

Formulation of Alternative Plans

Methodology

92. The alternative plans formulated for the Integrated Resource Study involved several steps. The first step is to screen the available viable technologies. The primary criteria for a technology are technical maturity and operational flexibility. (Niekum, Tr. 925-26; Tittle, Tr. 1000; Ex. 2, pp. 106-07).

We reject the above proposed finding of fact because the finding is vague.

93. If a technology meets Florida Power's criteria, it is a legitimate capacity alternative and is included in the planning process. The feasible choices were combustion turbines, combined cycle plants, pulverized coal plants,

integrated gasification combined cycle plants, and fluidized bed plants. (Niekum, Tr. 925-26; [*116] Tittle, Tr. 1000).

We accept the above proposed finding of fact; however, the finding is duplicative in substance to Finding 60 in Recommended Order.

94. The generation alternatives are subjected to economic evaluations to determine which scenario will have the lowest Cumulative Present Worth Revenue Requirement. (Foley, Tr. 1082; Niekum, Tr. 933; Ex. 105; Ex. 72; Ex. 73).

We accept the above proposed finding of fact; however, the finding is duplicative in substance to Finding 12 in Recommended Order.

95. Florida Power formulated two purchased power alternatives to examine the possibility of purchasing additional capacity for its need determination. (Foley, Tr. 1089; Ex. 104; Ex. 105; Ex. 69).

We accept the above proposed finding of fact with the clarification that Florida Power's two purchased power alternatives only considered purchases from utilities, and did not consider purchases from other sources. However, the finding is subsumed in Finding 62 in Recommended Order.

Technology Screening

96. Once a technology is accepted as a viable utility option, conceptual configurations are developed. When necessary, adjustments to generic industry data are made to better match [*117] the conditions on which the conceptual unit was based. Using a variety of analytical techniques, Florida Power develops conceptual cost and performance estimates for each configuration. The estimates are for all of the generation technology options are considered reasonable and appropriate for Florida Power. (Tittle, Tr. 995).

We reject the above proposed finding of fact because the finding is vague and is not material to the ultimate decision in this case. In addition, it is a conclusion of policy and not a statement of fact.

97. In Florida Power's highly integrated generation system, not all generation alternatives are suitable. Technologies such as geothermal, hydro, and wind turbines are not feasible in Florida at an industrial scale. Other generation alternatives such as nuclear, fuel cells, and photovoltaics, which are technically feasible, are currently not cost effective when compared to the fossil options. (Tittle, Tr. 996-997).

We reject the above proposed finding of fact because the finding is vague.

98. Five generation technologies were considered viable alternatives in the Integrated Resource Study: pulverized coal, combined cycle, combustion turbine, fluidized [*118] bed combustion, and integrated gasification combined cycle. (Tittle, Tr. 1000).

We accept the above proposed finding of fact.

99. Significant experience already exists with both combustion turbines and steam cycles, which are the primary components of combined cycle units. Increased interest and demand for the combined cycle option has prompted designers to further develop this technology, and as a result, it is one of the most efficient cycles available today. Combined cycle units have relatively short construction schedules. The plan to build four units over a three-year

period permits continuous construction that saves mobilization costs. (Tittle, Tr. 1007).

We accept the above proposed finding of fact in part. See Finding 61 in Recommended Order.

Description of the Alternatives

100. Florida Power considered the following 10 alternative plans:

* Alternative 1: two 165 MW combustion turbines on distillate and one 700 MW pulverized coal unit.

* Alternative 2: three 165 MW combustion turbines on distillate and one 450 MW pulverized coal unit.

* Alternative 3: four 235 MW combined cycle on gas.

* Alternative 4: four 235 MW combined cycle on distillate.

* Alternative [*119] 5: twenty-four 40 MW small combustion turbines on gas.

* Alternative 6: 110 MW of capacity from Orlando Utilities and four 235 MW combined cycle on gas.

* Alternative 7: one 165 MW combustion turbine on distillate and 870 MW of integrated gasification on coal.

* Alternative 8: one 165 MW combustion turbine on distillate and 750 MW of fluidized bed combustion on coal.

* Alternative 9: 593 MW from orimulsion gasification combined cycle and two 165 MW combustion turbines on distillate.

* Alternative 10: two 165 MW of combustion turbine on gas, one 376 MW pulverized coal purchase, and one combined cycle on gas for 235 MW. (Foley, Ex. 104).

We accept the above proposed finding of fact with clarification. See Finding 62 in Recommended Order.

Economic and Risk Analysis

Reliability Considerations

101. Florida Power uses two reliability criteria -- the 15-percent reserve margin and the Loss of Load Probability (LOLP) -- to provide a balanced evaluation of system reliability. The LOLP calculation provides a probabilistic evaluation that takes into account the uncertain nature of generator forced-outage rates and tie-line assistance from other areas. (Niekum, Tr. 917; Ex. 2, p. [*120] 113).

We accept the above proposed finding of fact with minor changes. See Finding 9 in Recommended Order.

102. Florida Power's methodology for calculating LOLP is generally accepted by the Florida Public Service Commission and the utility industry. The calculation of reserve margin provides a straightforward determination of total system capacity compared to the system peak load. (Niekum, Tr. 917).

We accept the above proposed finding of fact with the elimination of the word "straightforward". See Finding 10 in Recommended Order.

103. A utility's reserve margin provides a measure of its ability to serve peak demand and allows a utility to reliably serve its customers under a wide range of contingency conditions, such as abnormal weather. Florida Power raised its reserve margin from 10 to 15 percent to ensure system reliability. (Niekum, Tr. 979-80; Ex. 80, p. 1).

We reject the above proposed finding of fact in part because the finding is confusing. In addition, some of the information is duplicated in Finding 9 in Recommended Order.

104. Florida Power's reserve margin was increased to 15 percent for two reasons. The first is that, upon examination, the reserve margins [*121] for other utilities in Florida and the Southeast ranged from 15 to 20 percent. The second is that Florida Power's planned DSM programs, because they substantially reduce winter peaks, would have the effect of lowering the summer reserve margin. (Niekum, Tr. 979-80; Ex. 80, pp. 1-4).

We reject the above proposed finding of fact because the finding is repetitive and it mixes fact with policy.

105. Even though Florida Power has added 1,445 MW of DSM induced-capacity savings and over 900 MW of future QF capacity, its system requires additional capacity to meet its reliability standards. (Foley, Tr. 1081; Ex. 2, pp. 1-2). With all expected resources, Florida Power will not meet its 15-percent winter reserve margin criterion. Since Florida Power's 500 MW of capacity from the new tie-line will be used for economy and emergency purchases, this capacity cannot be used in the reserve margin calculation. As a result, Florida Power's winter reserve margin will range from 13.9 percent for 1998-1999 to 5.6 percent in 2000-2001. (Niekum, Tr. 924; Ex. 68).

We accept the above proposed finding of fact in part. See Findings 55 and 74 in Recommended Order.

Economic and Risk Analysis Methods [*122]

106. Each of Florida Power's 10 proposed alternatives was (sic.) modeled using the PROSCREEN II production costing and economic model with 27 sets of input assumptions. This resulted (sic.) in 270 PROSCREEN II models to test all alternatives under all combinations of input variations. (Niekum, Tr. 932-33; Foley, Tr. 1090; Ex. 69; Ex. 71).

We accept the above proposed finding of fact; however, the finding is duplicative in substance to Finding 11 in Recommended Order.

107. Since Florida Power's 10 proposed alternatives consist of approximately equal capacity additions and since all meet SO[2] limits, the next step in the decision analysis is to identify key input variables and use them to test each option's long-term sensitivity. The key input variables are the demand-and-energy forecast, the fuel forecast, and the cost-of-technologies forecast. Each forecast has a high, medium, and low scenario with assigned probabilities of occurrence. (Niekum, Tr. 931-32; Foley, Tr. 1089-90; Ex. 2, pp. 136-37).

We accept the above proposed finding of fact; however, the finding is duplicative in substance. The first sentence is included in Finding 67 in Recommended Order and the remainder [*123] is included in Finding 13 in Recommended Order.

108. Florida Power developed a high, medium, and low forecast for each of the primary input assumptions: demand and energy, fuel prices, and capital cost of technologies. The analysis evaluated the 27 possible combinations of these assumptions. (Niekum, Tr. 918).

We accept the above proposed finding of fact.

109. The assigned probabilities for the fuel forecast were (sic.) 20 percent for the high scenario, 55 percent for the medium scenario, and 25 percent for the low scenario. The assigned probabilities for the demand-and-energy and the cost-of-technology forecasts were (sic.) 25 percent for the high scenario, 50 percent for the medium scenario, and 25 percent for the low scenario. (Niekum, Tr. 932; Ex. 2, p. 137).

We accept the above proposed finding of fact.

110. With the given multiple of forecasts, a total of 27 (3 X 3 X 3 = 27) individual scenarios were developed to test each alternative plan. (Niekum, Tr. 932; Foley, Tr. 1089-90; Ex. 71).

We accept the above proposed finding of fact; however, the finding is duplicative in substance to Finding 11 in Recommended Order.

Results of the Economic and Risk Analyses

111. [*124] Four 235 MW combined cycle units are the most cost-effective alternative to meet Florida Power's need in the 1998-2000 time frame, taking into account all appropriate risk factors. (Niekum, Tr. 939; Foley, Tr. 1088; Ex. 105).

We reject the above proposed finding of fact for the following reason: While, Florida Power's study shows the four 235 MW combined cycle units appear to be the most cost-effective alternative, we reject this proposed finding of fact because the cost-effectiveness of constructing the third unit in 1998 as opposed to 1999 is marginal. Since it is not necessary to commit to the construction of the third unit at this time, it would be beneficial to wait.

112. The Polk County units are expected to meet about 19 percent or 940 MW of the 2001 winter peak demand. The plants are highly efficient, and will enable Florida Power to comply with the regulations of the Clean Air Act. (Foley, Tr. 1093; Ex. 3).

We reject the above proposed finding of fact because the finding is misleading. The Polk County units are not the only things that will enable Florida Power to comply with the Clean Air Act.

113. The cumulative present worth risk analysis graphs extended until [*125] 2030 also show that Alternative 3, the 940 MW on combined cycle, is the best option for adding new capacity to Florida Power's system. (Ex. 83, pp. 1-5). The risk analysis showed that there is a low probability that any of the alternatives will have a lower cost than Alternative 3. (Niekum, Tr. 935; Ex. 74; Ex. 75).

We accept the above proposed finding of fact in part. See Finding 69 in Recommended Order. We reject the last sentence because it is vague.

114. The purchased power alternatives, 10 and 6, were not as cost effective as the proposed Polk County units. When compared to Alternative 3 in present value dollars, Alternative 6 cost approximately $ 17.5 million more, and

Alternative 10 cost approximately $ 80 million more. (Foley, Tr. 1089; Ex. 105).

We accept the above proposed finding of fact with modification. See Finding 70 in Recommended Order.

115. Alternative 6 was the second best option. Alternative 6 included a short-term purchase of 110 MW of coal-fired capacity from the Orlando Utilities Commission (OUC). Florida Power determined that OUC's power was not sufficient to fulfill its capacity need for the late 1990s. (Foley, Tr. 1086; Niekum, Tr. 935-6; [*126] Ex. 105).

We accept the above proposed finding of fact with modification. See Finding 71 in Recommended Order.

116. In 1991 dollars, the expected total cost of alternatives to ratepayers shows Alternative 3 as the best option at approximately $ 20.6 billion. The next best alternative, number 6, would cost Florida Power's ratepayers about $ 17.5 million dollars more. (Ex. 105).

We accept the above proposed finding of fact in part. We reject the last sentence as being duplicative in substance. Also, Florida Power's exhibit 87 states that Alternative 3 will cost $ 20.4 billion. See Finding 73 in Recommended Order.

500 kV Line

117. The addition of the 500 kV tie-line improves the loss-of-load probability by between .02 and .03. The line also improves the reliability of other utilities in the state, which in turn further improves Florida Power's reliability. (Niekum, Tr. 976).

We accept the above proposed finding of fact with modification. See Finding 55 in Recommended Order.

118. If the 1997 500 kV line were not constructed, the number of megawatts that Florida Power would have to add to the proposed Polk County units in order to keep its LOLP at 0.1 days per year would [*127] be 225 MW for 1997. If the tie-line were not built, more than 500 MW of combined cycle would be needed to replace it and maintain system reliability. (Ex. 8, pp. 1-2).

We accept the above proposed finding of fact with the following clarification: "maintain system reliability" means "maintain system reliability equal to the reliability if the tie-line had been constructed". Florida Power would not have to construct 500 MW of combined cycle capacity to maintain an adequate system reliability of 0.1 days per year. See Finding 59 in Recommended Order.

119. With the construction of the 500 kV line from Florida to Southern Company, the First Contingency Total Transfer Capability (FCTTC) will be increased by 1,300 MW to 4,900 MW. The existing facilities will account for 3,600 MW of transfer capability and the new 500 kV line will account for 1,300 MW. (Ex. 2, p. 117).

We accept the above proposed finding of fact.

120. From the new 500 kV as well as other facility additions on Florida Power's system, Florida Power's tie capacity to the Florida assistance area will increase to 2,200 MW. (Ex. 2, p. 117).

We accept the above proposed finding of fact with modification. See Finding [*128] 57 in Recommended Order.

121. The negotiations and logistics involved in building the 500 kV line are extensive. The January 1997 completion date was the best estimate at the time the IRP study began. There are distinct possibilities that the actual completion date (sic.) could be later. (Niekum, Tr. 948).

We accept the above proposed finding of fact.

Financial Analysis

122. Analyzing the financial impacts of alternative resource planning decisions was an important part of the IRP study. Facts relating to financial issues, including those pertaining to the Polk County units and those pertaining to power purchases, are all addressed together to improve the organization and readability of this document.

We reject the above proposed finding of fact because the finding is not a fact. In addition, this finding is not material to the ultimate decision in this case.

Strategic Analysis

123. Strategic analysis refers to systematic consideration of issues such as fuel choices, environmental and siting benefits, and operational flexibility. Some of these issues are long term in nature and/or difficult to quantify. (Foley, Tr. 1081, Ex. 2, pp. 175-76).

We accept the above proposed [*129] finding of fact.

124. Adding a block of natural gas-fired generation will allow Florida Power to diversify away from the risks of interruptions, price changes, or environmental restrictions associated with reliance on coal and oil. (Foley, Tr. 1092).

We accept the above proposed finding of fact; however, the finding is duplicative in substance to Finding 84 in Recommended Order.

125. The addition of a single, large, long-term customer will prompt the addition of substantial new gas pipeline capacity into Florida, providing benefits to both the Florida Power system and the state as a whole. (Foley, Tr. 1092).

We reject the above proposed finding of fact because the finding is vague.

126. The minimum capacity additions to meet Florida Power's reliability criteria would be 381 MW for 1999's winter and summer peak load. However, the minimum amount of megawatts required may not be the most appropriate amount to add to Florida Power's system. These minimum capacity additions may not be economical, and they may not enable Florida Power to meet some of its strategic goals, such as complying with the Clean Air Act. (Ex. 81, p. 1).

We reject the above proposed finding of fact [*130] because the finding is misleading. In order to meet Florida Power's forecasted 1999 winter and summer peak load, Florida Power must add a minimum of 83 MW in November, 1998, in addition to 381 MW in November, 1999.

CLEAN AIR ACT COMPLIANCE

127. Any long-term factors affecting Florida Power's Clean Air compliance strategy after 2000 must be evaluated for any potential resource addition. (Niekum, Tr. 916-17).

We accept the above proposed finding of fact with modification: See Finding 66 in Recommended Order.

128. There are three ways for a utility to comply with the Clean Air Act. One is to reduce loads so that fewer kWh need to be produced. A second way is to reduce emissions at existing plants by switching fuels or putting on scrubbers. The third is to build new plants so that existing plants are used less. In the long run, a mix of these approaches is probably the lowest cost approach. (Chernick, Tr. 1411-1412).

We accept the above proposed finding of fact except for the last sentence which is an opinion, not supported by a study or analysis of the Clean Air Compliance costs on Florida Power's system. See Finding 65 in Recommended Order.

129. If the proposed Polk [*131] County units were operated below an average capacity factor of 40 percent based on the current load forecast, additional measures (for example, scrubbing or fuel-switching) would be needed to meet the Clean Air Act requirements. (Ex. 84).

We accept the above proposed finding of fact with the clarification that it is Florida Power's projection that additional measures would be necessary, should the units be operated at capacity factors below 40 percent. However, this finding is not material to the ultimate decision in this case.

130. Florida Power's proposed generation expansion plan was designed to be operated on an economic dispatch basis and to also meet Clean Air Act regulations. In addition, the Bartow plant and Crystal River 1 and 2 plants will be switched from burning high-sulfur fuel to a lower-sulfur fuel. No units were run off economic dispatch in the study; however, this may be done for emergency conditions. (Ex. 85).

We accept the above proposed finding of fact with the exception of the last sentence, which could be misinterpreted. In addition, it is clarified that it is Florida Power's plan to switch fuels. See Finding 67 in Recommended Order.

131. The units' [*132] natural gas fuel supply, which produces no sulfur emissions when burned, plays a critical role in Florida Power's compliance with the Clean Air Act under Phase II. Also, since the units are operated as intermediates, they can be base loaded to reduce sulfur emissions further at an incremental dispatch cost. (Ex. 2, p. 84).

We accept the above proposed finding of fact in substance. See Finding 68 in Recommended Order.

132. The addition of the combined cycle unit in November 1999 would reduce system emissions by approximately 3,800 tons. (Niekum, Tr. 972).

