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LAWSON, MCWHIRTER, GRANDOFF & REEVES
ATTORNEYS AT LAW

JOHN W. BAKAS, JR.
ENOLA T. BROWN
LEWIS J. CONWELL
C. THOMAS DAVIDSON
AILEEN S. DAVIS
STEPHEN O. DECKER
J. BERT GRANDOFF
G. CALVIN HAYES
LESLIE JOUGHIN, III
VICKI GORDON KAUFMAN
JOHN R. LAWSON, JR.
THOMAS A. MANN, II
JOSEPH A. MCGLOTHLIN
JOHN W. MCWHIRTER, JR.
RICHARD W. REEVES
WILLIAM W. SHIELDS, III
MATTHEW D. SOYSTER
DANA G. TOOLE

PLEASE REPLY TO:
TALLAHASSEE

201 EAST KENNEDY BLVD., SUITE 800
TAMPA, FLORIDA 33602
(813) 224-0866
TELECOPIER: (813) 221-1854
CABLE GRANDLAW

MAILING ADDRESS: TAMPA
P. O. BOX 3350, TAMPA, FLORIDA 33601

MAILING ADDRESS: TALLAHASSEE
522 EAST PARK AVENUE
SUITE 200
TALLAHASSEE, FLORIDA 32301
(904) 222-2525
TELECOPIER: (904) 222-5606


May 2, 1990

HAND DELIVERED

Mr. Steve Tribble, Director
Division of Records and Reporting
Florida Public Service Commission
101 East Gaines Street
Tallahassee, Florida 32399

Re: Docket No. 891345-EI, Petition of Gulf Power Company for an increase in its rates and charges.

Dear Mr. Tribble:

Enclosed for filing and distribution are the original and fifteen copies of the Testimony, Exhibit and Appendices of Jeffrey Pollock, on behalf of the Industrial Intervenors. An extra copy is enclosed for acknowledgment of receipt; please return it to me.

If you have any questions, please call.

Yours truly,

Joe McGlothlin

Joseph A. McGlothlin

JAM/jfg

Enclosures

ACK ✓
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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

| | |
|---|---|
| In re: Petition of Gulf Power Company for an increase in its rates and charges. | DOCKET NO. 891345-EI<br>Dated: May 2, 1990 |

## CERTIFICATE OF SERVICE

I HEREBY CERTIFY that true and correct copies of the Testimony, Exhibit and Appendices of Jeffry Pollock, on behalf of Air Products & Chemicals, Inc., American Cyanamid Company, Monsanto Company, Stone Container Corporation, Champion International Corporation and Exxon Company, USA, ("Industrial Intervenors") have been furnished by U.S. Mail to the following parties of record, this 2nd day of May, 1990:

G. Edison Holland
Jeffrey A. Stone
Beggs and Lane
Post Office Box 12950
Pensacola, FL 32576

Jack Haskins
Gulf Power Company
Corporate Headquarters
500 Bayfront Parkway
Pensacola, FL 32501

Suzanne Brownless
Division of Legal Services
Florida Public Service Commission
101 East Gaines Street
Tallahassee, FL 32399-0872

Major Gary A. Enders
HQ USAF/ULT
Stop 21
Tyndall AFB, FL 32403-6081

Jack Shreve, Public Counsel
Stephen C. Burgess, Deputy Public Counsel
Office of the Public Counsel
c/o The Florida Legislature
111 W. Madison Street, Rm. 801
Tallahassee, FL 32399-1400

Joseph A. McGlothlin

Joseph A. McGlothlin
Lawson, McWhirter, Grandoff
& Reeves
522 E. Park Avenue, Suite 200
Tallahassee, Florida 32301
904/222-2525

John W. McWhirter, Jr.
Lawson, McWhirter, Grandoff
& Reeves
201 East Kennedy Boulevard
Suite 800
Post Office Box 3350
Tampa, Florida 33601
813/224-0866

Attorneys for the Industrial Intervenors

Before the

Florida Public Service Commission

Docket No. 891345-EI



# GULF POWER COMPANY

Testimony of

**JEFFRY POLLOCK**

On behalf of:

**AIR PRODUCTS AND CHEMICALS, INC.**
**AMERICAN CYANAMID COMPANY**
**CHAMPION INTERNATIONAL CORPORATION**
**EXXON COMPANY, U.S.A.**
**MONSANTO COMPANY**
**STONE CONTAINER CORPORATION**

Project 5095
May 1990

Drazen-Brubaker & Associates, Inc.
St. Louis, Missouri 63141-0110

Before the

FLORIDA PUBLIC SERVICE COMMISSION

In Re: Application of GULF POWER COMPANY )
for a Rate Increase ) Docket No. 891345-EI
)

AFFIDAVIT OF JEFFRY POLLOCK

STATE OF MISSOURI )
) SS
COUNTY OF ST. LOUIS )

Jeffry Pollock, being first duly sworn, on his oath states:

1. My name is Jeffry Pollock. I am a Principal in the firm of Drazen-Brubaker & Associates, Inc., having its principal place of business at 12312 Olive Boulevard, St. Louis, Missouri. I reside at 14006 New Bedford Court, Chesterfield, Missouri. We have been retained by the Industrial Intervenors, consisting of Air Products and Chemicals, Inc., American Cyanamid Company, Champion International Corporation, Exxon Company, U.S.A., Monsanto Company, and Stone Container Corporation to testify in this proceeding on their behalf.

2. Attached hereto and made a part hereof for all purposes is my testimony, consisting of Pages 1 through 69, inclusive; Appendices A, B and C and Exhibit JP-1 (   ) consisting of Schedules 1 through 17; all of which testimony and exhibits have been prepared in written form for introduction into evidence in Florida Public Service Commission Docket No. 891345-EI.

3. I hereby swear and affirm that my answers contained in the testimony are true and correct and that the attached appendices and exhibit were prepared under my supervision and direction and truly and correctly show the matters and things they purport to show.

Jeffry Pollock

Jeffry Pollock

Subscribed and sworn to before me this 1st day of May, 1990.

Virginia D. Robinson

Notary Public

My Commission expires March 4, 1992.

# GULF POWER COMPANY

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## to the Testimony of Jeffry Pollock

# GULF POWER COMPANY

**before the**

**Florida Public Service Commission**

**Docket No. 891345-EI**

## Testimony of Jeffry Pollock

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock, 12312 Olive Boulevard, St. Louis, Missouri.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am a consultant in the field of public utility regulation and am a principal in the firm of Drazen-Brubaker & Associates, Inc., utility rate and economic consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This is summarized in Appendix A to the testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS DOCKET?

A I am appearing on behalf of the a group of Industrial Intervenors, as follows:

- Air Products and Chemicals, Inc.
- American Cyanamid Company
- Champion International Corporation
- Exxon Company, U.S.A.
- Monsanto Company
- Stone Container Corporation

These Intervenors are customers of Gulf Power Company. During 1989, these six companies purchased 978,000,000 kilowatthours, approximately 13% of Gulf's total retail sales. All six companies are served on Rate PXT. Several of the Intervenors also take service on Rate SS.

Q **WHAT ISSUES ARE YOU ADDRESSING?**

A I shall address various cost allocation and rate design issues, including:

(1) Production costing methodology;

(2) Transmission costing methodology;

(3) Classification of distribution capital costs;

(4) The distribution of the proposed base rate increase among the rate classes (i.e., rate spread); and

(5) The design of Rates PX/PXT and SS.

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

A I am submitting Exhibit JP-1 (     ), consisting of seventeen schedules. The analysis presented in these schedules is based on Gulf's corrected and revised class cost-of-service study provided in response to Industrial Intervenors' Second Request for Production of Documents. This latest study incorporates the corrections to the original filed study (as provided in response to FEA's Second Set of Interrogatories, Question No. 16), and the "without migration" scenario.

Q **WHAT OTHER MATERIALS ARE YOU SUBMITTING AT THIS TIME IN CONNECTION WITH YOUR COST-OF-SERVICE AND RATE DESIGN TESTIMONY?**

A I am also submitting Appendices B and C to the testimony.

Appendix B is a narrative entitled "Cost-of-Service Determination Procedures." It provides an overview of the three basic phases of a rate case; a closer look at the various cost-of-service steps (i.e., functionalization, classification and allocation); and explains the reasons why the cost per kilowatthour is lower for industrial customers than for other customers.

Appendix C is a critique of the Equivalent Peaker (EP) methods of costing. Specifically, it addresses the lack of "fuel symmetry" with the original and revised EP methods and the implicit (and incorrect) assumption (in the original EP) that annual kWh sales determine the type of capacity to be installed.

Q **IS THE FACT THAT YOUR TESTIMONY ADDRESSES COST ALLOCATION AND RATE DESIGN ISSUES AN ENDORSEMENT OF GULF'S CLAIMED $26.1 MILLION REVENUE DEFICIENCY?**

A No.

## COST ALLOCATION ISSUES

Q **BEFORE ADDRESSING THE VARIOUS COST ALLOCATION ISSUES, COULD YOU PLEASE EXPLAIN HOW A CLASS COST-OF-SERVICE STUDY IS PREPARED?**

A The basic procedure is simple, although the amount of detail can obscure this simplicity. In an allocated cost-of-service study, we identify the different types of cost (functionalization), determine their primary causative factors (classification), and then apportion each item of cost among the various rate classes (allocation). Adding up the individual pieces give the total cost for each class. A more detailed explanation is provided in Appendix B.

Q **IS THE COST-OF-SERVICE FRAMEWORK DESCRIBED IN APPENDIX B USED THROUGHOUT THE UTILITY INDUSTRY?**

A Yes. In fact, every logical cost analysis must use these procedures of functionalizing costs (into generation, transmission, distribution and so on), classifying them (into demand-related, energy-related and customer-related) and allocating them among classes. There can, of course, be differences in format, but the basic framework is always the same.

Q **DOES THE APPLICATION OF THESE GENERAL COSTING PRINCIPLES RESULT IN DIFFERENCES IN THE PER UNIT COST OF SERVING THE VARIOUS TYPES OF CUSTOMERS?**

A Yes. Large users are less costly to serve because of the differences in (1) load factor, (2) delivery voltage, and (3) size. Further, the process of delivering electricity to residences is more involved than the process of delivering electricity to industry, because it requires substantially more distribution plant to provide service at the point of consumption. Many industries, by comparison, provide their own (in-house) distribution facilities. The significance of these differences is that costs cannot simply be allocated on the basis of kilowatthours sold. The per unit cost is lower as service is taken at higher voltage levels and as customer size and load factor increase. Because large users tend to be served at higher voltages, consume more energy per location and use their capacity more efficiently (e.g., operate at a higher load factor) than small users, it follows that the per unit cost is also lower. This lower per unit cost justifies a lower per unit rate, a fact which is demonstrated on Page 14 of Appendix B (Table 5).

## PRODUCTION COSTING METHODOLOGY

Q **WHAT ISSUES NEED TO BE ADDRESSED IN DETERMINING AN APPROPRIATE PRODUCTION COSTING METHODOLOGY?**

A Production costs can be separated into two major components: capital costs and operating costs.

Capital costs are related to the specific facilities that are used and useful in providing service at the point of consumption to satisfy the customers demand and energy requirements. They include:

- Return on investment;
- Fixed operation and maintenance (O&M) expenses;
- Depreciation expense; and
- Related income and other taxes (e.g., ad valorem, payroll, etc.).

