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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 SIXTH DAY MORNING SESSION

VOLUME - XII

Pages 1657 through 1874

FPSC Hearing Room 106
Fletcher Building
101 E. Gaines Street
Tallahassee, Florida 32399

Monday, June 18, 1990

Met pursuant to adjournment at 8:30 a.m.

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

APPEARANCES:

(As heretofore noted.)

ALSO PRESENT:

DONALD G. HALE, Office of Public Counsel.

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P R O C E E D I N G S

(Hearing reconvened at 8:35 a.m.)

MR. STONE: Commissioner, at this point in the record, it's my understanding that we are supposed to insert the testimony of Dr. Roger A. Morin into the record by stipulation.

CHAIRMAN WILSON: That's correct.

MR. STONE: Dr. Morin revised his testimony, as we had noted at the prehearing conference to take advantage of the fact that there had been substantial passage of time since the initial testimony was submitted. It's now been updated to reflect current market conditions as of mid May, and the record copy that I will be giving to the court reporter is a completely new typed version bearing all the things that relate to that.

Although those changes have been given to the parties, I have new versions which I'm waiting on one page, which I'll be able to hand out to the parties later, including the Commission.

Record Copy 1662

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony of
Dr. Roger A. Morin
In Support of Rate Relief
Docket No. 891345-EI
Date of Filing December 15, 1989 Revised June 4, 1990

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

A. My name is Dr. Roger A. Morin. My business is 640 Clearlake Terrace, Roswell, Georgia, 30076. 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. Please describe your educational background.

A. I hold a Bachelor of Engineering degree and an MBA in Finance from McGill University, Montreal, Canada. I received my Ph.D in Finance and Econometrics at the Wharton School of Finance, University of Pennsylvania.

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

A. Yes.

Counsel: We ask that Dr. Morin's Exhibit, comprised of 8 Schedules, be marked for identification as Exhibit NoS. 108-115 (RAM-1).

Q. Please summarize your academic and business career.

A. I have taught at the Wharton School of Finance, University of Pennsylvania, at the Amos Tuck School of Business at Dartmouth College where I was Visiting Professor of Finance in 1986, at Drexel University, University of Montreal, McGill University. I have been a professor of Finance at the College of Business Administration at Georgia State University since 1979. I was a faculty member of Advanced Management Research International, and I am currently a faculty member of The Management Exchange, Inc., where I conduct frequent national executive-level education seminars throughout the United States and Canada. In the last five years and throughout 1989, I have conducted national seminars on "Utility Cost of Capital" and "Utility Capital Allocation." These are programs which I have developed on behalf of The Management Exchange, Inc., in conjunction with Public Utilities Reports, Inc.

I have authored or co-authored several books, monographs, and articles in academic and scientific journals on the subject of finance, including the

Journal of Finance, the Journal of Business Administration, International Management Review, and Public Utility Fortnightly. I have also published a widely-used textbook on regulatory finance, entitled Utilities Cost of Capital, published by Public Utility Reports, Inc., Arlingtn, VA, 1984, and have engaged in extensive consulting activities on behalf of numerous corporations and legal firms in matters of financial management and corporate litigation. Schedule 1 describes my professional credentials in more detail.

Q. Have you ever testified on cost of capital before?

A. Yes, I have been a cost of capital witness before numerous regulatory boards across the U.S. and Canada, including the Federal Energy Regulatory Commission and the Federal Communications Commission. The details of my participation in regulatory proceedings are provided in Schedule 1.

Q. Have you had any association with Regulatory Commissions?

A. Yes, in the summer of 1989, I was a consultant for the Ontario Telephone Service Commission (OTSC) to establish procedures for determining the cost of capital for municipal, cooperative, and investor-owned telephone utilities regulated by the OTSC. Currently, I am assisting the Illinois Commerce Commission staff in assessing cost of capital methodologies.

Q. What is the purpose of your testimony?

A. I have been asked to conduct an independent appraisal of the cost of common equity capital for the Gulf Power Company (Gulf, the Company), and to recommend a return on such capital which will be fair to the ratepayer, allow the company to attract capital on reasonable terms, and maintain its financial integrity.

Q. Please summarize your testimony and recommendation.

A. I recommend the adoption of a return on common equity of 13.50 percent. My recommendation is derived from studies I performed using the discounted cash flow (DCF) and risk premium methodologies.

I performed DCF analyses on two different surrogates for Gulf: The Southern Company (Southern) and a group of comparable risk electric utilities.

I also performed five risk premium analyses. In addition to three traditional risk premium analyses applied to Southern and to an electric utility industry index, I used the capital asset pricing model (CAPM) and an empirical approximation of the CAPM (ECAPM).

My recommended rate of return reflects the average equity return from my various DCF and risk premium analyses and the application of my professional judgment to the results in light of GPC's current business risk environment.

Q. What economic and financial concepts have guided your assessment of Gulf's cost of common equity?

A. Two fundamental economic principles underlie the appraisal of Gulf's cost of equity, one relating to the supply side of capital markets, the other to the demand side. According to the first principle, a rational investor is maximizing the performance of his portfolio only if he expects the returns earned on investments of comparable risk to be the same. If not, the rational investor will switch out of those investments yielding lower returns at a given risk level in favor of those investment activities offering higher returns for the same degree of risk. This principle implies that a company will be unable to attract the capital funds it needs to meet its service demands and to maintain financial integrity unless it can offer returns to capital suppliers which are comparable to those achieved on alternate competing investments of similar risk.

On the demand side, the second principle asserts that a company will continue to invest in real physical assets if the return on these investments exceeds or equals the company's cost of capital. This concept suggests that a regulatory commission should set rates at a level sufficient to create an equality between the return on physical asset investments and the company's cost of capital.

These pivotal concepts were articulated in landmark statements of the nation's highest court in the well-known cases of Federal Power Commission vs Hope Natural Gas Company, 320 U.S. 591 (1944), and Bluefield Water Works & Improvements Company vs Public Service Commission of West Virginia, 262 U.S. 679 (1923). The U.S. Supreme Court reiterated the criteria set forth in Hope in the Federal Power Commission vs Memphis Light, Gas & Water Division, 411 U.S. 458 (1973), Permian Basin Rate Cases, 390 U.S. 747 (1968), and most recently in Duquesne Light Co. and Pennsylvania Power Co. vs D.M. Barasch, etc., et al. No. 87-1160, 109 U.S. 609 (1989).

Q. Under traditional cost of service regulation, please explain how a regulated company's rates should be set.

A. Under the traditional regulatory process, a regulated company's rates should be set so that the company covers its costs, including taxes and depreciation, plus a fair and reasonable return on its invested capital. The allowed rate of return must necessarily reflect the cost of the funds obtained, that is, investors' return requirements. In determining a company's rate of return, the starting point is investors' return requirements in financial markets. A rate of return can then be set at a level sufficient to enable the company to earn a return commensurate with the cost of those funds.

Funds can be obtained in two general forms: debt capital and equity capital. The cost of debt funds and preferred stock funds can be easily ascertained from an examination of the contractual interest payments and preferred dividends. The cost of common equity funds, that is, investors' required rate of return, is more difficult to estimate. It is the purpose of this testimony to estimate a fair and reasonable return on the common equity capital of Gulf.

Q. What must be considered in estimating a fair return on equity?

A. The basic premise, as stated in the Hope and Bluefield cases, is that the allowable return on equity should be commensurate with returns on investments in other firms having corresponding risks. The allowed return should be sufficient to assure confidence in the financial integrity of the firm in order to maintain creditworthiness and ability to attract capital on reasonable terms.

The attraction of capital standard focuses on investors' return requirements which are generally determined using market value methods, such as the Discounted Cash Flow (DCF) or risk premium methods. These market value tests define fair return as the return investors anticipate when they purchase equity shares of comparable risk in the financial marketplace. This is a market rate of return, defined in terms of anticipated dividends and capital gains as determined by expected changes in stock prices, and reflects the opportunity cost of capital. The economic basis for market value tests is that new capital will be attracted to a firm only if the return expected by the suppliers of funds is commensurate with that available from alternatives of comparable risk.

Q. Please describe how your testimony is organized.

A. My testimony is organized in four sections:

I. DCF Methodology

II. Flotation Cost

III. Risk Premium

IV. Summary and Recommendation

The first section focuses on the capital attraction standard through the market value (DCF) method. Investor return requirements are determined by the rates at which investors are discounting expected future cash flows from Gulf or from companies of similar risk. The second section describes the need for a flotation cost allowance and its magnitude. The third section considers the relative risk premium between equity securities and bonds in order to arrive at the required return on Gulf's common equity. In the last section, the results from the various approaches used in determining a fair return are summarized.

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

A. No one individual method provides a level of precision 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.

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.

I. DCF METHODOLOGY

Q. How do you estimate the cost of equity capital for a public utility?

A. A utility's cost of equity is estimated using a variety of equally-weighted market-based techniques. The DCF model is usually applied to company-specific data, or to its parent company, as a starting point. Then, the DCF model is applied to one or more samples of companies which are comparable in risk. As a check on the DCF results, one or more risk premium tests are also applied to either company-specific data, industry-wide data, or to aggregate market data. The average results from all the tests then form the basis for the recommended return.

I followed this general process, even though I have some reservations concerning the applicability of the DCF model to utility stocks at this time in the current capital market environment.

Q. Please elaborate on your concern regarding the applicability of the standard DCF model at this time.

A. Caution has to be used in applying the DCF model to utility stocks at this time. The traditional DCF model is not equipped to deal with surges in market-to-book and price-earnings ratios, as has been experienced by utility stocks during 1989. The standard infinite growth DCF model assumes constancy in such ratios. That is, the model assumes that the investors expect the ratio of market price to dividends (or earnings) in any given year to be the same as the current price/dividend (or earnings) ratio. This must be true if the infinite growth assumption is made. This is discussed in detail in my book entitled Utilities Cost of Capital, Public Utility Reports, Inc., Arlington, VA, 1984, Chapter 5.

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. This is especially true in the short run. Investors can be myopic and make investment decisions based on time horizons that are far from infinite. Investors may very well assume that the price/earnings ratio will, in fact, continue to increase in the short run, thereby raising the expected rate of return.

In other words, the constancy of the price/earnings ratio required in the standard DCF model may not be a perfectly accurate assumption for Southern or for the other companies used in a

DCF analysis. To the extent that increases/decreases in relative market valuation are anticipated by investors, especially investors with short-term investment horizons, the standard DCF model understates/overstates the cost of equity. A simple numerical example clearly illustrates this phenomenon.

Given that a stock is trading at $100, assume further that its earnings per share are expected to be $8.00 for the current year, and are expected to grow at 10 percent per year in the future. Finally, assume that the company pays out one half of its earnings as dividends. If the stock is initially trading at 12.5 times earnings, the dividend yield is 4 percent. If investors do not expect the price/earnings ratio of 12.5 to change in the next year, the estimated expected return from holding the stock for one year using the standard DCF model is as follows: a dividend yield of 4 percent, plus growth in value (stock price) from $100 to $110, or 10 percent, for a total return of 14 percent. The ending stock price is $110, that is, 12.5 times next year's earnings of $8.80.

But what if investors expect an increase in the price/earnings ratio from 12.5 to say 13.0? Then, the growth in value is from $100 to $114.40, or

13.0 times next year's earnings of $8.80, for a total return of 18.40 percent (dividend yield of 4 percent, plus growth in value of 14.40 percent). The orthodox DCF model would indicate returns of 14 percent, whereas the investors' true expected return is 18.4 percent. Investor expected returns are substantially understated whenever investors anticipate increases in relative market valuation, and conversely.

Q. **Given your reservations concerning the applicability of the DCF model at this time, how did you estimate Gulf's cost of equity?**

A. Despite my concerns with the applicability of the DCF model at this particular point in time, I have nevertheless applied it to the Southern data and to a group of comparable risk firms. The DCF model is widely used by cost of capital witnesses, and its inclusion in my analysis offers a traditional benchmark which the Commission may find useful.

Given the circumstances under which the standard DCF model's application may be questionable, it is imperative that, as a minimum, comparable groups of companies be used as additional sources of DCF estimates, and that other methodologies, such as risk premium, be applied to arrive at market derived cost of equity for Gulf. I have, therefore, included several risk premium tests in order to arrive at my final recommendation on Gulf's cost of equity.

Q. Please explain the discounted cash flow approach.

A. The value of any security to an investor is the expected discounted value of the future stream of dividends or other benefits. One widely used method to measure these anticipated benefits in the case of a non-static company is to examine the current dividend plus the increases in future dividend payments expected by investors. This valuation process can be represented by the following formula, which is the traditional DCF model:

$$K_e = D_1/P_o + g$$

where: K_e = investors' expected return on equity
D_1 = expected dividend during the coming year
P_o = current stock price
g = expected growth rate of future dividends

The traditional DCF formula states that under certain assumptions which have been articulated in several articles in professional journals and in testimony before regulatory agencies, the equity investor's expected return, K_e, can be viewed as the sum of an expected dividend yield, D_1/P_0, plus the expected growth rate of future dividends, g. The principal appeal of the DCF approach is its simplicity and its correspondence with the intuitive notion of dividends plus capital appreciation as a measure of investors' expected return. The returns anticipated at the given market price are not directly observable and must be quantified from statistical market information. The idea of the market value approach is to infer "K_e" from the observed share price and from an estimate of investors' expected future growth.

The assumptions underlying this valuation formulation are well known. The assumptions are discussed in detail in my book mentioned above, Chapter 5. The traditional DCF model assumes a constant average growth trend for both dividends and earnings, a stable dividend payout policy, a discount rate in excess of the expected growth rate, and a constant price-earnings multiple, which implies that growth in price is synonymous with growth in earnings and dividends. I must emphasize the latter assumption because the recent runup in utility stock prices in a short period, which have resulted in changes in their P/E ratios, casts a shadow on the applicability of the traditional DCF model at the present time. The traditional DCF model also assumes that dividends are paid annually when, in fact, dividend payments are normally made on a quarterly basis.

Q. **How did you apply the discounted cash flow (DCF) approach to determine Gulf's cost of equity capital?**

A. Gulf's stock is not publicly traded, since the company is a wholly owned subsidiary of Southern. Therefore, any market value approach to determine the investor's expected return on equity must be applied indirectly.

The stock of Southern, however, is publicly traded. Therefore, I applied estimating techniques to Southern as a proxy for Gulf, since we have observable market valuation signals for Southern.

In order to estimate Gulf's cost of equity, I have applied the DCF model to Southern data using an average of security analysts' growth expectations, the sustainable growth rate method, and historical growth rates as a proxy for expected growth. I also applied the DCF formula to a control group of comparable risk companies as a means of comparison, using an average of both historical growth rates and 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 broad set of information. This implies that observed current prices represent the true fundamental value of a security, and that a cost of capital estimate should be based on current prices.

To guard against the possibility that the current stock price reflects abnormal conditions or constitutes a temporary aberration, while at the same time retaining the spirit of market efficiency, averaging stock prices over several recent trading days is a reasonable compromise. In implementing the DCF model to calculate Southern's cost of equity, I have relied on the average closing stock price calculated over the most recent ten trading days period, at the time of preparing my testimony, May 1st to May 14, 1990. A similar average computed over a one-month period rather than a 10-day period would not be unreasonable. Closing stock prices are obtained from Dow Jones News/Retrieval's Historical Quotes service. In implementing the DCF model across larger groups of comparable companies, I have used the recent stock price cited in Value Line Investment Survey's Summary & Index, May 25, 1990 edition.

The expected dividend, D_1, in the traditional DCF model can be obtained by multiplying the current indicated annual dividend rate by a growth factor, which depends on how long the current quarterly dividend rate has been in effect and on the timing of the anticipated dividend increase. In general, it can be shown that the expected dividend can be obtained by multiplying the spot dividend by (1+n/4g), where n is the number of quarters since the last dividend increase. To illustrate, in applying the DCF model to Southern, I have examined the quarterly pattern of past dividends and assumed that an investor buying Southern stock at this time expects to receive four quarterly dividends of \$0.535(1 + g) in the next year, because the current quarterly rate has been in effect for four quarters already. This assumption is in conformity with the assumptions of the traditional DCF model. The expected dividend can be obtained by multiplying the current quarterly rate by an appropriate growth factor, here (1 + 4/4 g) = (1 + g).

One further modification to the expected dividend yield is warranted to account for the quarterly nature of dividend payments. The traditional DCF model assumes that dividend payments are made annually at the end of the year, while most companies, in fact, pay dividends on a quarterly basis. Since investors are aware of the quarterly timing of dividend payments, this knowledge is reflected in stock prices. Clearly, a stock that pays four quarterly dividends of one dollar would command a higher price than a stock that pays a four dollar dividend a year hence, holding risk and growth constant. 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. Since the stock price employed in the DCF model already reflects the quarterly stream of dividends to be received, consistency, therefore, requires explicit recognition of the quarterly nature of dividend payments.

Schedule 2 restates the traditional DCF model to recognize the quarterly nature of dividend payments, and the value to the investor of receiving money earlier than later. As shown on page 4 of Schedule 2, the magnitude of the error using the annual model rather than the quarterly model is in the order of 40 basis points (0.40 percent) for any reasonable values of Southern data. In determining the cost of equity with the DCF model, I have employed the quarterly version of the DCF model discussed in Schedule 2, using the appropriate dividend stream for a given company in equation 2, given past dividend patterns. Finally, as will be discussed more fully later, I have translated my market-based cost of capital estimate into a fair return on equity by an allowance for flotation cost through the dividend yield component.

Q. Is the quarterly DCF model widely recognized by the regulatory community?

A. Although financial theory indicates unambiguously that the quarterly DCF model is the correct model to use in assessing investor return requirements, the annual DCF model enjoys wider usage. However, the use of the quarterly DCF model is becoming more frequent. For example, the staff of this Commission and of the Wisconsin regulatory commission employ the quarterly DCF model; the Mississippi commission employs the quarterly DCF model in determining the benchmark ROE in its Performance Evaluation Plan.

The traditional annual DCF model is based on the limiting assumptions that dividends are paid annually, and that dividends increase once a year starting in 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 investors. Because dividends are paid quarterly in practice, the investors' required return should be determined with a DCF model that reflects accurately the quarterly nature of dividends.

The use of the annual rather than the quarterly DCF model violates the capital attraction standard described earlier in my testimony. If an investor has a choice between investing $1,000 in a bank account which promises a return of 10 percent compounded annually and another bank account which promises a return of 10 percent but compounded quarterly, he will clearly select the latter. Due to the quarterly compounding of interest, the investor earns an effective return of 10.38 percent on the latter bank account versus 10 percent on the former.

If the first investment was a stock investment of a public utility that is only allowed to earn the annual DCF return of 10 percent, and the second investment was the stock of another company of comparable risk which was expected to earn the quarterly DCF return of 10.38 percent, the investor would clearly choose the latter. At the end of the year, the investor's wealth would only be $1,100.00 with the first investment, compared to $1,103.80 for the second investment. Therefore, the investor will not invest funds in a public utility stock which is only allowed to earn the annual DCF return when comparable risk alternatives are earning more.

GROWTH COMPONENT

Q. **Please elaborate on how you determined expected growth in applying the DCF method to Southern.**

A. As a proxy for Southern's growth, I have taken a simple average of three growth estimates, one based on historical data, and two based on prospective data.

Q. **Please describe your estimate of historical growth.**

A. In computing historical growth rates, three decisions must be made:

1) which historical data series is most relevant for determining expected "g,"
2) over what past period, and
3) which computational method is most appropriate.

Q. **What historical data did you employ in determining** expected growth?

A. DCF proponents have variously based their historical growth computations on earnings per share, dividends per share, and book value per share. Of the three possible growth rate measures, growth in dividends per share is conceptually preferable. DCF theory states clearly that it is expected future cash flows in the form of dividends which constitute investment value.

Since the ability to pay dividends stems from a company's ability to generate earnings, growth in earnings per share can be expected to influence the market's dividend expectations. Dividend growth can only be sustained if there is growth in earnings. However, confining attention to historical earnings growth alone as a surrogate for expected dividend growth can be misleading, since historical earnings per share are frequently more volatile than dividends per share. This is clearly the case for Southern, as seen from the graphic display of its earnings on page 1 of Schedule 3.

Dividend growth rates are more stable. They are much less affected by year-to-year inconsistencies in accounting procedures, and they are not likely to be distorted by an unusually poor year, or by episodic writeoffs. Most companies, and utilities in particular, are reluctant to alter their dividend policies in response to transitory earnings variations.

Under certain circumstances, historical growth in book value per share may also be useful as a proxy for future dividend growth. Earnings per share is the product of book value per share and rate of return on book equity so that historical growth in book value per share may provide an indication of the growth in earnings that would have occurred if past rates of return had remained constant. Past growth in book value per share, however, is an adequate proxy for future growth only if two crucial assumptions are met: 1) that investors expect no change in earnings per share arising from changes in the future in the book rate of return on equity, and 2) that market-to-book ratios have remained stable. The latter assumption is vital, for book value may increase or decrease based on issuances of common stock at a premium or discount from existing book value. Based on a simple examination of historical data, these two assumptions are frequently violated, particularly in the case of utilities. Therefore, I rely more heavily on dividend per share growth, whenever using historical growth rates.

TIME PERIOD

Q. Over what time period should historical growth be measured?

A. Once an appropriate historical data series has been selected, and that history is deemed relevant for that company, the period over which the growth is to be measured must be determined. Historical growth rates are customarily computed over the last five or ten years. The period must be long enough to avoid undue distortions by short-term influences and by abnormal years. Dividend growth over the past year is hardly representative of a trend. The last year is normally the most recent year. The period, however, should be short enough to encompass current and foreseeable conditions relevant for investors' assessment of the future. I have relied on the five-year historical dividend growth rate in my calculations which required such estimates.

