Florida Public Service Commission

Fletcher Building
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Tallahassee, Florida 32399-0850

MEMORANDUM

July 30, 1990

TO: DIRECTOR, DIVISION OF RECORDS AND REPORTING

FROM: DIVISION OF ELECTRIC AND GAS (JENKINS) JDJ
DIVISION OF AUDITING AND FINANCIAL ANALYSIS (DEVLIN) TD
DIVISION OF LEGAL SERVICES (VANDIVER) R

RE: DOCKET NO. 891345-EI, APPLICATION OF GULF POWER COMPANY FOR A RATE INCREASE (COST OF SERVICE AND RATE DESIGN ISSUES)

AGENDA: AUGUST 9, 10, and 14, 1990 - SPECIAL AGENDA

CRITICAL DATES: 8-MONTH EFFECTIVE DATE: 08/15/90

Attached are the original, 7 tabbed copies and 14 untabbed copies of the Staff's recommendation on cost of service and rate design issues in this docket.

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STIPULATED
ISSUE 113: Are the company's estimated revenues for sales of electricity based upon reasonable estimates of customers, KW and KWH billing determinants by rate class? (KUMMER)

RECOMMENDATION: Yes, with the exception that the utility should have included billing determinants for the PXT customer who used 7959 KW of standby power in 1989. The billing determinants are based on the no migration filing.

POSITION OF PARTIES

GULF: Yes.

OPC: Agree with Staff.

FRF: Agree with Staff.

STAFF ANALYSIS: Witness Haskins stated that the customer in question experienced a forced outage during September 1989 (TR 1965) and that it was their opinion that the customer took 7959 KW of standby power during that outage (TR 1966). Despite the failure by the customer to report the outage and despite the fact that the customer had subscribed for zero standby capacity, the company agrees that the power taken during the specified outage met the definition of a forced outage as defined in both the tariff and Order No. 17159.

If the Commission decides that this was not standby power, the customer does not qualify for the PXT rate on basis of annual load factor and the appropriate cost of service study to be used in the rate case must be be based on five customers in the PXT class and this customer relegated to the LPT class because he does not meet the 75 percent load factor required to take service on the PXT rate schedule.

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STIPULATED
ISSUE 114: The present and proposed revenues for 1990 are calculated using a correction factor. Is this appropriate? (KUMMER)

RECOMMENDATION: Yes. While staff believes proper estimating procedure would eliminate the need for correction factors, the method used by Gulf requires that the revenue forecast done by revenue class in aggregate be reconciled with the forecast developed by the rate section.

POSITION OF PARTIES

GULF: Agree with Staff.

OPC: Yes. Agree with Staff.

FRF: Agree with staff.

STAFF ANALYSIS: For internal budgeting purposes, Gulf, as well as other utilities utilizes a forecasting model which projects KWH and number of customers. This generates a total revenue target based on aggregrate billing determinant forecast Rate design, however, utilizes a more detailed development of individual billing units, including consideration of any appropriate discounts.

The budget projections and the rate revenue projections are done separately and will only coincidentally agree exactly. Therefore, Gulf has developed a factor to reconcile the revenues using historical relationship of rate revenue to budget revenue. Other utilities more closely integrate their rate and budgeting forecasts so as to eliminate the need for correction factors and staff recommends that Gulf pursue this as well. However, given their current forecast methodology, some measure is necessary to reconcile the two revenue amounts. The use of historical relationships is reasonable.

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ISSUE 116: How should distribution costs be treated within the cost of service study? (MEETER)

RECOMMENDATION: No distribution costs other than service drops and meters should be classified as customer-related. Demand-related cost should be allocated on a demand allocator, and customer-related cost on a customer allocator.

POSITION OF PARTIES

GULF: Distribution cost should be separated into demand and customer classifications. The demand classified cost should be allocated on a demand allocator and customer classified cost should be allocated on a demand allocator and customer classified cost should be allocated on a corresponding customer related allocator.

OPC: The costs of dedicated facilities should be directly assigned to the classes whose members are served by the dedicated facilities. Other distribution costs, except service drops and meters, should be classified as demand-related and allocated on the basis of class NPC demands.

II: In allocating distribution costs, land and station investment in distribution facilities should be demand related. Investment in poles, overhead conductors, underground conduit conductors and line transformers should be allocated 70% to demand and 30% to customer cost. The cost of meters and installations on customers' premises should be allocated as a customer cost.

FRF: Agree with II.

STAFF ANALYSIS: Commission policy since the early 1980s has been to classify only the service drop and meter portion of the distribution system as customer-related. (Order No. 10306 in Docket No. 810002-EI, at page 43; Order No. 11307 in Docket No. 820007-EU at page 36; Order No. 11437 in Docket No. 820097 at page 46; Order No. 11498 at page 41; Tr. 1822-1823)

The II and the utility advocate classifying a significant portion of the remainder of the distribution system, including poles, conductors, and transformers, as customer-related. This method is often referred to as the Minimum Distribution System concept. Staff believes there is a fundamental flaw in their proposal. The fundamental flaw is that under the proposal, part of the distribution system only is classified as customer-related. None of the subtransmission and transmission system would be classified as customer-related. Hence, customers served at primary voltage through dedicated substations, and customers served at higher voltages would not pay for any of this network path through this concept. (Pollock, Tr. 2923-2924) Yet, both Gulf and II support classification of more of the distribution system as customer-related because their presence as a customer of the utility forces the company to have a "certain minimal amount of equipment to be there available to serve." (O'Sheasy, Tr. 3289) In support of classifying more of the distribution system as customer-related, II's Mr. Pollock testified that

> 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 <u>each</u> and <u>every</u> customer regardless of the peak demand or energy consumed. (Tr. p. 2828) (Emphasis added)

Staff believes this minimum distribution system approach should be rejected because it is inequitable and inconsistent to apply the concept to only those customers served at secondary voltage or at primary voltage through common substations, particularly in light of Mr. Pollock's argument that the path must be there to serve <u>each</u> and <u>every</u> customer. The Commission should continue its present policy on classification of distribution system plant.

Staff is of the opinion that there already is an inequity between secondary and nonsecondary customers with respect to service drops or taps in the cost of service studies. Drops for <u>secondary</u>-voltage customers only are booked in Account 369, and classified as customers-related; only the secondary voltage customers have service drops allocated to them on a per customer basis. Service drops or taps for customer served at primary or higher voltages are booked along with all other conduit in the FERC accounts for transmission and distribution lines. Therefore, none of the cost of the drops for nonsecondary customers has been classified as customer-related and allocated or assigned to these customers only. (O'Sheasy, Tr. 1863-1864)

A further inequity is caused by the fact that Gulf does not allocate any primary line cost to primary voltage customers served through dedicated substations. Yet for six of these primary voltage customers with dedicated substations, Gulf owns some of the primary lines between the customer's facility and the substation. (Exhibit 603)

Staff, therefore, agrees with the Citizens that to the extent practicable, distribution facilities, that function as service drops or dedicated tap lines, should be directly assigned to the classes whose members the facilities serve.

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ISSUE 117: How should uncollectible expenses be allocated? (MEETER)

RECOMMENDATION: Uncollectible expense should be classified as revenue-related and allocated to all rate classes on revenues so that a customer's cost responsibility would be approximately proportional to the size of his bill.

POSITION OF PARTIES

GULF: Uncollectible expenses should be assigned to the classes which incurred the expenses or allocated upon a cost causitive allocator.

OPC: Uncollectible expense should be allocated to all rate classes based on revenues.

II: Uncollectible expenses should be allocated to those classes which incurred them.

FRF: Agree with II.

STAFF ANALYSIS: The company assigned uncollectible accounts expenses to the RS, GS and GSD classes on average number of customers and classified the expense as customer-related. The result of this classification and assignment or allocation of uncollectible accounts expense is that the expense is included in the customer charge unit cost. If the customer charges for these classes have been and are set at or near unit cost, all customers in the RS, GS and GSD rate classes pay an equal amount for uncollectible expense each month, regardless of the size of these bills. (Wright, Tr. 2140-2141) Commission policy has been to allocate uncollectible expense on revenues and not include it in the customer unit cost. (See Order No. 11307 at page 36, Order No. 11498 at page 43 and Order No. 11628 at page 35.)

The company's and II's position is that uncollectible expense should be allocated or assigned to the classes which incurred the expense. The company, however, does not record the expense by rate class and indicated in response to a staff interrogatory that uncollectible expense by rate class is not available. (McMillan, Tr. 808 and Exhibit 438) In response to cross examination, Mr. McMillan stated that for two or three prior rate cases dating back to the late 1970s and early 1980s, an individual recorded each uncollectible account by rate class and summed them up. He further stated that "over the course of two or three rate cases, looking at the charge-offs, it was pretty obvious that these three classes, in essence, consume the total of our uncollectible write-offs and that the customer relationship within those three rate classes fairly closely mirror the actual write-offs. (Tr. 809) No evidence in the form of data for these analyses for earlier rate cases was provided, however. In response to later cross examination he indicated that "based upon anybody's recollection in the company or by records we have, there have never been any write-offs in the industrial class. (Tr. 812) The Citizens Witness, Mr. Wright, however, cited an example where a large customer of another utility had entered bankrupcy, leaving the utility with a debt in excess of $1 million. (Tr. 2141)

Given that uncollectible expense by rate class is unavailable and that past Commission policy has been to allocate uncollectible accounts expense on revenues to all classes, staff recommends that this expense should be allocated in this docket to all classes on revenues.

The Commission's policy of not including uncollectible expense in the customer unit cost and not recovering it through the customer charge, i.e., not classifying uncollectible expense as customer-related should be continued. Staff believes the company's classification of the cost as customer-related is inequitable because it results in a small customer paying as much uncollectible expense as a large customer (within and between the RS, GS and GSD classes), if customer charges are set at unit cost. (Wright, Tr. 2140-2141) However, if the account of a customer becomes uncollectible, a customer with a large bill would cause the company to incur much more uncollectible expense that a customer with a small bill. (Wright, Tr. 2140)

Citizens' witness Wright testified on cross examination that it would be more equitable to allocate the uncollectibles between and within classes on revenues and classify it as revenue related." Staff is in agreement with the Citizens that uncollectibles should be classified as revenue-related so that cost responsibility for uncollectible expense would be proportional to the size of a customer's bill.

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ISSUE 118: How should fuel stocks be classified? (JENKINS/MEETER)

PRIMARY RECOMMENDATION: (Jenkins) Fuel inventory cost should be classified as demand-related.

ALTERNATIVE RECOMMENDATION: (Meeter) The level of fuel stock or inventory allowed in rate base has been based on a specific number of days burn which is a function of the KWH projected to be generated in the test year. Therefore, fuel stock should be classified as energy-related and allocated on energy.

POSITION OF PARTIES

GULF: The amount of fuel inventory required for a generating plant is a function, to a large degree, of its capacity. It should be allocated on both demand and energy, not solely on energy.

OPC: The level of fuel inventory allowed in rate base has been based on a calculated number of days burn which is a function of number of KWH to be generated. Therefore, fuel stock should be classified as energy-related.

II: Fuel stocks should be classified to demand or energy based on its use in the system.

FRF: Agree with Staff.

STAFF ANALYSIS: (Primary) Gulf allocated fuel inventory based on a 12 CP and 1/13th cost allocation methodology. However, the primary purpose of fuel inventory is to ensure a reliable supply of fuel. If the purpose of fuel inventory is reliability, all fuel inventory cost should be allocated on demand. An energy allocation implies the purpose of a fuel inventory is solely to have BTUs irrespective of when those BTUs are consumed. The confusion seems to be that fuel inventory is calculated based on fuel burn without considering the reason for a fuel inventory.