We reject the above proposed finding of fact because the finding is vague and does not state which combined cycle is referred to or when the reduction will take place.

CAPITAL COSTS OF UTILITY BUILT POWER PLANT VERSUS CAPITAL COSTS OF NON-UTILITY GENERATORS (NUGs)

Traditional Utility Construction Contracting

133. The "traditional utility approach" to power plant construction is one where utilities act as the owners and main construction supervisors of the plants under consideration. Utilities generally hire an engineer/architect to produce detailed plant design specifications. They then put these specifications out to [*133] bid and award multiple, fixed-price equipment and construction contracts to the most qualified vendors. (Ruisch, Tr. 102; Major, Tr. 1033; Ex. 2, p. 186).

We accept the above proposed finding of fact; however, the finding is not material to the ultimate decision in this case.

134. The traditional utility approach entails use of multiple, fixed-price contracts. Manufacturers and construction contractors are responsible for supplying equipment and services for a well-defined, fixed scope of work based on the technical specifications and detailed drawings prepared by the engineer. (Ruisch, Tr. 102; Major, Tr. 1033; Ex. 2, p. 186).

We accept the above proposed finding of fact; however, the finding is not material to the ultimate decision in this case.

135. The traditional utility approach allows the owner to have total project control. The manufacturer and construction contractor risks are minimized and limited to controllable factors such as labor productivity and wage rates. Since risks for factors outside manufacturer or contractor control are limited, little or no contingencies need to be included in contract prices. These reduced contingencies create a lower plant cost. [*134] (Ruisch, Tr. 103; Major, Tr. 1033).

We accept the above proposed finding of fact; however, the finding is not material to the ultimate decision in this case.

136. Florida Power used multiple fixed-price contracts for its Crystal River Units 4 and 5 project. Crystal River Unit 4 began commercial operation in 1982 at $ 683/kW ($ 621/kW without AFUDC). This compares to an industry average of $ 779/kW for coal-fired utility power plants also entering commercial operation that year. In 1984, Crystal River Unit 5 began commercial operation at $ 576/kW ($ 483/kW without AFUDC) compared to 1984 industry average of $ 1,089/kW. (Ruisch, Tr. 103; Ex. 2, p. 187).

We accept the above proposed finding of fact; however, the finding is not material to the ultimate decision in this case.

Turnkey Construction Practices Used by Non-Utility Projects

137. IPP/QF projects and investor-owned utilities use the same engineering organizations to design and build their plants. (Ruisch, Tr. 116). IPP/QF projects, however, are typically designed, procured, and constructed on a "turnkey" basis. Developers solicit bids for the design and complete construction of the plant, from site work through [*135] commercial planning, and then select one contractor. This "turnkey" contractor bids a fixed price for completing the entire plant. (Ruisch, Tr. 104).

We reject the above proposed finding of fact because the finding implies that all QFs and IPPs use the same engineering organizations as utilities. The evidence in the record has not demonstrated that there are no exceptions to this claim.

138. With the turnkey approach, a single contract is awarded at the project's beginning, before the plant is largely designed. For example, if permitting and licensing are not complete at the time the contract is awarded, it will not be possible to include all of the final permit requirements. The owner and the turnkey contractor must negotiate any subsequent changes in design or scope. Since the owner has very little leverage during these negotiations, the change order price will probably be high. (Ruisch, Tr. 105).

We reject the above proposed finding of fact because the finding is vague. While we agree that with the turnkey approach, a single contract is awarded at the project's beginning, we reject this finding because it is a prediction of the witness of future events, and not a fact, [*136] that the owner will have little leverage and that future change order prices will be high for turnkey projects.

139. IPPs and QFs use the turnkey method even though it results in a more expensive construction cost because most do not have the cash flow to self-finance the project. In order to obtain money to build plants, IPPs/QFs often borrow as much as 100 percent of the project's value on a nonrecourse basis. (Ruisch, Tr. 106).

We reject the above proposed finding of fact.

140. The turnkey contractor assumes all project responsibilities and risks. These risks include schedule, performance, and price. Some portion of these risks can be passed on to various subcontractors. However, only the turnkey contractor is entitled to the reward/risk pool in the form of additional profit and turnkey contingencies. These turnkey contractor contingencies are in addition to owner contingencies for those risks that cannot be passed on. (Ruisch, Tr. 104-05; Ex. 5).

We accept the above proposed finding of fact; however, the finding is not material to the ultimate decision in this case.

141. The contingency cost component of a turnkey contract can raise the project price by 4 to 10 [*137] percent. In addition, the profit component of a turnkey contract will make it 3 to 9 percent more expensive than the traditional utility approach. (Ex. 5).

We reject the above proposed finding of fact.

142. The total costs for a construction project completed with a turnkey contract can be 7 to 20 percent higher than multiple, fixed-price contracts that characterize the traditional utility approach. The cost components that make the turnkey contract more expensive than the traditional utility approach are for liquidated damage insurance, profit, and contingency. (Ex. 5).

We reject the above proposed finding of fact.

143. Concluding that the turnkey approach is more expensive than the traditional utility one is consistent with Black and Veatch's recent turnkey proposal for the Florida Power and Light (FPL) Martin units. After examining all turnkey proposals submitted, FPL elected to proceed with the project using the traditional utility approach. (Ruisch, Tr. 107).

We reject the above proposed finding of fact.

144. The turnkey contractor is responsible for administrating all subcontracted equipment and services. These additional administrative costs

require the contractor [*138] to charge a markup, which often includes a profit. The traditional utility approach does not require this. (Ruisch, Tr. 106).

We accept the above proposed finding of fact; however, the finding is not material to the ultimate decision in this case.

Other Distinctions Between Utility Generation and Purchased Power

145. If a QF misses the scheduled on-line date and forfeits the security deposit, Florida Power will still experience costs accruing from the need to find replacement power. Customers still bear the burden of these costs. (Foley, Tr. 1149).

We reject the above proposed finding of fact because the finding incorrectly assumes that the cost accruing from the need to find replacement power will exceed the amount of the security deposit. While this is possible, it is also possible that the security deposit will more than compensate for any costs incurred as a result of the default of a QF.

146. The Seminole Fertilizer contract was for the sale of between 15 MW and 47 MW of capacity. Recently, it sold only 15 MW, understating the amount assumed by Florida Power in its Integrated Resource Study by 32 MW. (Dolan, Tr. 868).

We accept the above proposed finding of fact [*139] in part; however, the finding is not material to the ultimate decision in this case.

147. The cost of a generating plant built by Florida Power is likely to be less than the costs of a QF or IPP developer building an equivalent plant. It would not be more. (Ruisch, Tr. 122; Ex. 5).

We reject the above proposed finding of fact because the finding is not a fact; it is an opinion of what will happen in the future.

148. IPP and QF plant construction costs more than utility construction because their procurement and engineering methods are not efficient. In contrast, Florida Power has an excellent construction management record. (Foley, Tr. 1098-99; Ruisch, Tr. 103-06; Ex. 178, p. 187).

We reject the above proposed finding of fact.

149. Utilities can design modular plants as well as QFs. Utilities and QFs use much the same designs and plant components. There is no basis for asserting that QFs can be modular while utilities cannot. (Ruisch, Tr. 116-17).

We accept the above proposed finding of fact; however, the finding is not material to the ultimate decision in this case.

150. Utility power plants do not have a steam host, and utilities can and often build several exact [*140] duplicates of other plants in order to take advantages of the economics of standardization. (Ruisch, Tr. 117).

We accept the above proposed finding of fact; however, the finding is not material to the ultimate decision in this case.

151. If the costs of utility-constructed plants exceed estimates, the Florida Public Service Commission decides whether ratepayers will bear the costs of the overrun. (Foley, Tr. 1145). If costs for a utility-constructed power

plant end up being lower than those projected, customers receive all the cost savings under Florida Public Service Commission rules. (Foley, Tr. 1178).

We accept the above proposed finding of fact; however, the finding is not material to the ultimate decision in this case.

FINANCIAL IMPACTS

Financial Impacts of Planned Investments Included in the Integrated Resource Plan

152. Florida Power has conducted analyses to ensure that the Polk units will not adversely affect its financial portfolio. (Foley, Tr. 1083; Abrams, Tr. 197; Wieland, Tr. 277-78; (Ex. 2, pp. 150-55).

We accept the above proposed finding of fact.

153. Florida Power can finance the investments included in its Integrated Resource Study, Docket No. 910759-EI, [*141] through conventional means without threatening its AA bond rating. (Wieland, Tr. 307).

We accept the above proposed finding of fact with the clarification that Florida Power has stated it can finance the investments included in its Integrated Resource Study through conventional means without threatening its AA bond rating. See Finding 108 in Recommended Order.

154. Florida Power is not planning to contribute more than 10 percent of the equity for a gas pipeline projected to have a total cost of approximately $ 600 million. Negotiations with potential partners in such a project have indicated that this amount of equity would allow Florida Power sufficient input and operating control to ensure that its needs would be met. (Watsey, Tr. 457-58).

We reject the above proposed finding of fact because this statement represents a projection of what the company may or may not do and is not considered a fact.

Impacts of Power Purchases On Credit Ratings

Credit-Rating Agencies

155. Rating agencies agree that long-term purchased power obligations carry risk for the purchasing utility, as represented in a credit analysis. (Abrams, Tr. 194).

We accept the above proposed finding of [*142] fact; however, the finding is duplicative in substance to Findings 117, 120, and 121 in Recommended Order.

156. Increased utility industry reliance on purchased power has received attention from ratings analysts and the financial community, who are reassessing the consequences of this development. The legal and financial complexities of purchased power transactions have outstripped conventional analytical tools, resulting in divided opinions regarding the specific degree of consequences from having significant levels of purchased power. (Abrams, Tr. 193).

We accept the above proposed finding of fact.

157. Power purchase agreements have been recognized as an issue by all major credit agencies. The financial community gives purchased power policy close scrutiny when the amount of purchase capacity reaches 10 to 15 percent of the utility's total available resources. (Ex. 12, p. 3).

We accept the above proposed finding of fact.

158. Increased financial pressure expected to accrue from generating capacity purchases contributed to several Duff and Phelps rating actions in 1989 and 1990. Credit downgrades for Consolidated Edison Company (Ex. 10), the Delaware Economic Development [*143] Authority (a project of Delmarva Power and Light Company), Orange and Rockland Utilities, Inc., Eastern Edison Company, Public Service Electric and Gas Company, and Potomac Electric Power Company all cited the impact of purchased power as contributing to the downgrade action. (Abrams, Tr. 176-7; Ex. 13).

We accept the above proposed finding of fact with some clarifications about construction also contributing to these downgrades. First, the news releases from Duff & Phelps (D&P) concerning the credit downgrades of Consolidated Edison Company, the Delaware Economic Development Authority (a project of Delmarva Power and Light Company), Orange and Rockland Utilities, Inc., and Potomac Electric Power Company all cite the impact of purchased power and construction as contributing to the downgrade action. (Abrams, TR 176-7, 243-4; EX 10; EX 13) As a result, it may be misleading to point only to the use of purchased power as contributing to the downgrades. The news release from D&P concerning the credit downgrade of Public Service Electric and Gas Company states that the utility plans to rely primarily on independent power producers and cogenerators to meet its future generation needs [*144] over the next several years. (Abrams, EX 13) The fact that Florida Power is contesting even the exercise of soliciting bids for purchased power confirms that the company has no intention of relying primarily on these sources for its future generation needs. Because of this difference, this example is not comparable to the situation at Florida Power. Finally, all of the news releases from D&P cite declining interest coverage ratios, declining equity ratios, and a general deterioration in financial protection measures that have been occurring in some cases over the past several years. (Abrams, TR 243-4; EX 10; EX 13) This has not been the case at Florida Power. In fact, since its last heavy construction cycle in 1982, Florida Power has taken great strides to improve its financial protection measures and put itself in a strong financial position for the start of this growth cycle. (Abrams, TR 236) Florida Power has improved its equity position from 44.6% of investor capital in 1982 to 56% in 1990 and has improved its interest coverage ratio from 2.42x to 3.89x over the same period. (Wieland, TR 375) These actions have enabled Florida Power to improve its credit rating from A to [*145] AA, one of only four utilities to do so in the past six years. (Abrams, TR 171) As a result, it would be misleading to imply that the planned future use of purchased power would necessarily portend a credit downgrade without also mentioning that the credit downgrades in these examples were the result of a pattern of declining financial measures over an extended period of time. See Finding 122 in Recommended Order.

Why Power Purchases Affect Credit Ratings

159. When a utility builds a plant and then places it in its rate base, the utility obtains revenue to cover operating costs and capital costs. The operating costs include depreciation, return on equity, and sometimes deferred taxes. The revenues covering each of the costs are available to the utility to reinvest in the utility system as customer needs require. (Abrams, Tr. 270; Ex. 2, p. 156). In contrast, when a utility purchases capacity, the revenues obtained flow through to another party to cover its debt and pay dividends to its shareholders. (Abrams, Tr. 270).

We accept the above proposed finding of fact.

160. Excluding variable costs such as fuel, interest payments are the only fixed long-term financial obligation [*146] associated with a utility-owned power plant. Other revenue requirement components associated with a utility-owned generating plant include the equity return and depreciation. These funds ensure that the utility can meet its interest obligations at all times, which is the primary concern of credit-rating agencies. (Wieland, Tr. 308-09).

We accept the above proposed finding of fact.

161. Capacity payments contribute to the overall utility credit risk because these payments increase the utility's aggregate fixed-charge obligations. As the total level of fixed obligations increases, the risk of the utility not being able to satisfy obligations individually and collectively increases accordingly. (Abrams, Tr. 188).

We accept the above proposed finding of fact in part. While it is true that capacity payments contribute to the overall fixed-charge obligations of the utility, the qualitative factors associated with the terms of purchased power contracts can reduce the financial risk of these types of payments. See Finding 117 in Recommended Order.

162. Capacity payment risks concern bondholders because there is no corresponding equity investment to buffer project risk (as there [*147] is with utility-owned capacity, which has been financed with a mixture of debt and equity). (Abrams, Tr. 188-89).

We reject the above proposed finding of fact.

163. Qualitatively, determining credit quality includes a judgmental assessment of any and all circumstances that bear on risk exposure. Such circumstances include the outlook for sales, competition, management quality, the regulatory environment, the quality of reported earnings, and the quality of the balance sheet. (Abrams, Tr. 167; Ex. 6, p. 2).

We accept the above proposed finding of fact.

164. Quantitatively, utility credit quality is based on a number of financial ratios. Three of the primary ratios are debt leverage, interest coverage, and the internal funds ratio. A lower value for the first and higher values for the (second and) third of these ratios indicate - all other things being equal - lower risk to bondholders and higher credit quality. (Abrams, Tr. 166-67; Ex. 6, p. 3).

We accept the above proposed finding of fact.

165. Relying on a NUG purchase, as opposed to a generation asset constructed and owned by the utility, reduces depreciation cost recovery as a source of cash to the utility. Depreciation [*148] cost recovery is the single larges source of cash flow available for investing in new facilities to serve customers. (Abrams, Tr. 180; Ex. 2, p. 156).

We accept the above proposed finding of fact.

166. A utility engaged in a purchased power contract is obligated to make fixed payments. The financial impact is equivalent to the utility taking out a loan, meaning that purchased power contracts must be appraised for credit evaluation as a form of debt financing for the utility. This approach has been

taken with many industries where fixed assets are leased or otherwise controlled by long-term contracts or agreements. (Abrams, Tr. 171-2).

We reject the above proposed finding of fact. See Findings 120 and 121 in Recommended Order.

167. In measuring the financial impact of purchased power contracts, Duff and Phelps converts the fixed obligations for the contracts into debt equivalents on a utility's income statement and balance sheet. Duff and Phelps reclassifies one-third of the total capacity charges associated with purchased power as the equivalent of interest expense on the income statement. The approximate value of the assets that provide the capacity are added to the [*149] balance sheet as the equivalent of additional debt. In the absence of a compensating adjustment to the utility's capitalization ratios, these changes will increase risk and reduce credit quality. (Abrams, Tr. 174-5; Ex. 6).

We accept the above proposed finding of fact with the exception of the final sentence. Witness Abrams testified that coverage and capitalization ratios may move somewhat within ranges without impacting the credit rating of the utility. Furthermore, he stated that credit ratings are assigned with substantial weight given to the expected long-term trend in performance and level of risk, and with the understanding that there may be moderate fluctuations in the ratios upon which the credit rating is based. (TR 182) Therefore, the absence of a corresponding adjustment to the utility's capitalization ratios may not necessarily increase risk and reduce credit quality. See Finding 119 in Recommended Order.

168. Performance-based contracts and take-or-pay contracts involve a utility entering into a set of commitments for the use of fixed assets. These contracts decrease the utility's financial flexibility. (Abrams, Tr. 189).

We accept the above proposed finding [*150] of fact; however, the finding is not material to the ultimate decision in this case.

169. Performance-based contracts are preferable to take-or-pay contracts, but they do not eliminate the risk associated with QF capacity and energy payments. If a utility is relieved of contract obligations due to inadequate performance, it is still necessary to replace the capacity with another purchase or with utility-owned facilities. (Abrams, Tr. 189; Ex. 12, p. 4; Ex. 2, p. 155).

We reject the above proposed finding of fact because the finding incorrectly assumes that the utility will always incur replacement power costs if a QF defaults. This would not be the case if a utility had too much capacity.