GROWTH RATE COMPUTATION

Q. How should growth be calculated?

A. The method of calculating growth is most meaningful in the context of compound interest. If dividends grow from $2 to $3 over a ten-year period, for example, the total growth is 50 percent, or a simple average per annum rate of 5 percent. But 5 percent is not a meaningful expression of the growth rate, because it ignores compounding, that is, the accrual of interest on interest as well as on the original value. Assuming annual compounding, $2 grows to $3 in ten years at a rate of 4.1 percent. The latter percentage can be obtained either from a set of standard compound interest tables or from a specialized financial calculator.

Use of the compounding method of calculating growth may be vulnerable to a potential distortion. If either the initial or terminal values are unrepresentative, usually high or low, the resulting growth rate will not truly reflect the developments during the period. For example, if the terminal year happens to be one of severely depressed earnings due to inflation or acute regulatory lag, and the initial year reflects an economic boom, the indicated growth rate will be unrealistically low. On the other hand, if conditions were changed, the reverse might be true. This potential distortion can be avoided by the use of smoothed compound growth rates; instead of using single years' data as end points, the averages of the first few and last few years' data are used. The latter method is preferable because it involves less subjective judgment. For most companies, smoothed historical five-year growth rates are available in the Value Line Data Base for earnings, dividends, book value, revenues, and cash flows. Base periods used in the Value Line computation are three-year averages in order to temper cyclicality and to mitigate any potential distortion due to sensitivity to end points. I have used Value Line's smoothed historical compound growth rates when applying the DCF method to control groups with historical growth rates.

Another method of calculating a growth rate is to fit a "lease-squares line" to the logarithms of all the data in the series. The log-linear method is theoretically more precise than the compound growth method because it includes each observation of the period rather than merely the end points. The method, however, is computationally and statistically laborious when applied to several companies.

ANALYSTS' GROWTH FORECASTS

Q. **Please describe your second method of estimating growth.**

A. A reasonable method of determining expected growth is to use analysts' growth forecasts. Projected long-term growth rates actually used by institutional investors to determine the desirability of investing in different securities influence investors' growth anticipations. These forecasts are made by large reputable organizations, and the data are readily available to investors and are representative of the consensus view of investors. Because of the dominance of institutional investors in investment management and security selection, and their influence on individual investment decisions, analysts' growth forecasts influence investor growth expectations and provide a sound basis for estimating the cost of equity with the DCF model. Growth rate forecasts of several analysts are available from published investment newsletters and from systematic compilations of analysts' forecasts, such as those tabulated in Institutional Brokers' Estimate System's (IBES) or Zacks Investment Research's (Zacks) monthly publications. I have used analysts' long-term growth forecasts contained in IBES as proxies for investors' growth expectations in applying the DCF model to Southern and to the other comparable group of companies.

Q. **Is there any empirical evidence that analysts' growth forecasts influence investors' growth expectations?**

A. Yes. Several studies in the academic finance literature demonstrate that growth forecasts made by security analysts are reasonable indicators of investor expectations, and that investors rely on analysts' forecasts and not just on historical growth rates. Studies of historical growth rates may be used by investors along with analysts' growth forecasts to assess the expected long-run growth rate of future dividends, insofar as they affect investor anticipations.

DCF RESULTS: THE SOUTHERN COMPANY

Q. **How did you determine the expected growth term in implementing the DCF model to Southern market data?**

A. As stated previously, studies of historical growth rates may be used by investors to assess the expected long-run growth rate of future dividends, insofar as they affect investor anticipations. Page 1 of Schedule 3 shows the pattern of Southern's per share earnings and dividends in recent years. Value Line reports a smoothed historical growth rate in dividends over the past five years for Southern of 5.00 percent.

Although historical information provides a primary foundation for expectations, investors use additional information to supplement past growth rates. Extrapolating past history alone without consideration of historical trends and anticipated economic events would assume either that past rates will persist over time or that investors' expectations are based entirely on history. I have, therefore, examined two other methods to determine Southern's expected growth: analysts' growth forecasts and the sustainable growth method.

I reviewed the 5-year earnings growth estimates by financial analysts compiled by IBES. For Southern, the May 1990 issue of IBES reports a consensus median expected earnings growth rate of 3.25 percent over the next five years.

An alternate method sometimes used to predict future growth is to multiply the fraction of earnings expected to be retained by the company, "b", by the expected return on book equity, "r". That is,

$g = b \times r$

where

g = expected growth rate in earnings

b = expected retention ratio

r = expected return on book equity

To apply the sustainable growth formula, two quantities are required, the expected retention ratio (b) and the expected return on equity (r). As an estimate for "r", I have used 12.5 percent, which is Value Line's projected long-term return on common equity. For the expected retention ratio, I have used 25.81 percent, which is Value Line's expected ratio for Southern over the next several years. The implied growth rate is obtained by multiplying the expected return on book equity of 12.5 percent by the retention ratio of 25.81 percent to produce a growth rate of 3.23 percent.

It should be pointed out that proper implementation of the sustainable growth method requires that the fraction of earnings expected to be retained by the company be multiplied by the expected return on book equity. The implementation of this technique would be flawed if historical realized book returns on equity rather than expected returns on equity were used.

It should also be emphasized that the sustainable method of predicting growth is only accurate under the assumptions that the return on book equity (ROE) is constant over time and that no new common stock is issued by the company, or if so, it is sold at book value. Moreover, the sustainable growth method contains a potential logical trap: the method requires an estimate of ROE to be implemented. But is the ROE input required by the model differs from the recommended return on equity, a fundamental contradiction in logic follows.

A last cautionary note with respect to the method is in order. The empirical finance literature demonstrates that the sustainable growth method of determining growth is not as significantly correlated to measures of value, such as stock price and price/earnings ratios, as other historical growth measures or analysts' growth forecasts.

Combining the historical growth figure of 5.0 percent, analysts' growth forecasts of 3.25 percent and the sustainable growth estimate of 3.23 percent, I obtained a simple average of 3.83 percent. I have used the latter as proxy for Southern's expected growth rate in dividends in the DCF model.

Q. **What expected return on equity does this growth estimate imply for Southern?**

A. Application of the DCF formulation is shown on page 2 of Schedule 3. The growth rate of 3.83 percent (Column 7) is combined with the expected dividend yield in the first year (Column 6), to produce an estimate of the cost of common equity (Column 8). The stock price (Column 2) used, $26.00, is the average closing stock price for the first ten trading days in the month of May 1990, which was the period during which I prepared my testimony. Closing stock prices were obtained from the Dow Jones Historical Quote Service. As explained previously, the expected dividend is obtained by multiplying the current indicated quarterly dividend rate (Column 3) of 4 x $0.535 = $2.13 by a growth factor, which depends on how long the current quarterly dividend rate has been in effect and on the timing of the anticipated dividend increase (Column 4). Since, at the time of preparing my testimony, the current quarterly rate has been in effect for four quarters, an investor buying Southern stock expects to receive in the next year four dividends at the new rate of $0.535 (1 + g), according to the tenets of the DCF model. The expected dividend without the quarterly timing adjustment is, therefore, computed by multiplying the current indicated dividend by an appropriate growth factor, here (1 + g).

The expected growth rate (Column 7) of 3.83 percent is combined with the expected dividend yield (Column 6) of 8.55 percent to produce the cost of capital estimate of 12.78 percent (Column 8). The latter is obtained by solving iteratively the quarterly version of the DCF model presented in Schedule 2. To solve the latter equation, the following input data for Southern:

$$D_{10} = \$0.5350(1 + .0383)$$
$$D_{20} = \$0.5350(1 + .0383)$$
$$D_{30} = \$0.5350(1 + .0383)$$
$$D_{40} = \$0.5350(1 + .0383)$$
$$P_0 = \$26.00$$
$$g = 3.83 \text{ percent}$$

The data are substituted in the appropriate format into the appropriate form of equation No. 2 of Schedule 2 using the dividend sequence assumed for Southern, and the latter equation is solved iteratively by successive approximations for K_e, the cost of equity Here, K_e, = 12.78 percent.

As discussed later, the cost of equity capital estimate of 12.78 percent must be translated into a fair return on equity by allowing for flotation costs. This is accomplished by dividing the dividend yield component of the cost of equity figure by 0.95. In Column 9 of Schedule 3, I have, therefore, applied a conservative allowance of 5 percent to the dividend yield component by dividing by 0.95 (100 percent - 5 percent) to produce a fair DCF rate of return on equity of 13.25 percent.

In summary, based on a stock price of $26.00, an expected dividend yield of 8.55 percent, and a growth rate of 3.83 percent, my DCF estimate of a fair return on equity for Southern is 13.25 percent, following adjustment for quarterly timing and flotation cost.

DCF COMPARABLE GROUPS

Q. Have you applied the discounted cash flow approach to other companies as a means of comparison?

A. Yes. As explained previously, the basic notion underlying the cost of common equity capital is that at any point in time, securities are priced so that all securities of equivalent risk offer the same expected rate of return. For Gulf, the basic problem is thus to determine the expected rate of return for its particular risk class.

My group of comparable risk companies is drawn from a large selection of electric utilities which are primarily in the same industry and which face similar investment risks as Gulf. The initial sample consisted of the 100 electric utilities monitored in Salomon Brothers' Electric Utility Monthly. The companies also had to be included in the Value Line Data Base and in the IBES summary of analysts' growth forecasts. Companies which have suspended dividends were eliminated from the sample. The master list of surviving companies then consisted of 88 electric utilities, for which data were available in all the aforementioned data sources. The sample of companies is shown in Schedule 4.

Q. **How did you select a sample of companies comparable to Gulf from the master list of electric utilities?**

A. I use the beta measure of risk to identify electric utilities with investment risks similar to those of Gulf.

The beta coefficient aims at assessing the volatility of a security's return relative to that of the market. The beta coefficient compares the volatility and direction of movement of the return on investment with those of the market as a whole. Specifically, the beta coefficient of a particular stock measures the degree to which the return on the stock follows the trend of the market. It indicates that change in the rate of return on a stock associated with a one percentage point change in the rate of return on the market. The beta coefficient thus measures the degree to which that stock shares the same risk as the market as a whole. Beta risk measures are readily available from investment services and are in wide use by the investment community.

Technically, the beta coefficient for a stock is a measure of the covariance of the return on the stock with the return on the market as a whole so that it measures the dispersion or volatility in the stock's return which cannot be reduced through market diversification. In a large diversified portfolio, the dispersion or the volatility in the rate of return on the entire portfolio is closely related to the beta coefficients of the constituent stocks. Most institutional stock is held in such larger diversified portfolios. A significant fraction of individuals' holdings would also be held in similarly diversified portfolios. It should be pointed out that the objective of using beta is to ascertain the relative values of beta for different firms rather than estimating the precise absolute value of beta. It is reasonable to suppose that the relative ranking of the betas are less sensitive to the computational details in estimating beta than would the absolute values of beta.

The final group of companies consisted of all those electric utilities from the master list of Schedule 4 whose beta is the same as Southern's beta, the latter as a proxy for Gulf's beta.

The betas for the various electric utilities on the master list range from a high of 0.85 to a low of 0.50, with a mean of 0.69. Since Southern's beta is 0.75, my group of companies consisted of those 18 companies with the same beta of 0.75. The 13 companies are shown in Schedule 5. Although there may be substantial differences in characteristics between these companies, which may result in varying risk assessments by investors, they are all subject to similar kinds of economic and regulatory risk influences, and the average risk of the group can be considered comparable to Gulf.

As additional checks on the risk comparability of the companies in the group, over and above beta, I examined the common equity ratio and the bond ratings of the companies in the group. The average common equity ratio for the 18 companies in the group is 0.44, which is higher, hence less risky, than Gulf's common equity ratio of approximately 0.40, attesting to the conservatism of the group based on this criterion.

Salomon Brothers' Electric Utility Monthly classifies electric utilities into the following six rating categories, based on Moody's/Standard & Poors' bond ratings:

Aaa/AA
Aa/AA
Aa/A or A/AA
A/BBB or Baa/A
Baa/BBB
Below Baa/BBB

Using numerical scores from 1 (Aaa/AA) to 6 (Baa/BBB) for each of the six bond rating classes above, the average bond rating for the companies is slightly less than A at 4.11. This compares with Culf's bond rating of A, which is 4 on the numerical scale, or about the same as the group average.

Q. How did you apply your DCF formulation to these comparable companies?

A. Application of the DCF formulation to each of the companies in the reference group proceeds in an identical manner to that of the previous application to Southern. Schedule 5 displays the DCF analysis for each company using Value Line's 5-year historical dividend growth rate on page 1 and the IBES median growth forecast by analysts on page 2 as proxies for expected growth. Proceeding for each company in the group exactly as before in the DCF analysis of Southern, the average cost of common equity estimate for the group is 13.74 percent using historical growth, and 12.32 percent using growth forecasts. The average of the two estimates is 13.03 percent. These results are adjusted for flotation costs and quarterly dividend payments.

In summary, my DCF analysis of Southern data produced a cost of equity estimate of 13.25 percent and that of comparable risk electrics yielded an estimate of 13.03 percent. At this point, I reemphasize the cautions which I discussed earlier on the applicability of the DCF model to Southern data and to utility stocks in general at this time.

II. FLOTATION COST ADJUSTMENT

Q. **Please explain the flotation cost adjustment which you have used in all your DCF analyses.**

A. Flotation costs are very similar to the closing costs on a home mortgage. In the case of issues of new equity, flotation costs represent the discounts that must be provided to place the new securities. Flotation costs have a direct and an indirect component. The direct component is the compensation to the security underwriter for his marketing/consulting services, for the risks involved in distributing the issue, and for any operating expenses associated with the issue (printing, legal, prospectus, etc.). The indirect component represents the downward pressure on the stock price as a result of the increased supply of stock from the new issue. The latter component is frequently referred to as "market pressure."

Investors must be compensated for flotation costs on an ongoing basis to the extent that such costs are not expensed in the past and, therefore, that the adjustment must continue for the entire time that these initial funds are retained in the firm. Appendix A discusses flotation costs and provides numerical illustrations which clearly show that, even if a utility does not contemplate any further common stock offerings, a flotation cost adjustment is still permanently required. This is analogous to the flotation costs associated with past bond issues, which continue to be amortized over the life of the bond, even though no new bond issues are contemplated.

By analogy, in the case of a bond issue, flotation costs are not expensed but are amortized over the life of the bond, and the annual amortization charge is embedded in the cost-of-service. The flotation adjustment is also analogous to the process of depreciation, which allows the recovery of funds invested in utility plant. The recovery of bond flotation expense continues year after year, irrespective of whether the company issues new debt capital in the future, until recovery is complete, in the same way that the recovery of past investments in plant and equipment through depreciation allowances continues in the future even if no new construction is contemplated. In the case of common stock which has no finite life, flotation costs are not amortized. Therefore, the recovery of flotation cost requires an upward adjustment to the allowed return on equity.

According to empirical studies, underwriting costs and expenses average at least 4 percent of gross proceeds for utility stock offerings. (See Logue & Jarrow: "Negotiation vs Competitive Bidding in the Sale of Securities by Public Utilities," Financial Management, Fall 1978). A recent study of 641 common stock issues by 95 electric utilities identified a flotation cost allowance of 5.5 percent (see Borum & Malley: "Total Flotation Cost for Electric Company Equity Issues," Public Utilities Fortnightly, February 20th, 1986).

As far as the market pressure effect is concerned, empirical studies suggest an allowance of 1 percent. Logue and Jarrow found that the absolute magnitude of the relative price decline due to market pressure was less than 1.5 percent. Bower and Yawitz examined 278 public utility stock issues and found an average market pressure of 0.72 percent (see Bower & Yawitz, "The Effect of New Equity Issues on Utility Stock Prices," Public Utilities Fortnightly, May 22, 1980).

Eckbo & Masulis ("Rights vs. Underwritten

Stock Offerings: An Empirical Analysis," Univ. of British Columbia, Working Paper No. 1208, Sept. 1987) found an average flotation cost of 4.175 percent for utility common stock offerings. For the market pressure effect, they found that the relative price decline due to market pressure in the days surrounding the announcement amounted to slightly more than 1.5 percent. Adding the two effects, the indicated total flotation cost allowance is above 5.5 percent, corroborating the results of earlier studies. Therefore, based on empirical studies, total flotation costs including market pressure conservatively amount to 5 percent of gross proceeds.

Appendix A shows why it is necessary to apply an allowance of 5 percent to the dividend yield component of equity cost by dividing that yield by 0.95 (100 percent - 5 percent) to obtain the fair return on equity capital. The appendix also demonstrates that even if no further stock issues are contemplated, the flotation adjustment is still permanently required to avoid confiscation. Flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years.

The flotation cost adjustment is not a one-time adjustment, but rather a permanent requirement to keep shareholders whole. Failure to include an allowance for flotation costs results in a downward-biased estimate of equity costs of approximately 30-40 basis points.

III. RISK PREMIUM ESTIMATES

Q. Please describe the risk premium method for determining the cost of common equity.

A. Given the cautions I expressed earlier on the applicability of the DCF model at a point in time for a given company, I have performed several Risk Premium tests. The Risk Premium method of determining the cost of equity recognizes the fundamental principle that common equity capital is more risky than debt from an investor's standpoint, and that investors require higher returns on stocks than on bonds to compensate for the additional risk. The general approach is relatively straightforward: First, one must determine the historical spread between the return on debt and the return on equity. Second, this spread must be added to the current debt yield to derive an estimate of current equity return requirements.

The risk premium approach to estimating the cost of equity derives its usefulness from the simple fact that, while equity return requirements cannot be readily quantified at a given point in time, the returns on bonds can be assessed precisely at every instant in time. If the magnitude of the risk premium between stocks and bonds is known, this information can be utilized to determine the cost of common equity.

Q. Please describe your risk premium analysis.

A. To quantify the actual risk premium for Gulf, I have performed five risk premium studies. The first two studies deal directly with Southern data, and the third deals with the electric utility industry. The remaining two studies deal with aggregate stock market risk premium evidence, and are based on modern financial theory.

Q. Could you discuss the results of your first risk premium study?

A. A forward-looking risk premium for Southern was estimated with a time-series analysis over the

1979-1988 period. This analysis is depicted in Schedule 6. Fundamentally, the risk premium was estimated by computing the cost of equity capital for each year over the 1979-1988 period using the DCF methodology, and then subtracting the yield on Moody's Utility Bond index for that year.

The upper panel of Schedule 6 shows the history of dividends per share and the log-linear growth rate for each year, using successive five-year base periods. The lower panel displays the year-by-year analysis of expected equity returns and bond yields over the period 1979-1988. Equity returns are computed using the quarterly DCF model. The average spot dividend yield for each year obtained from Value Line (Column 1) is transformed into an expected dividend yield (Column 2) by multiplying by (1 + 0.5g), assuming that two quarterly dividends have already been received at the old rate. The growth rate each year (Column 3) is the 5-year log-linear growth rate, computed from the corresponding historical dividend data on the upper panel portion of the exhibit. The fair return on equity for each year (Column 4) is obtained by summing the expected dividend yield and the growth rate. The expected dividend yield component is divided by 0.95 to allow for flotation costs, and 40 basis points are added to account for quarterly dividend payments, as previously discussed. In column (5), the yield on Moody's A-rated Utility bonds for each year are subtracted from the cost of equity figures for the same year to arrive at the risk premium.

The average risk premium over the 10-year period for Southern was 3.08 percent over A-rated utility bonds. If the abnormal 1981-1982 results are omitted from the computation, the average risk premium was 3.78 percent. However, on a year to year basis over the period, the risk premium has fluctuated in a manner inversely related to interest rates. As interest rates decrease, the yield spread of stocks over bonds widens, owing to the falling interest rate risk faced by bond investors, and conversely. This inverse relationship between the risk premium and interest rates is depicted graphically on page 2 of Schedule 6. The functional relationship between the two can be determined by statistical regression techniques. The statistical relationship between interest rates and the risk premium from 1979 to 1988 is as follows, as shown on page 3 of Schedule 6:

RISK PREMIUM = 0.1366 - (0.8402 * INTEREST RATE)

Given that utility A-rated bonds such as Gulf Power's are currently yielding about 10 percent as of mid May 1990, the risk premium implied by the above relationship is 5.26 percent, that is 0.1366 - 0.8402 x .100. Adding the bond yield of 10 percent to the risk premium of 5.26 percent produces a cost of equity of 15.25 percent.

Q. **Please describe your second risk premium analysis.**

A. As a check on more current conditions, a forward-looking risk premium for Southern was also estimated with a month-to-month time series analysis over the past four years. The analysis is depicted in Schedule 7. The risk premium was estimated by computing the cost of equity capital for each month from November 1984 to October 1989 using the quarterly DCF model, and then subtracting the yield on Moody's A-rated Utility

Bond index for that month. The DCF analysis was performed as before, except that the expected growth was obtained for each month from the analysts' consensus forecast reported in IBES for that month, instead of relying on historical growth rates. The average risk premium over the period was 3.62 percent, adjusted for flotation cost.