STAFF ANALYSIS: (Alternative) The company and II have allocated fuel inventory in rate base on the 12 CP and 1/13th average demand, the same allocator they have used to allocate production plant investment. Thus, 12/13ths or 92.3 percent of the inventory has been classified as demand-related and allocated on each class's calculated or estimated demands during the system's 12 monthly peak hours. The other 7.7 percent has been classified as energy-related and allocated on energy.

In the company's last rate case (Docket No. 840086) projected daily burn was approved by the Commission as the basis for the calculation of the appropriate level of fuel inventory to be included in working capital, i.e., rate base. The approved level for the case was based on 107.5 days burn at an average projected daily burn of 9333.9 tons (Order No. 14030 at pages 10 and 11). In this docket staff has recommended the Commission reject the use of the Utilities Fuel Inventory Model (UFM) used by the utility to justify its coal inventory request. (See Issue 24.) Staff has recommended the use of the generic inventory policy of Order No. 12645 to determine a reasonable level of coal inventory. The generic policy for the inventory of coal is a level equal to 90 days projected burn (Order No. 12545 at pages 3 and 4). Gulf's requested inventory for coal is 97.3 percent of its total requested fuel inventory. (See Issues 22 through 24.)

Since projected average daily burn is a function of KWH projected to be generated and used in the test year, staff agrees with the Office of Public Counsel that fuel stock should be classified as energy-related and thus allocated on energy. In view of the previously approved and currently recommended method for calculating the appropriate level of fuel inventory, staff believes the energy classification and allocation of fuel more closely track cost causation than the company's and II's 92.3 percent allocation on 12 CP demands to recognize system reliability. (Pollock, Tr. 3155). Significantly, the fuel staff has recommended against the use of the UFIM because the four disruption scenarios the model incorporates probabilistically into the model are considered minor or unrealistic. In the Commission's method of determining the level of fuel stock would vary with the KWH projected to be burned in the test year.

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ISSUE 119: Are Gulf's separation of amounts for wholesale and retail jurisdictions appropriate? (MEETER)

RECOMMENDATION: Yes. Gulf's separation of amounts for wholesale and jurisdiction is appropriate. The actual separations used should be those in the cost of service study approved for use in this docket by the Commission.

POSITION OF PARTIES

GULF: Yes. Gulf's separation of amounts for wholesale and retail jurisdiction, as reflected in Exhibit 231, is appropriate.

OPC: The appropriate separation factors are those in the cost of service study requested in Staff's Interrogatory No. 209.

FRF: No position.

STAFF ANALYSIS: Since there are very small differences in the separations in the various cost of service studies, staff recommends that the actual separations used be those from the actual study approved by the Commission for use in this docket. All studies separate production and transmission plant rate base by jurisdiction on the 12 coincident peak hour demands (12 CP).

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ISSUE 120: Is the method employed by the company to develop its estimates by class of the 12 monthly coincident peak hour demands and the class non-coincident peak hours demand appropriate? (MEETER)

RECOMMENDATION: The company's exclusion of "supplemental energy" KWH in the development of the 12 monthly coincident peak hour demands for PX/PXT and LP/LPT and of the class noncoincident peak demand for LP/LPT unestimated these demands and resulted in an unallocation of production and transmission cost to the two classes. The PXT 12 CP KW should have been 6.8 percent higher and the LP/LPT's .79 percent higher. The exclusion of these KWH was inappropriate; the use of the methodology should be denied.

POSITION OF PARTIES

GULF: Yes. The company has demonstrated that the method employed in development of rate class estimates of monthly coincident peak (CP) and non coincident peak (NCP) hour demands is sound and yields reliable results. In fact, there is substantial evidence that suggests the company's development of CP and NCP estimates should no longer be an issue. Staff's prehearing position on this issue was based on a misunderstanding with regard to the company's treatment of energy sold under the Supplemental Energy (SE) rider.

OPC: No. The 12 CP and class (NCP) demands have been underestimated for LP/LPT and PX/PXT customers taking service on the Supplemental Energy Rider because all KWH forecast to be used during Supplemental Energy Periods have been excluded in the development of the demands. The assumptions for recreational lighting customers have underestimated at least their estimated class (NCP) demand.

II: Yes.

FEA: Yes.

FRF: Agree with staff.

STAFF ANALYSIS: The twelve monthly coincident peak hour demands (12 CP) are used to allocate demand-related production plant and transmission plant costs in all but the near-peak cost of service study. These demands must be estimated for all classes when using a projected test year. The 12 CP and class peak demands were estimated by class by dividing the 1990 KWH by 1987 KWH and multiplying that ratio times the 1987 12 CP for rate classes RS, GS and GSD. Under this method each class' 12 CP KW for the test year are increased over the historic load research data by the same percentage their KWH are projected to increase in the same time period, i.e., each class's 12 CP load factor is assumed to be the same as it was in the year of the historic load research data. Thus, each class's demand or use in the 12 monthly coincident peak hours relative to total KWH usage is projected to be the same in the test year as the historic load research year.

For those customers taking service on the SE rider, "supplemental energy" KWH were excluded from this calculation. The resulting 12 CP demand of 104,728 KW for the PXT class percent would have been 6.8 percent higher if the KWH had been included (111,893 KW on TR. 1765). The effect on the estimated demands of the LP/LPT class was insignificant (.79 percent) because the LP/LPT customers' response to the SE rider was minimal. The 104,728 KW represents a 12 CP load factor of 107 percent in the test year for PXT. (Kilgore, Tr. 1773) Thus, the PXT class would have been allocated about 6.8% more demand-related production and transmission plant cost if these KWH had not been excluded. The effect of the company's allocation is to reduce the costs allocated to the PXT class and thereby avoid or reduce a rate increase by inflating the class's rate of return.

Departure from Historical Data

The company's reason for excluding these KWH apparently is that it expects the SE customers to have a higher 12 CP load factor in the test year, i.e., to use less energy in the 12 monthly peak hours relative to their total usage. However, the data in Table 1 shows the 12 CP load factor for 1989 for the three groupings of PXT customers decreases instead of increases in 1989. The significant decrease from 101 percent to 91 percent for PX/PXT customers on the SE rider was inconsistent with the company's assumed increased load factor for the class.

Table 1

12 CP LOAD FACTORS

	Actual 1987	Actual 1989	Projected 1990
PXT class as a whole	101	95	107
PX/PXT customers on the SE rider	101	91	
PX/PXT customers not on SE rider	100	97	
LP/LPT class as awhole	83	83	84
LP/LPT customers on the SE rider	80	83	
LP/LPT customers not on the SE rider	84	84	

Source: Exhibit 488 for 1987 and 1989 actual data; calculation using KWH and unbalanced 12 CP KW in Exhibit 209 for projected 1990.

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If the company's projection of a 107 percent 12 CP load factor for PXT due to an assumed changing usage pattern of SE customers is to be realistic or representative of 1990, it is only reasonable to expect the load factor for the PX/PXT SE customers would have been higher in 1989 than 1987.

Other data supporting the argument that it is unreasonable to expect the 12 CP load factor for the PXT class to increase from 95 percent in 1989 to 107 are listed below:

(1) The number of supplemental energy KWH projected for 1990 is 20 percent less than 1989. (Exhibit 486)

(2) The number of hours projected to be designated as SE hours in 1990 is less than either 1988 or 1987. (Exhibit 487)

(3) The SE rider has been in effect since 1985 without revision. (Order No. 17568)

Therefore, one would not expect a markedly different response to the rider in 1990 than in 1989.

The company has not presented any data or evidence supporting the use of a load factor higher than the historic value. All of the PX/PXT customers have time-recording meters so that their 12 CP values are actual metered numbers and not estimates. (Tr. 1766) Therefore, the company had the 12 CP load factor data for the first four or five months of 1990 and could have entered it into the record during the hearing as evidence supporting the increased load resulting from their methodology. The company did not enter the data. Staff believes it is reasonable to assume that the data would have been entered if it corroborated the assumptions behind their methodology.

Staff is of the opinion that it was also clearly unreasonable to use 104,728 12 CP KW for 1990 for PXT because the 1989 actual (not estimated) value was <u>119,448</u> KW and the PXT KWH were projected to decrease only 1% from 1989 to 1990. (Data on Exhibits 488 and 231)

<u>Effect on Purpose of Load Research Rule</u>

Staff is extremely concerned about Gulf's departure from the policy (MFR Schedule E-14) of using the load characteristics determined from the load research collected pursuant to the Commission's Rule 25-6.0437 Cost of Service Load Research in developing various peak demands by class for the test year. The policy assumes the load characteristics, including load factor, are the same in the test year as the historic load research year. The primary purpose of the rule is "to require that load research that supports cost of service studies used in ratemaking procedures is of sufficient precision to reasonably assure that tariffs are equitable and reflect the true costs of serving each class of customers." (Rules of Florida Public Service Commission, page 6.2701) The utilities have spent large amounts of money to collect the load research required by this rule. The docket resulting in the rule was opened by the Commission because of problems with the load data used by the utilities in rate case cost of service studies. (Orders No. 10306, at p. 12, No. 10557, at p. 43, and No. 11498 at p. 43) Staff believes that Gulf's departure from the use of historical load characteristics for the PXT class negates and seriously undermines the purpose of the Commission's Cost of Service Load Research Rule. It is inequitable and should not be allowed.

Response to Company's Brief

To address the company's arguments in its brief, staff thinks a description of the SE rider would be helpful. The SE rider was approved as a time-of-use rate when it was permanently approved by the Commission.

> Because we approve this rate as a cost-based, time-of-use rate, customers participating in it shall become a separate rate class in the company's next rate case. So long as the rate is administered so that the on-peak hours (that is, the non-SE hours) are designated to include actual peak hours, in the long run, it may be beneficial to SE customers to shift their load to off-peak periods. (Order No. 17568, at page 2)

The SE rider differs from other time of use rates in that the on-peak (non-SE) hours and the off-peak (SE) hours are flexible and depend on the company's operating conditions. The company designates, from time to time, supplemental energy periods (off-peak) when none of three operating conditions is likely to occur. The SE rider provides for forgiveness of the customer's billing demand during SE periods, i.e., the customer is billed only on demand incurred during non-SE periods. The SE rider is not in any sense an interruptible rate as explained by Witness Wright.

Q. Are the KWH and capacity used by SE customers interruptible?

A. No, not in any sense in which the term "interruptible" is used as a rate design term of art by this Commission or anywhere else that I am aware of. Interruptible means and was explicitly defined to mean by this Commission in its nonfirm service terms and conditions rule, service that is interruptible, subject to being turned off by the electric utility at its discretion.

In other places interruptible does mean what we in Florida call curtailable, that is it's subject to a demand for curtailment by the utility, but neither of those cases applies to SE. If the customer wants to continue to use his load during a non-SE period, he's free to do it. He just pays the rates.

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In its brief, the company has contended that, because the amount of energy excluded in the LPT and PXT development is small, staff's concerns on this issue should have been alleviated. Regardless of whether it was appropriate to exclude the KWH, the amount of energy excluded for PXT was 8.4 percent of class usage which resulted in an underestimation of the 12 CP KWH by 6.4 percent. Thus, close to 6.8 percent more demand-related production and transmission cost would have been allocated to PXT if the KWH had not been excluded. Furthermore, production and transmission cost for PXT constitutes 73% (Exhibit 231) of class cost even with the underallocation. Whether the KWH excluded represent all KWH used during SE periods, or incremental KWH is immaterial to staff when there is no data in the record corroborating an actual higher 12 CP load factor for the customers. Staff would point out that for PXT-SE customers, the projected increase in SE KWH between 1987 and 1989 is <u>larger</u> than the increase in total KWH, an apparent inconsistency with the definition of SE KWH as incremental KWH.