Operating costs consist primarily of fuel and variable O&M expense. Unlike capital costs, operating costs generally vary with the amount of energy generated and sold.

An appropriate production costing methodology, thus, must consider how <u>both</u> capital and operating costs should be classified and then allocated to retail customer classes.

Q **ONE THEORY OF PRODUCTION COSTING THAT HAS BEEN PROPOSED FROM TIME-TO-TIME IS BASED ON THE NOTION THAT AN APPROPRIATE METHODOLOGY SHOULD PARALLEL THE SYSTEM PLANNING PROCESS. IS THIS A VALID THEORY?**

A Yes. Consistent with the principal of cost-causation, to the extent that production system planning criteria can be integrated into the cost classification and allocation process, it would result in an assignment of costs that would reflect the extent to which each class caused the utility to incur the cost. Because production system planners consider total (capital and operating) costs in evaluating capacity additions/retirements, etc., a production costing methodology must consider <u>both</u> capital and operating costs.

Q **HAVE ANY SUCH "SYSTEM PLANNING"-ORIENTED COSTING METHODS BEEN PRESENTED TO THIS COMMISSION?**

A Yes. Both the Equivalent Peaker (EP) and the Refined Equivalent Peaker (REP) methods purportedly emulate the utility system planning process.

These methods postulate that:

- Only the production capital costs equivalent to the cost of peaking capacity are demand-related; and
- The only justification for investing in more expensive types of generating capacity is to reduce fuel cost.

The above postulates are based on the theory of Capital Substitution (or CAPSUB). Under this theory, the utility is said to "substitute" capital investment for fuel cost--for example, by building a coal-fired base load plant instead of a combustion turbine peaking plant.

Q **HOW DOES THE EP METHOD ATTEMPT TO EMULATE THE PRODUCTION SYSTEM PLANNING PROCESS?**

A The EP method classifies production capital costs between demand and energy. The demand component is usually represented by the equivalent cost of peaking capacity. In other words, Gulf's generating capacity is revalued as though only peaking units were built instead of the various base load and intermediate units which actually exist. The *extra* capital costs (that is, the actual investment in excess of the cost of an equivalent amount of peaking capacity) are considered to be energy-related because they, allegedly, are incurred as a "tradeoff" for the lower cost of operating base load units.

**Q HOW ARE PRODUCTION CAPITAL COSTS ALLOCATED TO CLASSES UNDER THE EP METHOD?**

A In Gulf's response to Staff's first Set of Interrogatories, Item Nos. 1 and 2, demand-related production capital costs were allocated to classes using the Twelve Coincident Peak method. The remaining energy-related capital costs were allocated relative to "year-round" energy requirements.

**Q DOES THE EP METHOD ACCURATELY EMULATE THE PRODUCTION SYSTEM PLANNING PROCESS?**

A No. At best, it is an oversimplification of the system planning process. In reality, planners are faced with the dual dimensions of (1) providing reliable service and (2) minimizing total cost. Because electric energy cannot be stored in large quantities for any significant length of time, providing reliable service requires construction of sufficient generating capacity to meet the projected system peak demands and to provide an adequate reserve margin. This will ensure that whenever a consumer flips the switch an electric light or air conditioner will operate. Consumers often take it for granted that electricity will be instantaneously available whenever and at whatever rate of usage and quantity they demand.

Cost minimization is the requirement that the utility provide the service at the lowest overall cost. The utility strives to install the mix of generating capacity (i.e., base, intermediate and peaking) that, along with the existing generation, yields the lowest total cost. **In other words, the economic choice between a base load plant and a peaking plant must consider both capital costs and operating costs, and therefore is a function of average *total* costs.**

The capital cost of peaking plants is lower than the capital cost of base load plants, but the operating costs of peaking plants are higher than the operating costs of base load plants. Moreover, when the hours of use are considered, the capital cost per kilowatthour for the base load plant is usually less than the capital cost per kilowatthour for the peaking plant. Of course, since the fuel costs of base load plants are generally lower than the fuel costs of peaking plants, the overall cost per kilowatthour for base load plants is also less than the overall cost per kilowatthour for peaking plants.

System planners, therefore, must consider both capital costs and operating costs in light of the expected capacity factor of a new plant. **The fact that base load plants typically have lower fuel costs than peaking plants does not mean that the investment in base load plants is made strictly to achieve lower fuel costs.** Investment in a base load plant would be made to achieve lower total costs, of which capital costs <u>and</u> operating costs are the primary ingredients.

Q ARE THERE ANY OTHER FACTORS, BESIDES THE ECONOMIC TRADE-OFFS, THAT CAN AFFECT UTILITY INVESTMENT DECISIONS?

A Yes. For example, the decision can be affected by the existing generation mix, the availability of a suitable site for the plant, environmental restrictions, access to an ample supply of cooling water, the ability to obtain transmission rights of way, system stability, licensing, government and other regulatory restrictions (i.e., Fuel Use Act), fuel supply, fuel diversification, access to facilities to transport fuel to the plant, political priorities, etc.

Q ARE THERE OTHER REASONS--BESIDES THE CAPITAL/OPERATING COST TRADE-OFFS--FOR INSTALLING PEAKING PLANTS?

A Yes. One reason would be to provide the ability to ride through short-term peaks without starting-up additional base load units. Peaking capacity can be a source of emergency power in the event of large and unexpected forced outages, and it is available to provide start-up power for base load units. Further, the ability to place peaking units in service with a short lead time would enable a utility to meet unexpected increases in peak load. Each of these reasons were substantial in a publication entitled <u>Gas Turbine Electric Plant Construction Cost and Annual Production Expenses</u>--1978:

> "In recent years there has been a relatively rapid increase in the use of gas turbines for electric power generation. The northeast power failure of November 1965 provided the initial impetus for the present extensive use of gas turbines for a variety of

> electric power generation requirements. A relatively common deficiency uncovered by the northeast failure was the lack of emergency power for start-up, continued operation, and safe shut down of steam electric generating units during power failures, and for the subsequent restarting of the units when system power is not available. Also, because of the short lead time for manufacture and installation of gas turbines, many electric utilities have installed substantial amounts of such capacity to offset delays in the completion of desired generation, and to meet unexpected increases in load. Too, many systems which have traditionally increased capacity by installing efficient base load units are finding that overall system economy can sometimes be improved by including low cost peaking units in their generating capacity expansion programs."

Q **DOES THE OBSERVATION THAT THE CAPITAL COST OF NEW BASE LOAD UNITS MAY BE HIGHER THAN THE CAPITAL COST OF PEAKING CAPACITY NECESSARILY MEAN THAT THESE HIGHER COSTS WERE INCURRED TO SAVE OPERATING COSTS?**

A No. The fact that the capital cost of new base load units, in retrospect, may turn out to be significantly more expensive than the capital cost of a peaking unit does not necessarily mean that these higher costs were incurred to save operating costs. The differences in capital cost that we now observe are relatively recent phenomenon, resulting from a variety of factors that have little to do with the inherent economics of generating plants. For example, the Plant Daniel Units were installed in 1977 and 1981, respectively, at an average cost of $374 per kW. According to the EPRI <u>Technical Assessment Guide</u>, dated May, 1982, a combustion turbine plant could have been built in 1980 at an installed cost of over $200 per kW. Thus, the cost differential between coal and peaking units used to be less than $200 per kW. Today, the cost differential may be more than $1,000 per kW. In particular, many base load plants completed in recent years have shown higher capital costs because of delays and cost overruns that had nothing do to with the objective of obtaining lower cost energy. Therefore, it is wrong to assume that observed differences in capital costs are always the result of conscious decisions to spend more per kW in order to achieve lower operating costs.

Q **DO THE EP AND REP METHODS ALLOCATE THE SAME MIX OF CAPACITY (I.E., A SLICE-OF-THE SYSTEM) TO EACH RATE CLASS?**

A No. The EP method allocates a large portion of production capital costs on year-round energy. This assigns a larger portion of base load plant (and a correspondingly smaller portion of peaking plant) to high load factor customers. Customers with low load factors, conversely, are allocated a smaller portion of base load plant and a large portion of peaking plant.

Q **UNDER THE EP AND REP METHODS, IS THERE ANY ATTEMPT TO REALLOCATE PRODUCTION OPERATING COSTS CONSISTENT WITH THE ASSUMED CAPITAL/OPERATING COST TRADEOFFS IMPLICIT IN CLASSIFYING PRODUCTION CAPITAL COSTS UNDER THE EP AND REP METHODS?**

A No. Typically, and in the response to Staff's First Set of Interrogatories, operating costs--of which fuel is a primary component--are allocated to the classes in a traditional manner; that is, based on "year-round" energy requirements. This is tantamount to assuming that each rate class is served from the same mix of base load and peaking energy. Thus, from an operating cost perspective, each class is allocated a "slice-of-the system."

Because the EP and REP methods differentiate between the capacity mix but not the energy mix required to serve both high and low load factor customers, both fail to appropriately recognize the tradeoffs between capital costs and operating costs. This flaw is often referred to as the "Fuel Symmetry" problem.

**Q IF CUSTOMER CLASSES ARE ASSUMED TO BE SERVED FROM A DIFFERENT CAPACITY MIX, DOES IT ALSO FOLLOW THAT THE ENERGY MIX MUST ALSO BE DIFFERENT?**

A Yes. Appendix C demonstrates that differences in the capacity mix also imply differences in the energy mix. The lowest cost system to serve to Rate PX/PXT class, for example, would consist of 94% base load capacity and 99.8% base load energy. The optimum total Company base load capacity and generation mix would be 71% and 96.1%, respectively.

**Q WHAT IS THE SIGNIFICANCE OF THE DIFFERENCES BETWEEN THE OPTIMUM CAPACITY AND ENERGY MIX TO SERVE THE VARIOUS RATE CLASSES?**

A The significance is that if a lower load factor class is to be assigned below-average production capital costs (expressed on a per kW basis) because of the lower mix of base load capacity required to serve this class, then it should also be assigned above-average production operating costs (expressed on a per kWh basis) to reflect the larger share of peaking energy associated with the greater assignment of peaking capacity. Similarly, if a high load factor class is to be assigned above-average capital costs (because of the larger share of base load capacity required to serve this class) then it follows that this class should also be assigned a below-average operating cost to recognize the relatively larger share of base load energy providing service to this class.

Q **DO EITHER THE EP OR REP METHODS RECOGNIZE THE DIFFERENCES IN THE PER UNIT OPERATING COSTS TO SERVE THE VARIOUS CUSTOMER CLASSES CAUSED BY THE CORRESPONDING DIFFERENCES IN THE GENERATION CAPACITY MIX?**

A No. The EP and REP methods are simply a procedure for allocating production capital costs. Operating costs are allocated on a "slice-of-the system" approach. A "slice-of-the system" approach, however, assumes that all classes are served from the same mix of technologies. In other words, there is no difference between the generation mix to serve high and low load factor customers. Neither method, consequently, is consistent with the stated rationale and philosophy underlying the allocation of production capital costs, the result of which is to assign a different capacity mix to serve high and low load factor customers.