On a month-to-month basis over the period, however, the risk premium has fluctuated in a manner inversely related to interest rates, as was the case in the previous decennial analysis. As interest rates increase, the yield spread of stocks over bonds narrows, owing to the increasing interest rate risk faced by bond investors, and conversely. This inverse relationship between the risk premium and interest rates is depicted graphically on page 2 of Schedule 7. The functional relationship between the two can be determined by statistical regression techniques. The exact statistical relationship between interest rates and the risk premium from November 1984 to October 1989 is as follows, as shown on page 3 of Schedule 7:

RISK PREMIUM = 0.0643 - (0.2663 * INTEREST RATE)

Given that utility A-rated bonds are currently yielding about 10 percent as of May 1990, the risk premium implied by the above relationship is 3.77 percent, that is 0.0643 - (0.2663 x 0.100). Adding the bond yield of 10 percent, to the risk premium of 3.77 percent produces a cost of equity of 13.77 percent.

Q. **Please describe the results of your third risk premium study.**

A. The same study performed above on Southern was replicated on the electric industry as a whole, using Moody's Electric Utility Index as an industry proxy. The analysis is depicted in Schedule 8. The DCF analysis was performed as before; the spot dividend yield on Moody's Electric Utility Common Stocks Index was converted into an expected dividend yield as before, and the expected growth was obtained for each month from the analysts' consensus forecast reported in IBES for that month for the electric utility composite. The average risk premium over the period was 3.29 percent, adjusted for flotation cost.

As before, the risk premium fluctuated inversely to interest rates. The inverse relationship between the risk premium and interest rates is depicted graphically on page 2 of Schedule 8. The statistical relationship between interest rates and the risk premium is as follows, as shown on page 3 of Schedule 8:

RISK PREMIUM = 0.0640 - (0.2932 * INTEREST RATE)

Given that utility A-rated bonds are currently yielding about 10 percent as of May 1990, the risk premium implied by the above relationship is 3.47 percent, that is 0.0640 - (0.2932 x 0.100). Adding the bond yield of 10 percent to the risk premium of 3.47 percent produces a cost of equity of 13.47 percent.

CAPM ESTIMATE

Q. Did you estimate the risk premium of common stocks using any other methodology?

A. Yes. I developed two estimates based respectively on the Capital Asset Pricing Model

(CAPM), and on an empirical approximation to the CAPM (ECAPM). The fundamental idea underlying the CAPM is that risk-averse investors demand higher returns for assuming additional risk, and higher-risk securities are priced to yield higher expected returns that lower-risk securities. The CAPM quantifies the additional return, or risk premium, required for bearing incremental risk, and provides a formal risk-return relationship anchored on the basic idea that only market risk matters, as measured by beta. According to the CAPM, securities are priced such that:

EXPECTED RETURN = RISK-FREE RATE + RISK PREMIUM

Demoting the risk-free rate by R_F and the return on the market as a whole by R_M, the CAPM is stated as follows:

$$K_e = R_F + BETA(R_M - R_F)$$

This is the seminal CAPM expression to be applied. As a proxy for the risk-free rate, I used the current yield on long-term Treasury bonds of 8.7 percent as of the end of May 1990.

As a proxy for Gulf's beta, I used Southern's beta of 0.75 as a proxy for Gulf. For the market risk premium, a range of 5.0 to 7.0 percent was used. The 7.4 percent estimate is obtained from the seminal Ibbotson-Sinquefield study of historical stock and bond returns from 1926 to 1988. The study shows that stocks have outperformed long-term government securities by 7.4 percent over long time periods. Since long-term government bonds are currently yielding 8.7 percent, the implied market return is 7.4 percent + 8.7 percent = 16.11 percent for the market.

The 5.0 percent market risk premium is consistent with a simple annual DCF analysis applied to the market as a whole. The dividend yield on the aggregate market is currently 3.1 percent (Value Line Investment Survey's median of estimated yields, 05/25/90), and the mean consensus growth for the IBES universe of common stocks is of the order of 11.5 percent. Adding the two components together produces an expected return on the aggregate equity market of close to 14.6 percent, or a risk premium in excess of 5 percent over long-term Treasury bonds. Since long-term government bonds are currently yielding 8.7 percent, the implied market return is 5.0 percent + 8.7 percent = 13.70 percent for the market.

Using those input values, my CAPM estimates of equity costs ranged from 12.45 percent to 14.25 percent, with a midpoint of 13.35 percent. For example, using a beta of 0.75 and a market risk premium of 7.4 percent, the CAPM equation becomes:

$$K_e = 8.7\% + 0.75 \times (16.1\% - 8.7\%) = 14.25\%$$

I then added a conservative allowance of 30 basis points to the midpoint estimate of 13.35 percent to reflect flotation costs. The resulting CAPM-derived estimate for Gulf's common equity cost is 13.65 percent.

EMPIRICAL CAPM ESTIMATE

As is well known in the academic finance literature, the CAPM model produces a downward-biased estimate of equity cost for companies with a beta of less than 1.00. Expanded CAPM models have been developed which relax some of the more restrictive assumptions underlying the traditional CAPM responsible for this bias, and which enrich its conceptual validity. These expanded CAPM models typically produce a risk-return relationship that is flatter than the traditional CAPM's prediction, consistent with the empirical findings of the finance literature. This literature is summarized in Copeland & Weston, Financial Theory Corporate Policy, Addison Wesley, 3rd ed., 1988, Chapter 7. The following equation provides a viable and conservative approximation of the cost of equity capital estimate suggested by these expanded CAPM's:

$$K_e = R_F + 0.25\ (R_M - R_F) + 0.75\ \text{BETA}\ (R_M - R_F)$$

If the same input data ranges are inserted that were used with the traditional CAPM, the above equation produces estimates ranging from 12.76 percent to 14.71 percent, with a midpoint of 13.74 percent. Adding a 30 basis points flotation allowance yields an ROE estimate of 14.04 percent.

Q. Please summarize your risk premium estimates of Gulf'S cost of equity.

A. The table below summarizes the return on equity results from my five risk premium studies:

Study	Implied Equity Return
Southern Company long-term	15.26%
Southern Company short-term	13.77%
Electric Utility Industry	13.47%
CAPM	13.65%
Empirical CAPM	14.04%

I did not place any weight on the risk premium estimate derived from the long-term analysis of Southern market data, as it is upward-biased relative to the other four results.

IV. SUMMARY AND RECOMMENDATIONS

Q. **Please summarize the results of your analyses regarding the cost of Gulf's cost of equity.**

A. The table below summarizes the estimates of cost of common equity obtained from the various methods. The average rate of return on equity based on all the techniques is 13.54 percent, and the truncated mean, obtained by removing the high and low estimates from the computation of the average, is 13.54 percent.

It is important to point out that these results must be viewed as a whole rather than selectively. It would be appropriate to select any one particular number from the table and infer Gulf's equity costs from that number alone. No one individual result provides an infallible estimate of a fair return, but each result provides useful evidence from a different perspective. I also reiterate my earlier caveat concerning the applicability of the standard DCF model in the current environment of increasing relative market valuation and volatile stock prices.

Southern Company's cost of equity reflects the weighted average risk of its constituent subsidiaries. Since four of its five operating subsidiaries do not have nuclear risk exposure, while Georgia Power, which represents approximately one-half of Southern Company's assets, does experience substantial nuclear risk exposure, the expected equity return of 13.25 percent applicable to Gulf Power, to the extent that it was partially derived from market data based on Southern Company risk and return data, is slightly upward-biased. But as stated earlier, to the extent that the fair return was partially derived from market data based on electric utilities which have less financial risk than Gulf Power, the fair return is slightly downward-biased, partially offsetting the former effect.

It should be pointed out that Gulf Power's non-utility operations represent a negligbie proportion of its total operations and, therefore, have no effect on the cost of capital estimates I have developed; investors perceive Gulf Power as an electric utility operation at this time. If such operations were to be segregated, it should not be imputed to the equity cost but rather to the weighted average of the capital structure.

Based on the results of all my analyses, it is my opinion that a just and reasonable return on the common equity of Gulf Power at this time is 13.50 percent.

COST OF EQUITY

SUMMARY OF RESULTS

DCF METHODS	Return
Southern Company	13.25%
Comparable Risk Electrics	13.03%
RISK PREMIUM METHODS	
Southern Company	13.77%
Electric Utility Industry	13.47%
CAPM	13.65%
ECAPM	14.04%
AVERAGE	13.54%
TRUNCTUATED AVERAGE	13.54%

Q. If interest rates or risk premiums change significantly between the date of filing your direct testimony and the date oral testimony is presented, would this cause you to revise your estimated cost of equity?

A. Yes. Interest rates do change over time, and risk premiums change also, although much more sluggishly. If substantial changes were to occur between filing time and the time the record is closed, they should be reflected in the order.

Q. Does this conclude your testimony?

A. Yes, it does.

MR. STONE: There is also an Appendix A to his testimony. It's a paper on Flotation Cost Allowance, and we neglected to have an exhibit number assigned to that.

CHAIRMAN WILSON: 599.

(Exhibit No. 599 marked for identification.)

MR. STONE: With that, our next witness will be Mr. Kilgore.

J. THOMAS KILGORE, JR.

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

DIRECT EXAMINATION

BY MR. STONE:

Q Would you state your name and your position with Gulf Power Company and your business address for the record.

A J. T. Kilgore, Jr. I'm Manager of Marketing, Planning and Research for Gulf Power Company. My business address is 500 Bayfront Parkway, Pensacola, Florida, 32501.

Q Mr. Kilgore, are you the same individual that prefiled direct testimony, in your name, dated December 15, 1989, in this docket?

A Yes, I am.

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

A Yes, I do. We have made a change to one assumption regarding the migration of a large industrial customer from the PXT to the LPT rate class. This assumption change affected the LPT PXT and SS rate classes in Schedules 1, 2 and 3 of my direct testimony. These have been replaced by updated Schedules 7, 8 and 9, respectively, in my rebuttal testimony.

In addition, Schedules 10, 11, 12 and 13 of my rebuttal testimony represent dated versions of certain MFRs that were affected by this assumption change.

Q With those noted changes, if I were to ask you the questions contained in direct testimony, would your answers be the same?

A Yes, they would.

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

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

(Exhibit Nos. 200 through 216 marked for identification>)

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony of
J. Thomas Kilgore, Jr.
In Support of Rate Relief
Docket No. 891345-EI
Date of Filing December 15, 1989

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. Please describe your education and professional background.

A. I graduated from Auburn University in 1980 with a Bachelor of Science degree in Industrial Engineering. I am a member and past chairman of the Marketing Planning and Research section of the Southeastern Electric Exchange, Marketing Division, and I am also a member and past chairman of the Research and Forecasting Committee of the Florida Electric Power Coordinating Group. In addition, I am an active member of the Electric Utility Market Research Council, and the Electric Utility Forecasters' Forum, and have served as chairman or member of a number of committees and task forces within the Southern electric system.

I began my career in the electric utility industry at Alabama Power Company in 1976 as a cooperative education student. Upon graduation from Auburn University in 1980, I began work with Gulf Power Company as a Technical Services Engineer. In 1982, I was promoted to Supervisor of Forecasting and Marketing Planning and served in that capacity until January, 1988, when I was promoted to my current position as Manager of Marketing Planning and Research.

Q. **What are your areas of responsibility with Gulf Power Company?**

A. I am responsible for the following areas:
(1) Forecasts of Customers, Energy Sales, Peak Demands, and Base Revenues, (2) Load Research, (3) Marketing Research and, (4) Marketing Planning.

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

A. The purpose of my testimony is to present the approach, methods and results associated with Gulf's forecast of customers, energy sales, peak demands and base revenues.

I will also address the Company's cost of service load research activities and results.

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, comprised of 6 Schedules, be marked for identification as Exhibits 100 205 (JTK-1)

Q Are yo" the sponsor of certain Minimum Filing Requirements (MFRs)?

A. Yes, these are listed on Schedule 6 at the end of my exhibit. To the best of my knowledge, the information contained in these MFRs is true and correct.

Q. Mr. Kilgore, you indicated you are responsible for the forecasts of Gulf's customers, energy sales, peak demands and base revenues. What tabulations have you provided detailing your retail projections for 1990?

A. I have provided three tabulations of test year forecast data: Schedule 1 details retail customers by rate; Schedule 2 details retail energy sales by rate; and finally Schedule 3 details retail base revenues by rate. These schedules also provide totals by customer classification.

Q. Please summarize your Schedule 1.

A. Our projections call for a total of 292,610 retail customers by year-end 1990, an increase of 6,756 customers over revised year-end projections for 1989. This represents an anticipated annual growth rate of 2.4 percent for 1990. By comparison, historical growth rates of 3.5 percent, 2.6 percent and 2.3 percent were experienced in 1986, 1987, and 1988, respectively. Current projections for year-end 1989 indicate an annual growth rate of 2.2 percent.

Q. Please summarize your Schedule 2.

A. Retail energy sales are expected to total 7,699,490,093 kilowatthours in 1990, representing an increase of 4.2 percent over revised year-end projections for 1989. The retail kilowatthour sales forecast by class consists of the following: Residential: 3,344,901,953, comprising 43.4 percent of retail; Commercial: 2,214,169,017, comprising

23.8 percent; Industrial: 2,124,157,282, comprising 27.6 percent; and Street Lighting: 16,261,841, comprising 0.2 percent.

Q. Please summarize your Schedule 3.

A. Retail base revenues are expected to total $249,281,859 in 1990. The base revenue forecast by class consists of the following: Residential: $133,163,227, comprising 53.4 percent of retail; Commercial: $73,877,125, comprising 29.6 percent; Industrial: 40,978,153, comprising 16.4 percent; and Street Lighting: 1,263,354, comprising 0.5 percent.

Q. What are the objectives of your forecasting efforts?

A. As with any forecast which serves as a basis for planning, we strive for the greatest possible accuracy, particularly in the short-term (0-2 years). We recognize the fallacy, especially in the long-term, of believing that we can accurately predict all of the major factors comprising the changing economic, legislative and market environments. With this recognition of change, we have adopted two primary objectives in preparing our long-term forecasts: (1) comprehensive coverage of major issues and trends that may impact Gulf and its customers, which are addressed and quantified through the use of scenarios, and (2) effective communication to management and planning functions of the underlying causes and potential implications associated with various scenarios. We have implemented this scenario approach to enhance our flexibility and allow for more informed decision-making in a changing environment.

Since the primary focus in these proceedings is on the short-term forecast, particularly the test year, the base case or most likely forecast scenario will serve as the basis for discussion of forecast results.

Q. **What level of accuracy has been achieved in your recent short-term forecasts of retail customers, energy sales and base rate revenues?**

A. Employing the same basic methods and approach currently in use, our forecast accuracy has consistently exceeded the standards which we consider appropriate for planning purposes. Schedule 4 provides a summary of our short-term accuracy for the last four budget forecasts issued prior to the test year forecast.

Q. What rate schedules are included in your residential class forecast of customers and energy sales?

A. Our residential class is comprised of three rate schedules: RS (residential service) which represents the majority of class energy sales, rate schedule RST (residential service, time-of-use), and finally rate schedule OS (outdoor service - lighting).

Q. Please describe the methods used to prepare your forecast of residential customers.

A. The immediate short-term forecast (0-2 years) of residential customers is based primarily on projections prepared by division personnel. This approach takes advantage of their knowledge of local market and economic conditions, which is gained through direct interaction with economic development agencies, state and federal agencies, developers, builders, lending institutions, and other key contacts.

For the remaining forecast horizon (3-25 years), the Regional Economic Growth Impact Study (REGIS), a mathematically intensive forecasting model, is utilized in the development of residential customer projections. At the center of this system is a cohort survival routine approach in which population by age group is aged from one time period to the next. The model's migration/demographic component, given an initial population age distribution, together with forecasts of migration, births and deaths, projects population by age group into the future.

The forecast of residential customers is an outcome of the final section of the migration/demographic element of the model. The number of residential customers Gulf expects to serve is calculated by multiplying the total number of households located in the eight counties in which Gulf provides service by the percentage of customers in these eight counties for which Gulf currently provides service.

The number of households referred to above is computed by applying a household formation trend to the previously mentioned population by age group, and then by summing the number of households in each of five adult age categories. As indicated, there is a relationship between households, or residential customers, and the age structure of the population of the area, as well as household formation trends. The household formation trend is the product of initial year household formation rates in the Gulf service area and projected U.S. trends in household formation.

Q. Please describe the methods used to prepare your residential class energy sales forecast.

A. The residential energy sales forecast is prepared using the Residential End-Use Energy Planning System (REEPS), a model developed for the Electric Power Research Institute (EPRI) by Cambridge Systematics, Incorporated, under Project RP1211-2. The REEPS model integrates elements of both econometric and engineering end-use approaches to energy forecasting. Market penetrations and energy consumption rates for major appliance end-uses are treated explicitly. REEPS produces forecasts of appliance installations, operating efficiencies and utilization patterns for space heating, water heating, air conditioning and cooking, as well as other major end-uses. Each of these decisions is responsive to energy prices and conservation/demand-side initiatives, as well as household/dwelling characteristics and geographical variables.

The major behavioral responses in the simulation model have been estimated statistically from an analysis of household survey data. Residential market surveys provide the data source required to identify the responsiveness of household energy decisions to prices and other variables.

The REEPS model forecasts energy decisions for a specified number of different population segments. These segments represent households with different demographic and dwelling characteristics. Together, the population segments reflect the full distribution of characteristics in the customer population. The total service area forecast of residential energy decisions is represented as the sum of the choices of various segments. This approach enhances evaluation of the distributional impacts of marketing or demand-side initiatives.

For each of the major end-uses, REEPS forecasts equipment purchases, efficiency and utilization choices. The model distinguishes among appliance installations in new housing, retrofit installations and purchases of portable units. Within the simulation, the probability of installing a given appliance in a new dwelling depends on the operating and performance characteristics of the competing alternatives, as well as household and dwelling features. The installation probabilities for certain end-use categories are highly interdependent.

Appliance operating efficiency and utilization rates are simulated in the REEPS model as interdependent decisions. Efficiency choice is dependent on operating cost at the planned utilization rate, while actual utilization depends on operating cost given the appliance efficiency. Appliance and building standards affect efficiency directly by mandating higher levels than those otherwise expected.

The sensitivity of efficiency and utilization decisions to costs, climate, household and dwelling size, and income has been estimated from historical survey data.

Major appliance base-year unit energy consumption (UEC) estimates are based on either metered appliance data or conditional energy demand regression analysis. The latter is a technique employed in the absence of metered observations of individual appliance usage and involves the disaggregation of total household demand for electricity into appliance specific demand functions.

Conditional energy demand models are regressions which explain residential customers' demands for electricity as functions of the energy-using equipment that they own, weather conditions, demographic and dwelling characteristics, and other factors playing a major role in total household energy consumption. The mathematics underlying this method rely upon the premise that consumption through a particular end-use must be zero if the end-use is not present, and if the end-use is present, energy consumption levels are represented as dependent on weather, demographics, income and other variables.

The structural design of the REEPS model is oriented primarily toward long-term forecasting and strategic analysis, with energy forecast outputs stated in annual terms. In order to develop monthly allocations and to enhance short-term (0-2 years) sales forecast accuracy, a disaggregate single equation econometric model is used in calibrating the short-term REEPS model output. The basic structure of this econometric model represents monthly kilowatthours per customer per billing day as a function of weather (heating and cooling degree hours), price of electricity and seasonal variations.

Q. What rate schedules are included in your commercial class forecast of customers and energy sales?

A. The commercial class represents the most heterogeneous market served by Gulf. Included in this class are customers from the following seven rate schedules: GS (general service), GST (general service, time-of-use), GSD (general service demand), GSDT (general service demand, time-of-use), LP (large power service), LPT (large power service, time-of-use) and OS (outdoor service).

Q. Please describe the method used to prepare the commercial class customer forecast.

A. The immediate short-term forecast (0-2 years) of commercial customers, as in the residential sector, is prepared by division personnel. A review of the techniques and results for each division is undertaken by the corporate forecasting section, under my direction. Special attention is given to the incorporation of new major commercial establishments and consistency with general assumptions.

Beyond the immediate short-term period, commercial customers are forecast as a function of residential customers, reflecting the growth of commercial services to meet the needs of new residents. Implicit in the commercial customer forecast is the relationship between growth in total real disposable income and growth in the commercial sector.

Q. **Please describe the methods used to prepare your commercial class energy sales forecast.**

A. The Commercial Sector End-Use Energy Demand Forecasting Model (COMMEND), which was developed by the Georgia Institute of Technology through EPRI Project RP1216-06, serves as the basis for the major portion of Gulf's commercial energy sales forecast. Specifically, the GSD, GSDT, LP and LPT rate schedule customers within the commercial class are represented in the COMMEND forecast.

The COMMEND model is an extension of the capital-stock approach used in most econometric studies. This approach views the demand for energy as a product of three factors. The first of these factors is the physical stock of energy-using capital, the second factor is base-year energy use, and the third is a utilization factor representing utilization of equipment relative to the base-year.

Changes in equipment utilization are modeled using short-run econometric fuel price elasticities. Fuel choice is forecast with a life-cycle cost/behavioral microsimulation submodel, and changes in equipment efficiency are determined using engineering and cost information for space heating, cooling and ventilation equipment and econometric elasticity estimates for the other end-uses (lighting, water heating, ventilation cooking, refrigeration, and others).

Three characteristics of COMMEND distinguish it from traditional modeling approaches. First, the reliance on engineering relationships to determine future heating and cooling efficiency provides a more sound basis for forecasting long-run changes in space heating and cooling energy requirements than a pure econometric approach can supply. Second, the simulation model uses a variety of engineering data on the energy-using characteristics of commercial buildings. Third, COMMEND provides estimates of energy use detailed by end-use, fuel type and building type.

