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BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

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| In The Matter of | DOCKET NO. 891345-EI |
| Application of GULF POWER COMPANY for an increase in rates and charges. | HEARING<br>SEVENTH DAY<br>LATE EVENING SESSION |

VOLUME - XVIII

Pages 2609 through 2787



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

Tuesday, June 19, 1990

Met pursuant to adjournment at 12:37 p.m.

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

APPEARANCES:

(As heretofore noted.)

REPORTED BY:

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# I N D E X

## WITNESSES

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EXHIBITS

| Number: | | Identified | Admitted |
|---|---|---|---|
| 609 | (Schultz) | | 2616 |
| 354 | Through 357 (Johnson) | 2618 | |
| 338 | Through 349 (Rothschild) | 2668 | |
| 610 | (Kisla) | 2750 | |
| 358 | Through 360 (Kisla) | 2751 | |

P R O C E E D I N G S

(transcript follows in sequence from Volume XVII.)

CHAIRMAN WILSON: Questions, Commissioners? No questions?

Redirect?

MR. BURGESS: Could I have one minute, please, sir?

CHAIRMAN WILSON: Sure.

MR. BURGESS: Thank you. (Pause)

COMMISSIONER EASLEY: Are you ready?

MR. BURGESS: Yes, Commissioner.

REDIRECT EXAMINATION

BY MR. BURGESS:

Q Mr. Schultz, you were asked to read, somewhat extensively, from Order No. -- I think it was 21317, is that correct? Is that the one from Docket No. 890003.

A Yes, I did read from that, yes.

Q And are the page numbers on yours those cited at the top as "FPSC Reporter"; that is, would you have read from Page No. 40?

A That's correct.

Q Would you turn back to Page 38, please, of the same order, or do you have that?

A I have that.

Q Does that indicate that at that point the order is dealing with Gulf Power Company programs?

A Yes.

Q Would you turn to Page 39, please?

A I'm there.

Q And this is a continuation of the section that began on Gulf Power on Page 38, is that correct?

A That's correct.

Q Would you please read, beginning with the top of Page 39?

A "On cross examination, Mr. Young admitted the Company does not have data on what efficiency equipment would be installed without the Good Cents Program, nor does it know with precision what efficiency equipment is being replaced by this program. This leads us to conclude that even the demand savings Gulf claims for that program may be overly optimistic and perhaps even nonexist.

"We find that Gulf has not demonstrated that enough demand and energy savings result from the program to provide residual benefits to all of the Utility's ratepayers. The Utility has done no retrofit analysis. Side-by-side demand metering of participating and nonparticipating homes would be prohibitively expensive.

"Further, without reference to this program, the marketplace is rapidly improving equipment efficiencies. As laudable as Gulf program objectives may be, we cannot permit the Utility to subsidize participating customers' comfort or value.

"We, therefore, order that this program be phased out by May 1, 1990."

MR. BURGESS: Thank you, Mr. Schultz. That's all we have on cross examination -- or redirect.

MR. HOLLAND: May I just ask one further question, just to clarify for the record?

CHAIRMAN WILSON: Go ahead.

RECROSS EXAMINATION

BY MR. HOLLAND:

Q The provision you just read in that order was with respect to the improved program, was it not, Mr. Schultz, and not the New Home Program?

A No.

Q Huh?

A No. It was not.

MR. BURGESS: Perhaps Mr. Schultz can read, again, the sentence that begins on the top of Page 39?

MR. HOLLAND: That's fine, please do.

MR. BURGESS: Just the first sentence on the top of Page 39, if you would read that aloud?

WITNESS SCHULTZ: "Upon cross examination, Mr. Young admitted the Company does not have data on what efficiency equipment would be installed without the Good Cents Program."

MR. HOLLAND: Okay. And read, if you would, the first sentence to the entire portion that you began quoting; it begins, "Staff recommended. "

WITNESS SCHULTZ: "Staff recommended the elimination of Gulf's Super Good Cents Existing Home Program for several reasons."

MR. HOLLAND: Thank you, that's all I have.

MR. BURGESS: Excuse me, I have to follow up, if I may?

REDIRECT EXAMINATION

BY MR. BURGESS:

Q Does the reference to the programs that you read about on Page 39, does that reference the Super Good Cents Program?

A Well, if I take and look at Page 36 --

CHAIRMAN WILSON: I think what the best thing would be would be for us to have the order and we can take judicial notice of it and we can tell what it says.

MR. BURGESS: I think so. I think you just needed some more for context. You were read a lot from the last page and I think that adds some context.

CHAIRMAN WILSON: Anything further? If not, do you want to move 609?

MR. HOLLAND: Yes.

CHAIRMAN WILSON: It's moved, admitted into evidence. All right, thank you very much.

(Witness Schultz excused.)

(Exhibit No. 609 received in evidence.)

CHAIRMAN WILSON: Call the next witness.

MAJOR ENDERS: May we have about five minutes to get set up?

CHAIRMAN WILSON: Sure.

(Brief recess.)

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CHAIRMAN WILSON: Are you ready?

MAJOR ENDERS: Yes, sir. Federal Executive Agencies calls Dr. Charles Johnson, and he has not yet been sworn.

CHARLES JOHNSON

appeared as a witness on behalf of the Federal Executive Agencies and, after being first duly sworn, testified as follows:

DIRECT EXAMINATION

BY MAJOR ENDERS:

Q Could you please state your name and business address?

A My name is Charles Johnson. My business address is 10801 Lockwood drive, Suite 350, Silver Spring, Maryland 20901.

Q Are you the same Charles Johnson that prefiled testimony in this case on April 27th, 1990?

A Yes. I am.

Q Do you have any additions or corrections or amendments you wish to make to your testimony?

A Yes. I have. My Exhibit CEJ-3, Page 1, contained an erroneous calculation for the base rate that should be charged to provide the correct revenue with the discounts that I provided. I have prepared a page that I have titled, "Revised Exhibit No. CEJ-3, Page 1 of the 3," for that exhibit. That contains the corrected numbers.

Q Is there a typo as to the columns?

A I would note that the word processing equipment went wild and moved the column headings to the left, so that the column heading in the center that says "FEA" should, in fact, be over the rightmost column and the column heading at the left of that says, "Gulf Power" should be over the center column.

COMMISSIONER BEARD: Did you type this on my machine? (Laughter)

WITNESS SCHULTZ: I checked the numbers this time carefully and I didn't notice that the headings had moved, so I'm sorry about that.

The second page is titled, "Revised Exhibit No. CEJ-4, Page 1 of 1." That simply is a computation of bills for typical customers under these corrected rates.

Those are the only corrections I have.

Q Subject to the changes you just made today, if I asked the questions contained in your prefiled testimony, would your answers be the same?

A Yes. They would.

Q I would move Dr. Johnson's prefiled testimony inserted into the record, as though read.

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

MAJOR ENDERS: And I believe, Mr. Chairman, his exhibits are 354 through 357, and they have been stipulated into the record.

CHAIRMAN WILSON: All right, good.

(Exhibits Nos. 354 through 357 inclusive stipulated into evidence)

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition of Gulf Power Company for a Rate Increase ) Docket No. 891345-EI Filed April 27, 1990

DIRECT TESTIMONY OF
DR. CHARLES E. JOHNSON

QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND ADDRESS.

A. My name is Charles E. Johnson. I am a Principal with Exeter Associates, Inc. Our offices are located at 10801 Lockwood Drive, Silver Spring, Maryland, 20901.

Q. PLEASE OUTLINE YOUR EDUCATIONAL BACKGROUND.

A. I hold a combined B.S. Degree in Chemistry and Physics from the University of Utah, an M.S. in Mathematics from the University of Wisconsin, and a Ph.D. in Mathematics from the Ohio State University.

Q. HOW HAVE YOU BEEN EMPLOYED SINCE RECEIVING YOUR DEGREES?

A. After completing my graduate education, I was an Instructor of Mathematics at Kansas State University in Manhattan, and an Assistant Professor of Mathematics at Wichita State University. In 1974, I left the academic environment and was employed by Control Data Corporation as a Manager responsible for mathematical modeling. In 1977, I joined the economic consulting firm of J.W. Wilson & Associates, Inc. Since that time, I have been consulting in the area of energy economics and utility regulation, for part of that time as an independent consultant. I became a principal of Exeter Associates, Inc. in January 1986.

Q. HAVE YOU TESTIFIED PREVIOUSLY IN REGULATORY PROCEEDINGS?

A. Yes, I have testified as an expert witness before regulatory commissions in the District of Columbia, New Jersey, New Hampshire, Minnesota, Pennsylvania, North Carolina, South Carolina, Oklahoma and Texas. These proceedings have involved the regulation of electric and gas utilities and I have addressed such topics as class cost-of-service studies, rate design, accounting issues and financial issues.

Q. WOULD YOU PLEASE DESCRIBE SOME OF YOUR ADDITIONAL PROFESSIONAL ACTIVITIES?

A. I have provided assistance to numerous entities involved in business and economic rate regulation. Much of this work has been in public utility regulation on behalf of state regulatory agencies or other public authorities such as state attorneys general and federal agencies. I have also provided assistance to independent consumer groups. I have assisted a number of industrial enterprises in examining their operations in light of their tariff options and the potential for altering usage patterns or installing cogeneration facilities. Recent work has been in the area of power supply; determining the optimal means of meeting a facility's energy requirements from all of the potential sources of power available to that facility and negotiating contracts to provide that power.

I have also provided assistance to public authorities involved in insurance rate regulation. I have provided consulting services to the California State Legislature and the District of Columbia Insurance Department in the area of property/casualty insurance ratemaking, and I have provided assistance in conjunction with workers compensation rate filings in Montana, Oklahoma, North Carolina, South Carolina and Florida.

PURPOSE

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS CASE?

A. I have been requested by the United States Federal Executive Agencies (FEA) to review the electric rates proposed by Gulf Power Company. My review includes an examination of the class cost-of-service study filed by Mr. O'Sheasy and the rate proposals presented by Mr. Jack L. Haskins and a determination of the propriety of the Gulf Power Company tariffs for large power customers.

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR REVIEW.

A. I recommend that the Florida Public Service Commission modify the Gulf Power Company proposal and increase rates base for the LP/LPT and the PXT classes by the same percentage rather than by different percentages. At the Company-requested revenue level, that percentage would be 8.48 percent. This recommendation is based on a review of the Gulf Power 1990 class cost-of-service study that shows the study to be flawed. I have also made a comparison of the 1990 study with the results of one performed by the Company in 1989.

I recommend that the discounts for service at primary and transmission voltage be increased to reflect the difference in cost and I propose a revised rate schedule for the LP/LPT class. This Commission has increasingly recognized the lower cost to serve customers at higher voltage levels over the course of the last several Gulf Power proceedings. However, the lower cost to serve these customers is not fully reflected in the discount in the current rates nor in the rates proposed by Gulf Power.

I have determined that voltage differences between customers is only a subsidy problem within the LP/LPT class and I restrict my recommendations to that class. My voltage discount rate proposal simply moves to eliminate intra-class subsidies in the LP/LPT class and do not affect the rates or rate levels of any other class.

My use of the Company-proposed revenue level is not an endorsement of the Gulf Power revenue request, but is merely based on the same revenue level as the Company's proposed rate design for ease of comparing my rate design proposals with those of the Company. If this Commission were to award Gulf Power a smaller amount of revenue, my recommended base rate charge per kW should be reduced accordingly.

CLASS COST-OF-SERVICE STUDY

Q. HAS GULF POWER COMPANY SUBMITTED A CLASS COST-OF-SERVICE STUDY IN THIS PROCEEDING?

A. Yes. Mr. O'Sheasy filed an embedded class cost-of-service study as part of Gulf Power's original filing. That study was based on allocating investment in production plant to the Florida retail customers based on an average of the 12 monthly coincident peak demands, with one-thirteenth of the investment allocated based on the class' energy consumption. Mr. O'Sheasy stated that techniques used in the retail cost allocation conform with those approved previously by the Florida PSC.

Q. HAVE YOU REVIEWED THE CLASS COST-OF-SERVICE STUDIES FILED BY GULF POWER COMPANY?

A. Yes. I have reviewed the class cost-of-service study filed by Mr. M.T. O'Sheasy on behalf of the Company. It is his position that this study represents a fair and accurate statement of the Gulf Power Company's class rates of return.

Q. DO YOU AGREE WITH MR. O'SHEASY'S ASSESSMENT?

A. I do not entirely agree with Mr. O'Sheasy's assessment that his cost-of-service study represents a fair and accurate statement of Gulf Power Company's class rates of return. Specifically, Mr. O'Sheasy's study overstates the cost of providing service to the LP/LPT class.

Q. IN WHAT WAYS DOES GULF POWER COMPANY'S CLASS COST-OF-SERVICE STUDY OVERSTATE THE COST OF PROVIDING SERVICE TO THE LP/LPT CLASS?

A. There are several ways that the class cost-of-service study filed by Gulf Power Company overstates the cost of providing service to the LP/LPT class.

The primary reason that Gulf Power's study overstates costs of serving the LP/LPT class is because generating capacity associated with Gulf States Utilities' default on unit power sales is allocated to the Florida jurisdictional rates classes. These costs fall on all jurisdictional customers, but fall more heavily on classes for which production plant makes up a large portion of costs, such as the LP/LPT class.

Q. WHY DOES THE GULF STATES' DEFAULT OVERSTATE COSTS TO THE FLORIDA RETAIL JURISDICTION?

A. Investment in generating plant that was planned for unit power sales was not intended to serve native load at this time. Gulf Power witness E.B. Parsons, Jr. testified that the Company has attempted to make off-system sales to the maximum extent possible, but has been unable to market 63 mW of Plant Sherer capacity. Company witness M.W. Howell testified that the Southern system may have capacity available to sell until the mid 1990's, if a purchaser can be located, including the 63 mW of Plant Sherer Unit 3. Thus, if Gulf States had not defaulted, or if the Company could otherwise sell the output from Plant Sherer, these cost would not fall on the Florida retail customers.

Q. WHAT WOULD THE FLORIDA RETAIL RATE OF RETURN BE IF THE 63 MW OF PLANT SHERER WERE SOLD AS UNIT POWER SALES?

A. I have determined that the Florida retail rate of return would be forty basis points higher if the 63 mW of Plant Sherer were not included.

Q. DO YOU RECOMMEND THAT THE 63 MW OF PLANT SHERER COSTS BE DISALLOWED?

A. I am making no recommendation on revenue requirements for Gulf Power Company. The purpose of my analysis is to determine the distributional effects of including the costs of the default on Florida jurisdictional customers.

Q. WHAT ARE THE DISTRIBUTIONAL EFFECTS OF INCLUDING THE COSTS OF THE 63 MW OF PLANT SHERER IN FLORIDA JURISDICTIONAL COSTS?

A. The costs associated with the 63 mW of Plant Sherer will fall disproportionately on the LP/LPT and PXT rate classes.

Q. WHY DOES THE BURDEN OF THE PLANT SHERER CAPACITY FALL MORE HEAVILY ON THE LP/LPT AND PXT CLASSES?

A. A greater proportion of production plant is allocated to the LP/LPT and PXT rate classes than the proportion of transmission or distribution plant. Thus, production costs make up a larger portion of the rates for LP/LPT and PXT customers.

The costs associated with the default could be considered as a surcharge on the cost of service and not as a cost of providing service to Florida retail customers. Considering it as a surcharge, there are numerous ways of assigning or allocating that surcharge to the retail rate classes. It could be allocated on total revenue so that each class would have its charges increased by the same percentage, for example. By allocating this surcharge as Gulf Power has in its class cost-of-service study, the surcharge is placed most heavily on the rate classes whose usage is primarily at higher voltages, because production costs make up a larger portion of their total costs.

Q. SINCE PLANT SHERER COSTS ARE RELATED TO PRODUCTION PLANT, ISN'T IT APPROPRIATE TO ALLOCATE THEM TO RATE CLASSES BASED ON THE SAME PRODUCTION ALLOCATOR USED IN THE COST-OF-SERVICE STUDY?

A. It is not necessarily appropriate to do so, because strictly speaking, these are not a part of the cost of providing service. If Gulf States had not defaulted, or if Gulf Power were able to sell the 63 mW as unit power sales to another customer, little would change for Florida retail customers, except the rate level being requested. It is important to note that the revenue requested from the LP/LPT and PXT classes would then be reduced by a greater percentage than average.

Q. YOU IDENTIFY THE GULF STATES DEFAULT AS THE PRIMARY REASON THAT GULF POWER'S CLASS COST-OF-SERVICE STUDY OVERSTATES THE COST OF SERVICE THE LP/LPT CLASS. ARE THERE OTHER REASONS.

A. Yes, there are other reasons that Gulf Power's class cost-of-service study overstates the cost of serving the LP/LPT class. The Company is apparently expecting substantial changes in the PXT class, including customers transferring to the LPT rate schedule. One large consumer, in particular, was expected to transfer from the PXT rate to the LPT rate, but has not done so. The PXT class mWh sales are expected to be 11 percent lower in 1990 than in

1989, while LP/LPT sales are expected to be 12 percent higher. Further, comparing the most recent historical year with the projected test year sales for SE power, the PXT sales level is expected to drop by half, while the Company is expecting a severalfold increase in SE sales for the LP/LPT class.

These expectations of the Company are questionable, at best, and have the effect of overstating the cost of service the LP/LPT class. For example, the one large PXT customer that was expected to transfer to the LPT rate had nearly $2,000,000 worth of special facilities constructed by the Company. Recovery of the costs associated with this investment are not recovered directly from the customer, but are recovered through base rates over a period of years. This is the reason that Gulf Power is proposing its Local Facilities Charge. While the Local Facilities Charge may ensure the eventual recovery of the special facilities expenditure over time, this treatment does increase the cost of serving this customer above the revenue level currently being recovered. It also increases the cost of serving the class to which the customer belongs, without a commensurate increase in the revenue associated with the class. By incorrectly including this customer in the LP/LPT class, Gulf Power's cost-of-service study overstates the cost of serving the LP/LPT class and understates the rate of return. The same action understates the cost of serving the PXT class and overstates the PXT class rate of return.

Q. HOW DOES THIS AFFECT THE INCREASE IN REVENUE AS PROPOSED BY GULF POWER?

A. These problems with calculating the cost of serving the LP/LPT and PXT rate classes call the Company's proposal into question. Mr. Haskins has proposed a larger increase for the LP/LPT class than for the PXT class, based largely on the faulty cost study. I recommend that the Florida Public Service Commission not adopt the Company's proposal.

Q. HOW DO YOU RECOMMEND THE COMMISSION SET THE REVENUE LEVELS FOR THESE TWO CLASSES?

A. I recommend that the Commission increase rates for the LP/LPT and PXT classes by equal percentages. At the Company-requested revenue level, the increase would be an 8.48 percent increase. A comparison of my proposal with Gulf Power Company's appears in Exhibit 34 (CEJ-1).

I base this recommendation on the following:

1. The rates of return for the LP/LPT and PXT classes in the 1989 cost study were 7.21 and 7.18 percent, respectively, versus a retail rate of return of 6.88 percent.
2. The rate of return for the LP/LPT class in the 1990 cost study of 6.54 understates the correct level.
3. The rate of return for the PXT class in the 1990 cost study of 8.92 overstates the correct level.
4. The 1990 rate of return for the two classes combined is 7.22 percent, compared to the retail level of 6.60 percent.

5. The Company-proposed allocation of the GSU default increases costs to the PXT and LP/LPT classes by a greater percentage than to other classes.

In summary, the results for the aggregate of the two classes for both years is consistent; the 1990 study would show results more like the 1989 study if some of the errors were corrected; and the rates of return for both classes would be increased by more than average, were it not for the GSU default.

VOLTAGE DISCOUNT

Q. DOES THE CURRENT LP/LPT TARIFF PROPERLY CHARGE CUSTOMERS FOR SERVICE AT DIFFERENT VOLTAGE LEVELS?

A. No. Gulf Power Company's LP/LPT tariff overcharges customers taking service at higher voltage levels. The current and proposed tariffs provide a discount to customers who own their transformers, but these discounts should be provided to all primary and transmission level customers. Customers not providing their own transformers should be charged for the costs incurred by Gulf Power on their behalf. Additionally, the lower level of costs imposed on the system by customers taking service at high voltage levels warrants much greater discounts than are currently provided.

