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BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In The Matter of : DOCKET NO. 891345-EI

Application of GULF POWER COMPANY for an increase in rates and charges. : HEARING EIGHTH DAY MID-AFTERNOON SESSION

VOLUME - XXII

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Fletcher Building
101 E. Gaines Street
Tallahassee, Florida 32399

Wednesday, June 20, 1990

Met pursuant to adjournment at 1:10 p.m.

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

APPEARANCES:

(As heretofore noted.)

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I N D E X

WITNESSES

Index Continued:

EXHIBITS

MID-AFTERNOON SESSION

(Transcript follows in sequence from Volume XXI.)

REDIRECT EXAMINATION

BY MR. McGLOTHLIN:

Q Mr. Pollock, when you were asked to make some observations about the trend for load factor of PXT rate, you asked if the figures included all kilowatt hours including incremental supplementary energy sales. What is the significance of the fact that all kilowatt hours are included in those calculations?

A Well, keep in mind that the 12-CP demands are the 12-CP demands of the customers as they impose for their firm requirements. By definition, during the 12-CPs there is no supplemental energy being sold during those periods. So that would not factor into determining what the appropriate 12-CPs were for cost allocation purposes in the cost of service study.

Q Would the same consideration have an impact upon the observation of the increase in the 12-CP demand that was characterized as increasing by 50%?

A I'm sorry, I don't know what same consideration you're referring to.

Q The fact that the load factor calculations included all kilowatt hour sales. Does that apply also to the increase in demand that was pointed out in the exhibit?

A It's shouldn't, no.

Q Take the case of a customer that has only one generator. Could that customer experience occasions when it could possibly buy SE power cheaper than its own generation?

A It would depend upon whether the customer needed to have the steam. But conceivably if the customer had adequate steam and was in balance but needed to buy more electricity, that customer could go out and buy SE power if it were available under those circumstances.

Q Would that customer also benefit from the proposal for the dispatch of SE that you have outlined for other customers?

A Yes.

MR. McGLOTHLIN: Those are all the questions I have.

CHAIRMAN WILSON: All right, would you like to move Exhibit 614?

MR. McGLOTHLIN: I so move.

CHAIRMAN WILSON: Without objection, that's admitted into the record.

(Exhibit No. 614 received in evidence.)

CHAIRMAN WILSON: Thank you, Mr. Pollock, you may stand down.

WITNESS POLLOCK: Thank you, Commissioner.

(Witness Pollock excused.)

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MR. STONE: Mr. Chairman, at this point in the reco.d, the next witness would be Dr. Morin. His testimony has been stipulated into the record

CHAIRMAN WILSON: All right. It will be inserted into the record as though read without objection.

GULF POWER COMPANY

Before the Florida Public Service Commission
Rebuttal Testimony of
Roger A. Morin
In Support of Rate Relief
Docket No. 891345-EI
Date of Filing May 21, 1990

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

A. My name is Dr. Roger A. Morin. My permanent residence is in Atlanta, Georgia. I am Professor of Finance at the College of Business Administration, Georgia State University and Professor of Finance for Regulated Industry at the Center for the Study of Regulated Industry at Georgia State University.

Q. Are you the same Dr. R. A. Morin who has filed rate of return testimony in this same proceeding?

A. Yes, I am.

Q. What is the purpose of this rebuttal testimony?

A. This testimony is in rebuttal to Mr. Rothschild's (Office of the Public Counsel), and Mr. Seery's (Florida Public Service Commission Staff) cost of capital testimonies.

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

A. Yes.

Counsel: We ask that Dr. Morin's Exhibit (RAM-2), comprised of four schedules, be marked for identification as Exhibits 196 - 199 .

Q. How is your testimony organized?

A. My testimony is organized in two parts dealing with the testimony of Messrs. Rothschild and Seery.

COMMENTS ON MR. ROTHSCHILD'S TESTIMONY

Q. Please summarize Mr. Rothschild's rate of return recommendation.

A. In determining the cost of equity applicable to Gulf Power's Florida operations, Mr. Rothschild applies DCF analysis to The Southern Company, as a proxy for Gulf Power, and to a group of non-nuclear electric utilities drawn from Moody's 24 Electrics. As a check on the DCF results, he performs a Comparable Earnings check using the DOW Jones Industrials Index and an alleged market-to-book ratio check. Based on the results of these analyses, he recommends a return of 11.75 percent on Gulf's common equity capital.

Q. Do you have any general comments on Mr. Rothschild's testimony?

A. Yes. Before I engage in specific criticisms of

Mr. Rothschild's testimony, my general reaction to his testimony is that it is extremely narrow in scope, relying solely on the fragile sustainable growth DCF model results applied to Southern Company and to Moody's 24 Electrics and on a questionable Comparable Earnings test applied to a composite of industrial companies. His recommendation of 11.75 percent rests entirely on one DCF variant. Using this particular variant of the DCF method, Mr. Rothschild was forced to assume the ROE answer before he even began his determination of Gulf Power's equity costs using that method.

No other DCF results are performed, including the conventional historical growth DCF model, nor are useful traditional cross-checks on the DCF results implemented, such as Risk Premium or Capital Asset Pricing Model methodologies. Mr. Rothschild has put all his eggs in the DCF sustainable growth basket, and thereby has set a very dangerous precedent for this Commission. Moreover, not only is his recommendation of 11.75 percent based on faulty premises and methodologies, but it is also highly unreasonable, since it is barely above, if at all, the current yield on Gulf's bonds, which is about 10.25 percent. The implied risk premium is far less than the risk premiums found in the general academic finance literature and in Mr. Rothschild's own testimony. I also show that his divisional cost of capital allocation as between industrial and residential customers is based on erroneous conceptual premises, and is inconsistent with modern financial theory.

Q. **What fundamental objection do you have to the cost of equity recommendation contained in Mr. Rothschild's testimony?**

A. My fundamental objection is that it is dangerous and inappropriate to rely on only one variant of the DCF model, as Mr. Rothschild has done. This variant is the most fragile conceptually and the least valid empirically. By relying solely on a single variant of the DCF model, the Commission greatly limits its flexibility and increases the results of authorizing unreasonable rates of return. The results from one method are likely to contain a high degree of measurement error. The Commission's hands should not be bound to one methodology of estimating equity costs, nor should the Commission ignore relevant evidence and back itself into a corner.

There are three broad generic methodologies available to measure the cost of equity: DCF, Risk

Premium, which are market-oriented, and Comparable Earnings, which is accounting-oriented. Each generic market-based methodology in turn contains several variants; for example, the CAPM and Empirical CAPM are sub-species of the Risk Premium methodology. Mr. Rothschild has chosen to rely on only one variant of one method, namely the retention ratio version of the DCF method, although he does perform a perfunctory comparable earnings check on his DCF result.

I firmly believe that, when measuring equity costs, which essentially deals with the measurement of investor expectations, no one single methodology provides a foolproof panacea. Each methodology requires the exercise of considerable judgment on the reasonableness of the assumptions underlying the methodology and on the reasonableness of the proxies used to validate the theory. The failure of the traditional infinite growth DCF model to account for changes in relative market valuation discussed in my original testimony is a vivid example of the potential shortcomings of the DCF model when applied to a given company. It follows that more than one methodology should be employed in arriving at a judgment on the cost of equity and that these methodologies should be applied across a series of comparable risk companies.

Each methodology possesses its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Each method proceeds from different fundamental premises which cannot be validated empirically. Investors do not necessarily subscribe to any method, nor does the stock price reflect the application of any one single method by the price-setting investor. There is no monopoly as to which method is used by investors. Absent any hard evidence as to which method outdoes the other, all relevant evidence should be used and weighted equally, in order to minimize judgmental error, measurement error, and conceptual infirmities. I submit that the Commission should rely on the results of a variety of methods applied to a variety of comparable groups, and not, as Mr. Rothschild has done, on one variant or on one subset of a particular method. There is no guarantee that a single DCF result is necessarily the ideal predictor of the stock price and of the cost of equity reflected in that price, just as there is no guarantee that a single CAPM result constitutes the perfect explanation of that stock price.

Q. Why should you use more than one approach for estimating the cost of equity?

A. Mr. Rothschild relies heavily and almost exclusively on the fragile "retention growth" DCF model applied to Southern Company and to a sample of non-nuclear electric utilities. This is a very dangerous procedure. As I stated in my original testimony, no one individual method provides an exclusive foolproof formula for determining a fair return, but each method provides useful evidence so as to facilitate the exercise of an informed judgment. Reliance on any single method or preset formula is inappropriate when dealing with investor expectations. Moreover, the advantage of using several different approaches is that the results of each one can be used to check the others.

Q. Do you have some reservations concerning the applicability of the standard DCF model to utility stocks at this time?

A. Yes. Notwithstanding my fundamental thesis that several methods and/or variants of such methods should be used in measuring equity costs, Mr. Rothschild has selected a methodology which is particularly fragile at this time. Moreover, the particular variant of that methodology chosen by Mr. Rothschild is even more fragile, as I will discuss later. Caution must be exercised when implementing the standard DCF model in a mechanistic fashion, for it may fail to recognize changes in relative market valuations. The traditional DCF model is not equipped to deal with surges in market-to-book and price-earnings ratios. The standard infinite growth DCF model assumes constancy in such ratios.

As I stated in my original testimony, contrary to the standard DCF assumption of a constant price/ earnings ratio, stock price may not necessarily be expected to grow at the same rate as earnings and dividends by investors. In other words, the constancy of the price/earnings ratio required in the standard DCF model may not be a perfectly accurate assumption in a DCF analysis. To the extent that increases in relative market valuation are anticipated by investors, especially investors with short-term investment horizons, the standard DCF model understates the cost of equity. Of course, the converse is also true.

Several fundamental and structural changes are transforming the utility industry from the times when the standard DCF model and its assumptions were developed by Professor Gordon. Increased competition triggered by national policy, accounting rule changes, represcription of capital recovery rates, changes in customer attitudes regarding utility services, the evolution of alternative energy sources, deregulation, and mergers-acquisitions have all influenced stock prices in ways vastly different from the early assumptions of the DCF model. These changes suggest that some of the raw assumptions underlying the standard DCF model, particularly that of constant growth, are of questionable pertinence at this point in time, and that the DCF model should be at least complemented by alternate methodologies to estimate the cost of common equity.

Q. **Please summarize your specific criticisms of Mr. Rothschild's testimony.**

A. The specific criticisms which I discuss include:

1. The quarterly timing of dividend payments. Mr. Rothschild's application of the DCF model ignores the time value of quarterly dividend payments, and thus understates the expected return on equity. His comments on the Quarterly DCF model's lack of validity are erroneous.

2. The expected growth rate for utilities in the DCF model. The evidence is that investors expect substantially higher growth rates for electric utilities than Mr. Rothschild has found. Moreover, there are serious logical inconsistencies in his

the exercise of an informed judgment. Reliance on any single method or preset formula is inappropriate when dealing with investor expectations. Moreover, the advantage of using several different approaches is that the results of each one can be used to check the others.

As a general proposition, it is dangerous to rely on only one generic methodology to estimate equity costs. The difficulty is compounded when only one variance of that methodology is employed. It is compounded even further when that one methodology is applied to a single company. Hence, several methodologies should be employed to estimate the cost of capital, and such methodologies should be applied to several comparable groups of companies.

Q. **What is your recommendation on Gulf's return on common equity?**

A. Based on my judgment and the results of my various studies, it is my opinion that a rate of return on common equity of 13.50 percent is reasonable at this time. This return will allow the company to attract capital on reasonable terms and to maintain its financial integrity.

the role of market-to-book ratios in regulation are flawed and assume irrational behavior on the part of investors.

7. The Relative Risks of Customer Classes.

Mr. Rothschild argues that industrial customer sales are more risky than residential sales, because revenue variability is greater, and that, therefore, a higher cost of equity capital rate should be assigned to the industrial class. The idea that differences in revenue variability cause differences in capital costs misses the crucial connection between revenue variability and earnings variability and its critical role in determining investor risk.

My comments will show that proper use of his own Comparable Earnings data, recognition of realistic growth rates in his DCF methodology, and addition of an appropriate allowance for flotation costs and quarterly timing of dividend payments will produce a cost of equity recommendation which is substantially higher than his recommended 11.75 percent. I also respond to several of Mr. Rothschild's comments on my testimony, and show that they are unfounded.

DCF MODEL

QUARTERLY TIMING

Q. Please discuss the quarterly timing adjustments to the DCF model.

A. I disagree with Mr. Rothschild's dividend yield calculation in his DCF analysis because he ignores the quarterly nature of dividend payments.

The traditional DCF model which Mr. Rothschild employs assumes that the dividends received by investors are received annually, while in fact, most utilities pay dividends on a quarterly basis. Investors receive their cash flow (dividends) on a quarterly basis, and not on an annual basis.

It is a rudimentary tenet of finance that when determining investor return requirements, the cost of equity is the discount rate which equates the present value of future cash receipts, here a stream of quarterly dividends, to the observed market price which reflects the quarterly nature of dividend payments. Clearly, given that dividends are paid quarterly and given the observed stock price, the market required return must recognize quarterly compounding, because the investor receives dividend checks and reinvests the proceeds on a quarterly schedule, and not annually as

Mr. Rothschild has assumed.

Since investors are aware of the quarterly timing of dividend payments, this knowledge is reflected in stock prices. Since the stock price already fully reflects the quarterly payment of dividends, it is essential that the DCF model used to estimate equity costs also reflect the actual timing of quarterly dividends. As I demonstrated in Exhibit ___ (RAM-1) of my original testimony, the use of the annual version of the DCF model understates the cost of equity by approximately 30-40 basis points, depending on the magnitude of the dividend yield component. By analogy, a bank rate on deposits which does not take into consideration the timing of the interest payments understates the true yield if you receive the interest payments more than once a year. The actual yield will exceed the stated nominal rate.

It is precisely because the stock price reflects the quarterly timing of dividend payments that the quarterly adjustment must be made to the standard DCF model, which assumes annual dividend payments. It is inconsistent to use a stock price which reflects quarterly dividends in a model which assumes annual dividend payments. As both a practical and theoretical matter, in the same way that bond yield calculations are routinely adjusted for the receipts of semi-annual interest payments, stock yield calculations must be adjusted for the receipt of cash flows on a quarterly basis, and not annually as Mr. Rothschild has done.

Q. **Please comment on the validity of Mr. Rothschild's objections to your quarterly DCF model.**

A. Mr. Rothschild does not present any valid arguments for rejecting the quarterly DCF model. Instead, he focuses on two allegedly false contentions in my original testimony. To the extent that these contentions are in fact correct, I can only surmise that Mr. Rothschild would otherwise endorse the quarterly DCF model.

My first false contention, according to Mr. Rothschild, was that a stock that pays four quarterly dividends of one dollar would command a higher return than a stock that pays a four dollar dividend a year hence. His conclusion is so obviously transparent that it hardly warrants addressing. One only has to think of what would happen to stock prices if U.S. corporations were to announce that dividends are paid only once a year from now on instead of quarterly. Clearly, stock prices would fall because of the lost time value of money to investors of receiving money sooner. Mr. Rothschild argues that the company paying the $4 once a year instead of $1 every quarter would have the use of the funds for a longer period and would thus benefit from higher earnings, experience higher growth, and presumably would be more valuable. The logical extension of Mr. Rothschild's argument is that companies should never pay dividends so as to maximize earnings and growth! This is absurd, and contrary to logic and to the fundamental signaling and value-enhancement aspects of dividends. The acid test for the relevance of dividends is the impact on stock price and shareholder value, not on earnings.

Second, Mr. Rothschild argues that my contention that the stock price is higher for the company paying quarterly dividends is flawed and that the very opposite is the case. In other words, according to Mr. Rothschild, a company paying a dividend of $4 once a year would command a higher price than a company paying $1 per quarter for four quarters. This is a baffling statement, contrary to intuition, common sense, and financial theory. This is analogous to saying that investors would rather have their savings account pay interest annually instead of quarterly. Mr. Rothschild argues instead that the average stock price of a company paying an annual dividend is higher than the average stock price of a company paying the same dividend in four quarterly installments because of the "ex-dividend" behavior of stock prices. This argument is totally without merit, for it ignores that the stock price of the company paying he annual dividend would start out at a lower level than the stock price of the same company paying the same dividend in four quarterly installments by an amount equal to the lost time value of money to investors.

Moreover, a company's capital attraction ability is diminished unless its investors are allowed the quarterly DCF return. This is simply because investors are able to earn a larger return from competing comparable risk investments, and unless the company can earn at the same market-based rate of return as its investors can earn externally, the company's capital-raising ability is endangered.

Q. Can you illustrate why the quarterly DCF model is required?

A. Yes, I show below that the investor will not realize the required rate of return, unless the quarterly return is allowed.

Schedule 1 shows the numerical illustration. page 1 shows the assumptions of the example. Page 2 of 3 shows what happens to the investor if the quarterly

DCF return is allowed, and page 3 shows what happens to investors if the annual DCF return is allowed.

Page 2 shows that the utility should be allowed to earn the quarterly rate of 14.04 percent on its equity rate base if the company is to provide shareholders with their 14.04 percent required rate of return. The example shows that the shareholders would receive their expected dividends of $0.70 per quarter and that the quantity of earnings over the year is $4.19 but that the allowed return must be the quarterly DCF return of 14.04 percent, or 1.10 percent per month. In the example, the 14.04 percent market return is converted to an equivalent monthly rate of return of 1.10 percent. The required earnings are obtained by multiplying the equivalent monthly required equity return by the beginning of the month equity book value for the year. This produces earnings of $4.19. The investor receives dividends of $2.80 for the year, that is, a dividend yield of 9.08 percent, and a capital appreciation from $30.85 to $32.24, that is, expected 4.50 percent growth rate. In other words, the investor's 14.04 percent required return is fulfilled.

The annual DCF rate of 14.04 percent, $K_{mkt, ann}$, is routinely converted to an equivalent monthly rate $K_{mkt, 12}$ by the correct formula:

analysts' growth forecasts as proxy for growth.

DCF IMPLEMENTATION

Q. How did you apply the DCF methodology?

A. The measurement of K_e can be broken down into two components: measurement of the expected dividend yield, D_1/P_o, and the measurement of growth, g.

DIVIDEND YIELD COMPONENT

Two issues are involved in the determination of the dividend yield: the appropriate stock price, P_o, and the appropriate dividend to employ, D_1.

Conceptually, the stock price to employ is the current price of the security at the time of estimating the cost of equity. The current stock prices provide a better indication of expected future prices than any other price in an efficient market. An efficient market implies that prices adjust instantaneously to the arrival of new information. Therefore, current prices reflect the fundamental economic value of a security. A considerable body of empirical evidence indicates that U.S. capital markets are remarkably efficient with respect to a earnings per share, dividends per share, and book value per share, (2) analysts' growth forecasts, and (3) sustainable growth method, where the growth rate is based on the equation g = b(ROE), where b is the percentage of earnings retained and ROE is the expected earned rate of return on book equity. In his DCF analysis of The Southern Company and Moody's 24 Electrics, Mr. Rothschild estimates the growth component using only the last method. He rejects the customary alternatives of relying on analysts' growth forecasts and on historical growth rate in earnings, dividends, and book value.

By relying solely on a single growth-estimating technique in the DCF model as Mr. Rothschild has done, the Commission would set a very dangerous precedent for future ratemaking procedures. A single technique to estimate investor growth expectations is likely to contain a high degree of measurement error and may be distorted by short-term aberrations. The Commission's hands should not be bound to one single estimate of growth in the DCF determination of equity costs. The advantage of using several different approaches in estimating growth is that the results of each one can be used to check the others.

SUSTAINABLE GROWTH RATE

Q. Do you have any objections to the sustainable growth estimates used by Mr. Rothschild?

A. Since Mr. Rothschild's entire testimony and his 11.75 percent cost of equity recommendation hinge on the sustainable growth cornerstone, it is important to point out the dangers and flaws of this cornerstone method. To apply the retention ratio growth in his DCF analysis, Mr. Rothschild multiplies the utility's retention ratio by the return on equity. The latter is proxied by the actual 1988 and 1989 earned ROE and by Value Line's forecast of ROE. To compute the former, in a strange turnabout, rather than simply take the actual retention ratio and the retention ratio forecast by Value Line as he did for the ROE, Mr. Rothschild computes the retention ratio indirectly, as one minus the book dividend yield divided by the ROE, that is, (1 - D/rB). In other words, the two components of growth, ROE and retention ratio, are determined simultaneously and are functionally interdependent. Thus, any error in one component is inherently compounded when applied to the other component.

Mr. Rothschild correctly recognizes and adds to his sustainable growth estimate any growth stemming from external financing. The growth results are shown on line 5 in his Schedules 2 and 3 for The Southern Company and Moody's Non-Nuclear electrics, respectively. The average growth rate range for The Southern Company is 2.77 percent - 3.77 percent and 3.68 percent - 3.84 percent for the non-nuclear electrics.

There are two fundamental problems with Mr. Rothschild's sustainable growth methodology:

(1) Mr. Rothschild's sustainable growth method contains a fatal logical flaw: the method requires an estimate of ROE to be implemented. In other words, his method requires him to assume the ROE answer to start with. But if the ROE input required by the model differs from the recommended return on equity, a fundamental contradiction in logic follows. Mr. Rothschild's recommended 11.75 percent return on equity is far removed from the ROE's he uses in the sustainable growth method, both historically and prospectively. On his Schedules 2 and 3, he uses an expected return of 13.00 percent for The Southern Company, and 13.9 percent for the non-nuclear electrics, which are all above Mr. Rothschild's recommended 11.75 percent range. The vast majority of the historical and Value Line prospective ROE's for each company reported on Schedules 2 and 3 and used in

Mr. Rothschild's sustainable growth computation exceeds his recommended 11.75 percent and average 13.5 percent.