170. The existence of a "regulatory out" clause does not have a material effect on credit quality because it does not eliminate the present or future obligations to make capacity payments under a purchase contract. (Abrams, Tr. 178; Ex. 12, p. 5). Cost-recovery clauses do not eliminate fundamental concerns that rating agencies have regarding the overall risk to investors from assuming fixed long-term obligations without having adequate equity. QF capacity payments compete with all other [*151] business obligations for satisfaction. (Abrams, Tr. 187-88).

We reject the above proposed finding of fact.

171. Fuel contracts are not a fixed obligation because they are an operating expense. Unlike capacity purchases, they are not an operating expense that is substituted for a fixed asset. (Abrams, Tr. 208).

We accept the above proposed finding of fact; however, the finding is not material to the ultimate decision in this case.

172. Energy conservation costs and load management payments are controllable operating expenses. These items are not fixed charges because there are no long-term fixed commitments associated with them. (Abrams, Tr. 190).

We accept the above proposed finding of fact; however, the finding is not material to the ultimate decision in this case.

Florida Power's Large Amount of Planned Purchases

173. Florida Power has contracted for significant amounts of power as measured by methods recognized and used by credit-rating agencies in the financial community. Purchased power is projected to represent 15 percent of Florida Power's total generation resources by 1998. (Abrams, Tr. 165, 182; Ex. 2, p. 157).

We accept the above proposed finding of fact. [*152]

174. The 1,000 MW that Florida Power is currently committed to purchase will create capacity charges that comprise approximately 280 percent of its interest charges. If the 940 MW of capacity for the Polk County plants were replaced by purchases, the total capacity charges would make up approximately 560 percent of Florida Power's interest charges. (Abrams, Tr. 249).

We reject the above proposed finding of fact because the finding is vague. It cannot be determined if the claim that if the 940 MW of capacity for the Polk County plants were replaced by purchases would result in total capacity charges of approximately 560 percent of Florida Power's interest charges assumes that Florida Power will not incur any additional interest expense on debt associated with the remaining $ 3.5 billion in capital expenditures that Florida Power plans to make by the year 2000.

175. Florida Power is committed to capacity payments several times as large as its interest expense. Florida Power makes no profit on this money - there is no compensation for the equity it has committed to these purchases. (Abrams, Tr. 212-13).

We reject the above proposed finding of fact because Florida Power has [*153] not committed an equity investment to these purchases.

176. In previous dockets, Florida Power viewed purchased capacity as cost effective because the level of purchased power that Florida Power had at the time was lower than the amount currently planned. (Niekum, Tr. 1127).

We accept the above proposed finding of fact; however, the finding is not material to the ultimate decision in this case.

177. Total purchased power capacity charges are projected to reach 178 percent of interest expense in 1997, based on the Integrated Resource Study, which assumes a 75-percent success rate for contracts of future purchased power delivery (exclusive of the Southern UPS contract). (Abrams, Tr. 182; Ex. 2, p. 157).

We accept the above proposed finding of fact.

Benefits of a Strong Credit Rating

178. Florida Power is currently rated AA- by Duff and Phelps, representing an upgrade from its 1986 rating of A+. Florida Power has similar lower tier AA class credit quality ratings from the other major credit-rating agencies. (Abrams, Tr. 168; Ex. 2, p. 150).

We accept the above proposed finding of fact.

179. Retaining an AA credit rating will minimize the cost of capital to Florida Power [*154] and the revenue requirements needed to support capital. Lower credit ratings will increase interest rates and customer rates, all other things being equal. (Abrams, Tr. 170).

We accept the above proposed finding of fact; however, the finding is not material to the ultimate decision in this case.

180. One reason to retain an AA credit rating relates to borrowing reserve capability, which is the ability to access capital markets under a broad range of circumstances. The large amount of utility borrowing projected for the next three years will heighten competition for funds and widen the spread in costs between higher and lower credit ratings. (Abrams, Tr. 169).

We accept the above proposed finding of fact; however, the finding is not material to the ultimate decision in this case.

181. NUG projects obtain competitive interest rates on their debt, despite being highly leveraged, because of the credit strength of the utility providing a guaranteed payment. (Wieland, Tr. 280).

We accept the above proposed finding of fact; however, the finding is not material to the ultimate decision in this case.

182. Non-utility generators can engage in projects selectively and enter or [*155] leave the business of power generation at will. Utilities must finance and construct generation capacity to meet the needs of their customer base. To fulfill this responsibility at the lowest cost and without undue risk, the utility must preserve its financial viability. (Abrams, Tr. 191; Ex. 2, p. 156).

We reject the above proposed finding of fact because it is misleading. While non-utility generators may selectively choose projects, once the company is contractually obligated to provide service there are monetary awards for non-performance. (Abrams, TR 252) This finding implies that there are no financial consequences for non-performance.

183. It is difficult to re-establish prior credit quality. In the past six years, only eight BBB companies rated by Duff and Phelps reached an A rating, and none have reached an AA rating. Florida Power Corporation is one of the four A-rated companies that have achieved an AA rating. (Abrams, Tr. 171).

We accept the above proposed finding of fact in part. See Finding 126 in Recommended Order.

The Hidden Costs of Power Purchases

Nature of Hidden Costs

184. The "hidden cost" of a power purchase is the cost imposed on the purchasing [*156] utility due to diminished credit quality that accompanies large capacity purchases. (Wieland, Tr. 283-83).

We reject the above proposed finding of fact because this is an unsupported conclusion of law that is unrelated to this docket.

185. There are two ways of compensating for the financial consequences of increased purchased power obligations. One is to increase the proportion of equity used to finance other utility assets. The second is to increase the rate of return on equity. Both represent real costs of purchased capacity. (Abrams, Tr. 181).

We accept the above proposed finding of fact.

186. The cost of compensating equity for the imputed debt associated with purchased power obligations is absolutely necessary in order to meaningfully compare the costs of such a purchase with the cost of utility-owned capacity. (Wieland, Tr. 283).

We reject the above proposed finding of fact because this is an unsupported conclusion of law that is unrelated to this docket.

187. Utilities have been evaluating similar types of "make-versus-buy" decisions for many years. For example, a long-term lease on a utility truck would, compared to owning the truck, be treated by a financial [*157] rating agency in a manner similar to an interest payment and would cause the utility's coverage ratios to deteriorate if not mitigated. (Wieland, Tr. 292).

We accept the above proposed finding of fact; however, the finding is not material to the ultimate decision in this case.

Methods of Determining Hidden Costs

188. Quantifying the financial impacts of the reduced planning and operating flexibility caused by power purchases is difficult. In addition, there is no agreed-on method for calculating increases in risks that result from them. The most widely used methods indicate that there is a substantial "hidden" component to the costs of long-term capacity purchases from NUGs. (Wieland, Tr. 296, 299; Ex. 16).

We accept the above proposed finding of fact with the clarification that none of the positions presented in the record from the three rating agencies make any mention of a substantial "hidden" cost of capacity purchases from NUGs. See Finding 112 in Recommended Order.

189. The added costs attributable to relying on NUG purchases ranges between 21 and 63 percent of the direct costs of the purchased capacity. (Wieland, Tr. 296, 299; Ex. 16, pp. 1-3).

We reject the above [*158] proposed finding of fact. During cross examination, Witness Wieland admitted that the top of this range would not be reasonable for Florida Power since it assumes that the contracts are treated by rating agencies as 100% debt equivalents. (TR 339) This is not the case. Witness Wieland also admitted that, because of the specific terms and conditions of Florida Power's contracts, the risk factor would be 20%. (TR 339) The methodology used by S&P as reflected in Exhibit 11 indicates that the risk factor could be as low as 10%. (Wieland, TR 329; Abrams, EX 11, p. 7) Therefore, this testimony is suspect.

190. The "hidden cost" of compensating the equity associated with purchased power obligations is developed in three steps:

* The purchased power transaction is added to the utility's base-case projection. This includes coverage ratios to properly reflect the fixed charge qualities of the power purchase. (Wieland, Tr. 282-83).

* Secondly, any change in the coverage ratios occurring because of the power purchase is measured. Then, a sufficient amount of equity is added to restore the capitalization and coverage ratios to their initial level in the base case. (Wieland, Tr. 283). [*159]

* Third, the revenue requirements of the additional equity are added to the cost of the purchased power to arrive at an adjusted total cost for the purchased power transaction. (Wieland, Tr. 283).

We reject the above proposed finding of fact. Witness Wieland admitted that the methods he presented in Exhibits 14 - 16 do not represent how rating agencies will evaluate the quantitative and qualitative factors associated with purchased power. (TR 322)

191. Even though it is unrealistic to surmise that a utility could finance the second plant entirely with equity, such a scenario does not change the conclusion - a utility needs to restore its coverage ratio to the initial levels after buying purchased power. When a utility buys power, fixed charges go up but "coverage" does not. More equity is needed to restore a coverage ratio to its initial level. (Wieland, Tr. 289).

We accept the above proposed finding of fact; however, the finding is not material to the ultimate decision in this case.

192. The utility adjusts its capital structure to restore the coverage ratio prior to the purchase of the first unit because any comparison of capacity options should yield equal amounts [*160] of financial risk and power. (Wieland, Tr. 291-92).

We accept the above proposed finding of fact; however, the finding is not material to the ultimate decision in this case.

Costs Imposed on Florida Power's Ratepayers

193. Prior to 1991, Florida Power's power purchases were below the 10 to 15 percent threshold where the aggregate impact of purchased power becomes financially significant. The current projected level of purchased power is substantial and may require Florida Power to compensate for any resulting financial impacts. (Abrams, Tr. 193).

We accept the above proposed finding of fact; however, the finding is duplicative in substance to another finding.

194. Replacing the capacity Florida Power currently plans to construct during 1998-2000 with purchased power would represent a serious increase in purchased capacity as a percentage of total generation. The associated deterioration would result, all other things being equal, in a credit downgrade for Florida Power. (Abrams, Tr. 183).

We reject the above proposed finding of fact because the finding is a prediction and not a statement of fact.

195. Any increase in the planned level of capacity purchases would necessitate [*161] an additional compensating adjustment in the company's equity capitalization in order to avoid a downgrade. (Abrams, Tr. 183-4).

We reject the above proposed finding of fact. See Finding 113 in Recommended Order.

196. In the course of a rate case, utility commissions examine the cost of capital. Since the cost of capital depends on the costs of debt, commissions take into account the views of ratings agencies. (Abrams, Tr. 379).

We accept the above proposed finding of fact; however, the finding is not material to the ultimate decision in this case.

WHY ADDITIONAL POWER PURCHASES, THROUGH BIDDING OR OTHER MEANS, ARE ILL-ADVISED IN THIS CASE

197. When deciding to purchase additional capacity, a utility should examine many issues such as financial risk, reliability, operational impacts, and regulatory treatment. The decision to purchase capacity should not be based on apparent cost alone. (Foley, Tr. 1102).

We reject the above proposed finding of fact because the finding is a conclusion of policy, and not a finding of fact.

198. Existing competitive bidding methods only recognize the payments paid directly to winning bidders. A utility's avoided cost, on the other hand, [*162] is based on its target capital structure and represents the full cost of a capacity increment. Bidding processes, because they do not represent the costs of compensating equity, are biased in favor of selecting nonutility projects. (Wieland, Tr. 296).

We reject the above proposed finding of fact.

199. A bidding competition is a reasonable way of selecting the best capacity to purchase in the event that additional purchases are warranted, but not a good way of determining whether a utility should buy or build the next increment of capacity. (Foley, Tr. 1102).

We reject the above proposed finding of fact.

200. The fact that Florida Power should not make additional purchases now, via bidding or otherwise, does not mean that all utility purchases are not cost effective. Rather, additional Florida Power purchases are inadvisable because it already relies heavily on purchased power and other specific circumstances. (Foley, Tr. 1100).

We reject the above proposed finding of fact.

201. It is unrealistic to think that IPPs and QFs can build reliable, long-lasting capacity more inexpensively than Florida Power can build the Polk County units. It is particularly unrealistic to [*163] think that reliable, long-lasting capacity can be sold to Florida Power at a price that is so much less than the Polk County units that the lower price offsets the hidden financial and other costs. (Foley, Tr. 1099-1100).

We reject the above proposed finding of fact.

202. In the previous solicitation approved as part of Docket 910401, the bids received were only 1 to 2 percent below the avoided costs that Florida

Power published. (Foley, Tr. 1177), even though QFs were bidding against a high avoided cost core unit. (Foley, Tr. 1141-42).

We accept the above proposed finding of fact with the modification that the contracts, not the solicitation process, were approved. See Finding 49 in Recommended Order.

203. Power plants operate for periods longer than the term of a typical purchased power contract. By purchasing capacity, Florida Power will be left with only contract renewal options. However, with owned capacity, Florida Power will have fully depreciated plants, which will provide customers with economical service. (Foley, Tr. 1097-98).

We reject the above proposed finding of fact because Florida Power has not demonstrated that the Polk County units will not have additional [*164] capital improvements which would prevent them from ever be fully depreciated.

204. Non-dispatchable QFs, under current Florida Public Service Commission rules, impose substantial costs on Florida Power customers. (Dolan, Tr. 901).

We reject the above proposed finding of fact because it is misleading. Nothing in the Florida Public Service Commission rules require QFs to be non-dispatchable.

205. Florida Power already employs competitive bidding in its power plant construction and in its fuel procurement. (Foley, Tr. 1177-78).

We accept the above proposed findings of fact in substance. See Finding 149 in Recommended Order.

SELF-SERVICE GENERATION

206. Self-service generation has been addressed in the Integrated Resource Study, Docket No. 910759-EI, in the forecast of future demand and energy. The forecast assumes that self-service generation will not increase. QF developers have made aggressive efforts in the past to take advantage of such opportunities. (Wieland, Tr. 301).

We accept the above proposed finding of fact in part. See Finding 20 in Recommended Order.

207. Florida Power does not have the same degree of control over self-service generation as it does over [*165] its other resource planning options. (Wieland, Tr. 301).

We accept the above proposed finding of fact.

208. Financial risks associated with self-service are addressed as part of the overall credit-risk analysis. Significant levels of self-service activity would push Florida Power's credit rating down. (Wieland, Tr. 304).

We reject the above proposed finding of fact.

209. Large amounts of self-service generation pose several types of financial risk for a utility. Self-service generation causes sales levels to decrease. This reduction can impede a utility's ability to cover the fixed obligations for investments made to meet customer needs. (Wieland, Tr. 303).

We accept the above proposed finding of fact; however, the finding is not material to the ultimate decision in this case.

FUEL ISSUES

Natural Gas Supply

Florida Power's Existing Gas Use

210. Florida Power currently uses very small volumes of natural gas on its system. (Foley, Tr. 1091). Florida Power's Bartow, Higgins, Turner, and Avon Park plants all have natural gas capability and are served by FGT on an interruptible basis. (Ex. 2, p. 170). The Suwannee plant is served by SGNG, also on an interruptible [*166] basis. Id. Florida Power plans to use about 8.8 MMCFD of natural gas at its planned facility at the University of Florida. Id.

We accept the above proposed finding of fact.

Anclote Plant Conversion

211. Florida Power is actively considering a possible conversion of its Anclote plant in late 1994 or early 1995. (Ex. 2, p. 160). There are a number of options as to how Anclote could be converted. (Niekum, Tr. 959). However, it is expected that Anclote will require approximately 120 MMCFD of natural gas in the summer and about 50 to 55 MMCFD in the winter. (Watsey, Tr. 450). The Anclote units are expected to have less than a 50-percent capacity factor for a number of years. (Watsey, Tr. 405).

We accept the above proposed finding of fact with modifications. See Finding 82 in Recommended Order.

212. Converting the Anclote plant would provide for a phasing-in of the natural gas supply to Florida Power's Polk County units, and would enhance the security of supply by bringing substantial volumes of gas to the Florida Power system before the initial in-service date of the Polk County units. (Ex. 2, p. 160).

We reject the above proposed finding of fact because the statement [*167] represents a projection. It is unknown whether converting the Anclote plant would lead to enhanced security of natural gas supply for the Polk County units.

Polk County Units

213. The four Polk County units (940 MW) will require about 100 MMCFD on average, and will have a peak demand of between 200 and 216 MMCFD. (Watsey, Tr. 449; Ex. 2, p. 172)

We accept the above proposed finding of fact.

214. The Polk County units will contribute to fuel diversity on Florida Power's system and in peninsular Florida. (Foley, Tr. 1091-1092; Ex. 2, p. 126.) The Polk County units will increase the percentage of installed gas-fired combined cycle generating capacity in peninsular Florida to about 6 percent in 1998/1999 and about 9 percent in 2000/2001. (Foley, Tr. 1092; Ex. 106, p. 2). This addition of a substantial block of gas-fired capacity to Florida Power's system will system will enable the company to mitigate some of the risks of coal and oil supply interruptions, price changes, and environmental restrictions. (Foley, Tr. 1092).

We accept the above proposed findings of fact with the deletion of the last sentence and changes in wording of the first two sentences. Although a substantial [*168] block of gas-fired capacity to Florida Power's system will enable the company to mitigate some of the risks of coal and oil supply interruptions, and price changes, the same risks related to natural gas will replace those of coal and oil. See Finding 84 in Recommended Order.

Supply Adequacy

215. Natural gas reserves and resources in the United States are vast and well documented. (Schlesinger, Tr. 579; Waller, Tr. 497). Recent studies estimate the nation's gas resource base to be in excess of 1 quadrillion cubic feet. (Schlesinger, Tr. 579; Ex. 34, pp. 1-2; Ex. 2, pp. 163, 167). In 1990, less gas was consumed than was added to the reserve base. (Waller, Tr. 497; Ex. 2, p. 163). In relation to these vast resources, Florida Power's expected natural gas requirements are quite small. (Schlesinger, Tr. 578). Natural gas supplies to Florida Power will be ample when needed for the Polk County units, if the transportation capacity exists to deliver such gas. (Waller, Tr. 497, 502).