To give an analogy, suppose that two different customers are required to rent a fleet of cars and that there are two types of cars. One type has a high fixed charge per day and gets many miles to the gallon (analogous to a base load plant), while the other type has a low fixed charge per day but gets poor mileage (analogous to a peaking plant). Both the EP and REP methods argue that a customer who drives his/her car only a few miles a day (a low load factor customer) should be allocated more gas-guzzlers and fewer of the more efficient cars, with the opposite type of allocation for the customer that will put in many miles per day (a high load factor customer). While recognizing that the low load factor customer will pay a lower per day charge for his/her car than the higher load factor customer, neither the EP nor the REP methods recognize that the lower load factor customer should also incur a higher fuel cost per mile driven then the higher load factor customer.

Q **IS THERE A SECOND MAJOR CONCEPTUAL FLAW WITH THE EP METHOD?**

A Yes. When a utility determines the type of generating capacity it will install in order to minimize costs, it will examine how many hours the new unit can be expected to run. If the unit is expected to run beyond a certain point, called the break-even point, it is more economical to install base load capacity rather than peaking capacity. In other words, once the break-even threshold is reached, additional energy use (and the fuel cost savings resulting therefrom) would not affect the investment decision.

The conceptual flaw with the EP method, therefore, is the assumption that all hours of the year cause a utility to incur the extra capital costs of installing a base load unit. This is at odds with the planning process. All production from a plant is not the critical factor in deciding which type of capacity to install. Once a plant is expected to run beyond the break-even point, all additional generation is irrelevant to the investment. Therefore, load duration may influence capital investment decisions, but only up to a precisely determined point. It would be an abandonment of the logic underlying the EP method to allocate a major portion of production capital costs to all 8,760 hours per year.

Consider again the analogy with the cars that get different miles per gallon. Suppose that the break-even point were 100 miles; that is, the high mileage car has a lower total cost per mile if operated more than 100 miles. If one customer were to drive the car 200 miles and the second customer were to drive the car 400 miles, both customers would choose the same car--the more efficient one. The EP and REP methods, however, would assign twice as much car to the second customer.

Q **DOESN'T THE SECOND CUSTOMER GET TWICE AS MUCH BENEFIT FROM THE INCREASED FUEL EFFICIENCY AS THE FIRST CUSTOMER?**

A That is true, but an appropriate allocation method should be based on cost-causation, not benefit. Consider for instance, the example of the two rental car customers that I mentioned previously.

Despite the difference in benefits received, both customers would pay the same dollar per day charge.

Q **DOES THE REP METHOD ALSO SUFFER FROM THE SAME LEAP OF LOGIC?**

A No. A critical difference between the EP and REP methods is that, unlike the EP method, the REP method allocates the extra capital costs relative to each class' contribution to only the break-even hours. According to Gulf's response to the Staff Interrogatory No. 2, the break-even point was 1,430 hours.

Q **ARE YOU SAYING THAT THE REP METHOD AS PRESENTED IN THE RESPONSE TO THE STAFF'S INTERROGATORY APPROPRIATELY REFLECTS PRODUCTION SYSTEM PLANNING CRITERIA?**

A No, it is a decided improvement, but there are still several serious conceptual flaws in the REP method as presented in Gulf's response to the Staff Interrogatory.

First, the 12CP method was used to allocate the demand-related capital costs. As I shall demonstrate later, the 12CP method is inappropriate for the Gulf Power system because it sends the wrong price signals to customers. Further, as demonstrated in Exhibit JP-1 (    ), Schedule 1, it is inconsistent with the allocation of the extra (nondemand-related) production capital cost.

Q **PLEASE EXPLAIN THE INCONSISTENCY.**

A Exhibit JP-1 ( ), Schedule 1, is Gulf's total system load duration curve for the test year. The load duration curve is shown by the blue line. Also shown are the highest 1,430 hours (the red-shaded area) and the occurrence of each of the twelve monthly system peak demands (the black squares and vertical lines). During the test year, five of the monthly peaks would occur beyond the 1,430 hour break-even point derived by Gulf. Thus, Schedule 1 clearly demonstrates that demand-related capital costs (which are related to peaking capacity) would be allocated relative to loads occurring beyond the break-even threshold. This is inconsistent with the definition of cost-causation under the REP method because the loads beyond the 1,430 break-even threshold neither cause Gulf to install peaking capacity, nor do they cause the Company to invest in base load generating capacity. It was previously demonstrated, in Appendix C, that the loads up to the break-even point would, at most, affect the type of generating capacity that is most cost-effective in providing service. Further, Gulf could not satisfy its projected 1,743 MW summer peak demand if it only had 1,362 MW (i.e., the average of the twelve monthly peak demands) of installed capacity. The amount of capacity required to maintain reliable service, thus, is a function of the system peak, and not the 12CP, demand.

Q **WHAT IS THE SECOND REMAINING FLAW WITH THE REP METHOD?**

A As I previously testified, the REP method is incomplete because it--like the EP--fails to carry the capital/operating cost tradeoffs through to their logical conclusion. Under the REP method, higher load factor customer classes are allocated above-average capital costs, while lower load factor customer classes are allocated below-average capital costs. This is shown in Exhibit JP-1 ( ), Schedule 2, Columns 1 through 4. However, as also shown in this schedule, in Columns 5 through 8, both high load factor and low load factor customer classes are allocated *average* operating costs. In other words, the REP method "de-averages" the allocation of capital costs (by assigning a larger share of expensive base load capacity to high load factor customers), but it fails to similarly "de-average" the allocation of operating costs (so as to assign to high load factor customers a larger share of the lower fuel costs of that expensive capacity). As demonstrated in Appendix C, the failure to also "de-average" the operating costs is contrary to the Capital Substitution theory on which both the EP and REP methods are founded.

Q **ARE THERE ANY OTHER PROBLEMS WITH THE REP METHOD?**

A Yes. The REP method assumes that a utility relying solely on peaking capacity to serve its peak demands would install the same amount of capacity as a utility that typically employs a mix of base load and peaking capacity to provide continuous service during the peak period. In other words, 1 kW of peaking capacity is assuming to be equivalent to 1 kW of base load capacity.

Q **IS IT REASONABLE TO ASSUME THAT 1 KW OF PEAKING CAPACITY WOULD BE EQUIVALENT TO 1 KW OF BASE LOAD CAPACITY?**

A No. This assumption fails to take into account the reality that there is a wide difference in reliability between base load coal-fired units and those generating technologies that are typically used as peaking capacity.

To illustrate, Exhibit JP-1 ( ), Schedule 3, is a comparison of the forced outage rates between base load coal-fired units and various types of peaking capacity. The data comes from the National Electric Reliability Council's Report entitled "Generation Availability Report." The reliability statistics shown are for the years 1984 through 1988.

Comparing the forced outage rates (FOR), base load coal-fired plants had an average forced outage rate of 6.9%. By contrast, the corresponding FORs for jet engines, gas turbines and diesel were 31.6%, 53.5% and 56.4%, respectively.

Gulf has had even worse experience with its Smith A combustion turbine. In five of the six years, this unit has operated between 1982 and 1989, Smith A had an FOR that exceeded 54%.

Given the substantially higher forced outage rates of peaking technologies, it follows that a utility would have to install considerably more peaking capacity to produce the same level of reliability of a utility system comprised of primarily base load capacity. In other words, there is no equivalence in the equivalent peaker.

Q **IS THE EP METHOD PRONE TO THE SAME PROBLEM?**

A Yes. The EP method also makes the same assumption that 1 kW of peaking capacity is equivalent to 1 kW of base load capacity.

Q **HOW CAN THE EQUIVALENCE BE RESTORED TO THE EP AND REP METHODS?**

A One approach would be to use a loss of load probability (LOLP) analysis to determine the amount of peaking capacity that would be required to provide the same degree of reliability as Gulf's existing system during the peak hours.

A more simplified approach would be to calculate the expected amount of capacity available at the time of the system peak based on the forced outage rate of the various generating technologies.

Q **PLEASE EXPLAIN.**

A Gulf presently has 2,134.5 MW of generating capacity. Assuming that, on average, Gulf's units each had a 6% forced outage rate, then the expected amount of capacity available at the time of the system peak would be 2,006.4 MW [2,134.5 MW x (100% - 6%)].

Now let's assume that all 2,134.5 MW of capacity were replaced by a series of 39.4 MW peaking units having a 50% forced outage rate. Based on this very realistic assumption, each unit could be expected to generate 19.7 MW [39.4 MW x (100% - 50%)] at the time of the system peak. Therefore, to obtain the equivalent amount of capacity as Gulf's existing system, it would have to install nearly 102 peaking units (2,006.4 MW ÷ 19.7 MW), or 4,012.8 MW of peaking capacity. Assuming an average cost of peaking capacity of $162 per kW (which is based on Gulf's response to Staff Interrogatory No. 1), the 4,012.8 MW of equivalent peaking capacity would cost about $650 million. Gulf's actual embedded cost of peaking capacity is $4.2 million. Therefore, the total cost of an equivalent amount of peaking capacity would be $654 million, or about 87% of Gulf's embedded production plant investment. (If Plant Scherer 3 were removed from the analysis, the ratio would be even higher.)

Thus, in this simplified illustration, at least 87%, rather than 45%, of Gulf's production investment should be classified to demand to restore the equivalence to the Equivalent Peaker method.

Q WHAT WOULD BE THE CORRESPONDING RATIO UNDER THE REP METHOD?

A Applying a similar approach to Gulf's response to Staff Interrogatory No. 1, Page 4, would result in classifying 77% of Production Plant to demand (instead of only 40% in the interrogatory response). This result is derived in Exhibit JP-1 ( ), Schedule 4.

## TRANSMISSION COSTING METHODOLOGY

Q SHOULD TRANSMISSION CAPITAL COSTS BE CLASSIFIED TO DEMAND?

A Yes. In order to maintain nearly continuous service, a utility must have sufficient transmission capacity to meet the projected peak demand. Unlike production plant, however, there is no choice between different technologies (i.e., peaking versus base load units, etc.). The cost of a transmission line or substation is not affected by whether it is used to connect a base load plant or a combustion turbine to the system. Similarly, the utility will typically have a significant capital investment in the switchyard facilities and associated protective equipment just to connect the generating station to the transmission grid. The need for these facilities not only is independent of the type of fuel burned in the generating plant, but it is independent of the plant location.

Q **DOES TRANSMISSION PLANT SERVE ANY OTHER FUNCTION BESIDES DELIVERING THE OUTPUT OF THE GENERATING PLANT INTO THE SYSTEM?**

A Yes. There are significant transmission facilities which interconnect Gulf with other utility systems. These interconnections help to improve system reliability by providing alternative transmission paths and by enabling Gulf to call upon the capacity resources of other utilities, either to provide the necessary operating reserves or to replace Gulf-owned generation during periods of scheduled and forced outages.

In summary, classifying transmission capital costs to demand is consistent with the realities of planning and operating a transmission system.

## RECOMMENDED ALLOCATION OF PRODUCTION AND TRANSMISSION CAPITAL COSTS

Q **WHAT CRITERIA SHOULD BE USED TO DETERMINE AN APPROPRIATE DEMAND ALLOCATION METHOD?**

A The specific demand allocation method should reflect the load characteristics of the utility. If, for example, a utility has a high summer peak relative to the demands in other seasons, then the responsibility for production and transmission costs should be based on each customer class's contribution to that system peak (or peaks). If a utility has predominant peaks in both the summer and winter periods, then an appropriate allocation method would be based on the coincident demands during both the summer and winter peaks. For a utility having a relatively high load factor and/or nonseasonal load pattern, either the Twelve Coincident Peak or Average and Excess methods might be more appropriate.