He is assuming, in effect, that the companies will earn at a return rate exceeding his recommended equity range forever, but he is recommending that a different rate be granted by the Commission. While this scenario may be imaginable for an unregulated company with substantial market power, it is implausible for a regulated company whose rates are set so that they will earn a return equal to their cost of capital. I consider this logical flaw extremely damaging and sufficient to reject Mr. Rothschild's results produced by the method, and hence the crux of his testimony. In essence, Mr. Rothschild is using an ROE that differs from his final recommended cost of equity, and is requesting the Commission to adopt two different returns.

To quote from Mr. Rothschild's page 39, lines 15-18:

> At this time, the majority of investors should be expecting that a typical group of non-nuclear electric utility should be able to sustain any average earned return on equity of no more than 13.9 percent on equity in the future.

The only logical conclusion to be drawn from that statement is that Gulf Power's cost of equity is 13.9 percent, since rates must be set to earn 13.9 percent.

I am extremely perplexed as to why Mr. Rothschild assumes that non-nuclear electrics are expected to earn 13.9 percent forever, but yet he recommends 11.75 percent. The only way that electric utilities can earn 13.9 percent is that rates be set so that they will in fact earn 13.9 percent. So, how can the cost of equity be any different from 13.9 percent?

(2) The empirical finance literature demonstrates that the sustainable growth method is a poor explanatory variable of value, and is not significantly correlated to measures of value, such as stock price and price/earnings ratios. Mr. Rothschild's chronic rejection of the use of both historical growth rates in several parts of his testimony (page 15, lines 20-23; page 16, lines 9-11; page 21, lines 16-23; page 66, lines 15-16) and analysts' growth forecasts (page 22, lines 1-9) in the DCF model is in flagrant contradiction to the scholarly research and academic literature on the subject.

HISTORICAL GROWTH

Q. Can you comment on Mr. Rothschild's historic growth rates?

A. On page 22, lines 5-9 of his testimony, Mr. Rothschild dismisses the use of historical growth rates in dividends, earnings, and book value as proxies for investor expectations on the general grounds that they are not sustainable. This is a gratuitous statement, not substantiated by Mr. Rothschild; he has not performed or alluded to any empirical studies that support such a claim. Surely, investor growth expectations are influenced to some extent by historical growth rates in formulating their future growth expectations. It is not perfectly clear as to why Mr. Rothschild ignored this relevant data. Ironically, his own estimates of expected ROE when he implements the sustainable growth method are partially driven by historical ROE's.

On page 22 and elsewhere, he cautions the use of historical growth rates on the grounds that earned ROE's and dividend payout ratios were not constant and that dividend growth rates cannot exceed earnings growth rates forever. I share similar concerns, especially when dealing with the data of a single company. Yet, Mr. Rothschild himself forecasts an earned ROE different (Schedule 2, page 1) from the sample companies' and The Southern Company's current ROE (page 42, lines 3 - 9). His use of the b x ROE procedure to implement a single growth rate DCF model is internally inconsistent. Whenever the ROE or the retention ratio is expected to change as he has inherently assumed, the intermediate-term growth rate in dividends would not, in general, equal the long-term growth rate. Intuitively, this follows from the fact that dividend/earnings growth must adjust to the changing ROE. Given Mr. Rothschild's assumptions regarding changing ROE's and thus changing growth rates, the inevitable conclusion is that a more complete two-growth rate DCF model is required, and that a single growth rate DCF model is deficient.

It is ironic that Mr. Rothschild criticizes my historical growth DCF model for changing ROE's and payout ratio, and that his own forward-looking sustainable growth DCF model designed to circumvent these problems is itself misspecified for the same reasons.

Q. Do investors rely on historical data?

A. On page 15 of his testimony, Mr. Rothschild makes the astounding statement that "sophisticated investors do not compute historic five or ten year growth rates and use that result to determine what growth rates are probable..." (page 15, lines 21-23). This statement is startling, counterintuitive and erroneous.

Historical indicators are widely used by analysts, investors, and expert witnesses. Cohen, Zinbarg, and Zeikel (<u>Investment Analysis and Portfolio Management</u>, 5th edition, Irwin, 1987, Part 4 Security Analysis, pp. 537-538) which is a recommended textbook for CFA (Chartered Financial Analyst) certification and examination, suggest the calculation of historical growth rates as a first step in security analysis. Techniques of historical growth analysis for individual companies are described in Chapter 12. Professional certified financial analysts are certainly well versed in the use of historical growth indicators.

A simple inventory of cost of capital testimonies over a reasonable time period in a given jurisdiction will reveal that DCF is widely used by academic and staff witnesses and that historical indicators are in wide usage in such testimonies. Such a survey appeared in Appendix C "Summary of Rate of Return Methods in Testimony and Decisions" in Methods Used to Estimate the Cost of Equity Capital in Public Utility Rates Cases: A Guide to Theory and Practice, Charles River Associates Inc., CRA Report No. 607, prepared for the California Public Utilities Commission. The use of historical indicators was clearly indicated in this survey.

Historical indicators are used extensively in scholarly research. There exists a vast literature in empirical finance designed to evaluate the use of historical information as surrogates for expected quantities. This literature is complied in summary form in Annotated Bibliography of Earnings Expectations Research, Lynch, Jones & Ryan, 1988.

ANALYSTS' GROWTH FORECASTS

Q. Can you comment on Mr. Rothschild's growth forecasts?

A. Yes. Mr. Rothschild's laborious and convoluted procedure for computing sustainable (b x ROE) growth rates requires several subjective input forecasts: expected ROE, market-to-book ratio, dividend yield on book, and new financing growth. It would appear far more economical and expeditious to use available growth forecasts directly instead of relying on four individual forecasts of the determinants of such growth. It only seems logical that the measurement and forecasting errors inherent in using four different variables to predict growth far exceed the forecasting error inherent in a direct forecast of growth itself.

It is also ironic that Mr. Rothschild employs analysts' growth forecasts from Zacks, which he earlier dismissed as inadequate, in order to derive his expected

ROE estimate in the sustainable growth method, which itself provides a measure of expected growth. This procedure is hopelessly circular; he uses "inadequate" analysts' growth forecasts to obtain expected ROE to in turn obtain growth. Why not simply use the growth forecast?

Mr. Rothschild conveniently rejects Value Line's growth forecast in earnings/dividends, yet finds that Value Line's growth forecast of ROE is adequate. His reasoning is that Value Line's growth forecasts are not the average constant growth rates which are required in the simple DCF model. This is curious reasoning, for the same argument applies to Value Line's ROE forecast; the latter is a forecast for the specific period 1992-1994, and not necessarily the forecast required in the DCF model.

Sustainable growth rates are poor surrogates for the consensus growth expectations of investors. The empirical finance literature demonstrates that the sustainable growth method of determining growth is a poor explanatory variable of market value, and is not significantly correlated to measures of value, such as stock price and price/earnings ratios. Averages of analysts' growth forecasts are more reliable estimates of the investors' consensus expectations. Studies in

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the academic literature also demonstrate that the consensus growth forecast made by security analysts is a reasonable indicator of investor expectations, and that investors rely on such analysts' forecasts. The consensus long-term growth forecast of analysts provides a good proxy for investors' growth expectations when applying the DCF model.
Mr. Rothschild has chosen not to rely on analyst growth forecasts in spite of the superiority of such forecasts in representing investor growth expectations.

Both empirical research and common sense indicate that investors rely heavily on analysts' growth rate forecasts. It stands to reason that analysts produce better forecasts than could be obtained using only historical data, because analysts have available not only past data but also a knowledge of such crucial factors as current economic trends, rate case decisions, construction programs, new products, cost data, impending tax law changes, and so on. The variations in historical ROE's and payout ratios which concerned Mr. Rothschild and caused him to question the elevance of historical growth rates in the DCF model are known to investors, and are reflected in their growth forecasts.

Although historical information provides a primary foundation of expectations, investors use additional information to supplement past growth rates in arriving at their forecasts. Not only do analysts extrapolate past history, but they also consider historical trends and anticipated economic events before arriving at a growth forecast.

In view of the above, my Schedule 2 shows Value Line's historical and projected growth rates for dividends and earnings for the electric utility companies used by Mr. Rothschild in his DCF analysis. The last column shows the consensus mean long-term growth forecast obtained from IBES. For the non-nuclear electrics used in Mr. Rothschild's analysis, the average growth rates range from 3.5 percent to 5.5 percent with an average close to 4.5 percent. These growth substantially exceed Mr. Rothschild's average sustainable growth estimates for non-nuclear electrics by approximately 75 basis points.

Q. Can you summarize your comments on Mr. Rothschild's DCF growth rates?

A. In summary, Mr. Rothschild has disregarded both historical growth rates and analysts' growth forecasts, two of the most widely used and empirically validated sources of growth rates. He has ignored the empirical findings of the finance literature, pointing to the superiority of such forecasts. His sustainable growth rate methodology contains serious theoretical, conceptual, empirical, and methodological flaws, and should be disregarded by the Commission.

My own recommendation to the Commission with regards to DCF growth rates is that equal weight should be accorded to DCF results based on history and those based on analysts' forecasts, and that very little weight should be accorded to sustainable growth results, in view of the empirical evidence and the conceptual justification discussed above. Each proxy for expected growth brings information to the judgment process from a different light. Neither proxy is without blemish, each has advantages and shortcomings. Historical growth rates are available and easily verifiable but may no longer be applicable if structural shifts have occurred. Analysts' growth forecasts may be more relevant since they encompass both history and current changes, but are nevertheless imperfect proxies.

FLOTATION COST

Q. Please comment on Mr. Rothschild's flotation cost adjustment.

A. Both Mr. Rothschild and I agree on the need to adjust the cost of equity for flotation cost. But we disag [illegible] on the size of the allowance and on the mode of application of the adjustment. With respect to size, he uses 3.5 percent compared to my 5 percent. I have already enumerated and described the results of several empirical studies on the magnitude of flotation cost for utility stock offerings in my original testimony. These studies indicate clearly that 5 percent is a reasonable and conservative number. With respect to implementation, Mr. Rothschild argues that it is only necessary to apply the adjustment to the external common equity component, and not to the retained earnings portion. He, therefore, computes a weighted average flotation cost, with a 3.5 percent cost applied to external equity and a 0 percent cost applied to retained earnings, with the weights based on historical proportions of equity raised externally and internally.

I have two disagreements with this procedure. First, the flotation cost allowance must be applied to total equity capital and not to the external equity component. The numerical examples in Appendix B of my original testimony showed that not only is the flotation adjustment always required each and every year, whether or not new stock issues are sold in the future, but that the allowed return on equity must be earned on total equity, including retained earnings, for investors to earn the cost of equity.

Mr. Rothschild's legitimate concern of not applying a flotation cost allowance to retained earnings is already implicitly embedded and recognized in his formula adjustment. The flotation cost adjustment formula used in my testimony and by Mr. Rothschild deals with the fact that flotation costs are incurred only when new stock is sold, and not when earnings are retained. This is because the flotation adjustment is only applied to the dividend yield of the DCF formula, and not the growth component. Any growth through the reinvestment of earnings, that is, the larger the fraction of earnings retained, the higher the growth rate, the lower the dividend yield component, and the smaller the flotation cost adjustment. Therefore, Mr. Rothschild's blended flotation cost allowance double counts the internal financing component at a zero weight, in effect, understanding the cost of equity by about 10 basis points.

MARKET-TO-BOOK RATIOS

Q. Please comment on Mr. Rothschild's views regarding market-to-book ratios.

A. Mr. Rothschild argues that since current market-to-book (M/B) ratios for electric utilities are in excess of 1.00, "this is a clear sign that the company is expected by investors to be able to earn more than its cost of equity" (page 13, line 1 - 2), and that the regulating authority should lower the authorized return on equity so that "the stock price will decline to the proper level" (page 13, line 7 - 8). Mr. Rothschild would, therefore, find it plausible that stock prices drop from the current 1.20 times book to the desired M/B ratio range of 1.00 to 1.05 times book.

There are several reasons why M/B ratios are largely irrelevant and why I disagree with Mr. Rothschild's own view of the role of M/B in regulation.

1) Mr. Rothschild's inference that M/B ratios are relevant and that regulators should set an ROE so as to produce an M/B of 1.0 is erroneous. The stock price is set by the market, not by regulators. The M/B ratio is the result of regulation, not its starting point. The regime of regulation envisioned by Mr. Rothschild, that

is, that the Commission will set an allowed rate of return so as to produce an M/B of close to 1.0, presumes that investors are congenital masochists; they commit capital to a utility with an M/B in excess of 1.0, knowing full well that they will be inflicted a capital loss by regulators. This is not a realistic or accurate view of regulation.

2) The condition that the M/B will gravitate toward 1.00 if regulators set the allowed return equal to capital costs will be met only if the actual return expected to be earned by investors is at least equal to the cost of capital on a consistent long-term basis. The cost of capital of a company refers to the expected long-run earnings level of other firms with similar risk. If investors expect a utility to earn an ROE equal to its cost of equity in each period, then its M/B ratio would be approximately 1.00, or about 1.05 with the proper allowance for flotation cost.

But a company's achieved earnings in any given year are likely to exceed or be less than their long-run average. Depressed or inflated M/B ratios are to a considerable degree a function of forces outside the control of regulators, such as the general state of the economy, or general economic or financial circumstances which may affect the yields on securities of unregulated as well as regulated enterprises. I regard the achievement of a 1.05 M/B ratio as appropriate, but only in a long-run sense. For utilities to exhibit a long-run M/B ratio of 1.05, it is clear that during economic upturns and more favorable capital market conditions, the M/B ratio must exceed its long-run average of 1.05 to compensate for the periods during which the M/B ratio is less than its long-run average under less favorable economic and capital market conditions.

Historically, the M/B ratio for utilities has fluctuated above and below 1.05. This indicates that earnings below capital costs and M/B ratios below 1.05 during less favorable economic and capital market conditions must necessarily be accompanied by earnings in excess of capital costs and M/B ratios above 1.05 during more favorable economic and capital market conditions.

It should also be pointed out that M/B ratios are determined by the marketplace, and utilities cannot be expected to attract capital in an environment where industrials are commanding M/B ratios well in excess of 1.00. Moreover, if regulators were to currently set rates so as to produce an M/B ratio of 1.05, not only would the long-run target M/B ratio of 1.05 be violated, but more importantly, the inevitable consequence would be to inflict severe capital losses on shareholders. Investors have not committed capital to utilities with the expectation of incurring capital losses from a misguided regulatory process.

The fundamental goal of regulation should be to set the expected economic profit for a public utility equal to the level of profits expected to be earned by firms of comparable risk; in short, to emulate the competitive result. For unregulated firms, the natural forces of competition will ensure that in the long-run the ratio of the market value of these firm's securities equals the replacement cost of their assets. This suggests that a fair and reasonable price for a public utility's common stock is one that produces equality between the market price of its common equity and the replacement cost of its physical assets. The latter circumstance will not necessarily occur when the M/B ratio is 1.0; only when the book value of the firm's common equity equals the value of the firm's equity at replacement assets will equality hold.

COMPARABLE EARNINGS

Q. **Please discuss Mr. Rothschild's comparable earnings test.**

A. In his implementation of the comparable earnings test, Mr. Rothschild looks to the realized returns on book equity (ROE) achieved by a broad group of industrials, namely the DOW Jones Industrial Index, made up of 30 companies, as a proper guide for setting Gulf Power's cost of common equity. Mr. Rothschild's Comparable Earnings analysis is flawed on three counts: (1) lack of proper risk differentiation, (2) logical inconsistency, and (3) investors are expecting substantially higher ROE's than Mr. Rothschild finds. I will now treat each of the three points in turn.

(1) Mr. Rothschild fails to examine the earnings rate of industrials with the same risk as Gulf Power. He simply looks at the overall achieved returns on book equity for a broad and diverse group of companies without further differentiation. The major problem with this approach is that investors do not disregard the relative riskiness of stocks within this broad group.

The inclusion of a broad market composite is inconsistent with the seminal Hope-Bluefield doctrine of risk comparability. The sample of industrials should be carefully censored statistically for risk comparability. The rate of return standard, as expounded in Hope and Bluefield, is to allow an equity return commensurate with returns on investments in other enterprises having corresponding risks. There is no reason to believe that the 30 industrial companies provided in Mr. Rothschild's sample are comparable in all important respects relating to risk.

(2) Mr. Rothschild goes on to say that the firms in the DOW Jones Industrial Index are riskier than Gulf Power, as evidenced by their much higher average beta, implying that his comparable earnings ROE drawn from that index of companies is conservative. By relating Gulf Power's book rate of return to that of firms of comparable risk, Mr. Rothschild is assuming that there is a fundamental theoretical relationship which exists in financial theory between accounting return and risk as a basis for making such an adjustment. There is no theoretical or conceptual relationship in finance which exists between accounting rates of return (ROE) and risk.

(3) Finally, there is a fundamental disagreement between Mr. Rothschild's estimate of actual earned ROE's by these companies and the expected ROE reported

in Value Line, which Mr. Rothschild uses extensively in his DCF analysis. Surely, the expected ROE data is more relevant to the determination of cost of capital than realized ROE data. My Schedule 3 reports Value Line's estimate of expected ROE for the 30 companies in the DOW Jones Index used by Mr. Rothschild. The average expected ROE for the 30 companies judged to be comparable to Gulf Power by Mr. Rothschild is 15.89 percent. Thus, the evidence is that investors expect substantially higher ROE's than Mr. Rothschild has found for these companies.

I have also shown on that same exhibit a rough DCF calculation for the 30 industrials. Adding the spot dividend yield of 3.3 percent to the expected growth in dividends or earnings which lies in the 11 percent to 14 percent range produces DCF equity costs in the 14 percent to 17 percent range. It is not clear as to why Mr. Rothschild chose not to report any DCF results at all for those industrials which he considers comparable to Gulf Power.

He correctly argues that these companies are riskier than Gulf Power, as evidenced by their average beta of approximately 1.00 compared to Gulf Power's 0.70. But since his comparable earnings analysis of the DOW Jones Industrial Index companies indicates earned ROE's in the 11 percent - 12 percent range, and since these companies are substantially riskier than Gulf Power, it logically follows from Mr. Rothschild's analysis that Gulf Power's own return should be considerably below the 11 percent - 12 percent range, and even below the company's own yield. This is clearly an absurd result, and demonstrates the inadequacy of his so-called comparable earnings check.

Mr. Rothschild also alleges that he has checked his equity cost recommendation for reasonableness by reviewing the relationship between M/B ratios and the earned return on equity (page 10, lines 14-17). I was unable to locate such a formal empirical check or study in his testimony. The only reference to M/B ratios in his testimony is that the DOW Jones Industrials Index companies have M/B ratios well above 1.00. No further analysis or formal connection between these results and his recommended 11.75 percent cost of equity are offered.

RISK PREMIUM

Q. Please discuss Mr. Rothschild's criticism of your risk premium analysis.

A. Although Mr. Rothschild did not perform a specific risk premium study to estimate a specific cost of capital estimate, he briefly discusses the limitations of my risk premium approach on page 78, lines 13 - 20 of his testimony. Mr. Rothschild argues that 1) my risk premium study is unreliable to the extent that it is based on DCF, which Mr. Rothschild claims is unreliable, 2) the risk premium is unstable, and 3) changes in tax laws have altered the debt-equity risk premium relationship.

With regard to the first argument, I have already shown that Mr. Rothschild's critique of my DCF analysis is without foundation. My equity return estimates in my risk premium study are based on the DCF model, which Mr. Rothschild himself labels as the most accurate method. While I certainly do not disagree that return estimates are subject to error, the DCF estimates on which my risk premium study is based contain far less measurement error than Mr. Rothschild's own DCF estimates, I have already shown that Mr. Rothschild's critique of my DCF analysis is without foundation, and have also discussed the serious limitations and omissions of his own DCF estimates. My risk premium study is a month-by-month study of the cost of equity over the cost of debt. In contrast to the traditional DCF, which is a point-in-time cross-sectional estimate, the risk premium approach takes a time-series view. Surely, the recent past relationship between equity costs and debt costs is relevant as a cross-check of the DCF estimate. If the DCF method which both Mr. Rothschild and I use at a specific point in time is a pertinent exercise, it is all the more so at several points in time.

Mr. Rothschild's second criticism is that the risk premium is unstable in time. I agree that the risk premium is not constant in time. But surely this criticism can be directed at any cost of equity measurement technique, and is not endemic to the risk premium methodology. Mr. Rothschild's DCF analysis is marred by similar instabilities; for example, dividend yields, ROE's, payout ratios, and DCF growth rates are certainly not constant in time. This is not a sufficient reason for rejection. I have indeed allowed for the instability of the risk premium over the business and interest rate cycle by statistically relating the risk premium to interest rates in my risk premium studies.

Mr. Rothschild's third comment revolved around the effect of tax law changes on the risk premium. Although investors maximize their after-tax returns on a risk-adjusted basis, I have not adjusted the returns for taxes for two reasons. First, it is important that the cost of equity to Gulf Power not be confused with the return to the equity investor. Only from a return view is taxability a consideration. From a utility cost of capital viewpoint, the investor's tax bracket makes no difference in the cost of capital. The cost of equity is viewed correctly from the market place. Second, if a regulatory commission were to seek to enable the utility to compensate investors for their after-tax returns, we could have as many returns as there are tax bracket variations, and they would defy analysis. Several institutional investors such as pension funds are tax-exempt, others are fully taxable. Even if tax adjustments were warranted, it is impractical to determine the constellation of tax brackets for all the company's shareholders, and to determine the identity and tax bracket of the marginal price-setting investor.

One also has to be careful not to double-count any tax effects. Security prices already reflect the security's tax treatment. The returns implied in those prices already allow for the taxation burden. This is why, for example, tax-exempt municipal bonds are traded on the basis of much lower returns compared to risk-equivalent corporate bonds. Another example is the lower return offered by preferred stock compared to that of a corporate bond issued by the same company, because of the more generous tax treatment of preferred dividend income. Any further tax adjustment procedure would result in double counting.