Q. WHY IS A LOWER LEVEL OF COSTS IMPOSED ON THE SYSTEM BY CUSTOMERS TAKING SERVICE AT HIGHER VOLTAGE LEVELS?

A. There are two reasons that customers taking service at higher voltage impose lower costs on the utility than a customer with similar loads but at secondary distribution voltage:

1. Losses for customers taking service at distribution voltage are about 6 times as great as losses for customers at transmission voltage, and about 2.5 times as great as losses for primary customers.
2. Service to customers at distribution voltage requires additional substations, conductor, poles, transformers and other equipment that are not used to provide service at higher voltage.

Q. PLEASE ELABORATE ON HOW DIFFERING LOSSES FOR SERVICE AT DIFFERENT VOLTAGES PRODUCE A LOWER COST FOR EACH KWH OR KW DELIVERED AT A HIGHER VOLTAGE.

A. Each kWh delivered to an LP/LPT transmission level customer requires about 1.014 kWh to be generated. The .014 kWh is lost in getting the energy through the transmission system to the customer's meter. Distribution level LP/LPT customers require about 1.083 kWh to be generated for each 1 kWh delivered, or about 6.8% more energy must be generated for each kWh provided to distribution-level customers than for transmission level customers. Thus, the difference in losses between service at distribution and transmission levels accounts for an energy cost difference of nearly 7 percent. For demand, the difference in losses is even greater, at over 9 percent. The differences in losses between secondary and primary customers are over 4 percent for energy and 6 percent for demand.

Q. WHAT DISCOUNT SHOULD BE PROVIDED TO ALL PRIMARY AND TRANSMISSION LEVEL CUSTOMERS TO ACCOUNT FOR THE DIFFERENCE IN LOSSES AT HIGHER VOLTAGE?

A. In order to be certain of not overstating the discount, I have rounded each down to the next lower whole percentage point. On that basis, the difference in losses at higher voltage justifies a discount for primary customers of 4 percent for energy and 6 percent for demand. For transmission customers, the difference in losses justifies an energy discount of 6 percent and a demand discount of 9 percent. I recommend that this Commission adopt these discounts to account for the difference in losses for customers taking service at higher voltage.

Q. DO THESE LOSSES ALSO APPLY TO THE FUEL CONSUMED BY GULF POWER COMPANY?

A. Yes. Each kWh received at the customer's meter required that the Company generate more than one kWh to account for losses in the system. The larger the losses, the more fuel that is required to produce the energy received by the customer. Thus, Gulf Power must burn more fuel to produce a kWh used by customers at lower voltage than for a kWh used by a customer at high voltage.

Q. SHOULD LOSSES BE CONSIDERED IN SETTING THE FOSSIL FUEL AND PURCHASED POWER COST RECOVERY CLAUSE (RATE SCHEDULE CR)?

A. Yes. Rate Schedule CR is differentiated now by rate schedule, which accounts for average losses for the rate schedule. The fuel cost differences by voltage level within rate schedules should also be reflected in Schedule CR.

Q. IS IT NECESSARY TO DEVELOP VOLTAGE-DIFFERENTIATED FUEL CHARGES FOR EACH RATE?

A. No. Voltage differences only have an impact on the LP/LPT class, and a voltage-differentiated CR tariff only needs to be developed for this class. Other classes are more homogeneous. All of the Residential and Outdoor Service is provided at distribution voltage, only one-half of one percent of the GS/GSD sales are not at distribution voltage, and all of the PXT sales are at primary voltage. By contrast, the LP/LPT class is composed of customers spread through all voltage levels. The following table gives the distribution of sales by voltage level for the LP/LPT class:

| | Voltage Level | Percent of Sales |
|---|---|---|
| Distribution | (Level 5) | 24.5% |
| Primary | (Level 4) | 34.9% |
| | (Level 3) | 19.5% |
| Transmission | (Level 2) | 21.1%. |

The 21.1% percent of sales at Level 2 and 19.5 percent of sales at Level 3 are subsidizing the sales at Level 4 and Level 5, and Schedule CR should be modified to reduce the subsidies being provided to lower voltage customers.

Q. HOW DO YOU PROPOSED TO SET THE CR TARIFF FOR THE LP/LPT CLASS?

A. In order to properly recognize the difference in the cost of fuel required to produce a kWh at the customer's meter for different voltage levels, I propose that the Commission change the CR tariff to account for these losses. I have calculated charges for each voltage level of the LP/LPT class that maintain the relationship between time of use (TOU) and standard rates and that will produce the same revenue as the current CR tariff. The fuel charge for the three voltage levels I propose is shown in the following table:

Proposed LP/LPT CR Tariff
(cents/kWh)

| | Distribution | Primary | Transmission |
|---|---|---|---|
| Standard | 2.151 | 2.065 | 2.022 |
| TOU: On-peak | 2.242 | 2.152 | 2.107 |
| Off-peak | 2.116 | 2.031 | 1.989 |

In addition, I recommend that the Commission direct Gulf Power Company to file a voltage-differentiated CR tariff for the LP/LPT class in the future. This voltage-differentiated tariff should incorporate the energy losses for each voltage level of service.

Q. PLEASE TURN TO THE SECOND REASON THAT CUSTOMERS TAKING SERVICE AT HIGHER VOLTAGE LEVELS IMPOSE LOWER COSTS ON THE UTILITY, NAMELY THAT SERVICE TO CUSTOMERS AT LOWER VOLTAGE LEVELS REQUIRES ADDITIONAL EQUIPMENT THAT IS NOT USED TO PROVIDE SERVICE AT HIGHER VOLTAGE. HAVE YOU QUANTIFIED THE AMOUNT OF DIFFERENCE IN COSTS FOR THE VOLTAGE LEVELS?

A. Yes, I have determined that if all LP/LPT customers were served at level 2, i.e., transmission voltage, the costs imposed on Gulf Power Company would be reduced by $3,675,000. If all LP/LPT customers were served at either primary or transmission voltage, costs would be reduced by $2,104,522.

Q. HOW HAVE YOU MADE THIS DETERMINATION?

A. I have expanded the original embedded cost study prepared by Company witness O'Sheasy to voltage levels for the LP/LPT rate class. I did not modify my analysis to account for revisions made by Mr. O'Sheasy to his study, but those changes should have little effect on my results. This expansion identifies all costs that would be associated with service to the class if all customers took electricity at each higher voltage level. For example, I determined which costs would be incurred if all customers took service at voltage level 2, transmission service, and excluded costs associated with the lower level distribution system. Because I excluded only those costs that were clearly related to service at lower voltages, the amount excluded understates the real cost difference. The results from my expansion of the O'Sheasy cost study appears in Exhibit 355 (CEJ-2).

Of the total $31,141,000 revenue required from sales to produce the current 6.54 percent rate of return for the LP/LPT class, only $27,466,000 would be required if all service were at voltage level 2. That is, only 88.2 percent of the average cost of LPS service would be required to provide service if all customers took service at transmission level. If all service were at voltage level 2 or 3, the required revenue would be $28,339,000, and if all service were at voltage levels 2, 3, or 4, the required revenue would be $30,539,000. Because the primary service level includes both voltage levels 3 and 4, the revenue requirement for service at primary level was calculated at the weighted average of levels 3 and 4, which is 93.2 percent of the average cost.

Q. HOW DO YOU PROPOSE TO INCORPORATE THE COST DIFFERENCE ASSOCIATED WITH VOLTAGE LEVEL INTO A RATE DISCOUNT?

A. Because most of the cost of the distribution system is recovered through demand charges, it is appropriate to reduce the maximum demand charge for customers taking service at higher voltage to account for this difference in cost. The Company's proposed base revenue for LPT transmission level customers (excluding customer charges and voltage discounts) is $7,252,290. This is the amount that would be paid if the electricity were taken at distribution voltage with no discount. Costs if all LPT customers took service at transmission level account for approximately 88.2% of this amount, $6,396,520, which is $850,770 less than under the base demand charge. Dividing this difference by the maximum billing kw produces a reduction in cost of $1.35/kWh. For the primary discount, the reduction must be prorated between standard and time-of-use billing kw. The resulting cost reduction per kW is $0.76 for standard rates and $0.72 for time-of-use rates.

Q. WHAT DISCOUNTS DO YOU PROPOSE FOR CUSTOMERS TAKING SERVICE AT HIGHER VOLTAGE?

A. From the difference in cost that I just described, I propose a discount of $1.30 per kW for transmission level LPT customers and $0.70 per kW for primary level LPT customers. In addition, based on the difference in losses for higher voltage customers, I propose a discount of 6 percent for energy and 9 percent for demand for transmission level customers, and 6 percent and 4 percent for demand and energy, respectively, for primary voltage customers.

Q. SHOULD THERE BE A RATE DIFFERENTIAL FOR THOSE CUSTOMERS WHO OWN THEIR TRANSFORMERS?

A. Yes. Customers who own and maintain their transformers enable the utility to avoid the cost associated with installing and maintaining this equipment; and this cost difference should be reflected in the utility rates.

Q. HOW SHOULD THIS RATE DIFFERENCE BE STRUCTURED?

A. There are several ways that the difference in cost associated with ownership of the transformers can be reflected in rates. One that is commonly used is to require customers to provide transformation, and to assess a specific facilities charge against those customers who do not. This will recover the costs expended specifically on their behalf by the utility. Calculation of such a charge requires that the amount of the investment for each customer be known. Then the carrying costs of the investment plus appropriate O&M costs can be assessed to each customer using utility-owned transformers. However, it appears that little or no electricity is sold by Gulf Power to high voltage customers that do not own their transformers at this time. Therefore, I recommend that Gulf Power Company be directed to prepare a tariff that contains a provision for recovering costs from those customers that do not own their transformers, if those customers have not made full contributions in aid of construction for their facilities.

Q. HAVE YOU DEVELOPED RATES FOR THE LP/LPT CLASS THAT INCORPORATES YOUR PROPOSED DISCOUNTS?

A. Yes. These rates differ from Gulf Power's proposed rates in the following ways:

1. The charge per kW for secondary service is greater and voltage discounts for primary and transmission service are higher.
2. The energy and demand percentage discounts are greater.
3. Rate Schedule CR contains voltage-differentiated charges for the LP/LPT class.

A comparison of the Company's proposed rates with mine is contained in Exhibit 36 (CEJ-3). Page 1 of Exhibit 36 (CEJ-3) contains the demand and energy charges, page 2 contains the proposed schedule CR, and page 3 contains the discounts for service at higher voltage.

Q. IS YOUR PROPOSAL CONSISTENT WITH PAST COMMISSION ACTIONS?

A. Yes. In past rate cases, the Florida Public Service Commission has moved closer to cost-based rates by modifying the voltage discounts for higher voltage customers. I am recommending that the Commission complete that process in this proceeding and totally eliminate the intra-class subsidy in the LP/LPT class. It must be kept in mind that the higher voltage customers have been and still are subsidizing the lower voltage customers. Until the discounts I have proposed are adopted, that subsidization will continue.

Q. HAVE YOU EXAMINED THE IMPACT YOUR PROPOSAL WILL HAVE ON TYPICAL CUSTOMERS IN THE LP/LPT CLASS?

A. Yes. I have calculated the increase for each typical LP/LPT customer appearing in Schedule A-3 of the Minimum Filing Requirements. Under the rates I propose, the increase in rates for secondary distribution customers will be from two to six percentage points higher than under the Gulf Power proposal, the increase for primary customers will be about the same as proposed by the Company, and the increase for transmission customers will be less than proposed by the Company. The comparisons for those customers appears in Exhibit 367 (CEJ-4).

As can be seen in Exhibit 367 (CEJ-4), the increase to higher voltage customers is smaller than to distribution voltage customers. In addition, the increase in high load factor customers (such as Customer number 1) is less than to low load factor customers (such as Customer number 3).

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Q Doctor Johnson, have you prepared a summary for the Commission?

A Yes, I have. I have addressed two primary areas in my testimony. The first one is the increases to the LP/LPT and PXT rate classes. The second general area about which I testify is the voltage discounts to the LP/LPT rate class.

Class revenue levels are based partially on the class cost of service study filed by Mr. O'Sheasy, which is flawed and which overstates the cost of providing service to the LP/LPT class. The primary reason for this is that the Plant Scherer costs have been allocated as though they were production plant, that is used and useful, to providing service to the rate classes. Inclusion of Plant Scherer costs in the production allocation results in a larger portion of production plant costs being allocated to the LP/LPT and the PXT rate classes because the production component makes up a larger percentage of their total costs than it does for other rate classes.

Gulf Power has tried to sell this 63 megawatts of Plant Scherer, so the Company obviously does not consider this production plant as needed to complete its current jurisdictional load requirements.

If the Commission were to disallow recovery for this Plant Scherer investment, rates of return under the Gulf Power class cost of service study would increase by a greater amount for these two rate classes and for the other classes. But even without excluding Plant Scherer from rate base, it is clear that the allocation of these costs, as though they were needed for production of electricity, penalizes these two classes, and therefore should not be based solely on the production cost allocation.

Other reasons that the study misstates the cost of serving have to do with the data used for the LP/LPT and the PXT classes. For example, no change to rates has occurred since the Company's filing a year ago. That cost of service study showed that both classes were earning about the same rate of return, which was above the overall retail rate of return. In this cost of service study, filed with this docket, those rates of return changed substantially.

In examining the reason for that, I found several problems with data used in -- in the cost of service study. One instance was the inclusion of a large customer for which -- which nearly $2 million of facilities were built. This customer was included as an LPT customer rather than a PXT customer, and all of those investment dollars were included in the LP/LPT class cost of service rather than the PXT class.

Gulf Power has corrected this error and the revised study shows a slightly higher rate of return for the LP/LPT class and a slightly lower rate of return for the PXT class than the original study. But, there are still other problems with the data.

Another example was the projected sales data differed drastically from the recent historical data, particularly for the SE sales. These difficulties with data make the relative rates of return for the PXT and the LPT class suspect, and I have recommended that the Commission increase rates for these two classes jointly rather than as separate rate classes.

The second major area I address is voltage discounts within the LP/LPT rate class. This class is the only class with significant sales at more than one voltage level. So it's the only class that the issue needs to be addressed. There are two reasons that customers at higher voltages are less costly to serve. The first one is the losses are different, and the second is that the facilities require to serve the customers are different.

Gulf Power has proposed discounts in its rebuttal testimony that only include a portion of these differences in costs. Losses in transforming power from one voltage level to another do not comprise the entire difference in losses between voltage levels. Transmission level LPT customers require 1.014 kilowatt hours to be generated in order to get one kilowatt hour delivered; for distribution customers, 1.083 kilowatt hours of generation is required. Thus, about 7% more energy must be generated for a customer at secondary voltage than a customer taking service at transmission voltage.

The same is true for each kilowatt of demand, but the difference there is 9%. What this means is that Gulf Power requires 9% more generating capacity for each kilowatt delivered to secondary customers than to transmission customers. This difference in cost is not limited to the difference in losses for transforming power from transmission voltage levels to second -- secondary voltage levels.

The second reason for the voltage discounts is that the utility is required to invest in facilities in order to provide service to customers at lower voltages. These facilities include transformers and other items such as poles and conductor.

I have gone through the Company's class cost of service study and isolated those costs that relate to each voltage level for the LP/LPT class. My exhibit, CEJ 2 contains the results of that analysis. Thus, in that exhibit, Column 3, headed "LPT Level 2" contains only costs associated with providing service to the LPT class as though all customers took service at transmission voltage; that is, demand-related costs at lower voltage levels have been excluded. All customer-related costs have been retained.

I have used the results of this analysis to determine the cost of facilities required to provide services -- to provide service to customers at lower voltage levels, and from that have calculated voltage discounts proposed in my testimony.

I have also proposed that the fuel cost recovery rate, CR, be modified to incorporate these lost factors. The CR rate now includes average losses for the rate classes but is not distinguished by voltage levels for the LP/LPT class.

That concludes my summary.

MAJOR ENDERS: Tender the witness for cross.

CROSS EXAMINATION

BY MR. STONE:

Q Good evening, Mr. Johnson. Mr. Johnson, you do not hold yourself out as an expert on the planning of generating units to satisfy an electric utility's capacity and energy needs, do you?

A I'm fairly knowledgable about capacity expansion and utility system planning. I have not testified as to the propriety of Gulf Power's planning in this proceeding, however.

Q Have you ever been involved in the planning of a utility's generation system?

A For a utility, no.

Q Have you consulted with any of the system planners or any of the individuals at Gulf Power involved in system planning?

A No.

Q Would you agree that individuals associated with Gulf and involved in planning the capacity additions to Gulf's system are in the better position to provide the reason for acquiring any of the generating capacity owned by the Company?

A Well, the Company has testified that it planned to sell the Plant Scherer capacity and is trying to sell it. So I take their word for it that that was their intent. I have not done an independent study as to why Plant Scherer was --

Q Mr. Johnson, I would ask that you please answer my question. Would you agree that the individuals at Gulf associated with planning Gulf's system are in the better position to provide the reason for Gulf's acquiring any of the generating units on its system?

A A better position than I am?

Q Yes.

A Sure.

Q Your testimony as filed refers to the original cost of service study filed by the Company of December 15, 1989, isn't that correct?

A I refer to that in my testimony.

Q But you have acknowledged that the Company has, in fact, filed revised cost of service studies to take care of the change in the forecast which shows that the customer formally expected to migrate to LPT did, in fact, not migrate and has stayed on the PX/PXT class?

A Yes, I stated that the Company had filed such a revised class Cost of Service Study.

Q As a result of that revised study, would the numbers on Page 11 of your testimony for the rate of return for the LP/LPT class actually now become, instead of 6.54, become 6.63, and for the PXT class on Line 22, instead of 8.92, be 8.33.

A I don't have those numbers. That sounds about right.

Q But if those numbers were taken from Exhibit

231, which is the Company's revised schedule, you would agree those are the numbers the Company is proposing? Or supporting?

A Yeah, if those numbers come from the revised Cost of Service Study, that's correct. However, the Company filed its rates based on the original Cost of Service Study and has not revised the rates because of this revision to the Cost of Service Study.

Q Well, in terms of present rates in the 1990 Cost of Service Study, the revised study that has been sponsored by the Company under Exhibit 231, isn't it correct that the LP/LPT class at present rates is at parity?

A I'm sorry, at parity with other classes you mean? With the jurisdictional overall?

Q With the Company overall rate of return.

A It's not far from it, that's true.

Q Well, based on your own testimony, if you accept my numbers subject to check, 6.63 for the LP/LPT class, as compared to the retail level of 6.60%, if anything, it is above parity, would you not agree?

A Right. Actually, yes. My point was that because there is not a great deal of difference between these two classes, the increase to the PXT and the LPT classes should be about the same instead of tilted the way they are in the Company's proposals. So I have no objection to agreeing with your statement, no.

Q Would you also agree that the Company has in its proposed rates maintained the class LP/LPT at parity?

A No, I don't think I would.

Q Based on your -- well, let me ask you this: You have proposed some LP/LPT rates. Have you not?

A Yes.

Q Have you calculated the revenue impact of our proposed rates on the entire rate class?

A You mean on the class as a whole?

Q LP/LPT, yes.

A Yes, that's the reason for my revised exhibit. As was pointed out by the Company witness, there was an error in my calculation that provided excess revenues from the class, so I recalculated that based on the -- you have to understand, this is based on the test year billing units and does not account for any migration.

Q What is the rate of return index for the class under your proposed rates?

A Well, since my rate recovers the same revenue as the Company's does, and I did that because I did not calculate a difference in revenues for the LPT class, the rate of return would be the same as under the Company's.

My rate would have to be modified to reflect whatever actual increase was awarded to the Company for the LPT class.

Q Have you designed rates for the PX/PXT class?

A No.

Q Have you designed rates for the GS/GSDT class?

A No, I haven't done that either.

Q Do you know what effect your single rate proposal would have on other rates which might be affected from crossovers from or to the LP/LPT class?

A No, as I just said, I did not take into account that there would be some migration.

Q Did you design any street lighting rates?

A No.

Q Have you designed a general service nondemand rate?