Q **WHICH METHOD WOULD BE THE MOST APPROPRIATE FOR ALLOCATING PRODUCTION AND TRANSMISSION CAPITAL COSTS ON THE GULF SYSTEM?**

A A summer coincident peak method would be appropriate because--consistent with my analysis--it recognizes the predominant summer-peaking characteristic of the Gulf system. It also recognizes that the Southern Company--which is responsible for the joint development and coordination of electric operations, including decisions about scheduled maintenance outages--generally experiences its lowest reserve and capacity margins during the summer (peak) months. Thus, the demands imposed during the summer months determine the amount of capacity which must be installed to enable Gulf to provide nearly continuous service.

Q HAVE YOU ANALYZED GULF'S LOAD CHARACTERISTICS?

A Yes. Gulf is a summer-peaking utility, as shown in Exhibit JP-1 (   ), Schedule 5.

Schedule 5, Page 1, shows the monthly peak demands as a percent of the annual system peak for the years 1984 through 1989. The monthly peaks are shown in blue. The peak months are denoted by the red/blue bars. The annual system peak is shown in red. Except for 1985 and the unusually cold winter of 1989, Gulf has had, and continues to have, a predominant summer peak. The summer peaks typically occur in the months June through September.

Gulf's predominant summer peak is further analyzed on Page 2 of Schedule 5. Page 2 shows the ratio of the annual system peak demand to the minimum monthly and average monthly peak. If the load pattern were nonseasonal, then these ratios would be close to 1.0. For Gulf, however, the maximum-to-minimum monthly peak has ranged from 1.47 to 1.83 times (Column 2). Similarly, the ratio of the maximum-to-average monthly peak has ranged from 1.18 to 1.29 times. Finally, Gulf's annual load factor (Column 4) has remained in the 50%-56% range. The predominant seasonal peak load characteristic coupled with a below-average load factor mean that the Twelve Coincident Peak (12CP) method of allocation--which virtually ignores seasonality--would be especially inappropriate for Gulf.

Q EARLIER, YOU TESTIFIED THAT THE SOUTHERN COMPANY IS RESPONSIBLE FOR THE JOINT DEVELOPMENT AND COORDINATION OF ELECTRIC OPERATIONS, INCLUDING THE DISPATCH OF GULF POWER'S GENERATING UNITS. DO GULF POWER AND THE SOUTHERN COMPANY HAVE SIMILAR LOAD PATTERNS?

A Yes, they do. Exhibit JP-1 ( ), Schedule 6, is an analysis of the Southern Company monthly system peaks as a percent of the annual system peak. This analysis demonstrates that Southern's total system load pattern is also highly seasonal and that the annual system peak always occurs during the summer period. The peak demands during the nonsummer months are generally below 85% of the annual system peak. Further, based on the ratios presented on Page 2 of Schedule 6, it is apparent that the Southern system is even more predominantly summer-peaking than Gulf Power.

Q ARE THE DEMANDS DURING THE NONSUMMER MONTHS ALSO IMPORTANT BECAUSE OF THE NEED TO PERFORM SCHEDULED MAINTENANCE?

A In general, this proposition is not supported by the evidence. Exhibit JP-1 ( ), Schedule 7, is an analysis of the monthly reserve margins of the Southern Company expressed as a percent of peak demand for the years 1984 through 1989. The reserves are shown in two ways: (1) before and (2) after planned and scheduled maintenance outages. The reserve margins before planned and scheduled maintenance outages are represented by the orange and blue bars. The orange portion of each bar denotes the portion of total reserve unavailable because of planned and scheduled maintenance outages.

The blue portion, therefore, represents the reserve margins after removing planned and scheduled maintenance outages.

The overall reserve margins (orange and blue bars) are demonstrably lower during the summer peak months, which are identified by the yellow line. Further, Southern schedules most of the planned and maintenance outages during the nonsummer period. This maximizes the availability of capacity during the more critical summer peak months.

Q **DOES THE FACT THAT THE BLUE BARS, ON OCCASION, ARE SMALLER DURING SELECTED NONSUMMER MONTHS MEAN THAT A SUMMER COINCIDENT PEAK METHOD IS NOT APPROPRIATE?**

A No, it does not. First, Southern has some discretion over the timing of these outages. It should be possible to coordinate planned outages with other Southeastern Electric Reliability Council (SERC) utilities. If a problem occurs, additional capacity could be made available from one of Southern's numerous interconnections. Second, because the SERC is also a summer-peaking system, other utilities are more likely to have surplus capacity during the nonsummer months than during the summer months.

Q **DO FORCED OUTAGES ALSO NEED TO BE TAKEN INTO ACCOUNT IN CONFIRMING THE APPROPRIATENESS OF A SUMMER COINCIDENT PEAK METHOD?**

A No, they do not. Unlike scheduled outages which are planned, forced outages are random events which generally occur when equipment malfunctions. The uncertainties of such outages and of the forecast load, coupled with the obligation to provide service upon demand, are precisely the reason why utilities must construct adequate generating capacity to meet the projected system peak and to provide an adequate reserve margin. Thus, no purpose would be served by measuring the reserve margins net of forced outages.

Q **SPECIFICALLY, WHAT DEMAND ALLOCATION METHOD ARE YOU RECOMMENDING IN THIS DOCKET?**

A I am recommending the "Near-Peak" method to allocate demand-related production and transmission capital costs. Under this method, demand cost responsibility is assigned to each customer class based on an average of the coincident peak demands during those hours when the system is "near" a peak. Thus, unlike the one, two, three and four CP methods, considerably more demand measurements are utilized in developing the allocation factors for each customer class.

Q **HOW ARE THE NEAR-PEAK DEMAND ALLOCATION FACTORS DERIVED?**

A The Near-Peak allocation factors were derived by summing the coincident demands of each customer class during those hours in which the total system demand was within 5% of the annual system peak. This is shown in Exhibit JP-1 (     ), Schedule 8. (The hourly load data was provided in response to Industrial Intervenors' First Request for Production of Documents, Item No. 10.) As shown on Pages 2 and 3 of Schedule 8, there were 71 such occurrences during the test year which included the hours between 1:00 P.M. and 7:00 P.M. By contrast, the monthly peak demands (within 5% of the annual system peak) occurred at 5:00 P.M. By providing 71 measurements over a two-month period, the Near-Peak method covers a broader spectrum of hours than the other summer CP methods. This provides a more representative measurement of the coincident demands of the various classes during those hours when the system is in a "peaking mode." Further, because the allocation factors are not sensitive to the absolute timing of the monthly system peaks, the Near-Peak method would produce more stable results over time than would the other summer CP methods. Thus, it overcomes one of the frequent criticisms associated with peak responsibility allocation methods.

Q **WHAT IS THE BASIS FOR USING 5% AS THE THRESHOLD FOR DETERMINING WHEN THE SYSTEM IS NEAR THE PEAK?**

A It provides a more representative sample. Further, this is the period when system reliability is usually the most critical.

Q **ONE CRITICISM OF THE COINCIDENT PEAK METHOD IS THAT IT CREATES A "FREE RIDE" FOR OFF-PEAK LOADS, SUCH AS STREET LIGHTING. IS THIS A VALID REASON FOR REJECTING THIS METHOD?**

A No, it is not. Because costs are usually allocated to customer classes (and not to individual loads), it is unlikely that a CP method of allocation would create a free ride for any major firm customer class. Seldom is a class completely "on" during the off-peak hours and completely "off" during the on-peak hours. The only obvious exception would be the lighting classes. However, this is a small exception and, therefore, it should not control the selection of an appropriate demand cost allocation method to be applied to the remaining (and much larger) customer classes.

In summary, the Near-Peak method appropriately reflects cost-causation for Gulf, and it should be used to allocate both production and transmission capital costs.

Q **SHOULD THE NEAR-PEAK METHOD BE APPLIED TO ALL PRODUCTION AND TRANSMISSION CAPITAL COSTS?**

A Yes. Unless an explicit fuel symmetry adjustment were made to recognize the different energy mix implicit in classifying a portion of production capital cost to energy, my recommendation would be to use the near peak method to allocate all production and transmission capital costs. Further, my recommendation is consistent with the Commission's Fuel Adjustment mechanism in which each class pays the same average fuel cost. This procedure (i.e., classifying all production capital costs to demand and recovering average fuel costs) effectively assigns an identical mix of generation capacity and energy to each rate class. In essence, each class gets a "slice-of-the system" with respect to both capital and operating costs.

## CRITIQUE OF THE 12CP METHOD

Q ARE THERE ANY OTHER PROBLEMS WITH USING THE 12CP METHOD TO ALLOCATE PRODUCTION DEMAND-RELATED CAPITAL COSTS?

A Yes, there are. Besides failing to adequately recognize the seasonal load characteristics of the Gulf Power and Southern Company systems and the fact that Southern schedules most of its outages during the nonsummer period, the 12CP method is relatively insensitive to seasonal load shifts. As a result, the 12CP method could send the wrong price signal. To illustrate, Exhibit JP-1 (     ), Schedule 9 is an illustration showing the impact of shifting load on the allocation factors derived under the 12CP method. For simplicity, it is assumed that the utility consists of two classes--Class "A" and Class "B". Both the utility and Class "A" are assumed to be summer-peaking. Class "B", by comparison, is assumed to have a constant demand throughout the year. Under the base case, the 12CP method would assign about 89% and 11% of capital costs to Class "A" and to Class "B", respectively.

Now let's assume that Class "B" shifts 10% (15 MW) of load from April to August. As a consequence, the utility becomes even more predominantly summer-peaking and may require additional capacity in order to maintain nearly continuous service. Despite the fact that Class "B" may be causing the need for additional capacity, the 12CP method allocates the same percentage of capital costs after the load shift as was allocated, under the base case, prior to the load shift. If the utility subsequently incurs higher capital costs, then these higher capital costs will be allocated, under the 12CP method, to both Class "A" and to Class "B" even though Class "B" caused the utility to incur these higher costs. This is further proof that the 12CP method is inappropriate for allocating demand-related capital costs, particularly for a utility system, like Gulf, which has a highly seasonal load pattern.

Q **WOULD THE USE OF THE 12CP METHOD BE JUSTIFIED BY THE FACT THAT THE CAPACITY EQUALIZATION CHARGES (OR CREDITS) UNDER THE INTERCOMPANY INTERCHANGE CONTRACT (IIC) ARE A FUNCTION OF THE MONTHLY PEAK DEMANDS OF THE FIVE SOUTHERN OPERATING COMPANIES, INCLUDING GULF?**

A No. First, it should be noted that the IIC is regulated by the Federal Energy Regulatory Commission (FERC). It would be inappropriate for the FERC (which regulates only a small portion of Gulf's operations) to dictate the manner in which production demand-related capital costs should be allocated among the retail customers classes subject to this Commission's jurisdiction.

Second, one of the main purposes of the IIC is to equalize <u>reserve</u> generating capacity among the five operating companies. By equalizing the reserves, the IIC maximizes the benefits derived from the joint planning and ownership of generating capacity.

Finally, it should be noted that the FERC does not allocate costs to "end-use" customer classes, as is the case with Gulf's class cost-of-service study in this Docket. Rather, the FERC uses a cost allocation method to provide a jurisdictional separation between retail and wholesale markets. Because the wholesale class typically consists of a mix of end-use customer groups, the results are usually much less sensitive to changes in the allocation method.