Q. What are your comments on Mr. Rothschild's Implied Risk Premium?

A. Mr. Rothschild's final recommendation as to the cost of common equity is 11.75 percent. I find this estimate implausible, since it is barely above the current yield on Gulf Power bonds, which is of the order of 10.25 percent currently. The risk premium between common stocks and bonds implied in Mr. Rothschild's recommendation is about 1.5 percent The empirical risk premium literature indicates much higher risk premiums. His own risk premium results shown on Schedule 11 indicate risk premiums of 3.25 percent over Treasury bonds, which would in turn imply equity costs above 12 percent for Gulf Power using current Treasury yields. It is not clear why Mr. Rothschild has chosen to omit these results from his analysis.

CONCLUSION

Q. What do you conclude from Mr. Rothschild's DCF analysis?

A. My general conclusions are: 1) his DCF analysis hinges solely on the "sustainable growth" method, only one of several methods traditionally used in regulatory proceedings, and certainly the most fragile method, 2) his application of the method is questionable and contains a serious logical trap, 3) he has ignored historical dividend/earnings growth rates and analysts' growth forecasts for dubious reasons, and 4) I have already alluded to the absence of a reasonable stock-bond risk premium in his recommendation. It is difficult not to conclude that Mr. Rothschild's cost of capital testimony from which Risk Premium Tests, historical Dividend/Earnings Growth DCF, and analysts' growth forecasts DCF are absent is grossly incomplete. It is also difficult to accept Mr. Rothschild's claim that investors are expecting 11.75 percent when: 1) his own data indicates that investors are expecting more, 2) the company's bonds are yielding about 10.25 percent, implying a grossly deficient risk premium, and 3) Mr. Rothschild's recommended 11.75 percent is more than one standard deviation away from the average authorized equity return in 1989 for utilities.

My specific conclusions are that Mr. Rothschild has committed several serious conceptual and methodological errors in his DCF analysis: (1) insufficient flotation cost adjustment, about 10 basis points error, (2) omission of quarterly timing of dividend payments, 30 to 40 basis points error, and (3) exclusive reliance on substainable growth rates, and failure to consider historical dividends/earnings growth rates and the analysts' consensus growth forecasts, at least 75 basis points. Any reasonable, conservative quantification of these errors and omissions easily increases his cost of equity estimate by a minimum of 115 to 125 basis points, from the DCF method alone, as shown below:

ITEM	SIZE OF ERROR (basis points)
INSUFFICIENT FLOTATION ADJUSTMENT	10
OMISSION OF QUARTERLY TIMING	30 - 40
DOWNWARD-BIASED GROWTH RATES	minimum 75
TOTAL	minimum 115 - 125

In a nutshell, Mr. Rothschild's 11.75 percent cost of equity recommendation is well below a credible level, and there are serious problems with his methods and his concepts.

INDUSTRIAL CLASS RISK

Q. Do you agree with Mr. Rothschild's cost of capital and risk adjustment for industrial class versus residential class customers?

A. No. I do not. Starting on page 52, line 6 of his testimony, Mr. Rothschild argues that his cost of equity capital of 11.75 percent is not equally applicable to each customer class served by Gulf Power. He argues that serving industrial customers entails a higher degree of risk than serving residential or commercial customers.

Mr. Rothschild argues and shows empirically (pages 54-58) that the industrial class is more risky to serve than the other classes because of the higher volatility of sales of the industrial class. If indeed industrial sales volatility translates into net income volatility, then the industrial class is indeed riskier than the other classes and should be assigned a higher return component.

The flaw in Mr. Rothschild's approach is that he has not demonstrated that differences in sales variability translate into differences in earnings variability. He has ignored the critical link between revenue variability and earnings variability, and the crucial role of the latter in determining risk. It is earnings variability rather than sales volatility which is the determinant of risk and investor required returns. Two classes of customers can have the same sales variability yet vastly different earning variability because of the variability in cost structure, and more specifically the ratio of fixed to variable costs. Mr. Rothschild has not addressed the relative cost structure of the various customer classes. It stands to reason that two customer classes with the same sales variability can have vastly different earnings variability if their cost structures are different. It is therefore inappropriate to connect capital costs to sales variability directly, as Mr. Rothschild has done. It is crucial to examine the relative underlying cost structures.

II. COMMENTS ON MR. SEERY'S TESTIMONY

Q. Please summarize Mr. Seery's rate of return recommendation.

A. In determining the cost of equity applicable to Gulf Power's Florida operations, Mr. Seery (1) applies DCF analysis to a group of high-quality electric utilities, and (2) applies a DCF-based risk premium analysis for the same group of electric utilities over a 10-year period. He derives an equity cost range of 11.00 percent to 11.50 percent based on the results of these analyses. He then adds 60 basis points to the top of the latter range in recognition of Gulf Power's higher risk relative to the high-quality group and recommends a cost of equity of 12.1 percent for Gulf Power.

Q. **Please summarize your criticisms of Mr. Seery's testimony.**

A. Mr. Seery's recommended return of 12.1 percent understates Gulf Power's cost of equity capital because:

1. <u>The quarterly timing of dividend payments</u>. Mr. Seery does not use the correct quarterly version of the DCF model. I have demonstrated that the market-based DCF return prescribed by the quarterly DCF model is the only measure of allowed return which will allow investors to earn their required return and which is consistent with the capital attraction dictates of Bluefield and Hope.
2. <u>The expected growth rate for utilities in the DCF model</u>. The evidence is that investors expect higher growth rates for electric utilities than Mr. Seery has found. Moreover, there is a logical inconsistency in his implementation of the

two-growth rate DCF model, related to his use of the sustainable growth rate method to calculate long-term growth.

3. <u>The proper allowance for flotation costs</u>.
Although Mr. Seery allows for flotation costs, his methodology produces a slight shortfall in the amount recovered, understating the expected return on equity, and a legitimate stockholder expense is left partially unrecovered.

My comments will show that recognition of realistic growth rates in his DCF methodology and addition of an appropriate allowance for flotation costs and for the quarterly nature of dividend payments will produce a cost of equity recommendation which is higher than his recommended 12.1 percent and close to my own recommended return.

QUARTERLY DCF MODEL

Q. Please comment on Mr.Seery's annual DCF model results.

A. In sharp contrast to past Commission Staff practices in recent years, Mr. Seery used the annual version of the DCF model rather than the correct quarterly version. The DCF model used by Mr. Seery assumes that dividend payments are made annually at the end of the year, while most utilities in fact pay dividends on a quarterly basis. This understates the cost of equity capital by about 40 basis points. Mr. Seery did not perform the iterative solution techniques required by the Quarterly DCF model, but relied instead on the annual form of the DCF model.

Since the stock price fully reflects the quarterly payment of dividends, it is essential that the DCF model used to estimate equity costs also reflect the actual timing of quarterly dividends, in the same way that bond yield calculations are routinely adjusted to reflect semiannual interest payments.

The traditional annual DCF model used by Mr. Seery is based on the limiting assumptions that dividends are paid annually, and that dividends increase once a year starting exactly one year from the present. These assumptions are unnecessarily restrictive. The quarterly DCF model refines the annual model so as to capture the exact timing of cash flows received by the investor.

Mr. Seery justifies his omission of the quarterly nature of dividend payments on the grounds that one should not recognize the time value to investors of receiving dividends quarterly rather than annually because one does not recognize the time value to the company of receiving revenues on a monthly basis. Two wrongs make a right, according to Mr. Seery's symmetrical treatment argument.

In other words, the utility itself enjoys the reinvestment of its earnings more than once a year, and the use of the quarterly DCF model, therefore, would result in a double-counting effect. Not only is this argument not peculiar to the quarterly DCF mode, for it can be directed at any DCF model, but it is invalid for several reasons. First, it confounds the investors' market return with the company's earned return. Second, the frequency of the company's reinvestment of earnings is already embedded in investors' forecasts of earnings and dividends, which drive the stock price and the DCF estimate. Third, and most important, if a regulated firm is only allowed to earn the annual DCF return on the equity component of its rate base, it will be unable to attract capital because investors can earn higher return elsewhere.

I have shown earlier in my discussion of Mr. Rothschild's testimony that the investor will not realize the required rate of return, unless the effective quarterly return is allowed. I also have shown that the company's capital attraction is in jeopardy unless the effective quarterly DCF return is allowed.

DCF GROWTH RATES

Q. Can you comment on Mr. Seery's growth estimates in the DCF model?

A. In his DCF analysis, Mr. Seery estimates the intermediate growth term component of his two-growth rate DCF model using Value Line's forecast dividends for the next four years. He estimates the second stage long-term growth component using the sustainable growth method.

SUSTAINABLE GROWTH RATE

Q. Do you have any objections to the sustainable growth estimates used by Mr. Seery?

A. To apply the sustainable growth method, he multiplies the utility's expected retention ratio by the expected earned return on equity, as forecast by Value Line for the 1992-1994 period. It should be pointed out that this sustainable growth estimate exerts a much stronger influence on the final DCF result than the intermediate growth rate assumed for the first four years, since it captures the effects of growth from the fourth year into perpetuity. It is, therefore, imperative that it be estimated accurately if the DCF results are to be reliable.

As was the case earlier in Mr. Rothschild's testimony, Mr. Seery's sustainable growth method contains a logical trap: the method requires an estimate of ROE to be implemented. But if the ROE input required by the model differs from the recommended return on equity, a fundamental contradiction in logic follows. Mr. Seery's recommended 12.10 percent return on equity is lower than the ROE's he uses in the sustainable growth method. Column 6 of his Schedule 9 shows Value Line's expected ROE's used in the sustainable growth computation for AA-rated electrics; the average expected ROE for the group is 13.62 percent, which is in excess of his recommended return of 12.10 percent. He is assuming in effect that the companies as a group will earn at a return rate exceeding his recommended equity range from year 4 forever, and that rates will be set so that these companies earn 13.62 percent, but he is recommending that a different rate be granted by the Commission.

Moreover, as I stated earlier when discussing Mr. Rothschild's testimony, the empirical finance literature demonstrates that the sustainable growth method of determining growth is a poor explanatory variable of market value and is not significantly correlated to measures of value, such as stock price and price/earnings ratios.

Q. Do you agree that investors are expecting growth rates in the range of 3.00 percent - 3.68 percent for high-quality electric utilities?

A. No. The evidence shows that investors are expecting growth rates above Mr. Seery's intermediate-term growth estimate of 3.00 percent for the next four years and his long-term growth estimate of 3.63 percent for AA-rated electric utilities (see his Schedule 9). The April 1990 issue of IBES provides consensus growth forecasts for the AA-rated electric utilities employed in Mr. Seery's comparable group; these are shown in Schedule 4. The average consensus long-term growth rate for the 13 companies in the group is 4.14 percent, which is above Mr. Seery's estimate of 3.00 percent - 3.63 percent. Thus, the evidence indicates that investors expect growth rates at least 50 basis points higher than Mr. Seery's estimate.

One related point which Mr. Seery never clarifies is why a two-stage two-growth rate DCF model was selected throughout his testimony as opposed to the constant growth rate DCF model. It is not at all clear why Mr. Seery assumes that the electric utilities in his sample will experience an intermediate growth rate of 3 percent (see Seery's Schedule 9, average dividend growth) over the next four years and an increase in growth to 3.63 percent thereafter.

Q. Do you see any dangers in relying on Value Line as an exclusive source of forecasts in applying the DCF model?

A. Yes. Mr. Seery's exclusive reliance on Value Line as a source of analysts' growth forecasts in both his DCF and Risk Premium analyses runs the risk of being unrepresentative of investors' consensus forecasts. One would expect that averages of analysts' growth forecasts such as those contained in IBES to be more reliable estimates of the investors' consensus expectations likely to be impounded in stock prices. Moreover, the empirical finance literature has shown that consensus analysts' growth forecasts are reflected in stock prices, possess a high explanatory power of equity values, and are used by investors.

FLOTATION COST

Q. Please comment on Mr. Seery's flotation cost adjustment.

A. Both Mr. Seery and I agree on the need to adjust the cost of equity for flotation cost, but we disagree slightly on the size of the allowance. With respect to size, he uses 3 percent, compared to my 5 percent. I have already enumerated and described the results of several empirical studies on the magnitude of flotation cost for utility stock offerings in my original testimony. These studies indicate clearly that 5 percent is a reasonable and conservative number. Mr. Seery thus slightly underestimates the cost of equity capital by about 15 basis points.

CONCLUSION

Q. What do you conclude from Mr. Seery's DCF Analysis?

A. My general conclusions are:

(1) His DCF analysis hinges solely on the "sustainable growth" method, only one of several methods traditionally used in regulatory proceedings, and certainly the most fragile method.

(2) His application of the method is questionable and

contains a serious logical trap.

My specific conclusions are that Mr. Seery has omitted the following elements in his DCF analysis: 1) insufficient flotation cost adjustment, about 15 basis points error, 2) omission of quarterly timing of dividend payments, 30 to 40 basis points error, and 3) failure to consider the analysts' consensus growth forecasts, about 50 basis points downward-bias. Any reasonable conservative quantification of these errors and omissions easily increases his cost of equity estimate by about 100 basis points, from the DCF method alone, as shown below:

ITEM	SIZE OF ERROR (basis points)
INSUFFICIENT FLOTATION ADJUSTMENT	15
OMISSION OF QUARTERLY TIMING	30 - 40
DOWNWARD-BIASED GROWTH RATES	50
TOTAL	minimum 95 - 105

In a nutshell, Mr. Seery's 12.10 percent cost of equity recommendation is downward-biased by about 100 basis points.

It should finally be pointed out that Mr. Seery's risk premium analysis performed on the same companies, using the same DCF approach for each year in the last ten years, is vulnerable to the same criticism as his DCF analysis. To the extent that his DCF analysis is downward-biased by about 100 basis points, his risk premium estimate of 3.2 percent, derived from the same DCF analysis, is also downward-biased by 100 basis points, and lies closer to 4.2 percent. Given current Treasury bond yields of 9 percent this would suggest equity costs of 13.2 percent for Gulf Power.

NON-UTILITY INVESTMENTS

Q. Mr. Seery recommends that all non-utility investments should be removed directly from equity unless the Company can show through competent evidence that to do otherwise would result in a more equitable determination of the cost of capital for regulatory purposes. Do you agree?

A. No, I do not agree. Mr. Seery as well as all other cost of capital witnesses have used proxies for determining the cost of capital for Gulf Power, and those proxies are based on utility investments and the capital structure of Gulf Power. There has been no evidence presented suggesting that the small investment Gulf has in non-utility operation has impacted the cost of capital calculation of any witness.

Besides, such exclusion would ignore the risk-reducing benefits of diversification. Presumably, Gulf Power's diversified activities into both utility and non-utility operations reduces the risk to those investors who are not diversified on their own. Mr. Seery's exclusion of such activities, admittedly very small, ignores the potential benefits of diversification to the investor.

Mr. Seery appears to be asking the Company to prove a negative, which is difficult if not impossible to do. Gulf's negligible investment in non-utility operation does not affect the cost of capital as included in my recommendation or the recommendation of any witness on the subject. Therefore, to allocate all of this investment to equity would be punitive to the Company and would require the non-utility business to support the utility in an inequitable manner.

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

MR. STONE: The next live witness is Mr. Kilgore. (Pause)

CHAIRMAN WILSON: Do you want to take a break or keep on going?

COMMISSIONER GUNTER: Keep on going.

CHAIRMAN WILSON: All right. Okay.

COMMISSIONER GUNTER: Are you ready, Mr. Stone?

MR. STONE: Yes, sir.

J. THOMAS KILGORE, JR.

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

DIRECT EXAMINATION

BY MR. STONE:

Q Mr. Kilgore, I believe you've previously been sworn?

A Yes.

Q And in fact have previously testified?

A Yes.

Q You have prefiled some rebuttal testimony in this docket, have you not?

A Yes. I have.

Q Do you have any changes or corrections to your prefiled rebuttal testimony?

A I have one minor correction to Schedule 14 of my rebuttal testimony. In the bar graph at the bottom of the page, the Y axis legend in parentheses should be titled "Billions of Kilowatt Hours" rather than "Millions of Kilowatt Hours."

Q With that change, if I were to ask you questions in your prefiled rebuttal testimony, would your responses be the same?

A Yes. They would.

MR. STONE: We ask that Mr. Kilgore's prefiled rebuttal testimony be inserted into the record as though read.

CHAIRMAN WILSON: It will be so inserted into the record.

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GULF POWER COMPANY

Before the Florida Public Service Commission
Rebuttal Testimony of
J. Thomas Kilgore, Jr.
In Support of Rate Relief
Docket No. 891345-EI
Date of Filing May 15, 1990

Q. **Will you please state your name, business address and occupation?**

A. My name is Joel Thomas Kilgore, Jr., and my business address is 500 Bayfront Parkway, Pensacola, Florida 32501. I am Manager of Marketing Planning and Research for Gulf Power Company.

Q. **Are you the same Joel Thomas Kilgore, Jr. who previously filed direct testimony in this proceeding?**

A. Yes.

Q. **Do you have any corrections or additions to the testimony and exhibits you have previously filed?**

A. Yes. Subsequent to filing this case it was determined that a test year forecast assumption regarding the transfer of one industrial customer from rate PXT to rate LPT needed to be revised. This resulted in minor changes to some schedules and MFRs previously filed. I have included these changes as follows:

Schedules 7, 8 and 9 replace Schedules 1, 2 and 3, respectively. Schedules 10, 11, 12 and 13 replace MFRs E14, E18a, E18b and E18c, respectively.

Some of these revisions have been filed previously in response to interrogatories. The net base rate revenue impact of these revisions is an increase in the test year estimate of $108,769, or only .04 percent. The impact on revenue and cost allocation between rate classes, however, was enough to justify revising the forecast.

Q. **What is the purpose of your testimony?**

A. To begin with, I will address Mr. Johnson's characterization of one test year forecast assumption as questionable.

The main purpose of my testimony is to point out shortcomings in Mr. Rosen's analysis of the Company's short-term forecast results. I will also discuss flaws in Mr. Rosen's conclusions regarding the test year forecast, and will explain the inappropriateness of adjustments to the forecast which have been proposed by Mr. Rosen and calculated by Mr. Larkin.

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

A. Yes.

Counsel: We ask that Mr. Kilgore's Exhibit, (JTK-2) comprised of twelve Schedules, be marked as Exhibits 206 through 217 for identification.

Q. Do you agree with Mr. Johnson's statements in his direct testimony concerning test year sales forecast expectations?

A. Not entirely. Mr. Johnson expresses concern over a test year assumption regarding the transfer of one large (high usage) customer from the PXT (Large High Load Factor Power Service Time-of-Use) to the LPT (Large Power Service-Time-of-Use) rate schedule. As I have already explained, changed circumstances subsequent to production of the forecast and preparation of the original filing in this proceeding warranted a revision to this assumption. The resulting changes have been provided in response to Industrial Intervenors' interrogatories and requests for production of documents, as well as in the revised MFRs and schedules contained in this testimony. This should address Mr. Johnson's concerns.

I believe it is equally important, however, to point out that the assumptions embedded in the original filing were well founded at that time. The transfer of the large customer from PXT to LPT was based on the historical billing determinants and contract in effect at the point in time the forecast was prepared. It also involved a thorough review of the customer's expected operating characteristics. The forecast assumption regarding migration to the LPT rate was necessary because the customer was expected to fall short of minimum load factor requirements associated with the PXT rate. Only after a new contract for standby power was negotiated with this customer in February, 1990 did it become obvious that a modification to the forecast might be necessary.

Q. **Please discuss Mr. Rosen's assessment of the Company's short-term forecasting accuracy.**

A. Mr. Rosen's Exhibit 337 (RAR-7), sheet 1, which summarizes the Company's short-term customer, energy sales and base rate revenue forecasts from 1983 through 1989, leads him to conclude in his testimony (pg. 41) that "the Company's forecasts have been fairly accurate in the past on an average basis although not on a year-to-year basis." Mr. Rosen further concludes that past forecasts of sales have exhibited a tendency to underestimate actual sales growth. His appendage of the 1983 through 1985 data in Exhibit 337 (RAR-7) to the data provided in Schedule 4 of my direct testimony for the more relevant 1986 through 1988 period completely over-looks important considerations which should be incorporated into any such analysis.

The first flaw in Mr. Rosen's use of the 1983 through 1985 data is his failure to recognize the underlying factors contributing to exceptional growth in sales during this period. The sustained economic growth experienced during these years exceeded the expectations of most forecasters, including the major forecasting services generally relied upon for projections of national and regional growth indices. Accordingly, electric utilities and most other industries which use these projections of economic growth in preparing their own forecasts understandably had greater difficulty in achieving short-term accuracy during this period. This is particularly true for utilities in the southeastern United States, which experienced robust growth during these years. During the years 1984 and 1985, which show the largest percentage deviations for the Company's forecast in Mr. Rosen's Exhibit 337 (RAR-~~8~~7), the Florida and Southern sub-regions of the North American Electric Reliability Council (NERC) produced net energy for load well above forecast levels, as shown in my Exhibit 213 Schedule 14 (JTK-2). In fact, during 1984 every NERC region in the United States, without exception, experienced growth above forecast levels. Given this frame of reference, it is apparent that the Company's forecast deviations during these years are mostly attributable to an unusual growth spurt, rather than an inherent bias in the process and methodology. This is further supported by my Exhibit 214 Schedule 15 (JTK-2), which illustrates the high rates of growth experienced by the Company during the 1983-1985 period relative to other recent years. Mr. Rosen's attempt to divert attention from the Company's exemplary short-term forecasting accuracy established during the more recent 1986 through 1989 period is not surprising, given the lack of supporting evidence for his recommended adjustments.

The analysis and conclusions offered by Mr. Rosen regarding the Company's forecast accuracy ignore another important consideration. As stated on page 6 of my direct testimony, Exhibit 203 Schedule 4 summarizes the accuracy of the Company's short-term retail forecast over a period of time (1986-1989) during which the same methods and models were employed as were used in producing the test year forecast. In terms of assessing trends in short-term accuracy resulting from the forecast process used for test year purposes, this is the only time frame that is relevant.