Gulf's most recent Commercial Market Survey, conducted in 1984, provided much of the input data required for the COMMEND model. This data is augmented with current floorspace estimates and projections. The model produces forecasts of energy use for the end-uses mentioned above, within each of the following business categories:

1. Food Stores
2. Offices
3. Retail and Personal Services
4. Public Utilities
5. Automotive Services
6. Restaurants
7. Elementary/Secondary Schools
8. Colleges/Trade Schools
9. Hospitals/Health Services
10. Hotels/Motels
11. Religious Organizations
12. Miscellaneous

The COMMEND model similar to the REEPS model used in the residential sector, is structurally oriented toward long-term forecasting and strategic analysis. A disaggregate single equation econometric model which represents monthly kilowatthours per customer per billing day as a function of weather (heating and cooling degree hours), price of electricity and seasonal variations is used to develop monthly allocations and to calibrate the short-term COMMEND model output.

Q. **What rate schedules are included in your industrial class forecast of customers and energy sales?**

A. Gulf's industrial customer class consists of customers billed under the GSD (general service-demand), GSDT (general service-demand, time-of-use), LP (large power service), LPT (large power service, time-of-use) and PXT (large high load factor service, time-of-use) rate schedules.

Q. **Describe the methods used to prepare your industrial class energy sales forecast.**

A. The short-term industrial energy sales forecast is developed using a combination of on-site surveys of major industrial customers, trending techniques, and multiple regression analysis. Forty-two of Gulf's largest customers, representing over 90 percent of industrial class sales, are interviewed to identify load changes due to equipment addition, replacement or changes in operating characteristics.

The short-term forecast of monthly sales to these major industrial customers is a synthesis of the detailed survey information and historical monthly load factor trends. The forecast of short-term sales to the remaining smaller industrial customers is developed using multiple regression analysis.

The long-term forecast of industrial energy sales is based on econometric models of the chemical, pulp and paper, other manufacturing, and nonmanufacturing sectors. The industrial forecast is further refined by accounting for expected cogeneration installations and the effects of the supplemental energy schedule.

Q. How was your forecast of territorial wholesale energy prepared?

A. The short-term forecast of energy sales to territorial wholesale customers is based on interviews with these customers, as well as recent historical data. A forecast of total monthly energy requirements at each wholesale delivery point is produced. Energy requirements purchased from the Southeastern

Power Administration (based on current contracts) by our wholesale customers are then removed from the total requirements to arrive at sales for resale. The long-term forecast is based on estimates of annual growth rates for each delivery point, according to future growth potential.

Q. **Please describe the methods used to prepare your peak demand forecast.**

A. The peak demand forecast is prepared using the Hourly Electric Load Model (HELM), developed by ICF, Incorporated, for EPRI under Project RP1955-1. The model forecasts hourly electrical loads over the long-term.

Load shape forecasts have always provided an important input to traditional system planning functions. Forecasts of the pattern of demand have acquired an added importance due to structural changes in the demand for electricity and increased utility involvement in influencing load patterns for the mutual benefit of the utility and its customers.

HELM represents an approach designed to better capture changes in the underlying structure of electricity consumption. Rapid increases in energy prices during the 1970's and early 1980's brought about changes in the efficiency of energy-using equipment. Additionally, sociodemographic and microeconomic developments have changed the composition of electricity consumption, including changes in fuel shares, housing mix, household age and size, construction features, mix of commercial services, and mix of industrial products.

In addition to these naturally occurring structural changes, utilities have become increasingly active in offering customers options which result in modified consumption patterns. An important input to the design of such demand-side programs is an assessment of their likely impact on utility system loads.

HELM has been designed to forecast electric utility load shapes and to analyze the impacts of factors sucn as alternative weather conditions, customer mix changes, fuel share changes, and demand-side programs. The structural detail of HELM provides forecasts of hourly class and system load curves by weighting and aggregating load shapes for individual end-use components.

Model inputs include energy forecasts and load shape data for the user-specified end-uses. Inputs are also required to reflect new technologies, rate structures and other demand-side programs. Model outputs include hourly system and class load curves, load duration curves, monthly system and class peaks, load factors and energy requirements by season and rating period.

The methodology embedded in HELM may be referred to as a "bottom-up" approach. Class and system load shapes are calculated by aggregating the load shapes of component end-uses.

Q. Please describe the procedure used to develop the 1990 retail base rate revenue forecast.

A. We applied the appropriate rate schedules to the monthly projections of customers, energy sales and billing demands for each customer classification. The revenue forecast is based upon rates currently reflected in Gulf's tariff.

Q. You indicated earlier that you are responsible for Gulf's load research activities. What tabulations have you provided detailing the load research data being used in these proceedings?

A. Schedule 5 provides a summary of rate class data collected during 1987, including presentation of significant variables which allow for relative comparisons. Also included in this summary is information concerning sample sizes, system coincident peak demand and relative accuracy.

Q. **Does your 1987 Cost of Service Load Research sample design meet the requirements of the Cost of Service Load Research Rule, Docket No. 820491-EU, Order No. 13026?**

A. Yes, the sample design does meet the requirements of the referenced rule.

Q. **Are you aware of any changes to the load data used for cost of service purposes?**

A. Yes, a correction was made to MFR E-14 subsequent to its use in the jurisdictional separation study. This correction involved modification of coincident peak demands for the test year. The change had no significant impact on test year retail rate base calculations. In fact, the 12 month average coincident retail peak demand was increased by only 262 kilowatts, or approximately .02 percent. Our decision to make the correction was based on our desire to achieve the best possible allocation of costs among individual rate classes, which was then incorporated within the rate design discussed in Mr. Haskins' testimony.

Q. Does this conclude your testimony?

A. Yes, it does.

COMMISSIONER EASLEY: Could I just ask a question.

Does that change any of the numbers, for instance on Page 5, where your summarize Schedule 3?

WITNESS KILGORE: It changes some numbers on Schedules 1, 2 and 3 of my direct testimony. I have those changes. There are about eight to ten numbers that are affected, but those are contained in my rebuttal testimony schedules.

COMMISSIONER EASLEY: Does it change the numbers as set forth in the narrative section of your direct testimony?

WITNESS KILGORE: No, there are no substantive changes there.

MR. PALECKI: Will there be copies of the changes handed out to the parties?

MR. STONE: All the schedules were handed out to the parties when the rebuttal testimony was filed. We are not changing anything other than --

MR. PALECKI: Oh, okay, so it's the same schedules that are with the rebuttal testimony?

MR. STONE: With one exception, that is Schedule 10, which I will hand out at this time.

MR. STONE: Just for clarification, the exhibits that Mr. Kilgore has identified as updating his initial direct testimony, go through Schedule 14 -- I'm sorry, Schedule 13 of his rebuttal testimony. Those were all prefiled. There is one change to Schedule 10 and we have handed that out to all the parties this morning, and with that, Mr. Kilgore is tendered for cross examination. I'm sorry, he has a summary of his testimony.

MR. PALECKI: Before we start the summary, you say there has been one change. It's a multipage document. Could you please point out where the change is located?

WITNESS KILGORE: Yes. The change in that document is in the LPT rate classification between voltage levels. We had one customer at the wrong voltage level, in the Schedule 10 version. So that would appear throughout -- on the period 1 and period 2 pages wherever you see the LPT voltage level row.

Q In which two voltage levels are you referring to?

A Those are levels 3 and 4. Also, before I begin my summary, I didn't listen carefully enough to Commissioner Easley's question.

The one number that does change consistent with my rebuttal testimony is the retail base rate revenue forecast. That's contained on Line 7 of Page 5 of my direct testimony. The correct number is 249,390,628.

Q With those changes your responses would be the same?

A Yes, they would.

MR. STONE: If I have not already asked, I would ask that his testimony be inserted into the record as though read.

CHAIRMAN WILSON: It's already been done.

Q (By Mr. Stone) Now, would you summarize your testimony?

A Yes. The purpose of my testimony is to demonstrate that the test year base rate revenue forecast and the load data provided on behalf of the Company in this docket represent a sound and a reliable basis for these proceedings.

I will briefly describe the forecast methods employed by the Company, the levels of short-term forecast accuracy achieved in recent years and the test year forecast results which I'm supporting. I will also briefly discuss the load research data provided for use in cost of service determination.

My responsibilities include directing the development and production of forecast of the Company's customers, energy, peak demands and base rate revenues.

We strive to achieve the greatest practical short-term accuracy, balancing this objective with others designed to yield comprehensive coverage of significant issues impacting the Company and our customers, and which provide a framework for estimating the effects of demand-side initiatives, including conservation, load management and cogeneration.

We employ advanced forecasting methods and approaches which are widely accepted in the electric utility industry. A blend of end use, econometric and customer survey based approaches are used with the objective of applying the techniques best suited to each customer segment.

These methods have yielded outstanding short-term accuracy results in recent years with mean percentage deviations over the period 1986 through 1989 of -0.6% per customer, 0.7% for weather normalized sales and 0.3% for base rate revenues. The 1990 test year forecast reflects a continuation of this record of short-term accuracy as evidenced by our year-to-date result.

My responsibilities also include direction of the Company's load research activities, the load data developed and provided for cost of service determination in this docket was collected during 1987.

The study design met the requirements of the Commission's cost of service load research rule and yielded reliable estimates of rate class coincident contributions to system peak demands.

In summary, the 1990 test year base rate revenue projections and rate class load estimates provided in this docket represent a sound and reliable basis for informed decision making by this Commission. This concludes my summary.

MR. STONE: I tender Mr. Kilgore for cross examination.

CROSS EXAMINATION

BY MR. BURGESS:

Q Mr. Kilgore, in projecting the revenues, do you have a factor included in the projection for elasticity of demand?

A Yes, we do.

Q Can you tell me, is that factor included for the entire year of 1990, or have you tried to space it, so to speak, for anticipating the date at which you would project the rate increase might be implemented?

A Our test year assumptions regarding price increases were that we would receive an interim increase effective the end of the first quarter of 1990. Our assumption was that we would receive what at the time we were assuming would be our full request for interim. At that time we had assumed that it would be on the order of $15 to $16 million. As it turned out, we ended up asking for more than that.

The impact of the permanent increase does not appear in our forecast results until 1991, as our assumption at the time that we prepared the forecast was that the permanent rates and the incremental increase associated with the effect of those rates would not take place until 1991.

Q I see. So would it be correct then that the amount of the rate increase then does not include any adjustment or taking into any account the elasticity of demand for the permanent increase?

A Not for the test year, that's correct.

Q But you do take it into account for the interim increase?

A That is also correct.

Q Is it also correct that you take into account other variables in the elasticity of demand, any kind of increase in taxes that might go on the bill?

A Yes. Our price assumptions reflect increases to all components of price, whether they be base rate, fuel, franchise fees that you mentioned -- and that's for obvious reasons. The effect that price increases have on customers' consumption is not really related to what component of the bill increases.

They see the bottom line increase and react accordingly. So, for a number of years, really since we have been able to come up with reliable price variables, we have included, for our forecast period, our best estimate of the total price that we'll see in the forecast horizon in our estimates.

Q So, if you anticipate, for example, an increase in fuel in a given year, even though that's not in base rates, it's nevertheless affects the elasticity of demand for the base rates, is that correct?

A It's affects customers' consumption through the elasticity effect, that's correct.

Q So, if you anticipated an increase in the fuel costs, then you would have factored in, what would you call it, a repression of rates or suppression of rates or suppression of usage, I'm sorry?

A Suppression, yes.

Q Suppression? The flip side of that would be stimulation, would it not?

A You could use that term, yes.

Q Historically, let's take, for example, the last rate case that Gulf Power was in, and you had a projected test year then also, is that correct?

A I believe that's correct. Are you referring to the 1984?

Q Yes, the 1984 case.

A I believe that's correct, yes.

Q Would you have also included a elasticity of demand variable in any projections in that case?

A Yes. To the extent that we could. We have made a lot of progress since that point in time, and have incorporated some new forecasting models that we feel better capture that price effect.

Q Do you happen to know whether, in the last rate case, the elasticity factor was calculated in for the base rate increase for the test year or was it similiar to this year, where you actually assumed implementation following the test year?

A I don't recall. I do know that the end use forecasting model that we used in the residential sector did not have an explicit price term. I also know, however, that we attempted to reflect in our short term forecast of the industrial sales, the effects of that price increase.

So, my recollection is there was some attempt to account for the price effect.

Q After you -- okay. So that would drive somewhat or have an effect on the billing determinancy, the estimated usage, the usage, is that correct?

A Yes.

Q And then the Commission comes, after the Commission reaches a decision as to how much increase actually to allow the Utility, which in the last case was lower than what the Utility sought, do you then adjust the usage projections to reflect a different increase than was initially incorporated into the projection?

A Of course, that would occur naturally in our next forecasting cycle. If the difference were significant, I would expect that we would be asked to perform that kind of adjustment.

Q Do you recall whether it was done in the last rate case?

A I don't recall.

Q Have you adjusted your projected usage figures for the actual interim increase that the Commission has allowed in this case?

A Would you repeat the question, please?

Q Yes. In this case, in the current docket, have you, subsequent to receiving your actual interim increase, adjusted the usage projection accordingly?

A No. We haven't. And I'll elaborate on that a little bit. That would, first of all, it required revisions to a great number of schedules involved. Even more importantly, though, the test year elasticity impact is rather small, approximately 2/10ths of 1% on test year revenues, as I recall.

That's in my rebuttal testimony. And primarily because we're showing that year-to-date through April, on a weather normalized basis, we have actually over forecast sales. We feel such an adjustment is not warranted, at this time.

Q So, you would say that you have probably not incorporated that or you have not incorporated that, but apparently there seemed to be other factors that work on the other side that have overcome that particular miss projection?

A That's correct.

MR. BURGESS: Thank you, Mr. Kilgore, that's all I have.

CROSS EXAMINATION

BY MR. McGLOTHLIN:

Q Mr. Kilgore, you're the individual who developed the test year demand and energy characteristics, is that correct?

A That's correct.

Q You did that by class, is that correct?

A By rate class, that's correct.
Q And the test period in this case is a forecast of the 1990 period, is that right?
A Yes.
Q Therefore it was necessary to start with some historical information and derive your projections from historical?
A Where we had historical information available, that's true.
Q With respect to the forecast for the 1990 coincident peak by class, is it true that you began with the 1987 historical actual figures?
A Yes. That is true.
Q And those were adjusted for known changes that would be in effect for 1990? Is that correct?
A Yes. By virtue of the fact that the 1990 test year that we are expanding to in the load development process, reflects the levels of coincident peak demand and energy that we're projecting for test year.
Q In projecting the test year coincident peak per class, you also utilized the 1987 historical kilowatt hour sales figures, is that right?
A That's also correct.
Q And the projections of coincident peaks were

arrived at by taking the ratio between projected 1990 kilowatt hour sales, '87 historical, and applying that to the '87 coincident peak, is that correct?

A That's correct, that's how we arrived at the unbalanced coincident.

Q Is it true that, with respect to the '87 historical kilowatt hour sales, and the 1990 projected kilowatt hour sales, that you used in deriving for most of the peak of the test period? You excluded supplemental energy kilowatt hour sales.

A Yes. And I need to explain what that means. We excluded what we estimate to be the incremental sales during those periods. Apparently there was some misunderstanding, and I believe Staff's position on that issue is stated in such a way, that one might think that we had excluded all sales during supplemental energy periods, and that's not the case.

We only excluded from both Period I and Period II, our estimates of incremental sales over and above the firm sales or sales that we normally would have expected to have seen.

Q Would you take a moment and describe the supplement energy rider that is the source of SE sales, some of which were excludeed in this exercise.

A Yes. I'll describe it, briefly. The

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arrived at by taking the ratio between projected 1990 kilowatt hour sales, '87 historical, and applying that to the '87 coincident peak, is that correct?

A That's correct, that's how we arrived at the unbalanced coincident.

Q Is it true that, with respect to the '87 historical kilowatt hour sales, and the 1990 projected kilowatt hour sales, that you used in deriving for most of the peak of the test period? You excluded supplemental energy kilowatt hour sales.

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We only excluded from both Period I and Period II, our estimates of incremental sales over and above the firm sales or sales that we normally would have expected to have seen.

Q Would you take a moment and describe the supplement energy rider that is the source of SE sales, some of which were excludeed in this exercise.

A Yes. I'll describe it, briefly. The

supplemental energy rider is available as a rider to any customer who is taking service under rate schedule LP, LPT, PX, or PXT. The Company may designate the supplemental energy periods, from time to time, by notifying all customers served under this rider. And that determination is at the sole discretion of the Company.

The tariff reads such that no supplemental energy period will be designated for less than a 24-hour period, and generally it's not the intention of the Company to declare a supplemental energy period when anyone of three conditions is likely to occur.

The first of those is that the average system fuel land for the SEP makes, exceeds the average fuel cost recovery factor. The second would be when the Southern System territorial monthly peak hour demand is being set. And then finally, when the Gulf System territorial monthly peak hourly demand is being set.

Is that what you're looking for, with that kind of explanation?

Q Yes, sir. And with respect to the three circumstances you just delineated under which, by terms of the SE rate, SE sales cannot be made. Would you agree that the latter two, that is, when it's likely that the Southern territorial peak maybe established or when the Gulf territory peak may be established, those two are designed to prevent SE sales from contributing to the additional demands calls, additional demand costs?

Q That's correct.

Q To your knowledge, does Gulf Power administer this SE rider in a way that prevents those sales from taking place during the prescribed circumstances we just discussed?

A Yes, we do.

Q So would you agree that by excluding certain portions of the SE sales, you have not distorted the calculation of the coincident peaks per class that are utilized with the '87 historical data and your '90 projections?

A I would agree with that statement, yes.

MR. McGLOTHLIN: No further questions.

CROSS EXAMINATION

BY MR. PALECKI:

Q Did you develop the 12 CPKW for the test year from historic demands estimated from the 1987 load research study?

A Yes, we did.

Q My next question concerns the development of the 1990 monthly CPKW for each class and voltage level with the exception of SE rider customers and OS-I, II and III, were the 1990 monthly CPKW for each class and voltage level developed as a product of 1987 historic monthly CPKW and the ratio of the projected month's kWh sales to the corresponding 1987 historic month's kWh sales?

A Yes.

Q For PXT and LP/LPT customers taking service on the SE rider, did you exclude what you considered to be the kWh used by SE customers during SE periods in this calculation?

A Well, as I expained earlier, we excluded what we considere^d to be the incremental sales during this period. I think it's important to distinguish between incremental sales and total sales during this period.

Q Where in any materials that you provided Staff is there any indication that only incremental kWh for SE customers were excluded in the development of the 12 CP?

A Hearing Exhibit 485 gives the best indication, and, first of all, I'll admit up front that we are used to and familiar with referring to SE energy sales at our Company in the context of those incremental sales. And in phone discussions with Staff, we might have presumed too much on the part of

Staff's familiarity with our use of the term "SE" because it is apparent from Staff's position that there was some confusion on that, and I've had discussion within the last week with Staff to make sure they understood, what, in fact, was excluded.

But, continuing with my answer, in hearing Exhibit 485, we were asked to provide for Period 1 and Period 2 for 1987 and for 1990 the rate class energy excluded and included ion the CPKW development. You can see in the columns entitled "Percentage," which represent SE as a percentage of the total kilowatt hour excluded figure that SE is rather small in proportion to the total energy sales.

Since we've also provided information in Hearing Exhibit 487 that indicates that we typically declare SE periods approximately 70% of the hours of the years, one would think it would be intuitively obviously that this would not represent, in Hearing Exhibit 485, total sales during that period, or else it would approximate something on the order of 70% of energy sales during the test year, or during the Period I year for that matter.

That would be the,probably, most obvious example of how we've only included the incrementals, or excluded the incremental SE sales in that CPKW development.

Q But nowhere on Exhibit 485 or anywhere else in the schedules that you gave Staff, did you actually state or point out that the incremental sales were not excluded?

A No, We did not.

Q Did your response to Interrogatory 137 of Staff's Eighth Set, which is Exhibit 488, show that the actual 1977 12 CPKW for PXT was 99,186?

A Yes, it does.

Q And for 1989 that actual 12 CPKW for PXT was 119,448?

A Yes, that's also correct.

Q Did you use an unbalanced 1990 12 CPKW in the development of the 12 CPKW of 104,728 per PXT; specifically, was that an unbalanced 1990 12 CPKW?

A That's correct.

Q Is this approximately 1500 kW less -- excuse me, 15,000 kW less than the actual 1990 12 CPKW in your revised nonmigration cost-of-service study?

A Yes, it is.

Q If you had not excluded the SE kWh in the development of the 12 CPKW for LPT and PXT, would the unbalanced 1990 23 CPKW for the PXT have been 111,893?

A Yes, it would have.

Q And for the LP/LPT, would it have been 135,245? (Pause)

A Would you repeat that number, please?

Q 135,245.

A Did you include LP in that number?

Q No.

A Let me recalculate it. I thought you said LP/LPT.

Q I'm sorry, we did include LP. That was LP/LPT. (Pause) I'm sorry, Mr. Kilgore, we want just LPT.

A Okay, you're sure?

Q Yes (Pause)

A 135,245?

Q Yes.

A Yes, that's correct.

Q Thank you. Are your 1987 and 1989 12 CP values for PXT and LPT actual numbers, and not estimates, because the customers have time-recording meters.

A Yes, the 1987 numbers are actual numbers.

Q What about the 1989 numbers?