With respect to the company's position in its brief that the company's treatment of incremental SE sales in the CP and NCP development does not constitute a change in methodology. Mr. Kilgore testified that "...I guess this is an instance of where we're talking about detail versus fundamental change in methodology. We feel that our <u>basic</u> methodology is essentially the same as it has been in previous cases." Staff agrees that, with the exception of the treatment of SE KWH, the company's basic methodology has not changed since it has had reliable load research collected using probability samples.

However, staff strongly disagrees that the treatment of the SE KWH is a detail - any such treatment which used a number of KWH 8.4 percent lower than it would otherwise have used is hardly a detail. Furthermore, the company did not exclude SE KWH in Docket 881167 (Kilgore, Tr. 1772), nor did it exclude KWH for any other time of use customers. Staff is unaware of any such deviation in this methodology by this utility or any other utility. In addition, contrary to Gulf's position, this treatment cannot be consistent with the basic methodology for all other rate classes to whom no KWH standard or time of use, were excluded for any and the unbalanced 12 CP load factors used for 1990 were the same as 1987's, the year of the historic load research.

On pages 349-350 of its brief, the company states that "In fact inclusion of the incremental SE sales in the CP and NCP development would have been contradictory to the basis premise underlying the methodology which is that class load characteristics remain relatively stable." This is apparently a misstatement because inclusion of the incremental SE sales in the development <u>would</u> have resulted in load characteristics, i.e., load factor, for 1990, which are the same as the 1987 historic value of 101% (983,828,000 - 111,893 x 8760 = 100.4%). In response to IT's cross examination Mr. Kilgore agreed that by removing the incremental SE sales, the company avoided a distortion that would have resulted from the increase in SE sales from the historical year (1987) to the test year (1990) (Tr. pp. 1786-1787). From Mr. McGlothlin's question on page 1786, Mr. Kilgore is clearly referring to the amount of 12 CP KW for the class. Staff believes that, instead of avoiding a distortion the company has actually created a distortion in the 12 CP KW. In 1989 the PXT class had a 12 CP KW of 119,448. (Kilgore, Tr. 1765; Exhibit 488) The company used 104,728 KW for 1990 before balancing, which is 15,000 KW or 12 percent less than the actual 1989 number of 119,448 KW. Staff views this as a distortion since the company has predicted only a one percent decrease in energy for PXT between 1989 and 1990.

Staff believes Mr. Kilgore's use of the statement that no SE sales were made coincident with system peak demands (Tr. pp. 1760-1762) to show that the 12 CP load factor for this group is enhanced through SE is confusing and contradicted by the data in this case. The SE rider is a time of use rate as described earlier in this recommendation. It is true that no KWH used during SE periods (off-peak hours) should be coincident with the 12 monthly system peak hour demands because SE periods are not to be designated during periods of peak operating conditions. However, the SE customers can and do use KWH during the 12 monthly coincident peak hours; the only difference in billing between use in SE versus non-SE hours is that the billing demand is based on demand incurred during non-SE periods. The entire increase in KWH for PXT-SE customers between 1987 and 1989 was classified as SE KWH. (Exhibit 486) Yet the load factor for the PXT-SE cutomers deteriorated significantly rather than improved during this time period. It decreased from 101 percent to 91 percent. (Exhibit 488)

1 Derivation of .79 percent is 135,245 (Tr. 1276) - 133,761 (Exhibit 209, page 12 of 15) -:- (133,761 + 53,769 [Exhibit 209]

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ISSUE 115: What is the appropriate cost of service methodology to be used in designing the rates of Gulf Power Company?

PRIMARY RECOMMENDATION: The 12 CP and 1/13th cost-of-service methodology should be used. If the Commission approves the staff recommendation in Issue 120, the company's study in Exhibit 231 (study with 7.29 percent rate of return for SS) with the staff adjustments is the most appropriate version. These adjustments reflect the impact of Issue 120 and the proper assignment of cost for additional facilities for OS-I/OS-II. (JENKINS)

ALTERNATE RECOMMENDATION: The Equivalent Peaker Cost of Service methodology (Exhibit 604) should be used.

POSITION OF PARTIES

GULF: 12 Monthly Coincident Peak (MCP) and 1/13 energy.

OPC: The Equivalent Peaker Cost methodology proposed by Citizens' witness, Robert Scheffel Wright. However, if the Commission decides to use a Refined Equivalent Peaker cost study, it should require that Gulf perform a study of energy consumption in the company's actual on-peak hours, not their energy use in the highest-demand hours under the load duration curve, to allocate the energy-related component of production plant. Additionally, the revised study should classify fuel inventory as energy-related and should directly assign the rate base value of primary and higher voltage level conductor that functions as dedicated distribution facilities to the rate classes that these dedicated facilities serve.

II: The "near peak" methodology approach is the best approach to fairly allocate the cost of production and transmission plant between the customer classes.

FEA: The FEA supports use of the Gulf Power Company study based on the 12 MCP and 1/13 energy for allocation of production costs, with the exception that the costs are not accurately distinguished for the LP/LPT and PXT classes. The appropriate costs of serving these two classes combined can be ascertained from the company's study.

FRF: Agree with OPC.

STAFF ANALYSIS: (PRIMARY) Cost is as costs are defined. Phrases like rates should be cost based, rates should track costs, and the cost causer should pay the cost give no guidance on what cost is. With reasonable definitions of cost, I would define costs based on what overall policy ought to be or where I believe the Commission should be headed.

Witness Pollock espoused his near peak method stating that it closely comports with the conservation goal of reducing peak demand. My hesitancy with his near peak method is that he is too near the peak. I would espouse his method if he included all peak period hours, roughly 1 to 7 p.m. in summer and 4 to 6 a.m. and 4 to 6 p.m. in the winter months with overlap during the valley load months. Other than the limited number of hours, witness Pollock's near peak methodology is acceptable.

The equivalent peaker (EP) methodology is too much of an abstraction of how system planners decide to recommend to management, and management decides, the Commission approves as needed, and the Governor and Cabinet certify, all surrounded with the uncertainty of projected fuel costs and environmental regulations. In addition there is the fuel symmetry issue, which is cured by the Refined Equivalent Peaker (REP) method, while acceptable, is too philosophically cumbersome to honestly say it emulates whatever is causing costs. Both the EP and REP suggest a refined degree of knowledge of costs that is misleading. I am particularly bothered by the allocation of plant costs to hours past the break-even point in the EP method.

When the Commission had numerical KW and KWH conservation goals, the EP methodology was consistent with those goals. Now that we seem to be emphasizing the avoidance of new power plants, saving KW, I believe our definition of costs should comport with what we are doing. Of course, policy will be better defined in the Commission's review of the conservation programs and expousing any policy now is regrettably premature.

While the 12 CP (12 MCP) and 1/13th may not be the perfect definition of costs, it is a reasonable one, has been used for a number of years, is still used by the FERC, and gives some weight to the year round loads, which in their totality, have some direct or indirect impact on costs, without giving ourselves credit for knowledge of costs we do not have.

Although I agree with the company's use of the 12 CP and 1/13th cost methodology, there are certain critical problems with their proposed study. The staff requested a rerun of the company's 12 CP and 1/13th study with the following specified revisions:

1. All of Account 364 should be classified as demand-related and allocated on class NCP.

   Commission policy has been that no distribution system costs other than service drops (Account 369) and meters should be classified as customer-related. In addition, for customers served at primary or higher voltage only the meter is classified as customer-related. (O'Sheasy, Tr. 1863-1864) Therefore, staff believes it was inequitable to the secondary voltage customers to classify secondary wire in Account 364 as customer-related when there was no similar classification of wire for higher voltage customers. See Issue 116.

2. Uncollectible expense should be allocated to all classes on the basis of revenue and be classified as revenue-related. It should not be classified as customer-related or included in the customer charge. See Issue 117.

3. Fuel inventory (stock) should be allocated on energy and classified as energy-related. See Issue 118.

4. The Supplemental Energy Optional Rider (SE) should be a separate rate class. The coincident and noncoincident demands should be developed using the same methodology used for all other rate classes. The SEP KWH should not be excluded in the development of the CP KW and NCP KW. See Issues 120 and 137. In Issue 137, the staff is recommending that SE not be a separate rate class.

5. The revenues, billing determinants and development of the 12 CP and NCP demands for the Standby Service Class should be based on the assumption that the PXT customer that is not migrating from PXT has a Standby Service Capacity of 7959 KW for the test year. See Issue 48.

6. Service drops should be allocated to the OS classes for at least recreational lighting and advertisement or billboard customers. Meter costs, which reflect the current level of metering, should be allocated to the recreational lights.

   All the recreational lights have meters. (Exhibit 508) There are probably service drops for each of these installations. (O'Sheasy 1858-1860) Therefore, the cost should be allocated to the class for these customers.

7. The rate base for additional facilities for OS-I/OS-II and the expenses [associated] with these facilities should be allocated to OS-I/OS-II.

   In his prefiled direct testimony on how a cost of service study is performed, Mr. O'Sheasy stated that "Certain costs are directly associated with one particular group of customers and are, therefore, assigned to that group." (Tr. 1807) This assignment was not done with respect to the additional facilities for OS-I/OS-II. The class has been credited with revenues of $424,653 but the rate base and expenses associated with the facilities except for those booked in Account 373 were not assigned to the class. (See Tr. 1861 and Exhibits 500, 231 and 501.) The rate of return in the revised study is 5.96 percent compared to 7.43 percent in the company's study in Exhibit 231. Staff believes the expenses should be matched with the costs so that the class' rate of return will not be significantly overstated to the detriment of the other rate classes.

8. Expenses for maintenance of cooling towers and coal pulverizers (grinding mills) should be allocated on energy and classified as energy-related.

   The company has changed the classification of some O&M expenses from demand to energy in the cost of service study compared to that of Docket No. 840086-EI. In Docket No. 881167-EI, Mr. Haskins stated that maintenance for both coal grinding mills and cooling towers vary with the KWH to be generated. (Tr. 1763) In response to cross examination Mr. Lee agreed that operation and maintenance expenses for coal pulverizers and the operation expenses for cooling towers vary with KWH generated but that the amount of maintenance varies little with KWH. (Tr. 1468)

9. The test year expenses for the four conservation (Good Cents New Home, Good Cents Improved Home, and Commercial Presentations/Energy Education Seminars) programs which were denied conservation cost recovery by the Commission on May 2, 1989 should be classified as energy-related and allocated on energy to the rate classes in the revenue class to which the cost has been assigned by Gulf Power.

   The test year expenses for these programs have been classified as customer-related by the company and included in the customer unit costs. Thus, the same amount of program cost is allocated to and recovered from a small RS customer as a large RS customer. (O'Sheasy, Tr. 1861-1863) Therefore, staff believes it is more equitable to continue to recover these costs on a per KWH basis rather than on a per customer basis. Demand-related costs are collected through the energy charge for the residential class. Therefore, if there is less demand-related cost allocated to the class due to demand reductions from class participation, the customers with large usage will benefit more from the conservation program than customers with small bills.