Finally, Mr. Rosen conveniently fails to mention that the Company's forecast of base rate revenues has in fact exceeded actual revenues for the two most recent years, 1988 and 1989. He also chooses to avoid calling attention to the fact that weather normalized energy sales were within 0.2 percent and 0.1 percent of forecast, respectively, for these same two years.

Q. **Please discuss Mr. Rosen's analysis of the growth component in assessing forecast accuracy.**

A. Again, Mr. Rosen uses an irrelevant period in his analysis time frame (1983-1985), as I have already discussed. He also uses a questionable approach in attempting to support his argument. Mr. Rosen presents a summary on sheet 2 of his Exhibit 337 (RAR-7) which attempts to depict the Company's short-term forecast as inaccurate on the basis of percent deviation on the growth component.

The evaluation of a forecast based on percent deviation on the growth component represents an unusual frame of reference. It is not commonly used in evaluating forecast accuracy unless the variable being forecast exhibits stable growth tendencies and is not subject to volatile influences, such as weather, which can result in large swings from one period to the next. Therefore, I would not consider it of much value in evaluating forecast accuracy for energy sales or base rate revenue, both of which are significantly impacted by weather and economic conditions, among other things.

However, since Mr. Rosen feels compelled to examine forecast accuracy on the growth component, one comparison is worth noting. In the Company's last rate filing (Docket No. 881167-EI), Mr. Rosen proposed a 0.5 percent upward adjustment to the Company's 1989 test year forecast. As calculated by Mr. Larkin in Docket No. 881167, Exhibit (HL-20), this resulted in an increase of $1,226,032 for a total test year base rate revenue estimate of $246,432,477. My Exhibit 215 Schedule 16 (JTK-2) provides a comparison of the Company's growth component forecast accuracy for 1989 with that of Mr. Rosen and Mr. Larkin. Despite the fact that the Rosen/Larkin estimate was made almost a year after the Company's forecast was produced, allowing them to use four months of actual data for the 1989 test year, their forecast error was more than twice that of the Company.

In summary, Mr. Rosen's analysis in his Exhibit 337 (RAR-7) represents an attempt to draw attention away from the real issue, which is the accuracy of the forecast of test year base rate revenues, not the change in sales or base rate revenues. Even if one does wish to consider forecast accuracy as measured on the growth component, Mr. Rosen and Mr.

Larkin have a poor track record in comparison to the Company.

Q. **Please discuss Mr. Rosen's statements and conclusions regarding the impact of price assumptions on the test year forecast.**

A. On pages 44 and 45 of his direct testimony, Mr. Rosen attempts to address the impact of price assumptions on the test year sales forecast. In doing so he makes some incorrect statements.

First, Mr. Rosen states that, in calculating 1990 test year sales, the Company assumed that the full rate increase originally requested by the Company would be implemented. While the Company did assume full recovery, the timing assumed for permanent rate relief was late 1990, so that only the assumed interim increase had any impact on the test year. Mr. Rosen also incorrectly states the amount of the interim increase request as $26.3 million, instead of the actual $22.8 million sought.

As I stated in my deposition by Public Counsel on April 5, 1990, the Company did, in fact, assume that an interim increase would be granted during 1990. We have performed an after-the-fact analysis, supplied as Late File Exhibit No. 1 to that deposition, which summarizes the impact of this assumption as compared to what we now believe our price levels will be through the end of the year. The difference, as Mr. Rosen correctly noted in his testimony, is only 19 GWH. This amount is of little significance, representing 0.2 percent of the test year retail sales forecast of 7,699 GWH.

Q. Do you consider Mr. Rosen's recommended adjustment to the forecast to be reasonable?

A. No, I do not. In fact, Mr. Rosen's recommended 1.0 percent adjustment is arbitrary and lacks substantive support. Mr. Rosen states on page 46 of his testimony that this recommended adjustment is reasonable for two reasons, but fails to provide credible support for either one.

The first reason offered by Mr. Rosen for the adjustment is that the Company "has tended to under-forecast year-to-year sales growth in the past." I have already discussed the inadequacies and false conclusions related to inclusion of the 1983 through 1985 time period in Mr. Rosen's Exhibit ____ (RAR-7). I have also presented data which clearly indicates that the Company's short-term forecasts have proven extremely accurate in recent years. In addition, my two page Exhibit 216 Schedule 17 (JTK-2) demonstrates that, for the relevant period for comparison purposes (1986-1990), the Company's forecast deviations have been both positive and negative.

Mr. Rosen's second reason for characterizing the 1.0 percent adjustment as reasonable is that "consideration of the current forecast shows that some under-forecast is quite likely to occur again for the test year." Part of Mr. Rosen's basis for this statement is his observation that, "the forecast increase is unprecedented since 1983 in being so low." Again, this reasoning fails to recognize the factors underlying growth. In particular, substantial reductions in construction and housing starts are currently being seen across the nation.

With regard to test year price assumptions, the impact on the test year forecast is very small, representing only 0.2 percent of the test year sales estimate. An adjustment for price assumptions should be considered only if other test year assumptions are examined, including those which would cause the forecast to be too high. I do not believe any adjustments are necessary, as it is evident from the year-to-date April comparison in my Exhibit 216 Schedule 17 that the test year forecast is reasonable.

Finally, based on the observed performance record of Mr. Larkin and Mr. Rosen in making adjustments to test year sales forecasts, I believe that their proposed adjustment for the 1990 test year is inappropriate. They used essentially the same argument for making an adjustment to the 1989 test year forecast in Docket No. 881167-EI. My Exhibit 217 Schedule 18 clearly demonstrates that the arbitrary approach used by Mr. Rosen and Mr. Larkin yields poor results in comparison to the Company's forecast. As indicated in the bar diagram, they overestimated 1989 test year revenues by $2,401,822. This exceeded the Company's forecast error by $1,226,032. Both past experience and available data indicate that the current adjustment proposed by Mr. Rosen and Mr. Larkin is also seriously flawed.

Q. Does this conclude your testimony?

A. Yes, it does.

Q Mr. Kilgore, please summarize your rebuttal testimony.

A The purpose of my rebuttal testimony is to point out serious shortcomings in Mr. Rosen's analysis of the Company's short-term forecast results. I will also discuss fundamental flaws in Mr. Rosen's conclusions regarding the test year forecast, and will explain the inappropriateness of an adjustment to the forecast which has been proposed by Mr. Rosen and calculated by Mr. Larkin.

Mr. Rosen concludes in his testimony that, and I quote, "The Company's forecasts have been fairly accurate in the past on an average basis, although not on a year-to-year basis," unquote.

He further concludes that past forecasts of sales by the Company have exhibited a tendency to underestimate actual sales growth. He bases these conclusions on an analysis of results over the period 1983 through 1989. His decision to combine data for the period 1983 through 1985 to the more relevant 1986 through 1989 period contained in my testimony overlooks important considerations and leads him to erroneous conclusions.

One major flaw in Mr. Rosen's use of the 1983 through 1985 data is his failure to recognize and consider underlying factors contributing to exceptional sales growth during this period. My rebuttal testimony contains an exhibit, Schedule 14, which illustrates the impact on utility forecasts associated with the fact that the entire southeastern United States experienced robust economic growth conditions during this period. This, understandably, led to difficulties in forecasting for all electric utilities in the region, as actual growth outpaced anticipated growth. This point is further accentuated by my exhibit, Schedule 15, which illustrates 1983 through 1985 growth rates for Gulf Power Company customers and retail energy sales in comparison to other years in recent history.

Of even more importance, perhaps, is the fact that Mr. Rosen chose to include in his analysis a period of time during which the Company employed a forecast methodology substantially different than the one used in preparing the test year forecast.

Mr. Rosen agreed during cross examination Tuesday that, in drawing conclusions regarding the accuracy of the Company's forecast, it is important to consider whether or not the methodology for the historical period matches that used in producing the test year forecast. This statement contradicts the approach that he actually used in his analysis.

Mr. Rosen also advocates the evaluation of a forecast based on a percent deviation on the growth component as a useful measure of accuracy. While I do not agree that the growth component deviation is a particularly useful measure of accuracy for a variable such as energy sales or revenues, both of which are significantly impacted by factors such as weather and economic conditions, my rebuttal includes exhibits which provide interesting comparisons using the measure advocated by Mr. Rosen.

In the Company's last rate filing, Docket No. 881167-EI, Mr. Rosen proposed a one-half of 1% upward adjustment to the Company's 1989 test year forecast. This adjustment was applied in an exhibit prepared by Mr. Larkin in that case. My exhibit, Schedule 16, provides a comparison of the Company's growth component forecast accuracy for 1989 with that of Mr. Rosen and Mr. Larkin.

Despite having the tremendous advantage of almost a full year's additional data, including several months of test year data, Mr. Rosen and Mr. Larkin combined their efforts to give birth to a forecast which had a growth component error more than twice that of the Company's forecast.

Regarding the impact of price increase

assumptions on the test year forecast, a late-filed exhibit to my deposition by Public Counsel clearly indicates that the difference between actual and assumed price impacts are insignificant, representing only two-tenths of 1% of test year retail sales.

Finally, Mr. Rosen admitted in his cross examination, to my surprise, that he had not reviewed actual versus forecast results year-to-date for the test year. He did concede, however, that these results should be taken into consideration, again contradicting his actual approach.

Test year results through April are contained in my exhibit, Schedule 17, and clearly indicate that the test year forecast is reasonable.

Based on these results and the observed performance record of Mr. Larkin and Mr. Rosen in making adjustments to test year forecasts, I believe that their proposed adjustment to 1990 test year sales is inappropriate. The Company's test year forecasts represents a sound and reliable basis for this proceeding.

This concludes my summary.

Q Mr. Kilgore, before I tender you for cross examination, I just discovered what I believe may be a typo in your testimony, I need your help with.

A All right.

Q On Page 6, you were referring to Mr. Rosen's exhibit. You have it designated at Line 8 as RAR-8 and I do not show an RAR-8 in his list of exhibits.

A This is on Page 6 of my testimony?

Q That's correct, at Line 8. Do you know which exhibit you were referring to?

A I believe I can find it if you will just bear with me for a second.

Q Please.

WITNESS KILGORE: Yes. That should read "RAR-7." That was a multipage exhibit in Mr. Rosen's direct testimony. I apologize for the error.

MR. STONE: For the record, that's Exhibit 337.

Thank you, Mr. Kilgore. We tender for cross examination.

MAJOR ENDERS: No questions, sir.

CHAIRMAN WILSON: Questions?

MR. McGLOTHLIN: A few.

CROSS EXAMINATION

BY MR. McGLOTHLIN:

Q Mr. Kilgore, in your rebuttal testimony you address some corrections to the assumptions concerning the customer classes demand and energy projections for

1990, is that correct?

A That is correct?

Q Did the results for 1989, which were available to you, have any bearing on the corrections you made to the 1990 projections?

A Yes, they had some bearing.

Q Would you please explain how that -- what bearing they had?

A Yes. Specifically, we had one assumption that I discussed yesterday during my direct testimony regarding the transfer of a customer from the PXT to the LPT rate schedule. That assumption was due to the fact that last summer, summer of '89, when we were preparing the forecast, we noted that that customer had established a demand on the system that we felt would prohibit that customer from meeting the minimum load factor requirement of the PXT rate schedule. For that reason we anticipated that the customer would actually migrate again to the LPT rate before the start of the test year.

As it turns out, negotiations with that customer on the standby rate led us to change that assumption. A new standby service contract was signed with that customer, I believe in February of 1990. So the change that was made during discovery on this case was to move that customer's energy and revenues back into the PXT rate classification.

Q Reference has been made to Hearing Exhibit 488, which I believe is a response to an interrogatory that you prepared, and it's been observed that that data shows a decline in load factor between '87 and '89 for PX/PXT. Did that decline in load factor affect your assumptions and your projections for 1990 incorporated in the test year?

A Let me make sure I understand the question.

MR. PALECKI: Commissioners, we object. I believe that is beyond the scope of the rebuttal. The rebuttal is pretty narrow with regard to this subject matter.

MR. McGLOTHLIN: The witness on rebuttal has described corrections to the assumptions used in the projections for 1990, and those energy and demand assumptions are reflected in attachments. He's indicated that the 1989 results had some impact. I'm asking if the decline in the '89 load factor was a consideration and, if not, why.

MR. PALECKI: We would have no objection if you asked him whether or not the corrections that were made would nave an impact, but other than the corrections I don't think that that's appropriate for rebuttal.

CHAIRMAN WILSON: What was your question about?

MR. McGLOTHLIN: Whether the decline in load factor for PXT that has been observed based upon a response to interrogatories that he prepared, affected the assumptions that went into the projections for 1990, which are described --

CHAIRMAN WILSON: He raised that on his rebuttal testimony, or is this something else?

MR. McGLOTHLIN: He described the corrections he made to the 1990 projections and attached the 1990 projections to his rebuttal exhibit.

CHAIRMAN WILSON: And your question is why he didn't make a correction?

MR. McGLOTHLIN: That's correct. If the answer is no, he didn't take that into account, then the question is why.

CHAIRMAN WILSON: I'll allow the question.

WITNESS KILGORE: I didn't directly take the decline in load factor into account. However, we did take, I believe, the conditions that resulted in that decline in the load factor into account, and so it's related.

Q (By Mr. McGlothlin) Would you explain the distinction you're making between the conditions and the decline itself?

A Yes. Again, this customer, at the time that we made the forecast, was just in the process of signing a standby contract with the Company, if my memory serves me correctly, for zero kW. In early 1990 the customer signed a new standby service contract which we felt would cause, for one thing, a change in their load characteristiccs, and in another would certainly cause some changes in the revenues attributable for that customer. We felt that those changes warranted a change to the test year forecast, and, in fact, the load patterns that we had seen during 1989 were not necessarily representative of what we would expect in a normal test year for this customer, or the group of customers that the particular customer fell in.

MR. McGLOTHLIN: No further questions.

CHAIRMAN WILSON: Mr. Palecki?

CROSS EXAMINATION

BY MR. PALECKI:

Q We have a question regarding the same customer. What is the annual load factor for this PXT customer who did not migrate to LP/LPT? And we'd like that using kWh for the latest 12 months for which it is available and an annual maximum billing demand of 22,959 kW, which is the billing demand that was provided to us by Gulf. Is that something you could provide to us now, or would you prefer doing that as a late-filed?

A If you're asking for it on the basis of the latest 12 months available, I'm certain we would have to provide it to you later

MR. PALECKI: We would ask for that as the next consecutive late-filed exhibit, and a short title would be Annual Load Factor for PXT Customer.

CHAIRMAN WILSON: 615?

MR. PRUITT: That's correct.

(Late-filed Exhibit No. 615 identified.)

MR. PALECKI: We have no further questions.

CHAIRMAN WILSON: Questions, Commissioners? Redirect?

MR. STONE: I have no redirect, but I do have a question for Mr. Kilgore.

I believe you were asked when you were up here on your direct testimony for a late-filed exhibit documenting the information you've provided to the Staff regarding the development of the SE rate?

WITNESS KILGORE: Yes.

MR. STONE: Is that late-filed exhibit ready to hand out at this time?

WITNESS KILGORE: Yes, we do have that.

MR. STONE: That's Exhibit No. 600, and with the Commission's indulgence I'd like to go ahead and pass that out.

CHAIRMAN WILSON: Yes, please do.

MR. McGLOTHLIN: Commissioners, this may be understood already, but with respect to Staff's most recent late-filed, will that be identified as Customer X, shielded in some way?

CHAIRMAN WILSON: Yes. We will not specifically identify customers.

MR. McGLOTHLIN: Thank you.

CHAIRMAN WILSON: And it's customary not to.

(Pause)

WITNESS KILGORE: Would you like for me to explain the late-filed exhibit?

MR. STONE: I'm not sure an explanation --

CHAIRMAN WILSON: Any questions on this?

MR. PALECKI: Staff has no questions on the late-filed.

CHAIRMAN WILSON: All right, good. Any redirect?

MR. STONE: None.

CHAIRMAN WILSON: All right. Thank you very much. Do you want to move this late-filed exhibit in?

MR. STONE: Yes, please.

CHAIRMAN WILSON: All right. Any objections? No objections. Late-filed Exhibit No. 600 is admitted into evidence.

(Late-Filed Exhibit No. 600 admitted into evidence.)

MR. STONE: Commissioners, the next witness is Mr. Michael T. O'Sheasy. I don't know if it's appropriate to take a break at this point or not.

CHAIRMAN WILSON: It's not.

MR. STONE: Commissioner, while we're waiting for Mr. O'Sheasy to return to the stand, may Mr. Kilgore be excused from further attendance from these hearings?

CHAIRMAN WILSON: Yes, he may.

(Witness Kilgore excused.) (Pause)

- - - - -

CHAIRMAN WILSON: Ready?

MR. STONE: Yes, sir.

MICHAEL T. O'SHEASY

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

DIRECT EXAMINATION

BY MR. STONE:

Q Mr. O'Sheasy, you have previously been sworn and have testified earlier in this proceeding.

A Yes.

Q You have prefiled rebuttal testimony in this docket dated May 21, 1990, have you not?

A Yes, I have.

Q Do you have any changes or corrections to your prefiled rebuttal?

A No, I do not; no, no changes.

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

A Yes, they would.

MR. STONE: I ask that it be inserted into the record as though read.

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

DIRECT EXAMINATION

BY MR. STONE:

Q Mr. O'Sheasy, you have previously been sworn and have testified earlier in this proceeding.

A Yes.

Q You have prefiled rebuttal testimony in this docket dated May 21, 1990, have you not?

A Yes, I have.

Q Do you have any changes or corrections to your prefiled rebuttal?

A No, I do not; no, no changes.

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

A Yes, they would.

MR. STONE: I ask that it be inserted into the record as though read.

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

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GULF POWER COMPANY
Before the Florida Public Service Commission
Rebuttal Testimony of
Michael T. O'Sheasy
In Support of Rate Relief
Docket No. 891345-EI
Date of Filing May 21, 1990

Q. **Mr. O'Sheasy, have you previously submitted testimony in this proceeding?**

A. Yes. I submitted prefiled direct testimony in this proceeding in support of the filed rates for Gulf Power Company.

Q. **Have you reviewed the testimony and exhibits of the witnesses intervening in this proceeding?**

A. Yes.

Q. **What is the purpose of this rebuttal testimony?**

A. It is to address the following cost of service subjects raised by the witnesses for the intervenors in this proceeding:

(1) Customer/Demand Classification of Distribution Accounts
(2) Proper Production Allocation for Gulf Power Company
(3) Equivalent Peaker (EP) and Refined Equivalent Peaker (REP)
(4) Allocation of Lines Investment
(5) Allocation of Plant Scherer

(6) Voltage Differentiated Rates

(7) Transformation Discounts.

CUSTOMER/DEMAND CLASSIFICATION

Q. On Page 36 of Mr. Pollock's testimony, he stater that he believes that the Commission should examine the customer-demand classification issue. Do you agree that a more representative costing analysis would recognize more customer related costs in distribution accounts?

A. Yes. As stated on page 21 of my prefiled testimony, our position is that the Minimum Distribution System is includable for ascertaining customer related cost. This is logical from a cost causative perspective.

Q. Why do you believe that it is logical from a cost-causative perspective?

A. There is a customer related portion of distribution investment required to serve customers independent of their anticipated demand and energy requirements. The mere fact that they wish to become a customer of Gulf Power forces a certain minimal amount of equipment to be there available to serve. Distribution facilities, including poles, conductors, and transformers, are required regardless of the Company's expectations regarding load. A part of the customer component is the theoretical minimum distribution system that would be required to serve customers. The NARUC Electric Cost Allocation Manual not only recognizes a customer related portion of distribution costs, but devotes an entire chapter to a discussion of the separation of the customer related portion from the demand related portion.

Q. **What would you recommend in this issue in order to define more accurately the cost to serve Gulf's customers?**

A. I recommend that we adopt the customer/demand classification factors that were recommended in Gulf's 1984 retail filing. In fact, I believe that a more current analysis would still produce quite similar results. These factors would be applied in the following manner:

FERC Account	Description	Customer %	Demand %
364	Poles	46.1%	53.9%
365	Overhead Conductors	13.8%	86.2%
366	Underground Conduits	13.8%	86.2%
367	Underground Conductors	13.8%	86.2%
368	Line Transformers	34.2%	65.8%
369	Services	100.0%	0%
370	Meters	100.0%	0%

PROPER PRODUCTION ALLOCATION FOR GULF POWER COMPANY

Q. **Mr. Pollock states in his testimony that a seasonal peaking allocator would be more appropriate for Gulf than the 12-MCP and 1/13 Energy which you utilized. Why did you choose 12-MCP and 1/13 Energy?**

A. It was the required methodology stated in FPSC's Final Order from Gulf's last rate case. As stated in my testimony, we felt that this method was appropriate because the results of this technique did not diverge dramatically from results of concepts which we believe more appropriate. Also, it is the methodology upon which current rates are based and has been so since 1981. Gulf's customers are therefore familiar with the price signal which it sends. Since the majority of this allocator is 12-MCP, it matches up nicely with the FERC's preference for 12-MCP and the fact that Gulf's IIC payments and credits are dependent upon its monthly peak. Finally, it recognizes the impact of scheduled maintenance performed in non-peak months.

Q. **Is Mr. Pollock's "Near Peak" procedure appropriate for Gulf Power Company?**

A. No, although Gulf's costs are sensitive to the seasons. His methodology is much too restrictive an interpretation for Gulf's load shape, as even his results show. Mr.

Pollock's 71-hour allocation contains specified hours found in only two summer months. Certainly there are other months of the year when Gulf is in a "peaking mode." Mr. Pollock's own Schedules 5 and 7 indicate that throughout the years 1984 through 1989 there are at least four to five different critical summertime months. In addition, Mr. Haskins' Exhibit No. 6 further supports the importance to Gulf of four summer months during 1987 and 1988.