A No.

Q Have you designed a residential rate?

A I have not designed any rate except this rate for the LP/LPT class.

Q The fact of the matter is, you do not know how your rate design proposal would fit into the complete rate design package that this Commission would order to become effective for Gulf's customers?

A I don't think any of us knows at this date how the rate design proposal for any one class would fit in with the Commission's directive coming out of an order in this docket.

Q Does the Federal Executive Agencies represent customers in all these customer classes?

A I don't know that there are customers in all of these classes. There are customers in classes other than the LP/LPT class.

Q I guess you don't really know who your clients are then, do you?

A I think I do.

MR. STONE: No further questions.

CHAIRMAN WILSON: Mr. McWhirter?

MR. McWHIRTER: We're ready to proceed. I have no questions.

CROSS EXAMINATION

BY MR. PALECKI:

Q Mr. Johnson, in the Prehearing Order, FEA's position to Issue 115 supports Gulf's use of the 12 CP and one-thirteenth Cost of Service Study.

Isn't it true that the costs of Plant Scherer have been allocated on the same methodology, the 12 CP and one-thirteenth energy?

A Yes, as the production allocator, that was the basis for allocation of Plant Scherer investment.

Q So the LP/LPT class has been allocated its share of Plant Scherer costs and all other production plant costs on the basis of 12 CP and one-thirteenth?

A That's correct.

Q Wouldn't your proposal on pages 8 and 9 of your testimony of collect Plant Scherer costs on a surcharge based on total revenue? Basically, what I'm saying is, your proposal would collect Plant Scherer costs on a surcharge based on total revenue, is that correct?

A I suggested that was one alternative the Commission could adopt.

My intention in presenting the issue about Plant Scherer was primarily to point out that if it is viewed as capacity that is not necessary to meet the needs of Florida jurisdictional customers, that it is not appropriate to allocate that cost based on the same production cost as other plant that is required to meet the Florida retail jurisdictional needs.

One alternative that I suggest here is doing it on total revenues.

Q Well, wouldn't the method that you suggest allocate to LP/LPT less cost for Plant Scherer than the 12 CP, one-thirteenth methodology?

A Yes.

Q Isn't your justification for assigning the cost of Plant Scherer to rate cases on the basis of revenue the fact that LP/LPT and PXT rate classes are allocated proportionately less transmission and distribution system cost than the other rate classes?

A That's right. The primary difference is because almost all of the PXT customers and a great many of the LPT and LP customers take service at higher voltages. They, therefore, make much less use of the secondary distribution system.

Q So it then follows that production plant makes up a larger portion of the LP/LPT class cost?

A Right. That's exactly the point that I was making. That if this were a -- for example, a nuclear plant that had been abandoned and these were abandonment costs, and the Commission were faced with essentially taxing all of the Florida ratepayers a tax to recover those abandonment costs, it would not be obvious to me that the appropriate method of doing that is by recovering it through production costs, and that was exactly the point I was trying to make here.

Q Well, why does the allocation of a smaller proportion of distribution and transmission systems' cost to LPT justify allocating or assigning Plant Scherer costs on revenues through a surcharge?

A Are you asking me to justify why it makes more sense to use revenue as an allocation means than production plant? Was that the thrust of your question?

Q Yes. You said that -- well, the LPT class is allocated a smaller proportion of distribution and transmission systems' costs than the proportion of production plant. And how does this justify allocating or assigning Plant Scherer costs on revenue through a surcharge?

A Oh, it wasn't intended to justify allocating the -- those excess costs on revenue.

The point behind that statement was simply that if we do consider Plant Scherer as unnecessary to actually meet the requirements, then allocation of it as though it was a necessary part of the production plant has no basis, in fact, and that some other means has to be found to assess that tax on the ratepayers.

Now, if the Commission wants to, it certainly can allocate that tax on production plant, the same production plant allocator as used in the Cost of Service Study.

I would assert that that has -- there is no particular rationale for doing that and simply because it is a plant that produces electricity does not provide any rationale.

Q Referring to Page 10 of your prefiled testimony, is it your position that the cost of service of the LP/LPT class has been overstated because one large PXT customer for whom Gulf has installed a $2 million dedicated substation was included in the LP/LPT class?

A That was one of the reasons that the original cost study overstated the cost of serving the LP/LPT rate class. But as I point out in my testimony, there are other reasons, too.

Q Well, would the cost to the LP/LPT class be overstated if there are other LP/LPT customers for whom the Company has installed dedicated substations?

A I'm sorry. I didn't follow your question. Would you try again?

Q Well, if there are other LP/LPT customers for whom the Company has installed dedicate substations, would you still say that the cost of LP/LPT is overstated?

A I don't think one can draw that conclusion from that, because there's simply no way of telling without looking at each and every one of them. But this one was brought to our attention in the filing, and it turned out that this one customer had a fairly large amount of local facilities built for it.

Q Now, it's your testimony that the 21.5% of sales at Level 2 and the 19.5% of sales at Level 3 are subsidizing the sales at Levels 4 and 5, is that correct?

A Right.

Q Are you aware that Level 3 customers are customers who take service at primary voltage but are served from a dedicated substation?

A Right. As I understand Level 3, customers at Level 3 take service from a substation and make no use of the primary distribution lines.

Q Are you aware that the PXT customer with the $2 million dedicated substation investment is a Level 3 customer?

A No.

Q If you were made aware of that fact, would you be able to reconcile your previous statement that Level 3 customers are subsidizing the sales of levels 4 and 5?

A Well, as a general statement, it's true.

Q Well, one of the factors that you considered as being highly important was this $2 million substation that was installed for this PXT customer.

So how can you say that this PXT customer, whom is a Level 3 customer for whom $2 million was spent on a dedicated substation, how can you say that they're subsidizing, Level 3 is subsidizing sales at Level 4 and 5?

A No. I said as a general statement, that's true. There may be certain of these customers who are not subsidizing customers at lower voltage levels. But on average, the customers taking service at higher voltage levels are subsidizing customers taking service at lower voltage levels because the voltage discounts that are currently offered are insufficient.

Q Have you made a Cost of Service Analysis of production and t-ansmission plant costs for customers served at each of the three voltage levels, based on the relative 12-CP and energy of each of the three groups?

A No. What I did in my analysis to produce my Exhibit CEJ-2 was to go through the entire Company's Cost of Service Study and isolate those items that were specifically related to a voltage level -- for example, below 2 -- and which were demand-related.

So, for example, the Company, in its Cost of

Service Study, had land and land rights at Level 2, and at Level 3, and so forth on down. So the column titled, "LPT Level 2," would have that portion of land and land rights that the Company had classified as being associated with Level 2, so long as it was demand-related.

So this does not purport to be a class Cost of Service Study of the type that allocates between different categories of customers the Cost of Service. It's an extension of the Company study, but not, it's not a study that separates the LPT class into components the same way the Company Study separates the jurisdictional total into rate classes.

Q Haven't you assumed the average LP/LPT production and transmission plant costs for each of the three voltage level subgroups?

A In the calculations that we've just been talking about that produced my Exhibit CEJ-2?

Q Correct, and the calculations you have made.

A Yeah, I guess that's fair to say. That's based on class-wide average demands and energy consumption.

Q Have you determined whether currently there is an under- or overrecovery of production and transmission plant costs relative to costs based on a specific cost analysis by voltage level for LP/LPT?

A I didn't understand the question, would you repeat it?

Q Have you determined whether there is an underrecovery or an overrecovery of production and transmission costs, relative to costs based on a specific cost analysis by voltage level of the class? (Pause)

A I don't understand how one could make that comparison. The revenues are not assigned to production, they're assigned to charges in the tariff. Some of the charges are demand-related, and some are customer-related and some are energy-related, but there are none that are associated with production. So I fail to see how someone could make the comparison you request.

Q The next issue we're talking about is concerned with discounts for transmission ownership. Would you agree that it is the Utility's responsibility to build the most cost-effective transmission and distribution system to serve its general body of ratepayers?

A As a general statement, I couldn't argue with that.

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

A I can certainly conceive of such instances.

Q And would you agree that under these special circumstances that additional lines, conductors, and/or substations that are requested by a customer may result in uneconomic expense to the Utility and the general ratepayer?

A Not necessarily. The Company could refuse to provide those facilities, unless the ratepayer was willing to front the costs. There are a great many ways of handling facilities that are necessary to provide service to a customer other than simply including it in a generate base.

If it's of that much benefit to the customer, the customer can pay to have the equipment installed. There are many instances where that occurs.

Q In general, could the level of a voltage discount encourage the Utility to build more plant than otherwise needed by the general ratepayers?

A I don't see how it could.

Q If plant costs, such as additional lines, conductors, substations, et cetera, were collected through rates, this would result in higher average rates for all customers, wouldn't it?

A Well, you're talking about additional lines and conductors and so forth above what level?

Q Well, that are specially requested by customers under special circumstances that they're uneconomic to the Utility, they're not in their general scheme.

A Well, if -- you're following that line of reasoning that if a customer asks for something that is unreasonable and the Company went ahead and did it, and the costs were greater than would have been if the Company had done something more economic, then, sure, the rest of the ratepayers are going to have to pick up the cost. But I don't accept that characterization as something that will flow from providing the proper voltage discounts to customers taking service at higher voltage levels.

Q Does your methodology provide for a discount for substations, lines, conductors and transformers along the Utility's distribution system?

A I'm sorry, can you repeat it again?

Q Does your methodology provide for such a discount for substations, lines, conductors, transformers, along the Utility system?

A If I understand the question correctly, for example, a customer taking service at transmission of voltage would not share in the cost burden of transformers, substations, lines and poles to provide service to customers at lower voltage levels.

So if I understand the question correctly, the answer is yes, it provides for that.

Q Were you aware of the Commission's past policy and recent decision in the Marianna and Fernandina Electric Rate Cases to recognize only transformation costs in developing voltage discounts?

A Can you give me the docket numberon that, please?

Q 8880158.

COMMISSIONER BEARD: Does Fernandina have any transmission lines?

MR. PALECKI: No, very little.

COMMISSIONER BEARD: I didn't think they did. There's all the substation distribution, primary and secondary voltage, right?

MR. PALECKI: Yes.

A In answer to your question, no, I'm not aware of any such decision. If the Commission were to make such a decision in this proceeding, I obviously would feel that's not the proper decision to make.

Q Are you advocating a specific facilities charge to be applied to customers who do not own their own transformation equipment?

A I would find that an acceptable way of dealing with it. As I understand it, almost all the sales that Gulf Power makes now at voltage levels higher than secondary are to customers who own their own transformers. If the Company wants to establish -- I'm sorry. If the Commission wants to establish that as the basis and charge a facilities charge to any customer who doesn't provide their own transformation, then that would be appropriate to do.

But the thrust of my testimony, actually, on this issue goes to what is the proper voltage discount for the difference in losses and the difference in facilities for customers at different voltage levels?

And you can handle the question of the facilities for the individual customer one of two ways: Either the Company can provide it for everybody, or you can require the individual customer to provide it; and if they don't, then assess them a special facilities. Doesn't really make much difference which way you do it.

Q Does Gulf Power allocate the average cost of transformation for each level of service in its Cost of Service Study, which will be recovered through rates?

A The cost of transformation are allocated in the Cost of Service Study.

Q Doesn't your proposal for a facilities charge on customers not owning transformers charge customers twice, once through rates and another time through the facilities charge?

A No. If you did it that way, you wouldn't -- if the customer were paying a facilities charge, you wouldn't allocate that to the class as a whole. I mean, it would be one place or the other.

And that's why I say you can do it one of two ways, you can either make a facilities charge or you can provide it to everybody and allocate the cost. And it really doesn't matter which way you do it. But you're right, if you tried to do it in both places, you would doubl_ collect.

Q Would it be equitable to provide voltage discounts to all demand rate classes?

A Well, if it were necessary. But I, as I pointed out in my testimony, no other class has any significant amount of sales at different voltage levels.

Now, if you want to go through and do the calculation for the, I think it was, 1/2 of 1% of the sales for the GD class that were not at secondary distribution, sure, you could do that. I didn't do it.

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

CHAIRMAN WILSON: Any questions, Commissions? Redirect?

MAJOR ENDERS: Just a couple.

MR. STONE: May I have one question on cross? Real brief, I promise. Well, I suppose.

FURTHER CROSS EXAMINATION

BY MR. STONE:

Q Mr. Johnson, you made the analogy for Plant Scherer to a cancelled nuclear plant. Isn't there a major distinction in the fact in the case of Plant Scherer, Gulf's territorial customers are, in fact, receiving capacity and energy out of the plant? And that would not be the case in a nuclear plant that was cancelled?

A That's certainly a difference, yeah.

MR. STONE: Thank you.

CHAIRMAN WILSON: As a matter of fact, I'm not aware of any instances where power is being gotten from a cancelled plant of any kind. Getting blood from a turnip?

WITNESS JOHNSON: I only meant to provide that as an instance where tax would be required and it might not be appropriate to allocate that tax on production allocator.

CHAIRMAN WILSON: Now redirect.

MAJOR ENDERS: Thank you, sir.

REDIRECT EXAMINATION

BY MAJOR ENDERS:

Q Dr. Johnson, Mr. Stone seemed to imply by his question you didn't know who your client was. Of the six military installations in the Florida Panhandle and their service area, do you know what percent of Gulf's total jurisdictional load they constitute?

CHAIRMAN WILSON: Subject to check?

(Laughter)

WITNESS JOHNSON: I did calculate that. I wish you hadn't asked, because -- withdrawn.

MAJOR ENDERS: You calculated it last year for last year's withdrawn case. Would you accept, subject to check, 8%?

COMMISSIONER EASLEY: What, 80?

MAJOR ENDERS: 8%.

WITNESS JOHNSON: I would accept that, subject to check.

COMMISSIONER BEARD: You mean to infer from that that he represents 8% of the customers? Just kidding, sorry, bad joke.

WITNESS JOHNSON: Yes, I would accept that, subject to check.

CHAIRMAN WILSON: Anything further on redirect?

MAJOR ENDERS: No, sir.

CHAIRMAN WILSON: Thank you very much. Any, all right, the exhibits have been stipulated, that's fine. Thank you very much. Let's do one more witness.

MR. BURGESS: Commissioners, while that witness is coming up or getting away from his pushups, I was wondering if I could move Mr. Rothschild's prefiled testimony into the record as though read.

CHAIRMAN WILSON: Yes. Without objection, his testimony is entered --

COMMISSIONER BEARD: Too late, you missed your chance.

CHAIRMAN WILSON: We're becoming real sticklers for procedure. (Laughter)

MR. BURGESS: I've noticed that.

And his exhibits, I believe, have been stipulated into the record.

CHAIRMAN WILSON: Yes, without objection.

COMMISSIONER BEARD: Be forewarned here, we're only going to take five more witnesses out of order.

MR. BURGESS: Mine are almost finished. I've only got one more.

CHAIRMAN WILSON: We are going to bring them back.

(Exhibit Nos. 338 through 349 inclusive, stipulated into evidence.)

# I. STATEMENT OF QUALIFICATIONS OF JAMES A. ROTHSCHILD

**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is James A. Rothschild and my address is 115 Scarlet Oak Drive, Wilton, Connecticut 06897.

**Q. WHAT IS YOUR OCCUPATION?**

A. I am a financial consultant specializing in utility regulation. I have experience in the regulation of electric, gas, telephone, sewer, and water utilities throughout the United States.

**Q. PLEASE SUMMARIZE YOUR UTILITY REGULATORY EXPERIENCE.**

A. I am president of Rothschild Financial Consulting and have been a consultant since 1972. From 1979 through January, 1985 I was a Principal of Georgetown Consulting Group, Inc. Prior to that, from 1976 to 1979 I was the President of J. Rothschild Associates. Both of these firms specialized in utility regulation. From 1972 through 1976 I was employed as a consultant at Touche Ross & Co., a "big eight" accounting firm. Much of my consulting work done while at Touche Ross related to utility regulation. While associated with all of the above firms, I have worked for various state Utility Commissions, Attorneys General, and

Public Advocates on matters relating to regulatory and financial issues. These included rate of return, financial issues, and accounting issues. (See Appendix.)

Q. PLEASE DESCRIBE CONSULTING WORK YOU HAVE DONE ON NON-UTILITY MATTERS.

A. I consulted in the preparation of bond prospectuses for five hospitals, assisted a major European chemical company in deciding whether to acquire an American owned chemical plant, served as a consultant to a major corporation that went into a Chapter XI bankruptcy, and advised the City of New York about procedures and attendant savings related to its payroll disbursement systems.

Q. WHAT DID YOU DO PRIOR TO BECOMING A MANAGEMENT CONSULTANT?

A. I worked for five years at Olin Corporation. During the first four years with Olin, I was a process engineer at one of their chemical plants. My last year at Olin was spent as an economic analyst in its Chemicals Group.

Q. PLEASE DESCRIBE SOME OF YOUR OTHER RELEVANT EXPERIENCE.

A. I was the chairman of a one week seminar given by the American Management Association entitled "Accounting and Finance for Non-Financial Executives". Also, I have lectured to the managements of Union Carbide Corporation, Celanese Corporation, and Olin Corporation. My topic was current value accounting applications in the chemical industry.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?
A. I received an M.B.A. in Banking and Finance from Case Western University (1971) and a B.S. in Chemical Engineering from the University of Pittsburgh (1967).

## II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?
A. This testimony addresses the cost of capital that Gulf Power should be allowed to earn on its utility rate base.

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## III. SUMMARY OF CONCLUSIONS

### A. Recommended Cost of Capital

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS ON THE COST OF CAPITAL TO GULF POWER COMPANY.

A. The overall cost of capital that should be allowed to Gulf Power Company is 7.92% (see Schedule 1, Page 1). This is based upon an investor supplied capital structure with 42.98% common equity, 8.10% preferred equity, and 48.92% debt. The cost of capital is based upon a cost of equity of 11.75%.

I also explain in this testimony that the cost of equity to service industrial customers is is estimated to be about 0.4% higher than to service residential or commercial customers. This means that the cost to service residential and commercial customers is probably somewhat below 11.75%, and the cost to service industrial customers is probably slightly higher than 11.75%.

Q. HAVE THE PROBLEMS WITH THE INTERNAL REVENUE SERVICE AND OTHER ALLEGED MANAGEMENT INDISCRETIONS INCREASED THE COST OF EQUITY OF GULF POWER?

A. Theoretically, yes. However, I do not believe it is proper for ratepayers to be charged for whatever extra costs might exist as a result of these problems. While I have not made any downward adjustment, to the extent possible this higher equity cost should not be included in the return on equity allowed to Gulf Power.

Q. YOUR RECOMMENDATION FOR THE COST OF EQUITY IS 1.25% LOWER THAN THE 13.0% RECOMMENDED BY DR. MORIN. PLEASE SUMMARIZE WHY THIS DIFFERENCE EXISTS.

A. Dr. Morin presented a wide array of DCF analyses, most of which have a theoretical basis that is inconsistent with the requirements of the D/P + g version of the DCF model. Specifically, he used non-constant growth rates as an input to this version of the DCF model which requires that constant growth rates be assumed. The one version of the DCF model he presented which does have some validity, because it at least does depend upon a constant growth rate, was applied in a much more limited way than he applied his other, invalid DCF techniques. In addition to the problems with his DCF method, he improperly increased his equity cost determination as a result of his view of the impact of the payment of quarterly dividends. In reality, the fact that dividends are paid quarterly instead of annually causes the annual DCF model to overstate, not understate the indicated cost of equity. The problems with Dr. Morin's DCF analysis are explained in detail in the Testimony Evaluation section of this testimony.

In addition to the DCF method, Dr. Morin says that he presented a risk premium analysis. As also explained in the Testimony Evaluation section of this testimony, the Risk Premium approach as he presented it is really his DCF method all over again, but with the additional problems that it is dependent upon the incorrect assumption that income tax laws and investors expectations for inflation have remained constant over the years.

Q. YOU SAID THAT THE USE OF AN ANNUAL DIVIDFND DCF MODEL FOR A COMPANY THAT PAYS DIVIDENDS QUARTERLY RESULTS IN THE MODEL OVERSTATING THE COST OF EQUITY. DID YOU CONSIDER THIS IN YOUR 11.75% COST OF EQUITY RECOMMENDATION?