I support all of staff's requested revisions to the company's 12 CP and 1/13th study with the exception of the classification of fuel stock and the separation of SE into a separate rate class at this time. Therefore, I would recommend the use of a 12 CP and 1/13th cost of service study with all of the requested revisions except these two. Unfortunately, we do not have a 12 CP and 1/13th cost study incorporating this combination of revisions. Because staff believes two of the requested revisions significantly impact the rate of return of the rate classes directly involved, staff has adjusted the company's 12 CP and 1/13th cost study (no migration study Ex. 231) for the two problems. One problem is the crediting of the revenues for additional facilities without the assignment of the cost for some of these facilities for OS-II and II. The second is the exclusion of the SE KWH in developing the 12

CP demands of the PXT class. For example, a comparison of the rates of return in column 1 of Schedule 1 to those in column 3 shows that there is a 1.47 percentage point difference (7.43 percent versus 5.96 percent) for OS-III.

For the PXT and LP/LPT classes, rate base was increased by 6.84 percent ($2,778,000) and .79 percent ($592,000), respectively, of the transmission and demand-related production net plant and the demand-related production materials and supplies. The NOI for these classes was reduced by 6.84 percent ($316,000) and .79 percent ($68,000), respectively, of the total transmission and demand-related production O&M expenses, production plant A&G expenses and transmission and demand-related depreciation expenses. These are the major items allocated on the 12 CP KW. (See Issue 120 for the derivation of the percentages.) For OS-I/OS-II, the rate base and NOI from the staff-requested 12 CP and 1/13th cost of service study (Exhibit 501), which reflect the assignment of the cost to the class for all its additional facilities, was substituted for the values in Exhibit 231. All classes' rate base and NOI were adjusted proportionately to equal the company's filed levels of rate base and NOI.

If the Commission approves the staff recommendation on the development of demands with respect to SE customers (Issue 120) and the use of a 12 CP and 1/13th cost of service study, staff recommends that, to be equitable to the customers in the other rate classes, this adjusted study should be used. Staff believes it would be unduly discriminatory to not use the adjusted study because of the large difference in the rates of return between the company's study and the adjusted study. The rate of return for the PXT class is 8.33 percent in the company's study compared to 7.49 percent in the adjusted study; for OS-I/OS-II it is 7.43 percent to 6.04 percent. (Columns 1 and 2 in Schedule 1)

<u>STAFF ANALYSIS:</u> (ALTERNATE) Policy should always be a consideration in rate design. If a cost of service study is to be performed to determine each class' revenue responsibility on cost, the allocation and assignment of cost should track <u>cost-causing</u> factors. Such a study should not be in conflict with overall policy. Costs allocated solely on policy and ignoring cost-causation may send inappropriate economic signals to customers.

I am recommending the use of the Equivalent Peaker (EP) methodology because I agree with Mr. Wright that this method tracks the cost-causing factors that affect utilities' plant investment decisions better than any other study in the case. (Tr. 2093-2094) Additionally, I agree with the Office of Public Counsel that "[T]he EP method is superior to methods that classify all production plant costs as demand-related because such methods simply ignore 'the fact that plant costs are incurred not only in consideration of meeting peak demands but also because of the energy loads to be served.'" (Brief, page 101; Tr. 2082-2083)

This classification of production plant costs is appropriate because the energy loads expected to be served by the plant caused the more expensive plant to be built. I agree with II that system peak demand "drives" the decision to incur the costs of providing additional capacity. Therefore, it is appropriate to classify as demand-related the cost necessary to serve the peak demands (if there were not also broad energy loads to be served) and that amount only. The actual cost incurred to provide that capacity, however, will be determined by the energy loads expected to be served throughout the planning horizon. The advocates of EP method contend that the additional cost (in excess of building peaking capacity) should be allocated to those customers with the energy loads that caused a baseload plant to be build instead of peaking generation. In this EP study demand-related production plant costs have been allocated on the 12 CP because of the cost impact on Gulf's customers of the Southern Intercompany Interchange Contract (IIC).

Both Gulf and II criticize the EP method as an "oversimplification" of the planning process. (Pollock, Tr. 2802; Howell, 3534) However, II's Mr. Pollock acknowledged that capital substitutions represent a "valid theory." Mr. Howell, admitted in response to cross examination, that economic considerations determined Gulf's decision as to the type of capacity to be added in 1995. (Tr. 3556) With respect to economic analyses for the additions of Plants Scherer and Daniel, he responded,

> I do know some economic analysis was done, but I feel sure it was not anywhere near the sophisticated approach we now have. (Tr. 3559-3560)

The Commission has recognized the impact of economic considerations in three prior dockets. In Docket No. 820097-EU on the initial conclusion of Florida Power and Light's nuclear production plant, St. Lucie II classified $179 (75 percent) million of the plant's revenue requirement as energy-related.

> Staff has recommended that $179 million of the revenue requirement be allocated to all classes on the basis of energy to offset the estimated jurisdictional fuel savings. The basis for the recommendation is the fact that the high capital costs involved in the construction of the plant will result in a great fuel savings via the fuel adjustment clause. ... However, we agree with staff that the projected KWH for the high-load factor customers was a basis for justification for the nuclear plant in the first place. (Order No. 12348 at 12)

In Docket No. 830465-EI an EP method was approved for the St. Lucie II plant only. (Order No. 13537 at pages 59 and 60) The Commission, in approving the use of the EP method in Docket No. 850050-EI (Tampa Electric Company) made the following finding:

> We find that this method is logically sound in its classification of the cost of equivalent peaking capacity (the amount that the utility would have spent to serve only peak demands) as demand-related, and in its classification of additional plant costs, which the utility incurred to obtain fuel savings over longer periods of operation, as energy-related.

In this case, as in earlier rate cases, II has alleged a lack of fuel symmetry in cost methodologies in which some production plant is allocated on average demand (i.e., on energy consumption) or in which any production plant is classified as energy-related. In this case the fuel symmetry problem is described as the failure to recognize the tradeoffs between capital costs and operating costs on the energy mix. (Pollock, Tr. 2807) I disagree with II that a fuel symmetry problem exists. I agree with the Office of Public Counsel that Exhibit 353 shows that with one very slight exception, the basic EP method yields a closer match between the classes' allocated shares of baseload plant cost responsibility and their allocated share of inexpensive baseload energy under the Commission's current average cost-based fuel pricing practices. (Brief, p. 107; Wright, Tr. 2072-2073)

While the EP method may be an oversimplification of the generation planning process, staff believes it most closely reflects the generation planning process and cost causation. A methodology in which all production plant cost is classified as demand-related <u>completely ignores</u> the impact of the economic considerations in the generation planning process on the level of production plant investment. In the Near Peak study all production plant investment is classified as demand-related; 92.31 percent is classified as demand-related in the 12 CP and 1/13th study.

The Near Peak study also does not properly reflect the impact of the Southern IIC. Under the IIC each Southern operating company pays (or receives) pool capacity charge (or revenues) on the company's equalized reserves during each of Southern System's 12 monthly peak hours. The Near Peak study includes hours for only two months. (Exhibit 368) Therefore, it ignores the cost impact on Gulf's customers of demands incurred during the other ten months.

I prefer the EP to the Refined Equivalent Peaker (REP) because I agree with Mr. Wright that the REP does not track utilities' actual generation expansion planning processes. The REP methodology is the same as the EP except that energy-related costs are allocated to the classes on the basis of their energy usage in the break-even hours, i.e., the 1430 hours of highest usage in this case. The REP does not track utilities' planning processes because it assigns costs responsibility on only 1430 hours while total energy is used in the generation expansion planning process. (Wright, Tr 2077) Secondly, there is the question of the appropriateness of the use of the highest-demand hours under the load duration curve because, as Mr. Wright testifies,

> [F]or technical reasons, a utility would almost surely not build a baseload plant to operate only in the highest demand hours of the year. This is because these hours generally fall within daily peak periods, of a few hours a day, and utilities strenuously endeavor to avoid frequent cycling of baseload units in order avoid wear on boiler components that results from frequent heating and cooling. Tr. 2078

SCHEDULE 1
JULY 27, 1990

COMPARISON OF RATES OF RETURN AT PRESENT
RATES FOR VARIOUS COST OF SERVICE STUDIES

RATE CODE	COMPANY'S 12 CP &1/13 (1) PRESENT ROR / INDEX	ADJUSTED 12 CP &1/13 (2) PRESENT ROR / INDEX	STAFF-REQUESTED 12 CP & 1/13 (3) PRESENT ROR / INDEX	EQUIVALENT PEAKER (4) PRESENT ROR / INDEX	REF.EQUIVALENT PEAKER (5) PRESENT ROR / INDEX	II'S NEAR PEAK (6) PRESENT ROR / INDEX
RS	5.66% / 0.86	5.74% / 0.87	5.85% / 0.89	6.36% / 0.96	6.04% / 0.92	5.95% / 0.90
GS	13.27% / 2.01	13.45% / 2.04	13.62% / 2.06	14.05% / 2.13	13.59% / 2.06	12.21% / 1.85
RS-GS	6.16% / 0.93	6.24% / 0.95	6.36% / 0.96	6.87% / 1.04	6.54% / 0.99	6.39% / 0.97
GSD	7.22% / 1.09	7.32% / 1.11	7.07% / 1.07	6.73% / 1.02	6.66% / 1.01	6.49% / 0.98
LP/LPT	6.63% / 1.00	6.62% / 1.00	6.33% / 0.96	5.63% / 0.85	6.09% / 0.92	5.93% / 0.90
PX/PXT	8.33% / 1.26	7.49% / 1.13	7.28% / 1.10	5.56% / 0.84	7.44% / 1.13	9.95% / 1.51
SE a			7.27% / 1.10	6.11% / 0.93	6.92% / 1.05	
LP-PX-SE	7.19% / 1.09	6.92% / 1.05	6.79% / 1.03	5.73% / 0.87	6.62% / 1.00	7.14% / 1.08
OSI-II	7.43% / 1.13	6.04% / 0.91	5.96% / 0.90	5.06% / 0.77	5.94% / 0.90	8.50% / 1.29
OS-III	21.48% / 3.26	21.77% / 3.30	19.47% / 2.95	17.24% / 2.61	19.74% / 2.99	25.29% / 3.83
SS	7.29% / 1.10	7.39% / 1.12	7.76% / 1.18	11.39% / 1.73	11.57% / 1.75	11.07% / 1.68
TOT.RET	6.60% / 1.00	6.60% / 1.00	6.60% / 1.00	6.60% / 1.00	6.60% / 1.00	6.60% / 1.00

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Sources: (1) Exhibit 231; (2) Exhibit 231 adjusted as explained in note below; (3) Exhibit 501; (4) Exhibit 503; (5) Exhibit 504; Exhibit 371.

Note on adjustment to Gulf's 12 CP & 1/13th cost of service study (Exhibit 231): To reflect an underallocation of cost, for the PXT and LP/LPT classes, rate base was increased by 6.84 percent and .79 percent, respectively, of the transmission and demand-related production plant rate base and the demand-related production materials and supplies. The NOI for these classes was reduced by 6.84 and .79 percent, respectively, of the total transmission and demand-related production O&M expense, production plant A&G expenses and transmission and demand-related depreciation expense. For the OS class the rate base and NOI from the staff-requested 12 CP & 1/13th cost of service study (Exhibit 501) was substituted for the values in Exhibit 231. All classes' rate base and NOI were adjusted proportionately to equal the company's filed levels of rate base and NOI.

a For the company's and the adjusted 12 CP and 1/13th cost of service studies, SE is included in LP/LPT and PX/PXT.