Q. **What is your opinion on Mr. Pollock's statement "besides failing to adequately recognize the seasonal load characteristics of the Gulf Power and Southern Company systems and the fact that Southern schedules most of its outages during the non-summer period, the 12CP method is relatively insensitive to seasonal load shifts. As a result, the 12CP method could send the wrong price signal?"**

A. His point that the 12CP method is relatively insensitive to seasonal load shifts is true, but many allocation methods would appear "relatively insensitive to seasonal load shifts" when compared with the ultra-sensitive "Near Peak" method whereby any load shifts from two specific summer months to any of ten other months would result in complete disappearance of any cost responsibility.

Q. **Do you agree with Mr. Pollock's statement that the "Near-Peak" method would produce more stable results over time than would the <u>other summer CP methods</u>?**

A. This could possibly be true when compared to strictly "summer" coincident peak methods. Mr. Pollock has not produced any data that shows it to be more stable than 12-MCP, however. In fact, many proponents of 12-MCP applaud the fact that for most major rates, the 12-MCP does indeed produce relatively stable results over time. Also, one must remember that while stable results are important, also very important is the assignment of cost to those customers who caused the cost to be incurred. To avoid associating cost responsibility to customers who may have demanded service from Gulf during any one of ten months other than July and August would be inequitable and incorrect.

Q. **What is your opinion on Mr. Pollock's stated basis for using 5 percent as the threshold since, "this is the period when system reliability is usually the most critical"?**

A. First of all, I question why the 5 percent figure was chosen. What is the magic of 5 percent that justifies it to define this specific time frame as most critical? Secondly, the highest 71 hours are contained in July and

August, but Schedule 7 reveals four out of six years where some other monthly reserve margins after planned/scheduled maintenance were at or below the reserve margins for July and August.

Q. **Of the demand allocation methodologies proposed for allocating generation cost in this case, which do you recommend?**

A. I recommend an allocator approximating the 12-MCP. The purpose of a cost of service study is to allocate "embedded" cost upon those factors that caused them to be incurred, and, under these conditions, determine the cost to serve. In order to do so, we must consider why these costs were incurred. We must recognize that a generating plant will service Gulf Power Company's customers over 30 years into the future.

This study is not a marginal cost study. It is not a customer specific cost study. It is an analysis based upon the "embedded" cost as defined by our industry and allocated upon the causation of each of those costs. The result is an <u>average</u> embedded cost study reflecting the cost responsibility of an average customer within the respective rate.

After this task has been completed, the rate designer can be handed the inputs upon which he can fulfill his responsibility. He will then take the average embedded cost to serve the average customer within a rate class and mold a price for specific customer groups which will appropriately reflect cost and satisfy other goals and objectives, while working within prevailing constraints for the time frame to which these rates will apply. For instance, the price signal which the rate artist provides Gulf's customers must consider that we want to minimize the cost to serve Gulf's customers over all future years. This goal could then justify rates that will alter Gulf's load shape, thereby producing a more efficient process.

The point here is that the selection of a costing methodology should be dependent upon cost causation and should mirror the system in place to service Gulf's customers. It should not be a methodology selected to achieve goals or objectives conditioned by economic, societal, political, regulatory, and other constraints -- this is the responsibility of the rate designer; in this case, Gulf's witness Haskins.

EQUIVALENT PEAKER AND REFINED EQUIVALENT PEAKER

Q. With that in mind, what do you think about the Equivalent Peaker concept and the Refined Equivalent Peaker concept?

A. Both Equivalent Peaker concepts contain serious flaws which prevent them from justifying departure from the tried and tested methodology proposed by Gulf in this rate case. They depend upon the proposition that additional production plant costs result from the utility's attempt to minimize total cost after factoring in running cost. They assume that serving peak loads only, with no consideration for running cost, would warrant a peaking type plant. Accordingly the difference in equivalent peaking cost and total cost is related to running time and should therefore be allocated upon KWH.

These concepts do embody considerations which must be made when planning a system to serve projected load at a minimum cost. There is no doubt that, if a projected load shape revealed a need to build plant, one criteria for alternative plant selection would be to minimize total cost by considering capital cost, running cost, and projected plant utilization. However, the ultimate decision of what to build is far too complex to simplify into a mere trade-off of operating cost versus fixed cost. Gulf's witness Mr. Howell will elaborate on some of these other considerations, but there is no doubt that governmental regulations, legal and societal constraints, availability of capital, plant location parameters including fuel delivery problems, current plant mix and the potential dangers of total commitment to one type of fuel all play a role in the decision making process.

Q. What failings do you see in the Equivalent Peaker concept in addition to the over simplification of the system planning process that is discussed by Mr. Howell?

A. When the decision was being made, the costs of peaking units versus base units were not necessarily the same peaking versus base relationships which we observe today. To discount embedded cost to constant dollars is an attempt in the right direction, but may not reflect what the original costs were. For example, one must determine whether the discount rates are appropriates, or whether something was added after initial construction which could not have been anticipated, such as scrubbers. Also, the differential in oil cost and coal cost has not always been constant. In fact, oil fired plants were at one time the least cost option.

If you do accept the breakeven analysis between a peaker and a base unit, why allocate the incremental costs upon 8,760 hours of energy? Only the hours up to the breakeven point were important in the decision. Past the breakeven point, no matter how far, the decision has been made and would not be altered no matter how the plant utilization improved. To allocate these incremental capital costs upon all hours would not track cost causation.

The costs of reserving a peaker (i.e., its reliability) may not be the same as those of a base unit. The presumptions of EP, REP, and 12-MCP and 1/13 are that reserve costs are identical. However, because EP and REP differentiate the cost of peakers and base units for allocation purposes, unlike 12-MCP and 1/13, this fact requires a review of this reserving question.

Q. What do you feel about the statement that there may well be a long run marginal generating plant cost of off-peak energy use in which the EP method "will embody an appropriate reflection"?

A. First of all, we are not allocating long run marginal cost -- we are allocating average embedded cost. Secondly, if there is some long term marginal generating cost of off-peak energy use, I do not see where EP quantifies this cost, and therefore, reflects it. It simply appears to make a contribution towards it, which may be over or under the true cost. Also, what if the utility has no long run marginal generating cost of off-peak energy use? No one has said or proven that there is long run marginal generating cost of off-peak energy use for Gulf Power Company. In this instance, costs would be allocated to hours where none actually existed.

In addition, we would be indicating to our customers that off-peak KWH growth is bad since we would be allocating fixed cost on a KWH basis whereas we did not under Gulf's present and proposed methodology. Correspondingly, we would be telling our customers that peaking growth is not nearly as bad as we once thought since those costs would now be transferred to some degree from peaking periods to off-peak periods. Over time, our customers will react accordingly. System load factors could easily deteriorate, creating a need for more C.T.'s and fewer base load units in Florida. This may or may not be the trend which is in the best interest of Gulf's customers.

Q. Are there also flaws in the Refined Equivalent Peaker concept?

A. Yes. This approach attempts to correct a major criticism of the Equivalent Peaker method by only allocating the incremental plant cost upon energy up to the breakeven point between a peaker and a base unit. This, in theory, is a logical enhancement. However, this in itself presents a major problem:

<u>How do you determine the breakeven point?</u>

The methodology used by Mr. William Slusser, Jr. of Florida Power Corporation in Docket No. 870220-EI and my submitted response to Interrogatory No. 2 of Staff's First Set of Interrogatories in this docket, discounts embedded net plant costs of coal units and C.T.'s to current costs in order to match up with today's current running cost; the breakeven point then falls out. Besides the question of selecting the appropriate discount rate, the volatility of fuel (running) cost creates a problem. It has been said that in the long run, coal cost may track oil cost. However, it is most difficult to determine the correct cost to enter when examining the current cost environment. Many of the workpapers supporting the Company's response to Interrogatory No. 2 were completed in November of 1988 based on then prevailing oil and coal prices. Consider the impact that the Valdez oil spill has caused on oil prices; this effect may be temporary, but also there may be some lasting influence much like the '73 Arab Oil Embargo.

The point to be made here is that the need to choose a proper discount rate as well as volatility of fuel prices will cause the breakeven point to jump around dramatically. I have seen the hours of breakeven jump from 900 hours in some studies to 3000 hours in others. The impact on the hours selected and resultant allocator may cause significant swings in implied cost responsibility. The end result may be an unstable rate design process requiring continuous rate adjustments.

The EP approach bases its energy/demand split upon levelized gross investment. The Refined EP method bases its energy/demand split upon levelized net plant. One results in a 45 percent demand portion while the other produces a 40 percent demand. It is not perfectly clear which figure is correct.

The logic underpinning the Refined EP may assume an optimization based upon certain planning parameters. Because of the lumpiness of plant additions, it is rare that any utility will always maintain an optimal mix for the current load shape. As Mr. Howell states in his testimony, "the philosophy of optimum generation mix did not become widespread until the 70's," when most of Gulf's current generation had been either constructed or committed.

<u>Does it then make sense to allocate actual embedded dollars upon a few theoretically presumed optimal parameters?</u>

By levelizing embedded capacity cost into today's constant dollars to synchronize with current running cost, we are attempting to replicate the parameters which the planner faced. However, the current day fixed cost/variable cost relationship for peakers versus base units is not necessarily the same factors which the system planner observed when he constructed Plant Daniel in the late 70's or Plant Smith in the mid 60's. The reason that we rolled forward the capacity cost to match up with current fuel cost is that we are not sure of the exact fuel considerations anticipated at the time of construction, nor are we certain that these costs are relevant because of the dramatic changes in oil prices since then. Therefore, we chose current day costs as a proxy, but they are only a proxy at best. As a result, we are allocating embedded dollars on a current cost calculation which may or may not be appropriate.

Is there an inherent inconsistency in logic if one assumes capital substitution theory in determining base rates but average running cost allocation in fuel recovery? Capital Substitution theory appears to suggest that, after considering the running cost of a peaker versus a base unit and the resultant breakeven point has been passed, a base unit will be chosen and operated: in other words, subsequent hours after the justification point will have load requirements satisfied through the running cost of base units. It seems inconsistent then to associate any peaker fuel cost to hours past the breakeven point; unfortunately, the average fuel clause methodology would do so. Therefore, it does seem as if some type of adjustment is appropriate. However, is is not clear exactly what type of adjustment would be fair and equitable, especially since Gulf is essentially all coal fired. It does appear, however, that EP requires more of an adjustment than REP merely because EP allocates fuel savings capital cost to hours in the off-peak that should not receive any.

The basis upon which the demand defined portion of REP (and EP) is allocated must be examined carefully. In response to Interrogatories No. 1 and No. 2 of Staff's First Set in this docket, it was done upon the 12-MCP's. However, some of these 12-MCP's fall outside the highest 1430 hours. It seems illogical then to allocate cost defined to be serving demand requirements only, upon hours not even necessary to justify the incremental "fuel savings" investment cost. However, the real answer might be to capture the highest 1430 hours from a reliability standpoint, such as LOLP or EUE, which might possibly contain all of the 12-MCP's.

<u>In which component of rates do you place the incremental cost allocated upon hours up to the breakeven point?</u>

It seems as if it should be the energy component. The analyst must still decide whether to place these costs in the annual energy rate or in a seasonal rate.

Q. Could you summarize your position on generation cost allocation?

A. Gulf's generation costs occur throughout the year. There are four methodologies presented in this case: 12-MCP and 1/13, Near Peak, Equivalent Peaker, and Refined Equivalent Peaker. Of these choices, the method which is most appropriate for Gulf, considering Gulf's load shape and other considerations previously mentioned, is definitely 12-MCP and 1/13. This method is the most sound and will continue to provide the stable, consistent price signals to which Gulf's customers are accustomed and which they expect to see. The 12-MCP methodology is a widely used and accepted methodology throughout our industry. The other methods are either inappropriate (Near Peak) or possess far too many flaws to warrant a departure from the current methodology.

Q. If a choice had to be made between Equivalent Peaker and Refined Equivalent Peaker, which alternative should be chosen?

A. Before answering this, let me point out a few implementation problems. First, both of these concepts are relatively new. As a result their stability and acceptability is still suspect. Obviously in order to become accepted, any new concept must be subjected to careful analysis and review. However, this is not the time to test a new cost-of-service methodology on Gulf's customers, given the other major issues in this case.

In fact, even if one of these procedures were required, some type of adjustment period would only be fair to Gulf's customers. Gulf's customers have been told through price signals for over 50 years that they should flatten their load shape, increase KWH usage in off-peak times and reduce peak KW. Either of these two techniques, especially the Equivalent Peaker method, would tell Gulf' customers that KWH growth is bad and there will be more allocation of cost as a result, while KW growth isn't so bad after all. Even if this is justifiable due to an evolution in our dynamic utility system and the costing models that attempt to track it, our customers cannot be expected to adapt overnight. They, over the years, have purchased equipment to match the price signals we have sent them. They would be sorely shocked by an immediate adoption of Equivalent Peaker.

However, if one had to choose between EP versus Refined EP, the best or least undesirable alternative would be Refined EP. It presents fewer flaws than the EP. However, the filed REP study should be re-examined to determine the correct demand allocator for the equivalent peaking cost and the question of a possible fuel cost adjustment should be researched.

ALLOCATION OF INVESTMENT IN LINES

Q. On page 32 of Public Counsel's witness Scheffel Wright's testimony, he states "the company should estimate the rate base value of primary and higher voltage-level conductor that functions as dedicated distribution facilities, or as a higher voltage service drop, and directly assign these estimated amounts to the classes that include the customers who are served by these facilities." Do you agree?

A. No. To examine this question more clearly, we must visualize Gulf's electrical delivery system whereby there is a network of interconnecting lines transmitting electricity around the system at predetermined, reliable voltage levels. From this network, taps branch off to serve load centers. As a result, all related customers are allocated an average portion of the network and taps according to the loads they place on the system.

Account 369-Services contains secondary service drops which must be installed to serve a customer at a secondary distribution no matter what his load requirements. It is, therefore, allocated upon number of customers. Line investment cost found within other FERC accounts is sized according to anticipated load requirements and, therefore, allocated upon demand. Gulf has never assigned line investment cost to specific customers. Some of the primary reasons are:

1. It would be very difficult to determine the line investment specifically serving one particular customer. Some very large customers might prove traceable but, if one accepted this methodology for a few large customers, it would only be equitable to do so for smaller customers. These smaller customers would be most onerous to trace.
2. If one did assign so called "dedicated taps," one would have to first determine the total investment in taps, segregate it from investment in networks and then remove dedicated ones leaving "common taps." The common taps would then be allocated to common customers only. To do otherwise would risk associating taps with these dedicated customers twice, once through the assignment process and second, through the allocation process.
3. A further delineation of load flow would prove necessary. The load from customers served by common taps would be placed into a demand allocator for the cost of common taps. Then, the load for these common customers must be combined with the load from

customers using dedicated taps in order to produce an allocator for the common network.

4. A tap serving one customer today may serve two or more customers tomorrow. Gulf does not generally incur large investments in lines designed to specifically serve one customer over the entire life of the line. What originally began as a line serving one customer may have new customers added to the line. Also, the line may become a closed loop which would serve many more customers. Given these possibilities, an annual review of dedicated taps would be required.

5. Where does the dedicated tap begin? Can this beginning point change as customers are added?

6. Not only would the accounting and load flows segregation be most difficult, but the cost of service model could require extensive revisions.

7. All the required effort would result in insignificant effects on the cost-of-service results. It is estimated that only 2 percent to 4 percent of lines investment would prove to be dedicated at a particular point in time. Due to the difficulty of ascertaining the specific cost of these facilities and the required annual updates, it is not certain that the results of the cost of service study would

be any more accurate at any decimal level even if one could perform this most difficult task. Mr. Howell discusses the system planning aspects of direct assignment of taps and gives a real example of why Mr. Wright's concept of dedicated taps is not appropriate for a utility such as Gulf.

ALLOCATION OF PLANT SCHERER

Q. **Do you agree with Dr. Johnson's statement that Plant Scherer should be considered a surcharge?**

A. No. I do not. Plant Scherer is definitely considered a production resource during the 1990 test period for the reasons fully explained by Messers. Parsons, Scarbrough, and Howell. As such, its allocation on a production allocator is entirely appropriate.

Q. **If it were to be considered a surcharge, should it be allocated upon revenues?**

A. No. It should not. If it were deemed appropriate to consider it as a surcharge, the basic reason that it would be so placed is that it would become used and useful as generating resource in the future. When it then did become an acknowledged production resource in the future, surely it would receive a production type of allocation.

Although it is not entirely clear, I presume Dr. Johnson is advocating the isolation of Plant Scherer's cost and the allocation of this cost in the cost of service study upon revenues. A revenue allocation, however, is actually an indirect allocation result of the cost of all services which have been allocated upon the direct allocators of KWH, KW, and number of customers. This revenue allocation result involves all functions of the utility: Production, Transmission, Distribution, Customer Accounting, and Customer Assistance. Plant Scherer is a production plant and to utilize an allocator also influenced by transmission, distribution, customer accounting, and customer assistance is illogical and certainly not cost based.

In addition, a cost-benefit inequity would result. If Plant Scherer were allocated in its early, more expensive years upon revenues, and during its cheaper, depreciated years upon a production allocator when its resource benefits were being enjoyed, we would have customers who were strongly affected by transmission, distribution, customer accounting, and customer assistance, paying for Plant Scherer but failing to enjoy commensurate benefits of the cheaper resource cost when it was deemed used and useful due to the same customers' smaller sensitivity to pure production allocation. To create this cost-benefit inequity would be incongruous and senseless. Plant Scherer is a production plant today, tomorrow, and until it is retired.

VOLTAGE DIFFERENTIATED RATES

Q. **What is your opinion on voltage differentiated rates?**

A. I do not disagree with the theoretical concept of voltage differentiated rates. In fact, Gulf currently has voltage differentiated rates and is proposing a cost based transformation discount in this docket.

Q. **Do you concur with Dr. Johnson's voltage differentiated rates?**

A. I do believe that if possible they should be cost based. Unfortunately, Dr. Johnson's procedure is not cost based in terms of unit cost. It would produce a discount, but that discount could be above or below what the true cost based discount should be.

Q. **Can you elaborate further on this distinction between Dr. Johnson's procedure and a pure unit cost method?**

A. His procedure appears to depend upon a factor which contains two ingredients: (1) The numerator represents his cost of serving the customers as they exist in the rate class from the uppermost voltage level down through the voltage level in question, and (2) the denominator reflects the total cost to serve all customers as they exist in the rate class, or as he terms it on his direct testimony, page 18, line 13, the average cost of LP/LPT service. So, in effect what we are dealing with is the cost of serving various loads at different voltage levels which is somewhat different from the cost of serving the same load at two different service levels. In order to base a discount on pure unit cost, one needs to determine the cost to serve a KW at level 5 and the cost to serve that same KW at level 2. The difference can then be used to accurately develop the discount.

Q. **What is your recommendation?**

A. If this Commission decides to implement voltage level differentiated rates for LP/LPT, implementation should be based upon a cumulative unit cost analysis which properly considers the cost differentials involved in serving separate voltage levels.

TRANSFORMATION DISCOUNTS

Q. **Do you agree with Dr. Johnson that a transformation discount is warranted?**

A. There is nothing wrong with a transformation discount where customers have purchased their own transformers. However, if one is advocating voltage differentiated rates, as he apparently is, one should not also give a transformation discount. This would provide a credit twice for the avoided transformation cost, since the discount would already have been embedded in the discounted voltage differentiated rates in this instance.

Q. **Is there a discount developed in this rate proceeding that reflects the cost to Gulf Power Company of transformation equipment?**

A. Yes. Gulf's responses to Interrogatories No. 110 and No. 111 of Staff's Eighth Set in this docket provide a discount for transformation cost. These discounts by rate class and by voltage level for customer owned transformation are shown below:

	Primary	Transmission
GSD/GSDT	$0.35/KW	$0.41/KW
LP/LPT	$0.42/KW	$0.52/KW
PX/PXT	N/A	$0.11/KW

In addition, in Interrogatory No. 113 of Staff's Eighth Set the following discounts were developed for metering voltage discounts to account for the reduction in line and transformation losses as a result of the customer taking service above the secondary distribution level. These discounts by rate class and by voltage level for customer owned transformation are shown below:

GSD/GSDT & LP/LPT	Primary	Transmission
Energy Discount	.82%	1.8313%
Demand Discount	1.26%	2.632%
PX/PXT		
Demand Discount		1.35531%
Energy Discount		1.00312%

Q. Does this conclude your rebuttal testimony?
A. Yes. It does.

Q (By Mr. Stone) Mr. O'Sheasy, please summarize your rebuttal testimony.

A The purpose of my rebuttal testimony is to review several cost of service issues raised by other parties and to reveal the correct solution to these issues by Gulf Power Companpy. It is of utmost importance that we concentrate on the solutions most appropriate for Gulf Power Company.

We must recognize that Gulf Power Company serves a unique section of the State of Florida and is a member of one of the largest utility systems in this country. As a result, depending on the issue, what may be appropriately or arbitrarily defined for a utility in Michigan or Tampa Electric Company, is not necessarily correct for Gulf Power Company.

I would like to point to the correct allocation methodology for Gulf's production plant costs. Also, please bear in mind that we are allocating the embedded costs on Gulf Power's books and records. We are not charged with performing a marginal cost study or an incremental analysis on what a visionary may think will cause cost incurrence in the future. Therefore, we must only consider what caused the embedded cost on Gulf's books in this test period to be incurred. This is a critical point.

12 MCP and one-thirteenth is correct for our Company for the following reasons: It recognizes Gulf's generating system was built to serve, and indeed must serve, peak load requirements every month of the year. The 12 MCP concept conforms well with load requirements Gulf's planners were asked to meet when Gulf's current system was constructed. This Commission has recognized this fact and required its usage by Gulf since the early '80s. It recognizes the fact that most scheduled maintenance is performed in off-peak months. It acknowledges that Gulf Power is a member of a very large pool; as a result, incurs monthly IIC cost based upon each and every month's coincident peak. In addition to being this Commission's stated method for Gulf, it's the FERC's preferred method.