We accept the above proposed finding of fact with the deletion of the last sentence. It is an assumption of future conditions and not a fact. See Finding 88 in Recommended Order.

216. If adequate [*169] transportation capability exists, there will be substantial competition among producers and marketers to sell gas to Florida consumers. Because transportation distances to Florida are relatively short and because Florida is perceived by many producers as a burgeoning gas market, gas supply to Florida on competitive terms will be constrained only by the availability of sufficient transportation capacity. (Schlesinger, Tr. 580; Waller, Tr. 502; Ex. 2, p. 168).

We reject the above proposed finding of fact because this is the witnesses' opinion of third parties' perceptions of the Florida market for natural gas. There is no documentation in the record to support the perceptions of the producers and marketers.

217. Florida is relatively close to significant potential onshore gas reserves in Louisiana, Mississippi, and Alabama, as well as the offshore Gulf Coast gas-producing regions and some of the country's largest coalbed methane deposits. (Schlesinger, Tr. 580; Waller, Tr. 502; Ex. 2, p. 162-164).

We accept the above proposed finding of fact.

Acquisition Strategy

218. Florida Power's natural gas supply strategy is to develop a supply portfolio that will provide diversity [*170] in terms of sources, terms and conditions of purchase, prices, firmness of supply, volume flexibility, expiration dates, and other important contract terms. (Watsey, Tr. 391; Ex. 2, pp. 168-169).

We accept the above proposed finding of fact; however the finding is not material to the ultimate decision in this case. This is a statement of fact as to Florida Power's strategy in developing a natural gas supply portfolio. However, because this statement merely reflects a projection of what the company may or may not be able to achieve in the future, it is irrelevant.

219. Because of the expected vigorous natural gas supply competition, and because Florida Power is a large volume gas customer, Florida Power will have

considerable flexibility to negotiate favorable terms for its gas supply and transportation. (Waller, Tr. 502; Schlesinger, Tr. 581; Ex. 2, p. 168).

We reject the above proposed finding of fact because the finding is a statement about expectations in natural gas supply markets. This assumption is used to draw a conclusion which may or may not be correct.

220. Although Florida Power's long-term fuel contracts will not match the 30-year or longer useful life of the [*171] Polk County units, Florida Power will be able to secure long-term contracts of up to 15 years. (Watsey, Tr. 393; Schlesinger, Tr. 581-582; Ex. 2, pp. 168-69).

We reject the above proposed finding of fact because the statement represents an opinion that Florida Power will be able to secure long-term fuel contracts up to 15 years. Since there are no signed letters of intent or contracts for gas supply or statements of gas suppliers in the record, it is unknown whether Florida Power will be able to secure long-term contracts of up to 15 years.

Supply Commitment Timing

221. Florida Power has not entered into any contracts or letters of intent for gas supply for the Polk County units. (Watsey, Tr. 391). Florida Power's strategy is to defer entering into fuel supply contracts until a time closer to the in-service date of the Polk county units. (Watsey, Tr. 391, 394-395; Ex. 2, p. 169). Florida Power does not expect to enter into contracts until after the Florida Power Commission (Florida Public Service Commission) and the Department of Environmental Resources have authorized the Polk County units. (Watsey, Tr. 394-395).

We accept the above proposed finding of fact.

222. Even [*172] if Florida Power were willing to enter into supply contracts before the need is established, in the currently depressed market for natural gas, most suppliers are not willing to sign long-term commitments seven years before the gas is expected to flow. (Waller, Tr. 494).

We reject the above proposed finding of fact because there is nothing in the record to support the statement that most suppliers are not willing to sign long-term commitments seven years before the gas is expected to flow. It seems as plausible that, because of the depressed natural gas markets, suppliers might be more willing today to sign long-term contracts to firm up their markets.

223. Even if a producer were willing to enter into long-term fuel contracts with Florida Power at this early date, it is likely that such an agreement would result in unnecessary and unreasonable costs for Florida Power. (Watsey, Tr. 391-92; Waller, Tr. 495-96; Schlesinger, Tr. 583). In this scenario, Florida Power would have little leverage to negotiate favorable terms. (Schlesinger, Tr. 583).

We reject the above proposed finding of fact because this statement represents an assumption regarding the provisions of an agreement [*173] that does not exist. This statement of projection is not considered factual. Again, it appears just as plausible that Florida Power could contract at most favorable terms because of the depressed markets referenced in the previous statement.

224. The initial contract prices of long-term contracts signed today would be well above current market prices, including annual escalation. (Watsey, Tr. 391-92). Such contracts would likely include provisions such as premiums,

inventory charges, or reservation fees. (Watsey, Tr. 391-92; Waller, Tr. 495; Schlesinger, Tr. 583). The natural gas fuel supply cost to Florida Power under these conditions would be greater than the fuel supply value. (Waller, Tr. 495).

We reject the above proposed finding of fact because this statement represents the opinion of the witnesses and is not considered a finding of fact.

225. Florida Power's best course of action is to commit for natural gas supplies at a point much closer to when it will need the gas. (Waller, Tr. 496; Watsey, Tr. 391-96; Schlesinger, Tr. 582). Many of the price-inflating provisions that Florida Power would have to accept now will be avoidable at a later date, and Florida Power [*174] would be in a better position to negotiate favorable supply and price terms. (Waller, Tr. 495-496; Schlesinger, Tr. 584).

We reject the above proposed finding of fact because the statements are merely opinions of the witnesses. The projections regarding price are not considered factual.

Florida Power Standards for QF Fuel Supplies

226. Florida Power has not held QFs to a standard different from its own in terms of fuel supply certainty. (Watsey, Tr. 418-19). The eight QFs obtained through Florida Power's recent bid are contractually committed to being operational by 1994, four years ahead of the Polk County units. (Ex. 2, pp. 98-100). Even with those earlier in-service dates, Florida Power has not required the QFs to have or produce contracts or letters of intent with fuel suppliers or transporters as a contract prerequisite. (Watsey, Tr. 418-19; Ex. 63).

We reject the above proposed finding of fact.

Natural Gas Transportation

Existing Transportation

227. Florida represents the only major demand growth area in the United States that is served by only one natural gas pipeline. (Watsey, Tr. 396). FGT is the only major natural gas pipeline currently serving peninsular [*175] Florida. (Ex. 2, pp. 170-171). The FGT system has been expanded recently in two stages. Id. The second stage is expected to be complete late in 1991 or early in 1992. Id. Virtually all of FGT's resulting delivery capability (925 MMCFD) has been reserved on a firm basis. Id. Florida Power has reserved 8.8 MMCFD of transportation capacity from the Phase II expansion to serve Florida Power's planned University of Florida plant. (Ex. 2, p.170).

We accept the above proposed finding of fact.

228. FGT currently is planning a Phase III expansion to be completed in 1994 or 1995. Id. The capacity expected to be available from this expansion has been heavily oversubscribed by potential shippers. Id. Florida Power has not executed a contract with FGT, but it has placed an initial request for Phase III capacity in the following amounts: (a) May-September - 140 MMCFD; (b) October-April 55 MMCFD. (Id.; Watsey, Tr. 431-432). This capacity could accommodate a conversion of the Anclote units in the mid-1990's, but is not expected to accommodate the needs of the Polk County units. (Watsey, Tr. 431, 396).

We accept the above proposed finding of fact.

Transportation [*176] Options

229. Florida Power initially identified three gas transportation options. (Watsey, Tr. 397; Ex. 2, pp. 172-173). Option A was the development of a new independent pipeline owned by Florida Power and others. (Watsey, Tr. 397; Ex. 2, p. 172). Option B was a subsequent expansion of FGT's system (beyond Phase III) to accommodate the Polk county units, while committing the Anclote gas requirements to FGT's Phase III expansion. (Watsey, Tr. 397; Ex. 2, 172). Option C was to commit to capacity on a new, competitive pipeline to be constructed by a party or parties other than Florida Power of FGT. (Watsey, Tr. 397; Ex. 2, pp. 172-173).

We accept the above proposed finding of fact.

230. All three of Florida Power's pipeline options were shown to be potentially viable for purposes of bringing natural gas to the Polk County units, if initiated promptly. (Watsey, Tr. 397; Schlesinger, Tr. 588).

We reject the above proposed finding of fact because this statement represents a projection of viability. The pipeline options were not shown to be potentially viable. Florida Power's measure of viability was merely determined based on the opinions of Witness Watsey and Witness Schlesinger. [*177]

231. Florida Power's evaluation of pipeline options has been an ongoing process. (Watsey, Tr. 397, 427, 446-447; Ex. 2, p. 173). Since the Florida Power Commission (Florida Public Service Commission) hearing, Florida Power has not abandoned Option A but is no longer actively pursuing it. (Watsey, Tr. 427, 446). Instead, Florida Power is focusing on Option B and, particularly, on Option C. Id.

We reject the above proposed finding of fact. We accept the fact that the Witness testified that Florida Power's evaluation of pipeline options has been ongoing. However, Witness Watsey testified that Florida Power was concentrating equally on Option B and Option C, and that Option A was not actively being pursued at this time.

Letter of Intent

232. Florida Power has been negotiating with a newly-formed joint venture consisting of United Gas Pipeline Company (United) and the ANR Pipeline Company (ANR) (a division of Coastal Corporation). (Watsey, Tr. 427, 443-444). The "Suncoast Venture" has been formed for the purpose of building a new pipeline in Florida. (Watsey, Tr. 443-444; Ex. 28).

We accept the above proposed finding of fact.

233. Florida Power has executed a [*178] December 4, 1991 Letter of Intent (the Letter) with respect to the SunCoast Venture, under which a joint venture would construct a new 560-mile intrastate pipeline predicated on firm transportation commitments to the four Polk County units (Ex. 28) under the following terms:

* The parties are (1) United, (2) ANR, (3) SunCoast Venture, a developmental joint venture by and between Florida Gulf South Pipeline Company and ANR Southern Pipeline Company, (4) Gateway Pipeline, and (5) Florida Power. (Ex. 28).

* The Letter of Intent represents a non-binding statement of the parties' present intention to enter into a discussion aimed at developing a new natural gas pipeline in Florida. Id.

* The Letter provides that the pipeline would be 36 inches in diameter, including various smaller pipes, and approximately 560 miles in length. Id.

* The pipeline would extend from United's facilities at or near Pensacola along the west coast of Florida to a terminus near the Polk County units. Id.

* The Letter provides for an initial design capacity of approximately 400 MMCF per day, and a subsequent capacity of up to 745 MMCF per day. Id.

* The Letter provides that firm transportation [*179] service rates to Florida Power on the new pipeline would be provided under competitive rates. Id.

* The Letter contemplates a 20-year agreement between SunCoast and Florida Power. Id.

* The Letter provides that Florida Power's advance commitment of 180,000 MCF per day of firm transportation capacity to the Polk County units is essential to the basic design and economic viability of the new pipeline. Id.

* The Letter contemplates a phase-in of Florida Power's firm transportation or delivery rights up to an aggregate total of 300,000 MMBtu per day in four phases (Ex. 28):

(1) 1995 - 120,000 MMBtu for Anclote

(2) 1998 - 45,000 MMBtu for Polk Unit 1

(3) 1999 - 90,000 MMBtu for Polk Units 2 and 3

(4) 2000 - 45,000 MMBtu for Polk Unit 4

* The Letter of Intent is terminable by any party if the Polk County units are not certified by the Florida Power Commission (Florida Public Service Commission). (Ex. 28).

We accept the above proposed finding of fact in part with the exception of some statements. See Finding 95 in Recommended Order. Portions of this finding of fact which are not accepted include:

1. The letter states the pipeline to be 560 miles, yet the attached [*180] exhibit (Exhibit B) states the pipeline to be approximately 579 miles.

2. The letter states that the initial design capacity of approximately 400 MMCF per day, and a subsequent capacity of up to 745 MMCF per day. However, Exhibit B states that the subsequent capacity to be 800 MMCF per day.

3. The finding of fact states that firm transportation service rates to Florida Power on the new pipeline would be provided under competitive rates. To clarify this statement, the letter of intent states that firm transportation service shall be competitive with the aggregate amount of the rate and charges applicable for services of a comparable duration, quality, quantity and distance reflected in bona fide offers by third parties to Florida Power.

4. The letter of intent is no longer terminable by any party if the Polk County units are not certified by the Florida Public Service Commission. The December 3, 1991 "Letter of Intent") was amended on December 10, 1991. The amendment is entitled Supplement #2 to Late-Filed Exhibit No. 28.

234. As of the signing of the Letter of Intent, FGT has not presented Florida Power with any proposal that would be more advantageous to Florida Power [*181] than the SunCoast proposal. (Ex. 28)

We accept the above proposed finding of fact.

235. Florida Power does not contemplate holding more than a small equity interest (up to 10 percent or about $ 60 million), if any, in a new pipeline. (Watsey, Tr. 458). Florida Power might contribute existing right-of-way as an equity contribution. Id.

We reject the above proposed finding of fact because this statement represents a projection of what the company may or may not do and is not considered a fact.

Benefits of Pipeline Competition

236. In assessing pipeline options, Florida Power must consider both short-run fuel savings and the long-term benefits of developing competitive pipeline capacity in Florida. (Watsey, Tr. 415-16, 435-38). It is not necessarily in the long-run best interests of Florida Power's customers for Florida Power to capture short-term fuel savings by foregoing the cost savings or strategic benefits that competitive gas transportation can generate. Id.

We accept the above proposed finding of fact.

237. The absence of pipeline competition has hampered Florida Power's ability to obtain desired terms and conditions of transportation service. (Watsey, [*182] Tr. 441). The introduction of competition could help facilitate more attractive terms of service and prices. (Watsey, Tr. 437, 441; Waller, Tr. 500).

We accept the above proposed finding of fact.

238. Competition among pipelines can lower transportation costs in at least two ways. (Waller, Tr. 498). First, competing pipelines will discount their tariff rates to attract load and, second, pipelines will be induced to lower the total cost of service on which their rates are based. Id. Competition can lower overall costs more than regulation alone. (Waller, Tr. 500).

We reject the above proposed finding of fact because the statement reflects what may or may not happen when pipelines are faced with competition. A proposed new pipeline may or may not have delivery points that overlap with the existing gas pipeline, so direct competition may or may not exist. There is no documentation in the record which proves that pipelines will be induced to lower the total cost of service, nor is there documentation which proves that competition lowers overall costs more than regulation alone.

Polk County Anchor Load

239. Failure to obtain certification for even one of the Polk County [*183] units will jeopardize development of a timely and viable natural gas transportation system to the Polk County site, regardless of the option selected. (Watsey, Tr. 405; Ex. 28).

We reject the above proposed finding of fact because the original project criteria was based on the construction of a pipeline with 600 MMCFD capacity. The revised plan is to initially construct a pipeline with a capacity of 400 MMCFD. Since we agree that an anchor of one-third to one-half is usually required to entice pipeline development, an anchor requiring between 133 and 200 MMCFD would be required with respect to the revised pipeline plan.

240. The minimum size for an economically feasible pipeline of several hundred miles is about 600 MMCFD. (Waller, Tr. p. 477). The cost of designing, certificating, building, and testing a new pipeline averages $ 1 million per mile. (Id.; Watsey, Tr. 401). Therefore, a 600-mile pipeline would cost approximately $ 600 million. (Waller, Tr. 477; Watsey, Tr. 401).

We reject the above proposed finding of fact. Since the Suncoast project is planned to have an initial capacity of 400 MMCFD, the statement that the minimum size for an economically feasible [*184] pipeline of 600 MMCFD is not considered a fact. (Ex. 28)

241. The initiation of every major pipeline project in the nation in recent years has been based on the advance gas transportation commitments of one or more key shippers, or, in other words, an "anchor load." (Waller, Tr. 480-481; Ex. 24).

We accept the above proposed finding of fact.

242. An anchor load ensure that a pipeline will be built in sufficiently large diameter to achieve economies of scale. (Waller, Tr. 476-477). Such economies will allow transportation rates to be held to levels that will attract shippers and allow the gas transported on the new system to remain competitive with alternative fuels. Id. Firm contracts with credit-worthy shippers typically are required for the pipeline sponsor to obtain financing. (Waller, Tr. 477).

We accept the above proposed finding of fact in substance. See Finding 100 in Recommended Order.

243. An anchor load must be sufficiently large to justify the several million dollar expenditure necessary to do preliminary analyses and get a pipeline project to the stage of the required regulatory filings. (Waller, Tr. 479-80). Ideally, project development would not begin [*185] without firm commitments for all of the pipeline's capacity. (Waller, Tr. 477).

We accept the above proposed finding of fact.

244. Generally, an anchor load represents a volumetric commitment of between one-third and one-half of the pipeline's capacity. (Waller, Tr. 483). More committed load at the outset translates to an increased likelihood that a competitively sized pipeline will be constructed. (Waller, Tr. 503).

We accept the above proposed finding of fact.

245. An anchor load is a "core load" of critical mass in a confined location at the pipeline's terminus. (Waller, Tr. 503-04; Schlesinger, Tr. 602). A "rifle-barrel" pipeline configuration with a single, large diameter all the way to the terminus provides the greatest economies of scale and results in the best possible transportation rates anywhere along the pipeline. (Waller, Tr. 505-507).