A Yes, they are also, as provided in this exhibit.

Q Excuse me?

A As provided in this exhibit.

Q Doesn't your methodology of excluding the kWh result in a higher 12 CP load factor, as well as the use of a smaller number of 12 CPKW for these customers and these classes?

A It results in a higher 12 CPKW load factor than if we had included that energy. It does not result in a higher CPKW load factor than what I would expect in a normal test year. And that's because of the conditions of supplemental energy sales. And the reason that we excluded those SE sales is that our estimate of SE sales has increased by over fourfold since Period 1. And I know that this issue is kind of difficult to explain. If it would help, I've got a two-page handout that might help illustrate what we're talking about here, if that would be helpful.

Q If your counsel wishes to bring that out in redirect, we have no objection to that.

MR. STONE: Except that he's offering to explain it now and I think if it fits with his explanation, it would be more helpful to the Commission.

CHAIRMAN WILSON: Let's do it this way.

(Pause)

Q (By Mr. Palecki) While the exhibit is being handed out, is your forecast of the 1990 SE kWH less than the SE customers used in 1989?

A Yes, it is slightly less.

Q And if you could please explain the handout you've just --

A Yes, I'd be glad to. This exhibit is intended to illustrate the effects of our removing the incremental SE sales from the load development using a one-week period in September, for example purposes. It's a two-page exhibit, Page 1, or the top page, is a graph showing September 1987 peak week, supplemental energy sales in relation to total energy sales for this group of customers, this group of customers being those customers on the SE rider. We used actual load data to prepare this graph.

But, to explain, the cross-hatched areas represent periods during which we were declaring the supplemental energy rider. The period in the middle is a non-SE period during which we anticipated we might achieve a monthly system peak. The dark areas on the top of the cross-hatched line represent what we estimate to be the incremental sales attributable to the SE rider; that is, sales that we otherwise would not have seen without the rider.

The second page carries that same baseline load shape, baseline being without the SE sales, forward to the test year, drawn by the ratio of the energy in Period II to Period I.

You can see, if you compare the two, that the amount of area under the supplemental energy designation has grown considerably, and that, in essence, is our reason for excluding the SE energy in our CPKW development both from Periods I and Period II.

If we had in our Period I data a level of SE sales that was close to what we expected for the test year, we would have, in fact, probably included the SE energy. If, for example, we had used 1989 load research data, if that had been available to us at the time of the filing, that represents a level of SE sales, very similar to what we expected for the test year, and this adjustment would not have been warranted. However, because of the level of increase in SE sales and because of the fact that the conditions of the rider warrant that that energy is not used coincident with the system peaks, we thought it was inappropriate to include that in the expansion.

COMMISSIONER BEARD: Tell me again what the cross-hatched area represents?

WITNESS KILGORE: The cross-hatched area represents supplemental energy periods. The actual energy that you see in that cross-hatch is sales that we normally would have expected to have seen during those supplemental energy periods.

COMMISSIONER BEARD: Why would I -- apparently, I am incorrect in finding it odd that I can overlay the cross-hatched areas from September of '87 to September of '90.

WITNESS KILGORE: Okay --

COMMISSIONER BEARD: Direcly overlay.

WITNESS KILGORE: Yes. And the reason for that is to reflect the process that we actually used to expand the 1987, or Period I load characteristic on the test year in development of CPKW. This exhibit and the fact that you're able to overlay Period II with Period I, is consistent with the approach that we use in developing CPKW for 1990 test year.

COMMISSIONER BEARD: The reality is that you would expect -- I understand the methodology you're using, but does the methodology match reality? You don't expect the same number of megawatt sales in 1990 that you had in 1987?

WITNESS KILGORE: Of course not.

COMMISSIONER BEARD: But you've got a significant dramatic change in the rider portion of that. It would seem that you have an apples-and-oranges, just from a layman's standpoint anyway.

WITNESS KILGORE: Well, then, this is for illustrative purposes. The graph is not intended to indicate that we expect Period 2 sales to exactly equal Period 1 sales, but simply to demonstrate that there is quite a significant difference between what we expect Period 2 supplemental energy sales to be compared to what they were in 1987.

COMMISSIONER BEARD: Well -- and I understand that. I guess the point I'm trying -- I'm trying to understand the relationship of -- let's talk theory for a minute. Obviously, there is a dramatic difference.

Can I assume that relationship to be correct? I.e., if you've doubled your standard sales, then the relationship may, in fact, be not so significant, they may have remained fairly constant, or can I assume from this that you'll have a greater number of rider sales percentage sales relative to your basic sales?

WITNESS KILGORE: Yes, you can, and that's also reflected in the hearing exhibit that we were looking at earlier. Hearing Exhibit 485 provides a comparison of the actual percentages seen in 1987, and expected in 1990; and for the LPT rate class we've got an increase going from .39% to .89%, so that one more than doubles. For the PXT rate class it goes from 2% to over 9%, so that one increases more than fourfold.

COMMISSIONER BEARD: Okay. Go ahead. I'm sorry.

Q (By Mr. Palecki) Doesn't the SE rider simply provide forgiveness of billing demand during SE periods?

A It is true that it provides forgiveness, if you'd like to use that term, of demands.

It does not -- demands experienced during that period are not used for billing purposes.

Q Isn't it true that all kWh used by customers taking servic_ on the SE rider must be served by Gulf?

A Yes, I believe that's also a condition of the tariff, of the rider.

Q And the SE rider sends a price signal that it will be more expensive kWh to use during non-SE periods?

A Yes. I could agree with that.

Q Doesn't your response to Interrogatory 137 of Staff's Eighth set, which is Exhibit 488, show that the actual 12 CP load factor for the PXT class in 1987 was 101 percent?

A 1987?

Q Yes, 1987 for the PXT class.

A Yes, that's correct.

Q Is the load factor for the 12 CPKW for PXT used in the nonmigration study 107%?

A Let me check a number. Yes, that's correct.

Q Why did Gulf deviate from the methodology described in E-14 in the Minimum Filing Requirements for all rate classes except OS in developing test year unbalanced 12 CPKW for the SE customers?

A I'm sorry, could you repeat that question?

Q Specifically, I'm asking why Gulf deviated from the methodology described in the MFRs.

A In development of the --

Q Where they excluded this kWh.

A For SE?

Q Yes.

A Well, as I attempted to explain earlier with the handout, it's simply because we feel that doing so would unfairly penalize customers on the SE rider by including energy that we know from the conditions of the tariff cannot be delivered during periods coincident with our system peaks.

Q Gulf didn't exclude the SE kWh in developing the 12 CP when they filed the last rate case in Docket 881167, did they?

A No. But we feel that we should have after the fact.

Q Well, why the difference in methodology, and why wasn't it pointed out to Staff when you filed your schedules?

A We feel that it was obvious from the work papers that are required to be filed in the case, specifically the MFR E-14, that some energy had been excluded.

I've already explained the rational for excluding that energy. It was our feeling that it would be obvious from the information filed in the case that that energy had been excluded.

Q Have you seen the thickness of the filing of the MFRs, the extensiveness of the paper work that was filed in this case?

A Yes, and I've also seen the thickness of the follow-up, the interrogatories and other discovery.

Q If SE customers had changed their usage patterns in these peak hours relative to their SE and total energy usage, shouldn't there be an improvement in their actual 1989 12 CP load factors compared to the 1987 load factor?

A All other things being held equal, there should be.

Q Does Gulf's response to Interrogatory 137 of

Staff's Eighth Set, which is also Exhibit 488, show that the actual 1989 12 CP load factor for the SE customers is 91% compared to 101% in 1987?

A Yes, that's correct.

Q For the next set of questions I'd ask you to refer to the MFR Schedule E-14. Specifically, MFR Schedule E-14 requires the Utility to provide a description to show how coincident and noncoincident demands for the test year were developed for each class at the meter. The work papers for the actual calculations are to be provided. If a methodology other than the application of ratios to class coincident an noncoincident load to actual MWH sales is used, to derive the project demands, the justification for the use of the methodology must be provided.

Does the Company's text anywhere on Schedule E-14 state that the kWh used during SE periods were excluded from actual kWh and forecast kWh?

A No, that's not contained in the text.

Q And in compliance with the MFR, is a justification provided in the MFR for the deviation in methodology for SE customers?

A I'm not sure I understand what you mean when you say a justification for the change.

Q Would you agree that there was a change or a derivation in methodology used? And to follow that, do you agree that the Minimum Filing Requirements, the requirements of this Commission, are that you provide justification for any such deviation?

A The requirements are that we provide an explanation of changes to methodology, and I guess this is an instance where we're talking about detail versus fundamental change in methodology. We feel that our basic methodology is essentially the same as it has been in previous cases. There were a number of minor items contained within the volume of this load development that we were unable to spell out in narrative, probably a large number of points. But this is just one of those, and we didn't feel was significant enough to include in this narrative explanation.

Q Are all kWh SE and non-SE shown in the work papers on Pages 2 through 21 of the MFR Schedule E-14?

A Yes. Excuse me. Only the non-SE, or what we consider the firm or baseload sales are contained in these pages, and that's another place -- or another reason it should have been apparent is that there is an obvious mismatch between the total energy sales numbers provided here and the those provided in the E schedules for billing determinants.

Q Well, could you recheck your answer on that? Are you sure? It appears to Staff that both SE and non-SE are shown on the work papers.

A Maybe it would help. Which version of the MFR E-14? There have been numerous versions along the way; which version are we lookirg at?

Q The original MFRs that were filed in the case.

A Okay. (Pause)

Q I'll refer you to Pages 103 and 122 of the original MFRs, specifically for PXT, we have the annual sales, MWH, 879,877. Going to Page 122, we have a similar figure. Our point is that, one, in reading the MFRs, would never know that these SE figures were excluded, is that correct?

A Yes. And that would concern me if we hadn't spent numerous hours along the way on the telephone with Staff and through discovery on interrogatories explaining exactly how, the approach that we've taken in will developing the CPKW.

That track is well documented and littered with pages and pages of explanatory material on our approach used in developing the CPKW. So, it's obvious that there was not any attempt on the Company's part to just push that aside.

Q Well, how long did it take Staff to get to that point where you were confronted with this situation?

A You'd have to ask Staff that question.

Q Is there any data or calculation in the work papers on Pages 3 to 21 of the MFRs to show that these kWh had been excluded?

A Not in those work papers, no.

Q And by applying the methodology you described on Page 1 of Schedule E-14, to the data on Pages 2 through 21 of Schedule 14, could one arrive at the CPKWs shown on Pages 123 through 127?

A Let me make sure I understand the question. Your question is, using the Period I energies, whether or not one could arrive at the Period II CPKW?

Q Correct. Using the data supplied on Pages 2 through 21 of Schedule 14, using that data, could one arrive at the 12 CPKWs shown on Pages 123 through 127?

A Just a second. (Pause) not in the work papers contained in the original MFR filing, which provide a breakdown of voltage level at the numeric level or using the numeric designation. That was provided to Staff in additional work papers, which broke out in more detail the voltage levels so that the calculations could be followed through.

Q Those were provided to Staff at the end of April, correct?

A We first provided those in January.

Q We would ask a late-filed showing documentation of when that was provided to Staff.

A Yes. We would be glad to provide that.

MR. PALECKI: May we have a number for that?

CHAIRMAN WILSON: That would be 600.

(Late-filed Exhibit No. 600 identified.)

Q (By Mr. Palecki) When the original MFRs were calculated, the actual adjustment was made on slightly more detailed work paper that was not provided to Staff, correct? That's not in the MFRs?

CHAIRMAN WILSON: What is the, what's the point of this cross examination?

MR. PALECKI: Well, Staff's position is that there, this was our next question, that there have been three deviations from the Minimum Filing Requirements, in that it took Staff extensive digging, discovery and just sheer perseverance to ever even be able to realize what exactly was done in this particular circumstance.

CHAIRMAN WILSON: Well, I appreciate that, but what's the point of the cross examination?

MR. PALECKI: We'll go on. We just wanted to point out there has been deviation from the Commission's Minimum Filing Requirements, and a violation of the rule.

Q (By Mr. Palecki) The next set of questions I would like to ask refer to Issue 137. Does the Company currently have time-recording meters on all SE customers, LP/LPT, Stratum Two customers with demands over 900 kW, and all PXT customers?

A Yes. We do.

Q Do these meters provide as much or more data than the meters used to collect the load research data required by Commission Rule 25-6.0437, Cost of Service Load Research Data?

A They provide as much as. I couldn't say they provide more information.

Q Since all SEPX and larger LP/LPT customers have time recording meters, isn't it true that you can actually sum their demand for the 12 monthly peaks to arrive at a group value, rather than estimating the value, using a complicated statistical formula?

A Yes, that's true; for a historical period, you can do that.

Q These next questions refer to Issue 138, how should rates for a separate supplemental or how should rates for a supplemental energy rate schedule be designed? At your deposition you were asked to provide a maximum metered kW expected for SE customers for 1990 by rate class. Was your response, in Deposition Exhibit 6, which is Exhibit 495 in this hearing, that you found no reason to expect any change of enough magnitude to warrant development of different estimates over the 1989 maximum, actual maximum metered kW?

A Yes. Given the information that we had available to us, we felt that our current test year forecast was appropriate.

Q This next set of questions refers to GSD customers. Does the Company currently have any contracts with GSD customers? (Pause)

A I'm not sure. Perhaps Mr. Haskins could better answer that question.

Q We'll refer those questions to him.

These next questions refer to recreational lighting. Did you assume, in developing the 12-monthly or 12 CPKW, that recreational lighting would be used every day of the year from sunset to 10 p.m. and at a constant rate everyone of these hours?

A Yes. We did.

Q Would you agree that these assumptions are the most favorable you could have used with respect to developing class peak hour demand, which allocate primary distribution system costs for recreation lighting?

A They were favorable in terms of the noncoincident peak kW development. However, I'm informed by Mr. O'Sheasy, that the impact on the cost of service study is insignificant.

Q Well, in other words, it results in the smallest number class peak kW and the smallest amount of primary distribution costs you could arrive at, correct?

A That's correct. But what I'm saying is, if we had varied our assumption a great deal in either direction, it would have made very little difference, one way or the other.

Q Would you agree that it is unclear whether these assumptions result in an over- or underestimation of this class's demands during the 12 monthly coincident peak hours?

A Yes. I would agree. But I would have to qualify that by saying that we used the best information available for this class of customers. It would be cost prohibitive, in my opinion, to have load research recorders set aside separately for the recreational class of customers, which represents less than 15% of the OS-III rate Schedule.

Q Have you or your staff reviewed the sheets with the monthly kWh and kW data for these customers?

A What sheets are you referring to?

Q The monthly CAM sheets which reflect kWh and kW data.

A Yes. We've reviewed the customer accounting memo sheets that have actual meter reading consumption data.

Q Have you observed that approximately 36% of the billing month had zero kWh usage? (Pause).

A There were some with readings of zero. Of course, they were not billed zero for that month.

Q Will you accept, subject to check, that 36% of the billing months had zero usage?

A Subject to check, yes.

Q Does the Company intend to put load research meters on a sample of the recreational lights?

A As I mentioned earlier, I believe that's cost prohibitive. Our preferred approach to getting better information for that segment of customers is to survey the customers themselves and gain some information regarding the usage profiles, by season and day type, and apply that to our assumptions in load development.

Q So you would agree, then, that this is a rate whose costs are judgmental?

A As with most any other rate in a forecast test year, that's true.

Q These next questions refer to Issue 153: "Should the assumed 10% forced outage rate for self-generating customers that is built into the SS rate design be continued?" Order 17159, which is the order in generic investigations of standby rates, requires the utilities to file annual reports on billing data load, coincidence and load factor data, and customer generation and availability data. Has Gulf Power filed any of these annual reports?

A The first year for which we have four years data for any of the customers was 1989, and we plan on making our first filing of that data, even though it will be of limited value, this year.

Q The next questions concerned migration between rate classes. Because the load research for the GS, GSD and Stratum One of LP/LPT is collected through probability samples of each of these classes, wouldn't there be statistical problems with estimating 12 CP and NPC demands, if the class populations are altered by significant migrations of customers between the three classes?

A Those three classes, again, being GSD --

Q RS and GS, and GSD.

A I would be very surprised to see migrations between RS and GSD. RS is a residential rate.

Q Excuse me, let me go over the classes again: GS, GSD and Stratum One of LP/LPT.

A That would depend on the magnitude of the migrations, and to some extent on the load characteristics of those customers migrating. (Pause)

Q Do you have some revisions to Interrogatory 217 of Staff's Thirteenth set?

A Do I have that? Is that the question, whether I have that?

Q Yes.

A Yes.

Q Have you provided those to Staff?

A Yes.

Q We'd like to have these revisions marked as the next consecutive exhibit number.

CHAIRMAN WILSON: That would be 601.

(Exhibit No. 601 marked for identification.)

MR. PALECKI: Thank you, we have no questions.

CHAIRMAN WILSON: Any questions? Redirect?

MR. McGLOTHLIN: Mr. Wilson, this was passed out after my turn at cross. Would you permit just a couple of questions on that?

CHAIRMAN WILSON: Yes.

FURTHER CROSS EXAMINATION

BY MR. McGLOTHLIN:

Q Mr. Kilgore, I want to make sure I understand the relationship shown on the two-paged diagram you passed out.

A All right.

Q Does the methodology for deriving projected CP from historical CP depend on consistency between the ratio of energy to CP during '87and the projected ratio of energy to CP for '90?

A Yes, it is dependent.

Q And if I understand what you have done here, you've shown that with respect to that portion of SE energy that is considered incremental, that would not have occurred but for the SE rider, the portion that is incremental is projected to increase substantially relative to the overall portion of SE sales, is that correct?

A That's correct.

Q And so if you were to include the solid-line incremental sales in '87 and larger solid line of '90 in the ratioing and the derivation of the CPs for '90, that would have the effect of increasing the projected CP for '90, even though under the terms of the rate, these sales cannot contribute to coincident peak, is that correct?

A That is also correct.

MR. McGLOTHLIN: Commissioner, I'd like to have a number assigned to that.

CHAIRMAN WILSON: We'll make this Exhibit No. 602.

(Exhibit No. 602 marked for identification.)

Q (By Mr. McGlothlin) And the last question, Mr. Kilgore, would you agree then that by removing the solid-line incremental sales, you have avoided distortion rather than creating one?

A That's certainly what we attempted to do. That's correct.

MR. McGLOTHLIN: Thank you, Mr. Wilson.

CHAIRMAN WILSON: Let me ask you a question. In your testimony on Page 18 you refer that you make a forecast of territorial wholesale energy. Where would I find the information about what wholesale energy sales are made by Gulf Power, or are there any?

WITNESS KILGORE: I don't believe it's contained in the filing.

CHAIRMAN WILSON: Are there territorial wholesale sales?

WITNESS KILGORE: Yes, there are.

CHAIRMAN WILSON: To whom?

WITNESS KILGORE: We have essentially two customers, Florida Public Utilities, that's four delivery points, I believe, or five; and the City of Blountstown, a municipality.

CHAIRMAN WILSON: FPUC and who?

WITNESS KILGORE: The City of Blountstown.

COMMISSIONER BEARD: Those are handled directly by Gulf as opposed to going through Southern Services?

WITNESS KILGORE: I'm not sure I understand the question.

COMMISSIONER BEARD: Does Gulf Power directly sell wholesale power to Blountstown and Florida Public Utilities, or do they -- does Southern Services sell it to Blountstown?

WITNESS KILGORE: Gulf Power Company sells that energy. It's territorial sales for Gulf Power Company to those wholesale customers.

CHAIRMAN WILSON: What's the magnitude of those sales, just ballpark?

WITNESS KILGORE: I've got a number here, so that I won't have to guess. (Pause)

For the test year, about 267 million kilowatt hours.

CHAIRMAN WILSON: For the two of them?

WITNESS KILGORE: For the two. And that's about 3%, roughly, of total territorial sales.

COMMISSIONER BEARD: Help me. Maybe I just missed the boat somewhere. Tell me the difference between a UPS sale and a territorial sale.

WITNESS KILGORE: I probably couldn't elaborate on all the differences, but what I can tell you is that the sales to territorial wholesale customers are under the RE tariff in our rate book, and are a part of our service territory, or ten-county northwest Florida service territory, where generally the UPS sales are to what we refer to as off-system customers.

COMMISSIONER BEARD: Is there a contractual length of time associated with those territorial sales?

WITNESS KILGORE: Yes, there is.

COMMISSIONER BEARD: But no particular unit, per se, in other words?

WITNESS KILGORE: Not to my knowledge.

COMMISSIONER BEARD: Do you have data relating to demand, peak demand, for those two customers?

WITNESS KILGORE: We have data available. I'm not sure that I have any here with me today that I can refer to, but we certainly have data available.

COMMISSIONER BEARD: If you aren't the appropriate witness for these questions, who would be?

WITNESS KILGORE: I'm not sure where the line of questioning is going, so I'm not sure.

COMMISSIONER BEARD: Well, I really just want to understand territorial. I think I understand, one, that it's -- I understand that they're in your territory. I understand that.

WITNESS KILGORE: Right.

COMMISSIONER BEARD: And they are full requirements customers?

WITNESS KILGORE: Yes.

COMMISSIONER BEARD: And there is a time, associated length of contract associated with those sales?

WITNESS KILGORE: That's also correct.

COMMISSIONER BEARD: And FERC sets the rate?

WITNESS KILGORE: Yes.

CHAIRMAN WILSON: Could you see if a later witness could have that information, which is the demand that these customers put on the system?