Finally one must consider the ultimate ramifications upon rate design.

Our customers are well experienced with the price signals of 12 MCP and one-thirteenth. These prices were ingredients in the anticipation of future costs. 12 MCP produces stable results for major rate classes and our customers expect to see the consistent price signals which it has and will send.

Finally, Gulf's generating plant is indeed sensitive to the seasons but certainly not absent during nonsummer months.

Capital substitution theories such as equivalent peaker and refined equivalent peaker have presumptions that are embedded in system planning. However, those few assumptions are woefully inadequate to properly reflect Gulf's system planning and EP and REP methodologies ignore far too many considerations to justify their usage for Gulf Company.

There are at leaste four major obstacles preventing an equivalent peaker, refined equivalent peaker usage, for allocating Gulf Power Company's generating plant cost. It is a major oversimplification of the system planning process. It raises some most complex analytical modeling problems. It possesses additional theoretical revenue considerations that may be addressed, that must be addressed, if one accepts the basic premise. And finally, it evokes considerable rate design problems.

All of this considered, the bottom line denominator which we must consider in determining an allocation methodology for Gulf's production plant, is what were the cost causative factors which caused Gulf's current system and result in embedded cost being incurred? Not a speculative factor which may cause future costs to be incurred.

In other words, this is not a marginal or incremental analysis, is it an embedded cost of service study. Gulf System planning witness, Bill Howell, very clearly points out the history of cost incurrence for Gulf's current system.

He further notes that adoption of complex computer driven planning models which possess a myriad of considerations, relatively recent enhancments. Gulf's system was built to serve peak requirements throughout the year, the 12 MCP and one-thirteenth methodology, in which we believe reflects this most appropriately.

The other issue I'd like to highlight in my oral summary is the allocation of investment in lines. Gulf's delivery system, both at the transmission level and primary distribution level, should be shown as a network with spokes or taps branching off the load centers. The vast majority of these taps serve a load center serving numberous customers.

Very few of these taps may appear at a particular point in time to serve only one customer. The cost of the network and all taps are allocated to all customers who impose a related demand on the system. The clear rationale for not assigning a particular tap which may only be serving one customer at a particular point in time, to that particular customer rate group is as follows: Number one, in general, Gulf does not plan their electrical delivery system for the purpose of serving one mere customer.

It is much too expensive to construct large expensive taps for one customer. The idea is that a tap serving this particular customer today, will accommodate additional customer growth tomorrow, or may increase system stability or reliability in adjoining load centers.

Two, from a accounting standpoint it would be most difficult to trace these line costs, plus an annual review would be necessary to determine if new customers had been added off of this tap.

Three, the allocation process would require additional complexity. Line investment would need to be divided into three subcategories; the network, common taps and dedicated taps. The load development would be complicated in that load from common tap customers would need to be segregated from dedicated tap customers, and an allocator developed for the common customers; otherwise, you would risk charging the customer with the assigned tap twice; once in the assignment process, once in the allocation process.

However, the load for common and dedicated customers would have to be combined for the purpose of developing an allocator for the common network. And finally, all of this effort would prove to be relatively diminimus. We've estimated that at any one particular point in time, only 2 to 4% of all all lines serve only one customer.

So, in effect, this would prove expensive, complex and would not improve the results of the Cost of Service Study to any significant degree, and would not in deed reflect cost causation.

This conclude my oral summary.

MR. STONE: I tender the witness.

CHAIRMAN WILSON: Mr. Burgess.

CROSS EXAMINATION

BY MR. BURGESS:

Q Mr. O'Sheasy, what is the break-even number?

A 1,430 hours.

Q Would you please briefly describe how that is calculated?

A Certainly. We evaluated two alternatives, a combustion turbine, and a coal unit, and we looked at the fixed cost of each technology versus the running cost of each technology, and computed from a algebraic relationship a break-even point.

Q The object then is the break-even point at which there is a neutrality of total cost?

A That's correct.

Q And as I understand it, the more kilowatt hours that are used as you go up in the number of kilowatt hours that are to be sold out of it, then it's begins to lean more heavily toward the baseload unit as being the more cost effective?

A Yes, I think you could draw that conclusion, everything else being equal.

Q Okay. So in the calculation you've got the fixed cost of each, and then you try to determine the number of running hours that is required to make the two costs equate, is that correct? The total cost of those two?

A That's correct.

Q And as I understand it, incorporated in that calculation is -- the hours that you use are the highest demand hours of the year, is that correct?

A In terms of developing the allocator that we used for the refind equivalent peaker study?

Q Yes.

A We did select the highest 1,430 hours for that allocator. In the break-even analysis you're not looking at particular hours.

Q I'm not sure I understand. Basically, the number of hours that determines break-even; what really determines the break-even point is the kilowatt hours generated, is that correct? For the variable O&M cost?

A It's the hours necessary to equate the two total cost lines or curves.

Q You're saying that in the calculation of the break-even point, it does not involve the highest, what is ultimately calculated as 1,430 hours, is that the 1,430 hours of highest demand of the year?

A It's just a mathematical relationship and it's just trying to determine how many hours it would take to equate the two technologies.

Q But the number of hours it would take also depends on the amount of demand in a given hour, is that correct?

A I'm not sure I understand that statement?

Q Well, if the demand is higher in a given hour than another hour, than the higher demand hour would draw more kilowatt hours than would the lower demand hour, is that correct?

A If you're comparing two hours, and one hour has a higher demand than the other, it would be a resultant larger kilowatt hour measurement underneath that particular hour.

Q And does that affect the break-even point?

A Break-even point?

Q As to the number of hours.

A No. I think you're confusing two different issues here.

What we're saying is, you've got a combustion turbine, for example, the cost might be -- just to throw out a number -- $50 per kW, plus 7 cents per kilowatt hour. And then you have an equivalent equation for a base unit and it might be $200 per kilowatt hour and 2 cents, excuse me, $200 per kilowatt and 2 cents per kilowatt hour, and you're merely looking at the number of hours it takes to justify or equate those two technologies, and it's basically a per kW analysis.

You're not looking at a load shape and saying, "Okay, how many kW do we have here and how many kW do we have during this hour?" It's a per kW analysis.

Q Is the amount of variable O&M cost driven by the amount of kWh?

A Say that again, please?

Q Is the amount of O&M, the variable O&M cost from each plant driven by the amount of kW that would be served by each plant?

A The presumption in our models is that the cost per kilowatt hour, for running costs, does not vary with hours of run time. In other words, it's constant.

Now, that might not be entirely true as you dispatch your plants, of course, but it was relatively true.

Q Thank you, Mr. O'Sheasy, that's all I have.

CROSS EXAMINATION

BY MAJOR ENDERS:

Q Mr. O'Sheasy, you don't disagree with the concept of the voltage differentiated rates, do you?

A Not if they are cost-based.

Q And you also don't disagree with transformation discounts?

A That's correct. I don't disagree with them. I don't think you should -- well, I don't think if in your voltage differentiated rate you are compensating for avoided transformation costs, I don't believe you need a transformation discount in addition to a voltage --

Q Well, in fact, Gulf in this docket currently has voltage differentiated rates and has proposed a cost-based transformation discount, is that not correct?

A Gulf has proposed transformation discounts.

What are you referring to when you say, "voltage differentiated rates?"

Q I don't want to get into your discussion of Dr. Johnson's voltage differentiated rates. You could bring that up with Mr. Stone.

Let's go to Page 26 of your rebuttal testimony.

A All right.

Q Line 19, you reference question one-thirteenth in Staff's Eighth Set of interrogatories, and that's Exhibit 269 in this case, and you made the calculation.

A That's correct.

Q What in your calculation did you exclude in developing your metering voltage discount? (Pause)

A Basically, it's what we have represented in these loss factors here, are the losses incurred in making the transformation from primary voltage down to secondary voltage

Q Let me ask you a few questions to follow up on that. Did you exclude line losses?

A Yes.

Q Did you exclude other voltage stepdown, say from Level 3 to 4?

A Yes.

Q Did you exclude other secondary costs avoided by customers at higher voltage?

A I'm not sure I understand what you're asking this?

Q Poles, conductors.

A Maybe I can answer it another way. The line loss factor which you see here specified as distribution line transformers, is only the losses incurred in making that distribution line transformation, and the losses that are represented are reflected in making the transformation from transmission to primary, are only the losses made in making the transformation from transmission voltage to primary distribution voltage. And they do exclude any inherent line losses in the system.

Q Wjould it be fair to say that your proposal understates the credit that should be given to higher voltage customers?

A I don't think it's fair to say that, or I'm not drawing that conclusion. I'm just stating what I was asked to do, which was produce these loss factors in this setting and that's what I did.

Q And the Staff was the one that asked you to did that?

A That's correct.

MAJ. ENDERS: I have no further questions.

CROSS EXAMINATION

BY MR. McWHIRTER:

Q Mr. O'Sheasy, is Gulf Power more likely to operate peakers during the time of the highest 1,430 hours per year than other times? I guess that means the 1,430 hours when the greatest demand is on your system as opposed to the other times.

A Intuitively one would think so but as a matter of record, Gulf does not have a significant amount of combustion turbines at this time. But intuitively speaking, one would expect to run peakers more often during peak times than nonpeak times.

Q How about if you had a major unit down for maintenance during the shoulder period?

A Well, it all depends on what you've got available. You -- depending on your mix of units, you could easily have, you could have a baseload unit that could run during those times.

But it is also conceivable that you could have a combustion turbine running while the base unit was down.

Q Is it fair to say that you believe the 12-CP method to be the soundest allocation method presented in this case?

A Most definitely.

Q If the Commission didn't follow your concept but determined that the equivalent peaker concept might be more effective, which of the EP studies filed in this docket do you think would be more appropriate? The one filed by Mr. Wright of the refined equivalent peaker study requested by the Staff, or the corrected refined equivalent peaker method filed by Mr. Pollock?

A I don't particular like any one of those studies. In general, my -- if I had to choose between a capital substitution theory, I would prefer one that embedded the refined equivalent peaker concept.

Q As opposed to the corrected refined equivalent peaker which takes fuel symmetry into consideration?

A I believe that a fuel symmetry adjustment is probably warranted, but I'm not sure at this juncture because I don't -- I don't necessarily believe that that philosophy is best for Gulf. So I don't -- I'm not sure at this juncture what is the correct fuel symmetry adjustment to make, but I do believe that one is probably warranted.

Q If this Commission adopted an equivalent peaker concept, would it be in the avant-garde of commissions throughout the United States in undertaking such an endeavor, in your opinion?

A In the systems that I'm familiar with, yes.

Q If the EP concept were adopted, should the 12-CP method be used to allocate the demand-related investment?

A No. I don't believe so.

Q Should the energy-related investment be allocated to classes relative to their year-round energy?

A No. I believe that, based on my preference for the refined equivalent peaker concept, that you should consider the hours up to the break-even point and the energy within.

Q How should the energy investment be allocated, to the hours up to the break-even point or after that?

A Up to the break-even point.

Q Is it your testimony that some adjustment is necessary to recognize fuel symmetry? You have just said yes.

A Yes. I believe so.

Q What is your understanding of fuel symmetry?

A Basically, if one accepts capital substitution theory as opposed to a peaker philosophy -- excuse me, coincident peak philosophy -- you must accept that there are two ingredients to this theory, this capital substitution theory. One is the fixed cost ingredient, the other is the running cost ingredient. And you can't divorce one from the other; they go hand-in-hand. And you must consider, therefore, how your running cost is being considered in terms of cost allocation. At the same time, you consider how your capital costs will be allocated.

And I'm afraid that, with the capital substitution theory and the way we are considering allocating fixed costs, the running cost allocation is going to be out of sync with that theory.

Q That's Mr. Wright's theory? Or even the refined equivalent.

A Yeah, I'm not -- when you say "Mr. Wright's," I believe that a fuel symmetry adjustment is probably warranted for both methods, both equivalent peaker and refined equivalent peaker.

Q If Mr. Wright's equivalent peaker or the REP concept were adopted, do you foresee any adverse impacts on customers in terms of pricing signals?

A Yes. I do. I've gone over this with the marketing people at our company very thoroughly and there would be a significant shift or transfer of cost not only between rates but between components within a rate.

Your demand cost would go down considerably. Your energy cost would go up considerably. And I'm afraid our customers have been used to the price signals that we have been sending them in a particular relationship. And if we change that relationship, there is going to be some severe adjustments that will have to be taken into account. Our customers are going to react unfavorably in many situations.

Q Is one of the reactions that they might leave the system and become cogenerators?

A I think that's a possibility, but I'm not really the authority to address that.

MR. McWHIRTER: I tender the witness.

CROSS EXAMINATION

BY MR. PALECKI:

Q You state on Page 25, Lines 14 through 18, "If voltage level rates are adopted for LP/LPT, that they should be based on a cumulative unit cost analysis which considers the cost differentials of serving separate voltage levels."

Would you please elaborate on what a cumulative unit cost analysis is and what it's designed to accomplish.

A Certainly. A cumulative unit cost analysis indicates what the cost is to serve a particular load at a particular voltage level and that same load at another voltage level.

For example, if we wanted to know what the cost to serve a customer at transmission voltage was per kW, it might fall out to be $4 per kW. Well, then the next question is what is the resultant cost to serve that same load, it's a prime distribution voltage. And a cumulative unit cost analysis would do that. It would tack on, in effect, to the $4 charge at transmission, the extra incremental cost to get that load down to primary distribution. And that's what we mean by cumulative unit cost analysis. And one could subtract those two numbers to get a feel for what the incremental cost is in serving that lower voltage level.

Q Would you agree that if the rates are differentiated by voltage levels for LP/LPT, it would be equitable to do so for all demand rate customers?

A It's my observation that it might be equitable, but it might not be necessary. It's the LP/LPT class seems to have a wider dispersion of customers over voltage levels than most other rates. Most other rates seem to be concentrated on a few particular voltage levels. So any variance, any costs and benefit in equity between average embedded ratemaking and charging a customer wherever he falls, that problem is not as paramount in other rates as it is in the LP/LPT.

Q Does Gulf attempt to build the most economical or cost effective transmission and distribution system for serving its customers?

A Yes.

Q Would you agree that there may be situations when customers do not have the choice of voltage levels due to the Company's need for building the most economical transmission and/or distribution system?

A That's a possibility.

Q Would you agree that for these special circumstances that additional lines, conductors and/or substations would have to be built to meet the customers' needs, resulting in uneconomic expense to the general ratepayers?

A I suppose that's possible.

Q If this plant cost were collected through rates, wouldn't the average rates for all classes of customers increase according to their allocated share of the rate base?

A In your hypothesis there, it certainly would. But that's no different from any change in our system.

Every time we add a customer, more than likely to some degree we're going to have to add more current investment cost, which is going to be more expensive than older vintage embedded cost, so that the average cost to all customers would go up.

Q Is it your understanding that past Commission policy in rate cases has been to recognize the avoided transformation costs in the transformer voltage discount and the associated core losses associated with transformation as the metering voltage discount?

A Yes.

Q Are you aware that both Florida Power Corporation and Tampa Electric Company have transformer ownership discounts and metering voltage discounts designed in this manner?

A I have been told that. I'm not fluent in that, but I have been told that.

MR. PALECKI: Thank you. Staff has no further questions.

COMMISSIONER GUNTER: Commissioners? Redirect?

REDIRECT EXAMINATION

BY MR. STONE:

Q Mr. O'Sheasy, you've testified on to the relative effects between the equivalent peaker and the

12-CP method. What would happen to the peak demand usage on an equivalent peaker type of concept relative to the 12-CP method?

A Because the unit cost would, for demand, would go down using this concept. If that was translated into the actual rate design, then I could perceive where the customer would not be as sensitive to curbing his peak load usage. And he would be more sensitive to controlling his kilowatt hour usage than he would currently be. So it would not surprise me to see a load factor deterioration.

In other words, peak usage could go up and off-peak usage could go down as a result.

Q What effect would that load factor deterioration have on the ratepayers as a whole?

A Well, in general, it would cause the per-unit cost to go up.

MR. STONE: That completes our redirect.

MR. PALECKI: At this time, Staff would like to readdress the issue of the late-filed exhibit that Mr. O'Sheasy was asked to provide by Staff.

There was not a ruling by the Commission; it was a deferred ruling. We had represented that we thought further testimony that came out during the hearing would point out the need for this particular cost of service study. And Staff's opinion is that there has been substantial testimony which has pointed out that need, and we'd like to go into that now, if it's the Commission's pleasure.

RECROSS EXAMINATION

BY MR. PALECKI:

Q This is a cost of service study in which we asked that the SE class be broken into two classes, SE/PXT and SE/LPT. And since the original testimony, Witness Wright has testified that he thinks there is an underrecovery of substation costs to PXT customers taking service on the SE rider. He also indicated that underrecovery of production and transmission plant depends on the ratio of billing kW to 12-CP kW. The ratios for the billing kW to 12-CP for SE/PXT, versus PXT and SE/LPT, indicate there is a problem of underrecovery in these classes.

Third, a change in the rate of return for PXT with and without one SE customer -- it was an SE customer that switched -- from 8.92 without the one customer to 8.33 with the one customer, shows that a single customer has a great impact on this class. And for that reason, we think that the cost of service study is fully warranted that we've requested.

I think there's sufficient indication that there is an underrecovery or a very high likelihood of an underrecovery to the PXT customers taking service on the SE rider and, therefore, we would, once again, request the late-filed exhibit that we previously requested.

And we have written guidelines that we would submit to the Company and to the witness for the guidelines we would like the cost of service study run on.

MR. McWHIRTER: I have a visceral aversion to a late-filed exhibit developed under guidelines we haven't seen before. Obviously this affects one of my clients. I'm not sure that all the appropriate guidelines are included in it. I am not sure that whe.. the information is provided we would have an opportunity to give facts that might relevant to the circumstances, and it's possible that that exhibit will come in, you know, much later, just before decision is rendered. And it is kind of scary, unless we can come up with scme safeguards about we can be entitled to due process protection.

MR. PALECKI: Commissioners, we stated the guidelines --

COMMISSIONER GUNTER: One at a time. You've stated your argument. Company?

MR. STONE: Commissioner, if I may, although they have stated the guidelines, they were stated a long time ago, and I've never had an opportunity to actually read them, and as usual, these guidelines are quite lengthy. If we might have a few moments to look over these guidelines, I might be in a position to fully respond.

COMMISSIONER GUNTER: Why don't we take about a five-minute break.

(Brief recess.)

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MR. STONE: Mr. Chairman, we are discussing once again Staff's request for two additional cost of service studies. These would be cost of service studies in addition to the 11 that have already been prepared in this case. It is the Company's contention that this request for additional cost of service studies at this point is either more properly addressed in discovery and therefore moot, because we are well past the period of discovery, or it is more on the lines of an academic exercise and would not render useful information to the Commission's decision.

The testimony of Mr. Pollock and Mr. O'Sheasy clearly indicates that they do not believe it would render any significant result.

The only testimony supportive of such a study is that of Mr. Wright. However, Mr. Wright could offer no definitive evidence to support his theory that there might be an underrecovery problem. It seems to me that considering the burden of having to prepare these additional cost of service studies at this late date is not warranted considering the value, the limited value that such a study would provide this Commission.

It is with great concern that the Company objects to the requests, but we feel that it is important to recognize that there is a time when you must cut off the process of discovery, and we believe that time has long since been exceeded.

In terms of the results of any potential study, it would require a modeling assumption to model what the SE customers would have done had there not been SE. The Company is not in the position of being able to get into the minds of the SE customers to resolve that dilemma, and it is for that reason that we believe any results that might come out of this study would have no value and do not warrant the burden it would undertake for us to produce them.

MR. PALECKI: Unless there are any questions from the Commissioners, Staff would rely on its previous arguments.

CHAIRMAN WILSON: Well, I'm unconvinced that it will really produce information that's going to be very useful to you. So I'm -- I don't know what -- deny, disallow, whatever.

MR. STONE: I guess you would deny Staff's request.

CHAIRMAN WILSON: Fine.

MR. STONE: With that, Commissioner, may Mr. O'Sheasy be excused from further attendance of these hearings?

CHAIRMAN WILSON: No further questions?

Yes, he may. Thank you.

(Witness O'Sheasy excused.)

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MR. STONE: The next witness is Jack Haskins.

(Pause)

Mr. Chairman, may we proceed?

CHAIRMAN WILSON: Yes.

JACK L. HASKINS

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

DIRECT EXAMINATION

BY MR. STONE:

Q Mr. Haskins, you have previously been sworn and have previously testified in this docket, and I believe you have also prefiled rebuttal testimony in this docket dated May 21, 1990, is that correct?

A Yes, it is.

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

A Yes, I have corrections on two pages. The first is on Page 8 at Line 19, change the words "response to an interrogatory" to "the minimum bill provisions of the PX/PXT tariffs."

Q Just so that -- since that was such a lengthy response, would you now read the Line 19 as it would read with your change?

A Line 19 would now read, "was proposed in the minimum bill provisions of the PX/PXT tariffs."

Q "In the"?

A "In the," that's correct.

On Page 39, on Line 12, delete the words, "the unit costs in the." There's no addition there.

And then on the next line, Line 13, delete the word "study."

Q With these changes, would your responses to the questions in your prefiled rebuttal testimony be the same?

A Yes.

Q We ask that his prefiled rebuttal testimony be inserted into the record as though read.

CHAIRMAN WILSON: It will be so inserted into the record without objection.