A. I did not lower my cost of equity recommendation as a result of the quarterly payment of dividends. For this reason, and others explained later in this testimony, my 11.75% cost of equity recommendation is conservatively high.

IV. CAPITAL STRUCTURE

Q. WHAT DO YOU RECOMMEND FOR THE CAPITAL STRUCTURE OF GULF POWER COMPANY?

A. As explained in the summary of conclusions of this testimony, the capital structure I have used to formulate my overall cost of capital recommendation is shown on Schedule 1, Page 1. This capital structure is the same one that has been proposed by the company. If the Commission should determine that any adjustments to the capital structure are appropriate, then my cost of capital recommendation should be adjusted accordingly.

V. COST OF FIXED CAPITAL

Q. HOW DID DEFINE THE TERM COST OF FIXED CAPITAL THAT SHOULD BE ALLOWED TO GULF POWER?

A. I adopted the embedded costs as presented by the company.

## VI. COST OF COMMON EQUITY

### A. Summary of Conclusions on Cost of Equity

Q. WHAT IS THE COST OF EQUITY TO GULF POWER COMPANY?
A. The return on common equity this Commission should allow Gulf Power Company is 11.75%.

My recommended return on equity is based primarily upon the application of the DCF method to the electric companies in the Moody's Electric Utility Common Stocks (Moody's 24) which are not in the midst of nuclear construction uncertainties, and to the Southern Company which is the parent of Gulf Power.

The equity cost recommendation has been checked for reasonableness by making a review of the relationship between market-to-book ratios and the earned return on equity and by comparable earnings observations of the the actual return on book equity that has been achieved by the Dow Jones 30 industrials.

### B. Definition of Cost of Equity

Q. HOW DO YOU DEFINE THE TERM COST OF COMMON EQUITY?

A. The cost of common equity is the profit opportunity rate investors require in order to be willing to exchange current cash for the right to future dividends and future capital appreciation.

Q. WHAT DETERMINES THE MARKET PRICE OF A UTILITY'S STOCK?

A. The perceived success of management in earning profits on assets, not the cost of the assets, determines the market price for essentially any stock. If profit expectations grow to where they exceed investors' requirements, market price will exceed the net original cost (book value) and if profit expectations fall below investor requirements, market price will be less than book value. The market price can properly be compared to book value per share to determine the adequacy of the earnings prospects that investors expect management to achieve on the company's assets. The commonly used statistic to compare these factors is the market-to-book ratio.

Q. FOR A COMPANY WITH A MARKET PRICE IN EXCESS OF BOOK VALUE, HOW LONG WILL THE STOCK PRICE STAY ABOVE BOOK VALUE?

The stock price will remain above book value as long as investors continue to expect the return on book equity to be higher than they demand on their market price investment. If, in the future business conditions change such that investors no longer expect the company to be able to earn a return on book equity in excess of the return demanded on market, the market price will decline.

Q. HOW DOES THIS APPLY TO A REGULATED UTILITY COMPANY?

For a utility, if all assets are included in the rate base, and if all expenses are deemed to be appropriate, regulators should strive to set authorized earnings at the level required to result in a market-to-book ratio averaging approximately 1.0 in the long run. If regulators were to set earnings at a level which would cause investors to set the market price below book value, the earnings power of the assets would be perceived to be worth less than the net original cost. Conversely, if regulators were to set earnings at a level which would cause investors to set the market price above book value, this would mean investors would be perceiving that the profits on the assets would be high enough to make them worth more than the original cost of the assets.

Q. WHAT IF A UTILITY COMPANY'S COMMON STOCK PRICE IS ALREADY SIGNIFICANTLY ABOVE BOOK VALUE?

A. This is a clear sign that the company is expected by investors to be able to earn more than its cost of equity. To the extent that this high rate of earnings is the result of the expectations from the regulated utility operations, the regulating authority should take the appropriate action, such as lowering the authorized return on equity. Once investors change their expectations accordingly, the stock price will decline to the proper level.

Q. ARE THERE ANY UNDESIRABLE RESULTS ASSOCIATED WITH SETTING A RETURN AT SOME LEVEL OTHER THAN THAT WHICH WOULD RESULT IN A MARKET PRICE EQUAL TO THE BOOK VALUE OF USED AND USEFUL UTILITY INVESTMENT?

A. Yes. If the market-to-book ratio target were less than 1.0, management might resist making new capital investments in order to minimize dilution. Conversely, a market-to-book ratio above 1.0 derived from the authorized return would also be an undesirable target for a regulated company. Not only would it result in higher profits than necessary, it also would give management an incentive to invest in unneeded new assets. Equity raised to finance the new assets would cause the book value to inflate. Therefore, if regulation permits a utility to increase its book value per share merely by purchasing new assets, a potential risk exists that more assets would be purchased than needed to provide safe and adequate service. It is possible that the high market-to-book ratios in the 1960's and early 1970's contributed to the extra capacity that exists today in many parts of the country.

The DCF method is specifically designed to measure the return on equity investors expect to earn on their market price investment.

Q. CAN THE COST OF EQUITY BE DETERMINED PRECISELY?

A. A certain degree of imprecision exists in the determination of equity cost because a company's market price is dependent upon investors' expectations of future average earnings levels. Future expectations are not subject to precise computation. However, the greatest source of imprecision in arriving at the cost of equity in utility rate proceedings comes from the improper selection of techniques, or the misapplication of the selected techniques rather than for a difficulty in quantifying investors' expectations. For example, if in the DCF method, one approaches the quantification of investor growth expectations by merely observing historic growth in earnings per share or dividends per share without basing future expectations on an understanding of what it is in the historic data that causes growth, it is possible to reach a growth conclusion which is substantially different from that expected by investors. Alternatively, if growth is quantified by recognizing that it occurs because earnings have been and will be retained in the business and used to purchase used and useful assets, a much more accurate estimate of growth is possible.

Q. DOES THE USE OF AN ARRAY OF IMPRECISE METHODS HELP TO IMPROVE PRECISION?

A. No. Using a collection of inaccurate methods can only serve to dilute the accuracy of the answer obtained from the accurate methods. Quantity is not a substitute for quality. For example, as explained in the Testimony Evaluation section of this testimony, considering the results of a risk premium analysis only serve to reduce the accuracy of the computed cost of equity.

Q. IS HISTORIC DATA HELPFUL?

A. Yes. Investors and analysts examine historic data to help understand what is probable for the future. However, sophisticated investors do not compute historic five or ten year growth rates and use that result to determine what growth rates are probable to occur in the future.

C. Cost of Equity Computation

1. Introduction

Q. HOW HAVE YOU COMPUTED THE COST OF COMMON EQUITY?

A. I have computed the cost of equity by using a properly applied DCF method. By properly applied, I mean a method that is consistent with the basic assumptions referenced later in my testimony are required to implement the DCF method. This essentially means that my estimate of growth is based upon a future sustainable growth rate, not a growth rate that might have by chance happened over any particular historic period.

As will be explained in this section of my testimony, to properly apply the simplified, or D/P + "g" version of the DCF method it is necessary to make the four following determinations:

1) the dividend yield

2) the return on equity rate which investors anticipate for the future

3) the dividend payout ratio (or retention rate) that is consistent with the dividend yield and return on equity expectation

4) the impact of any sales of new common equity at other than book value.

Q. DID YOU RELY ON ANY TECHNIQUES OTHER THAN THE DCF METHOD?

A. Properly applied, the DCF method is far superior to other equity costing methods. Therefore, it should be given primary weight.

I have checked the results from my DCF method by observing the relationship between the earned return on equity and the market-to-book ratios, and have presented a comparable earnings study. The comparable earnings study is helpful to show that my equity cost recommendation is sufficient to provide a return on equity commensurate with the returns being earned by unregulated firms.

## 2. Description of DCF Method

Q. PLEASE EXPLAIN THE DCF METHOD.

A. The Discounted Cash Flow, or DCF method, is based upon the principle that there is a time value associated with money. That is, $1,000 received next year is worth less than $1,000 received today. This is true, if for no other reason, because one person could take the $1,000 received today, put it in a bank account guaranteed by the federal government, then, one year later withdraw those funds from that account. Assuming an interest rate of 6% compounded annually, at the time of withdrawal, one would receive approximately $1,060 from the bank. In this way, $1,000 today is worth the same as $1,060 received in one year. Because of this time value associated with money, the relative value difference of the $1,000 received next year versus the $1,000 received today is dependent upon the interest rate, or cost of capital.

The concept of time value as explained above is directly applicable to a decision to purchase common stock. The essential difference between an investment in common stock and an investment in the bank account is that, unlike with a bank account, the exact total yield from an investment in common stock is not specified and there is no federal guarantee that either the principal will be returned or that any dividends will ever be paid. While the stock investment is more risky, the basic principle of the time value of money remains the same.

When an investor either buys stock in a company, or deposits money in a bank account, he or she gives up cash today in exchange for the right to potential future gains. The investor in the bank account gets the specified interest income, whereas the investor in common stock gets any dividends the company may declare plus the right to sell the stock at prevailing market prices. Today's stock price is the present value equivalent of the expected dividends and the proceeds from eventually selling the stock. The interest rate, or, discount rate, that makes the future anticipated dividends and future anticipated selling price equal to the present market price is the cost of equity.

Conceptually, it is possible to use a "full" DCF method by making a separate year-by-year estimate of what the dividend for any given company will be. Then, each year's dividend could be separately discounted back to arrive at its net present value. Through a series of repeated computations, eventually the discount rate can be determined that is sufficient for the stream of future cash flows to have the same net present value as the current market price. This procedure is moderately cumbersome. When certain specific conditions exist, it is possible to greatly simplify the process. If it is reasonable to expect that earnings, dividends, book value, and stock price will all grow at a constant rate in the future, it is mathematically acceptable to use the simplified version of the DCF formula.

The simplified formula is k = D/P + g where k equals the cost of equity, D equals the dividend, P equals market price and g equals the future anticipated rate of growth in dividends, earnings, book value, and stock price.

For reasons that will be explained later, if a decision to use this simplified version of the DCF formula is made, as I have done in my testimony) it is critical that the retention rate times return on equity, which is commonly referred to as the "b x r" approach, be used to compute growth. This is because the "b x r" approach arrives at a future sustainable constant growth rate. Other techniques, such as the historic rate of change in dividends, are derived from environments in which earnings, dividends, and book value all grew at varying rates. Therefore, they are not the type of growth rates that can be used in the simplified, or D/P +g version of the DCF formula.

The simplified version of the DCF method is applied by computing D/P(dividend yield), determining g and then adding these two results together.

Q. IS IT GENERALLY APPROPRIATE TO USE THE D/P + g SIMPLIFIED VERSION OF THE DCF METHOD FOR PUBLIC UTILITIES?

A. Yes. For most utilities, future business conditions are generally expected to be relatively stable. Earnings fluctuate to a certain degree based upon local weather and economic cycles, extraordinary events and the timing of rate cases. However, results generally tend to cycle back to a normal profit allowances as a result of rate increase awards. This is in contrast to some non-utility companies that might have a fad product with a profit expectation for only a few years or a developing company which might be expected to have several years of poor earnings before its product becomes successful.

Q. IS THE DCF METHOD ALWAYS APPLIED PROPERLY?

A. No, not always. A common mistake that must be avoided in the implementation of the DCF method for public utilities is to simply compute a compound annual growth rate from an historic period as a starting point and to apply that "g" to the simplified D/P + g formulation. As will be described in detail later in this testimony, this is one of the critical mistakes made by by Gulf Powers' witness Dr. Morin.

Because analysts published five-year growth rates are measured from an historic year to a forecasted future year, these growth rates should only be used in the complex version of the DCF method and should not be used in the simplified version of the method. Relying upon growth from an historic period for use in the DCF method, even if the historic period is the most recently completed year, is incorrect. As a general rule such growth is not sustainable and is not reflected in stock price movement. Unless the historic base period contained a return on equity and payout ratio that is exactly equal to the future anticipated return on equity and payout ratio.

For example, if a utility company earned 10.0% on its equity in 1988, but investors believed the company was capable of earning 12.0% on equity in the future, the increase in earnings per share necessary to bring the 10.0% to 12.0% would show up as a very high increment to growth in analysts estimates for growth over the next few years. An increase from a 10% return on equity to a 12% return on equity is a one-time growth in earnings per share of 20%! A non-recurring source of growth such as this, even spread out over five years would still have a very large distortive effect on the growth rate the analyst would publish. This growth rate is not sustainable because the earned return on equity cannot realistically be expected to increase to 14%, then 16%, then 18%, etc. The analysts growth forecast may be correct, but it is still inappropriate to use that type of a growth in the D/P +g simplified formulation of the DCF model.

Q. CAN YOU PROVIDE A CALCULATION THAT DEMONSTRATES THE EFFECT YOU ARE DESCRIBING?

A. Yes. Assume that a company in 1988 had a book value of $10.00 per share, earned $1.00 per share, and paid a dividend of $ .50 per share. Based upon these assumptions, it would have earned a return on equity of approximately 10%. Assume for purposes of this discussion that the company's regulators approve a rate increase resulting in an earned return on equity of 12%. Increasing the return on equity from 10% to 12% would result in an immediate increase in the company's ability to earn by 20%! A return on equity of 12% on a $10.00 book value produces earnings of $1.20, or 20% higher than the $1.00 earned when the earned return was only 10%. If the company kept the payout ratio constant, it could also increase dividends, in this case from $.50 to $.60. Therefore, dividends would also see a one-time growth spurt of 20%. In this example, if the analyst expected the return on equity to be increased from 10% to 12%, the one-time growth spurt of 20% that is required merely to bring the return on equity up to current cost rates would increase the annual average growth by 20%/5years, or about 4% (actually, 3.7% higher on a compound annual computation). While on the one hand, the astute analyst would recognize that this one time extraordinary growth would occur in the first future five year period, the same analyst could not expect this extraordinary growth to reoccur in all periods subsequent to the first five years. Use of the D/P + g version of the DCF method, however, requires the assumption that the growth rate, or "g" used will continue far beyond the first five years. Since in the above example, any rational analyst would recognize that the growth rate predicted for the first five years would not continue into the subsequent time periods, such an analyst would not use the D/P + g formulation in conjunction with that five year growth rate.

Q. HOW SHOULD THE GROWTH RATES FOR USE IN THE SIMPLIFIED VERSION OF THE DCF MODEL BE ESTIMATED?

A. The future growth rate is dependent upon the future earnings a utility will achieve. The future growth rate, or "g" portion of the D/P + g formula, is properly determined by multiplying the future expected earned return on equity by the portion of these future earnings that are expected to be retained in the business rather than paid out as a dividend (retention rate). This results in the ongoing, sustainable growth rate which is appropriate for use in the simplified version of the DCF method. Earnings retained in the business are what is available for reinvestment in utility assets. Ultimately, the earnings of a utility company are dependent upon the value of the assets included in rate base.

Q. COULD YOU GIVE AN EXAMPLE THAT SHOWS HOW THE RETENTION OF EARNINGS PRODUCES GROWTH?

A. Yes. Exactly how retained earnings and earned return on equity combine to produce growth can be seen in the following example:

> Assume a company with a book value of $20.00 per share at the beginning of a year earns 10% on equity and pays a dividend of $1.50 per share. Its earnings in that year would be $2.00 (the $20.00 book value multiplied by 10%). Retained earnings would be $2.00 less $1.50 of dividends, or $0.50. Since the $0.50 represents a permanent increase in equity capital, the book value of the company at the end of the year would be $20.50 per share. In this way, by foregoing the additional potential $.50 dividend, the common equity holder has, in fact, invested an additional $.50 in the business.

If the company is anticipated to continue to earn 10%, then earnings in the next year will be anticipated to be $2.05 ($20.50 multiplied by 10%). In this example the growth in earnings is $2.05/$2.00 - 1.025 or 2.5% growth. Mathematically, it is possible to express the growth caused by retained earnings as b times r where b equals the retention rate and r equals the future anticipated return on equity. I note, once again, that the cause of growth in earnings per share for a utility may properly be compared to the cause of growth of earnings in a savings account. If an investor has $1,000 in a savings account paying 6% interest, in the first year earnings will be $60. At the end of one year the account will contain $1,060. If the investor decides to leave the $60 in the account (or "retain" all earnings), then earnings in the next year will grow from $60 to $63.60 (1,060 x 6%). Conversely, if the investor decides to withdraw the $60 of first-year earnings, earnings in the second year will not grow to $63.60, but will remain at $60. Exactly the same principle holds for a common stock investment. If earnings are retained, they will be reinvested in the business and become available for future earnings growth, but if they are paid out as dividends, they will not be available for reinvestment.

Q. TO WHAT DOES THE GROWTH COMPONENT OF THE DCF FORMULA REFER?

A. The formula refers to the determination of the discounted value of future cash flows. Cash flows include dividends plus the eventual proceeds from the sale of the stock. Some analysts incorrectly oversimplify the DCF model by saying that it is only dividends being discounted. Earnings either go to pay dividends or to increase the market price of a stock. Therefore, if the DCF model were to examine only one factor, earnings would be preferable to dividends as the indicator of total future cash flow.

Q. IS THERE ANYTHING OTHER THAN EARNINGS AND DIVIDENDS WHICH CAN INFLUENCE THE BOOK VALUE GROWTH OF A COMPANY?

A. Yes. If a company sells new common stock equity, the amount received per share is equal to market price (less financing costs), not book value. The proceeds from the sale of new stock are added to the total common stock equity at the same time the number of shares outstanding is increased. Book value per share is equal to total common equity divided by total shares outstanding. Therefore, if a new common equity sale is accomplished at a price above the book value, the book value per share will increase and if that sale is made below book value, the book value per share will decrease.

Q. HOW DOES A CHANGE IN BOOK VALUE PER SHARE IMPACT EARNINGS?

A. Earnings per share is equal to the book value per share times earned return on equity. Therefore, anything that causes the book value per share of a utility company to decrease will tend to cause the earnings per share to decrease and anything that causes the book value per share to increase will tend to cause the earnings per share to increase.

Q. PLEASE SUMMARIZE WHAT HAS TO BE DETERMINED IN ORDER TO BE ABLE TO CORRECTLY APPLY THE D/P + g VERSION OF THE DCF METHOD TO ARRIVE AT AN INDICATED COST OF EQUITY.

A. As explained previously, to properly apply the D/P + g formulation of the DCF Method, four determinations need to be made:

1. Dividend Yield

2. The return on equity rate which investors anticipate a Company will earn in the future

3. The dividend payout ratio (or retention rate) that will be maintained in the future

4. The impact of any sales of new equity at other than book value.

Whether using the D/P +g simplified version of the DCF method, or using the full DCF method, it is essential that the above determinations be internally consistent. For example, assume:

| | | |
|---|---|---|
| Market Price | = | $14.00/share |
| Book Value | = | 10.00/share |
| Dividend | = | 1.00/share |

Then Dividend Yield = $ 1.00/14.00 = 7.14%

If an analyst concluded that investors anticipated this hypothetical company to be able to earn 12.0% on its equity in the future, the only consistent payout ratio that can be correctly used with the above assumptions is determined as follows:

Anticipated Return on Equity of 12.0% x
Book Value of $10.00 = $1.20 earnings per share

$$\frac{\text{Dividend of \$1.00}}{\text{Earnings per Share of \$1.20}} = 0.833 \text{ Payout Ratio}$$

The point here is that the dividend yield computation and the growth rate computation are interdependent, not independent determinations. This is because each dollar of earnings available to a company may be either allocated to dividends and sent directly to investors or reinvested in the business to provide a growth in earnings for the future cash flow benefit of investors.

### 3. Implementation of DCF Method

Q. TO WHAT COMPANY OR COMPANIES DID YOU APPLY THE DCF METHOD IN THIS CASE?

A. In order to determine the cost of equity component of the overall rate of return to be applied to the Company's rate base, a DCF analysis was performed on both The Southern Company and on Moody's 24 electric utilities. The Moody's 24 was analyzed in two groups, one group made up of electric utilities not engaged in nuclear construction, and the other with electric companies that are engaged in nuclear construction. My use of the Southern Company as a proxy for Gulf Power is conservative because while Gulf Power does not have any nuclear risk exposure, the Southern Company does.