We reject the above proposed finding of fact because the statement about core load provides an impression that this is an absolute definition. However, Witness Waller stated that the concept of a core load is not something that can be stated with absolute precision (Waller, Tr. 503, lines 7-9). Further, Witness Waller stated [*186] that a "rifle-barrel" pipeline configuration may be less expensive (Waller, Tr. 507, lines 16-17). With respect to attached

Exhibit A of late-filed Exhibit 28, a map of the proposed Suncoast pipeline is shown as a telescoping pipeline.

246. The four Polk County units together with the converted Anclote units satisfy all of the basic characteristics of an anchor load for a new 600 MMCFD pipeline. (Waller, Tr. 481-82, 501, 503; Schlesinger, Tr. 610; Ex. 28). Together these units will require about 336 MMCFD, or roughly half of the expected pipeline capacity. (Watsey, Tr. 449-50).

We reject the above proposed finding of fact. Although we agree that the four Polk County units together with the converted Anclote units satisfy the anchor load requirement of a 600 MMCFD pipeline, since the Suncoast plan specifies an initial pipeline capacity of 400 MMCFD, a sufficient anchor load needs only to be between 133 and 200 MMCFD.

247. The Polk County units alone will represent a maximum daily demand of about 216 MMCFD (or a third of the pipeline's capacity) at a single location at or very near the pipeline's terminus. (Id., Waller, Tr. 501). Florida Power's gas needs are known and [*187] identifiable (Ex. 28), and will, if authorized by the Florida Power Commission (Florida Public Service Commission), coincide with the lead time required to put a new pipeline in service. (Watsey, Tr. 402-04; Waller, Tr. 483-93; Schlesinger, Tr. 590-92).

We reject the above proposed finding of fact. Because the revised pipeline plan (Suncoast) specifies an initial pipeline capacity of 400 MMCFD, the Polk County units alone represent approximately 54 percent of the planned pipeline capacity.

248. If the pipeline is anchored by Florida Power's identified gas requirements, there will be ample additional demand to fill the balance of the pipeline's capacity. (Waller, Tr. 482-83).

We reject the above proposed finding of fact because this statement represents the witness' opinion and is not considered a statement of fact.

249. The fact that large pipeline companies are anxious to negotiate with Florida Power (Watsey, Tr. 427, 432, 443-44; Ex. 28) is indicative of the importance of an anchor load.

We reject the above proposed finding of fact because this statement represents an assumption. The fact that large pipeline companies are anxious to negotiate with Florida Power is only [*188] indicative of the desire of the companies to sell additional gas.

250. While the gas needs of the Anclote unit will facilitate project development (Watsey, Tr. 433; Waller, Tr. 511-12), they cannot be regarded as a substitute for the core gas requirements of the four Polk County units. (Waller, Tr. 503; Schlesinger, Tr. 610). The distinguishing factor is that the Polk County units will represent a substantial volume use at a single site. (Waller, Tr. 501, 503; Schlesinger, Tr. 610; Ex. 28).

We reject the above proposed finding of fact because the statements are premised on the construction of a pipeline that would have a capacity of 600 MMCFD. The statements leads to a conclusion that all four Polk County units are necessary to provide the substantial volume use at a single site. Since the proposed pipeline (Suncoast) has an initial capacity of 400 MMCFD, a sufficient anchor need only require between 133 and 200 MMCFD.

QFs Do Not Offer Anchor Load

251. The record cannot support a finding that QFs could effectively substitute for Florida Power as the anchor load for developing a new pipeline. (Watsey, Tr. 459-60; Schlesinger, Tr. 602-03). Individually, the known QFs in [*189] Florida Power's vicinity are relatively small in size. (Ex. 2, pp. 98-100). The largest will have a capacity of 104 MW, or less than one-ninth the size of the Polk County project. Id. Small QFs would fail to meet the basic criterion that an anchor load be sufficiently large to induce project development (i.e., between one-third and one-half of the pipeline's capacity). (Waller, Tr. 483).

We reject the above proposed finding of fact. Although we agree that the record does not clearly support the fact that QFs could effectively substitute as the anchor load for Florida Power, neither does the record support that a QFs would be unable to substitute as an anchor. The fact that the proposed pipeline (Suncoast) is telescoping in nature as opposed to a rifle-barrel lends more credence that a consortium of QFs may be able to provide an effective anchor.

252. Although there may be larger QFs in the future, because they are not yet known, quantifiable, or credit-worthy. (Waller, Tr. 480). A hypothetical need or a need that is not far enough in the future to match the pipeline's in-service date could not induce development. (Waller, Tr. 483). Even if a group of QFs could band [*190] together and negotiate effectively with pipeline builders, an "atomized" group of QF delivery points would fail to satisfy the geographic proximity criterion for an anchor load. (Watsey, Tr. 459; Schlesinger, Tr. 602, 605-06).

We reject the above proposed finding of fact because, as stated in discussion of previous proposed finding of fact, the fact that the proposed pipeline is telescoping in nature as opposed to rifle-barrel lends credence that a consortium of QFs may be able to provide an effective anchor load.

253. A geographically scattered set of gas delivery points, as compared with the Polk County units' "core" load, would increase the cost of pipeline construction materially. (Schlesinger, Tr. 602). If substantial loads are located upstream from the pipeline's terminus, the pipeline may not be built at its maximum optimal diameter along its entire length, with a resulting loss of overall economies of scale. (Waller, Tr. 504).

We reject the above proposed finding of fact. Since the proposed Suncoast pipeline has two delivery points upstream of the Polk County units, (Anclote and Peoples Gas System), the proposed pipeline already incorporates the costs of any additional [*191] construction costs that would be required.

254. There are costly impacts on the pipeline's pressure and compression characteristics whenever gas is diverted from the pipe's trunk line. (Waller, Tr. 507). Construction of numerous lateral delivery lines, at approximately $ 1 million per mile, can add substantial costs to the project. (Waller, Tr. 506; Schlesinger, Tr. 605-06).

We reject the above proposed finding of fact because the proposed pipeline construction configuration depicted in Exhibit A shows a lateral to Anclote and Peoples Gas System, as well as laterals to Orlando, Kissimmee, Lakeland, Teco-Hardee, Seminole-Tocala, and Teco-Power Park. Any costs related to these laterals has already been incorporated in the cost of construction.

Required Lead Time for New Gas Pipeline

Development and Construction

255. The contractual arrangements and design for and the engineering, permitting, certification, construction, and testing of a major natural gas pipeline can require a lead time of six to seven years. (Watsey, Tr. 403-04, 407; Waller, Tr. 483-93; Schlesinger, Tr. 590-92; Ex. 21). This lead time is approximately the same under any of the identified pipeline options. [*192] (Waller, Tr. 484-85; Schlesinger, Tr. 592). The tentative pipeline schedule shown in Exhibit 21 is reasonable because of the following factors:

* After a need for new gas pipeline capacity has been established, the contractual arrangements required to bring about such a development can take a year or more to finalize. (Schlesinger, Tr. 590; Watsey, Tr. 407).

* Before required filings are made for regulatory approvals of the pipeline, it can take 12 to 18 months (some of this time can overlap the contracting phase) to conduct the design and engineering work, the right-of-way evaluation and acquisition, and the development of cost estimates, pro forma rates, and a proposed tariff. (Waller, Tr. 487-89).

* Obtaining state, federal and local approvals for major natural gas pipeline construction can take four to five years, as evidenced by recent pipeline proceedings at FERC. (Waller, Tr. 490; Schlesinger, Tr. 591; Watsey, Tr. 403). Unexpected environmental issues or other complications will tend to draw out the process. (Waller, Tr. 489).

* Following regulatory approvals of a new natural gas pipeline, construction may be delayed by approximately six months to account for such [*193] factors as the final redesign necessary to comply with regulatory requirements, the finalization of the construction contract, the mobilization of construction forces, and the completion of financing. (Waller, Tr. 491-92). Thereafter, construction can be expected to take up to two years. (Waller, Tr. 492; Schlesinger, Tr. 592; Watsey, Tr. 407; Ex. 21).

We accept the above proposed finding of fact in substance. See Finding 105 in Recommended Order.

256. To ensure that sufficient new natural gas pipeline capacity will be available for the Polk County units, there can be no material delay in initiating significant pipeline development activities. (Watsey, Tr. 407, 421; Schlesinger, Tr. 589, 596). Pipeline capacity can be constructed between now and the 1998 in-service date for the Polk County units, but not if there is an initial delay in commencing the development process. (Watsey, Tr. 407; Schlesinger, Tr. 589).

We accept the above proposed finding of fact in substance. See Finding 106 in Recommended Order.

257. Because Florida Power's identified natural gas requirements will serve as the anchor load for new pipeline construction, Florida Power's current request for authorization [*194] of the four Polk County units is not premature. (Watsey, Tr. 407, 421; Schlesinger, Tr. 596).

We reject the above proposed finding of fact because, although we agree that the request for authorization to construct additional generating facilities is not premature as it relates to attaining sufficient natural gas delivery capability, the necessity for approval of all four units to serve as an anchor load is not essential. As the proposed Suncoast pipeline's initial capacity is 400 MMCFD, and not the 600 MMCFD discussed in the hearing, minimum sufficient anchor load requires 133 MMCFD of natural gas. The 133 MMCFD minimum anchor load can be obtained by as little as one Polk County unit and the converted Anclote plant.

Natural Gas Price Forecast

258. Florida Power's fuel forecast is reasonable and appropriate for the company to use in its system planning. (Schlesinger, Tr. 575). The fuel price forecast uses the same basic methodology as that used previously by Florida Power and reviewed by the Florida Power Commission as recently as the 1991 Annual Planning Hearing. (Williams, Tr. 536). Florida Power's natural gas price forecast is conservative and may show a relative price [*195] disadvantage for gas as compared to other fuels. (Schlesinger, Tr. 587, 595).

We accept the above proposed finding of fact with the exclusion of the first sentence because it is a conclusion of law. Previous review by the FPSC of the Florida Power fuel price forecast methodology and assumptions is true. In addition, the words "Florida Power Commission" have been changed to "Florida Public Service Commission." See Finding 85 in Recommended Order.

259. Florida Power's forecast of natural gas price trends is well within the range of projections compiled by other, recognized sources. (Schlesinger, Tr. 575, 577). Such sources include Data Resources, Inc., the Gas Research Institute, the American Gas Association, and the United States Department of Energy's Energy Information Administration. (Schlesinger, Tr. 576-77).

We accept the above proposed finding of fact.

260. In Florida Power's base- and low-case fuel forecasts, natural gas is expected to be priced at or below the price of low sulfur oil and well below the price of distillate oil. (Williams, Tr. 532,538; Ex. 2, pp. 71-73). Natural gas prices will remain below oil competition levels through most of the 1990s. (Schlesinger, [*196] Tr. 576). Most available fuel price forecasts are not predicting great increases in the price of natural gas. (Schlesinger, Tr. 599).

We accept the above proposed finding of fact with modification and deletion of the last sentence. See Finding 87 in Recommended Order.

261. Natural gas prices are not expected to rise significantly as a result of the expanded use of combined cycle gas units as a generating technology of choice, or the use of gas fired generation to satisfy Clean Air Act requirements. (Schlesinger, Tr. 597-98).

We reject the above proposed finding of fact. Staff agrees that Florida Power's fuel forecast does indicate an expectation of what the future fuel prices maybe and that the fuel forecast incorporates reasonable assumptions about the trends of fuel prices. However, the fuel price trends are not facts but assumptions, estimates and conclusions.

THE POLK COUNTY UNITS

262. The analyses in the Integrated Resource Study showed conclusively that the four 235 MW natural-gas-fired combined cycle units are the lowest cost and lowest risk option. (Niekum, Tr. 935; Foley, Tr. 1088; Ex. 74; Ex. 75; Ex. 105). The total installed cost estimate for all four Polk [*197] County units

would be approximately $ 862 million. This estimate includes escalation and AFUDC. The land and development cost for the Polk County site is approximately $ 64 million. The cost of the four combined cycle units is approximately $ 448 million. (Ex. 97). Current rate forecasts indicate that the addition of the Polk County units will not cause any increase in real electricity rates. (Niekum, Tr. 962).

We accept the above proposed finding of fact in part and with a clarification of which years dollars the values are given. We agree that Florida Power's analyses show that the Polk County units are the lowest cost and lowest risk option. We recognize that Florida Power has forecasted that the total installed cost of these units will be $ 862 million. However, the projected cost of the units is a forecast, and not a fact. In addition, we reject the last sentence regarding the effect on electricity rates since it is not a fact; rather, it is an opinion of what will happen in the future. See Findings 69 and 148 in Recommended Order.

263. Florida Power has refined its site-specific cost estimate for the Polk County Units as the project has developed. As preliminary [*198] engineering is completed, this estimate will be further refined. Florida Power's current estimate of $ 566/kW (1991 dollars), includes site development, associated transmission, and a potential gas lateral. (Ex. 97).

We accept the above proposed finding of fact.

264. The current site-specific cost estimate of $ 566/kW for the Polk County units compare favorably with the non-site-specific cost estimate of $ 599/kW used by Mr. Niekum in the evaluation of the alternative plans for planning purposes. (Major, Tr. 1034-35; Ex. 97).

We accept the above proposed finding of fact with the clarification that the dollar amounts are in 1991 dollars. See Finding 144 in Recommended Order.

265. The units will be constructed by Florida Power using the traditional approach to utility construction contracting as described in Mr. Ruisch's testimony. (Ruisch, Tr. 102). Florida Power will use an architect/engineer to design the plant and to assist Florida Power with construction management. Multiple fixed-price bid solicitations with well-defined work scopes will be used for equipment manufacturers and other subcontractors. This will minimize the risk of cost overruns. (Major, Tr. 1033). [*199]

We accept the above proposed finding of fact with the exclusion of the last sentence. See Finding 145 in Recommended Order.

266. The Polk County units are designed to operate on natural gas with distillate as a backup fuel. On-site storage of distillate oil sufficient for three days of continuous unit operation will be provided. (Major, Tr. 1030). The Polk County site can accommodate all necessary on-site gas facilities such as compressors and metering that may be required. (Major, Tr. 1030).

We accept the above proposed finding of fact in substance. See Findings 142 and 150 in Recommended Order.

267. Following the installation of the Polk County units, Florida Power's natural gas use will change from nearly zero to 11 percent. This will provide the system with greater insulation from fuel supply disruptions and price variability affecting any one of Florida Power's major fuels. (Ex. 2, p. 179).

We accept the above proposed finding of fact in part. See Finding 151 in Recommended Order.

268. With the addition of four 235 MW combined cycle units, Florida Power's reserve margin will improve to 17.5 percent (1,389 MW). With these reserves, the Florida Power system will [*200] have adequate capacity to withstand the loss of any large unit or combinations of any large and small units. (Niekum, Tr. 937-8; Ex. 76).

We accept the above proposed finding of fact because the finding is vague.

269. The Polk County units are extremely efficient and therefore have a low heat rate. As a result, these efficient plants use smaller amounts of fuel per unit of electric service delivered, and when combined with the use of a clean fuel, these units can reduce the exposure of Florida Power's system to new environmental rules or taxes. (Ex. 2, p. 180).

We accept the above proposed finding of fact in substance. See Finding 152 in Recommended Order.

270. The Polk County site is capable of future conversion to coal gasification. The site layout is designed to allow coal delivery, storage and handling, as well as allowing space for gasifiers and solid waste disposal areas for gasification byproducts. Preliminary air quality analyses for coal gasification emissions indicate the site is suitable. Two industrial-grade rail lines are adjacent to the site to facilitate future coal delivery. (Major, Tr. 1029).

We accept the above proposed finding of fact.

271. The [*201] four combined cycle units operate as intermediate (55-percent capacity factor) units on Florida Power's system. However, these units have the ability to run base load (continuous duty) as required. (Ex. 2, p. 84).

We accept the above proposed finding of fact with modification. See Finding 155 in Recommended Order.

272. The combined cycle units can be built for half the cost of a pulverized coal plant. (Ex. 2, p. 108). Other advantages of combined cycle technology are operational flexibility, moderate construction time, and fuel diversity. (Ex. 2, p. 108).

We accept the above proposed finding of fact with the following clarification: The costs referred to are capital costs only, and it is possible for plants of high capital cost to result in a lower system cost because of operational costs. See Finding 147 in Recommended Order.

Site Selection Process

273. Florida Power undertook a comprehensive and exhaustive selection study to identify a site capable of accommodating a wide range of fossil-fuel technologies, including combined cycle units fueld by natural gas. (Ex. 2., pp. 187-190). The site selection process considered environmental, socioeconomic, and engineering [*202] criteria, including fuel delivery facilities and the location of existing transmission. (Ex. 2, pp. 187-190). Florida Power received considerable assistance in this effort from an independent group of environmentalists, educators, and community leaders called the Environmental

Advisory Group (EAG). The EAG met regularly to review Florida Power's siting criteria and helped to identify issues of public concern. (Major, Tr. 1025).

We accept the above proposed finding of fact.

Site Description

274. The site chosen as a result of the selection process is the 8,000 acre Polk County site, located in southwest Polk County, approximately 40 miles east of Tampa and 3.5 miles northwest of Ft. Meade. (Major, Tr. 1027).

We accept the above proposed finding of fact.

275. The site has an ultimate capacity of approximately 3,000 megawatts, and can easily accommodate the initial 940 MW of the Polk County units at issue in this case. The site is capable of accommodating the future conversion of the Polk County units to coal gasification. (Major, Tr. 1038-39). The development of the Polk County site will be undertaken in a manner to provide adequate capability for future generation facilities. [*203] (Major, Tr. 1028).

We reject the above proposed finding of fact because the last sentence of the finding appears to be more of a policy statement than a recognizable fact. An event in the future cannot be stated as a fact.