Docket No. 891345-EI
July 26, 1990
1709E

ISSUE 121: If a revenue increase is granted, how should it be allocated among customer classes? (TROMBINO)

RECOMMENDATION: The increase should be spread among the rate classes in a manner that moves class rate of return indices closer to parity. Based on the 12 CP and 1/13th energy cost methodology recommended in Issue 115, the RS and OS-II rate classes should receive an increase of two times the system average increase with adjustments (fuel and ECCR). The GS class should receive a reduction commensurate with equalization of RS and GS rates pursuant to the Stipulation in Issue 115a. The OS-III class should receive a decrease of $50,000 as proposed by the company. Because OS-III and OS-IV are combined on the allocation schedule, and OS-IV is getting a $2,000 increase, the net amount is $48,000. The increase given to GSD, LP/LPT, PX/PXT and SS should leave these classes in essentially the same relative position in terms of rates of return.

If the Equivalent Peaker Cost Study is approved, the maximum increase to any one class should be approximately 1.6 times the system average increase. GS would receive a decrease commensurate with setting RS and GS rates equal, and OS-III would receive a $48,000 decrease. Because OS-III and OS-IV are combined on the allocation schedule, and OS-IV is getting a $2,000 increase, the net amount is $48,000. Because the SS class is already 1.5 times the system rate of return, no increase should be allocated to that class. The GSD class would be allocated the remainder of the increase.

POSITION OF PARTIES

GULF: The increase should be spread among the rate classes in a manner that moves class rate of return indices closer to parity. To the extent possible, increases should be limited to 1.5 times the retail system percentage increase in total revenues. It may be appropriate to lower a class' rates.

OPC: Any increase should be allocated among rate classes so as to bring class rate of return indices closer to parity as indicated by the cost of service study approved by the Commission in this case, subject to the transition rules usually followed by the Commission. It should be noted, however, that in determining parity, the Commission should recognize any risk differentials that exist between classes.

II: Agree with Staff. (Pollock)

FEA: Class increases should be calculated to move all classes toward cost of service as established by the Gulf Power Company class cost-of-service study, with the LP/LPT and PXT classes combined. This would result in a lower than average increase for these classes.

FRF: Agree with OPC.

STAFF ANALYSIS: Commission policy has been to spread increases in revenues to classes in a manner that moves class rate of return indices as close to parity as reasonable. Generally, the Commission has applied the following constraints: (1) No class receives an increase greater than 1.5 times the system average increase with all applicable adjustments (fuel, ECCR, and oil backout), and (2) no class receives a decrease.

Per the Stipulation in Issue 115a, the GS class has been lowered to set its rates equal to RS. (See Issue 115a) Staff supports Gulf's proposal to decrease the OS-III rate to bring the parity ratio for this class down to approximately 1.8. All parties agree that the revenue increases allocated among customer classes should reflect the cost of providing service.

Staff's recommended increase or decrease in present revenues for each rate schedule based on the company's 12 CP and 1/13th cost study adjusted by staff (See Issue 115) is shown in Schedule 2, column 6. The Stipulation on Issue 115a that the RS and GS classes charge be set equal results in a substantial decrease to the GS class. Staff also supports the company's proposal to decrease rates for OS-III. The proposed 9.58 percent reduction brings the parity ratio for the class to 2.33 from 3.31. Because of these decreases, it is necessary to deviate from the Commission's policy of not giving any class an increase greater than 1.5 times the system average increase. If these classes get a smaller percentage increase, the other classes would move farther from parity. Therefore, staff recommends the RS and OS-I/II classes be given two times the system average increase because the class is below parity. The combined increase to RS-GS is 3.96%, with GS receiving a reduction of 26.38%. The GSD, PX, OS, and SS classes' rate of return indices improve relative to present rates. The only exception is for rate LP/LPT. Staff has tried to keep the rate of return indices for GSD, LP, PX and SS as close to each other as possible, consistent with past practice. A revenue increase of 1.5 times the system average increase to the RS class would result in a little improvement to the parity ratios of the other rate classes and greater deterioration for GSD.

Implementation of the Primary Staff Recommendation would narrow the range in class indices from 0.87 to 3.31 at present rates to 0.98 to 2.33 at proposed rates.

If the Equivalent Peaker method is approved (Issue 115), and SE approved as a separate rate class (Issue 137), and the stipulation is accepted that RS and GS rates would be equal (Issue 115a), the following spread of the increase is appropriate.

GS would receive the decrease necessary to equalize the RS and GS rates. OS-III would receive the $50,000 decrease recommended by the utility to improve its parity ratio. Because OS-III and OS-IV are combined on the allocation schedule and OS-IV is given a $2,000 increase the net amount is a

$48,000 decrease. Currently, this class is earning 2.61 times the system rate of return. The staff endorses the company's proposed reduction in rates for this class to bring its rate of return closer to parity. The remainder of the classes except GSD and SS would receive the maximum increase. The 1.6 percent times the system average maximum increase resulting from this approach is not significantly different from the Commission policy of limiting increases to 1.5 percent. Again, due to the decreases in GS and OS-III, the 1.5 percent cap is not feasible because the remaining classes would then have to absorb a greater increase than if no class received a decrease. The SS class should not get any increase because its rate of return is well above parity. Therefore, the remainder of the increase would be assigned to GSD.

The proposed spread places the combined RS/GS class at a parity ratio of 1 and improves the parity ratios for GSD (1.04 to 1.01), OS-II (.77 to .80), and SS (1.73 to 1.51). Parity for RS worsens (.96 to 1.03) but this shift may be justified to offset the large decline in GS rates. (See Schedule 2)

This distribution of the increase narrows the range of class indices from .77 to 2.61 at present rates to .80 to 1.81 at the staff's proposed revenue increase, thereby improving the relative position of all classes in terms of contribution to total company revenues.

GULF POWER COMPANY
DOCKET NO. 891345-EI
RECOMMENDED REVENUE INCREASE BY CLASS
BASED ON COMPANY'S 12 CP AND 1/13TH COST OF SERVICE STUDY
SUMMARY OF CLASS ROR'S AND % INCREASE (000 DOLLARS)

SCHEDULE 2
JULY 30, 1990

(1) RATE CODE	(2) RECOMM. RATE BASE	(3) RECOMM. PRES.NOI	(4) PRESENT ROR/ INDEX	(5) INCREASE FROM SERVICE CHARGES	(6) INCREASE FROM SALES OF ELECTRICITY	(7) TOTAL INCREASE IN REVENUE	(8) REQUIRED NOI	(9) RECOMMENDED ROR/ INDEX	(10) % INCREASE IN REV FROM SALES OF ELEC W/ADJ	BASE
RS	$506,165	$30,406	6.01% / 0.87	$47	$14,148	$14,195	$39,106	7.73% / 0.98	6.86%	10.75%
GS	$35,574	$5,010	14.08% / 2.04	$47	($5,201)	($5,154)	$1,851	5.20% / 0.66	-26.38%	-34.71%
RS-GS	$541,740	$35,417	6.54% / 0.95	$94	$8,947	$9,041	$40,958	7.56% / 0.96	3.96%	6.11%
GSD	$187,196	$14,347	7.66% / 1.11	$1	$2,087	$2,088	$15,627	8.35% / 1.06	2.30%	4.02%
LP	$111,063	$7,704	6.94% / 1.00	$0	$2,627	$2,627	$9,314	8.39% / 1.06	4.37%	9.01%
PX	$57,653	$4,520	7.84% / 1.13	$0	$500	$500	$4,826	8.37% / 1.06	1.30%	3.06%
OSI-II	$14,285	$903	6.32% / 0.91	$0	$330	$330	$1,105	7.74% / 0.98	6.85%	8.78%
OS-III	$652	$149	22.85% / 3.31	$0	($48)	($48)	$120	18.40% / 2.33	-9.58%	-14.29%
SS	$3,303	$255	7.72% / 1.12	$0	$32	$32	$275	8.33% / 1.06	3.64%	4.07%
TOT.RET	$915,892	$63,295	6.91% / 1.00	$95	$14,475	$14,570	$72,224	7.89% / 1.00	3.43%	5.82%

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GULF POWER COMPANY
DOCKET NO. 891345-EI
RECOMMENDED REVENUE INCREASE BY CLASS
BASED ON EQUIVALENT PEAKER COST OF SERVICE STUDY
SUMMARY OF CLASS ROR'S AND % INCREASE (000 DOLLARS)

SCHEDULE 3
JULY 30, 1990

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	
RATE CODE	RECOMM. RATE BASE	RECOMM. PRES.NOI	PRESENT ROR/ INDEX	INCREASE FROM SERVICE CHARGES	INCREASE FROM SALES OF ELECTRICITY	TOTAL INCREASE IN REVENUE	REQUIRED NOI	RECOMMENDED ROR/ INDEX	% INCREASE IN REV FROM SALES OF ELEC W/ADJ	BASE
RS	$479,810	$31,946	6.66% / 0.96	$47	$11,303	$11,350	$38,902	8.11% / 1.03	5.48%	8.59%
GS	$34,443	$5,069	14.72% / 2.13	$47	($5,383)	($5,336)	$1,799	5.22% / 0.66	-27.30%	-35.92%
RS-GS	$514,254	$37,015	7.20% / 1.04	$94	$5,920	$6,014	$40,701	7.91% / 1.00	2.62%	4.04%
GSD	$195,178	$13,756	7.05% / 1.02	$1	$2,941	$2,942	$15,559	7.97% / 1.01	3.24%	5.67%
LP/LPT	$92,714	$5,465	5.89% / 0.85	$0	$2,489	$2,489	$6,990	7.54% / 0.96	5.48%	11.13%
PX/PXT	$49,110	$2,862	5.83% / 0.84	$0	$1,509	$1,509	$3,787	7.71% / 0.98	5.48%	12.89%
SE	$45,787	$2,932	6.40% / 0.93	$0	$1,400	$1,400	$3,790	8.28% / 1.05	5.48%	12.23%
LP-PX-SE	$187,611	$11,258	6.00% / 0.87	$0	$5,398	$5,398	$14,566	7.76% / 0.98	5.48%	11.86%
OSI-II	$15,540	$823	5.30% / 0.77	$0	$264	$264	$985	6.34% / 0.80	5.48%	7.03%
OS-III	$776	$140	18.04% / 2.61	$0	($48)	($48)	$111	14.30% / 1.81	-9.58%	-14.29%
SS	$2,533	$302	11.92% / 1.73	$0	$0	$0	$302	11.92% / 1.51	0.00%	0.00%
TOT.RET	$915,892	$63,295	6.91% / 1.00	$95	$14,475	$14,570	$72,224	7.89% / 1.00	3.43%	5.82%

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STIPULATED
ISSUE 115a: How should Gulf's GS rates be designed? (KUMMER)

RECOMMENDATION: The GS rate should be set equal to the RS rate.

POSITION OF PARTIES

GULF: Gulf's GS/GST rates should be set equal to the RS/RST rates. Combining the two classes for rate design purposes would increase RS/RST unit costs slightly but would result in a substantial decrease in GS/GST unit costs.

OPC: Gulf's GS rates should be set equal to the company's RS rates.

STAFF ANALYSIS: Cost of service studies in other utilities have consistently shown that the cost to serve RS and GS are nearly identical. In fact, the cost to serve GS may be less than the cost to serve RS. The character of service is essentially the same. Both are billed on the basis of a customer charge and KWH charge with no demand metering. While it is not advisable to set GS rates below RS rates to avoid rate switching, setting RS and GS charges equal is reasonable, based on the experience of other utilities. Gulf's proposed customer charges in their brief do not reflect the stipulation. Since the all parties stipulated to this issue, the rates proposed by staff equalizes both customer and energy charges for the RS/RST and GS/GST classes.