Q. WHY DID YOU SEPARATE THE MOODY'S 24 INTO GROUPS BASED UPON THEIR NUCLEAR CONSTRUCTION INVOLVEMENT?

A. In the current environment, investors are aware of the greater potential for future earnings problems caused by nuclear construction activities. Many electric companies engaged in nuclear construction have found it necessary to cut or eliminate the common dividend. This fact has had a material, negative impact on the stock price of electric utilities engaged in nuclear construction.

Q. HOW DID YOU SELECT MOODY'S 24 ELECTRIC UTILITIES TO COMPARE TO GULF POWER?
A. This is a list of electric utilities that was selected by Moody's to be representative of the electric utility industry in the United States. Furthermore, Moody's has compiled considerable historic data regarding these companies which greatly simplifies the analysis process.

Q. IS IT YOUR CONTENTION THAT EACH OF THESE COMPANIES IS THE SAME AS GULF POWER?
A. No. No two companies are identical in all respects. All companies have certain unique characteristics that make them in one way or another different from Gulf Power. However, the primary factors which influence the cost of equity are the same, -- they are regulated public utilities that obtain the majority of their income by selling electricity under the protection of a territorial monopoly.

Gulf Power has more financial risk than the average non-nuclear construction electric utility. However, it also has a lower business risk than both the Moody's 24 and The Southern Company because it has no nuclear capacity whatsoever. The greater financial risk exists because it has a lower than average level of common equity in the capital structure. As is shown on Schedule 1, Page 2, I have made an adjustment to increase the cost of equity as indicated from the analysis of the Moody's 24 to account for the higher financial risk. Based upon a Paine Webber report entitled Electric Utilities Industry, March 6, 1990 concludes that electric companies with no nuclear involvement have a 0.5% lower cost of equity than those with a nuclear involvement. However, to be conservative, I did not make the downward adjustment recommended by Paine Webber to account for the lower business risk enjoyed by Gulf Power than either the Southern Company or the Moody's 24 electric utilities.

Q. HOW SHOULD THE DIVIDEND YIELD USED WITH THE DCF METHOD BE OBTAINED?

A. Ideally, the dividend yield that is typical of the near term future should be used in implementing the DCF analysis for regulatory purposes. Some experts feel that a spot dividend yield is the best possible estimate because that yield reflects the most current aggregate estimate of investors. Others feel that a current dividend yield might contain market irregularities which temporarily distort the computed dividend yield. The DCF analysis I present is based upon both current spot dividend yield data and historic data. The recommended result is based upon both observing historic and the current spot dividend yields. In the current environment there is a relatively small difference between the current yields and the average yields over the last year.

Q. THE DCF THEORY REQUIRES THAT THE D IN THE D/P + g FORMULA USE NEXT YEAR'S DIVIDEND RATE RATHER THAN THE CURRENT DIVIDEND RATE. HAVE YOU ALLOWED FOR THIS REQUIREMENT?

A. Yes. In my DCF computations, I increased the current dividend rate by an amount equal to one-half of a year's growth in dividends. In this way, the DCF computations presented herein are based upon the average dividend rate expected for the next year.

Q. HOW HAVE YOU COMPUTED THE GROWTH RATE FOR USE IN THE DCF MODEL?

A. As mentioned previously, the critical number to the proper determination of the growth rate to use in the DCF analysis is the future return on equity level anticipated by investors. For purposes of applying the DCF method, factors such as allowed returns on equity, historic actual returns on equity and returns on equity as anticipated by Value Line, and as computed from the consensus growth rate developed by Zack's Investors Service were reviewed. A review of other analysts' reports, and general observations concerning financial conditions contributed to my analysis.

Q. WHY DID YOU USE VALUE LINE AND ZACK'S AS SOURCES TO PROVIDE THE FUTURE EARNED RETURN ON EQUITY?

A. These are the two sources available to me that provide long-term estimates of earned return on equity for a broad range of utility companies. Although many of the details of the method relied upon by these sources to produce the estimates are not disclosed, I am presenting these future return on equity estimates in this case because they provide a helpful balance to the other observable facts used to formulate an estimate as to what investors expect will be the future earned return on equity.

Nevertheless, one must view the Value Line projections with caution because they tend to base their future expected returns on equity on the historic allowed returns on equity. In the current environment, for those companies that have not had a rate case since 1985, it is probable that the future allowed return on equity will be less than in the past.

Q. ISN'T IT TRUE THAT IN ADDITION TO PROVIDING AN ESTIMATE OF FUTURE RETURN ON EQUITY, VALUE LINE ALSO PUBLISHES A FUTURE GROWTH RATE?

A. No, not exactly. Value Line publishes a growth rate that it calls growth from 1986-88 to 1992-94. This growth rate is part historical and part projected. It is **not** appropriate to use the growth rates in earnings per share or dividends per share as published in Value Line in the simplified D/P + g formulation of the DCF method. This is because these growth rates as computed by Value Line are not the average constant growth rates which are required in the use of the simplified version of the DCF method.

Q. HOW DO YOU KNOW THAT THESE ARE NOT AVERAGE CONSTANT GROWTH RATES?

A. Value Line describes its growth rate as the annual rates of change from either 1986-88, or 1987-89 depending upon the company, to 1992-94. This means that to the extent the base period had abnormally low or abnormally high earnings, the growth rate computed based upon it would not be reflective of the future sustainable growth rates.

Q. DOES ZACK'S PUBLISH GROWTH RATES?

A. Yes, Zack's publishes five year consensus earnings per share growth rates. These growth rates are obtained by compiling the growth rate estimates issued by the major investment bankers.

Q. CAN THESE GROWTH RATES BE USED DIRECTLY IN THE D/P + g VERSION OF THE DCF FORMULA?

A. No. These are five year growth rates, not the infinite time horizon growth rates required by the D/P + g version of the calculation. They provide the consensus anticipated earnings per share growth from the most recent historic year out to five years from now. If the earned return on equity an analyst felt was sustainable in the future was not achieved in the most recent historic year, then the published five-year growth rate will be higher than the long-term sustainable growth rate. Conversely, if the return on equity achieved in the most recent historic year was higher than the analyst felt was sustainable, then the five year growth rate forecast by analysts will be lower than the future sustainable growth rate.

Q. GIVEN THIS PROBLEM, HOW ARE THE ANALYSTS' GROWTH FORECASTS HELPFUL IN IMPLEMENTING THE DCF METHOD?

A. The five-year earnings per share growth rate can be converted into a sustainable growth rate by determining the earned return on equity a company would have to accomplish in order to be able to achieve the five-year growth rate expected by analysts. Then, this expected return on equity can be used in the return on equity x retention rate computation. Exactly how the consensus growth rates were converted into the future return on equity expected by analysts is shown on Schedule 6. On that schedule, both the the earnings per share and dividends per share were escalated at Zack's Consensus 5 Year Growth Rate. Book value was obtained by adding earnings and subtracting dividends from the beginning book value. The resultant future earnings per share was then divided by the future future expected average book value per share.

Q. IS THE RETURN ON EQUITY EXPECTED BY ANALYSTS THE SAME THING AS THE COST OF EQUITY?

A. No. The return on equity expected by analysts in and of itself says nothing about the cost of equity being demanded by investors. It is only after considering both the future expected return on equity and the market price and other data of a company in a formula such as the DCF method is it possible to reach an estimate of the cost of equity.

Q. PLEASE DESCRIBE HOW YOU DEVELOPED THE GROWTH RATE FOR THE MOODY'S 24 ELECTRIC UTILITY COMPANIES.

A. I used the D/P + g formulation of the DCF method because the same future return on equity expectation is appropriate for all future years. While it can be said with confidence that the future earned return on equity will fluctuate, it is not known at this time which future years will have a higher than expected return on equity result and which future years will have a lower future expected result. Therefore, no additional accuracy would be obtained by using the more complex version of the DCF method. Because I chose to use the D/P + g version of the DCF formula, I computed growth by use of the return on equity times retention rate, or b x r method. As previously explained, b x r should be used whenever applying the D/P + g version of the DCF formula.

Q. WHAT DID YOU CONCLUDE IS THE FUTURE EXPECTED RETURN ON EQUITY FOR THE AVERAGE NON-NUCLEAR CONSTRUCTION ELECTRIC UTILITY?

A. At this time, the majority of investors should be expecting that a typical group of non-nuclear electric utilities should be able to sustain an average earned return on equity of no more than 13.9% in the future. This conclusion was based upon the following observations:

1) According to a Merrill Lynch report entitled "Utility Industry, Quarterly Regulatory Report", the average return on equity allowed to electric utilities has been as follows:

| | |
|---|---|
| 1987 | 13.25% |
| 1988 | 13.08% |
| 1989 First Quarter | 12.89% |
| 1989 Second Quarter | 12.89% |

Based upon allowed returns on equity over the last several years, the companies would have to achieve returns above the levels allowed on equity in order to earn as much as the 13.9% on equity. Therefore, the above allowed returns on equity show that my use of a 13.9% future expected return on equity, for purposes of computing future expected cash flow, is conservative.

2) As shown on Schedule 4, Page 2, the average return on equity forecast by Value Line for the non-nuclear electric utilities is 13.69%. This also shows that my 13.9% estimate of investors future expectations is conservative.

3) As shown on Schedule 6, the return on equity that the non-nuclear construction electrics will earn in five years if the consensus growth rate as forecast

by analysts should occur is about 13.84%. This also shows that the 13.9% estimate I have used in my DCF computations is conservative.

4) As shown on Schedule 4, Page 2, the average earned return on equity achieved for the non-nuclear construction electrics was 13.63% in 1989. Therefore, my 13.9% estimate of future return on equity expectations is supported as a conservatively high estimate by the recent historic earned return on equity data.

Q. WHAT DID YOU CONCLUDE WAS THE AVERAGE FUTURE RETURN ON EQUITY ACHIEVABLE FOR THE NUCLEAR CONSTRUCTION ELECTRICS, AND HOW DID YOU REACH THAT CONCLUSION?

A. I concluded that investors expect the nuclear construction electrics to average 12.50% return on equity in the future. This conclusion was arrived at by considering the above points regarding the non-nuclear construction electrics and additionally observing that both the return on equity derived from the Zack's consensus and the Value Line projected return on equity are lower for the nuclear construction electrics than for the non-nuclear construction electrics.

Q. HOW DID YOU APPLY THE DCF METHOD TO THE FINANCIAL DATA OF THE SOUTHERN COMPANY?

A. I observed that Value Line predicted the Southern Company would earn 12.5% on its book equity in the future, and that the Zack's consensus growth rate required a 12.95% return on equity (See Schedule 2, Page 3). As shown on Schedule 2, Page 2, the return on equity achieved by the Southern Company in 1988 was 12.93%, and in 1989 was about 12.49%. Paine Webber in its March 6, 1989 Electric Utilities Industry report stated its opinion that the Southern Company would earn 12.5% to 13.0% on equity in the future. (In reviewing these numbers, it should be remembered that these are not the equity cost numbers being demanded by investors, they are merely the return on equity expectations used to determine the future cash flow anticipated by investors. It is only after the resultant cash flow is compared to the market price investors are willing to pay in order to obtain the rights to that cash flow that the cost of equity is addressed).

Q. HOW DID YOU OBTAIN THE RETENTION RATE YOU USED IN YOUR DCF COMPUTATIONS?

A. As explained earlier in this testimony, the retention rate used should be consistent with investors' future expectations and with the other inputs into the DCF model.

Since, by definition, the retention rate is the portion of earnings not paid out as dividends, and since both a dividend rate has been used for the dividend yield portion of the DCF equation and the future earnings rate is proportional to the future expected return on equity, the retention rate used should be directly derived from the dividend rate and the future expected return on equity. Any alternate approach would be inconsistent with other assumptions, and therefore inappropriate. For example, it would create unnecessary errors if one were to conclude that the historic retention rate was 20% if the following had already been concluded:

1) dividend yield had been computed based upon a $0.75 per share dividend rate,

2) the future expected return on equity was expected to be 13.0%,

3) book value was $10.00 per share.

Based on the above, the earnings per share determined to be typical of the future would be the 13% future expected return on equity times the $10.00 book, or $1.30. If dividends have already been determined to be $.75, then the only retention rate consistent with the other assumptions is ($1.30- $ 0.75)/($1.30), or 42.3%. In this hypothetical example, the only correct retention rate to use is 42.3%. The use of, for example, a retention rate of 20% would be the same as saying that it would be possible for dividends to be both $.75 and to be $1.04 (100%-20%, or 80% x $1.30= $1.04) at the same time.

Q. WHAT DO YOUR COMPUTATIONS SHOW?

A. Schedule 2, Page 1 shows the DCF computations for The Southern Company. Schedule 3, Page 1 shows the details of the DCF computations for the non-nuclear construction electric utilities, Schedule 3, Page 2 shows the same computations but for the nuclear construction electrics.

The market data as of March 31, 1990 shows that the dividend yield for the Southern Company averaged 8.09% for the year, and ended the year at 8.15%. The non-nuclear construction electrics averaged 7.11%, and completed the year yielding 6.87%. The nuclear construction electrics averaged 8.76% and finished the year at 8.82%.

Based upon the expected future return on equity for the Southern Company of 13.00%, the future sustainable growth rate from the retention of earnings that investors can rationally expect is 3.22%. Based upon Value Line's estimate of the company's expected issuances of new common equity, it is reasonable to estimate that the external financing rate will be 0.27% of stock outstanding per year. Therefore, as shown on Schedule 2, Page 1 growth in earnings or dividends caused by new stock sales is estimated to add about 0.04% to .05% to the growth rate. This makes the total expected growth 3.27%(See Schedule 2, Page 1).

The growth investors can rationally expect from the non-nuclear construction electrics is 3.89% to 4.09%. (See Schedule 3, Page 1). This is made up of retention, or reinvestment growth of 3.82% to 4.01% and new financing growth of between 0.07% and 0.08%.

For nuclear construction electrics, investor growth expectations are computed to be about 2.44%. (See Schedule 3, Page 2). This is made up of reinvestment growth of 2.41%, and new financing growth of 0.03%.

Q. PLEASE SUMMARIZE YOUR CONCLUSION FOR THE COST OF EQUITY BASED UPON THE DCF METHOD.

A. My overall conclusion for the cost of equity indicated for Gulf Power Company is 11.75% (see Schedule 1, Page 2). The 11.75% was developed by giving weight to both the analysis of the non-nuclear construction electric utilities and to the Southern Company. Since the level of common equity in the capital structure of Gulf Power is less than the average level of common equity for the non-nuclear construction electrics, when deriving the cost of equity for Gulf Power based upon the Moody's electric utilities, it is appropriate to make an upward adjustment to the cost of equity to consider this difference in financial risk. My overall equity cost recommendation is conservatively high in part because, unlike Paine Webber, I have not subtracted 0.5% from the computed cost of equity that they feel the lower risk that no nuclear capacity justifies.

4. Comparable Earnings Observations

Q. HOW DOES YOUR 11.75% RECOMMENDED COST OF EQUITY COMPARE TO THE RETURN AVAILABLE ON THE EQUITY OF THE 30 COMPANIES THAT MAKE UP THE DOW JONES INDUSTRIAL AVERAGE?

A. As shown on Schedule 10, Pages 1a and 1b of 3, and as graphed on Schedule 10, Page 2 of 3, the ten year moving average of the actual earned return on equity on average for the 30 companies that make up the Dow Jones Industrial average has been between 10% and 12% since the late 1950's. Even on a single year basis rather than on a 10 year moving average basis, the range in earned returns during the 1980's has been between the 13.10% high achieved in 1984 and the 7.00% low achieved in 1982.

Q. ARE YOU SUGGESTING THAT THE RETURN ON EQUITY EARNED ON THE DOW JONES INDUSTRIALS IS THE COST OF EQUITY TO THE DOW JONES INDUSTRIALS?

A. No. The earned return on equity is not the cost of equity. It is, however, the earned return on equity that will be the end result of the rates allowed from these proceedings. Therefore, it is directly comparable to the earned return on equity being achieved by the Dow Jones 30 industrials. Also, the relationship between the market price and the book value of the Dow Jones Industrials shows that investors have been more than satisfied with the returns actually earned.

Q. WHAT DOES THE MARKET-TO-BOOK RATIO DATA OF THE DOW JONES INDUSTRIALS SHOW?

A. As shown on Schedule 10, Pages 1a and 1b of 3, with a relatively minor exception during the 1978-1981 period, the market-to-book ratio achieved by the Dow Jones Industrials has been at or above book value since 1932, the very depth of the Great Depression. In fact, most of the time the market-to-book ratio has been substantially above 1.0. This shows that most of the time the cost of equity being demanded by investors on average for the Dow Jones Industrials has been less than whatever investors expect the companies will be able to earn on equity in the future.

Q. HOW DOES THE RISK OF THE DOW JONES INDUSTRIALS COMPARE TO THE RISK OF THE MOODY'S 24 ELECTRIC UTILITIES?

A. A standard measure of relative risk is the stock's beta. Beta is a number that quantifies the relative volatility of the stock price movements of a particular company with a broad based average such as the New York Stock Exchange Average. As shown on Schedule 10, Page 3, the beta of the Dow Jones Industrials averaged 1.077, as compared to 0.696 for the non-nuclear construction electrics and 0.723 for the nuclear construction electrics. In both cases, this indicates that the investment risk is higher, on average, for the Dow Jones Industrials than it is for the average electric utility.

D. Financing Costs and Market Pressure

Q. Please explain financing costs and market pressure.

A. When a utility company issues common stock, there are certain expenditures incurred. While other methods are possible, the usual way that ratepayers are charged for financing costs is to add an increment to the cost of equity.

Q. Have you determined what the appropriate allowance for financing costs should be?

A. Yes. The actual financing costs incurred by a company are a function of the size of its common stock issues. The larger the issue, the more dollars over which the costs can be spread. It should be recognized that not all common equity obtained by the Company has a financing cost associated with it. The common equity amounts raised as a result of retained earnings do not incur any financing cost. Therefore, in order to obtain an overall actual cost of externally raised capital, it is necessary to weight the zero cost of obtaining retained earnings equity with the cost incurred to raise external common equity.

Q. How much of the total equity is raised externally for the typical utility company?

A. Based upon the data on page a26 of the 1989 Moody's manual, for the most recent year shown about 68% of the total common equity for utilities was raised externally. This means that on average 32% of the equity was raised internally. There is no financing cost incurred on the internally generated equity. Therefore, no cost was incurred on about 32% of the common equity raised. Based upon the data on Schedule 9, it can be seen that an external financing cost of 3.75% or less is appropriate. A 3.75% cost of acquiring 68% of the equity blended with a 0% cost of acquiring 38% of the equity produces an overall appropriate allowance for financing costs of about 2.55%. This increment should be used to determine the target market-to-book ratio. A 2.55% allowance would mean that the Commission should set rates which would result in a market-to-book ratio of 102.55%.

Q. In addition to the financing costs paid to underwriters, are there any costs associated with "market pressure" at the time of issue?

A. Probably not. Dr. Sholes of the Massachusetts Institute of Technology conducted a thorough study which concluded that there was no depressant effect on the stock price of a public utility merely because it issued new common stock. However, the result of my study concluded that some slight market pressure, amounting to approximately 0.6% drop in market prices concurrent with the issuance of new common stock might be present. Therefore, to be conservative, the recommended cost of equity in this report included a market pressure allowance of 0.41% (0.6% from my study x 68% for external financing) be added to the 2.55% allowance for financing costs, making the total allowance for financing costs be equal to 2.96% increment to the appropriate market-to-book ratio and the final market-to-book ratio target, 1.0296%, which rounded becomes 1.03%.

In order to increase the market-to-book by 3%, sufficient incremental earnings need to be provided to increase only the dividend yield portion of the DCF equation. Growth need not change. Based upon the March 31, 1990 dividend yield for the Southern Company, the representative gas companies, the allowance for financing costs should be 8.15% x 3%, or 0.24%.

VII. COST OF CAPITAL BY CUSTOMER CLASS

Q. YOU HAVE RECOMMENDED AN 11.75% COST OF EQUITY FOR GULF POWER. IS THIS COST OF EQUITY EQUALLY APPLICABLE TO EACH CUSTOMER CLASS?