276. The site represents a rare opportunity to make beneficial use of land that has already been disturbed by the activities associated with on-going phosphate mining. Unlike more "traditional" site preparation and development activities, approximately two years of activity on the site will be required before actual construction of the generating units can begin. (Major, Tr. 1033, 1053).

We accept the above proposed finding of fact.

277. The location identified as the power block site is presently highly irregular and under water. As Mr. Major described in his testimony, approximately 8 million cubic yards of fill material will be required to develop the power block area - the equivalent of stacking 100 football fields 60 feet high. This fill will come from an existing pond on site which has not yet had clay deposited in it. (Major, Tr. 1041).

We accept the above proposed finding of fact.

278. One of the reasons it is so critical to proceed with [*204] the licensing activities at this time is to ensure that the required fill material remains suitable for fill. This will involve the relocation of some on-going mining activities to ensure that clay is not deposited in the settling pond that will be the source of the fill material. (Major, Tr. 1060-1061).

We accept the above proposed finding of fact with the change in the first sentence of the words "so critical" to "necessary" in order to make the proposed finding of fact more objective. See Finding 137 in Recommended Order.

Associated Facilities

279. The 1998 Polk County unit will require the looping of the existing Barcola-Ft. Meade 230 kV transmission line into a new 230 kV switchyard at the plant site. This line passes through the site. For the remaining units, a portion of the existing line from Barcola to the plant site will be rebuilt with double-circuit structures to support two 230 kV circuits. (Major, Tr. 1029-1030).

We accept the above proposed finding of fact in substance. The first two sentences of the proposed finding of fact are included in Finding 138 in Recommended Order. The remainder is included in Finding 139 in Recommended Order.

280. The portion [*205] of the line from the plant site to Ft. Meade will require the addition of a new 230 kV circuit and will likely use existing structures. By using the existing structures, it will be necessary to relocate approximately 2.7 miles of the existing Ft. Meade-Rockland 115 kV circuit, parallel to SR 630 west of the Ft. Meade substation. (Major, Tr. 1029-1030).

We accept the above proposed finding of fact with modification. See Finding 139 in Recommended Order.

281. Depending on the ownership arrangements and the ultimate routing of the new gas pipeline, it may be necessary to construct a natural gas lateral. Current estimates show that lateral to be approximately 17 miles in length and 20" in diameter. (Major, Tr. 1030). The cost of the lateral pipeline and metering station, if required, will be $ 11 million in 1991 dollars. (Major, Tr. 1030).

We reject the above proposed finding of fact because in the second line of the proposed finding of fact, it says it "may be necessary to construct a natural gas lateral." Therefore, one could conclude that it may not be necessary, and a fact is therefore not definitively stated.

282. If the pipeline is constructed by FGT, it is probable [*206] that a 17-mile lateral connecting the site with existing FGT facilities in Hillsborough County will be needed. It is this lateral that is included in the site-specific current cost estimate. (Major, Tr. 1030; Ex. 97). If a pipeline is built by SunCoast Venture or another third party, such a pipeline would run adjacent to or through the Polk County site, and a lateral of undetermined length, located entirely in Polk County, may be needed. To cover both contingencies, Florida Power asks that the Florida Public Service Commission find a need for an associated gas lateral to connect the plant site with the appropriate pipeline facilities. (Ex. 28). The gas pipeline, however, is not an associated facility because it is not dedicated exclusively or even in large part to the Polk County units. (Ex. 28). Less than one-third of the pipeline's capacity is expected to be dedicated to the Polk County units. (Ex. 28).

We reject the above proposed finding of fact because the first line of proposed finding states "it is probable." This does not state anything definitively. See Finding 141 in Recommended Order.

283. Only a small piece of the lateral gas pipe, if any, will be located [*207] in Hillsborough County if the lateral is needed. None of the contemplated transmission, or any other facility associated with the plant, will be located in Hillsborough County. (Watsey, Ex. 22).

We reject the above proposed finding of fact because the proposed finding of fact could result in two different conclusions: (1) a small piece of the pipeline will go through Hillsborough County, or (2) none of the pipeline will go through Hillsborough County. Therefore, a fact can not be extracted from the proposed finding.

STATEWIDE NEED

284. To assist in determining the consistency of the proposed Polk County Units with peninsular Florida's system reliability and need, an update of the Florida Electric Power Coordinating Group's (FCG) 1989 Planning Hearing Generation Expansion Planning Studies document (1989 APH) was provided. The 1989 APH showed an accumulated addition of 5,930 MW, 6,990 MW, and 7,785 MW of generating capacity would be required in the winters of 1998/99, 1999/00, and 2000/01, respectively, to meet the reliability criteria. (Speck, Tr. 622; Ex. 36).

We accept the above proposed finding of fact.

285. Adjustments were made to that information for known changes, [*208] including the removal of Florida Power's previously identified coal units. (Ex. 36). After these adjustments, the reserve margins for the winters of 1998/99 through 2000/01, excluding Florida Power's Polk County Units, are less than the amount necessary to maintain adequate peninsular Florida reliability. (Speck, Tr. 623-624; Ex. 36). Florida Power's proposed capacity additions will provide only a portion of the additional generating capacity that is needed for peninsular Florida to maintain an adequate level of reliability. (Speck, Tr. 621).

We accept the above proposed finding of fact.

286. The Polk County Units also will contribute toward maintaining fuel diversity for peninsular Florida. Using the 1991 IE-411 filed with the Southeastern Electric Reliability Council, and adjusting for the proposed units, the peninsula's percentage of installed generating capacity fueled by natural gas will increase from approximately 6 to 9 percent. (Foley, Tr. 1092; Ex. 106).

We accept the above proposed finding of fact; however, the finding is duplicative in substance to Finding 84 in Recommended Order.

287. The proposed Polk County Units are therefore consistent with the reliability [*209] needs of peninsular Florida and will contribute toward the maintenance of adequate fuel diversity for the peninsula. (Ex. 2, p. 197).

We reject the above proposed finding of fact because the finding is a conclusion of law, not a finding of fact.

CONSEQUENCES OF DELAY

288. Stopping the current Determination of Need proceeding and soliciting bids could jeopardize Florida Power's ability to:

* Meet Clean Air Act requirements (Foley, Tr. 1177; Ex. 2, p. 201),

* Develop the Polk County site (Foley, Tr. 1177; Ex. 98), and

* Bring a new gas pipeline into Florida. (Foley, Tr. 1177; Ex. 21; Ex. 2, pp. 201-02).

We reject the above proposed finding of fact.

289. The effects of NUG purchases will be compounded if Florida Power were required to undergo successive rounds of bidding for new capacity. In each round the Florida Power would need to add compensating equity in order to restore its coverage ratios, so its leverage will decrease and its cost of capital will increase. The utility will be disadvantaged even further in the

subsequent bidding process because of its higher cost of capital. (Wieland, Tr. 297-98).

We reject the above proposed finding of fact.

290. Each alternative [*210] was (sic.) compared to a base alternative under 27 different scenarios. The base option was Alternative 3, the addition of the planned Polk County units. (Niekum, Tr. 934; Ex. 105).

We accept the above proposed finding of fact; however, the finding is duplicative in substance to Findings 4 and 13 in Recommended Order.

291. If one of the 235 MW combined cycle units in the year 1999 was deferred until the year 2000, this alternative would result in a higher cumulative present worth revenue requirement (CPWRR) and higher SO[2] emissions. The level of SO[2] emissions would increase by 3,861 tons in 2000 and from 1991 to 2030, the CPWRR would be approximately $ 1.3 million more. (Ex. 87).

We accept the above proposed finding of fact in substance. See Finding 77 in Recommended Order.

292. A one-year delay in the in-service date of the each of the proposed units will cause Florida Power's winter reserve margin to drop below its minimum level of 15 percent. With this one-year delay, the reserve margins will range from a low of 12 percent in the winter of 1999/2000 to 14.5 percent the following winter. Further delays will have a more dramatic effect. (Ex. 2, pp. 199-200).

We [*211] accept the above proposed finding of fact with the clarification that the reserve margins referenced above are the forecasted reserve margins that would occur if all of the units were delayed by one year. The effects would be less dramatic if one unit is delayed by one year. See Finding 156 in Recommended Order.

293. A delay in the in-service dates of any of the units beyond 1999 also will lead to an increase in Florida Power's SO[2] emissions. Florida Power will be forced to run less efficient, less clean units more often. This may require Florida Power to take more costly measures to ensure compliance with the Clean Air Act. (Ex. 2, p. 201).

We reject the above proposed finding of fact because the finding is an opinion of what will happen in the future.

294. Florida Power's proposed schedule preserves the ability to bring the combined cycles on line early to meet any contingencies that might affect system reliability. If the units are delayed, strategic flexibility to mitigate problems such as a delay in QF capacity, a greater anticipated load, or a delay in the 500 kV line, would be unavailable. (Ex. 2, p. 201).

We accept the above proposed finding of fact.

FLORIDIANS [*212] FOR RESPONSIBLE UTILITY GROWTH

(#'s 1-7, pps. 19-22 Brief of FRG)

We reject the proposed findings of fact, because they are conclusions of law, and they are addressed as such on pages 40 and 41 of the Proposed Recommended Order.

Attachment B

STAFF RESPONSES TO EXCEPTIONS TO THE RECOMMENDED ORDER

Response to FICA's Exceptions to the Conclusions of Law

Timing Issues

Exception: FICA's alleged First error in the Recommended Order: "the three-year construction lead time for the combined cycle units would . . . . require the Commission to defer ruling on the need for even the first two Polk County units . . ." (p. 2)

Staff Response:

-- This statement totally neglects the consideration of the 2-year lead-time necessary to prepare the site before construction begins, as well as the lead-time necessary to construct a gas pipeline. Furthermore, if the Commission denies the need determination, the lead time necessary to prepare and process a second need certification must be added to the site preparation time and the pipeline development time.

Exception: "Virtually all of the factors cited by the Hearing Officer as justifying a delay in certifying the second two [*213] units apply to the first two units as well." (p. 7)

Staff Response:

-- This assertion is incorrect. The first units certified on the site require a longer lead time than subsequent units because of the two-year site preparation time and the lead time necessary to bring a new pipeline into service. In addition, the record contained competent substantial evidence that the first two units are needed and that they are the most cost-effective alternative available. The Hearing Officer found that the need for the last two units should not be granted at this time because the cost-effectiveness of constructing the third unit in 1999 was marginal and because the last two units do not require the additional lead time associated with site preparation and the pipeline.

Cogeneration Issues

Exception: FICA's alleged Second error in the Recommended Order: "The second error . . . . was the finding that FPC's planned Polk County units were the most cost-effective alternative available. The record clearly shows that FPC completely ignored cogeneration." (p. 2)

Staff Response:

-- Competent substantial evidence in the record demonstrates that FPC's first two planned Polk County [*214] units are the most cost-effective alternative available. The record contains no competent substantial evidence regarding a more cost-effective alternative. All evidence regarding the ability of QFs to construct more cost-effective projects was totally speculative. The record contains no proposals from non-utility generators from which to make a conclusive determination that non-utility generation is available, let alone a determination that such proposals are more cost-effective than the Polk County units.

-- The record shows that FPC has contracted for a substantial amount of cogeneration, and it also shows that FPC's Integrated Resource Study relied on 150 MW of non-utility generation that is yet to be contracted.

-- In addition, as discussed in the Recommended Order, the Hearing Officer considered strategic concerns associated with the proposed Polk County units in making her decision: the benefits of securing a site capable of housing 3,000 MW of generation, and the benefits of securing a second gas pipeline into peninsular Florida.

-- The record shows that if FPC were required to hold a bid to acquire non-utility generation and no suitable projects responded, the resultant [*215] delay could jeopardize the acquisition of the site and the siting of the second pipeline. At the least, the delay would cause increased site development costs, resulting in more expensive generation to FPC's ratepayers.

Exception: "the Commission recently approved over 600 MW of firm capacity contracts with various QFs to sell power to FPC at prices up to 5% below its total avoided cost . . . Moreover, FPC's recently-filed standard offer was based on an avoided combustion turbine unit, which has a construction cost well below that of a combined cycle unit, yet it received almost 500MW of contracts from QFs . . ."

Staff Response:

-- The average discount from avoided cost in the 600 MW of firm capacity contracts was 1.79 percent (See Order 24734 at page 13); therefore, the Hearing Officer's Finding No. 49 is accurate.

-- FICA's argument that QFs are lower cost than FPC's proposed Polk units because QFs previously contracted below FPC's avoided cost is misleading. The 600 MW of firm capacity contracts are all based on coal units which have a total cost that is higher than that of the Polk County combined cycle units. Similarly, the avoided combustion turbine unit [*216] has a higher total cost than the Polk County combined cycle units (coal units and combustion turbine units were rejected in the planning process to meet FPC's 1997 - 2000 needs because they resulted in higher costs than combined cycle units).

Exception: "The Recommended Order fails to acknowledge . . . the legislative mandate of Section 366.81, Florida Statutes, to liberally construe Section 403.519, Florida Statutes, in order to . . . '. . . encourage further development of cogeneration facilities . . .'" (p. 5) "These two legislative declarations provide a presumption that firm cogeneration capacity is cost-effective and is to be preferred over utility construction. Concrete proof to the contrary must be presented before a certification of need for utility construction can be issued." (p. 8)

Staff Response:

-- FICA's assertion that Section 366.81 of FEECA creates a rebuttable presumption that firm cogeneration capacity is cost effective and thus preferred over utility construction far exceeds a reasonable interpretation of the intent of FEECA. Section 366.81 states in pertinent part that:

ss. 366.80-366.85 and 403.519 are to be liberally construed in order to [*217] meet the complex problems of reducing and controlling the growth rates of electric consumption and reducing the growth rates of weather-sensitive peak demand; increasing the overall efficiency and cost-effectiveness of electricity and natural gas production and use; encouraging further development of cogeneration facilities; and conserving expensive resources, particularly petroleum fuels.

In response to this legislative directive the Commission considers relevant cogeneration issues as a matter of course in utility need determination proceedings. The question of whether a utility has adequately explored and evaluated the availability of non-utility generation to meet projected capacity needs is a standard line of inquiry in the Commission's investigation of the cost-effectiveness of proposed utility generation projects, as it was in this case. (See Issue 20 at page 6 of the Recommended Order) This is the "liberal construction" of section 403.519 that is contemplated by section 366.81.

-- FICA is asking the Commission to gamble with the reliability of FPC's system and jeopardize the economics of FPC's proposal based on the hope that suitable QFs will be there when the capacity [*218] is needed and the unsupported assumption that they would be more cost effective than utility construction.

Exception: As a matter of law, "QFs have no burden in this proceeding to present specific projects that will defer a utility's planned unit." (p. 18)

Staff Response:

-- In her Recommended order the Hearing Officer did not impose an undue burden upon QF's. She simply found that no competent substantial evidence existed on the record that would allow her to find that site-specific, viable, cost-effective cogeneration projects were available to fill the identified need for additional capacity on FPC's system. Because that evidence did not exist she could not hold that FPC had not adequately explored the availability of non-utility generation as a cost-effective alternative to construction of the proposed project.

-- It is not possible to prove a negative, and therefore FPC was not required to demonstrate that no specific cost-effective cogeneration projects could replace the proposed project.

Exception: "Since the grounds for FPC's deliberate rejection of additional non-utility purchases have themselves been rejected, it is impossible and illogical to conclude [*219] that FPC had "reasonably" explored and evaluated non-utility generation." (p. 12)

Staff Response:

-- This assertion is incorrect. As discussed in the Recommended Order, the Hearing Officer relied on grounds other than FPC's assertion that QFs cause "hidden costs" and FPC's assertion that QF projects cost more than utility projects. (See Recommended Order, pages 39 - 40)

Exception: "During the planning process, FPC evaluated two alternatives to construction: 1) additional conservation measures; and 2) additional purchases from utility sources. In contrast . . . FPC completely ignored additional non-utility purchases . . ." (p. 9)

Staff Response:

-- Conservation and additional utility purchases were alternatives that FPC could quantify and, therefore, evaluate during the planning process. The record contained no proposals from non-utility generators which could be input into FPC's computer models. Therefore, it was not possible to evaluate such proposals. It is unrealistic for QFs to demand that utilities not be permitted to plan to meet their needs without evaluating non-utility purchases, when QFs did not provide purchase offers which FPC could evaluate.

Exception: [*220] Alleged Third error in the Recommended Order: "The Third error committed . . . is the finding . . . that FPC did, in fact adequately consider cogeneration as an alternative to the proposed units." (p. 2 - 3)

Staff Response:

-- FICA's alleged Third error is similar to its alleged Second error in that FICA alleges that the planned Polk County units are not the most cost effective alternative because FPC did not adequately consider cogeneration. See previous discussions for Staff Response.

Site Issues

Exception: "nothing in the record suggests that FPC cannot simply purchase the land and reclaim it in accordance with established DNR requirements in preparation for eventual use as a construction site." (p. 4) "The record contains no evidence that FPC cannot buy nor reclaim the property in preparation for eventual construction of generating units if the Polk County units are not certified at this time." (p. 16 - 17)

Staff Response:

-- This exception is misleading in that it confuses reclamation of the site with preparation of the site. FPC must perform approximately $ 63.5 million of site preparation activities in excess of the reclamation activities required [*221] (and allowed) by the DNR. Most of these additional preparation activities relate to filling in the power block area. (Tr. 1058 - 1059) These site development activities -- which will take approximately two years -- may not be initiated until after FPC obtains certification of the site. Therefore, it is not possible for FPC to "simply purchase the land and reclaim it . . . in preparation for eventual use as a construction site" as FICA alleges. If FPC purchased the site and waited to obtain certification, the site would not be ready for construction at the needed time.