MR. STONE: The demand that -- we'll certainly be able to provide that either by late-filed exhibit or through a later witness.

CHAIRMAN WILSON: One way or the other.

WITNESS KILGORE: Or through my rebuttal. We can have it available.

COMMISSIONER BEARD: Yeah. I'm just interested in how that works.

MR. PALECKI: Staff has a brief question on Exhibit 602. This is the first time we've seen the exhibit.

FURTHER CROSS EXAMINATION

BY MR. PALECKI:

Q How did you format or forecast the SE sales during the non-SE hours for September 1990 in Exhibit 602?

A What we did for purposes of illustration is simply took the ratio of incremental SE sales for a period -- from Period II over Period I and applied that to the shaded area. So you're seeing roughly the four or four and a half of one ratio that you see on an annual basis in, I believe, Hearing Exhibit 45 that we looked at earlier.

Q If you hold this up to the light you see that it exactly matches the 1987 non-SE time period, is that correct?

A Yes, as we discussed with Commissioner Beard earlier.

Q Doesn't the historical data show that the non-SE periods have grown? These are on peak hours, correct?

A The cross-hatched areas?

Q No, the non-SE areas.

A Well, some of them are on-peak, some of them are off-peak. You're covering several days here. So you're going to have both on-peak and off-peak hours for these time-of-use rate customers embedded in that period.

Q What is your philosophy in showing them as identical to the 1987 period when historical data shows that they've grown in 1989?

A There's no philosophy. The reason we use that load shape is simply that we don't have a load shape forecast for this group of customers. I had no load shape to build from. What I wanted to illustrate, one more time here, was the impact of these incremental SE sales.

Q Wouldn't this chart be more accurate had you used the 1989 data? As a matter of fact, we'd like to ask for a late-filed.

A Can I answer that question first?

Q Well, yes. Answer the question.

A No, it would not, because the Period I load data that we used in the load development is from 1987, not from 1989.

MR. PALECKI: Thank you.

CHAIRMAN WILSON: All right. Redirect?

MR. STONE: Yes.

REDIRECT EXAMINATION

BY MR. STONE:

Q Mr. Kilgore, regardless of whether it was stated so directly in the MFRs, were the SEP -- I'm sorry, the SE, supplemental energy period, kilowatt hours excluded, did they only contain the incremental supplemental kilowatt hours?

A Yes.

Q And have you had extensive discussions with the Staff concerning that matter and the development of the exclusion?

A Very extensive.

Q And have you provided copies of the detailed work papers concerning this calculation?

A Yes, we have.

Q Has this calculation been the subject of much discovery in this docket?

A Yes, it has.

Q What is the purpose of the SE rider?

A The SE rider is designed to provide benefits to both participating customers and all ratepayers through sales of low-cost energy to the group of customers participating. Obviously the effect for those customers on the SE rider is a lower energy rate, cents per kilowatt hour.

Also, all ratepayers see the benefit in that we're spreading some base cost over a larger base of kilowatt hour sales.

Q This larger base of kilowatt hour sales, does it affect the Company's planning of resources to serve peak hour demand?

A No. Because, as we've discussed earlier, they're not coincident with our monthly peak demands and, more importantly, with our summer season peak demands.

Q Is the supplemental energy period which has the discounted or the lower price of energy for the SE customer, is that declared at the sole option of the Company?

A Yes. It is the sole discretion of the Company to declare -- on when to declare those SE periods.

Q And I believe you already indicated that the tariff itself specifies that there are three conditions which the Company shall not declare an SE period.

A That's correct.

Q Was it also your earlier testimony that the

Company has properly administered this tariff?

A Yes. I can speak particularly to the two conditions regarding coincident peaks, both Southern's and Gulf's, because that's something in my area we can monitor and evaluate continuously. To the best of my knowledge, all three conditions have been met since the inception of the rider.

MR. STONE: I have no further questions.

Commissioners, I would ask Exhibit 602 be admitted into evidence.

CHAIRMAN WILSON: Without objection.

COMMISSIONER GUNTER: Let me ask one question.

CHAIRMAN WILSON: Exhibit 602 will be admitted into evidence.

(Exhibit No. 602 admitted into evidence.)

CHAIRMAN WILSON: What about 601?

MR. PALECKI: Yes, we would move 601 be admitted.

CHAIRMAN WILSON: Without objection, Exhibit 601 will be admitted into evidence as well.

(Exhibit No. 601 admitted into evidence.)

COMMISSIONER GUNTER: Are you the proper witness to ask what your projected Schedule E sales would be?

WITNESS KILGORE: No, sir, I'm not.

COMMISSIONER GUNTER: Do you know who is?

WITNESS KILGORE: I believe that would be Mr. Parsons.

COMMISSIONER GUNTER: All right.

MR. STONE: Commissioner, if it's not Mr. Parsons it would be Mr. Howell, both of whom will be coming up on rebuttal.

CHAIRMAN WILSON: Thank you very much.

WITNESS KILGORE: Before I leave, I've got a 12 CPKW for the wholesale class that we did provide in response to Staff's set of interrogatories. It's roughly 43,000 kW, or 43 megawatts.

MR. PALECKI: Staff has one question on recross.

CHAIRMAN WILSON: Wait a minute. What is that in response to?

WITNESS KILGORE: To your -- excuse me -- to Commissioner Beard's question, I believe, regarding the level of demand for our wholesale, territorial wholesale customers.

COMMISSIONER BEARD: What is it?

WITNESS KILGORE: It's roughly 43 megawatts. It's an average 12 CPKW number that we use for the test year 1990.

MR. PALECKI: Staff has one question.

CHAIRMAN WILSON: All right, briefly.

RECROSS EXAMINATION

BY MR. PALECKI:

Q Referring to Exhibit No. 488 at Page 2 under Subsection B, which is the PX/PXT customer on the SE rider, the 1987 12 CPKW is reflected as approximately over 22,000, whereas through 1989 12 CPKW is almost 35,000. Don't we have an actual increase in usage of almost 15% -- excuse me, 50% in that class of customers in peak-hour demand?

A In 12 CPKW. It's not an annual peak-hour demand. If it would help, maybe an analogy would help here because I think what's at issue is whether or not we should have excluded those SE sales. And it's very difficult, just looking at these numbers, to get a yes or no answer to that question. But I'll try to keep this brief.

If we were to take a baseball player, for example, playing for the Boston Red Sox, and trade him to the St. Louis Cardinals and he's playing in a new league, got a new batting instructor, his batting average goes from 300 with ten home runs for the Red Sox to 280 with seven home runs for the St. Louis Cardinals.

On the basis of reviewing those numbers, one might come to the conclusion that, one, the batting instructor for the St. Louis Cardinals has done a poor job with this baseball player; and, two, that it was a bad trade, perhaps, for the Cardinals to make. But, upon closer examination, you take into account the fact that Fenway Park in Boston is a great place for hitters. So this particular baseball player's offensive statistics were tainted by the fact that he was playing in Fenway Park. He's playing now in the National League in not nearly so good a hitter's park in half of his games. You might also find out, if you look closer, that the batting instructor taught him to be a much more patient hitter. He strikes out less; he's on base more; he's actually a more valuable offensive player than he was when he was with Boston.

That's enough baseball, but the point of the analogy --

COMMISSIONER BEARD: What about the Cleveland Indians? Let's get down to brass tacks.

CHAIRMAN WILSON: What about the Chicago White Sox?

COMMISSIONER GUNTER: The White Sox are doing good right now.

WITNESS KILGORE: They do look good.

The point of the analogy is that you can look at the wrong numbers, in this case just the CPKW, and draw the conclusion that the SE rate, or our treatment of the SE kilowatt hours, had something to do with this decrease in load factor for the fact that we're selling SE perhaps coincident with peak.

And that's not the case. It's all these other factors that aren't accounted for in the 12 CPKW statistics and the other information that we've got that contribute to these different CPKW load factors. And as an example, we've got a group of customers here, one of which has converted from a brown paper production to white paper production. We've got another one that has substantially had some problems in this period from '87 to '89 with some of their generation, things that are over and beyond the impact of the SE rate schedule and which Gulf Power has no control over, that affect these numbers. And I think that it's -- especially for a small group of customers like this, you can use these statistics and draw some wrong conclusions. It's something that's done all the time. I've made the mistake myself and I think it's careful -- I think it's important that we not do that when we're talking about the SE issue here

COMMISSIONER BEARD: You've also taught your kilowatt hours to be more patient.

WITNESS KILGORE: That's correct.

CHAIRMAN WILSON: Wait for the right call.

COMMISSIONER BEARD: Wait for the right.

WITNESS KILGORE: Wait for the right SE period.

COMMISSIONER BEARD: Thank you.

CHAIRMAN WILSON: All right. No further questions. You may step down. Thank you very much.

(Witness Kilgore excused.)

CHAIRMAN WILSON: All right, we're going to take a 10-minute break and you can call your next witness and then we'll hopefully pick up the pace.

(Recess taken).

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COMMISSIONER GUNTER: All right. Let's get started.

MR. STONE: Commissioner, Mr. O'Sheasy has not been sworn.

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MICHAEL O'SHEASY

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

DIRECT EXAMINATION

BY MR. STONE:

Q Please state your name for the record.

A My name is Michael O'Sheasy and I work for Southern Company Services. My business address is 564 Perimeter Center, East, Atlanta, Georgia 30346

Q Are you the same Michael T. O'Sheasy who has prefiled direct testimony in this docket dated December 15, 1989?

A Yes, I am

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

A Yes, I do.

On Page 9, Line 3 of my direct testimony, that's Page 9, Line 3, there's a reference to "Schedule 8" that should read "Schedule 7."

Then on Page 15, Line 24, the word "his, h-i-s" should read "this, t-h-i-s." Those are the only changes.

Q With those changes, if I were to ask you the questions contained in your prefiled direct testimony would your responses be the same?

A Yes, they would.

MR. STONE: Mr. Chairman, I ask that Mr. O'Sheasy's testimony be inserted into the record as though read.

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

MR. STONE: Mr. O'Sheasy's exhibits have previously been identified and stipulated.

(Exhibit Nos. 170, 230, 231, and 232 previously stipulated into evidence.)

GULF POWER COMPANY
Before the Florida Public Service Commission
Direct Testimony of
Michael T. O'Sheasy
In Support of Rate Relief
Docket No. 891345-EI
Date of Filing December 15, 1989

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

A. Michael T. O'Sheasy, 64 Perimeter Center East, Atlanta, Georgia 30346. I am a Senior Engineer in the costing analysis section of the Marketing & Regulatory Support Department of Southern Company Services, Inc. (SCS).

Q. State briefly your educational background and experience.

A. I received a Bachelor of Industrial Engineering from Georgia Institute of Technology in 1970. In 1974, I earned a Master's in Business Administration from Georgia State University. From 1971 to 1975, I was employed by the John W. Eshelman Company -- Division of the Carnation Company -- as a plant superintendent in their Chamblee, Georgia, operation. From 1975 to 1980, I worked for the John Harland Corporation initially as an assistant plant manager and then as a plant manager in their Jacksonville, Florida, plant and finally as their plant manager in Miami, Florida.

I joined Southern Company Services in 1980 as an engineering cost analyst and progressed through various positions to the position which I now hold. Since 1982, my work has focused on activities for Gulf Power Company including cost-of-service support in conjunction with regulatory activities before the Florida Public Service Commission.

Q. What is the relationship between Southern Company Services and Gulf Power Company?

A. SCS is the service company for the operating companies in The Southern Company public utility holding company system. Its major function is to provide engineering and advisory services to the Southern operating companies upon request. These services are provided to the operating companies at cost.

Q. Have you previously testified before this Commission?

A. Yes. I testified before this Commission on behalf of Gulf Power Company in Docket No. 850673-EU regarding standby rates. I was the backup cost-of-service witness for Gulf Power Company in its last completed rate case, Docket No. 840086-EI, and was extensively involved in the preparation of exhibits and MFRs in that case. In addition, I was the cost-of-service witness and submitted prefiled testimony and exhibits in retail rate case Docket No. 881167-EI which was withdrawn before hearings were held.

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

A. The purpose of my testimony is to support the development and results of the cost-of-service study and other related analyses for the test year 1990.

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

A. Yes.

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

Q. Were all of the schedules in this exhibit prepared under your supervision?

A. Yes. Each schedule was prepared for Gulf Power Company under my direction and supervision and was prepared in the exact manner approved by this Commission in its final order for Gulf Power Company's last completed retail rate case, Docket No. 840086-EI.

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

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

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

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

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

Q. Please elaborate on the distinctions between various costs.

A. Certain costs are directly associated with one particular group of customers and are therefore, assigned to that group. For instance, Account 373 contains investment items associated with street lighting and is, therefore, directly assigned to this rate class. Many other costs, however, are used jointly to serve numerous customer rate classes. An example of this might be Account 312-Boiler Plant Equipment. In order to allocate these common costs to the rate groups, consideration must be given to the type and classes of customers, their load characteristics, their number, and various other expense and investment relationships in order to find the cost causative relationship between services provided and cost incurred.

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

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

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

A. The jurisdictional separation of rate base and net operating income developed in Schedules 1, 2, 3, and 4 of my exhibit was used by Mr. McMillan to determine the proposed jurisdictional revenue increase needed in order to achieve the requested rate of return. These jurisdictional separations were calculated according to accepted cost-of-service principles and followed the methodology approved by the Commission. Information from the cost-of-service study summary and unit cost sheets shown in Schedule 8 was used by Mr. Haskins as the primary basis for the design of proposed rates in this docket.

Q. Please explain the general makeup of your exhibit.

A. Schedule 1 of my exhibit is the result of the cost-of-service study in summary form for the 1990 test year utilizing the Company's present rates. It shows the Company's total rate base, revenues, expenses, and net operating income, and the corresponding responsibilities of the retail jurisdiction, as well as the rate classes within the retail jurisdiction. The column denoted "Total All Other Service" represents Gulf's wholesale customers.

while the remaining column represents Gulf's Unit Power Sales customers, all of which are under the jurisdiction of the FERC. Schedule 1.1 reveals the overall rate of return for each class that will exist under the Company's proposed rates.

Q. What section of the cost-of-service study describes investment allocation?

A. Schedules 2.1 through 2.5 describe investment allocations. Schedules 2.1 and 2.2 show how Gross Plant Investment and Accumulated Provision for Depreciation are analyzed and allocated in accordance with the reference notes. Schedule 2.3 produces the allocation of Materials & Supplies, Schedule 2.4 apportions Other Working Capital, and Schedule 2.5 develops Other Rate Base items.

Q. What do the remaining schedules provide?

A. Schedule 3 provides the Analysis of Revenues. Schedule 4.1 details the allocation of O & M expenses to jurisdiction and rate classes. Schedule 4.2 describes Depreciation expense allocation, and Schedule 4.3 presents the Analysis of Taxes Other Than Income Taxes. Schedule 5 contains the Table of Allocators and Percentages. The results of these various schedules, 2 through 5, are summarized in Schedule 1. Schedule 6 states the MFRs for which I am responsible. Schedule ~~6~~ 7 explains in more detail the voltage levels of service.

Q. What is the purpose of Schedule 8?

A. Gulf Power Company requested that I rerun the original 1990 test period cost-of-service study based upon a correction to the original 12 MCP KW loads shown on MFR-E14. This correction is explained by Mr. Kilgore in his testimony. Schedule 8 presents: (a) Present Rate Summary, (b) Proposed Rate Summary, (c) MFR E-8a, and (d) MFR E-8b. The purpose of Schedule 8 is to assist Mr. Haskins' in his rate design.

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

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

The load research data for the 1990 test year were supplied to us by Mr. Kilgore. Mr. Kilgore provided total territorial supply and losses for annual energy and for demand based upon the average of the twelve monthly coincident peaks (12-MCP) projected for 1990. In addition, annual energy sales, 12-MCP demands, non-coincident peak demands (NCP), and the average number of customers for 1990 were given to us by rate class and voltage level. These inputs were then used to calculate the "12-MCP," "NCP," "energy," and "number of customers" allocators.

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

A. The 12-MCP demand is the sum of the highest kilowatt load predicted to occur in each month of 1990 divided by twelve. This concept incorporates the fact that Gulf's system is planned and operated for the purposes of meeting these demands for electricity every month of the year. It also reflects a consideration for scheduled maintenance, unscheduled outages, firm sales and purchase commitments, and reliance on interconnections. In addition, 12-MCP has been the FERC's preferred allocation technique for determining wholesale jurisdictional obligations.

The 12-MCP allocation technique was combined with 1/13 of the energy allocator to produce a 12-MCP and 1/13 energy allocator deemed appropriate by this Commission to allocate generation level costs within the retail jurisdiction. Transmission and subtransmission accounts were allocated upon the 12-MCP allocator.

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

Q. How were the loads developed for the Standby Service (SS) rate class?

A. The SS rate class reflects customers whose self-generation is being backed-up by Gulf Power Company generation. It is only these customers' back-up service which is represented in the SS column; their supplemental service is found in the standard rate upon which their supplemental service is billed.

Q. If this column represents only backed-up service, what type of 12-MCP responsibility do they possess?

A. The FPSC stated in Order No. 17159 that a reservation charge will be calculated by assuming a 10 percent forced outage rate. Also, a self generating customer (SGC)'s outage experience for a particular month may cause a daily demand charge to exceed their normal reservation charge. The customer then pays the larger of the reservation charge or daily demand charge. This indeed is the inherent logic upon which Gulf's tariff is based.

To be consistent then with the tariff and reflect the load requirements which Gulf's planners must meet, the monthly CPKW for each SS customer was calculated by the following procedure:

a. If the customer incurred a reservation charge only for the month in question, his CPKW responsibility for the month was calculated by multiplying his contracted back-up KW by 10 percent.

b. If the customer incurred a daily demand charge for the month in question, his CPKW responsibility for the month was calculated by multiplying the daily billed KW times the number of peak days billed divided by the number of peak days in the month.

Their 12-MCP value was then developed by summing (a.) and (b.) above and dividing by 12.

Q. Why did you not merely pick off their contribution to the system peak from their respective monthly load shape?

A. SS customers are anticipated to only need the utilities' services during scheduled and unscheduled maintenance of their equipment. As a result, their demands on Gulf's system are erratic and difficult to predict. Therefore, a one-year snapshot of their experience would not necessarily be indicative of their typical load requirements of Gulf in following years, nor would it reflect the system requirements which Gulf planned for these customers. For example, there is a good probability that the SGC would not be down during the time of a monthly peak. However, it would not be equitable to attribute no demand responsibility to this customer during that month since Gulf planned investment to handle a 10 percent outage rate for this SGC. Similarly, if the customer share of demand responsibility incurred an outage rate greater than 10 percent, his should be correspondingly greater.

Q. How did you determine KWH responsibility for SS customers?

A. The results reflect the actual KWH predicted to be requested during the test period by the SS customers.

Q. How did you determine NCPKW responsibility for SS customers?

A. As mentioned earlier, primary distribution and secondary distribution costs are allocated upon NCPKW. Because of the erratic nature of SS loads and the fact that Gulf only has four SS customers, any type of class load shape development would not be reflective of the equipment Gulf had to place in service in preparation for serving the customers' eventual outage. As a result, we first looked at contracted back-up KW which is the load requirement for which Gulf planned distribution equipment.

Q. How did you then utilize their contract KW for their share of the NCP allocator?

A. We felt it would not be fair to charge SS customers in the allocation process for the maximum load they could ever incur on Gulf, basically their contract KW, while charging other customers for their NCPKW which is their respective contribution to the rate class peak. Therefore, we converted the SS customers' contract KW into "equivalent NCPKW."

Q. How did you develop "equivalent NCPKW"?

A. A sample of customers was drawn from each rate on which the SS customers' supplemental billing occurred. A factor was developed from the sample which used their NCPKW as a numerator and their contract KW as a denominator. This factor was then multiplied by the corresponding SS customer's contract KW to pare it down to "equivalent NCPKW." The result then became their demand responsibility within the NCPKW allocator.

Q. Do you believe that these methods for developing allocation factors produce accurate results for the SS rate cla ?

A. One must be very cautious when considering the SS rate of return presented on the summary page of Schedule 1 of my exhibit. These procedures for developing allocators are basically sound and are founded upon the principles resulting from the Standby Rate Docket No. 850673-EU. However, there are three major factors to consider here:

1. Standby customers' load requirements are very different from firm customer load requirements. The resulting allocators apportioned costs to this standby class based upon the characteristics of this class. However, the rate revenue was derived from a rate design based upon cost

characteristics of firm customers load requirements modified to resemble perceived standby requirements. This inherent difference in revenue origin and cost allocation could produce unusual results.

2. There are only three standby customers actually requiring backup KW. Of these three, one of them is nearly eight times the size of the remaining two SS customers combined. In addition, the SS class is very, very small compared to the other demand metered classes. It is potentially risky and dangerous to accept as totally accurate the results of an average embedded cost of service study of a rate with: (a) so few customers, (b) with one customer who dominates the class, and (c) inherently small compared to other demand metered classes.

3. As already mentioned, standby loads, by their nature are very erratic. Therefore, it is quite doubtful that a single year observation will necessarily be indicative of subsequent years.

Q. What conclusions should one draw from the rate of return results for this class?

A. Because the rate of return is in a reasonable range, given the possibilities for wide variations I have just discussed, one can deduce that the cost allocation techniques are reasonable. However, one should not infer that these results in their exactitude should control or dictate resultant rate revenue requirements or rate design.

Q. Let's go back to the overall study procedure. Can you explain the steps involved in producing the demand and energy allocators?