A. No. It is well recognized that serving industrial customers entails a higher degree of risk than serving residential or commercial customers. As will be explained later in this testimony, it is estimated that the cost of equity to be applied to industrial customers should be about 0.4% higher than the cost level to apply to residential or commercial customers. The returns allowed to each class should be weighted so that the overall effective allowed return is 11.75%.

Q. How did you conclude that it is well recognized that serving industrial customers has a higher degree of risk?

A. Page a23 of the 1989 Moody's Public Utility Manual states:

> The above revenue breakdown for each class of customers is very instructive not only when related to total income for each year, but also when compared with the table giving the kwh consumption for the same period for each class of ultimate consumer. A characteristic of residential sales growth has been its uniformity. **Industrial sales are more sensitive to fluctuations in our economy and have expanded less uniformly.** (Emphasis added)

A book entitled "Standard and Poors Rating Guide", published in 1979 by McGraw Hill, states on page 52 of the chapter entitled "Public Utilities":

> The mix of a company's revenues, earnings, and assets, and the growth thereof, provide basic measurements by which one can gauge relative exposure to normal operating, economic, and financial risks. **Industrial sales versus residential and commercial sales,** higher priority gas sales versus lower priority usage, toll versus local phone revenues, wholesale relative to retail business, earnings subject to regulation, and breakdowns of investments and earnings by regulatory jurisdictions **are fundamental.** (Emphasis added)

Q. Did you perform any computations to test the accuracy of the statements from Moody's and Standard and Poors?

A. Yes. I computed the actual annual change in kwh sales by customer class both on aggregate for the composite electric industry sales statistics as shown in Moody's, and individually for each of the electric utilities covered by Value Line. Value Line does not provide the kwh by customer class sales statistics, so I obtained them from "The P.U.R. Analysis of Investor-Owned Electric and Gas Utilities", 1989, 1988, and 1986 editions, published by Public Utility Reports, Inc. In a few instances, the numbers provided in this report were inconsistent usually because the company recategorized some customers. When these inconsistencies were observed, I directly contacted the company to obtain a consistent set of sales figures.

It was necessary to exclude seven companies because no breakdown between industrial and commercial sales was available (Central Vermont Public Service, Oklahoma Gas & Electric, Otter Tail Power, Philadelphia Electric, Potomac Electric, Iowa-Illinois Gas & Electric, San Diego Gas & Electric). Additionally, I excluded Public Service of New Hampshire both because they are in bankruptcy and because Value Line choose not to publish the beta for this company. This left 88 companies which were included in the study.

Q. What did the study show?

A. The study showed that the volatility of electric sales, as measured by the standard deviation in the annual rates of kwh growth from 1983 through 1988 was 5.06% for industrial sales, 2.21% for commercial sales, and 3.27% for residential sales. (See Schedule 11, Page 2.)

Q. Did you quantify the difference in the cost of equity between residential and commercial classes as compared to industrial classes?

A. I produced an empirical study which developed an estimate for the difference in the cost of equity between the customer classes. While the evidence regarding the standard deviation of growth rates, quotes from the literature, and common sense about the characteristics of industrial customers all serve to make it obvious that the cost of equity to serve industrial customers is greater than for residential or commercial customers, precise quantification is not possible. The best that can be done is to arrive at a reasonable estimate of the cost difference. Even though it is necessary to arrive at an estimate, a cost difference should be recognized. If, alternatively, no cost difference were to be assigned, this would be the same as quantifying the cost difference as zero, a result which is known to be incorrect.

Q. Please describe the empirical study.

A. I developed a group consisting of the previously described 88 electric companies that are both covered by Value Line and had consistent and available data regarding kwh sales by customer class for the five years from 1983 through 1988. These companies were ranked by percent of retail sales to industrial customers. Group statistics were prepared for the 44 companies with the percentage of sales to industrial customers below the median and for the

44 companies with the percentage of sales to industrial customers above the median. The market risk of the two groups was quantified by computing the average beta of both groups. For a representative group of companies, the higher the beta, the greater the risk contained in the group.

Q. Where did you obtain the Betas for the companies in your study?
A. They were obtained from Value Line.

Q. How does Value Line compute the Beta?
A. Value Line states that "The Beta is derived from a regression analysis between weekly percent changes in the price of a stock and weekly percent changes in the New York Stock Exchange Composite Index over a period of five years." This means that if the price of a particular stock tends to move up or down more rapidly than the average stock in the New York Stock Exchange it will have a Beta greater than 1.0, and if it tends to move up or down less rapidly than the average stock, it will tend to have a beta below 1.0 .

Q. If a company has a very low Beta does that automatically mean it is a low risk investment?

A. No, not necessarily. As Value Line states in its "A Subscriber's Guide", page 55, "... Beta's significance derives primarily from its usefulness in portfolios rather than in individual stocks...". For this reason, it is valid to examine the average Beta for a relatively large group of companies. The Beta for any one company or a small group of companies is less helpful as a risk quantification tool.

Q. What was shown by the comparison of the average Beta for the 44 electric utilities with sales to industrial customers below the median and the 44 companies with sales to industrial customers above the median?

A. As shown on Schedule 11, Page 3, the average Beta for the companies with industrial sales below the median averaged 0.6886, or .0159 lower than the 0.7045 average Beta for the group of companies with sales to industrial customers above the median shown on Schedule 11, Page 4.

Q. How did the sales to industrial customers compare?

A. The companies below the median averaged 26.53% of total retail kwh sales to industrial customers, whereas the companies above the median averaged 44.87% of sales to industrial customers.

Q. Can you be sure that the only difference in risk characteristics between the two groups of companies was the level of sales to industrial customers?

A. There is a slight difference between the financial, or capital structure, risk. But, this capital structure risk differential actually serves to mitigate what otherwise appears to be a risk differential caused by the difference in the level of sales to industrial companies. As shown on Schedule 11, Page 3, the companies below the median level of industrial sales had an average of 43.77% common equity in the capital structure, and the companies with industrial sales above the median had a average of 45.37%. Both groups contained companies experiencing risk from nuclear troubles.

There are undoubtedly other factors that may be associated with any one individual company in either of the groups which will tend to increase or decrease the overall risk quantification of the group. It is likely that the groups are large enough that all of the other factors affecting risk will tend to average out. Quantifying all of the infinite variety of factors that might affect risk would be an endless task.

As previously stated, the quantification of the risk difference must be considered an estimate, not a precise quantification.

Q. How does a difference in Beta translate into an equity cost difference

A. The risk premium between the cost of equity for a group of companies and the cost of a riskless investment such as long-term U.S. treasury bonds is proportional to the average Beta of the group of companies. This fact was relied upon to quantify how much of an equity cost difference is attributable to the impact of the level of sales to industrial customers. The specific method of estimating this is shown on Schedule 11, Page 1. As shown on that schedule, the estimated difference between the cost of equity to serve industrial customers and that to serve residential and commercial customers is estimated to be 0.4%.

VIII. Testimony Evaluation

Q. Have you reviewed the testimony of Dr. Morin as filed in this proceeding?
A. Yes.

Q. Please comment on that testimony.
A. Dr. Morin recommends that Gulf Power be allowed a return on equity of 13.0%. He arrived at this conclusion by presenting a wide array of both DCF analyses and risk premium analyses.

Q. Does the fact that he presented such a wide number of variations improve the accuracy of his result?
A. No. In order to be able to present such an array of approaches, he had to chose many that are highly questionable. For example, some of his DCF computations were based upon the historic growth in dividends as an indicator of future growth. He did this even though inconsistencies caused by increasing payout ratios and declining allowed returns on equity, mean that investors are aware that this historic growth is not representative of what future growth is likely to be.

Q. Did Dr. Morin rely upon the financial data from the Southern Company in arriving at his cost of equity recommendation for Gulf Power?

A. Yes.

Q. Has this caused him to overstate the cost of equity?

A. Based upon the principles Dr. Morin expressed in his testimony filed in a recent Georgia Power rate case, yes. In that testimony, on page 49 he stated that the Georgia Power subsidiary of Southern Company was more risky than the average Southern Company subsidiary because it has a lower than average bond rating "... and experiences substantial nuclear exposure ... ". He did not point out in this testimony that unlike Georgia Power, Gulf Power has a higher bond rating than does the average company owned by the Southern Company and has no nuclear exposure. As a result, to be consistent, he should have noted that his reliance on the financial data of the Southern Company would create an upward bias to his equity cost finding.

DCF METHOD

Q. Is there a problem common to all his DCF approaches?
A. Yes. All of his DCF results contain one common problem: an upward adjustment to the return to improperly allow for the quarterly compounding effect of dividends. For example, please examine closely his analysis of the Southern Company data that he shows on his Exhibit, Schedule 3, Page 2. On this schedule he concludes that the "cost of equity" to the Southern Company is 12.23%. Then, he adds another 44 basis points as a result of his "Solution to the quarterly timing DCF model ...", to obtain a "Fair Return" of 12.67%. While there has been serious debate before this Commission and the Federal Energy Regulatory Commission on whether the return on equity should be decreased as a result of the quarterly compounding approach, I am not aware of FERC ever seriously considering to increase the indicated cost of equity as a result of the quarterly dividend model. To do so would be backwards.

Dr. Morin's opinion that the quarterly compounding effect should be added rather than subtracted from the DCF indicated cost rate was based upon invalid underlying assumptions. If these underlying assumptions are corrected, then an opposite conclusion is reached.

Q. What are the invalid assumptions?

A. Dr. Morin provides the premise upon which his quarterly adjustment is based. On page 21 of his testimony, he states:

> 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.

There are two critical flaws with the above quoted statement. First, not only isn't it clear that the company that pays the four quarterly dividends would have a HIGHER price as he claims, in fact the company paying the quarterly dividend would have a LOWER price than a company that were to pay a dividend annually. The critical fact that Dr. Morin overlooked is that stock prices rise as the unpaid dividend accrues, and drops by the amount of the dividend once the dividend becomes payable to the stockholder of record. "sing Dr. Morin's example, if a company that paid an annual of dividend of $4.00 only once a year would have a higher average price than the company that paid the dividend quarterly because on average during the year its stock price would contain a $2.00 increment to reflect the value of the accrued dividend (zero at the beginning of the year, gradually growing to $4.00 at the end of the year, for an average of $2.00), whereas the company that paid the same annual dividend in quarterly installments would have a stock price that on average reflects $ 0.50 of accrued dividends (zero growing to $1.00 over three months, for an average of $ 0.50). In this example, other things being equal, a company that pays $4.00 per year in dividends would have an average stock price of about $1.50 higher that the company that pays the same $4.00 per year in four quarterly installments of $1.00 each(the $2.00 average level of accrued dividend for the annual company minus the $0.50 average accrued dividend for the quarterly company equals $1.50).

Q. Is this distinction important?

A. Yes. When Dr. Morin computed the dividend yield, he relied upon the stock price of companies that pay a dividend quarterly. The lower stock price that exists because of the quarterly payment of dividends results in his dividend yield being higher (and hence indicated the cost of equity) than it otherwise would have been. Given this higher dividend yield, Dr. Morin's additional adjustment to increase the allowed return on equity even further represents a double-count of the quarterly effect.

Q. Is there anything else wrong with the above statement you quoted from page 21 of his testimony?

A. Yes. He says that his decision to make an upward adjustment because of the quarterly compounding of dividends is based upon his expectation that growth would remain the same whether a company paid its dividends quarterly or annually. This is an unrealistic expectation. The company that pays dividends annually would have the use of the dividend funds considerably longer than would the company that pays the dividends quarterly. These funds would be either profitably invested, or used to partially offset the need for the company to otherwise obtain external funding to operate the company. Either of these alternatives would improve profits, and therefore increase the growth rate obtained by the company that pays the dividends annually rather than quarterly. Therefore, the second invalid assumption in Dr. Morin's quarterly dividend analysis is that he assumes that funds retained in the business just sit there without producing any benefit to the company retaining that cash. This means that a DCF method based upon the assumption of annual dividend payments for a company that in reality makes quarterly dividend payments actually overstates the cost of equity because it assumes that all of the earnings in a given year are fully available for reinvestment to cause growth.

Putting the above facts all together, it can be seen that the annual DCF model applied to data from a world that actually pays quarterly dividends overstates the cost of equity both because the dividend yield is over-stated and because the growth rate is overstated.

Q. Have you proposed an adjustment to lower the allowed return on equity as a result of the impact the quarterly payment of dividends has on the computations?

A. No. To be conservative, I have chosen not to do this. However, I could understand why the Commission might wish to make such an adjustment to lower the allowed return on equity.

Q. You said that the use of historic growth in dividends is not a helpful indicator of the growth expected by investors in the future. Does Dr. Morin recognize this?

A. Apparently he does. On page 17 of his testimony, he correctly states that:

> 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 synonyms with growth in earnings and dividends.

When he presents his historic growth indicators, they have not all grown at the same rate. This means using any or all of these historic growth rates are not appropriate in what he calls the "traditional" DCF model, and what I prefer to call the simplified DCF model. Also important is that investors do not determine future growth based upon historic growth rates.

Q. Can you provide an example to demonstrate your point that investors do not rely upon historic growth in dividends to form future growth expectations?

A. Yes. For example, AT&T is a large, company that is familiar to sophisticated investors. Its stock price has performed admirably in recent years, and is now selling substantially in excess of book value. Yet, its dividend has remained at $1.20 per share since 1984. With such a constant historic dividend rate, whatever method is used to compute historic growth in dividends, the answer is the same. Historic growth in dividends has been ZERO. If investors formed dividend growth expectations based upon the historic change in dividends of AT&T, then the cost of equity to AT&T should simply equal its dividend yield.

Q. Is the cost of equity equal to the dividend yield of AT&T?

A. No. The dividend yield of AT&T is about 3%. In order to be willing to settle for a dividend yield of only 3%, investors must expect substantial growth in the future. Therefore, in the case of AT&T, the historic growth in dividends varies from actual investor expected future growth rates by many hundreds of basis points.

Q. Are there any electric companies you can mention that illustrate the same point?

A. Yes. Commonwealth Edison Company, a very large electric utility that services Chicago, Illinois and the surrounding communities has paid an annual dividend of $3.00 per share, without change, since 1983. The dividend yield on Commonwealth Edison's common stock is slightly above 8%. If investors expected future growth in dividends would be equal to past growth, then the cost of equity would approximate 8%. Since it is obvious that the cost of equity to Commonwealth Edison is higher than 8%, investors must not be looking to the historic growth in dividends to formulate estimates of future growth.

Q. How do these examples compare to the problems in Dr. Morin's historical growth analysis?

A. While the distortions that result from using the historic growth in dividends as an indicator of future growth expectations are on average more subtle for the companies examined by Dr. Morin, the same conceptual errors influence his results.

Q. Can you point to evidence regarding the Southern Company which shows that investors expect future growth rates to be substantially different than the past?

A. Yes. One method relied upon by Dr. Morin to quantify investors future growth expectations for the Southern Company was to use the five year historic growth in dividends as shown in Value Line, which happened to be 5% per year. He accepted this 5% historic growth in dividends as meaningful and directly included it in his answer even though in the column right next to the place he obtained the Value Line 5% growth, Value Line shows that it expects both earnings and dividend growth for the Southern Company to be only 1.5% for the next five years. (See page 198 of the March 23, 1990 issue of Value Line.) He did not use the 1.5% growth expected by Value Line from 1986-88 to 1992-94.

Q. Is it true that he also relied upon the IBES consensus of analysts growth forecasts as an estimate of future growth?

A. Yes.

Q. Is this a proper approach?

A. Not the way Dr. Morin has applied it. I believe it is helpful to obtain an estimate of what analysts expect for the future by reviewing the data from sources such as IBES and Zack's, but one must take care in how that result is used in a DCF formula.

Q. Please explain.

A. The published growth rate is the consensus growth in earnings per share as expected by analysts from the most recently completed year to a point five years in the future. If the return on equity in the base year was lower or higher than the return on equity expected by analysts for the future, this five year growth rate would be proportionally higher or lower than the level sustainable into the future. Since the simplified, or "traditional" DCF model demands that the sustainable growth rate be used in order to obtain an accurate result, this IBES consensus growth rate should not merely be plugged into the DCF formula without further analysis.

Q. What further analysis should be done?

A. An analysis of the type I have done on Schedule 2, Page 3 needs to be performed in order to make the analysts consensus growth rate proper. This analysis shows what earned return on equity must be anticipated by analysts in order to achieve the five year growth rate.

Q. Dr. Morin also presents a "b x r" growth estimate for the Southern Company. Please comment on this.

A. The b x r approach, if properly evaluated, is fundamentally sound.

While there is room for some improvement in the way he applied this approach, the theoretical basis for his "b x r" computation is far superior to the other methods he presented.

Q. He says on page 34 of his testimony that the problem with the b x r approach is that it "requires an estimate of ROE to be implemented". ROE stands for return on equity. He thinks this is a "... logical trap...". Is this correct?

A. No. The "b x r" method does require an estimate of the future expected ROE, but this is NOT a "logical trap..." because the future expected ROE is NOT the same as the cost of equity. The DCF method is used to compute the cost of equity based upon future expected cash flows.

Since future expected cash flows are highly dependent upon the future actual level of ROE earned, this is a critical number to examine in the determination of future cash flows. It is not a "... logical trap..." to recognized that the DCF method is dependent upon future cash flows. After all, DCF stands for Discounted Cash Flow, and the cash flows to be discounted are future cash flows.

The advantage of the "b x r" method over the other methods proposed by Dr. Morin is that it causes the analyst to directly analyze the causes of future cash flow and to do so in a manner consistent with the demands of the "traditional" version of the DCF formula. Therefore, at least if the analyst does properly estimate the return on equity anticipated by investors, the DCF formula will properly estimate the cost of equity being demanded by investors. But, of course, the analyst must perform research and employ careful thought to the determination of what return on equity is expected by investors. This is because the quality of the answer from the DCF method is proportional to the quality of the estimate of future cash flow expected by investors, a statement that is true whether it is the "b x r" method, the historic growth in dividends method, or any other method.

Q. What return on equity did Dr. Morin feel was anticipated by the investors in the Southern Company?

A. He concluded that the future earned return on equity for the Southern Company as published by Value Line should be used as the value for "r" in the "b x r" growth computation.

Q. Is this proper?

A. I believe that it is valid to consider what Value Line forecasts, and have in part relied upon that number myself. As is explained earlier in this testimony, I believe that other factors such as the current returns on equity being allowed to utility companies and the return on equity that has to be earned in order for an analysts growth rate consensus number (such as that compiled by either IBES or Zack's) is also worthy of examination. It should be pointed out that since Dr. Morin prepared his testimony, Value Line has lowered its estimate of the future anticipated return on equity to be earned by the Southern Company from 13.0% to 12.5%. Nevertheless, in this case the 13.0% future expected return on equity (not the cost of equity) selected by Dr. Morin for use in the "b x r" approach is within the 12.5% to 13.0% range. In fact, my growth computations for the Southern Company are also based upon the future cash flow that would be derived from a future return on equity of 13.0%.

Q. Dr. Morin used a retention rate expectation as forecast by Value Line of 27.69%, yet you used a retention rate of 24.35%. Which is correct?

A. The 24.35% is correct because it is consistent with the dividend rate used in the computation of the dividend yield portion of the DCF formula. Of lesser import is the fact that it is also closer to the retention rate that is now projected by Value Line based upon its updated return on equity expectation.

Q. Does the proper application of the DCF formula require that the assumption used for the retention rate be consistent with the dividend yield computation?