## CLASSIFICATION AND ALLOCATION OF DISTRIBUTION CAPITAL COSTS

Q **HOW SHOULD DISTRIBUTION CAPITAL COSTS BE CLASSIFIED?**

A Distribution capital costs can be either demand-related and/or customer-related.

The primary purpose of the distribution system is to deliver power from the transmission grid to the customer, where it is eventually consumed. Certain investments (e.g., meters, service drops) must be made just to attach a customer to the system. These investments are customer-related. The remaining distribution investment is incurred to ensure that there is sufficient capacity to meet customer demands when they arise. This investment is demand-related.

Q **ARE CERTAIN DISTRIBUTION INVESTMENTS, OTHER THAN THE METER AND SERVICE DROP, ALSO CUSTOMER-RELATED?**

A Yes. A portion of the primary and secondary distribution network--poles, towers, fixtures, overhead lines, line transformers--is also customer-related. Classifying a portion of the distribution network as customer-related recognizes the reality that every utility must provide a path through which electricity can be delivered to each and every customer regardless of the peak demand or energy consumed. Further, that path must be in place if the utility is to meet its obligation to provide service upon demand.

If Gulf were to provide only a minimum amount of electric power to each customer, it would still have to construct nearly the same miles of line as is currently required to serve every customer. The poles, conductors and transformers would not need to be as large as they are now if every customer were supplied only a minimum level of service, but there is a definite limit to the size to which they could be reduced.

Q **HOW SHOULD THE CUSTOMER-RELATED PORTION OF THIS INVESTMENT BE DETERMINED?**

A This requires an engineering analysis. The customer-related portion is representative of the investment required simply to attach customers to the system, irrespective of their demand and energy requirements. Consider the diagram in Appendix B, Page 9. This shows the distribution network for a utility with two customer classes, A and B. The physical distribution network necessary to attach Class A, a residential subdivision for example, is designed to serve the same load as the distribution feeder serving Class B, a large shopping center or small factory. Clearly, a much more extensive distribution system is required to attach a multitude of small customers than to attach a single larger customer, even though the total demand of each customer class is the same.

Q **IS IT COMMON PRACTICE TO CLASSIFY A PORTION OF THE DISTRIBUTION NETWORK AS CUSTOMER-RELATED?**

A Yes. Exhibit JP-1 ( ), Schedule 10, demonstrates that this practice is widely recognized in the utility industry.

Page 1, for example, is an excerpt from the NARUC Cost Allocation manual, which shows the appropriateness of classifying a portion of the distribution network (i.e., Account Nos. 364 through 368) as customer-related.

Pages 2 through 4 are an excerpt from a survey conducted by Duke Power Company to evaluate the distribution costing practices used in the electric utility industry. This survey, which was based on responses received from 87 utilities, concluded that:

> "The accounts (364, 365, 366, 367, 368) which represent conductors and transformers investment are split approximately 70% demand and 30% customer. The remaining accounts (369, 370, 371, 373) are primarily customer-related."

Q **HAS GULF CLASSIFIED ANY DISTRIBUTION CAPITAL COSTS, OTHER THAN THE METER AND SERVICE DROP, AS CUSTOMER-RELATED?**

A Yes. Only 16.4% of Account 365 (overhead conductors) was classified as customer-related. Although Gulf's witness, Mr. O'Sheasy, agrees that some portion of other distribution capital costs are also customer-related, he has classified them to demand to reduce the controversy surrounding the various cost allocation/rate design issues (Testimony at Pages 21 and 22). While I concur with Mr.

O'Sheasy that revenue sensitive issues are important, I do not agree with his recommendation to limit the discussion of controversial cost-of-service allocation methodologies. This Commission has not seriously considered cost allocation methodologies since the Tampa Electric rate case, in 1985. If the highly controversial EP method is to be addressed in this Docket, then the classification of distribution capital costs should also be revisited.

Q DO YOU HAVE A SPECIFIC RECOMMENDATION TO OFFER AT THIS TIME?

A Yes. The Commission should instruct Gulf to conduct a study examining alternative methods of classifying distribution capital costs. The two most frequently used methods are the minimize size distribution system and the zero intercept method. A third alternative would be to quantify the labor component of primary and secondary distribution investment. The labor-related portion of the installed cost would be a conservative proxy for that portion of the investment in distribution plant which would have to be made just to connect customers to the system, irrespective of actual demand and energy consumption. The analysis should be conducted by FERC account for each method. A copy of the study should be filed with the Commission and distributed to all parties prior to Gulf's next general rate case. This should provide the Commission and all parties an objective basis for evaluating the merits of each method.

## REVISED COST-OF-SERVICE STUDIES

**Q HAVE YOU REVISED THE CLASS COST-OF-SERVICE STUDIES TO REFLECT YOUR VARIOUS COST ALLOCATION RECOMMENDATIONS?**

A Yes, I have. Exhibit JP-1 ( ), Schedule 11, is a summary of the class cost-of-service study based on the Near-Peak method, which I am recommending, rather than Gulf's proposed 12CP method. Specifically, I have revised the Level 1, 2 and 3 retail demand allocation factors by substituting the near-peak demands shown in Schedule 8 for the 12CP demands used by Gulf. All production and transmission capital costs were classified to demand. In all other respects, the revised cost-of-service study is identical to the Company's.

**Q WOULD YOU PLEASE SUMMARIZE THE RESULTS OF YOUR RECOMMENDED CLASS COST-OF-SERVICE STUDY?**

A Yes. The results at present rates, based on Gulf's claimed revenue requirement, are as follows:

**Summary of Cost-of-Service Study Results at Present Rates Near-Peak Method**

| Line | Rate Class | Rate of Return (1) | Relative Rate of Return (2) | Interclass Subsidy* (Millions) (3) |
|---|---|---|---|---|
| 1 | RS/RST | 5.95% | 90 | $(5.4) |
| 2 | GS/GST | 12.21 | 185 | 3.5 |
| 3 | GSD/GSDT | 6.49 | 98 | (0.3) |
| 4 | LP/LPT | 5.93 | 90 | (1.3) |
| 5 | PX/PXT | 9.95 | 151 | 2.7 |
| 6 | OS I & II | 8.50 | 129 | 0.4 |
| 7 | OS III | 25.29 | 383 | 0.2 |
| 8 | SS | 11.07 | 168 | 0.2 |

*A negative subsidy means that a class is being subsidized.

A positive subsidy means that a class is providing a subsidy.

Under the Near Peak method, the residential class rate of return is 26 basis points higher than in Gulf's 12CP & 1/13th Aug cost-of-service study.

Q **WOULD YOU PLEASE EXPLAIN THE TERMS "RATE OF RETURN," "RELATIVE RATE OF RETURN" AND "SUBSIDY?"**

A Rate of return is the ratio of: (1) operating income (i.e., operating revenues less allocated operating expenses and (2) allocated rate base (i.e., net plant in service, working capital, etc.). If a class is providing revenues sufficient to recover its cost of service, it will have a rate of return equal to the total Gulf return.

The relative rate of return (RROR) is the ratio of the class rate of return to the total Gulf rate of return. An RROR above 100 means that a class is providing a rate of return higher than the system average, while an RROR below 100 indicates that a class is providing a below-system average rate of return.

The subsidy measures the difference between the revenues required from each class and the revenues actually recovered. A negative amount indicates that a class is being subsidized each year (i.e., revenues are below cost), while a positive amount indicates that a class is providing a subsidy each year (i.e., revenues are above cost).

Q **EARLIER, YOU TESTIFIED THAT THE REP METHOD, WHICH GULF RERAN IN RESPONSE TO COMMISSION STAFF INTERROGATORY NO. 2, WAS FLAWED BECAUSE THE 12CP METHOD WAS USED TO ALLOCATE DEMAND-RELATED CAPITAL COSTS AND BECAUSE THE STUDY FAILED TO RECOGNIZE FUEL SYMMETRY. IS THAT CORRECT?**

A Yes.

Q **CAN YOU ILLUSTRATE HOW THE REP COST STUDY COULD BE CORRECTED TO TAKE INTO ACCOUNT YOUR TWO CRITICISMS?**

A Yes. First, 77% of production capital costs should be classified to demand, consistent with the much lower FOR's of peaking capacity.

Second, all production and transmission demand-related costs should be allocated using the Near-Peak method. Third, an explicit fuel symmetry adjustment should be made to appropriately recognize the production capital/operating cost tradeoffs on which both the EP and REP methods are founded.

Q HOW SHOULD THE FUEL SYMMETRY ADJUSTMENT BE MADE?

A The recommended fuel symmetry adjustment is derived in Exhibit JP-1 (    ), Schedule 12, Column 4. The specific adjustment should be made to the energy-related O&M expenses remaining after recoverable fuel and purchased costs have been removed. For example, the residential class energy-related O&M expenses should be increased by $865,000, while the Rate LP/LPT class O&M expenses should be decreased by $490,000.

Q HOW WAS THE FUEL SYMMETRY ADJUSTMENT DERIVED?

A As shown on Page 1 of Schedule 12, the fuel symmetry adjustment is the difference between the percent of total operating costs (Column 1) and Gulf's energy allocation factor (Column 2) multiplied by $168.3 million. The latter represents the costs recoverable under the Fuel and Purchased Power Cost Adjustment Clause for the test year which were removed from the analysis.

Q HOW WAS THE PERCENT OF TOTAL OPERATING COSTS DETERMINED FOR EACH RATE CLASS?

A This determination is shown on Page 2 of Schedule 12. The percent of total operating costs (Column 6) is derived by first summing the allocated peak and base period operating costs (i.e., Column 2 + Column 4) and expressing the result (Column 5) as a percent of total retail, excluding Rate SS. The allocated peak period operating costs shown in Column 2 are the product of Total Company peak period operating costs (Line 8) and the percentage of peak period loads contributed by each rate class (Column 1). Similarly, the allocated base period operating cost (Column 4) is the product of Total Company base period operating costs (Line 8) and the percentage of loads contributed by each rate class during the base period (Column 3).

Q **HOW WERE THE TOTAL COMPANY PEAK AND BASE PERIOD OPERATING COSTS DERIVED?**

A This is shown on Page 3 of Schedule 12. Column 1 shows the energy generated from peaking and base load capacity segregated between the peak period and base period.

The peak period energy was derived from an analysis of Gulf's system load shape (Appendix C, Schedule C-1) adjusted for the test year. Specifically, the total peak period energy requirement is the cumulative load during the first 1,430 hours, or 2,087.8 GWh. (Recall that 1,430 hours was derived by Gulf in response to Staff Interrogatory No. 2, and it represents the break-even threshold between peaking and base load technologies.) The base period energy consists of all of the remaining load beyond the 1,430-hour break-even threshold.

Referring to Appendix C, Schedule C-1, the load at 1,430 hours is approximately 71% of the projected system peak, or 1,229 MW, as shown in Schedule C-3. As explained in Appendix C, 1,229 MW is the amount of base load capacity consistent with providing electricity at the lowest total cost. The remaining 514 of Gulf's peak period load would be economically served from peaking capacity.