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GULF POWER COMPANY

Before the Florida Public Service Commission
Rebuttal Testimony of
Jack L. Haskins
In Support of Rate Relief
Docket No. 891345-EI
Date of Filing: May 21, 1990

Q. **Mr. Haskins, have you previously submitted testimony in this proceeding?**

A. Yes. I submitted direct prefiled testimony in this proceeding in support of the filed rates for Gulf Power Company.

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

A. Yes.

Counsel: We ask that Mr. Haskins' Exhibit (JLH-2) comprised of eight Schedules be marked for identification as Exhibit Nos. 241-248

Q. **Do you have any corrections or additions to the testimony and exhibits you have previously filed?**

A. Yes. We have revised my Schedules 1, 2, and 5 as shown in my prefiled direct testimony based on the results of the revised cost of service study and rate design as submitted in Industrial Intervenor's Second Set of Interrogatories, Nos. 12 and 13, and Industrial Intervenor's Second Request for Production of

Documents, No. 27. These three schedules, "Analysis of Proposed Revenue by Rate 12 Months Ending December 1990," "Rates of Return by Rate Class," and "Average Cost of Localized Investment" are shown as Schedules 1, 2, and 3, respectively, in my exhibit to this testimony. For convenience, we are referring to the revised study as the "No Migration" study.

Q. Have you reviewed the testimony and exhibits of the witnesses intervening in this proceeding?

A. Yes.

Q. Do the subjects addressed in the testimony of Scheffel Wright, Jeffry Pollock, Dr. Charles Johnson, and Tom Kisla fall in your area of responsibility?

A. Yes. In addition to addressing various aspects of their testimony, my rebuttal testimony will also address some of the issues raised by intervenors, Staff, and Gulf Power Company.

Q. How did you develop the proposed customer charges?

A. The unit costs from Mr. O'Sheasy's cost of service study were used as the starting point in selecting the various customer charges. The subsequent development of the proposed charges is discussed fully in my prefiled direct testimony on pages 7-11. No other testimony supporting any other charges has been submitted by any party in these proceedings other than Mr. Wright, who stated that the customer charges should be cost based.

Q. **How did you determine the proposed standard demand charges?**

A. Again, the first consideration was the demand unit cost from Mr. O'Sheasy's cost of service study. The subsequent development of the proposed charges is discussed in my direct testimony beginning on page 14. With the exception of Dr. Johnson's LP/LPT rates, no other witness has offered testimony supporting any other demand charges for standard rates GSD, LP, or PX.

Q. **How did you determine the demand charges which are included in Gulf's proposed TOU rates?**

A. As stated in my direct testimony on pages 18-20, the Load Factor Methodology that has been used and approved in our last three rate cases was the methodology chosen to design the demand charges for the TOU rates.

Q. What is this "Load Factor Methodology"?

A. This methodology is described extensively in my direct testimony which includes an example. This methodology utilizes the lower of class or system load factors to allocate revenues between on-peak and maximum demand charges. It provides a substantial incentive for customers to control their load so that their maximum demand coincides as little as possible with their peak period demand or vice-versa.

Q. Has any other party proposed a different method for determining TOU demand charges?

A. Yes. Witness Wright has proposed a method that would recover only a portion of distribution costs from the maximum demand charge. This charge would use the customer's highest measured demand occurring during the current or previous "ratchet period" of one to two years. Mr. Wright's proposal is essentially a proposal for a Local Facilities Charge for all demand metered customers. We appreciate his support in that regard since we are proposing a type of Local Facilities Charge for LP/LPT and PX/PXT customers. However, I do not believe his proposal is appropriate for a maximum demand charge. A customer who is able to shift most of his load off-peak could end up being subsidized by other customers since the maximum demand charge would not recover any production or transmission costs. Even if all usage is off-peak, there would still be some production and transmission costs incurred. Mr. Wright's proposal is a brief theoretical discussion, which has no regard for the effect implementation of his proposal might have on the affected customers. In fact, he cannot evaluate this effect because he has proposed no rates. The Staff has proposed the same methodology, without supporting testimony.

Further, when Mr. Wright's proposal is combined with his proposal on page 35 of his testimony to re-impose mandatory TOU rates, it could be devastating to those customers that simply cannot move demand from the on-peak period to the off-peak period.

Dr. Johnson's proposed LPT rate maintains the same ratios as Gulf's; however, his charges have to be higher to offset the much larger transformer ownership and metering voltage discounts that he is proposing.

Q. Are there any other views expressed in Mr. Wright's testimony and accompanying exhibits that cause you concern?

A. Yes. While we agree with Mr. Wright that costs do vary by the time of day and the time of year, we believe that time-of-use rates should be optional and not mandatory for all customers. In Gulf's 1982 rate case, a three commissioner panel imposed mandatory TOU rates on all of Gulf's large customers with demand over 2000 KW. A different three commissioner panel supported our views on mandatory TOU rates in Gulf's 1984 rate case and reversed the previous panel's decision. In this and other matters that affect their lives and business, electric customers expect fairness and equity. They also expect and deserve consistency of rates and regulations so that they can plan for the future with confidence. This consistency, or gradualism where change is necessary, is a basic principle that permeates all of Gulf's proposed rates. We see no concern for this principle in the proposals of Mr. Wright, although he purports to represent the citizens of the State of Florida.

Q. Since Gulf's methodology and Mr. Wright's are different in the area of TOU demand and energy charges, would you elaborate more on Gulf's TOU rate design methodology?

A. Yes. Each TOU rate was designed to be revenue neutral with its standard rate counterpart; that is, the TOU rates were designed to recover the proposed revenue for the class assuming all customers were on the TOU rate in lieu of the standard rate. The Load Factor Methodology was then used to calculate the TOU energy prices for rates RST and GST. It takes total energy related revenue and splits it into on-peak and off-peak energy related revenues. Total energy related revenue for rates RST and GST is just the total class revenue requirement less the revenues related to customer charges. After applying the class load factor, on-peak and off-peak energy related revenues are then divided by the number of on-peak and off-peak energy related billing determinants to obtain the energy prices.

The Load Factor Methodology was used to split the standard demand price, which was selected based on the demand unit cost from Mr. O'Sheasy's cost of service study and the resulting demand charge we proposed to maintain, into on-peak demand and maximum demand components. Then, for the LP/LPT rate a minimum off-peak energy charge of $0.00300 per kwh was selected to assure recovery of all non-fuel energy costs, and for the PXT rate an off-peak energy charge of $0.00260 per kwh was selected for the same reason. Through the iteration process, the off-peak energy charge for rate LPT was refined to $0.00303. The remaining revenue for LPT and PXT was used to develop the on-peak kilowatt hour charge.

Mr. Wright discusses an alternate methodology for determining energy charges, but again, does not express any concern for the effect his proposals may have on the customers he purports to represent. He has done no calculation, produced no costs, and offered no rates as alternatives to the Company's rates that were filed on December 15, 1989.

Q. On page 53 of Mr. Pollock's testimony, he refers to a revised Company proposal for the PX minimum bill provision. Where did the Company propose this revision?

A. In error, Mr. Pollock has included some language that was proposed in ~~response to an interrogatory~~ the minimum bill provisions in the withdrawn rate case, Docket No. 881167-EI. The revised proposals for the PX and PXT minimum bill provisions are shown in the Company's response to Interrogatory No. 144 of Staff's Eighth Set of Interrogatories in this Docket No. 891345-EI.

Q. Mr. Pollock states that the proposed PX minimum KW charge penalizes a PX customer with a monthly load factor of less than 75 percent even though the applicability section of the rate only requires an annual load factor of 75 percent. Would you agree with this statement?

A. Yes. We do agree with this statement regarding our original filed tariff. However, this situation has been corrected in our revised language for the PX/PXT minimum bill provisions as shown in the response to Interrogatory No. 144 (prices adjusted pursuant to No Migration study) of Staff's Eighth Set of Interrogatories and is shown below:

PX: Minimum Monthly Bill - In the event the customer's annual load factor for the current and preceding eleven months is less than 75 percent and in consideration of the readiness of the Company to furnish such service, the minimum monthly bill shall not be less than the customer charge plus $10.390 per KW of billing demand and the local facilities charge, if applicable.

PXT: Minimum Monthly Bill - In the event the customer's annual load factor for the current and preceding eleven months is less than 75 percent and in consideration of the readiness of the Company to furnish such service, the minimum monthly bill shall not be less than the customer charge plus $10.347 per KW of maximum billing demand and the local facilities charge, if applicable.

Q. Mr. Pollock recommends having a minimum annual billing demand charge with a true up provision. What are your thoughts about this alternative for the PX/PXT minimum bill provisions?

A. First, we agree with Mr. Pollock, as already stated, that a customer should not be penalized if his monthly load factor is less than 75 percent as long as his annual load factor is 75 percent or more. Further, we believe the PX/PXT minimum bills should be designed in such a way that the CED bill (includes customer, energy, and demand charges) would normally be more as long as the 75 percent annual load factor is maintained. Using the revised PXT rate and Mr. Pollock's methodology, an annual minimum bill demand charge of $124.16 per maximum annual on-peak KW was developed as shown below:

($10.347/kw)(12 months) = $124.16

This charge was then applied to the six PXT customers' billing determinants. As shown on my Schedule 4, Mr. Pollock's minimum annual billing demand charge would result in four of the six PXT customers paying less on the CED bill than their minimum annual charges, even though all six customers have annual load factors of 75 percent or more. However, Gulf's PXT minimum bill would be less than the CED bill. This difference in the relationship of the minimum bill to the CED bill when comparing Gulf's and

Mr. Pollock's methodologies is because Mr. Pollock uses the highest on-peak demand for the year and we use the customer's monthly maximum billing demand to calculate the minimum bill.

Because this is such a small class and the bills are reviewed monthly by customer accounting and marketing personnel, any customer who is consistently not meeting the annual load factor requirement can be readily identified and appropriate steps can be taken to place the customer on the appropriate rate. Let me emphasize again that if the annual load factor requirement is met, we do not choose to penalize a customer with a minimum bill in a month just because his load factor for that month is less than 75 percent.

Q. Mr. Wright states that Gulf's proposed minimum bill provision for the demand metered rates allows non-fuel energy and fuel charges to be used in the calculation of the minimum bill. If this is not correct, please explain how the minimum bill is calculated.

A. The proposed minimum bill provisions of all demand metered rates considers only the customer charge, demand charge, and local facilities charge, if applicable. This amount is then compared to the normal CED bill, and the customer pays the larger of the two. Whether the customer pays the minimum bill or the regular bill is irrelevant as far as the fuel charge because in either case the customer pays the same fuel charge. Further, if the customer is caught by the minimum bill provision, he would not pay the non-fuel energy charge. For clarification, my Schedule 5 shows an example of how a minimum bill for rate GSD would be calculated.

Q. The applicability clause of the three demand classes (GSD/GSDT, LP/LPT, and PX/PXT) is stated in terms of the amount of KW demand for which the customer contracts. Is this an appropriate basis for determining applicability?

A. Yes. This will especially be appropriate if the proposed Local Facilities Charge for rates LP, LPT, PX, and PXT is approved. Further, for a new customer you would have no actual demand upon which to base a contract or to determine which rate would be applicable. Thus, without a contract capacity, you would have no meaningful contract. We acknowledge that many of the LP or LPT customers listed on our response to Interrogatory No. 115 of Staff's Eighth Set of Interrogatories either do not have contracts, or their contract capacity is not consistent with their actual maximum demand. However, presently there is little reason to keep the contract capacity and actual maximum demand close as long as the substation is not overloaded and the customer is still on the proper rate, because the contract kw has no effect on the customer's bill. After the approval of the requested Local Facilities Charge, Gulf will initiate a review and possible revision of existing LP/LPT and PX/PXT contracts and the signing of appropriate new contracts with those LP/LPT customers who presently do not have a signed contract.

Q. The Local Facilities Charge that the Company has proposed for LP/LPT and PX/PXT customers would be applicable when the customer's highest billing demand for standard rates and highest maximum billing demand for TOU rates in the current and previous eleven months is less than 80 percent of the Capacity Required to be Maintained as specified in the Standard Form of Contract for Electric Power. The charge would be applied to all kw in excess of the billing kw necessary to reach 80 percent of the Capacity Required to be Maintained. Is it appropriate to base this charge on contract demand instead of actual demand?

A. Yes. As stated in response to the previous question, it may not be appropriate now with the existing LP/LPT contracts, but it will be appropriate if the Local Facilities Charge is approved. At that time all contracts will be reviewed or initiated to assure that the contract capacity represents the customer's actual demand requirement. If the charge was based on actual demand and we had a situation where facilities had been constructed to serve a particular load, then a customer would be under no obligation to pay for those facilities should he for some reason not use the load as contracted. This proposed Local Facilities Charge will protect other customers from having to subsidize these customers who on a temporary or permanent basis reduce their load or shut down completely. Such a customer would be obligated to pay at least the minimum monthly bill, which includes the Local Facilities Charge, if applicable, for the duration of the contract.

Q. The current GSD/GSDT and LP/LPT rate schedules have sections on the determination of billing demand that require that a certain minimum demand be charged if the customer does not actually use this minimum demand in the current or previous eleven months. Is this minimum demand provision appropriate for customers who opt for a higher rate class?

A. My answer to this question is a qualified no. While this might be a workable scenario, we do not have demand type meters on the majority of our GS/GST customers and thus do not readily know how many GS/GST customers would benefit from such a change. If this information were available and the bills associated with these GS/GST customers who might cross over could be compared with the GSD/GSDT costs, then this provision might have merit. Results of our initial analyses indicate that the GSD rate becomes cheaper than the GS rate as kw increases and also as load factor improves. At the proposed level of GS energy prices, these breakeven points are too low for reasonable implementation. However, if this relationship changes significantly as a result of other decisions in this case, then such a change may be workable; and if so, the Company would like to see it approved. Likewise, if this change is implemented for rates LP/LPT, we would need to redesign the rates to account for the change in the minimum demand provisions of the rate and the lost revenue that could result from any crossovers.

Q. The Company presently has seasonal rates for the RS and GS rate classes. Should seasonal rates be retained for RS and GS?

A. Yes. Gulf has offered seasonal RS and GS rates since 1962. We have been a summer peaking utility since the installation of air conditioning in the early 1950's. This trend is expected to continue into the foreseeable future. In fact, Gulf has had only two annual peaks occur in the winter season since the early 1950's. The primary purpose of seasonal rates is to reduce the growth of summer peak demand and to keep this differential from getting any worse. A secondary purpose is to improve the utilization of system resources. Seasonal rates historically have provided the customer a price signal with the effect of slowing the rate of growth in summer peak demand by minimizing the customer's use of electricity during the Company's peak period. Seasonal rates are simply time-differentiated rates based on an annual system load shape, much as daily TOU rates are based on daily system load shapes.

Q. Since Gulf still supports seasonal rates for rates RS and GS, why were seasonal demand rates not proposed?

A. We simply did not want to introduce the additional complexity of seasonal rates for those classes in this filing. Instead, we chose to just try to retain the seasonal rates we had on RS and GS and improve the differential we had on GS.

Q. If seasonal rates for RS and GS are continued, how should the rates be designed?

A. We propose to simply retain the same ratio of summer price to winter price as in the present RS rate and to apply this same ratio for the GS seasonal differential.

Q. Dr. Johnson proposed a different set of LP/LPT rates, transformer ownership discounts, and metering voltage discounts. Would Dr. Johnson's proposed charges and discounts produce the same revenue as Gulf's?

A. No. Dr. Johnson's rates would allow Gulf to collect $856,289.34 more in revenue than our original LP/LPT revenue target of $34,421,500 when rates are run in competition. I do not believe this would be allowed by the Commission. On the other hand, the ten LP/LPT FEA customers that he represents would generate $156,708.60 less in revenue than Gulf's original proposed rates. The remaining LP/LPT customers would be required to make up this deficit.

Q. **In Dr. Johnson's testimony, he addresses transformer ownership discounts--specifically for rates LP and LPT. What is the purpose of transformer ownership discounts?**

A. Some customers provide their own transformation. The transformer ownership discount is utilized to give these customers credit for transformation costs that are not incurred by the Company in order to serve these customers.

Q. **In what component of the demand rate does Gulf charge the transformation costs to customers?**

A. The demand charge component includes costs associated with all of the transformation necessary to provide service from the production plant down to the secondary distribution level. Thus, any customer providing his own transformation and taking service at a voltage level higher than secondary should be credited for those transformation costs not required to serve him. In other words, the Company returns that portion of the demand charge related to transformation to those customers to whom it does not apply.

Q. Gulf's present transmission transformer ownership discount is $.70/KW/month, and the present primary transformer ownership discount is $.25/KW/month. What do these prices represent?

A. These discounts are recognized as the amounts needed to account for the difference in the secondary tariff price and the rates associated with different voltage deliveries. The $.25/KW/month primary discount was approved by the Commission in Gulf's 1981 rate case, Docket No. 810136-EU, Order No. 10557. Between Gulf's 1981 and 1982 rate cases, the $.70/KW/month transmission discount was approved. Then both discounts were retained in the 1982 rate case, Docket No. 820150-EU, Order No. 11498. In both rate cases, the approved discounts were determined by the Commission and were not the ones proposed by Gulf.

Q. Why does the tariff for the demand rates provide a metering voltage discount in addition to a transformer ownership discount?

A. The transformer ownership discount gives the customer credit for transformation costs not required to serve that customer; however, it does not recognize the reduction in line and transformation losses as a result of the customer taking service above the secondary distribution level. The metering voltage discount does recognize this reduction in losses. A customer providing his own transformation and taking service at the primary voltage level would receive a primary transformer ownership discount of $.25/KW/month and an additional metering voltage discount of 1 percent of the energy charge and 1 percent of the demand charge under present rates. Likewise, a customer providing his own transformation and taking service at the transmission voltage level would receive a transmission transformer ownership discount of $.70/KW/month and an additional metering voltage discount of 2 percent of the energy charge and 2 percent of the demand charge under present rates.

Q. Is it appropriate to increase or decrease transformer ownership discounts at the same percentage as rates vary from unit costs?

A. Yes. If demand rates are set at unit cost from the cost of service study, then transformer ownership discounts should be set at their unit costs. However, if the demand rates do not fully recover the unit costs, then transformer ownership discounts should bear the same ratio to their unit costs as the demand charge does to its unit cost.

Q. **Is it appropriate to increase transformer ownership discounts at the same percentage as rates increase?**

A. No. An increase in a specific rate does not lead to the conclusion that differences between voltage classifications should increase accordingly. Overall costs at the corresponding levels may have increased or prices may be simply set closer to costs than under previous rates.

Q. **Does Gulf support retaining the present transformer ownership and metering voltage discounts?**

A. The Company proposes that the transformer ownership and metering voltage discounts, as developed in the Company's responses to Interrogatory Nos. 110, 111, and 113 of Staff's Eighth Set of Interrogatories, be approved after adjusting the transformer ownership discounts for the variance of demand charges from unit cost.

Q. **Should the SS and ISS rate schedules have provisions for both transformer ownership and metering voltage** discounts? If so, should the level of the discounts be set equal to the otherwise applicable rate schedule?

A. The SS and ISS rate schedules should provide for metering voltage discounts only, and the metering voltage discount should be applied to only the SS/ISS energy charges pursuant to the Commission's Order No. 17159 which states on page 15:

> The rate structure for backup and maintenance power service shall include a non-fuel energy charge set equal to the system energy unit cost, i.e., the total energy-related costs of the utility divided by total energy sales, with appropriate adjustments to reflect different line losses at different service voltage levels, if applicable.

Q. Should Gulf's proposed revisions to the language of the customer charge on the standby service rate schedules (SS and ISS) be approved?

A. No. As a result of the discussions with Staff, we agree that the wording of the customer charge section of the tariff needs to be revised in order to be in complete compliance with Order No. 17159. Shown below is a proposed revision to the customer charge section of the SS and ISS tariffs:

> <u>Customer Charge</u>
> A customer will pay a Standby Service customer charge of $25.00 plus the LP/LPT customer charge except for those customers taking supplementary service on rate PX/PXT. These customers will pay

the $25.00 Standby Service customer charge plus the PX/PXT customer charge.

Q. Should Gulf's proposed change in the definition of the capacity used to determine the applicable local facilities and fuel charges on the standby service rate schedules (SS and ISS) be approved?

A. No. Since this rate case was filed, we have worked with Staff on several revisions to the SS tariff. We now have a better understanding of how to apply the Local Facilities Charge for rate schedules SS and ISS. Even our present criteria for selecting the appropriate Local Facilities is not adequate because of an interpretation problem with capacities of 500 kw or more. This present inadequacy does not affect our current customers but may affect future standby customers and needs to be adjusted. Shown below is revised language for this charge:

<u>Local Facilities Charge</u> -

a. For those customers who have contracted for standby service capacity not less than 100 kw nor more than 499kw - $1.60/kw of BC.
b. For those customers who have contracted for standby service capacity not less than 500 kw - $1.35/kw of BC.
c. For those customers who have contracted for standby service capacity not less than 7500 kw and are taking supplementary service under the PX/PXT rate - $0.64/kw of BC.

In regard to fuel charges, shown below is revised language for that charge which will conform to the proposed Local Facilities Charge language shown above:

> <u>Fuel Charges</u> - Fuel charges as shown below will be applied to all Standby Service kwh:
>
> a. For those customers who have contracted for standby service capacity not less than 100 kw nor more than 499 kw, the fuel cost for rate schedules GSD/GSDT as shown on Sheet 6.15 will be applied.
>
> b. For those customers who have contracted for standby service capacity not less than 500 kw, the fuel cost for rate schedules LP/LPT as shown on Sheet 6.15 will be applied.
>
> c. For those customers who have contracted for standby service capacity not less than 7500 kw and are taking supplementary service under the PX/PXT rate, the fuel cost for rate schedules PX/PXT as shown on Sheet 6.15 will be applied.

Q. Should the proposed paragraph on the monthly charges for supplementary service on the SS and ISS rate schedule be approved?

A. Our reason for including the second sentence in that proposal was to clarify that a customer who contracts for 0 KW supplementary and uses only standby service must still pay the LP/LPT customer charge in addition to the $25.00 Standby Service customer charge. This condition affects only one of our present customers. Too much time and energy has already been consumed on the wording of this one paragraph. Thus, we will accept without further discussion whatever wording the Commission deems appropriate.

Q. Should the Interruptible Standby Service (ISS) tariff language be revised to comply with the final proposed Standby Service (SS) language if applicable?