Staff notes that this stipulation requires a substantial decrease in existing GS rates. Given Gulf's cost assignment, it may be advisable to take a more gradual approach to equalizing RS and GS rates for this utility. Rates have been designed based on the stipulation in Issue 115a, however, the equalization of RS and GS resulted in a much large decrease in GS than was anticipated. If the Commission agrees that the reduction in GS is too drastic to undertake in one step, staff would withdraw from the stipulation and apply a lesser decrease to the GS class.

STIPULATED
ISSUE 122: If an increase in revenues is approved, unbilled revenue will increase. Is the method used by the utility for calculating the increase in unbilled revenues by rate class appropriate? (KUMMER)

RECOMMENDATION: Yes. The assumption that unbilled revenues will bear the same relationship to the increase granted as to current revenues is a reasonable basis for assigning unbilled revenues.

POSITION OF PARTIES

GULF: Agree with Staff.

OPC: Agree with Staff's position as stated in Order No. 23025.

STAFF ANALYSIS: The method employed by Gulf to determine unbilled revenues relies on a sophisticated tracking mechanism which incorporates their seasonally differentiated rate structure. The method outlined in the current MFR Schedule E-15 would distort the amount of unbilled revenues for Gulf because it relies on a constant per KWH cost, which does not consider the variable impact of seasonal pricing. Gulf's method relies on historical relationships. It assumes that the amount of unbilled due to the increase will bear the same relationship to the amount of the increase as the total unbilled bears to the total revenues. Staff and parties agree that this assumption is reasonable.

STIPULATED
ISSUE 123: Should the increase in unbilled revenues be subtracted from the increase in revenue from sales of electricity used to calculate rates by class? (KUMMER)

RECOMMENDATION: Yes. If not, the increase in rates will be overstated.

POSITION OF PARTIES

GULF: Agree with Staff.

OPC: Agree with Staff's position as stated in Order No. 23025.

STAFF ANALYSIS: The purpose in calculating unbilled revenue due to the increase in rates is to determine the dollars the company will receive for service provided but not billed at the time the rates go into effect. This increase over what they would have received for that same service under current rates must be subtracted from the total increase granted before designing permanent rates. If not, the incremental revenues due simply to the timing of billing relative to the effective date of the increase approved will be recovered again in the setting of final rates. Parties agreed that the anticipated amount of increase in unbilled revenues should be subtracted from the final increase granted prior to setting rates.

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ISSUE 124: What are the appropriate customer charges? (KUMMER)

RECOMMENDATION: The customer charges should be set as follows:

RATE CLASS	UNIT COST	CURRENT CHARGES	GULF'S PROPOSAL	STAFF PROPOSAL
RS	$ 7.94	$ 6.25	$ 8.00	$ 8.00
RST		9.25.	11.00	11.00
GS	17.34	7.00	10.00	8.00
GST		10.00	13.00	11.00
GSD	41.47	27.00	40.00	40.00
GSDT		32.40	45.40	45.40
LP/LPT	447.83	51.00	225.00	225.00
PX/PXT	1222.21	146.00	570.00	570.00

POSITION OF PARTIES

GULF: The level of customer charges should reflect the unit costs assigned through the approved cost of service study (23-MCP and 1/13 energy).

OPC: Customer charges should be set as close as reasonably practicable to the customer unit costs indicated by the Commission-approved cost of service study.

II: The customer charges should parallel the unit cost developed in the approved cost of service study.

FRF: Agree with II.

STAFF ANALYSIS: Customer charges are designed to recover costs associated with the number of customers served. These costs include primarily the costs of billing and metering and customer service. Given that costs are properly allocated to the customer component, the charge for each class should reflect the cost to provide such services.

The customer unit costs cited above are taken from the staff's recommended cost of service study using the 12 CP and 1/13th Energy Cost methodology. If, however, the Commission decides to adopt a different cost methodology the costs allocated to the customer component does not vary significantly across all cost methodologies introduced in this docket.

Staff is in agreement with the company that if the customer charge is set below cost, seasonal residential customers may not pay their full share of on-going customer billing costs. Since the balance of the customer cost is reflected in the energy charge, customers who generate less than average KWH usage may not be covering their customer costs.

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Staff supports most of Gulf's proposed customer charges. Gulf did not, however, propose combined RS/RST and GS/GST customer charges pursuant to Stipulated Issue 115a. The proposed charges for RS/RST and GS/GST reflect the stipulation on Issue 115a, equalizing GS and RS rates.

The customer charges for the LP/LPT and PX/PXT classes are substantially below their unit costs. However, the charges requested by the company represent a four fold increase in current customer charges for these classes. Staff agrees that this is a significant one-time increase and in the interest of rate stability and predictability, staff supports Gulf's charges for these classes. The remaining classes track costs fairly closely.

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ISSUE 125: What are the appropriate demand charges? (KUMMER)

RECOMMENDATION: The level of demand charge for time-of-use rates depends on the Commission's decision of the appropriate cost of service methodology (Issue 115) and on the proper design of time-of-use rates (Issue 128). Staff's recommeded demand charges are based on the Equivalent Peaker cost methodology recommended in Issue 115 and the TOU rate design recommended in Issue 128. Also shown are the proposed demand charges based on the alternate staff recommended cost method, the Equivalent Peaker. The appropriate demand charges are as follows:

DEMAND CHARGE	12CP and 1/13th COST STUDY	EQUIVALENT PEAKER STUDY
GSD	$ 4.52	$ 4.52
GSDT		
Maximum	2.15	2.15
On-Peak	5.00	3.06
LP	8.51	6.00
LPT		
Maximum	1.81	1.70
On-Peak	7.26	4.45
PX	8.26	7.00
PXT		
Maximum	0.68	0.56
On-Peak	7.75	5.06

POSITION OF PARTIES

GULF: The concept of lower demand charges for GSD/GSDT than for LP/LPT and PX/PXT, as proposed by Gulf is appropriate. The GSD/GSDT class has more diversity and thus imposes less cost per unit of billing demand on the system peak than higher load factor classes. The appropriate demand charges are those porposed based on the revised cost of service study and rate design as developed in hearing exhibit 480 and shown below:

STANDARD RATE	PRESENT CHARGE	TOU RATE	DEMAND CHARGE
	$	GSDT	
GSD	4.52	Max	2.20
		On Peak	2.46
LP	8.51	LPT	
		Max	4.14
		On Peak	4.50
PX	8.26	PXT	
		Max	4.00
		On Peak	4.31

OPC: Basically agree with Staff position as stated in Order No. 23025.

II: Support approach of Gulf as to PX/PXT.

FRF: Agree with Staff.

STAFF ANALYSIS: Demand charges should reflect the production, transmission and distribution costs allocated to each class. The concept of lower demand charges for GSD/GSDT classes than for LP/LPT and PX/PXT classes as proposed by the company more appropriately recognize the diversity factor in demand found in GSD compared to LP/LPT and PX/PXT. Recommended KW charges for time of use rates, however, reflect Staff's position in Issue 128 and Issue 115. As can be seen, the Equivalent Peaker methodology collects less from demand reflecting less costs allocated on demand than is found under the 12 CP and 1/13th methodology.

The demand charges for firm rates represent the allocated cost of production, transmission, distribution, and any shortfall from the customer costs not recovered in the proposed customer charge. The time-of-use rate design reflects Staff's position in Issue 128 which sets KWH energy charges at energy unit cost for the class, recovers unit distribution costs in the maximum demand charge and sets the on-peak demand charge to recover transmission and production costs.

Gulf has proposed TOU demand charges based on the Load Factor methodology. Both methodologies begin with the cost of service study. They diverge in how the demand costs are split between maximum demand and on peak demand. Off peak costs consist primarily of costs for local facilities which must be in place for the customer all the time. Therefore, staff proposes to set the maximum demand charge at the distribution unit cost and collect the remainder from the on peak demand charge. Staff believes that the distribution costs incurred to serve the customer if assessed on actual maximum demand, whenever it occurs, properly recovers the local facilities in-place to serve the customer. Production related costs are more properly a function of the customer's on-peak demand and should be recovered through the on peak demand charge. Therefore, staff's proposed demand charges more closely track the cost study than the company's load factor method derived charges.

ISSUE 126: The company presently has seasonal rates for the RS and GS rate classes. Should seasonal rates be retained for RS and GS? If so, should they be required for GSD/GSDT, LP/LPT and PX/PXT?

RECOMMENDATION: Seasonal rates should be eliminated from Gulf's tariff. However, if seasonal rates are retained for RS and GS, they should be required for all rate classes.

POSITION OF PARTIES:

GULF: Yes. Seasonal rates for rates RS and GS should be retained. The company has had seasonal energy charges in rates RS and GS since 1962 in order to send the proper price signal to the summer peaking customers as an incentive to control peak demand. The company at this time is not proposing seasonal demand rates.

OPC: If the Commission determines that seasonal rates are cost-based and therefore should be retained for Gulf's RS and GS classes, then seasonal rates should also be implemented for Gulf's other rate classes. If the Commission determines that seasonal rates are not cost-based, then they should be eliminated for all rate classes.

FRF: Agree with Staff

STAFF ANALYSIS: Witness Haskins indicated that it was his opinion that seasonal rates were cost-based although the company did not provide any supporting seasonal costs data in this case (TR 2014). He also stated that seasonal rates charged the ultimate consumer of electricity do not track the company's cost of capacity, when Gulf buys power from the Southern pool. These costs represent a significant portion of Gulf's cost of service during those hours Gulf buys power. The energy portion of the costs, under the IIC, varies by time period as it occurs on the company's system (TR 2016). Thus, this evidence suggests that the price signal sent by the present seasonal differential under the RS and GS rate classes may not represent the true cost to the ultimate consumer on Gulf's system, thereby, tempering the reduction in peak-related costs, improvement of system load factor, and conservation of summer consumption sought by the seasonal design (TR 2013). A flat charge per KWH based on average costs for the RS and GS classes may produce a clearer price signal than the seasonal rates design proposed by the company.

Hearing exhibit 490 shows a comparison of Gulf's highest winter MW demand to the highest summer MW demand for the years 1982 through 1989. This pattern indicates two years which Gulf's winter peak demand exceeds the summer peak demand. Also, during the other years the magnitude of winter to summer peak was 85% to 95%. Witness Haskins believes that unless the gap between the winter and summer peak demands is closed completely that Gulf would continue to need a seasonal pricing differential as part of its rate design. Witness Haskins indicated that it was important to note that although the historical peaks are important, the company's planning horizon was an important element to consider in the design of seasonal rates (TR 2022-23).

Although the evidence is not clear regarding retention of seasonal rates for the RS and GS classes, witness Haskins acknowledged that the patterns of Coincident Peak KW (CP KW) for the demand rate classes exhibit seasonal load patterns (TR 2017-18). Additionally, the Office of Public Counsel states in its brief, that if seasonal rates are appropriately cost-based, the company's not proposing seasonal rates for the demand-metered rate classes is not justifiable because it unduly discriminates against the RS and GS classes.

Staff recommends the Commission eliminate seasonal rates for the RS and GS classes because the seasonal pricing differential does not appear to be cost-based and may not be sending the appropriate price signal during the hours Gulf buys power from the Southern pool. However, if the Commission is desirous of retaining seasonal rates for Gulf's RS and GS classes, then, seasonal rates should be designed for the GSD/GSDT, LP/LPT, and PX/PXT rate classes. The staff currently does not have data to develop seasonal rates for the remaining classes. If the Commission approves seasonal rates for all classes, the utility must be ordered to supply the necessary information for rate design.