A. Yes Remember that the simplified, or "traditional" DCF formula requires an assumption of a constant future payout ratio. The importance of this can be understood by recognizing that each dollar of expected earnings should be valued once and only once, either as part of the dividend rate or as part of the future growth rate. If the future payout ratio is different that the payout ratio consistent

**with sustainable ROE expectations, there will be an inconsistent and therefore improper re-distribution of the total return allocation between D/P and g.**

Q. How can you tell your retention rate is consistent with the dividend yield?

A. It is consistent because it was computed to be so. For example, at December 31, 1989 the book value of the stock of the Southern Company was estimated by Value Line to be about $21.75. If the 13.0% return on equity is expected by investors, then earnings per share based upon the current book value has to be expected by investors to be $21.75 times 13.0%, or $2.83. The dividend rate upon which the dividend yield is computed is $2.14 per share, meaning that if the normal, sustainable earnings per share investors expect is now about $2.83, the earnings left for retention after paying the dividend is $2.83 minus 2.14, or $0.69 per share. This represents a retention rate of 24.38%, or virtually identical to the retention rate I actually used. If the retention rate of 27.69% as used by Dr. Morin were correct, then he should have computed a dividend yield based upon a dividend rate consistent with this retention rate. Based upon the retention rate used by Dr. Morin, the dividend rate should have been only $2.05, not $2.14. This seemingly small difference caused him to have about a 35 basis point higher dividend yield than if he had used a dividend rate consistent with his own retention rate assumption.

While an error that causes the cost of equity to be overstated by only 35 basis points is small in comparison to the problems introduced by Dr. Morin from his historical growth rate DCF studies, this additional error is unnecessary. The degree of precision obtainable from the DCF method can and should be confined to the analysts determination of what the future expected return on equity will be.

Q. Did Dr. Morin also apply his DCF method to a group of comparable companies?
A. Yes.

Q. Did he use the same method for these companies?
A. No. He used historic growth, and analysts forecasts of growth, but he did not use the "b x r" method. The elimination of this method caused him to effectively give even more weight to the particularly invalid historic growth method.

Q. What growth rate did he arrive at for his comparable companies?

A. 4.44%, which is based upon the average of 5.24% he obtained from the historical dividend growth rate and 3.63% from merely averaging the raw consensus growth rate as compiled by IBES (See his Schedule 5, Pages 1 and 2).

Q. If he had used the same "b x r" method as he did for the Southern Company for his compatible companies, what growth estimate would be obtained?
A. As shown on my Schedule 12, pages 1 and 2, he would have obtained a growth of 3.50%, or 0.94% lower than he actually used with his comparable companies.

Q. How did you obtain this 3.50% "b x r" growth for Dr. Morin's comparable companies?
A. I used exactly the same method as presented by Dr. Morin. Both the future expected return on equity and the retention rate was obtained from the Value Line report for each of his companies. The retention rate and the return on equity were multiplied together to arrive at the growth rate. Then, each of the growth rates were averaged. The details of this procedure are shown on Schedule 12 of this testimony.

RISK PREMIUM

Q. Is it true that Dr. Morin presents a risk premium analysis in addition to his DCF analysis?

A. Not really. He presents a group of analyses that he refers to as risk premium, but all of the results rely upon answers from his DCF computations. Therefore, his risk premium approach is in actuality only his DCF analysis with even more improper assumptions layered on top. The end result is that his risk premium results are even less reliable than his DCF based conclusions.

Q. What are the additional assumptions that make his Risk Premium approach even less useful than his DCF analysis?

A. He assumes that the risk premium is constant in all years, and assumes that the federal income tax rates have also been constant. In reality, income tax laws, the future expectations for inflation, and the general supply and demand for deferent capital types has not been constant. Therefore it is inappropriate to conclude that whatever was the historic risk premium would be applicable to the current environment.

(End of Prefiled Direct Testimony)

COMMISSIONER GUNTER: I couldn't see that with binoculars (indicating).

WITNESS KISLA: Sorry about that.

COMMISSIONER BEARD: Is what was up on the wall what's on here (indicating)?

WITNESS KISLA: Fairly clear, yes, you can follow on there.

MR. McWHIRTER: You've got his testimony. What's on the wall is in his testimony and that's part of what would have gone on the wall.

CHAIRMAN WILSON: You can put it back on the wall if you take any comfort from that.

WITNESS KISLA: I appreciate that. I will.

(Pause)

CHAIRMAN WILSON: Have you been sworn?

COMMISSIONER EASLEY: Mr. Kisla, you need to move over to this one.

CHAIRMAN WILSON: Has this witness been sworn? Somebody answer me. (Laughter)

MR. McWHIRTER: He has not been sworn in.

CHAIRMAN WILSON: He has not been sworn?

WITNESS KISLA: No, I have not been sworn.

CHAIRMAN WILSON: Raise your right hand, please.

TOM KISLA

was called as a witness on behalf of the Industrial Intervenors and, having been first duly sworn, testified as follows:

CHAIRMAN WILSON: Carry on.

COMMISSIONER GUNTER: Mr. Kisla, I told you how it got the later it got. Wait until about midnight.

WITNESS KISLA: I am hard enough to understand early in the morning. This is going to be an interesting evening.

COMMISSIONER GUNTER: We will be in the morning. Can you imagine what it's going to be like at 8:00 in the morning?

WITNESS KISLA: No, let's not think about that.

DIRECT EXAMINATION

BY MR. McWHIRTER:

Q Would you please state your name for the Commission, sir?

A My name is Tom Kisla.

Q By whom are you employed, Mr. Kisla?

A Employed by Stone Container in the corporate office in Atlanta.

Q And you are headquartered in Atlanta and your plant is -- where is it located?

A The plant I'm representing is in Panama City, Florida, Stone Container.

Q Mr. Kisla, you have previously filed testimony in this case, and exhibits. If I were to ask you the same questions as you were asked in that prefiled testimony, would your responses be the same?

A Yes, by my interpretation of what the questions were.

Q All right. (Laughter)

COMMISSIONER EASLEY: Is that anticipating that Counsel may change them?

WITNESS KISLA: There is a minor point, I suspect, that we will get to somewhere, and it's my interpretation of --

Q (By Mr. McWhirter) We don't need to get to that.

A It is an important point, and I hope that Staff or someone would bring it up, and we can firm up exactly what's meant by 15 meg supplementary power.

Q We're not quite there yet.

MR. McWHIRTER: Mr. Chairman, we need a number for these exhibits.

CHAIRMAN WILSON: These have previously been stipulated?

COMMISSIONER GUNTER: Is this one exhibit?

MR. McWHIRTER: Yes, sir, one exhibit.

COMMISSIONER GUNTER: Three pages?

CHAIRMAN WILSON: We'll give that Exhibit No. 610.

(Exhibit No. 610 marked for identification.)

COMMISSIONER BEARD: Mr. Kisla, kind of think of this as a dance and Mr. McWhirter is your partner and he's leading.

Q (By Mr. McWhirter) Mr. Kisla, as I understand it, there is a modification in Exhibit 610, and we've handed out revised copies and furnished the court reporter with those copies. Would you tell us what the changes were, sir?

A In Page 2 of 3 in Exhibit 1, we've -- there had been an original error with "Purchase Required." The correct number is 12. It was shown as 13 on the original. That was the only error there.

There has been some minor spreading and modification of some calculations in the lower portion of Page 2 to make it more readable. There's no appreciable change in any of the values as they are calculated. I believe it's easier to follow.

And on Page 3, there is a minor change here. Under the column marked "Prior" on Page 3, the third entry on the corrected is an "8." It was misrepresented on the one that was handed out as 6. None of these are major, none of these changes anything -- any of the broad implications of testimony. They are just typographical errors on the original.

MR. McWHIRTER: Mr. Chairman, I move the testimony, as prefiled, into the record.

CHAIRMAN WILSON: Without objection, the direct testimony will be inserted into the record as though read.

(Exhibit Nos. 358 through 360 inclusive, stipulated into evidence.)

DIRECT TESTIMONY

OF

TOM KISLA

ON BEHALF OF STONE CONTAINER CORPORATION

DOCKET NO. 891345-EI

PETITION OF GULF POWER COMPANY

FOR AN INCREASE IN ITS RATES AND CHARGES

Q. **PLEASE STATE YOUR NAME, OCCUPATION, EMPLOYER AND BUSINESS ADDRESS.**

A. I am Tom Kisla, Senior Engineer, Stone Container Corporation, Atlanta Technology and Engineering Group, 2150 Parklake Drive, Atlanta, Georgia, 30345.

Q. **ON WHOSE BEHALF ARE YOU APPEARING IN THIS DOCKET?**

A. I appear on behalf of Stone Container, Panama City, but I believe my testimony could apply to other process industries which cogenerate a part of their electrical requirements.

Q. **WHAT IS THE SUBJECT OF YOUR TESTIMONY?**

A. I will address practical problems in the implementation of the existing standby rate design and how they affect my company and the utility. I will identify certain disincentives built into the rate, and suggest modifications which I think would provide benefits to the utility as well as to the customer. Our consultant, Jeffry Pollock of Drazen-Brubaker and Associates, will also be addressing these and related points in his testimony.

Q. **ARE YOU SPONSORING ANY EXHIBITS IN CONNECTION WITH YOUR TESTIMONY?**

A. I have prepared an exhibit consisting of three tables which are designed to provide a basic introduction to the interrelationship between the papermaking process and its associated purchased electricity requirements. A basic familiarity with our process is essential to an understanding of the impact of the present SS rate design on our operations.

Q. **PLEASE DESCRIBE THE TABLES AND THEIR PURPOSE.**

A. Table I is a brief overview of some aspects of the pulp and papermaking process. It is designed to show some of the unit operations, their gross electric needs, the amount of steam they require and the electric generation which that process steam can provide. Essentially, it shows that while each step in the process consumes electricity, the steam which some steps require can be used to produce sufficient electricity to provide much of the overall electrical requirement.

In our operation, the raw material (wood chips) moves in sequence from the woodyard, to the pulp mill, to the paper machines and through the driers. In a separate power house, we burn bark, process wastes, and, when necessary, fossil fuels to make steam. The steam passes through one of three turbine generators en route to the separate parts of the process where it is needed.

The first entry on Table I is designated "woodyard." Here the long logs are received, stored, debarked, chipped, and then inventoried until they are needed in the pulpmill. The process uses approximately six megawatts of electricity on average and uses no appreciable steam. This situation is typical of most noncogenerating process industries. Its maximum purchased electric requirement is fixed by the equipment installed and its load factor is a function of the time that equipment is run and the percentage load.

The next area shown on Table I is the pulpmill. Here the chips are placed into digesters and chemicals are added. The mixture is heated with steam so that the chemical reactions which occur during pulping will proceed at a faster rate. As shown, there are a number of digesters which in this example use about 190,000 pounds of steam per hour. The steam used by the digesters is produced in our boilers at temperatures and pressures much higher than required by the digesters. Before the steam enters the digesters it passes through one of our three steam turbogenerators. In the process of passing through the turbine, some of the energy in the steam is transferred to rotational energy to the turbine's shaft. Simultaneous with the energy transfer, the temperature and pressure of the steam drops to a level closer to that needed for use in the digester.

The energy that the steam places into the turbine shaft helps to turn the rotor in a generator. This produces electricity.

As shown, the steam sent to the digester produces about six megawatts of electricity. Since the digesters do not require much electricity, most of it is available for distribution to other parts of the mill.

After the digesters convert the chips into pulp, the pulp is washed while still in the pulpmill. This process separates the pulp from the chemicals, which form a new stream containing the used chemicals and degraded wood material. The washers use about seven megawatts of electricity and almost no steam. Thus, the net electric use in the pulpmill might average one megawatt.

The next operation shown is the evaporators. These use steam to evaporate water and concentrate the recovered chemical stream. The evaporators use about the same number of pounds of steam per hour as the digesters, but since they require a lower final temperature and pressure than the digesters on average, the turbine shaft receives more energy per pound and is able to generate more electricity; in this example, about eight megawatts per hour, or a net of seven megawatts for distribution to the rest of the mill.

The paper machines take the washed pulp and form it into a "wet sheet." The process requires a lot of electricity and very little steam. The average electric need in the example shown here is 20 megawatts (or 10 megawatts per paper machine). The wet sheet is pressed and then most of the water is evaporated using steam filled driers. The steam used in these driers is also made in the power house, and can also go through the turbogenerators to make about nine megawatts of electricity.

The last entry is meant to include all the other processes not specifically addressed.

The bottom line in this example shows a gross electric requirement of 42 megawatts. Typically the mill would generate about 30 megawatts of this, and thus it would have to buy an average of 12 megawatts, or about 30 percent of its average electric requirement. We produce about 1,100,000 pounds of steam per hour under average conditions.

Q. **WHY DO YOU EMPHASIZE "AVERAGE CONDITIONS"?**

A. There are a number of factors which will change the situation, and indeed a pulp and paper mill steam system is almost always in flux.

For instance, Table II shows just the effects of outside ambient temperature on our in-house generation. If the outside air is colder, the chips placed in the digesters are colder, and we have to supply more steam for heating to achieve the chemical reaction of the same efficiency. When we do so, more steam can pass through the turbine and more electricity is generated. As shown, there is a four megawatt difference in generation between the coldest and the hottest weather. This may seem like a lot, but it is less than a 1,000 pound increase in lower pressure steam requirements per ton of production or a six percent change overall. This translates to a range of 3 percent above and 3 percent below the average steam flow.

Q. **IS THE DIFFERENCE IN GENERATION BETWEEN THE HOT AND COLD MONTHS PERTINENT TO THE QUESTION OF STANDBY SERVICE?**

A. Very much so. The current standby contract states that the daily standby service is calculated by taking the maximum customer generation output in any interval since the last outage minus the generation during the on peak portion of the new outage minus the load reduction which is a direct result of the current generation outage.

Thus there could be a significant difference in the calculated standby charge just based on the effect weather has on our amount of self-generation. Clearly the rate structure appears to be highly punitive to cogenerators with systems like Stone's.

**Q. CAN YOU ILLUSTRATE WHY THIS PROVISION OF THE STANDBY RATE IS PUNITIVE?**

A. Yes. The lower part of Table II shows hypothetical large turbine outages. In the lower left we show winter operation. If the large turbine went out, the mill would transfer some load to the condensing turbine, giving us net in-plant generation of 14.5 megawatts. In that event, we would increase our supplementary purchase to 15 megawatts and take 7.5 megawatts of standby. But, to achieve balance, we must either reduce load or buy more power.

In winter scenario A we opt to reduce load by five megawatts to achieve balance. Winter scenario B supposes that we opt to purchase the additional five megawatts rather than reduce load.

The summer scenarios (C and D) are similar, except that because of the warmer weather we start with a generation of 28 megawatts and can only achieve an in-plant generation of 14 megawatts. We increase supplementary service to 15 megawatts and we take the contracted 7.5 megawatts of standby. In scenario C we reduce load by 5.5 megawatts, whereas in Scenario D we would increase purchases by 5.5 megawatts.

The lowest block of data shows the calculation of the standby KW and the monetary penalty related to each scenario. Note that following the methodology in the tariff, we calculate standby billings of 12.5 and 17.5 megawatts in the winter, and 12.5 and 18 megawatts in the summer.

Subtracting the standby actually used, we see that there is in each case a five megawatt discrepancy. This translates into an unwarranted penalty of $112,700.

Q. **COULD YOU SUGGEST A RATE STRUCTURE WHICH WOULD BE MORE EQUITABLE?**

A. Yes. The calculation of the daily standby service charge should not be based on the weather-sensitive nature of our operation. I should not be charged for service never received. The daily standby service demand charge should be based on the difference between the highest on peak readings in each day of an outage and the highest on-peak reading during a non-outage period of the same billing period. That is, the customer should pay the reservation charge that he would have experienced without the outage, or the daily demand charge for the additional standby service actually taken during the billing period, whichever is greater.

Q. YOU MENTIONED THAT YOU HAD PREPARED THREE TABLES. IS THE THIRD PERTINENT TO THIS DISCUSSION?

A. I believe it is.

Table III contains a brief overview of some of the situations which impact the electrical balance with some regularity. As shown, most of the changes are in the three to five megawatt range. Generally, when the generation is lost the mill has almost no real decrease in its electric load. Thus, if nothing were to change, the mill would have to buy the additional power required. This incremental demand would come at $7.55 per kWh under the PXT rate. The cost of paying $7,550 per MWH for infrequently required electricity has to be balanced against the mill's options to reduce purchased electricity during that time period. For instance, we can alter our operation to produce more electricity, even if the paper process doesn't require more steam. The trick is to supply more steam to the turbine, then remove the excess from the system before it proceeds to the other parts of the mill. This can be done in two ways.

First, one of our turbines has a condensing apparatus that immediately converts some of the steam to water. Typically, the condenser is not fully loaded, so more steam can be driven through the turbine to generate more electricity and then diverted to the condenser, without affecting the amount of steam delivered to the papermaking process. This is the preferred option, because it can be accomplished by simply burning more low-cost bark in the boiler. Still, this energy costs two times as much to produce as the PXT energy rate.

If the condenser is working to capacity, the other option is to produce more steam to pass through the turbine, then vent the excess to the air before delivering it to the process mill. This is a much more expensive option for two reasons. First, unlike the steam which is condensed, vented steam is lost and we must make it up with additional expensive demineralized water. Secondly, to achieve the immediate, incremental generation with vented steam, it has been our experience that we must burn expensive fossil fuel instead of cheap bark. For these reasons, power produced by venting steam costs three times as much as the PXT energy rate.

The other option available to the company--which we sometimes employ--is to reduce load by shutting down the woodyard or by shutting down selected washer lines. These courses of action are effective in keeping our demand down, but they disrupt operations and can cause changes in quality.

Q. **HOW COULD THIS SITUATION BE IMPROVED?**

A. We propose two modifications to govern two sets of circumstances. First, if we could purchase as-available energy on the SE rider to displace our more expensive alternatives (operating more costly generation through condensing and venting, or curtailing production), we could purchase more electricity from Gulf Power and simultaneously reduce our production cost and have more consistent product quality. We could curtail our use of SE in as little as 30 minutes' notification. The second circumstance concerns our ability to plan and coordinate with Gulf Power the scheduled maintenance of our largest generator.

Q. **WHAT HAPPENS WHEN THE LARGEST GENERATOR IS REMOVED FROM SERVICE FOR SCHEDULED MAINTENANCE?**

A. As shown in Table III the removal of our large turbine causes the biggest swing in our generation. This occurs about once every four years. In practice, a portion of the 18 MW of load normally supplied by this unit can be recouped by loading other turbines; perhaps as much as an additional four megawatts.

Panama City currently has a contract standby of 7,500 KW and the mill would probably use all of that, thus increasing purchases to about, in this case, 22.5 megawatts. As before, this would be 5.5 megawatts below the use we would normally have. We have seen these situations before in Table II. This time, however, we are dealing with the economics of proceeding with scenarios B or D of Table II; that is, the feasibility of purchasing additional standby service.

Q. **IS THERE AN INCENTIVE TO PURCHASE THE EXTRA 5.5 MW OF STANDBY SERVICE ONCE EVERY FOUR YEARS DURING A MAINTENANCE OUTAGE?**

A. No. This would cause our standby service capacity to be ratcheted upwards for the next 23 months, resulting in an additional cost of:

| | | | | |
|---|---|---|---|---|
| 5500 | 0.98 | 23 | = | $123,970 |
| kWh | $ Reservation | Months | | |

Since we would not expect to need that level of service for another four years, then the mill almost certainly will choose to schedule the turbine outage during a normal maintenance period and then restrict electric use and production if necessary until the job could be completed.

Q. **DO YOU BELIEVE THE PROBLEM COULD BE EQUITABLY RESOLVED?**

A. Certainly. Remember, this is not a forced outage. We can take it when we want, and we could notify Gulf Power ahead of time. In that way Stone Container and Gulf Power could time the outage to occur when Gulf Power could accommodate it without affecting its system adversely. If we offer to fully coordinate the outage with Gulf Power beforehand, there would be no reason to impose the ratchet feature of the rate to the extra maintenance power required every four years. Thus, we could purchase more electricity, make more product, and make better use of our manpower during this large mill-wide outage.

Q. **DO YOU FEEL TRAPPED IN A NEVER ENDING SPIRAL OF RISING ELECTRICITY COST?**

A. No. We can take measures to limit our costs. Our mills in Hopewell, Virginia and Florence, South Carolina already are self sufficient. We were considering an increase to our cogeneration capacity when we were offered the SE rate to maintain or increase our purchases of electricity from Gulf Power. If electric rates rise it will be that much easier to install equipment that would allow us to reduce our purchased electricity requirement. We could become electrically self sufficient. The possibility is carefully evaluated and reevaluated with changing times.