-- Also, as discussed below, delays in certification of the units would jeopardize the development of a gas pipeline to the Polk County site.

Exception: "Other utilities have held sites for future use for many years and there is nothing in the record to suggest that FPC cannot do the same." (p. 17)

Staff Response:

-- FICA did not provide any transcript references to support its assertion that other utilities have held sites for future use for many years. Nor did it provide transcript references which show that sites held by other utilities are comparable to FPC's proposed Polk County site.

-- In addition, [*222] as discussed previously, FPC must obtain certification of the site before it starts the lengthy site preparation process.

Exception: "Neither the New Pipeline Nor the Polk County Site Materially Affect Any Criteria Under 403.519." (p. 17)

Staff Response:

-- Regarding the Polk County Site, FICA's assertion that the purchase or use of a power plant site has no material relationship to the criteria for certification under 403.519 is incorrect. In making its determination of need, the Commission is required to "take into account . . . the need for adequate electricity at a reasonable cost, and whether the proposed plant is the most cost-effective alternative available." (403.519, Florida Statutes) Adequate electricity at a reasonable cost cannot be provided without a power plant site at a reasonable cost. Issues regarding the site of the proposed power plant are an essential part of the Commission's determination of need proceedings. (Staff's response to the exception as it pertains to the natural gas pipeline is found in the "Natural Gas Issues" below.)

Natural Gas Issues

Exception: FICA's alleged Fourth error in the Recommended Order: "The principle error concerns [*223] the construction lead time of the natural gas pipeline. In spite of the fact that FPC's letter of intent with SunCoast Venture (Exhibit 28) indicates service to Anclote would begin in 1995 (three years in the future) the Recommended Order finds that a six to seven-year lead time is required (Finding of Fact No. 105)" (p. 4)

Staff Response:

-- Exhibit 28 is a letter of intent that reduces to writing the agreement of several parties to proceed toward interrelated goals, one of which gives a date for service to Anclote and another, Paragraph 5, Pursuit of Regulatory Approvals. In Paragraph 5, SunCoast agrees to seek legislation to subject rates and services to regulation by this Commission. That would exempt the proposed pipeline from Federal Energy Regulatory Commission (FERC) jurisdiction. As a backup, SunCoast agrees in subparagraphs 5 (b) and 5 (c) to concurrently prepare an application to seek authority from the FERC to construct and operate an interstate natural gas pipeline. If the state legislative initiative fails, jurisdiction rests with the FERC, under the Natural Gas Act.

-- The record, both in Mr. Waller's testimony (TR. 479 and 487-494) and Mr. Schlesinger's [*224] testimony (TR. 591, lines 6-15, p. 596, lines 13-18, p. 607, line 25 - p. 608, line 6) provides unrefuted testimony that refers to FERC authority and the FERC's approval timelines. This Commission is correct in considering the longer FERC timelines for approval of a gas pipeline, because the authority rests with the FERC under existing law.

Exception: "The pipeline is not jeopardized if the Polk units are not certified at this time." (p. 16)

Staff Response:

-- FICA's comments related to the timing of the pipeline and the early delivery date to Anclote are incorrect for the reasons given in the discussion of the alleged fourth error in the Recommended Order. Early delivery of gas to the Anclote plant is a part of the agreement that includes changing Florida law. If that does not happen, the FERC has jurisdiction and the seven year lead time is supported adequately in the record.

Exception: Alleged Fifth error in the Recommended Order: "The Fifth error involves the conclusion that two of the Polk County units are needed to anchor a second gas pipeline into Florida. In fact, the findings in the order and the record itself show that FPC's planned conversion [*225] of Anclote, with a small amount of other firm load will be sufficient to anchor a new pipeline." (p. 5)

Staff Response:

-- FICA's position appears to stem from combining Mr. Waller's testimony on necessary "anchor load" of one third to one-half of pipeline design capacity, (TR p. 503, line 19 - p 504. line 1) with the 400 million cubic feet per day (MMCFD) stated as the proposed design capacity in Exhibit 28, the letter of intent for the SunCoast Venture. It ignores the fact that Mr. Waller's agreement with Mr. Palecki's statement that the one-third to one-half generic decision guideline is "talking about a line of 600 million cubic feet per day" (TR 504, lines 2 - 4). The record is not clear that the same ratio, particularly the one-third limit, holds true on a pipeline of lower initial capacity.

-- The proposed pipeline described in Exhibit 28 is a 36 inch pipeline, which meets Mr. Waller's definition of a large diameter pipeline "something in excess of 20 inches", which will cost an estimated $ 1 million per mile (TR 509, lines 19 - 21). The investment is approximately the same as a larger capacity line. It does not logically follow that an anchor load of only 1/3 of [*226] the design capacity would be sufficient to build the 400 MMCFD pipeline when the pipeline construction cost is not significantly lower than for the 600 MMCFD pipeline. It does logically follow that if 200 MMCFD is sufficient to serve as an anchor to support an estimated $ 600 million investment in a 600 MMCFD pipeline, then 200 MMCFD is a sufficient anchor to anchor a 400 MMCFD pipeline estimated to cost close to the same $ 600 million.

Exception: "The proposed pipeline can be anchored by FPC'S Anclote unit and other expected load" (p. 20) "The Hearing Officer's conclusion that two of FPC's units were needed to anchor the pipeline is clearly erroneous and cannot stand as a basis for certifying two units." (p. 21)

Staff Response:

-- In its discussion, FICA refers to Finding of Fact 103 in the Recommended Order. That finding does not logically support that a 400 MMCFD pipeline will be built for an anchor load of 1/3 of the design capacity. This is fully discussed in response to the alleged fifth error in the Recommended Order. FICA's conclusion that only 13 MMCFD need be added to attract a pipeline gives credence only to the ratio of 1/3 of design capacity, not to the [*227] logic behind the economics discussed previously.

Exception: "The value of a second pipeline is completely unknown." (p. 15)

Staff Response:

-- In transcript references provided by FICA (TR 442-443), Mr. Watsey states that the benefits have not been quantified, not that they are unknown as FICA asserts.

-- FICA's assertion that FPC does not expect transportation price concessions is irrelevant.

-- FICA's statement that the Commission ". . . rejected FPC's Proposed Finding of Fact No. 238 that claim that a second pipeline would lead to lower prices (Recommended Order at page 104)." misrepresents the position taken in the Recommended Order and ignores evidence in the record that supports the benefits of competition. Proposed Finding of Fact 238 relates only to the transportation component of natural gas pricing. It is in the transportation component that the Recommended Order finds the record weak. The larger component of gas price is the commodity, itself -- the supply. Mr. Watsey's testimony discusses other strategic and operating benefits, some that give lower costs, including gas-to-gas competition at the wellhead (TR 437 lines 2-14).

Exception: "Neither the [*228] New Pipeline Nor the Polk County Site Materially Affect Any Criteria Under 403.519." (p. 17)

Staff Response:

-- Regarding the pipeline, FICA's remarks that the construction and operation of a pipeline has no material relationship to the criteria for certification under 403.519 is incorrect. In making its determination of need, the Commission is required to "take into account . . . the need for adequate electricity at a reasonable cost, and whether the proposed plant is the most cost-effective alternative available." (403.519, Florida Statutes) Adequate electricity at a reasonable cost cannot be provided without adequate fuel at a reasonable cost and it cannot be provided without fuel delivered to the generating site.

Exception: "The purpose (of the need determination process) is not to explore means of inducing new pipelines. . . ." ". . . it is improper to venture so far afield into this wholly irrelevant realm." (p 18)

Staff Response:

-- FICA is correct that "The purpose (of the need determination process) is not to explore means of inducing new pipelines. . . ." FICA is wrong, however, when it continues, ". . . it is improper to venture so far afield into this [*229] wholly irrelevant realm." The Commission must be reasonably assured that adequate and reasonably priced fuel will be available to a proposed generating site before approving a need determination petition.

Response to FICA's Exceptions to the Findings of Fact

FICA's exception to Findings 6 and 7 is misleading. FPC included 150 MW of QF purchases that were not under contract; 70 MW of these purchases were not part of a standard offer.

FICA's exception to Finding 20 incorrectly characterizes the finding. Finding 20 simply states how self-service generation is considered in planning. It does not say that FPC has a program to encourage self-service generation.

FICA's exception to Finding 44 addresses the amount of contracted QF capacity. Finding 44 discusses FPC's units currently under construction and does not mention QF capacity.

FICA's exception to Finding 47 incorrectly characterizes the finding. Finding 47 does not address new purchases and it does not state that FPC is the State's largest purchaser of QF plus utility power.

FICA's exception to Finding 49 is misleading. The average discount from avoided cost in the 600 MW of firm capacity contracts [*230] was 1.79 percent (See Order 24734 at page 13); therefore, the Hearing Officer's Finding No. 49 is accurate. In addition, FICA's reference to a 12.5 percent discount refers only to capacity costs only and does not refer to total costs.

FICA's exception to Finding 50 mischaracterizes the finding. Finding 50 does not say or imply that the QF capacity incorporated is not under contract. This finding does not address new purchases.

Finding 65 is correct as stated. It identifies three methods of complying with the Clean Air Act: reduce loads, reduce emissions at existing plants, or build new plants so existing plants are used less. The Finding does not limit "built new plants" to utility-only plants as FICA claims.

Findings 69 and 78 are in the same document and will be considered together. It is inadvisable and unnecessary to combine these findings since Finding 78 should be considered along with other findings as well.

Finding 70 refers to two specific purchased power options, and does not imply a general consideration.

Finding 74 simply states FPC's expected capacity factor if its identified need is not met. This finding does not imply that there are no [*231] other methods of meeting the need. In addition, the Finding does not mention FPC's minimum reserve margin criteria -- even if it did, it is not necessary to mention the date that it was adopted, since it was not material to the decision in this case.

Finding 77 does not have to say that the figure is not significant because Finding 78 is in the same document and these findings will be read together. In addition, Finding 77 implies that the figure is insignificant because it says, "[t]his represents an expected increase of 0.007 percent."

Finding 84 is supported by competent, substantial evidence; it speaks to the fuel diversity of the Polk County units. It does not say, nor does it imply, that QFs would not provide fuel diversity.

In its exceptions to Findings of Fact Nos. 85, 86 and 87, FICA states that "the record suggests FPC's planning department tampered with or influenced their fuel forecast expert to reduce his 'high-case' forecast." FICA gives no transcript references or otherwise explains the source in the record of this suggestion of tampering or influence. For purposes of these comments, Staff assumes Mr. Sexton refers to his cross-examination of Mr. [*232] Williams, in which Mr. Williams explained the decision analysis technique used by FPC. According to Mr. Williams, in that process interviewers ask questions such as, "if you would win a car if you were right, would you bet that . . ." (TR 547, lines 20-21). The record there indicates that, rather than tampering with or influencing the forecast, or making an attempt to reduce the high forecast as alleged by FICA, the process was used to expose any unconscious biases that might be skewing Mr. Williams' forecast. Mr. Williams stated, ". . . through the interview process, they brought out that my underlying thoughts had a bias in them. . . ." (TR 548, lines 17-19) Mr. Schlesinger, in response to a question by Mr. Palecki that appeared to have been asked at least partly in jest, confirmed that he had participated in a number of interview processes like that used to uncover Mr. Williams inherent biases and that it is a legitimate process. (TR 611, lines 17-25)

In its exception to Finding 90, FICA states that this finding ignores Exhibit 28, ". . . which is in fact a letter of intent for the transportation segment of fuel supply for the Polk units . . ." [emphasis added]. Finding [*233] of Fact 90 refers to gas supply contracts, which are contracts for the gas, the commodity itself. The finding of fact is correct as stated.

In its exception to Finding 91, FICA states, "[t]his finding, as it relates to Florida being served by only one pipeline, is completely irrelevant to this proceeding. The Commission cannot certify the need for a power plant based on the need for a pipeline unless perhaps the entire pipeline is considered an associated facility of the Polk County project." The existing gas transportation grid is relevant. See the discussion under the above response to FICA's statement: "Neither the New Pipeline Nor the Polk County Site Materially Affect Any Criteria Under 403.519." Regarding FICA's statement, "[t]he Commission cannot certify the need for a power plant based on the need for a pipeline . . .": The Recommended Order is not certifying need on that basis, but it is also not ignoring information relevant to the need finding.

In FICA's exception to Finding 95, FICA states, "This finding is incomplete. It provides an update of many facts based on the Letter of Intent but it omits the fact that the Anclote unit will be served by the new [*234] pipeline beginning in 1995." The 1995 service to FPC's Anclote unit is not relevant. This issue is thoroughly discussed in Staff's response to FICA's alleged fourth error in the Recommended Order. This finding of fact is correct and it is complete because it includes all points intended for inclusion.

In its exception to Finding 96, FICA alleges, "This finding is based on an ex parte communication of FPC after hearing which is not record evidence and cannot be part of any late-filed exhibit. Therefore, this finding must be stricken." This finding is supported by the record. FICA's allegation of ex-parte communication is improper, unsupported and absolutely false. The finding is a conclusion drawn from two facts clearly in the record; 1) FPC's original Option B was an FGT extension and 2) FPC abandoned that option, agreeing in the letter of intent, Paragraph 6, Exclusive Negotiations, "FPC shall not negotiate or enter into any other agreements for the transportation or delivery service contemplated by Section 4 above." To then conclude that FGT had presented FPC with a better offer would take a leap of (ill) faith and a preponderance of poor judgement. The finding of fact [*235] simply states the conclusion as a fact. As to whether ex parte communication took place, this finding of fact was accepted as FPC's Proposed Finding of Fact 234, which is a part of the record.

FICA questions the complete accuracy of Finding 98 and states that it appears inconsistent with the ruling on FPC's Proposed Finding of Fact No. 238. The first sentence of this finding quotes the unrefuted record of what has been FPC's experience. The second states what could happen, and is not a statement of what will happen. FPC's Proposed Finding of Fact No. 238 was rejected because it stated future events as a fact, using the word "will" as if future events were an absolute, rather than a prediction.

In its exception to Finding 105, FICA states, "This finding is incorrect. The Letter of Intent with Suncoast shows that the lead time of a new pipeline is approximately 3 years. In fact, Suncoast proposes to begin deliveries to Anclote in 1995." See Staff response to alleged fourth error in Recommended Order.

FICA's exception to Finding 106 is essentially the same as for Finding 105. See Staff response to alleged fourth error in Recommended Order.

FICA's exception [*236] to Finding 119 incorrectly characterizes the Finding. Finding 119 simply reiterates Witness Abrams' testimony regarding the quantitative analysis Duff & Phelps employs when evaluating the financial impact of purchased power contracts.

Findings 109 - 121 clearly indicate that the Commission recognizes that a complete analysis of the financial impact of purchased power contracts requires consideration of both quantitative and qualitative factors in relation to the utility's total financial posture.

FICA's exception to Finding 131 incorrectly characterizes the Finding. Finding 131 does not imply that a reduction in cash flow will have a negative effect on credit quality as claimed by FICA. While the Commission agrees that Finding 131 implies a more significant reduction in cash flow than probably would be realized on a marginal basis, the Finding makes no reference to how this would impact credit quality.

FICA's exception to Finding 132 is supported by the record in part. The Finding as stated implies that there are only two ways of compensating for the financial consequences of increased purchased power obligations. However, in addition to the two methods cited in [*237] the Finding, a utility could also compensate for the financial consequences of acquiring this type of capacity if regulatory treatment of purchased power obligations is modified to allow the utility the opportunity to earn a return on this capacity. (See Issue 1 for Staff Proposed Wording for Finding 132) However, while the Commission does agree that Finding 132 is incomplete as stated, it does not agree with FICA's claim that the Finding is misleading. Findings 113, 118, 120, and 121 clearly indicate that the Commission recognizes that financial ratios can move within ranges without affecting the credit rating and that the credit rating agencies will weigh both the risks and benefits of purchased power capacity when assessing the impact on a utility's creditworthiness.

In FICA's exception to Finding 141, FICA states, "[t]his finding is misleading and incomplete. FPC needs not only a gas lateral, it also needs a 560 mile natural gas transportation pipeline . . ." This finding is neither misleading nor incomplete. FPC will have to build a lateral, as stated in the finding of fact. The 560 mile pipeline referred to by FICA is not an associated facility to be permitted [*238] in this case. It will likely be built by someone else. FPC may choose to be an equity participant in the pipeline, or it may not, but the 560 mile pipeline is not an associated facility on or near the site.

In its exception to Finding 142, FICA states, "[t]his finding is misleading in that it assumes the natural gas pipeline will be built. If it is not, FPC will require many millions of gallons of distillate storage or other facilities to fuel the project." To the contrary, it would be incorrect to assume that a gas pipeline will not be built. At page 42 of the Recommended Order, Recommendation B is to grant "the Petition for Determination of Need for the first two proposed Polk County Units . . ." Those units, as proposed, are fired with natural gas as the primary fuel and FPC states it intends to seek final certification to construct the Polk County Units as natural gas fired units. (Petition to determine Need for Electrical Power Plant, paragraph 6.) If the gas is not available, FPC does not have certification.

Finding 147 is correct in that it states that the combined cycle technology provides fuel diversity. It does not state that the combined cycle technology [*239] provides the most fuel diversity of any conceivable option.

In its exception to Finding 150, FICA states, ". . . if natural gas is not available, due to lack of a pipeline . . . firing the proposed units on distillate fuel would make them the most expensive of the 10 alternatives evaluated by FPC" See Staff response to Finding of Fact No. 142.