ISSUE 127: If seasonal rates are continued, how should they be designed?

RECOMMENDATION: The seasonal price differential for the RS and GS classes should be set at the company's proposed ratio of 1.18 to 1.00. The seasonal price differential should be uniform across the GSD/GSDT, LP/LPT, and PX/PXT rate classes and recovered through the standard demand charge for non-time of use rates and the on-peak demand charge for time of use rates.

POSITION OF PARTIES

GULF: The same ratio of summer price to winter price as in Gulf's present RS rate should be retained, and this same ratio should be used to obtain the GS seasonal differential.

OPC: If continued, seasonal rates should probably differ from non-seasonal rates by having greater amounts of demand-related production and transmission costs incorporated into the demand charges (for demand-metered customers) or non-fuel energy charges (for non-demand-metered customers) applicable during the months of the defined peak season or seasons, and by seasonally-differentiated fuel charges.

FRF: No position.

STAFF ANALYSIS: Witness Haskins stated that the appropriate recovery of production and transmission demand-related seasonal costs from the GSD/GSDT, LP/LPT, and PX/PXT classes is through the on-peak demand charge of the time of use customers or the standard demand charge of non-time of use customers. Also, witness Haskins stated that a method splitting demand-related costs between on-peak and off-peak periods and, recovering all on-peak costs during the summer months would be appropriate as a step towards designing seasonal demand rates (TR 2019).

The Office of Public Counsel's (OPC) position states that the justification for seasonally differentiated rates would primarily be attributable to differences in peak-demand-related production and transmission costs between seasons. OPC suggests using aggregate reliability index values in the peak and off-peak months as the basis for allocating the demand-related production and transmission costs. Further, OPC states that energy-related production costs, and the non-fuel energy charges based on these costs should not vary by season with the possible exception of variable O&M costs, if identifiable.

Witness Haskins acknowledged that the patterns of Coincident Peak KW (CP KW) for the demand rate classes exhibit seasonal load patterns (TR 2017-18) (Exhibit 491). If the Commission votes to implement a seasonal differential for the company's demand-metered rate classes, staff believes that adopting a differential of 1.18 to 1.00, as proposed by the company for RS and GS, or a uniform differential across rate classes is reasonable.

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ISSUE 128: How should time-of-use rates be designed?

RECOMMENDATION: Time-of-use rates should be developed as follows: The energy KWH charge should be set at class energy unit cost; the maximum billing demand charge should be set equal to distribution unit cost. The on-peak demand charge would be an amount sufficient to recover the remaining revenue requirement, including costs relating to the transmission plant and the demand-related production plant.

POSITION OF PARTIES

GULF: All TOU rates should be designed using the Load Factor Methodology as approved in Gulf's last three rate cases.

OPC: Agree with staff's position as stated in Order No. 23025.

II: Generally support the concept outlined in staff's position.

FRF: Agree with staff.

STAFF ANALYSIS: Two methodologies were presented at the hearing for the design of time of use rates.

Witness Haskins' testimony supports use of the load factor methodology approved by the Commission in the company's last three rate cases. Staff believes that the major drawback to the company's proposed load factor methodology is that it does not track costs as well as the time of use methodology (TOU) proposed by OPC's witness Wright.

OPC's witness Wright supports the use of a methodology which would recover distribution-related plant costs from the maximum demand charge; production and transmission-related demand costs through the on-peak demand charge; and energy-related production plant and operations and maintenance expenses through the energy charge (TR 2085-86). Mr. Wright's approach also includes a ratchet for recovery of local distribution plant costs. Staff believes the rate design for the maximum demand charge should be based on actual metered demand and not ratcheted KW as proposed by Mr. Wright.

Staff recommends time of use rates be calculated as follows:

1. The on-peak and off-peak non-fuel energy charges would be set equal to the energy unit cost from the cost study. (This would include the energy-related production plant and operations and maintenance expenses.)

2. The maximum billing demand charge (which is applied to the customer's maximum demand whenever it occurs) would be equal to the distribution plant unit cost.

3. The on-peak demand charge would be an amount sufficient to

recover the remaining revenue requirement including the transmission plant and the demand-related production plant.

Staff recommends the RST and GST rate classes be set equal to each other per the stipulation of issue 115a. Because customers served under RST and GST do not pay demand charges, the cost of distribution plant; transmission and demand-related production plant should be recovered through the on-peak energy charge under Staff's recommended methodology.

The resulting ratios between the charges of each class' time of use rate would vary by the cost of service methodology and revenue increase granted by the Commission. For example, if the Commission approved the equivalent peaker cost allocation methodology (EPC) and Staff's recommended TOU rates design, then the resulting ratio between the on-peak demand charge and maximum demand charge would be smaller than under a 12 CP & 1/13th energy cost allocation methodology (See Staff recommendation for issue 125). This is because a much greater proportion of production demand-related cost would be recovered through the energy charges of each respective time of use rate (TR 3178-79). The total class revenue requirement would be recovered regardless of time of use methodology selected; however, the rate per KW of on-peak demand would be greater under Staff's recommended TOU methodology based on a 12 CP & 1/13th energy costing approach, than under Staff's recommended TOU methodology using an EPC costing approach.

The following time of use rates are at Staff's proposed rates under the company's 12CP & 1/13 allocation with Staff adjustments (See Issue 115), using the company's load factor methodology and Staff's recommended TOU design.

RST/GST		COMPANY'S LOAD FACTOR	STAFF'S RECOMMENDED TOU RATE DESIGN
OFF-PEAK	KWH	$0.01567	$0.00594
ON-PEAK	KWH	$0.08459	$0.10614
GSDT			
OFF-PEAK	KWH	$0.00474	$0.00445
ON-PEAK	KWH	$0.02254	$0.00445
ON-PEAK	KW	$3.00	$5.00
MAXIMUM	KW	$2.50	$2.15

LPT

OFF-PEAK	KWH	$0.00300	$0.00417
ON-PEAK	KWH	$0.01010	$0.00417
ON-PEAK	KW	$4.50	$7.26
MAXIMUM	KW	$4.14	$1.81

PXT

OFF-PEAK	KWH	$0.00260	$0.00406
ON-PEAK	KWH	$0.00964	$0.00406
ON-PEAK	KW	$4.31	$7.75
MAXIMUM	KW	$4.00	$0.68

The following time of use rates are at Staff's proposed rates under the equivalent peaker cost allocation approach (See Issue 115), using the company's load factor methodology and Staff's recommended TOU design.

RST/GST		COMPANY'S LOAD FACTOR	STAFF'S RECOMMENDED TOU RATE DESIGN
OFF-PEAK	KWH	$0.01535	$0.01251
ON-PEAK	KWH	$0.08287	$0.08874
GSDT			
OFF-PEAK	KWH	$0.00563	$0.01130
ON-PEAK	KWH	$0.02675	$0.01130
ON-PEAK	KW	$2.70	$3.06
MAXIMUM	KW	$2.40	$2.15
LPT			
OFF-PEAK	KWH	$0.00481	$0.01025
ON-PEAK	KWH	$0.02308	$0.01025
ON-PEAK	KW	$3.50	$4.45

MAXIMUM	KW	$2.80	$1.70
PXT			
OFF-PEAK	KWH	$0.00305	$0.00939
ON-PEAK	KWH	$0.01624	$0.00939
ON-PEAK	KW	$4.00	$5.06
MAXIMUM	KW	$3.70	$0.56

The load factor methodology results in rates which recover some production and transmission costs during the off-peak periods through the maximum demand charge (TR 3395-3396, 3346-3347, 3422-3424). Staff believes that a time of use rate design should be based on how closely the rates charged customers track the type of cost imposed on the system. In general, we believe that the demand cost incurred during off-peak periods is primarily that cost associated with local distribution facilities. Staff has proposed that the maximum demand charge be set equal to the distribution unit costs. Production and transmission costs are more closely associated with on-peak demand and should therefore be recovered in an on-peak charge.

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ISSUE 130: The company currently gives transformer ownership discounts of $0.25 per KW for customers taking service at primary voltage and $0.70 per KW for customers taking service at transmission levels. Is the current level of discounts appropriate?

RECOMMENDATION: The transformer ownership discount for primary level customers should be set at $0.35/KW/Month for GSD/GSDT and $0.42/KW/Month for LP/LPT. The transformer ownership discounts for transmission level customers should be set at $0.41/KW/Month for GSD/GSDT, $0.52/KW/Month for LP/LPT, and $0.11/KW/Month for PX/PXT.

POSITION OF PARTIES:

GULF: No. The company proposes that the transformer ownership and metering voltage discounts be approved, as developed in the response to Interrogatory Nos. 110, 111, and 113 of Staff's Eighth Set of Interrogatories (Exhibits 266, 267, and 269, respectively), after adjustment for the variance of demand and energy charges from unit cost. (Tr. pp. 1955-1957, 3389-3390)

OPC: Agree with staff's position as stated in Order No. 23025.

FEA: The current transformer ownership discounts do not reflect the full difference in cost of taking service at different voltage levels. Transformer ownership credits and metering credits should be based on the full difference in cost of service at different voltage levels. Voltage discounts for the LP/LPT class should be set at the levels determined in Exhibit 356 (CEJ-3), page 3.

FRF: No position.

STAFF ANALYSIS: The company's present tariff provides for two types of voltage discounts which apply when customers take service at voltages above the standard distribution level.

The first discount applies for customers owning their transformation equipment. There is a $0.25 per KW discount for primary customers and a $0.70 per KW discount for transmission level customers served under Gulf's GSD/GSDT, LP/LPT, and PX/PXT rate classes. These discounts are applied to the demand charge under the rate because the demand component includes costs associated with the company's total cost of transformation. Therefore, a transformer ownership discount is warranted to cover the transformer costs not required or avoided in serving a customer at the primary or transmission level.

The second discount applies to the energy and demand charge of customers to recognize transformation losses absorbed by the customer metered at primary or transmission level. This is appropriate because if a customer is metered at the "high" side or primary voltage, the meter will register more units than if it were located on the "low" side or secondary side due to line transformation losses. These discounts are usually refered to as metering voltage discounts to avoid confusion with the aforementioned transformer ownership discounts.

The Commission's policy regarding voltage discounts has been to credit customers' bills for the cost of transformation and transformation line losses. All of Florida's investor-owned electric utilities have voltage discounts recognizing the costs of transformation. However, Florida Power & Light does not allow a metering voltage discount. In FPL's last rate case, Docket 830465-EI, the Commission voted not to accept the stipulation between the parties that metering voltage discounts be set at 1% for primary level and 2% for transmission level customers.

The company has proposed to set the transformer ownership discounts and metering voltage discounts as developed in the response to Staff's Eighth Set of Interrogatories Nos. 110, 111, and 113, (Hearing exhibits Nos. 266, 267, and 269). The company also proposes to adjust the transformer ownership discounts by any variance of the actual demand charge and energy charge from unit cost approved by the Commission. The company's methodology is cost-based and consistent with the Commission's past policy of recognizing only transformation costs in developing voltage discounts (TR 2662, TR 3334).

FEA, through its witness Dr. Johnson, has proposed voltage discounts and metering discounts which include the costs of poles, overhead/underground conducters, lines, and transformers (Exhibit 356). Staff is concerned that discounts of the magnitude proposed by Dr. Johnson would result in uneconomic expense (possibly uneconomic duplication) and a greater increase in the company's rate base because customers may find it more cost-effective to install their own transformation equipment, at the expense of the general body of ratepayers. In fact, both Dr Johnson and Mr. O'Sheasy acknowledged that each time the company adds a customer it adds to current investment, so the average costs to all customers goes up (TR 3334).