A. Balanced system load flows for demand and energy were first developed through a load flow program which spreads total system losses to each voltage level. These levels, which are defined in more detail in Schedule 7 - Levelization Definition, and Schedule E-13 of the Minimum Filing Requirements (MFRs), are used to describe the flow of electricity from generation, through the various transformations, across the various transmission and distribution lines, and the eventual delivery to the customer.

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

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

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

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

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

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

A. The jurisdictional separation was based upon the 12-MCP allocation concept. Again, this methodology is consistent with the one approved in Gulf's last rate case. The methodology also conforms with MFR E-1 and has been the preferred method of the FERC for jurisdictional separation.

Q. On Schedule 8 of your exhibit, the jurisdictional separation factors supplied vary from Schedules 1 through 5 of your exhibit. Is the difference material?

A. There is no material difference between the studies.

A correction was addressed in Mr. Kilgore's testimony, and I provided Schedule 8 to Mr. Haskins as a starting point for rate design. The effect of the correction on the jurisdictional separation is insignificant. I do believe that Schedule 8 provides more correct results for rate design purposes.

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

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

Q. Did you utilize the Minimum Distribution System for defining customer related costs?

A. No. In Order No. 11498 issued in Docket No. 820150-EU, the Commission's preference for defining customer component costs was noted by the statement. "In the last three electric utility rate cases, we have determined that only the meter and service drop portion of the distribution system are properly classified as customer related." In order to conform with Commission policy, the Minimum Distribution System concept was not employed in this study.

Q. You stated that the concepts utilized within the study are in compliance with the directives of the Commission in its final order for Gulf Power Company's last rate case. Do you agree with all of the Commission's stated allocation concepts?

A. No, not necessarily. The fact that we have utilized them in our study should not be construed as our agreement with the theory. We do not necessarily believe that 1/13 of our production plant should be energy related; however, the results of this technique do not diverge dramatically from results of concepts we do believe. Furthermore, we still believe that the Minimum Distribution System is the correct methodology for ascertaining customer related cost.

The Company believes everyone's interest will best be served by focusing on more revenue sensitive issues and not clouding this particular case with any somewhat controversial cost-of-service allocation methodologies.

Q. In your opinion, are the results of the cost-of-service study accurate representations of the rates of return?

A. Most definitely. The cost-of-service results shown on Schedule 1 of my exhibit are indeed fair and accurate statements of the rates of return produced by jurisdiction and by rate class for Gulf Power Company's 1990 test year.

Q. Does this conclude your testimony?

A. Yes, it does.

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

A Certainly.

Simply put, the purpose of my testimony and exhibits is to determine the cost to serve Gulf's retail customers. I will show in my exhibit and related MFRs the development of cost based upon sound, conservative and time-proven analyses that present a fair and accurate picture of the cost which our customers impose upon Gulf Power by requesting Gulf services. In the next few minutes, I shall define cost of service and tell you why it's necessary; reveal the procedures required in conducting a study, and comment on how the results were used in this filing. I'll mention the interaction of key players who helped to put together this complex analysis, and finally underscore the appropriateness of these results as a mechanism for indicating to our customers the economic realities of our valuable product.

A Cost of Service Study is simply a separation of the company's revenues, expenses, and investment in order to reveal how subgroups within the market are or are not contributing to the adequacy of compensation for the utility, for the cost of services which the utility is providing them.

The procedure for any analyst conducting such a study begins with a thorough investigation of all the investment, revenue and expense accounts. The purpose of this detailed review is to determine if any accounts are solely related to a particular customer group or a so-called common in that they were caused by the electrical request of various customer classes.

If the costs are common, the analyst must investigate the essence of each cost to determine their underlying cost-causative factors.

Invariably this research discloses three primary factors which cause costs to be incurred. Number one is the number of customers; number two is the amount of electricity requested over time measured in kilowatt hours, and number three is the maximum demands for electricity required during critical times measured in kilowatts.

After determining the driving influence for each individual cost, the analyst must next obtain reliable load research information.

COMMISSIONER EASLEY: Slow down a little.

WITNESS O'SHEASY: Excuse me. The analyst must next obtain reliable load research information to build cost causative allocators. After this step has been completed, the analyst will be equipped to complete the study.

Those accounts specifically related to a particular group will be assigned to that group. For example, FERC Account No. 373 is only related to the street lighting class and will be assigned to rate OS as a result. Common accounts will be allocated to the retail jurisdiction and retail rates within based strictly upon cost causative allocators. For example, FERC Account No. 355, which contains transmission poles and fixtures, serves all customer groups, and will, therefore, be allocated upon a common demand allocator.

The key sources of data required by this particular study were expenses and investments for the test period for Gulf Power Company and they were provided by Mr. McMillan. Proposed revenues were given to us by Mr. Haskins, and present revenues were supplied by Mr. McMillan. The load research information was submitted by Mr. Kilgore.

The results of the Study serve two primary purposes in this filing. Number one was to determine the cost -- the retail cost responsibility and resultant retail jurisdictional factors. Number two was to serve as a starting point in the individual rate design process by revealing unit costs on a retail rate basis.

We have submitted as part of Exhibit 231 a revised no migration Cost of Service Study. This cost of service analysis is the basis upon which revenue requirements and rate design should be determined for Gulf Power Company for the test year 1990.

The reason we're submitting this study is to improve earlier filed versions as a result of the following enhancements: Within the initial prefiled exhibits a large customer had been presumed to be migrating from PXT to LPT for the test period.

Later, it was determined this customer would remain in PXT. Since this is a large customer found in a rate class comprised of only six customers, it was felt the revision reflecting this fact would be appropriate. This revised study was then filed under Industrial Intervenor's Request for Production of Documents, No. 27.

It was later found that a slight correction was needed to the development of this nonmigrating customer CPKW development, and a customer voltage levalization needed to be changed. These enhancements are thereby reflected in this Cost of Service Study. The results as shown in this exhibit reveal a fair and accurate picture of cost imposed on Gulf Power by the retail jurisdiction in rate groups within. The costing methodologies used in the Study directly correspond with the request of this Commission in Gulf's last retail rate case. The Study was developed in a sound, conservative manner thereby minimizing controversy on provocative costing techniques in order to allow the Commission to focus on the dire need for rate relief.

In conclusion, this Study indicates the cost of providing service to our retail customers in the efficient, reliable manner Gulf's customers demand, and can indeed be used to fairly and appropriately cost Gulf's product. This concludes my summary.

MR. STONE: We tender Mr. O'Sheasy for cross examination.

CHAIRMAN WILSON: Mr. Burgess, do you have any questions?

MR. BURGESS: No, sir.

CHAIRMAN WILSON: Mr. McWhirter, it's nice to have you back with us.

MR. McWHIRTER: Shall I go ahead?

MR. STONE: Yes.

CROSS EXAMINATION

BY MR. McWHIRTER:

Q Mr. O'Sheasy, on Page 6 of your testimony, you identified the driving forces that --

CHAIRMAN WILSON: Is your microphone on, Mr.

McWhirter?

MR. McWHIRTER: I'm sorry.

Q You identified the attributes that you look at in order to develop your cost of service study, is that correct?

A Yes, sir.

Q One of those is the expected peak electrical demand imposed upon the utility, is that correct?

A That is correct.

Q Is it your testimony that customer class contributions to the 12-monthly coincident peak demands cause this Utility to incur production and transmission capital costs?

A Yes, it is, for the purposes of allocating costs.

Q Do you have available to you the MFR E-12?

A Yes. I do.

Q In that MFR, it shows that the average of the 12-monthly peaks is in a range of 1363 megawatts, is that correct?

A On E-12, I see a total system average 12-CP of 1361, 721?

Q Yes, that's on Page 103?

A Column 8, total system.

Q Yes, sir. Now, look at E-26, on Page 279.

A All right, sir.

Q And it shows that in July of this year, you anticipate what kind of peak demand on your system?

A It looks like 1750 megawatts.

Q Did Gulf build its system in order to meet that July demand when it occurs?

A Gulf built its system to serve not only that peak, but peaks throughout the year.

Q But it did build it to serve that peak, is that correct?

A It did, as well as other peaks.

Q And did it also build it to meet that peak plus a reserv_ margin?

A Yes, sir.

Q And what is the reserve margin?

A Well, normally for planning purposes, it's 20 to 25%.

Q All right. Now, if it had built its system, you said, to meet the other peaks as well, and those peaks are generally less than the peak in July, isn't that correct?

A Yes. That's correct, in this particular case here.

Q So if it meets the annual peak, it meets all the others as well, wouldn't it?

A Well, depending on your schedule maintenance requirements.

Q Let's deal with the schedule maintenance requirements. Generally you take your system down in the spring or in the fall, in what we call the shoulder months, for maintenance of scheduled outage?

A That's what you try to do, yes, sir.

Q At the present time, when you take it down in that fashion, what kind of reserve margin do you have, even with the units out during the off-peak months?

A I don't know the exact reserve margin you're looking for. But in general, your reserve margins after scheduled maintenance are less than they are before scheduled maintenance.

Q You mean by "after scheduled maintenance," you mean while scheduled maintenance is going on, that unit is out of service?

A Correct.

Q Therefore your reserved margin would be less?

A That's correct.

Q But even with those units excluded when you look at the demand, say, in the month of March, you still have a reserve margin in the range of 25 to 28%, don't you?

A Normally -- well, when I looked at 1990, I believe that was the case.

Q What about your responsibility for meeting the requirements of your sister companies, are they both, are they summer peaking companies as well?

A Yes.

Q And the Southern Energy Reliability Council, is it a summer peaking entity?

A I don't know.

Q I guess the thing that concerns me the most, that I've never had satisfactorily explained to me, is the old astronaut problem. That is, you have a shuttle there on the launching pad and it requires a couple of million pounds of thrust in order to get into orbit, and then it doesn't require too much thrust while it's orbiting and it doesn't require much at all when it comes down. But if you don't have the thrust to get it the air to begin with, everything falls apart, doesn't it?

A I would presume so.

Q And if you were designing a system such as that, you would design it based on the thrust needed to get it off the ground to begin with, rather than what it needs when it's in the third day of orbit, wouldn't you?

A You're asking some hypothetical questions I'm not an expert on, but --

Q I know you're an expert on many things, (Laughter) but the common man could conclude that even though you're not an aeronautical engineer, isn't that correct?

A It sounds reasonable.

Q So if you're designing a system to meet peak demands, the most important peak demand is that 1750. We found out a lot about that last Christmas when we had problems all through the state, when they weren't able to meet that peak. And that was very important to people at that time, wasn't it?

A Certainly was.

Q And the peak that Florida Power and Light would have had in March, if they designed to meet that, the situation would have been far worse in December than it would have been had they not designed to meet the December peak, isn't that correct?

A That's correct.

Q With your standby service allocation --

A May I add one thing to your analogy on the rocket?

Q Oh, yes, I'm always acceptable --

A I think a possible closer analogy to Gulf would be 12 space shuttle trips throughout the year that are required. And it's somewhat risky to look at one particular test period, like 1990, and pick out the highest peak whenever it fell by chance and say, "Well, that's the only critical point in time."

I think if you would examine Gulf's peaks over the last, say, five years, you would see peaks that fell in months other than July. You would see peaks that fell in, well, a couple times in the winter periods, and I don't think you can ignore that fact when allocating costs.

Q So what you're saying is that you ought to look at the maximum peak over a number of years or the near peaks in several main months, rather than looking just at July of 1990. Is that correct?

A I don't like to use the term "near peaks," but you have to look at the load shape over a considerable number of years.

Q In your space example, you said you'd look at several space shots over a number of years and not just one space shot. Would you look at the fuel requirements or the thrust requirements when they were out in space or the thrust requirement to take it off the ground?

A Well, once again, we're getting into the areas of a rocket scientist. But I think I would look at the thrust requirements to get it off the ground.

Q Yeah. All right, now, on your standby service, back in 1987 when cogeneration was coming into play, the Commission did some studies to determine how you would price self-generating customers' demands on your system for backup, is that correct?

A That's correct.

Q And you participated in that docket, did you not?

A Yes, sir. I did.

Q And the Commission -- because of the fact we were assuming things were going to happen, didn't have any actual experience -- the Commission set out some criteria for determining what the demand of the stand-by customers would be, and how you would allocate costs, isn't that correct, in that order?

A Yes, sir.

Q And that order also required you, however, did it not, to over time perform cost of service studies in order to ascertain what the actual costs were rather than relying on the assumed numbers, isn't that correct?

A I believe it guided us along those lines.

Q Do you believe or do you know?

A I believe it. I'm not sure whether it was laid out that the next cost of service study had to be based upon the actual CPKWs for the SS rate class or not.

Q That's Docket No. 850673, and it's Order 17159, in February of 1987. Is that about when it all occurred, to the best of your recollection?

A Yes. It is.

Q Bear with me just a minute, please. (Pause) I'm going to read you some language, and if this is what you remember, please state so. "In each utility's next rate case, we expect that stand-by customers would be treated as a separate class and be assigned costs consistent with the appropriate data in the new cost of service study. Until these cases are filed and processed and until the data necessary for new cost of service studies is collected, the cost study approved by the Commission in each Utility's last rate case should be the foundation."

So it told you to do it, and this is your next rate case, isn't it?

A That's correct.

Q And you did do a cost of service study, didn't you?

A That's correct.

Q And in your cost of service study, you found based on actual living experience, that the stand-by class is yielding better than an 18%, almost a 19% return, is that correct?

A I'm not familiar with those rates of return.

Q All right. I'd like you to look, if you will, to your exhibit. I'm looking at Page 1 of Schedule 8. Does that show the rates of return for the various classes?

A Yes, sir, it does.

Q Why did I say 18%? It shows here like it's only 14.29%.

A I don't know.

Q Is there another place that you show the proposed rates or return?

A All right, now, what you may have looked at was, if you will turn to Page 54 --

Q Yes, sir.

A You may have looked at the rate of return under proposed rates where the previous page was under present rates.

Q That's exactly what I did. Okay, so it looks like right now under your cost of service study that class is paying a 14% return, which is better than twice as much as your system average return. And instead of reducing that to bring it closer to the proposed system average of 8.65, you increased the rate under your proposed rates to nearly 19% return, is that correct?

A What I would like to do is point you --

Q Whoa, whoa, answer the question, yes or no.

Q Could you repeat the question?

Q The question is: Instead of bringing the rates back towards your system average rate of turn based on your cost of service study, your proposed rates take it even higher, so that now it's going to be close to 19% when your system average requirements are only 8.6%?

A In this particular example here, that is true.

Q All right.

A Now, what I would like to add to that is that these studies, which were initially filed, were revised for several improvements. One of those improvements was to take an LPT customer that we presumed was migrating to PXT -- excuse me, that we presumed was a PXT customer who was going to migrate to LPT in 1990 who didn't. So, we had to leave him in the PXT rate class. And when we did so, it was important that we add the fact that he was a standby service customer to our standby rate classification.

So in this initial filing which you see here, this Schedule 8, you don't have that customer in the SS rate class in the manner we feel like they should be pictured.

In addition to that, there were two other improvements that needed to be made to this new class of service. Number one, the SS class that you see here is only their load for their SS service. In other words, if you have got a customer that is taking supplemental service under PXT, those load requirements are showing up under the PXT classification. And only the SS service is showing up in this column.

Well, what became obvious to us as we got into the case after this initial filing, was that we needed to associate with this SS portion of his load some of the costs of his dedicated substation. So we did that.

In addition to that, we later found out that when we developed the SS load for this migrating or nonmigrating customer, if you will, there was an error made in the math. We needed to improve that. So as a result, you now have the Exhibit 231, which we have submitted, that has the correct rate of return for SS. And that, I believe, off the top of my head, is 7.96%.

Q That's under the proposed rates?

A No, sir, that's under the present rates, 7.9.

Q In your proposed rates, where does it go?

A We have not developed proposed rates for that study at this time.

Q They would go up, probably above your system average?

A You would have to talk to Mr. Haskins to see how he anticipated handling that class under the proposed rates.

Q Do you still take the assumption of a 10% forced outage rate for that class, which was the Commissioner's guess back in '87?

A That's what we're using in this study right now, unless the customer shows an incidence of higher than 10% under the daily demand charge concept.

Q In your actual cost-of-service study, what was the actual results of these persons being on line at the time of your various peak periods?

A Well, we don't have a cost-of-service study that shows that, but trying to help you out, I believe --

Q I appreciate that. I need all the help I can get.

A I believe from talking to Mr. Kilgore when we examined the little, very little standby service information we did have available -- and for example, I believe that in the standby rate class is basically for customers. Now, one of those customers is 70% of the total class. So that the class controls are driven very strongly by one customer. This customer, when we were developing forecasts, we only had seven months worth of data, actual data to work with, and as we looked at that actual data that was for that particular time period, there was not a significant amount of CPKW at the time of the system peak.

Q So what you're saying is that it was less that the 10%, but you chose the 10% anyway?

A That's correct.

Q Mr. Wright, in his testimony, talked about different cost of service studies and how different approachesd would place more of a production cost on high load factor customers and other studies would place less. And you'll have to bear with me while I kind of walk through this.

As I understand it, you have a generating plant that's used by all your customers. And the problem is assigning the fixed costs that go with that generating plant to the appropriate persons. And your cost of service study, if you do it on a coincident-peak basis, then a high load factor customer, which is one that uses substantially the same amount of energy all the way around, would pay for a lesser portion than those people who were what we call low load factor customers and -- such as the residential class, and have peaks at certain times of day and certain times of the year, is that correct, to use a coincident peak theory?

A I'm not sure I followed what you were saying. Normally, if you will use a coincident peak allocation technique for the allocation of generating costs, you will have a certain portion going to low load factor customers and a certain portion going to high load factor customers.

Now, if you wanted to measure or compare those results from the low load factor rate to the high load factor rate and you did it on a per kWh basis, or possibly -- well, I guess that would be a good comparison. The low load factor rate would have a higher portion.

Q On a kWh basis, the high load factor customer would pay for a greater portion of the production plant --

A Per --

Q -- because he uses more kWh during the course of the year, is that what you're saying?

A No, what I'm saying is if you had allocated all of your production costs on demand.

Q On demand?

A Right.

Q At the time of annual system peak?

A That's correct, or a multitude of peak, and you then took the -- that allocation to the low load factor rate and divided it by the low load factor rate's kWh and did the same thing for the high load factor rate, that factor would be higher for the low load factor rate than it would be for the high load factor rate.

Q If you did the customer's kWh based on his demand at time of system peak and his annual -- I don't quite understand how you mix the kWh and the demand.

A Well, maybe I am confusing your question. Could you state your question again?

Q Well, in July you project that there would be a demand on your system of 1750 megawatts.

A That's correct.

Q And if you were doing a peak responsiblity study, you would look at the demand of each customer class at that point in time and say we divide up the fixed cost of this plant based on their contribution to what's happening in July. Isn't that correct, under your coincident peak-type study?

A Now, you're looking at a one-coincident peak technique.

Q Just for purposes of simplicity.

A Certainly. And, yes, you're correct in what you said.

Q And under that, the customers who have a poor load factor, but happen to be there at time of system peak, would pay a greater portion of the plant cost than they would pay if you just looked at their annual consumption. If you did it the other way and just looked at the customer's annual energy consumption, that customer would pay a much lower share of the production plant and transmission plant than using the coincident-peak method?

A In general that's true. There can be exceptions to that, like the street lighting class and so forth. But I think what you're getting at is with most major rate classes, if you look at their characteristics, if they have a low load factor customer is -- happens to be on at the time of the July peak, and that is, indeed, one of his higher peaking periods, then he would get a greater proportion of that allocation than the high load factor rate would.

Q Now, here's the thing that gives me the trouble.

Unlike most other industries, your company has an annual -- your generating plants only operate about a little over 50% of the time; 50% of the time they're lying idle, aren't they?

A We really need to talk to Mr. Parsons about that.

Q Well, from your general knowledge of the load factor, of your system load factor, it's somewhere in the range of 50%?

A Well, I was under the impression it was in the high 50s, but I don't know that one can conclude from that, that the plant is sitting idle at the other times, but I will agree that the load factor itself is in the mid to high 50s.

Q So part of the time, or almost half of the time, the plant is not generating electricity for the benefit of customers and somebody has to pay for that plant, don't they?

A Somebody has to pay for the plant, that is true, but I don't like to use the term that it's not serving a purpose when it's not producing kilowatt hours.

Q Well, it's standiong by ready to serve, correct?

A That's correct.

Q And what is it standing by ready to service? Standing by ready to meet the next peak demand, isn't that correct?

A Or to meet the electrical requirements, unless, of course, it's down for maintenance.

Q Let me give you an illustration that's helpful to me, and it's the motel, say down on West Tennessee Street, and say a fellow has a motel that has four units in it, a very small motel, but he also has two trailers out back. And he has a man that lives in his motel all year long. And then during the week he has traveling salesmen come in and out and use the other two or three rooms, maybe one or two days, three days a week. And then on graduation time, during football games, when the Legislature is in session, he's able to rent all the rooms in the motel and the trailer.

When he does that, he's got to put on some extra help, some maids and so forth. It seems to me that fairness would say that the guy that lives there all year long and is there day in and day out paying the rent and helping with the fixed charge, you could pretty well determine the fixed costs related to his room, if you wanted to be fair and just charge him for that, rather than assigning him the cost for the maid service and the other five rooms and the two house trailers. Doesn't that seem fair to you?

A That's a method to do it. You could do it that way.

Q But isn't that a pretty fair method?