FICA's exception to Finding 156 mischaracterizes the finding. Finding 156 implies that no other capacity resources are employed. Otherwise, the capacity resources that were employed would be identified in the finding.

Finding 157 addresses the strategic flexibility provided by the Polk County units and does not address other options, nor does it need to address other options.

FICA's exception to Finding 158 is in error in that it assumes that it would be prudent for FPC to purchase and develop the Polk County site with no plans for certification or construction on the site.

Response to FICA's Exceptions to the Rulings on FPC's Proposed Findings of Fact

Proposed Finding 9: see response to exception of Finding 6.

Proposed Finding 13: see response to exception of Finding 7.

FICA's exception to Proposed Finding [*240] 61 is factually correct, but the proposed finding is not a description of Rule 25-17.008 F.A.C.; it merely recounts the results of the process, and describes the purposes of the tests.

FICA's exception to Proposed Finding 72 points out a typing error, as ". . . efficiency reductions . . ." should be replaced with ". . . efficiency improvements . . ."

Proposed Finding 82: see response to exception of Finding 47.

Proposed Finding 83: Since this finding was supported by competent, substantial evidence, it was accepted. But it was not included in the Recommended Order because it was duplicative.

FICA misinterpreted FPC's Proposed Finding 84. The finding does not imply that the QF capacity is intended to avoid the Polk County unit. Also, given that the hearing occurred in 1991, it would be logical to conclude that the contracts were not signed between 1992 and 1996; rather, the in-service dates of the contracts are between 1992 and 1996.

Proposed Finding 85: see response to exception of Finding 50.

FPC's proposed finding 101 was supported by competent, substantial evidence. It does not imply that FPC's reserve margin criteria was never different from [*241] 15%.

Proposed Finding 105: see response to exception of Finding 74.

Proposed Finding 111 was rejected by the Hearing Officer.

Proposed Finding 113 was not accepted as stated. See response to exception of Finding 69.

Proposed Finding 114 was not accepted as stated. See response to exception of Finding 70.

Proposed Finding 115 was not accepted as stated. However, FICA's discussion is not relevant since the proposed finding does not mention Alternative 3.

Proposed Finding 116 was not accepted as stated. There is no competent and substantial evidence in the record that there is a more cost-effective alternative than Alternative 3.

Proposed Finding 118 was not accepted as stated. However, FICA's exception is flawed since the proposed finding does not assume that FPC will construct the capacity. The proposed finding merely states the type and amount of capacity that will be needed, should the 500 kV line not be constructed.

Proposed Finding 124 was not included in the Recommended Order because it is duplicative in substance to Finding 84. See response to exception of Finding 84.

Proposed Finding 128: See response to Finding 65.

Proposed [*242] Finding 131 was not accepted as stated. FICA's exception is flawed because the proposed finding does not state or imply that there are no other ways of complying with the Clean Air Act.

Proposed Finding 135 is not included in the Recommended Order. FICA misread the proposed finding -- it does not claim to have control over uncontrollable variables.

Proposed Finding 136 is not included in the Recommended Order. FICA's exception to its acceptance is flawed because the proposed finding does not mention Clean Air compliance levels.

Proposed Finding 140 is not included in the Recommended Order. The proposed finding only discusses the contingency fee that turnkey operators charge. It does not need to address the traditional utility approach.

Proposed Finding 144 is not included in the Recommended Order because it is immaterial to the decision in this case. However, the proposed finding is supported by competent, substantial evidence in the record.

Proposed Finding 152 does not address investment in a pipeline; it only addresses the construction of the Polk County units. Therefore, the financial impacts of investing in a pipeline are not appropriately considered [*243] in this finding.

Proposed Finding 153 was not accepted as stated. The proposed finding says that FPC can finance the investments in its Integrated Resource Study. The pipeline is not in the study. Therefore, the financial impacts of investing in a pipeline are not appropriately considered in this finding.

Proposed Finding 155 is not duplicative of Finding 118 since Finding 118 considers the benefits of purchased power, not the risks of purchased power. Proposed Finding 155 considers the risks.

Proposed Finding 165: See response to exception of Finding 131.

Proposed Finding 172 was not included in the Recommended Order. However, it is supported by competent, substantial evidence. Contrary to FICA's exception, it is not necessary to discontinue programs to control the costs of conservation.

Proposed Finding 181 was not included in the Recommended Order. However, payments to QFs are guaranteed to the extent that the utility has a contractual commitment to pay the QF as long as the QF performs.

Proposed Finding 185: See response to exception of Finding 132.

The ruling on Proposed Finding 188 does reject the last sentence.

Proposed Finding 189 [*244] is not included in the Recommended Order. The ruling to reject this Finding is based on the language in Exhibit 11 which expressly states a range of 10% to 50%. (Ex 11, p. 7) It would be speculative to conclude at this time, based on the very limited presentation on the S&P methodology in Exhibit 18, that the lower limit is 0% rather than 10%.

Proposed Finding 191 is not included in the Recommended Order. However, while the Proposed Finding is not material to the ultimate decision in this case, it is supported by the record. This Proposed Finding states that as fixed charges go up, absent additional revenue, coverage ratios will go down. Contrary to FICA's claim, this Proposed Finding is not in error and does not imply that coverage ratios cannot move within an acceptable range without affecting credit quality. Furthermore, Finding 113 indicates that the Commission recognizes that coverage and capitalization ratios may move somewhat within ranges without impacting the credit rating of a utility.

Proposed Finding 192 is not included in the Recommended Order. However, while the Proposed Finding is not material to the ultimate decision in this case, it is supported by [*245] the record. Despite FICA's arguments to the contrary, companies do make capital structure decisions based on stockholders', rating agencies', regulatory commissions', and managements' perceptions of the trade off between risk and return with respect to coverage ratios, capitalization ratios, and the overall cost of capital.

Proposed Finding 196 is not included in the Recommended Order. However, it is supported by competent, substantial evidence. The proposed finding need not address what factors rating agencies consider.

Proposed Finding 202: See response to exception of Finding 49.

Proposed Finding 206 was not accepted as stated. See response to exception of Finding 20.

Proposed Finding 209 was not included in the Recommended Order. However, it is supported by competent, substantial evidence. FICA's exception is in error because the proposed finding does not mention conservation or the financial risk of conservation.

Proposed Finding 214 was not accepted as stated. See response to exception of Finding 84.

Proposed Finding 227 was accepted by the Hearing Officer and is included as Finding 91. FICA is incorrect in listing this Proposed Finding [*246] of Fact with the group deemed not material.

Proposed Finding 234: See response to exception of Finding 96.

Proposed Finding 237: See response to exception of Finding 98.

Proposed Finding 247 was rejected by the Hearing Officer. However, Staff disagrees with FICA's statement regarding the pipeline lead time. See Staff response to alleged Fourth error regarding construction lead time for the pipeline.

Proposed Findings 255 and 256: FICA's exception to these proposed findings is essentially the same as its exception for Finding of Fact No. 105. See Staff response to alleged Fourth error regarding construction lead time for pipeline.

Proposed Findings 258 and 260: Proposed Finding of Fact No. 258 and 260 are essentially the same as Findings of Fact Nos. 85, 86 and 87. See Staff response to Findings of Fact Nos. 85, 86 and 87.

Proposed Finding 262 was not accepted as stated. The proposed finding refers to the analysis in the Integrated Resource Study which compared the ten options. Finding 62 in the Recommended Order lists the plans considered in the Integrated Resource Study. Also, see response to exception of Finding 69.

Proposed Finding 266 was [*247] not accepted as stated. See responses to exceptions of Findings 142 and 150.

Proposed Findings 267 and 269 were not accepted as stated. However, FICA's exceptions to the proposed findings are in error because the proposed findings do not say or imply that the same benefit would not accrue from QF purchases. And they do not need to say that the same benefit would accrue since the need determination is for the Polk County units, and not for a QF.

Proposed Finding 272 does not need to mention QFs. It compares two generation technologies.

FICA's exception to proposed finding 278 is flawed because it assumes that FPC would be prudent to purchase a site and incur the expense to divert the clay even if it has no plans to certify or construct on the site.

Proposed Finding 286 does not say or imply that QFs could not provide the same benefit. And it does not need to say that the same benefit would accrue since the need determination is for the Polk County units, and not for a QF.

Proposed Finding 291: See response to exception of Finding 77.

Proposed Finding 293: See response to exception of Finding 156.

Proposed Finding 293 was rejected by the Hearing [*248] Officer.

Proposed Finding 294: See response to exception of Finding 157.

Proposed Findings 25, 30, 31, 32, 38, 40, 44, 46, 47, 49, 55, 60, 61, 63, 64, 65, 71, 72, 73, 74, 75, 87, 88, 122, 129, 133, 134, 135, 136, 144, 146, 149, 150, 151, 168, 171, 176, 179, 180, 181, 184, 186, 187, 192, 196, 209, and 218 were supported by competent substantial evidence in the record and were, therefore, accepted. They were not included in the Recommended Order because they were not material to the decision in this case. It is not necessary to reject such findings.

Response to Destec's Exceptions to the Conclusions of Law

Exception: Destec objects to the Hearing Officer's finding that "[s]ince no non-utility projects were proposed in this docket, I have no assurance that a bid would be successful." Destec seems to argue that FPC should be required to bid. (p. 2)

Staff Response:

-- As discussed in the Recommended Order, in this case, delaying the need determination for a bidding proceeding would have detrimental effects.

-- Destec's implication that a bid would be successful, just because previous bids were successful is flawed. The timing and costs of this bid would be [*249] different from previous bids. Also, Destec agrees that "[t]here is nothing in the record which defines what any QF or IPP could or could not do . . ." That is the point that the Hearing Officer made in the Recommended Order.

-- See also Staff response to FICA's alleged Second error.

Exception: "With regards to the ability of FPC to develop the site for future generation, what is to stop FPC from buying the property and 'sitting on it' until some later date?" (p. 3)

Staff Response:

-- Site development must begin in a timely manner so that the site will be ready for construction when it is needed. Site development activities not included in the reclamation plan may not take place until after the units are certified.

-- There is no evidence in the record that the current DNR reclamation plan is consistent with FPC's needs for site preparation. It would be a liability for FPC to purchase the land with a mandatory reclamation order if it had no concrete plans to construct and certify the property.

-- Also, FPC's avoided costs would be reduced to exclude the costs of land acquisition and preparation if FPC were to purchase and prepare the land.

Exception: "If a QF [*250] had a signed contract with FPC, it would be willing to sign the necessary commitment letter with the . . . Suncoast Venture." (p. 3)

Staff Response:

-- Destec's statement is pure speculation that is not supported by competent substantial evidence in the record. The record does not support the conclusion that a suitable QF will burn gas, or that its location will be suitable. If FPC did put these constraints on QFs, the probability of having a successful bid would be reduced.

Exception: "Further, Section 403.519, F. S., gives the Commission the authority to take into account 'other matters within the Commission's jurisdiction which it deems relevant' in evaluating the need for proposed power plants. Natural gas pipelines are not within the Commission's jurisidictions." (p. 3)

Staff Response:

-- Although they are not within the Commission's jurisdiction, construction and operation of a pipeline have a material relationship to certification under 403.519. In making its determination of need, the Commission is required to "take into account . . . the need for adequate electricity at a reasonable cost, and whether the proposed plant is the most cost-effective alternative [*251] available." (Section 403.519, Florida Statutes) Adequate fuel at a reasonable cost must be available at the generating site to produce adequate electricity at reasonable cost.

-- Further, generating fuel costs and the mix of fuels used in electric generation in Florida are within the Commission's jurisdiction and are relevant. The Recommended Order should not and does not make a determination of need based solely on additional gas pipeline capacity, but neither does the Recommended Order ignore the very relevant matter of generating fuel mix and fuel availability.

Exception: "Destec disagrees with the statement . . . that the issue of whether FPC should be held to the same cost and performance standards as that of QFs is beyond the scope of this docket." (p. 3 - 4)

Staff Response:

-- As discussed in the Recommended Order, issues related to the recovery of costs incurred in constructing power plants are considered in a utility's rate case. If Destec is asking that the Commission change its regulatory policy to require utilities to be held to the same cost and performance standards as that of QFs, this would have to be done in a rulemaking.

Response to Destec's Exceptions [*252] to the Findings of Fact

Findings 48 and 50 are not redundant because one deals with the amount of QF capacity that is contracted and the other deals with how FPC modeled QF capacity in its planning. Exhibit 102 shows that FPC included 918.5 MW of QF capacity as a base assumption in its plan.

Finding 77 implies that sulfur dioxide emissions would be higher "if all other parameters stayed the same". Otherwise, the finding would identify the parameters that were changed.

Destec's exception to Finding 132 in the Recommended Order (FPC's proposed Finding 185) is supported by the record. The Finding as stated implies that there are only two ways of compensating for the financial consequences of increased purchased power obligations. However, in addition to the two methods cited in the Finding, a utility could also compensate for the financial consequences of acquiring this type of capacity if regulatory treatment of purchased power obligations is modified to allow the utility the opportunity to earn a return on this capacity.

Response to FRG's Exceptions to the Conclusions of Law

Exception: "the Company's claim that its integrated planning process determines [*253] the optimum amount of DSM, are (sic.) unsupported by the evidence on the record unless the Commission is prepared to rule that the optimum amount of DSM necessarily excludes measures that fail the RIM test . . ." (p. 1)

Staff Response:

-- In Docket No. 891324-EU, the Commission revised its rules on the format for reporting cost-effectiveness data for conservation and self-service generation. The Commission approved the use of the Rate Impact Test (RIM), the Participants Test, and the Total Resource Test for the reporting of cost-effectiveness data for any demand side program proposed by an electric utility for approval by the Commission. FRG is arguing that the Commission violate its own rules and deny the use of the RIM test in favor of the Total Resource Test.

-- Under FEECA, the Commission has authorization from the Legislature to require each utility to develop plans and implement programs for increasing energy efficiency and conservation. Florida Power's conservation plan was approved with modification in September 1990. Florida Power's existing plan complies with its approved conservation plan. In fact, FPC has expanded its programs to acquire additional [*254] conservation as part of its Integrated Resource Study. Denying FPC's need on the grounds of inadequate conservation would be unfair, given the fact that FPC is complying with its approved conservation plan.

Exception: ". . . FPC's claim that its analyses show that the Polk County units are 'the lowest cost and lowest risk option,' is not supported by the record unless the Commission rules that only supply-side options should be considered in making cost and risk comparisons." (p. 2)

Staff Response:

-- The Polk County units are the lowest cost and lowest risk option, as found by the Hearing Officer. FPC, in its planning process, determined the amount of its need that could be met through other sources, including DSM, then evaluated the appropriate generation source. This exception requires a statement of policy which is outside the purview of this proceeding.

-- FRG would have the Commission deny FPC's entire need based on the "hope" that cost-effective conservation would materialize. However, FRG acknowledges that "the evidence in this case does not support a judgment that all of the proposed new capacity could be replaced by lower cost DSM . . ." (p. 3). [*255] The Hearing Officer did not recommend approval of all of the proposed capacity. Staff believes that the Hearing Officer has taken a fair and optimal approach in approving the first half of FPC's identified need and requiring FPC to file an updated conservation plan at least one year prior to requesting certification of the remaining two Polk County units. In taking this approach, the Hearing Officer is ensuring that FPC has adequate capacity to meet its 1998-1999 needs while leaving room for additional cost-effective conservation to defer the last two units.

Exception: "The proposed ruling at the top of page 41, that Florida law does not require a utility 'to examine and use all reasonably available conservation measures that might mitigate the need for the proposed plant,' is contrary to the intent of 403.519, F.S. . . ." (p. 3)

Staff Response:

-- The Hearing Officer's ruling is not contrary to the intent of section 403.519, Florida Statutes. It is consistent with the clear language of the statute which states that:

In making its determination the Commission shall take into account the need for electric system reliability and integrity, the need for adequate [*256] electricity at a reasonable cost, and whether the proposed plant is the most cost-effective alternative available. The commission shall also expressly consider the conservation measures taken by or reasonably available to the applicant or its members that might mitigate the need for the proposed plant . . .

If the legislature intended to require a utility to use all reasonably available conservation measures that might mitigate the need for a proposed plant it would have used that language in the statute. The Hearing Officer's ruling is not contrary to the intent of section 403.519, Florida Statutes. Had the legislature intended for a utility to use all reasonably available conservation measures that might mitigate the need for a proposed plant, it would have used that language in the statute.

Exception: ". . . there is substantial evidence on the record regarding cost-effective conservation programs, measures and end-uses that are not being implemented by FPC (TR 1321-1322 & 1333-1335), and these include the TRC (Total Resource Test) cost-effective measures that FPC admitted were eliminated solely for failure to pass the RIM (Rate Impact Test)." (p. 5)

Staff Response: [*257]

-- The Commission does not have a rule or policy on how a utility should screen DSM programs. The Commission directs utilities on how to evaluate programs that they propose for approval by the Commission. The hearing officer found that Florida Power is taking those conservation measures reasonably available to it.

-- Also, see previous discussions regarding the fact that the Hearing Officer is providing an opportunity for cost-effective conservation to defer or avoid the construction of the last two units.

Exception: "There is additional evidence on the inadequacies of several of FPC's current program designs (TR 1342-1357)." (p. 5)

Staff Response:

-- The Hearing officer considered the testimony of Mr. Chernick regarding his assertions concerning the inadequacies of FPC's programs in making the finding that Florida Power is taking those conservation measures reasonably available to it and in requiring FPC to submit its conservation plan prior to requesting certification of the remaining Polk County units.