Peak period energy, thus, is generated from both peaking and base load capacity. The energy generated from base load capacity would be the product of the amount of base load capacity, 1,229 MW, and 1,430 hours, or 1,757.5 GWh. The remaining 330.3 GWh of peak period energy would be generated from peaking capacity. All of the base load energy would be generated from base load capacity.

The operating cost assigned to each time period are derived in Column 3. Column 3 is the product of Column 1 (generation by capacity type) and Column 2 (per unit operating cost by capacity type). (The per unit operating costs by capacity type were derived by Gulf Power in response to Staff Interrogatory No. 1, Pages 5 and 6.)

Q **ARE THE PEAK AND BASE PERIOD ALLOCATION FACTORS DERIVED?**

A They were derived from an analysis of the rate class hourly loads during the peak period. The results of this analysis are shown in Schedule 12, Page 4, Column 1. The peak period allocation factor (Column 2) is the peak period energy (Column 1) expressed as a percentage of Total Company peak period energy use.

Base period energy use (Column 4) is the difference between annual energy use (Column 3) and peak period energy use (Column 1). The corresponding base period allocation factors, thus, are derived by expressing the base period energy use (Column 4) as a percentage of Total Company base period energy use.

Q **WHY WAS RATE SS EXCLUDED FROM THE FUEL SYMMETRY ANALYSIS?**

A Rate SS is not a typical cost-of-service class and there is not sufficient representative hourly data to determine the Rate SS peak period demands.

Q **WHY IS RATE SS NOT A TYPICAL COST-OF-SERVICE CLASS?**

A Unlike the other classes, the Rate SS class coincident demands are based on the expectation that 10% of the Standby Service Contract Capacity will occur during peak hours. This assumption was based on the Commission's Order in Docket No. 850673-EU--Generic Investigation of Standby Rates for Electric Utilities. The Rate SS class' coincident demands for the test year are projected to be much lower than 10% of the Standby Service Contract Capacity. In some years, however, the Rate SS coincident demands may exceed 10% of the expected Standby Service Contract Capacity. Therefore, as Mr. O'Sheasy testifies, it is appropriate to use the expected Rate SS class loads to provide a more stable cost allocation from one rate case to the next. (Later in my testimony, I shall comment on the reasonableness of the 10% assumption.)

Q **HAVE YOU RERUN THE COST-OF-SERVICE STUDY BASED ON A CORRECTED VERSION OF THE REFINED EQUIVALENT PEAKER METHOD?**

A Yes. The revised study is shown in Exhibit JP-1 (     ), Schedule 13. This study incorporates the same two corrections identified previously. The results can be summarized as follows:

**Summary of Cost-of-Service Study Results at Present Rates**
**Corrected Refined Equivalent Peaker Method**

| Line | Rate Class | Rate of Return (1) | Relative Rate of Return (2) | Interclass Subsidy* (Millions) (3) |
|---|---|---|---|---|
| 1 | RS/RST | 5.90% | 89 | $(5.7) |
| 2 | GS/GST | 12.30 | 186 | 3.5 |
| 3 | GSD/GSDT | 6.43 | 97 | (0.5) |
| 4 | LP/LPT | 6.27 | 95 | (0.6) |
| 5 | PX/PXT | 9.52 | 144 | 2.5 |
| 6 | OS I & II | 8.60 | 130 | 0.4 |
| 7 | OS III | 25.76 | 390 | 0.2 |
| 8 | SS | 12.31 | 187 | 0.2 |

*A negative subsidy means that a class is being subsidized.

A positive subsidy means that a class is providing a subsidy.

Q **ARE THE CORRECTED REP COST STUDY RESULTS MATERIALLY DIFFERENT FROM THE RESULTS OF THE NEAR-PEAK COST-OF-SERVICE STUDY?**

A No. Actually, with the exception of Rate SS, the results are quite similar, as shown below:

**Summary of Cost-of-Service Study Results at Present Rates Between the Near Peak Method and the Corrected Refined Equivalent Peaker Method**

| Rate Class | Rate of Return | | Relative Rate of Return | |
|---|---|---|---|---|
| | Near Peak (1) | Corrected REP (2) | Near Peak (3) | Corrected REP (4) |
| RS/RST | 5.95% | 5.90% | 90 | 89 |
| GS/GST | 12.21 | 12.30 | 185 | 186 |
| GSD/GSDT | 6.49 | 6.43 | 98 | 97 |
| LP/LPT | 5.93 | 6.27 | 90 | 95 |
| PX/PXT | 9.95 | 9.52 | 151 | 144 |
| OS I & II | 8.50 | 8.60 | 129 | 130 |
| OS III | 25.29 | 25.76 | 383 | 390 |
| SS | 11.07 | 12.31 | 168 | 187 |

In both instances, the residential class rate of return is higher than under Gulf's proposed cost-of-service study.

## RATE SPREAD ISSUES

Q **IF THE COMMISSION APPROVES A PERMANENT BASE RATE INCREASE FOR GULF, WHAT FACTORS SHOULD BE CONSIDERED IN DETERMINING AN EQUITABLE SPREAD OF THAT INCREASE?**

A Although other factors may be considered, such as gradualism, rate continuity, ease of administration, customer acceptance and simplicity, primary emphasis should be placed on the cost of providing service to determine the revenue requirements from each class and from each customer within a class. The basic reasons for adhering to the cost-of-service principle throughout the rate spread and rate design phases are *equity*, *engineering efficiency* (cost-minimization), *stability* and *conservation*.

Rates which reflect primarily cost-of-service considerations are *equitable* because each customer pays what it costs the utility to serve him, no more and no less. If rates are not based on costs, then some customers must pay part of the costs of providing service to other customers, which is inequitable.

With respect to *engineering efficiency*, when rates are designed so that demand and energy charges are properly reflected in the rate structure, the utility has an incentive to construct the most economical mix of plants, and customers are provided with the proper incentive to minimize their costs, which will in turn minimize the costs to the utility.

When rates are closely tied to cost, the utility's *earnings are stabilized* because changes in customer use patterns would result in parallel changes in revenues and expenses. Cost-based rates also provide a more stable basis for determining future levels of power costs. If rates are based, instead, on vague social policies, it becomes much more difficult to translate expected utility-wide cost changes into changes in the rates charged to particular customer classes. This added element of uncertainty will lessen the attractiveness of industrial expansion either by new or existing industries. To the extent that rates do not reflect costs, multi-plant firms will be encouraged to shift production from high energy cost plants to lower energy cost plants in order to remain competitive. Such a shifting of production would reduce employment and the overall contribution of the manufacturing concern to the state and local economy. This would, in turn, be self-defeating to the presumed beneficiaries of below-cost electric rates.

Finally, by providing balanced price signals against which to make consumption decisions, cost-based rates encourage *conservation* (of both capacity and energy), which is properly defined as the avoidance of wasteful or inefficient use (and not just less use). If rates are not based on costs, then the choices are distorted.

Q **HOW IS GULF PROPOSING TO SPREAD THE INCREASE AMONG THE RATE CLASSES?**

A Gulf's proposed base revenue distribution, as modified by the new class cost-of-service study, is shown in Exhibit JP-1 (   ), Schedule 14. Specifically, Gulf is proposing an above-average percent increase to the residential, Rate LP/LPT and Rate SS classes, while the remaining classes would either receive below-average increases, no increase or a rate decrease.

Q **IS GULF'S PROPOSED BASE REVENUE DISTRIBUTION CONSISTENT WITH THE OBJECTIVE OF MOVING RATES CLOSER TO COST?**

A Yes. However, this conclusion is based on Gulf's flawed class cost-of-service study.

Q **WOULD GULF'S PROPOSED BASE REVENUE DISTRIBUTION REDUCE THE INTERCLASS SUBSIDIES OF ALL RATE CLASSES BASED ON YOUR RECOMMENDED COST-OF-SERVICE STUDY?**

A No, not in all cases, as shown in Exhibit JP-1 (   ), Schedule 15, and in the chart below:

**Summary of Interclass Subsidies at Present and Proposed Rates Near-Peak Method (Millions)**

| Rate Class | Present Rates (1) | Proposed Rates (2) | Movement Toward Cost (3) |
|---|---|---|---|
| RS/RST | $(5.4) | $(2.1) | 60% |
| GS/GST | 3.5 | 2.4 | 31% |
| GSD/GSDT | (0.3) | (1.3) | No |
| LP/LPT | (1.3) | (0.9) | 30% |
| PX/PXT | 2.7 | 1.3 | 54% |
| OS I & II | 0.4 | 0.2 | 52% |
| OS III | 0.2 | 0.1 | 42% |
| SS | 0.2 | 0.3 | No |

Specifically, the Rate GSD/GSDT and Rate SS subsidies would increase.

Q **IF THE COMMISSION WERE TO AWARD GULF A PERMANENT BASE REVENUE INCREASE, HOW SHOULD THAT INCREASE BE SPREAD AMONG THE CLASSES?**

A My recommendation, which is based on Gulf's claimed revenue deficiency, is presented in Exhibit JP-1 (    ), Schedule 16. It is based on the results of the Near-Peak cost-of-service study (Schedule 11).

Q **WHAT IS THE BASIS FOR YOUR RECOMMENDED REVENUE DISTRIBUTION SHOWN IN SCHEDULE 16?**

A The objective was to move all rate classes about half the way closer to cost of service by reducing the interclass subsidies at present rates by about 50%. This result is illustrated in Exhibit JP-1

(     ), Schedule 17. In most instances, the interclass subsidies under the recommended allocation (Column 6) would be about 50% lower than the corresponding subsidies at present rates (Column 5). An exception was to Rate SS which would recover no increase under my recommendation. The subsidy provided by the Rate SS class would be 30% smaller.

Q **UNDER YOUR RECOMMENDATION, CERTAIN RATE CLASSES WOULD RECEIVE SIGNIFICANTLY BELOW-AVERAGE INCREASES, WHILE OTHERS WOULD RECEIVE RATE DECREASES. MIGHT THIS SEND THE WRONG PRICE SIGNALS TO THESE CUSTOMERS?**

A No, I do not believe so. The reason for the significantly below-average increases and the rate decreases for certain rate classes is the fact that their respective rates of return are significantly above the system average. Given the significant disparity between the revenue/cost relationships of certain rate classes, the only way to move them meaningfully closer to cost in this Docket would be to assign either below-average percent increases or a rate decrease. I must emphasize, however, that moving only one-half of the way to cost, as per my recommendation, is only a very modest step in the right direction.

Q **WOULD YOUR RECOMMENDATION DIFFER IF IT HAD BEEN BASED ON THE CORRECTED REP METHOD?**

A No. Because of the similarity of the results between the Near-Peak and Corrected REP studies, my recommendation would not be materially different if the latter method were adopted.

Q **IF THE COMMISSION WERE TO AWARD GULF A SMALLER BASE REVENUE INCREASE THAN IT IS PROPOSING, HOW SHOULD THAT LOWER INCREASE BE ALLOCATED AMONG THE RATE CLASSES?**

A My recommendation would be to apply the same approach--that is, to reduce the subsidies of all rate classes by at least one-half based on the results of an approved cost-of-service study. The latter would take into account all of the Commission-approved adjustments to Gulf's proposed rate base, revenues and operating expenses, and it would be based on the approved cost allocation methodology. This process, by definition, warrants thorough review by the Commission, the Staff and all parties to the case.

## RATE DESIGN ISSUES

Q WHAT RATE DESIGN ISSUES ARE YOU ADDRESSING?