Q. **DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes, it does.

Q (By Mr. McWhirter) Mr. Kisla, would you briefly summarize for us your testimony and then I'll turn you over to the wolves.

A Okay. Thank you, Mr. McWhirter.

Briefly, ladies and gentlemen, what I've attempted to do was to describe how a pulp and paper mill steam generating system works, and it's not an easy concept. To show how the steam we generate generates electric, and how this coupled with purchased electric supplies our total demand for processing electricity. As we have purtibations (phonetic) and changes in the system, our approaches to electric can bounce from 10 to 20 megs if we would let it, but we have the ability to control it and we do control it.

But, you have to understand that potential variations can occur in the pulp and paper mill system before you can appreciate what a cogenerator does; and how it has really a special place in the purchased electric relative to someone who just turns the switch and has a constant while that switch is on.

I'll go through three tables, and hopefully you can follow along on the sheets that I handed out, but it will help me organize my thoughts.

Q That's Page 1 of Exhibit 610?

COMMISSIONER EASLEY: He needs to be at a microphone. I think they've removed it. What did we do with the mike? (Pause)

WITNESS KISLA: Can you hear if I go this loud? I'll try and we'll fake it.

MR. McWHIRTER: Stretch that thing out as long as you can.

WITNESS KISLA: It's a lot more difficult, but I'll try.

COMMISSIONER EASLEY: Why don't you point for him.

WITNESS KISLA: This may go as a ventriloquist act later.

Okay. The first entry we tried to cover there is we called "Woodyard," and in essence I -- boy this is expensive help, too. In essence what happens here is we have no steam used. We have a 6-megawatt pull. This is conventional electric. When it runs, it pulls at 6 megs. That's an average number. It can go more depending on the load.

In another area of the pulp mill, we have a digester. Basically, what happens here is that we mix the chips with chemicals and steam. The steam that is used to cook these chips is generated at a much higher temperature and pressure than is needed. It passes through a turbine generator. In the process of passing through a turbine generator, that extra energy in that steam, a portion of it is transferred to rotational energy in the turbine shaft.

Simultaneous with that transfer, the temperature and pressure drops to a level much closer to that needed in processing. That steams goes on to process. That energy that was turned into the shaft makes electricity. So steam used in a paper mill makes electricity.

In this particular area, I show that we will use 7 megs in the total process. It generates 6.

The next area is the evaporators. Here the liquor taken from the pulp, which pulp has gone through washers, the chemicals have been recaptured. They call it a black liquor. Here we take it through an evaporation step as part of the recyclying effort. 99% of the chemicals in the pulp mill are recaptured, reprocessed nd reused. The evaporation uses a lot of steam.

Here we're showing 1 megawatt needed to run the plant, but 8 megawatts generated. So notice that interplay between steam used and electricity generated. We now have surplus electricity in that particular case.

The powerhouse where we make electric, make steam, we'll use 7,000 pounds -- we use 7 megs. The steam used for auxiliaries may generate 3, so it's a net user.

The paper machines, we have two of those, they'll take about 20 megs, and the steam that we use there would generate 8. And in miscellaneous we have, I guess, about 7 and 3. So basically what we look at there is a total process used of 42 megawatts, of which three are generated -- and this is an average condition.

Now, recognize this is an average condition, and like any number where people tell you it's an average, there is something higher and there's something lower. That is an important concept I think we'll have to pound home later on, on how it affects our demand, when we come to calculating these standby rates.

We are just taking those average conditions on an unaverage day. That might be -- a middle-temperature day. If the weather is colder or warmer, it would require less steam to bring parts of the process up to temperature. (Pause)

CHAIRMAN WILSON: Mr. McWhirter, do you need some help? (Laughter)

COMMISSIONER GUNTER: Your dummy is going to do it to you.

WITNESS KISLA: Anyway, if the temperature is warmer, then we would have to use less steam to bring the pulp mixtures and other things up to temperature. Obviously, if we're making less steam, that's that much less steam that passes through the turbine; that's that much less electric that the plant generates.

In the case I have shown here where we show average of 30, and the average needed 42, and the average purchase 12, which would be coming right off Table I, the warmer weather we'll see that we might only be able to generate a total of 28 megs, and we show the distribution on three turbine generators that we have in the plant site. That's 17, 7, and 4, for a total of 28.

COMMISSIONER GUNTER: Primarily, when you're talking about the temperature differential, you're really startin~ with the chips going into the digester.

WITNESS KISLA: Yes, sir.

COMMISSIONER GUNTER: And having to have on colder days, having to raise the temperature of the product going in in order to have the digester work properly?

WITNESS KISLA: Yes, sir.

COMMISSIONER GUNTER: Does it follow all the way through? It seems as though you get to the paper machine and it sort of --

WITNESS KISLA: No.

COMMISSIONER GUNTER: It doesn't matter, you know, it just requires electricity.

WITNESS KISLA: Well, that's not completely correct. The paper machine has dryer sections on it, and generally you're talking about having to evaporate the same amount of water from a sheet. That part is true. But we have air handling systems, so what has to happen, instead of us supplying the air at 70 degrees, if you're supplying it at 30, you don't supply it at 30. You heat it back to actually 120 or so, so you have the air.

Same thing with water. The steam that's lost to the atmosphere or other places must be replaced with makeup water. That water can come in at 70 degrees; it can come in at 50 dgrees; it can come in at 90 degrees. It's all got to get up to the same final temperature, so it's going to go. It's just like your water heater in the winter.

COMMISSIONER GUNTER: To just give you an idea, the plant you all own in Jacksonville --

WITNESS KISLA: Yes, sir.

COMMISSIONER GUNTER: I went to work there when it first started operation so I'm just trying to recall. Back when St. Regis opened it in 1952.

COMMISSIONER EASLEY: I didn't know they had paper when you were a little boy.

COMMISSIONER GUNTER: They were making it from papyrus.

COMMISSIONER BEARD: It also explains why they have had difficulty making a profit there ever since.

WITNESS KISLA: Pardon?

COMMISSIONER BEARD: That's why they've had difficulty making a profit there ever since he worked there.

WITNESS KISLA: I'm not going to touch that one.

But yes, that's exactly what happens. That happens in the cold weather and the opposite happens in the hot weather. When everything is warmer, it takes that much less steam to get it up to temperature and again less steam needed, less steam made; less steam through the turbine, less electric produced in the turbine. And really the concept is very simple: You make a lot of steam for process; you make a lot of electric. You make less; you make less electric.

And that's what we're trying to show in this particular case. And we call it warmer 177428. Needing 42, we'd have to average purchasing 14 megs to supply that 14 average. Again, average does not mean anything about the moment-to-moment requirements. It means level; not what's up here, not what's down here. We're running into a lot of problems with this. And a lot of people have a real problem understanding average as it is in a paper mill. If you've worked there, you know what I mean.

The coldest situation -- look at the turbines it's 19,9 and 4, the output there is 32. We need 42; now we only have to borrow -- buy 10. So right off the top we see while we have an average of 12 megs generated, they are very easily times where we're making 14 and very many times where we're just making 10. The average there is very simple; the average is 12.

Now, the question I pose is, what happens if you were to, using the current -- if you'd have a turbine outage, what would happen if you were to lose the major 20-meg turbine at either the winter condition or in the summer condition?

Now, in the winter condition where we were in 19,9 and 4, with a total self-generation of 32, buying ten on a supplementary --

MR. PALECKI: Staff would pose an objection to this summary of the testimony. We would point out that the entire prefiled testimony of Mr. Kisla is 13 pages, plus his exhibits. And this is much more detailed and seems to defeat the Commission's policy of requiring prefiled testimony.

COMMISSIONER BEARD: We're going to enter this in the record as read. Because this --

WITNESS KISLA: The concept is important. If you want to understand why cogenerators are getting punished by the standby rates and charge, you have to understand --

MR. VANDIVER: I don't know that the witness can argue with Counsel.

MR. PALECKI: We're saying this is going far beyond the extent of his prefiled testimony.

CHAIRMAN WILSON: Let me do this: I've read the testimony. I think all the Commissioners have read the testimony. I understand the concept of the averages. I do.

WITNESS KISLA: Well, fine.

CHAIRMAN WILSON: If you can get to --

WITNESS KISLA: Okay. We'll just drop to the calculation, then, if you'd like.

CHAIRMAN WILSON: Yes, if you do that and run through that real quickly.

WITNESS KISLA: Following the current --

CHAIRMAN WILSON: And then let Counsel ask you questions --

WITNESS KISLA: Yes, sir

CHAIRMAN WILSON: -- if they have them about the calculations that you've made.

WITNESS KISLA: Well, following the current tariff on standby power, if you would go and take the maximum generation,0 which was 32 megs, which we put in here, subtract the daily -- the generation which was available on the day of the outage, adjust for a reduction and you would calculate a standby power. Where I have here, in my case is A, B, C and D, it's 12.5, 17.5, 12.5 and 18. You'll see from the -- we showed in the area above that, that the actual megawatts used was 7.5, 12.5, 7.5 and 13. In each case there was a 5-megawatt error.

With a $9.98 per kilowatt-hour reservation charge and a 23-month ratchet this represents a penalty of $112,000 for service never taken.

So one of the problems I have and one of the things the concepts I'm trying to get some relief on is to have standby power based on the load actually put on Gulf's system, rather than some arbitrary calculation of maximum generation during some given period.

What we have -- what capability we have to generate power really shouldn't enter into that. It's the pulled load we put on to the Gulf system.

Now, this applies only to the average variations based on season. My Table 3 showed how each individual area could swing. Here we'll see that each area could lose steam or lose process and drop as many as 15 megs. If all these incidences occurred at one time, you'd add up to a loss of 15 megs of generation. If you're going to maintain 42 megawatts total, then you have to impose an additional 15-megawatt load. So this is the nature of the beast we're working with. We can get up to 15-megawatt swings. We don't see them because we put load control on, but load control is expensive.

And one of the concepts we wanted to seek relief from was to go into like an economic dispatch situation that the Florida utilities have. We would like to have the able to buy SE power when it's available and displace our more expensive generation that we use for load control when it's available. The current rate would let us do that but it says "If and when you have any of your electrical generating systems go off line, you're off the SE rate." We really see no reason for that.

The third thing we seek relief from is those conditions where we have to take our major turbine outages down. We have 20-meg turbines. Every four, five years they have to come off line. These are scheduled outages. We could coordinate these with Gulf Power. There is no reason why we couldn't schedule them, take them down when Gulf said we have plenty of surplus power available.

We could do that; we can make better use of our time and facilities; we could give Gulf additional revenues. The structure, as you currently have, would prevent us from doing that. There is no reason why we would take 5-1/2 megs of power and then be subject -- that we would only need every four years and be subject to a 23-month ratchet. So there are really three areas we're seeking relief from, and I guess that concludes my testimony or my summary.

CHAIRMAN WILSON: Questions?

MR. STONE: No questions.

CROSS EXAMINATION

BY MR. PALECKI:

Q We have just a few questions.

I would refer you to Page 13 of your testimony, and I quote, "We were considering an increase to our cogeneration capacity when we were offered the SE rate to maintain or increase our purchases of electricity from Gulf Power."

What do you mean by that statement?

A At that time, we were actively talking to several different companies who approached us as being host for a cogeneration plant to build a PURPA machine. We would take the qualifying steam. They would make anywhere from 30 to 70 megs and sell that to Gulf Power.

We were approched by Gulf Power. Gulf Power said, "Stone Container, we have an incentive rate to you that might -- that you might choose to take instead of going to cogeneration, all you have to do is put up $2.6 million." Which we did. It cost us 2.6 million to adjust our in-house electrical distribution system.

Prior to that, we could only pull 9 megs. Up through February, 1989, we only pulled about 9 or 10 megawatts of electric. We couldn't pull any more than that. We spent 2.6 million to get to the 30 megawatt tie. That 30 megawatt tie was supposed to supply us with SE power. SE power was supposed to be available to us at all times; i.e., anytime SE power was available, we could use it. There were no restrictions.

Further, we weren't supposed to have any charge for any aid-in-construction. It was clearly stipulated in our deal in lieu of aid-in-construction, Stone would agree to stay on line five years, X amount of time. So basically what we did was put away our cogeneration plans, we invested 2.6 million of capital money to upgrade our tie.

We have in Stone Container a mill in Florence, South Carolina, which is electrically independent and sells electric. We have a mill at Hopewell, Virginia, which is electrically independent and sells electric. These are classical cogenerators. their uses weren't very much different from Panama City before we put the big bucks into them. That's what I, I guess, what I meant.

Q Did Stone Container perform a cost effectiveness analysis whether it would be more cost effective to install more cogeneration capacity or take service on the SE rider?

A Oh, I'm sure they did. I wasn't personally involved in that.

Q Are you aware of the results of the analysis?

A I could speculate.

Q No, I wouldn't ask you to speculate. Are you aware, do you know of the results of that analysis?

A Typically, what you have there are a variation in returns, but a different capital requirement.

CHAIRMAN WILSON: The question is whether you are --

WITNESS KISLA: No, I'm not aware of the exact amounts.

Q (By Mr. Palecki) Did your generator have a forced outage on September 2, 1989, due to the bark burned for fuel clogging the rotary grate?

A No.

Q Was Stone Container the customer who used 22,759 kilowatts on September 2, 1989?

A Yes, we did.

Q What was the reason for that jump in electrical use?

A Could I put a slid up that would help explain that?

CHAIRMAN WILSON: Yes.

MR. PALECKI: Yes.

CHAIRMAN WILSON: Do we have copies of that?

WITNESS KISLA: Yes, I do.

MR. PALECKI: Let me rephrase my question so maybe we can speed this up.

Q Did you have a generator that was either turned off or was no longer able to generate because of your jump in electrical use?

A Now, what happened, on the Tuesday prior, the bark system on No. 4 boiler, I believe, it was No. 3 or No. 4 boiler, both operated 1,200 pound, developed some problems with its ash removal system; its grade system. Okay. It was a problem. The boilers were able to run.

The mill was not fully aware of a number of things in their electric policy. They chose to take the boiler down Saturday, off peak. They scheduled a down. That in retrospect may have been a mistake on their part. They made another mistake: They also chose to take the turbine down. The turbine did not have to come down. They chose to take it down.

We could have very easily left it on line and cranked up the other boiler to its maximum steaming capacity. We also could very well have shut down other parts of the mill and controlled it so that there would have been no peak, no aberration whatsoever.

What you see over here is 15-minute moving intervals that are available -- and I got this data from Gulf Power. This is what they have. Every 15-minute interval, 24 hours a day, 365 days a year.

You can see prior to that we were on the SE rate. I like this slide and I appreciate your asking me this question, because you can see from the variation exactly what I'm talking about the mill running uncontrolled. You can see how she'll peak.

To the left, in that SE period, we are not doing anything to have demand control. You can see the variation, the ups, the downs. Now, you can see where she levels into the 12-and-a-half meg. What happened there was Gulf Power called us up, they said, "Supplementary power is going off, go back on load control." And that's what we did. We cranked up our condenser, we stricted our electrical use. We bought less electric from Gulf Power.

It cost us more money to buy less electric from Gulf Power because we had to generate that electric ourselves. And then we ran through until Saturday morning, about 8:00 o'clock, when they took the turbine down, and that was a mistake in retrospect.

That's what happened. She went up to 22 megs.

Q Why didn't you report that you took standby power on that date?

A There was no need -- the mill really didn't believe it had a need to report because it did not believe it took any standby power.

Q Are you aware now that that's required of your tariff?

A I am aware that the tariff says that you're required to report when standby power is taken. But the question is: If you have zero standby power, when do you take standby power? The answer is, the mill suggested, was never. If you have none and you can't buy any, then you don't take any. So whatever you take is on billing demand. And that's what they took. They took 22 megs of billing demand which they paid $60,000 for.

Q And you were down for maintenance during that period, correct?

A They took the boiler down. They took the boiler down for maintenance to repair it.

Q Were you ever billed standby, for standby service by Gulf as a result of that incident?

A That bill -- the following month's bill contained a billing demand of 22.whatever megs which the mill paid at $7.55 a throw.

COMMISSIONER EASLEY: Was that the standby rate?

WITNESS KISLA: Ma'am, they did not file for standby.

COMMISSIONER EASLEY: No, the question was were you billed for standby? And I was trying to figure out if the rate you just cited was a standby?

WITNESS KISLA: No, ma'am. We were not on a standby rate. We paid the supplemental energy demand charge, which was $60,000.

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

CHAIRMAN WILSON: Questions, Commissioners? Redirect?

MR. McWHIRTER: No, he --

COMMISSIONER EASLEY: I do have just one question. I'm sorry, it just occurred to me.

At that point when they took the boiler down and then took the turbine down, would you have had any power if Gulf Power had not been available?

WITNESS KISLA: Yes, we still had the two other turbines that maintain on line.

COMMISSIONER EASLEY: Okay, thank you.

MR. McWHIRTER: No redirect.

COMMISSIONER EASLEY: Mr. Chairman?

MR. McWHIRTER: Mr. Chairman, I would like to offer our exhibits and I'd like to number --

CHAIRMAN WILSON: Just a moment.

COMMISSIONER BEARD: You're doing what he wanted to do.

MR. STONE: I defer to Mr. McWhirter.

MR. McWHIRTER: I would like to request that you number the graph that we saw that was handed out as Exhibit 611.

CHAIRMAN WILSON: That would be 611.

MR. McWHIRTER: And I offer 610 and 611 into the record.

CHAIRMAN WILSON: Without objection, those are admitted into evidence.

(Exhibits Nos. 610 and 611 received into evidence.)

CHAIRMAN WILSON: Do we have a calculation or will we be able to calculate in the recommendation when we see the difference between what they paid and what they would have paid on the standby tariffs? (Pause) All right.

MR. PALECKI: Staff tells me no, that we will not.

CHAIRMAN WILSON: It's a calculable number, though, isn't it?

MS. MEETER: Staff's recommendation will take care of that problem.

CHAIRMAN WILSON: Does that mean I'll see the number?

MS. MEETER: No.

CHAIRMAN WILSON: I want to see the number.

MS. MEETER: Yes, I can show you the number, yeah.

CHAIRMAN WILSON: Somebody's going to have to show me the number. I don't care who it is, as long as it's right.

WITNESS KISLA: Excuse me --

COMMISSIONER BEARD: Well, wait a minute, is that a necessary standard?

WITNESS KISLA: Excuse me. This may be irregular, but I understand Mr. Haskins in his rebuttal rebutted my calculations, and no one here has asked me about --

MR. VANDIVER: I'm going to have to object, Commissioners, there's no question pending.

CHAIRMAN WILSON: No, there's not a question pending.

MR. McWHIRTER: You can't deal with that.

MR. VANDIVER: Move to strike his comments.

CHAIRMAN WILSON: Since it wasn't substantive, I don't think it makes any difference.

All right, anything further of this witness?

MR. McWHIRTER: No, sir.

CHAIRMAN WILSON: Thank you very much, we appreciate it.

WITNESS KISLA: Thank you.

(Witness Kisla excused.)

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CHAIRMAN WILSON: All right, how much cross examination for Mr. Pollock?

MR. PALECKI: Staff has pretty much cross for Mr. Pollock.

CHAIRMAN WILSON: How much is pretty much?

MR. PALECKI: I would say 45 minutes. And that's if we really rushed it.

COMMISSIONER EASLEY: Does that count his answers?

MR. PALECKI: I think it would, yeah. We could say the questions in about, I'd say, 12 minutes.

COMMISSIONER BEARD: Why don't you just give all the questions at once and he can give all the answers at once? (Laughter)

CHAIRMAN WILSON: What time do you want to come back in the morning?

COMMISSIONER EASLEY: It depends on what time you're going to get through tonight.

CHAIRMAN WILSON: Well, do you want to keep going?

COMMISSIONER GUNTER: Yes.

COMMISSIONER BEARD: Yes. Let's keep going.

CHAIRMAN WILSON: Hold on just a second, let me go off the record for a minute.

(Discussion off the record.)

CHAIRMAN WILSON: We're going to adjourn now. We'll come back at 8:30 in the morning.

(Thereupon, hearing recessed at 9:55 p.m., to reconvene at 8:30 a.m. Wednesday, June 20, 1990 at the same location.)