A. Yes.

Q. In Dr. Johnson's testimony, he also supports fuel costs differentiated within a rate schedule by voltage level for LP and LPT rates. Has this change to the fuel cost adjustment ever been considered?

A. Yes. This subject has been addressed by the Commission in the past. However, Order No. 10289, Docket No. 810001-EU, page 3, states:

> Having reviewed the various retail class line loss allocation factors, we conclude that utilization of every factor is unnecessarily confusing. Certain customer classes of each utility have similar line loss factors, and those classes should be subject to the same multiplier.

Thus, for simplicity of design, application, and administration, the Commission has ordered that each class of fuel costs should represent the average voltage level losses for those customers. The purpose of the four rate groups is to serve as a proxy for voltage level. In any event, fuel cost recovery rate design is not a proper subject for these hearings on base rates.

Q. Are there any views expressed in the testimony and accompanying exhibits of Mr. Kisla that cause you concern?

A. Yes. It is noted that Mr. Kisla in his Table II for both the winter and summer scenarios shows the supplementary MW's for the four scenarios incorrectly. We need to emphasize that the contract for supplementary service gives the customer the option of using up to his contract capacity, but this capacity is not a substitute for standby service capacity. The supplementary service for the scenarios A and B would be 10.0 MW and for scenarios C and D would be 14.0 MW. The extra 5.0 MW in the winter and the 1.0 MW in the summer should be included as standby service as shown in the revised portion of the table on my Schedule 6.

Q. Mr. Pollock and Mr. Kisla both agree that a seasonal type of customer could be charged more standby demand than actually taken certain times of the year. Do you agree?

A. We understand their concern. It is certainly not the intention of the tariff to penalize customers with seasonal variations in their generation. We suggest that a modification be made in the formula and language as shown on Standby Service tariff sheet no.

6.30. This revision, as shown on my Schedule 7, would adjust the "maximum totalized customer generation output occurring in any interval between the end of the prior outage and the beginning of the current outage" portion of the formula for seasonal variation in generation output. In order for us to apply this adjustment to customers with seasonal generation, we would need any such customers to annually provide us a monthly schedule that would state what this monthly adjustment (kw) should be. For example, using the revised table in my Schedule 6 and a seasonal reduction of 4 MW from the winter to the summer season, if the maximum customer generation since the last outage occurred during a winter month with generation of 32 megawatts and the current outage is in a summer month (scenario C), then 32 MW - 4 MW - 14 MW - 5.5 MW = 8.5 MW standby service which is the same as if the maximum generation since the last outage occurred during a summer month with no seasonal adjustment in generation output. By properly utilizing the formula, a customer should never be charged for more standby service than that customer actually takes.

Q. Are there any other problem areas in Mr. Kisla's testimony?

A. Yes. In comparing his scenarios to the tariff at the bottom of his Table II, Mr. Kisla incorrectly stated the MAX for scenarios C and D at 32 MW. It should be 28 MW as shown in the "Summer Hot" column of Mr. Kisla's Table II. This correction would result in standby service of 8.5 MW and 14.0 MW in lieu of the incorrect amounts of 12.5 MW and 18.0 MW.

Q. Mr. Kisla has stated that subtracting the actual standby used results in a 5 MW discrepancy for each scenario. Do you agree with this statement?

A. No. As previously stated, for the winter scenarios Mr. Kisla counted 5 MW as supplementary service, and for the summer scenarios counted 1 MW as supplementary service when in actuality these are standby service MW's.

Q. Mr. Kisla has recommended calculating the daily standby service demand by taking the difference between the highest on-peak readings in each day of an outage and the highest on-peak reading during a non outage period of the same billing period. What is your opinion of this method?

A. First, this method would not work if a customer took supplementary service with the SE rider applied. Use of SE would inflate the customer's normal usage pattern and cause the customer to pay less for standby than actually taken. In addition, because outages can extend beyond one billing period, you may not be able to select the two readings in the same billing period. Further, considerable thought and time have been spent on the present wording of the determination of standby service (kw) rendered section of the SS tariff utilizing input from Commission Staff, Company employees, and our customers. We were striving for a method that would make the calculation of standby service demand more exact and eliminate any guesswork. We believe that, with our previously proposed inclusion of an adjustment for seasonal variation in generation output, that this method will work well. We did, however, calculate the standby service demand for the four scenarios in Mr. Kisla's Table II using his methodology. With this set of variables, the standby service calculated per the tariff, modified as I have proposed, and per Mr. Kisla's methodology are the same as shown on my Schedule 8 including the correction I discussed on page 26.

Q. Why did Gulf choose the customer's highest generation output since the end of the previous outage and the beginning of the current outage in the formula instead of the customer's normal generation?

A. First, we were trying to remedy a problem that developed with the wording on the standby service demand determination section of the tariff when the SS tariff was revised February 1, 1990. Our goal, as stated previously, was to come up with a methodology that would make the determination of the daily standby service demand a much easier and more exact task. The previous method of selecting the generation in the second prior interval was at times a hindrance to the customer. Normally, if the customer experiences an outage, it may not be immediate but demand may ramp up for several demand intervals. Thus by just comparing the second prior interval, this would not necessarily be the customer's "normal generation." We also believed that using a so-called "normal generation demand" was not specific enough. Thus we chose to use the maximum generation since the last outage as the so-called "normal generation." We believe this is more representative of the customer's normal generation. The inclusion of the new adjustment for seasonal variation in generation output in the formula will take care of any seasonal types of variation in generation.

Q. **Mr. Kisla, as well as Mr. Pollock suggested that standby customers be allowed to purchase as-available energy under the SE rider in lieu of standby service. What are Gulf's thoughts on this alternative?**

A. If the Commission did not require that a customer take service under the SS rate if his total generating capability (1) exceeds 100 KW, (2) supplies at least 20 percent of this total electrical load, and (3) is operated for other than emergency and test purposes, then the SE rider might be an option for the customer. However, since that is not the case, and in order to be in compliance with the Commission's standby service Order No. 17159, any backup or maintenance service as defined by that order must be billed under the applicable standby service rate. Further, Order No. 17159 states on page 17:

> . . . standby customers shall not be permitted to take backup or maintenance power on the otherwise applicable full requirements rate schedule.

Thus, maintenance power must be billed under the standby service rate as required by the standby service order. In addition, according to the applicability section of the SE rider, this rider can only be applied to full requirements customers on the LP, LPT, PX, or PXT rate.

Q. Mr. Pollock, as well as Mr. Kisla, recommends a different treatment of backup and maintenance power as far as establishing a ratchet for determination of the standby service demand to be used in the calculation of the local facilities charge and reservation charge. He refers to page 21 of order no. 17159 and implies that the ratchet refers only to backup power. Would Gulf raise the contract KW if the customer's maintenance demand exceeded his standby service contract demand?

A. Yes. The beginning of that paragraph in Order No. 17159 states that the initial contract demand represents the maximum backup or maintenance demand that the customer expects to impose on the utility. Because the initial contract is based on backup or maintenance, any change in either type of service need would warrant a change in the contract capacity. Further, on page 5 of order no. 17159 it states:

> While we find that the expected load characteristics of both backup and maintenance power are sufficiently different from standard services to warrant separate rate schedules, we cannot, based upon the record in this case, find that backup and maintenance power are sufficiently different from each other to warrant separate

> cost-based rates. In theory, if maintenance power service can be scheduled to avoid a utility's peaks, it should not be assigned any cost responsibility for demand related production and bulk transmission costs. However, there are several factors that may make it difficult or impossible to distinguish between backup and maintenance power. FPC witness William Slusser testified that backup and maintenance are difficult to distinguish from the utility's perspective because the utility must provide the same level of replacement power regardless of whether the customers' generator is out for scheduled maintenance or has been forced out. Mr. Slusser added that customers with more than one generator may simultaneously experience forced and scheduled outages. He testified that he found it difficult to distinguish any difference in the standby cost impact of the two.
>
> We find Mr. Slusser's testimony to be persuasive. In a cost-of-service analysis using a 12 CP allocator to allocate demand-related costs, the cost responsibility will be the same for 10 MW of maintenance power taken for a full month as for 10 MW of backup power taken intermittently but only during one monthly peak hour of the year. (emphasis added)

Q. Mr. Pollock proposed a different method of calculating the non-fuel energy charge and reservation charge. Did the Company follow the guidelines established in standby rate Order No. 17159 in calculating these charges? If so, is there any reason for not deviating from this method?

A. Yes. The final Order states that "the public interest will best be served by requiring a uniform approach to cost allocation and rate design for standby services." That uniform approach for the design of all standby service rate components is spelled out very specifically in the Order.

Q. **Why did the Company increase the SS rate class by more than 1.5 times the overall system average percentage rate change?**

A. As stated in my prefiled testimony, the SS rate was designed per the rate design procedures specified in Order No. 17159 in the standby rate docket.

Q. **Mr. Pollock suggests using a different forced outage rate in the design of the reservation charge and daily demand charge. Would this be appropriate?**

A. Again, the Commission insisted on a uniform approach to rate design in the State. Thus, since the Order specified using a forced outage rate of 10 percent in the design of the reservation charge and daily demand charges, we chose not to use a different forced outage rate. In addition, Mr. Pollock appears to contradict himself since he is supporting a different forced outage rate for rate design purposes; and yet for the Cost-of-Service Study, he recommends using the 10 percent forced outage rate.

Q. Should Gulf revise the forecasted KW for the customer who experienced an outage of his generation capacity and took back-up power from Gulf but was not billed on the SS rate?

A. No. The 7959 KW was not reported as standby service by the customer. This KW is Gulf's current best estimate of what we now believe could have been reported by the customer as standby in September of 1989 had they had a better understanding of when an outage should be reported. The estimate was prepared as my Late Filed Exhibit No. 15 to my deposition by the Staff in this docket. We do not believe it is appropriate to backbill the customer based on the 7959 KW nor do we intend to change their BC from the present BC of 7500 KW. In the revised cost of service study and the revised rate design, we used the new contract KW's of 3000 KW in February 1990 and 7500 KW beginning March 1990 in our forecast. We believe forecasting 7959 SS KW would be overstating the forecast as the Company has contracted for only 7500 KW at the present time. We believe the customer will limit its standby to no more 7500 KW in the future. In fact, its max SS has been no more than 7500 KW since the one time occurrence of 7959 KW eight months ago.

Q. **Has Gulf complied with Order No. 17568, Docket No. 850102-EI, by making the SE Rider customers a separate rate class in this rate case?**

A. During a preliminary conference regarding the MFR's before filing our withdrawn case, Docket No. 881167-EI, a verbal agreement between the Company and the then Bureau Chief of Electric Rates was reached not to separate the SE customers from the others in their respective rate classes because SE is an optional rider applied to other rate classes and not a separate rate class in itself. This is the same treatment given to customers in the residential class taking the optional levelized billing rider and for customers on all of the optional TOU rates. The Company has relied on this very reasonable agreement.

Nevertheless, on May 9, 1990, as a part of Staff's Thirteenth Set of Interrogatories, Mr. O'Sheasy has been requested to redo the cost of service study making several changes. One such change is to make the SE Rider customers a separate rate class. We will file the Company's study in response to these interrogatories as soon as practicable.

Q. **Why is Gulf opposed to making the SE Schedule a rate and not an optional rider?**

A. Because it would disrupt the standard rate classes and destroy the SE rider. LP/LPT and PX/PXT customers opting for the rider would be grouped together. The Company has no obligation under the optional rider to declare SE periods, and the customer can go off the rider at any time. This would not be the case if it was changed to a separate rate schedule. If customers could not freely leave the rider, we would almost certainly have to state a minimum for the number and duration of SE periods that would be declared.

Q. With SE remaining a rider, how should rates be designed?

A. Billing determinants for customers opting for the SE rider should be combined with non SE customers' billing determinants for rate design purposes. This is the procedure used in designing Gulf's proposed rates. This issue related to Rider SE was introduced by the Staff, but no testimony has been offered to support a position.

Q. How were Gulf's proposed service charges derived?

A. The proposed service charges were selected based on our cost studies shown in MFR Schedule No. E-10.

Q. What are the appropriate service charges to be collected by Gulf Power Company?

A. The following are the Company's proposed service charges:

Initial Connection	$20.00
Investigation Charge	55.00
Temporary Service Pole	60.00

All other service charges remain at current levels.

Q. Staff has taken the position that four of the service charges should be less than Gulf's proposed charges. Can you tell us why your proposed charges are appropriate?

A. In designing our proposed rates as well as our proposed service charges, basic rate making philosophies of simplicity of design, application, and administration were utilized. For these reasons, Gulf supports our proposed service charges in lieu of Staff's. For example, we have proposed to allow two different types of reconnection charges to remain unchanged at $16.00. The Staff proposes to increase one by $1.60 and reduce the other by $1.50 to move them closer to costs. We believe this is needless tinkering with the rates. One of our objectives has been to keep all of these prices at whole dollar amounts. The Staff would have us reduce our proposed initial service charge by $.25. The effect of this change on total retail jurisdictional revenue is less than $200 per month!

Q. **You have reviewed Mr. Pollock's testimony and accompanying exhibits. Are there any other areas of his testimony that you would like to address?**

A. Yes. We disagree with Mr. Pollock's method of allocating the revenue increase among the various rate classes by moving all rate classes an arbitrary one half of the way closer to ~~the unit costs in the~~ cost of service ~~study~~. He must revert to this method of severely limiting the movement of customers on his proposed rates because of the drastic distortion his cost method introduces relative to the method used by the Company and approved by the Commission in the Company's past several rate cases. Without this limitation, Mr. Pollock would be requesting a $1,323,000 rate reduction for his clients.

Q. **What method does Gulf use to allocate the revenue increase among the various rate classes?**

A. The cost of service study for present rates served as the starting point for allocating the increase among the classes. From there, the proposed $26,295,000 revenue increase was spread in a manner that caused the rate of return for each class to move closer to the retail system average rate of return at the proposed revenue level. The exception is the revenue from the SS class, which resulted from the use of rate design procedures specified in Order No. 17159 in the standby rate docket. In compliance with this Commission's previously stated guideline that no class should receive an increase or decrease greater than 1.5 times the overall system average percent increase, the decrease in the OS-III class was restrained. Gulf's allocation method gives proper recognition to the impact the increases will have on each class, Commission precedent, previous rate case treatment of the various classes, as well as Mr. O'Sheasy's cost of service study.

Q. In Mr. Wright's testimony, he advocates setting GS rates equal to RS rates. Would Gulf consider setting the GS rates equal to the RS rates as well as GST rates equal to RST rates?

A. Yes. Both groups are served by non-demand meters, and their load factors are quite close. Combining the two groups of customers would result in an energy charge unit cost of $0.0034789 per KWH and a customer charge unit cost of $10.45 under proposed rates. These charges remain fairly close to the proposed RS unit costs of $0.0034472 per KWH and a $9.71 customer charge; however, they represent a substantial decrease in GS unit costs under proposed rates and would help to eliminate the subsidy problem that exists with both rates.

Q. If it is not appropriate to assume that customers on present rates would remain on the same rate when proposed rates become effective, explain why this is not the case.

A. This would not be an appropriate rate design assumption. Let me explain Gulf's rate design process. First we produce rates designed using the forecasted billing determinants for each rate class. Next, with our rate design computer program, we run the forecasted customer billing determinants against these preliminary rates and also run the preliminary rates in competition with other rates to assure that each customer is on the most economical rate for that customer; assuring, of course, that all qualifications or restrictions of the rate are met. Through this process the Company is able then to do any necessary fine tuning of the rates through successive iterations in order to get as close as possible to the proposed revenue target. If we did not check for crossovers (competition runs), we would not recover the proposed revenue because those customers crossing to a different rate would be paying lower prices and thus not producing the revenue that was originally intended.

Q. Once an increase is granted, would it be appropriate to allow the Company to redesign the rates to recover the approved revenue, run the rates in competition, and go through the same iteration process as was done in the original filing of the case and the revised portion of this case?

A. Yes. If not allowed this opportunity because of the customer crossovers I just discussed, the Company would not collect the full amount of the granted revenue increase as intended by the Commission in its decision.

Prior to the 1984 rate case, the Commission has always allowed Gulf to go through this iteration process. However, the final implementation of rates in that case was delayed seven days because of this issue. We hope by discussing this issue now, the Commission will understand the need for the Company to participate in this part of the rate design process, so that we will not experience the same needless delay when final rates in this case are implemented.

Q. **How should the revenue shortfall, if any, be recovered in order to properly recognize crossovers between rates?**

A. First, let me explain in more detail how the iteration process works. If, for example, the revenue target for rate class GSD/GSDT was $50,000,000 and after running the proposed rates against the forecasted customer billing determinants, the GSD/GSDT rate class only produced $44,000,000 in proposed revenue due to crossovers to cheaper rates, then it would be necessary to fine tune the GSD/GSDT proposed rates to recover the adjusted $6,000,000 revenue shortfall (the adjustment results from accounting for any revisions to rates that the crossovers are billed under) from the customers who would remain on the GSD/GSDT rates. Using this methodology, the original GSD/GSDT customers would produce the total revenue target of $50,000,000 as originally intended. This same methodology should be used for all demand rate classes in order to recover any revenue shortfall that results from crossovers between rates or classes. For the non-demand rate classes (RS/RST and GS/GST) this methodology would not be necessary because the only crossovers we are able to predict are those which occur within the class if a TOU customer crosses over to the standard rate.

A thorough review of each customer's usage is done during this iteration and crossover process to assure that customers are on the appropriate rate schedule under proposed rates. After the rate case, any customers that would benefit significantly by crossing over to another applicable rate schedule would be notified and given the opportunity to change rates.

Q. **Should the Company's rates for street and outdoor lights be approved?**

A. Yes. No other party has filed testimony regarding Gulf's street and outdoor light rates. Nevertheless, the Staff has taken some unsupported positions in their preliminary list of issues.

Q. **Is it appropriate to eliminate the general provisions pertaining to replacement of lighting systems on the Outdoor Service Schedule (OS)?**

A. Yes. Gulf proposes to eliminate such a provision from the tariff altogether. This would allow proper price signals to encourage replacement of these old mercury vapor fixtures. An issue has been raised in this proceeding seeking a revised provision dealing with the replacement of a mercury vapor fixture with a high pressure sodium fixture. This would impede the replacement process which Gulf hopes to encourage with the proposed rate design for the lighting services. We believe most customers will be unwilling to pay the undepreciated cost of the fixture and the cost of removal in order to get the more efficient sodium vapor fixture. Customers will soon realize they can avoid this payment simply by telling us to take down the mercury vapor light one day and then call back later and request a new sodium vapor light. Because two trips will be required, this will double the Company's removal and installation expense.

Q. Should recreational lighting customers that currently take service under OS-III be transferred to OS-IV?

A. Yes. These type customers consist of baseball parks, football and soccer fields, and tennis courts which are only used during portions of night-time hours. Since these customers' load characteristics differ from OS-III and OS-II, they should not receive service under those sections. Customers receiving service under OS-III have a continuous load characteristic. OS-II loads are photo-cell or time-clock controlled and remain on during the entire period of darkness, whereas recreational lighting loads are on at random times during the early part of the night. I do not support moving a group of customers with varying usage characteristics into a group with very homogeneous usage characteristics.

Q. **Should recreational lighting customers that currently take service under OS-III be transferred to the GS or GS-D rate?**

A. No. These recreational lighting customers have a load characteristic which peaks at a different time than the coincident peak or system peak of GSD or GS customers. This difference shows that these customers should not have the same demand allocated cost as the GSD or GS rates.

Q. **Does this conclude your rebuttal testimony?**

A. Yes.

Q Mr. Haskins, please summarize your rebuttal testimony.

A We believe that the final rates in this case should be designed, using as a basis, Mr. O'Sheasy's Cost of Service Study, as shown in the revised reponse to Industrial Intervenor's Second Request for Production of Documents No. 27, identified as hearing Exhibit No. 231.

The proposed revenue increase should be allocated among the various classes in such a manner that causes the rate of return for each class to move closer to the retail system average rate of return at the proposed rate level.

Dr. Johnson's proposed allocation of the revenue increase for the LP/LPT and the PX/PXT rate classes would take the LP/LPT class of customers that was at parity under the present rates, to a relative index of .95 on proposed rates. Whereas, under this same study, Gulf had proposed to keep the LP/LPT class at parity.

The methodology used in the development of the transformer ownership and metering voltage discounts, as shown in the Company's Response to Interrogatory Nos. 110, 111, and 113 of Staff's Eighth Set of Interrogatories should be adopted. These are now identified as hearing Exhibits 266, 267 and 269.

The transformer ownerships discounts in these exhibits should then be adjusted for any reduction issue of demand charges from unit cost.

Both Mr. Pollock and Mr. Kisla mentioned that seasonal variations and generation output might result in a customer's being charged for more standby service that was actually taken. It was certainly not the intention of the standby service tariff to penalize customers with seasonal variations in generation output. Schedule 7 of my rebuttal testimony shows a modification to the tariff to account for any such seasonal variations.

A couple of items that are relatively minor related to our outdoor service tariffs but, nevertheless, are important to those specific tariffs: In the OS-1 and OS-2 outdoor service schedules, by Commission approval, mercury vapor lighting has not be installed since 1982. Any contract signed when these mercury vapor lights were installed have now been expired for at least three years. The expiration of these contracts now eliminates the need for the general provisions for replacement that is shown at the conclusion of that tariff and should be eliminated.

Recreational lighting customers that

currently take service under rate OS-3 should be transferred to the new proposed OS-4 section and not to the GS or GSD rate, because these recreational lighting customers have a load characteristics which peaks at a different time than the coincident peak or system peak of the GS or GSD customers. There are other subjects included in my prefiled rebuttal testimony, such as rate rider SE and seasonal rates, which were discussed at length during cross examination on my direct testimony, and I will not elaborate on them in my summary.

This concludes my summary.

MR. STONE: We tender the witness.

(Transcript follows in sequence in Volume XXIII.)