A I shall address the design of Rate Schedules PX/PXT and SS.

### RATE PX/PXT

Q WHAT CHANGES ARE BEING PROPOSED FOR RATE SCHEDULE PX?

A Gulf is proposing to decrease the customer charge, increase the demand charge and reduce the energy charge.

Q DO YOU AGREE WITH GULF'S PROPOSED CHANGES IN THE DEMAND AND ENERGY CHARGES?

A Yes. The proposed reduction in the Rate PX energy charge, from $5.21 to $4.45/MWh, is consistent with the results of the unit cost study, which shows that the average nonfuel variable costs are about $1.9/MWh. (The nonfuel energy unit cost, which also includes some fixed costs, is $3.27/MWh under Gulf's revised class cost-of-service study.) Even with the proposed $0.76/MWh reduction, the proposed Rate PX energy charge would continue to be above cost. The Company's proposal recognizes gradualism, and it should, therefore, be adopted.

Q DO YOU HAVE ANY COMMENTS WITH RESPECT TO THE PROPOSED ON AND OFF-PEAK ENERGY CHARGES IN RATE PXT?

A Gulf is proposing to decrease the on-peak energy charge and to increase the off-peak charge. On balance, however, the revenues collected through the energy charge would be lower. This is consistent with the unit cost study results. Further, I would note that there is no significant difference in the correlation coefficients between PX customers' contributions to the twelve monthly coincident peak demands and either billing demand or on-peak kWh to support the retention of a high on-peak energy charge. (I am not suggesting that the correlation coefficient analysis is even relevant to the issue of determining an appropriate rate design.)

Q **WHAT OTHER CHANGES IS GULF PROPOSING FOR RATE PX?**

A Gulf is also proposing to change the Minimum Monthly Bill. Under its revised proposal, the Minimum Monthly Bill:

> "Shall not be less than the Customer Charge plus:
>
> (a) Highest demand for the current month or previous eleven or
>
> (b) The contract capacity whichever is greater or
>
> $10.686 per kW of Billing Demand and the Local Facilities Charge, if applicable." (As Gulf's response to Staff's Third Set of Interrogatories, Item No. 48.)

The proposed $10.686 minimum bill is equivalent to the demand and energy charge at a 75% <u>monthly</u> load factor.

Q **HOW WOULD THE PROPOSED MINIMUM MONTHLY BILL REQUIRE RATE PX CUSTOMERS TO OPERATE AT LEAST A 75% MONTHLY LOAD FACTOR?**

A The proposed $10.686 per kW charge is equivalent to the proposed $8.25 per kW demand charge and the proposed 0.445¢ per kWh energy charge at a 75% load factor, as illustrated below:

**Rate PX Minimum Monthly Bill**

| Line | Description | Amount |
|---|---|---|
| 1 | Total | $10.686 |
| 2 | Demand Charge | 8.250 |
| 3 | Minimum Energy Charge | $ 2.436 |
| 4 | Proposed Energy Charge | 0.445¢ |
| 5 | Minimum Hours' Use (Line 3 ÷ Line 4 x 100) | 547 |
| 6 | Minimum Monthly Load Factor (Line 5 ÷ 730) | 75% |

Q **IS GULF'S PROPOSED $10.686 PER KW MINIMUM CHARGE APPROPRIATE?**

A No. As written, the proposed Minimum Monthly Bill would penalize a PX customer for operating below a 75% minimum monthly load factor even if the customer's annual load factor exceeded 75%.

Q **HOW IS THE ANNUAL LOAD FACTOR RELEVANT?**

A The Applicability criterion in both the present and proposed PX/PXT rates states:

> "Applicable for three-phase lighting and power service to any customer contracting for not less than 7,500 kilowatts (kW), with *an annual load factor* of not less than seventy-five percent (75%)." Haskins, Schedule No. 3, Page 11. (Emphasis added)

A PX/PXT customer, thus, could still qualify for the rate even though the monthly load factor may be below 75% load factor in a particular month. The Commission, therefore, should reject the way in which this portion of the proposed Monthly Minimum Bill is written.

Q **DOES THE PROPOSED RATE PXT ALSO INCLUDE A SIMILAR MINIMUM MONTHLY BILL PROVISION?**

A Yes. The proposed Rate PXT Minimum Monthly Bill would be $10.648 per kW of Maximum Billing Demand, according to Gulf's Response to Staff's Eighth Set of Interrogatories, Item No. 124. The $10.648 per kW charge is also based on the assumption that a PXT customer should operate at a 75% monthly load factor.

Q **HOW SHOULD THE 75% ANNUAL LOAD FACTOR REQUIREMENT OF RATES PX AND PXT BE ENFORCED?**

A Consistent with the Applicability paragraph, Rate PX/PXT customers should be subject to a minimum annual billing demand charge.

For example, using Gulf's proposed Rate PX demand and energy charges of $8.25/kW and 0.445¢/kWh, respectively, a minimum annual billing demand charge would be $128.24 per kW ($10.686 x 12). The minimum annual bill, thus, would be $128.24 per kW times the highest billing demand occurring in the current or previous 11 billing months. This would provide a true-up in the event that a customer's annual load factor were to fall below the 75% minimum required.

Q SHOULD THE RATE PXT MINIMUM ANNUAL BILLING DEMAND CHARGE BE SIMILARLY CALCULATED?

A Yes. However, consistent with encouraging customers to minimize on-peak demands, the minimum should be based on the maximum on-peak demand during the current and previous 11 months, rather than the maximum demand, in either on or off-peak hours, as Gulf is proposing.

**RATE SS**

Q HAVE YOU REVIEWED GULF'S PROPOSED STANDBY SERVICE RATE (RATE SS)?

A Yes.

Q MR. HASKINS, TESTIFYING FOR GULF POWER COMPANY, STATES (ON PAGE 22) THAT "STANDBY RATE ORDER 17159 IS VERY SPECIFIC ABOUT THE DESIGN OF EACH RATE COMPONENT OF THE STANDBY SERVICE RATE." ARE YOU FAMILIAR WITH ORDER NO. 17159?

A Yes.

Q DOES GULF'S PROPOSED RATE SS COMPLY WITH THAT ORDER?

A No. In my opinion, neither the proposed $1.08 per kW reservation charge nor the 0.344¢/kWh energy charge fully comply with the provisions of that Order.

Q PLEASE EXPLAIN.

A Pages 12 through 15 of Order No. 17159 describe the parameters that were to be used to design an <u>initial</u> standby rate for purposes of the Commission's Generic Investigation. The design of present Rate SS, for example, was based on the full demand-related production and transmission unit cost per coincident peak kilowatt of demand and the energy-related production unit cost per kilowatthour based on the cost-of-service study used for rate-making purposes in Gulf's last general rate case.

**Q WHY WAS A "SYSTEM AVERAGE" COSTING APPROACH USED IN DOCKET NO. 850673-EU TO DESIGN RATE SS?**

A This "system average" costing approach was necessary because the standby service customers were not treated as a separate class in Gulf's last rate case.

**Q DOES THIS MEAN THAT THE SAME APPROACH MUST BE USED FOR DETERMINING THE RESERVATION AND ENERGY CHARGES IN A GENERAL RATE CASE?**

A No. In fact, the Commission was very specific in ordering each utility to treat standby customers as a separate customer class and be assigned costs consistent with the appropriate data in the new cost-of-service study, in each utility's next rate case.

**Q HAS GULF TREATED RATE SS CUSTOMERS AS A SEPARATE CUSTOMER CLASS IN ITS COST-OF-SERVICE STUDY?**

A Yes.

Q SHOULD THE RATE PXT MINIMUM ANNUAL BILLING DEMAND CHARGE BE SIMILARLY CALCULATED?

A Yes. However, consistent with encouraging customers to minimize on-peak demands, the minimum should be based on the maximum on-peak demand during the current and previous 11 months, rather than the maximum demand, in either on or off-peak hours, as Gulf is proposing.

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Q **HAS GULF TREATED RATE SS CUSTOMERS AS A SEPARATE CUSTOMER CLASS IN ITS COST-OF-SERVICE STUDY?**

A Yes.

Q **WERE THE RESERVATION AND ENERGY CHARGES DERIVED FROM THE COSTS ALLOCATED TO THE RATE SS CLASS?**

A No. As explained earlier, Gulf used "system-average" costing. This is also evident from the fact that Gulf is proposing a 17.1% base rate increase to Rate SS--which is 1.6 times the system average--even though this class is already providing a substantially above-average rate of return at present rates. Consequently, the Rate SS class would move farther from cost, in violation of this Commission's long-standing practice of moving all rate classes closer to cost of service.

Q **HOW SHOULD THE RATE SS RESERVATION AND NONFUEL ENERGY CHARGES BE SET?**

A The nonfuel energy charges in Rate SS should be identical to the corresponding nonfuel energy charges in the otherwise applicable full requirements tariff. Rate SS customers who are also taking supplementary power on Rate PXT, for example, should pay the Rate PXT nonfuel energy charges.

This approach is necessary because not all of the Rate SS customers take standby service at the same delivery voltage, nor do all of these customers purchase supplementary power on the same rate schedule.

The remaining nonfuel revenue requirement--not otherwise recovered in the customer, local facilities and nonfuel energy charges--should be recovered through the reservation charge consistent with the Commission's long-standing policy of moving all rate classes closer to cost of service. My recommended base revenue distribution, for example, would not assign any increase to the Rate SS class, as shown in Schedule 16. This is appropriate because, as shown in Schedule 17, the class would move closer to cost of service, consistent with Commission policy.

Q **ARE THERE ANY OTHER ISSUES YOU WISH TO ADDRESS CONCERNING RATE SS?**

A Yes. These issues concern:

- The assumption that Rate SS customers would impose 10% of their Standby Service Contract Capacity during system peak periods;
- The 23-month demand ratchet; and
- The calculation of the Daily Standby Service kW.

Q **WHAT IS THE ORIGIN OF THE 10% FACTOR BEING USED TO ESTABLISH THE COINCIDENT DEMANDS OF THE RATE SS CLASS?**

A The Commission Order in Docket No. 850673-EU states on Page 13, that:

> "The reservation charge is to be calculated by multiplying *an assumed 10 percent forced outage rate* for SGCs' generators times the utility system's unit cost per coincident peak kilowatt (CPKW) for demand-related production and transmission (P&T) functions." (Emphasis added)

Thus, 10% was the assumed forced outage rate (FOR) of the SGC's.

Q **SHOULD THE 10% FOR ASSUMPTION BE CARRIED FORWARD INDEFINITELY?**

A No. The Order clearly states that the 10% FOR was an assumption. To assure that the approved standby rates would continue to be fair and cost-based, the Commission also ordered the utilities and the SGCs:

> "to undertake such data collection and reporting activities as are necessary to permit analysis of the load and usage characteristics of back-up, maintenance and supplemental electric service." (Order No. 17159, Page 22)

Specifically, each utility was to collect and report certain specified data for its standby customers, including:

- Billing data,
- Load, coincidence and load factor data,
- Customer Generation and availability data, and
- Additional data deemed necessary for proper cost-of-service analyses and rate design.

Q **HAS GULF PERFORMED ANY SUCH ANALYSES OF THE CHARACTERISTICS OF ITS SGCs FOR PURPOSES OF THIS CASE?**

A No. Gulf continues to use the 10% forced outage rate assumption to allocate demand-related capital costs and to design the proposed Rate SS reservation charge.