A Well, I'm really not that familiar with the motel business and --

Q Well, you did a good job there on the aeronautical stuff, common sense.

A That is a method that sounds reasonable.

Q And if you attempted to charge him the same prices that you charge the other people during the football games, don't you think he'd go find another motel somewhere?

A It's possible.

MR. McWHIRTER: I tender the witness.

CROSS EXAMINATION

BY MAJOR ENDERS:

Q Good morning, sir.

A Good morning.

Q I'd like you to pull Staff's Eighth Set of Interrogatories, specifically Questions 110, 11 and 13.

CHAIRMAN WILSON: Does that have an exhibit number at present so I could follow along?

MR. PALECKI: Which interrogatory from Staff's Set are you referring to?

MAJOR ENDERS: Staff's Eighth Set of Interrogatories, Questions 110, 111, and 113.

MR. PALECKI: All right, sir.

Q (By Major Enders) You're the person who performed those calculations, are you not

A That's correct.

CHAIRMAN WILSON: It's not going to do me any good at all to listen to this if I can't follow along with it. So if somebody can determine whether these interrogatories are an exhibit or whether we have copies of them or not, be extremely helpful.

COMMISSIONER EASLEY: I can't find that we have anything but the first set of interrogatories, excerpts from that.

Major, was that marked with a hearing exhibit number?

MAJOR ENDERS: I don't know, ma'am.

MR. PALECKI: It appears that the only interrogatory from the Eighth Set is No. 114 that was introduced. I'm not sure that the specific interrogatories that have been referred to have been introduced into the record yet.

MR. STONE: Well, I think I found some that have been.

Major Enders, could you read them again to me. Eighth Set beginning with 110?

MAJOR ENDERS: 110, 111, and 113

MR. STONE: 110 is Exhibit 266, 111 is 267 and 113 is 269.

MAJOR ENDERS: Say again, please.

CHAIRMAN WILSON: 266, 267 and 269.

COMMISSIONER GUNTER: Do we know if those have been handed out? We have been sort of getting them piecemeal.

MR. PALECKI: Those are Gulf's exhibits, so they would be in Gulf's set.

COMMISSIONER GUNTER: Have you all handed those out yet? The way we're getting them is sort of piecemeal?

MR. STONE: Since they are Mr. Haskins' exhibits, they have not been handed out.

MR. STONE: Think we have them. If you will give us about five minutes we'll get them for you.

COMMISSIONER EASLEY: Why don't we take five?

COMMISSIONER GUNTER: Take five.

(Recess)

MR. STONE: Commissioner, I've handed out to all parties Mr. Haskins' package of miscellaneous exhibits which have been prenumbered and stipulated into the record.

CHAIRMAN WILSON: All right.

MR. STONE: And I believe that three of them are the ones that Major Enders was referring to.

CHAIRMAN WILSON: Go ahead, Major.

MAJOR ENDERS: Thank you, sir.

Q (By Major Enders) I asked before, but I'll ask again, you prepared the answers to those exhibits, Staffs Eighth Set of Interrogatories 110, 111, and 113.

A That's correct, Major.

Q Directing your attention, Mr. O'Sheasy, to 110. This request is for the transformer ownership discount for Level 4 customers who own their own transformation equipment?

A That's correct.

Q Still on 110, explain to me the revenue requirements described in Account 368.

A Well, that is the revenue necessary to pay for that investment, and the primary ingredients would be a rate of return and income tax on that investment.

Q Is Account 368 the gross investment booked for line transformers?

A Yes, it is, in general. There are many items in there other than that, but that is one of the big ingredients.

Q When Gulf Power calculates its return, does it do so on a gross amount or the amount net of depreciation reserve?

A It's net of depreciation. In other words, one can think it in terms of a rate base.

Q So this calculation is based on a different investment level than the Company's calculation cost of service for revenue requirements?

A No, sir. This is -- one can think of as a rate base related to Account 368.

Q Moving now to Account 584, you have extracted the transformation related operation expenses and materiels and supplies associated with line transformers.

A Yes, sir.

Q Can you tell me what is contained in Account 584?

A Well, it's the -- one portion of it is the operating expenses incurred on line transformation equipment, and there are some other operating expenses in there also, but the relevant expenses that we were trying to glean from this account here were those operating expenses associated with line transformers found in that account.

Q Can you tell me what's contained in Account 583?

A 583.

Q Let me help you. Is that overhead line expenses?

A Yes, it is. If you'd like I can get a classification of accounts and read the entire list, but that is one of the big items in there is the operating expense and maintaining overhead lines.

Q Do both 583 and Account 584 include transformation-related operation expenses?

A 584 does. I'm not sure about 583.

Q Do you include the cost of employee pensions and benefits anywhere in your calculation?

A On this interrogatory here?

Q Yeah.

A If the Operating Expense Account 584, one of the drivers in there would be the employees' salaries And wages, and if the pensions and benefits were included in those salaries and wages, yes, they would be included.

Q Mr. O'Sheasy, what's Account 368?

A I'm sorry, would you repeat that?

Q 368.

A What is Account 368?

Q Yeah.

A Well, it's a FERC account, and it's primarily line transformers, but there are a lot of other items in there besides line transformers; capacity and so forth.

Q Would you agree that FERC Account 368 -- and I'm just going to paraphrase it -- this account shall include the cost of installed overhead and underground distribution line transformers.

A That sounds reasonable.

Q Looking at 111 now, this would be Exhibit 267. You again performed these calculations, correct?

A That's correct.

Q Is it your understanding that this calculation is based solely on the cost of transforming power from Level 2 to Level 3?

A It is the transformation that occurred at what we call Level 3. In other words, it is transforming electricity from what we call transmission level service to primary distribution level service.

Q Would it be fair to say that your calculation in no way incorporates the difference in cost to serve customers at lower voltage levels?

A This interrogatory that you're referring to as 111, includes the cost of transforming electricity from transformation -- transmission level service to primary level service, and would not include the cost of transforming electricity from primary to secondary distribution, if that's the question you're getting at.

Q That's what I was getting at. That's because poles, lines or other facilities or expenses are not there?

A That's correct.

Q Let's take a look at 113, Mr. O'Sheasy. You characterized this as loss --

CHAIRMAN WILSON: For the record that's Exhibit No. 269?

MAJOR ENDERS: Yes. Thank you, Mr. Chairman.

Q You characterize this as the losses for distribution in line transformers, is that correct?

A That's correct.

Q Are there any other losses, such as line losses, included in your calculations?

A No, sir.

Q From the time power is generated until it is delivered to a primary level customer, certain losses are incurred, are there not?

A That is correct.

Q Similarly, for power delivered to a secondary customer, losses are incurred in delivering that power to the customer, are they not?

A That is correct.

Q Is the only difference between losses for primary and losses for delivery at secondary voltage this percentage loss for distribution line transformers?

A No. There are other loses incurred in making that transformation.

Q The line loss is the main loss, is it not?

A That's -- and another additional component, line losses would be.

MAJOR ENDERS: I have no further questions, Mr. Chairman.

CHAIRMAN WILSON: Mr. Palecki?

CROSS EXAMINATION

BY MR. PALECKI:

Q Has part of the Commission policy for voltage discounts been to recognize only the costs associated with transformation equipment?

A That's my understanding.

Q Is it correct that Mr. Johnson's methodology for voltage discounts recognizes all lines, conductors, transformers, and overhead and underground lines to be removed from the rate?

A Yes, sir.

Q This next question refers to some of the things that Mr. Kilgore testified to, specifically concerning recreational lighting customers.

If recreational lighting customers were a separate class in the cost of service study, how much would doubling the NCP demand for recreational lighting affect the rate of return?

A If the recreational lighting class of customers was a separate class of service and you doubled their noncoincident peak calculation, I would guess that it could affect their overall rate of return for that one small group, the recreational lighting customers, possibly 10 to 15%.

Q Isn't it true that they get very little production plant costs?

A Relative to most of the other rates, that's correct.

Q So isn't it logical that the effect would be more than 10 or 15%?

A I don't know, I'd just have to do an analysis to see.

Q The next set of questions refers to Issue 115. Did you correct the miscalculation regarding the derivation of 12 CPKW for standby service?

A This was Interrogatory 115?

Q No, this is Issue 115 concerning the cost of service methodology. (Pause) Specifically, does the second cost of service study in Exhibit 231 reflect such a correction?

A Yes.

Q Was there an error in the cost allocation for dedicated substations for customers taking standby service in the cost of service study filed as part of the MFRs and your testimony?

A There was a correction or an enhancement that was warranted.

Q And this correction was made in Exhibit 231?

A That's correct.

Q Have service drops been allocated to OS-III for lighting sports fields or billboards?

A Now, which? We've filed a multitude of studies in this hearing, which particular study are you referring to.

Q The cost of service study filed as part of Exhibit 231. And also in the original MFRs. (Pause)

A No, sir.

Q Wouldn't the service drop have been required for each of these installations?

A Possibly so. When we looked at this before, we found out that it was going to take an extensive amount of field research to determine the answer to this. And the engineers that I talked to at Gulf Power indicated to me that, whatever they found out, they felt like it would be a relatively small amount of service drops going to this small portion of the rate and that at this time we didn't have the time nor the money to conduct such a study, nor could it be justified for a small change.

Q Was that only with respect to the street and outdoor area lights you were told that?

A Yes.

Q Were service drops allocated to OS-I and OS-II for streetlights and private outdoor lights?

A No, sir.

Q Wouldn't a service drop be required for most private area outdoor lights and perhaps most streetlights as well?

A I asked the same question of the engineers at Gulf, and they indicated to me that there was not a significant amount of service drops going to these rate classes.

Q What about with respect to sport fields or billboards, same answer?

A Well, once again, the indication I got was that that small amount of service drops that might be going to sport fields was not a significant amount and could not justify an intense research to determine what small percentage that might be.

Q Was meter costs allocated or assigned to OS for recreational lighting customers?

A No, sir.

Q Do all recreational lighting customers have meters?

A I have been told that yes, they do.

Q And that was, that was Gulf's answer in Exhibit 508, was it not, that yes, they do all have meters?

A Subject to check, I'll agree with that.

Q Does the revenue calculated in the MFR schedules for OS-I and OS-II include revenue for additional facilities?

A I'm sorry, could you be a little more detailed on your question?

Q I'll refer you to MFR E-160 concerning revenue -- excuse me, E-16d, concerning revenue calculated for OS-I and OS-II. And the question is whether they include revenue for additional facilities. That's Page 166 of the MFRs.

A That's really a question you need to ask Mr. Haskins. I don't know. He developed this particular schedule and I'm not familiar with whether he's got additional facilities in those revenue calculations or not.

Q Were the rate base and O&M expenses for additional facilities assigned to OS-I and OS-II in Gulf's cost of service studies?

A The additional facilities that are found within FERC Account 373 were assigned to the street lighting class of customers.

Q Were the costs of poles installed for streetlights included?

A If it was found within FERC Account 373, it was assigned to the street lighting class.

Q Were those costs assigned to the street lighting customers?

A Yes, sir.

Q In your response to Interrogatory 209, were they assigned to customers?

A Yes, sir.

Q Exhibit 441 lists the test year expenses for the four conservation programs removed from ECCR in May of 1989. Did the data provided to you by Gulf for the test year expenses for these programs assign the expenses for the first three classes to the residential revenue class and those for the fourth to the commercial class?

A Yes, sir, that is correct.

Q Did you allocate these costs to rate classes within each revenue class on average number of customers?

A Now, once again, which cost of service study are we talking about? Are we talking about Staff's 209?

Q In your original study.

A In the original study, they would have been allocated on number of customers.

Q Did you classify them as customer-related so they are included in the customer unit cost supporting the customer charge?

A Yes, sir, that is correct.

Q Doesn't this mean, for example, that a small RS customer will pay the same amount for these costs as a large RS customer?

A Well, if you're talking about rate design questions now, I'm not sure. What we do when we allocate costs is we allocate to a total rate class. We don't allocate to a small customer or to a large customer, we allocate to the entire rate class with all the customers together.

Q Would that mean that a small GS customer would pay the same as a larger GSD customer?

A Well, when you say "pay the same," it sounds like you're referring to a rate question or a revenue calculation.

I think what you're getting at is the inherent weighting of the allocation itself the same? And if that's what you're getting at, you're correct. When you allocate to the entire rate class, you treat the small customers -- well, the small customers' influence on that allocation is the same as the large customers' influence on that allocation.

Q Is investment for service drops for customers taking service at the secondary voltage booked in Account 369?

A Yes.

Q Is it classified as customer-related and allocated on an average number of customers taking service at secondary voltage?

A Yes.

Q Did you also classify all of the secondary wire in Account 365 as customer-related?

A Yes.

Q Did you allocate it to secondary voltage customers on average number of customers?

A Yes.

Q Are transmission drops or taps for customers taking service at primary or transmission voltage booked in a separate account for drops of taps?

A When you say, "separate," I presume what you mean is, is it not accounted for in the Account 369, and that is true. It's not in Account 369.

Q Is it accounted for separately in any other account?

A Not separately. You'll find the investment in all of your lines in a specific FERC account. There will be one for transmission and one for distribution.

(Pause)

Q Has any of the primary for transmission wire or conductor been classified as customer-related and assigned to customers, or allocated to groups of customers on average number of customers

A No.

Q Has the conduit running between the Company's common distribution line and customer-owned transformer been classified as customer-related and assigned to these customers?

A No, sir, nor should it be.

Q So it's been allocated to the customers on average number of customers, or has it been assigned to these customers on average number of customers?

A No, sir.

Q Has the Company's conduit running between a substation and the customer's facilities been classified as customer-related, and assigned to these customers or allocated to these customers on average number of customers?

A No, sir.

Q Who owns the line running between a dedicated substation and the customer's facilities?

A It depends. It could be -- well, excuse me, let me understand your question. Your question is who owns the line between a dedicated substation and the customer itself. And I would think in most cases the customer would own the line. There might be exceptions to that, but I would think in most cases the customer owns the line.

Q Could you provide that information as a late-filed exhibit?

A All right. Let me make sure I understand --

Q A short title is, "For All Customers Having Dedicated Substations, Information on Who Owns the Line Running Between the Substation and the Customer's Facility."

CHAIRMAN WILSON: That's a short title? (Laughter)

COMMISSIONER GUNTER: Wouldn't that be -- let me ask a question as soon as the witness gets through conferring. (Pause)

Wouldn't that be contingent on where the metering point was?

WITNESS O'SHEASY: Yes, it would.

COMMISSIONER GUNTER: If the metering point were at the substation, the customer owns the line downstream of the meter.

WITNESS O'SHEASY: That's correct.

COMMISSIONER GUNTER: If you had a situation where a customer's meter would be on the side of his building, still that's the demarcation point. Upstream you own it; downstream they own it, isn't that right?

WITNESS O'SHEASY: That's correct; that's correct, and you can have both circumstances.

COMMISSIONER GUNTER: I understand. That's really the key. It's not the transformer station, but the meter?

WITNESS O'SHEASY: That's correct. That's normally the point of ownership.

To answer your question, it will take some research to do that, but we can, I think, prepare a late-filed exhibit that would show that.

MR. PALECKI: Do we have a number?

CHAIRMAN WILSON: That will be Exhibit No. 603.

(Late-Filed Exhibit No. 603 identified.)

Q (By Mr. Palecki) When the decision was made to use the fixed and variable definition in the IIC contract of O&M for the classification of O&M expenses in the cost-of-service study, did you review the types of equipment for which the expenses were reclassified and determined that none of the expenses vary with kilowatt hour generated?

A This study that you're referring to was conducted over a period of time by some very knowledgeable people who did a very thorough investigation of whether these accounts were being driven by energy or demand-related costs. And I relied upon their expertise and did review their work, but was not a party to that actual study. And so I'm not intimately familiar with the exact details, but I felt comfortable with what they had done.

Q Who are the parties that conducted that study and are they available to testify, or have they testified or will they testify in this proceeding?

A They are not specifically testifying in this proceeding. They are employees of the Southern System that worked on this project. I'm sure there was a representative from Gulf on this project.

Q Why do you think changes in the IIC contract should affect the classification of these expenses in the cost of service study?

A They shouldn't dictate how we classify costs in the cost of service study. And they don't. What happened was the revision to the IIC required a new, updated analysis of these accounts to see whether they were driven by energy or demand, and, if so, at what proportion. And the older analyses that we had been relying on prior to were simply outdated.

In the dynamic industry that we are in, conditions change. And what you try to do is use the most recent, current analyses that you have available. And it just so happened that there was an analysis from a work study group that was conducted by the IIC, and we used their results.

Q Well, since you're the only witness we have here to testify as to this, I have to refer these questions to you. For an example, I'd like to ask, shouldn't factors such as maintenance for grinding mills or coal pulverizers and cooling towers, which vary with use as kilowatt hours are generated, continue to be classified as energy related?

A We're getting into specific questions on specific accounts that I'm not familiar with, but let me just offer a few thoughts on it.

When you do a study like this, you have to go in and analyze the accounts, as best you can, for particular time frames that you're looking at, and if you find one particular account that is possibly not exactly on the money for this particular time frame, the concept is that there is another account that may counterbalance that.

Now, you talk about cooling towers, for example, I believe you brought that up. It's my understanding from talking to engineers at Gulf Power Company that the majority of the maintenance expenses on cooling towers are not energy-related, that they're primarily demand-related, and that the more that you run your cooling unit, the less maintenance cost there is on it.

Q What about a coal pulverizer? That would seem to be directly energy-related.

A My intuition agrees with you, that in general, I would think that a coal pulverizer would have a higher portion of energy-related costs than demand-related costs.

Q If an oil-burning plant is converted to burn coal because the cost of conversion is less than the projected fuel savings, would you classify the cost as demand rated for cost of service purpose?

A Could you repeat the question, please?

Q If an oil-burning plant is converted to burn coal, because the cost of the conversion is less than the projected fuel savings, would you classify the cost as demand related for cost of service purposes?

A Now, we are talking about a hypothetical situation, of course, that has not occurred for Gulf Power Company, and if in that hypothetical situation that occurred, I think you'd have to look at what type philosophy do you believe your generating plants are out there for. And the philosophy that we believe at Gulf Power is that our generating plants are out there to serve the demands for electricty, the peak loads, and whether you decide to substitute a coal plant for an oil plant, the point is those generating plants are still serving the peak load requirements of Gulf Power Company. And we would continue to allocate it on demand.

Now, if you had a different philosophy on your approach towards generating costs, such as has been mentioned in this case, capital substitution, then using a philosophy like that, one could indeed conceptualize that those replacement costs should be energy-related.

Q This next group of questions relates to uncollectible expenses.

Are uncollectible expenses classified as customer-related?

A All right. Now, we have, once again, make sure we understand which study we are talking about. If we're talking about Exhibit 231, then yes, indeed, uncollectibles are classified as customer-related.

Q What about in all cost of service studies sponsored by the Company; that would be the same answer?

A You're correct.

Q Doesn't classifying these costs as customer-related mean that for a particular rate class a customer with a small bill will pay just as muuch uncollectible expense as a customer with a large bill?

A Well, once again, we're getting into the question of pay. What we do in a cost of service study is we allocate costs to an entire rate class. We don't allocate costs to a small customer and then to a large customer. We allocate costs to all the customers in that rate class.

Now, if your question is, is the inherent weighting of your allocation to that rate class identical for a small customer as a large customer, then I would agree with that.

Q And because you classified the expense as customer-related and allocated the expense on average number of customers, would not an RS customer with a small bill pay just much uncollectible expense as an RS or GSD customer with a large bill?

A I hate to keep beating this, but when we say, "pay," that's a rate design question there. If we talk about the influence in the allocation, then your answer is correct; that customer, that small RS customer, would have the same relative cost allocation as the large customer, but, of course, like I said before, we're not allocating cost to individual customers, we are allocating to the entire rate.

Q If the customer charge is set at unit cost, wouldn't the large -- or small customer pay just as much as the large customer?

A Yes.

Q Why is this appropriate?

A From what I have been told from the studies that I have seen Gulf Power put out, the incidence of bad debt expense, uncollectibles, is such that there are basically three classes that cause these costs to be incurred: RS, GS, and GSD. And I have seen a number of customers allocator from, I believe it's 1990, test period, apply to the last three years of actual experience of bad debt expense for Gulf, does provide a reasonable allocation scheme.

Q If the account of a customer becomes uncollectible, wouldn't the customer with a large bill normally cause the Company to incur more uncollectible expense than a customer with a small bill?

A Ceteris paribus, you're exactly right, but I think what you need to understand is you just can't blanketly make statements like that until you do an analysis. It's very possible that if you didan analysis on uncollectibles, bad debt experience for Gulf Power Company, for the RS class, you might find that your smaller customers had a much higher proportion of bad debt expense than the large customers that would counterbalance this revenue impact you're talking about, such that number of customer was indeed an appropriate allocator.

Q Interrogatory No. 209 of Staff's Eighth Set --

CHAIRMAN WILSON: Are you changing subjects?

MR. PALECKI: Yes.

CHAIRMAN WILSON: I think we'll -- I've got a quarter of 12. I think we'll adjourn for lunch and come back at 12:30.

Commissioner Easley is a newly-made grandmother, her second granddaughter. (Applause)

COMMISSIONER EASLEY: Fifth time.

CHAIRMAN WILSON: This time, all right, just this morning.

COMMISSIONER EASLEY: I work hard at it.

CHAIRMAN WILSON: We'll come back at 12:30.

(Thereupon, lunch recess was taken at 11:45 a.m.)

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