Q **IS THERE ANY EVIDENCE THAT THE FORCED OUTAGE RATE OF GULF'S SGCs IS DIFFERENT FROM THE 10% ASSUMPTION?**

A Yes. In response to Monsanto's First Set of Interrogatories, Item No. 11, Gulf supplied data necessary to calculate the FOR's of three of its four SGCs. While the proprietary nature of the response prevents full disclosure of the results, my analysis indicates that the FORs of the three SGCs were all significantly below 10%, in the 1% to 4% range.

Q **ISN'T IT UNUSUAL FOR SGCs TO HAVE FORCED OUTAGE RATES CONSIDERABLY BELOW 10%?**

A No. An analysis of the SGCs in the Houston Lighting & Power Company service territory, for example, revealed a composite equivalent FOR of only 3%. I am also aware of other similar experiences, but these other experiences cannot be disclosed for confidentiality reasons.

Q **SHOULD A DIFFERENT FORCED OUTAGE RATE, OTHER THAN 10%, BE ASSURED FOR PURPOSES OF DETERMINING THE COINCIDENT DEMANDS AND THE RESERVATION CHARGE FOR THE RATE SS CLASS IN THIS DOCKET?**

A No. This would not be necessary because the Rate SS class is already providing a substantially above-average rate of return at present rates. Also, one SGC refused to disclose the necessary information to calculate the FOR.

As required in Order No. 17159, Gulf should already be collecting and analyzing the load characteristics and reliability of each SGC. This analysis, which is based on actual experience, should be utilized in the class cost-of-service study in Gulf's next rate case.

Q **WHAT IS THE 23-MONTH RATCHET TO WHICH YOU REFER?**

A The billing demand used in applying the reservation charge

> "will be the greater of the Standby Service Capacity (kW) in accordance with the Contract for Standby Service or the Maximum Standby Service (kW) taken in the current and twenty-three (23) previous service months." (Section No. VI, First Revised Sheet No. 6.31)

Thus, if a customer were to contract for 7.5 MW of standby service capacity, but the maximum daily standby demand were 13 MW, the customer would be charged for the extra 5.5 MW for the current and the subsequent 23 months. At $.98 per kW, this would translate into about $124,000 in additional reservation costs.

Q **ISN'T THAT PROPER BECAUSE THE UTILITY HAS TO STAND READY TO PROVIDE THE EXTRA STANDBY CAPACITY WHEN THE CUSTOMER DEMANDS IT?**

A It would not be proper under all circumstances. Although standby power is used intermittently, when an SGC experiences either a forced or scheduled outage of his/her generating equipment, not all of these outages are random in nature.

Q **PLEASE EXPLAIN.**

A Certain maintenance outages, for example, may occur only infrequently--once every three to five years--at the SGC's discretion. These outages are similar to the ones that Gulf Power incurs to make extensive repairs on a boiler or to rebuild a turbine generator. Such extended outages would have to be scheduled in advance to enable Gulf to obtain the labor and material required to perform the necessary maintenance. Also, each outage would have to be coordinated with Gulf's sister operating companies to ensure that such outages do not create a capacity deficit on The Southern system.

Q **CAN AN SGC ALSO PRE-SCHEDULE SUCH UNIT MAINTENANCE OUTAGES?**

A Yes. There is no fundamental difference between a utility and an SGC as regards the need to schedule maintenance outages well in advance.

Q **IS THERE ANY INCENTIVE FOR AN SGC TO PRE-SCHEDULE A MAINTENANCE OUTAGE UNDER GULF'S PRESENT RATE SS?**

A No. For pricing purposes, no distinction is made whatsoever between back-up and maintenance outages. This is despite the fact that back-up power is often more random in nature--because forced outages are rather unpredictable--while maintenance outages can typically be pre-scheduled in advance.

Q **DOES THE COMMISSION'S STANDBY RATE ORDER PROHIBIT A UTILITY FROM DIFFERENTIATING BETWEEN BACK-UP AND MAINTENANCE POWER?**

A No. The Order does not preclude a utility from offering for a discount on, or forgiveness of, demand-related production plant charges if the customers schedules maintenance in advance with the utility to provide "useful coordination" (Order No. 17159, Page 10). Therefore, waiving the 23-month demand ratchet for such maintenance outages would not be contrary to the Commission's standby rate order.

Q DIDN'T THE COMMISSION FIND, IN DOCKET NO. 850673-EU, THAT BACK-UP AND MAINTENANCE POWER WERE NOT SUFFICIENTLY DIFFERENT FROM EACH OTHER TO WARRANT SEPARATE COST-BASED RATES?

A Yes. However, the rationale for this finding was that it was difficult to distinguish between back-up and maintenance power because the utility must provide the same level of replacement power regardless of whether the customer's generator is out for scheduled maintenance or has been forced out.

Although the same level of service may be required to provide both back-up and maintenance power, clearly an SGC that is able to usefully coordinate a maintenance outage with a utility can be distinguished from a SGC that may require back-up power on a moment's notice. In the former case, the utility can plan well ahead to provide the necessary capacity when it is needed. If the utility knows in advance that sufficient capacity is not available in the amount requested during the planned maintenance outage, it would not have an obligation to provide the service. (The SGC and the Utility would then have to determine when adequate capacity would be available before a commitment could be firmed-up.) In the case of back-up power, by contrast, the utility must stand ready to meet the additional back-up power demand whenever it may be imposed.

Because a maintenance outage that an SGC is required to schedule well in advance and in full coordination with the utility represents a different quality of service, a lower rate would be cost justified. At a minimum, the 23-month ratchet should not apply under these circumstances.

Q DID THE COMMISSION MANDATE THE 23-MONTH RATCHET?

A No. On Page 21 of Order No. 17159, the Commission stated:

> "To discourage initial misrepresentation of maximum standby power demand levels, the utilities *may* incorporate into their tariffs "ratchet" provisions that increase the contract demand for up to 24 months following an outage during which the customer's *back-up demand* exceeded his contractually specified maximum back-up demand. Alternatively, the utilities may propose other appropriate penalties instead of a ratchet provision." (Emphasis added)

Not only was the 23-month ratchet not mandated, Gulf was given the discretion to develop alternatives to the ratchet that may be appropriate to prevent misrepresentation of the maximum standby power demand levels.

Q HAVE YOU REVIEWED THE TESTIMONY OF MR. TOM KISLA ON BEHALF OF STONE CONTAINER CORPORATION?

A Yes.

Q ARE THE CIRCUMSTANCES DESCRIBED IN MR. KISLA'S TESTIMONY REGARDING MAINTENANCE OF THE 18 MW TURBINE RELEVANT TO YOUR DISCUSSION OF THE 23-MONTH RATCHET?

A Yes.

Q **MR. KISLA ALSO SUGGESTS THAT STONE BE ALLOWED TO PURCHASE ADDITIONAL CAPACITY AND ENERGY ON THE SUPPLEMENTAL ENERGY (SE) RIDER UNDER CERTAIN CIRCUMSTANCES. WOULD SUCH ADDITIONAL PURCHASES CAUSE OTHER RATEPAYERS TO SUBSIDIZE STONE?**

A No. With minor modification, the SE Rider would be an appropriate vehicle to enable Gulf Power Company to sell additional capacity and energy when the opportunity arises.

Q **WHAT MODIFICATION WOULD HAVE TO BE MADE TO THE SE RIDER?**

A In order that the ratepayers do not subsidize these additional opportunity purchases, the Rider should be modified to enable Gulf to terminate an SE period on as little as 30-minutes notice if it is necessary to avoid contributing to the monthly Southern system territorial peak. The 30-minute notice of curtailment provision would enable Gulf to exclude the SE demand in determining the Capacity Equalization Charges under the Intercompany Interchange Contract. This provision is described more fully in Gulf's response to Staff's 3rd Set of Interrogatories, Item No. 69. I would further note that both Alabama Power and Georgia Power are presently able to exclude their respective interruptible loads from the IIC under similar circumstances.

Q **WOULD USING THE SE RIDER IN THE MANNER DESCRIBED BY MR. KISLA BE IN VIOLATION OF THE TERMS AND CONDITIONS OF THE STANDBY SERVICE RATE?**

A No. As I understand Mr. Kisla's testimony, he is not asking for the opportunity to use SE as a substitute for normal back-up and maintenance power requirements. Rather, the SE Rider would be used to displace available, but less economical generation. Because this would afford Gulf the opportunity increase electric sales when adequate, cost-effective capacity and energy are readily available, the additional revenues generated from such sales would benefit Gulf's other ratepayers.

Q **MR. KISLA ALSO CRITICIZES THE CALCULATION OF THE DAILY STANDBY SERVICE KW. WHAT IS THE PROBLEM WITH THE CALCULATION?**

A The starting point for calculating the Daily Standby Service kW is the SGC's maximum totalized generation output since the most recent outage but prior to the current outage. Because Stone is required to generate more during the cold winter months than is the normally the case at other times, Stone could be charged for more standby power than is actually used (TK Exhibit 1, Page 2).

Q **DO OTHER UTILITIES USE THE SAME FORMULA TO CALCULATE DAILY STANDBY SERVICE KW?**

A No. Florida Power Corporation, for example, calculates Daily Standby Power on either the amount of load ordinarily supplied by customer's generation or a specified amount of self-service generating capability.

Q **DOES THE COMMISSION STANDBY RATE ORDER ADDRESS THIS ISSUE?**

A Yes. The Order requires a utility to "diligently analyze the customer's generator operation and power usage *for the period immediately preceding an outage*." The Order goes on to state that this analysis "should enable the identification of back-up power taken to replace the customer's *normal* generation and supplemental power taken in excess of *normal* generation." (Order No. 17159, Page 21; emphasis added.)

Q **DOES GULF'S METHODOLOGY FOR CALCULATING DAILY STANDBY SERVICE KW COMPLY WITH THE ORDER?**

A No. The Order refers to power usage for the period immediately preceding an outage, whereas Gulf's calculation of daily standby service kW considers the maximum generator output during the entire period following a prior outage. For an SGC, this period could be as long as several months.

More importantly, as Mr. Kisla demonstrates, the highest generator output since the most recent outage may have little relevance in determining the actual amount of standby power being taken. In my opinion, the Commission intended for a utility to determine, as closely as practicable, the actual amount of standby power taken.

Q **HOW SHOULD THE DAILY STANDBY SERVICE KW BE CALCULATED?**

A I see nothing wrong with Mr. Kisla's suggestion that the amount of standby power be equal to the difference between the maximum metered demand during an outage period and the corresponding maximum demand in a non-outage period, during the current billing month. Not only is this approach simpler to use, it would more closely reflect the actual amount of standby power used.

Q **WOULD FPC'S FORMULA FOR CALCULATING STANDBY POWER ALSO BE AN ACCEPTABLE ALTERNATIVE?**

A Yes, the FPC formula could be an acceptable alternative if it were possible to seasonally differentiate between the amount of load ordinarily supplied by customer's generation. Seasonal differentiation would more accurately charge the customer for the amount of standby power being purchased to replace the capacity formerly being supplied by the customer's own generation. If more generation capacity is used during the winter months, then the Daily Standby Power kW should reflect this higher capacity when an outage occurs, minus the amount of load reduction as a result of the outage.

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

A Yes, it does.