FEA points out in its brief that Account 583 was omitted from the calculation of the transformer ownership discount found in exhibit 266. However, this account consists of overhead line expenses as well as transformation equipment. The allocated portion to LP/LPT for this account is approximately $45,000 of the total $875,000 system revenue requirement. Therefore, after removing expenses not associated with transformation, the impact on transformer ownership discounts is not great. Similarly, the impact of the other costs omitted, such as A&G related to transformation equipment is negligible on a billing KW basis. Further, there is no evidence in the record correcting these flaws pointed out by FEA.

Staff recommends the Commission approve the proposed transformer ownership and metering voltage discounts as set forth in exhibits nos. 266, 267, and 269. For simplicity of design, these discounts should not be adjusted for any variance in the demand charge from unit cost. For example, if the demand charge were set below unit cost, some transformation costs would be recovered through the energy charge under the rate, and the energy charge would need to be adjusted for customers providing their own transformation equipment. Witness Haskins agreed that a voltage discount in the energy charge would be needed to reflect the transformation cost being allocated by the energy charge (TR 3426).

ISSUE 131: All general service demand rate schedules (GSD, GSDT, LP, LPT, PX, and PXT) except Standby Service (SS) and Interruptible Standby Service (ISS) provide for transformer ownership and metering discounts. The company has proposed providing metering discounts only for standby service rate schedules. Should the SS and ISS rate schedules have provisions for both transformer ownership and metering voltage discounts? If so, should the level of the transformer ownership and metering voltage discounts for SS and ISS be set equal to the otherwise applicable rate schedule?

RECOMMENDATION: Yes, the SS and ISS classes should have provisions for transformer ownership and metering voltage discounts, however; the discounts should not be set equal to the otherwise applicable full requirements rate schedules. The level of the transformer ownership discount should be calculated based on 100 percent ratcheted billing demand in order to match the calculation of the local facilities demand charge applicable to standby service. Paying the same credits as applicable under full requirements rate schedules may provide too great a credit because these are calculated on the sum of annual billing demand (i.e. the sum of each customer's maximum demand during the year times 12).

POSITION OF PARTIES:

GULF: The SS and ISS rate schedules, pursuant to Order No. 17159, should only provide for metering voltage discounts. In addition, pursuant to that order, the discount should be applied only to the energy portion of the bill. The metering voltage discount to be applied to the energy portion of the bill should be the same as the discount for the otherwise applicable demand rate schedule.

OPC: Yes as to providing transformer ownership credits to standby customers; no as to setting them equal to those of the otherwise applicable full requirements rate schedules.

II: Yes, the SS rate schedule should have provisions identical to the corresponding full requirements demand schedules, as to transmission and metering discounts.

FEA: Yes and no.

FRF: No position.

STAFF ANALYSIS: At the hearing, witness Haskins acknowledged that providing transformer ownership discounts based on 100% ratcheted KW and the full transformation cost of the class that SS and ISS customers might otherwise belong seemed reasonable. Mr. Haskins also stated the appropriate billing determinents for calculating transformer ownership discounts for the SS and ISS classes were prepared in his late-filed deposition exhibit (Exhibit 515). If the Commission approves a transformer ownership discount for SS and ISS, the discounts would apply to the local facilities charge under the rates (TR 2020-2021). Further, the metering voltage discounts should be set equal to the otherwise applicable rate schedule for SS and ISS and apply to both the KW and KWH charge under the rate.

The company proposes to discount the energy charge of the SS and ISS class. This discount recognizes transformation line losses associate with energy only for primary and/or transmission level customers; it does not consider losses associated with demand. In support of its position, the company's brief sites Order 17159, which describes the methodolgy for designing non-fuel energy charges for backup and mainternance power (TR 3363-3364).

Staff recommends the Commission set the level of the transformer ownership based on 100% ratcheted billing KW in order to match the calculation of the local facilities charge. As acknowledged by witness Haskins at the hearing, the local facilities costs for SS and ISS include the cost of transformation. Therefore, it would be reasonable to design transformation discounts consistent with the design of local facilities charges under the SS and ISS rates. Further, the metering voltage discounts should apply to both the energy and demand charges under the SS and ISS rates, as is the practice with the company's other demand rate schedules (TR 2020-2021).

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STIPULATED
ISSUE 132: Should Gulf's proposed revision of the statement of the customer charge on the standby service rate schedules (SS and ISS) be approved?

STIPULATION: No. Order No. 17159 at 18 requires that, if a company does not have a curtailable rate schedule, it shall utilize the customer charge of the otherwise applicable general service large demand rate schedule plus $25 for the customer charge for standby service. Thus, the LP/LPT customer charge plus $25 should be the customer charge for all standby service customers, except for those taking supplementary service on PX/PXT for whom the charge should be the PX/PXT customer charge plus $25.

POSITION OF PARTIES

GULF: No. The wording of the customer charge section of the tariff needs to be revised in order to be in complete compliance with Order No. 17159.

OPC: Agree with Staff's position as stated in Order No. 23025.

II: Agree with Staff.

FRF: No position.

STAFF ANALYSIS: The company's present and proposed customer charges for standby service are not in conformance with the language in Order No. 17159 at 18 on the customer charge included in the above stipulation. The present customer charges are not in conformance because customers taking supplementary service on the small general service demand rate (GSD/GSDT) are charged $52, the present GSD customer charge plus $25. The proposed statement of the customer charge does not conform because it requires a customer to pay a customer charge of $25 for Standby Service in addition to the customer charge applied to their Supplementary Service.

To bring the statement of the customer charge in conformance with this order, the standby service customer charge should be $25 plus the approved LP/LPT customer charge for all standby service customers except those taking service on PX/PXT for whom the charge should be the approved PX/PXT customer charge plus $25.

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STIPULATED
ISSUE 133: Should Gulf's proposed change in the definition of the capacity used to determine the applicable local facilities and fuel charges on the standby service rate schedules (SS and ISS) be approved? (MEETER)

STIPULATION: No. The changes in the definition of the capacity used to determine the local facilities and [fuel] charges is not in conformance with the terms and conditions prescribed in Order No. 17159 for standby service.

POSITION OF PARTIES

GULF: No. The wording of the local facilities charge and fuel charge section of the SS/ISS tariffs, as originally proposed by Gulf, should not be approved.

OPC: Agree with Staff's position as stated in Order No. 23025.

FRF: No position.

STAFF ANALYSIS: Gulf has proposed a change from the use of the contracted standby service capacity to the use of the customer's total capacity requirement in the determination of the applicable local facilities demand charge for standby service. The same change in capacity was made on Sheet No. 6.32 to determine applicable fuel charges. Staff believes this change in the capacity used to determine the applicable charges is not in conformance with Order No. 17159. In Order No. 17159, the Commission found that, "the costs of dedicated local facilities... of standby customers shall be recovered through a charge consisting of the distribution unit cost, calculated using 100% ratcheted billing KW as the billing determinant, for the class to which the customer would otherwise belong." Order No. 17159 at 17. Staff believes that the class to which the customer would otherwise belong means the rate class under which the standby service alone would be served if the customer was not required to take service under the standby service rate schedule, i.e., if the customer was not a cogenerator. Therefore, the current tariff's paragraph on the local facilities charge is in conformance with Order No. 17159 and the revision should be denied.

Even though this issue was stipulated the company has proposed new language in its brief. Because this language appears to not be in conformance with Order No. 17159 for the reason outlined above and there is a stipulation on this issue, this language should also be denied.

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STIPULATED
ISSUE 134: Should the proposed paragraph on the monthly charges for supplementary service on the SS and ISS rate schedules be approved?

STIPULATION: No. To be consistent with the position on the customer charge for standby service, the second sentence should be eliminated or revised to indicate that the customer does not have a second customer charge for supplementary service.

GULF: Gulf will accept whatever wording the Commission deems appropriate.

II: Agree with Staff.

STAFF ANALYSIS: The company has proposed the addition of a paragraph on the monthly charges for supplementary service. The second sentence of the paragraph specifies that if the customer contracts for zero Supplementary Service, the Standby Service customer charge will be the customer charge for the otherwise applicable rate plus the normal $25 customer charge for Standby Service. Since there is a stipulation that the customer charge for standby service will be set at the general service large demand (LP/LPT) customer charge plus $25 except for those taking supplementary service on PX/PXT for whom the charge will be the PX/PXT customer charge, the second sentence should be eliminated or revised to indicate that the customer does not pay a second customer charge for supplementary service.

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ISSUE 135: Should the Interruptible Standby Service (ISS) Rate Schedule's sections on the Applicability and Determination of Standby Service (KW) Rendered be replaced by the language approved for the firm Standby Service (SS) in Docket No. 891304-EI? (MEETER)

RECOMMENDATION: Only the language in the Determination of Standby Service (KW) Rendered should be replaced. The formula for calculating the daily standby service demand should be replaced with the formula approved in Issue 135a. That portion of the language in this section which is not changed by Issue 135a in this docket should be replaced with the language which was approved for the current firm SS tariff in Docket No. 891304-EI.

POSITION OF PARTIES

GULF: Only the Determination of Standby Service (KW) Rendered section should be replaced by the approved language for the Standby Service Rate.

OPC: Agree with Staff's position as stated in Order No. 23025.

II: No position at this time.

FRF: No position

STAFF ANALYSIS: Order No. 22458, Docket No. 891304-EI, approved revisions to the Applicability and Determination of Standby Service (KW) Rendered sections of the firm Standby Service tariff. The revision to the Determination of Standby Service (KW) Rendered section requires the customer to notify the company when he has an outage of his generating equipment and to provide the company with a written report containing the data necessary to determine the amount of standby service taken. The firm SS tariff effective at that time and the currently effective ISS rate schedule require that the customer notify the company of an outage only if the outage requires standby service. A revision in the formula for determination of the daily standby service KW was to use the customer's maximum generation output between the end of the prior outage and the beginning of the current outage in the calculation. The firm SS tariff effective at that time and the currently effective ISS rate schedule use the 15-minute demand interval immediately prior to the outage.

The revisions to this section were approved by the Commission in Order No. 22458 at page 2 for the reasons enumerated below:

> This revised provision for the determination of standby service KW taken conforms more closely with Order No. 17159 than the current tariff because Gulf, and not the customer, will make the determination of whether standby service was taken

> and, if so, in what amount. Order No. 17159 at 21. This is true because the current tariff requires that the customer notify the company of an outage of his generating equipment <u>only</u> when standby service is required. Thus, the customer can manipulate the rate structure by not notifying the company of the outages when his bill would be lower if he were charged supplemental service charges. (Supplemental service is energy and capacity supplied by the company in addition to that normally provided by the customer's own generating equipment.) Based on the above, we find that Gulf's proposed revisions to Sheet No. 6.30 result in greater conformance with Order No. 17159 and reduce potential rate manipulation and we approve them. (Order No. 22458, page 2)

For the aforementioned reasons, staff recommends that the current language in the section on Determination of Standby Service (KW) Rendered approved pursuant to Order No. 22458 for the SS rate schedule should be used for the ISS rate schedule. If the Commission decides in Issue 135a to revise the formula for calculating daily standby service demand, that language should apply to both the firm and interruptible rate schedules.

Staff agrees with the company that the change in the Applicability Section approved in Docket No. 891304-EI for firm standby service does not apply to interruptible standby service because the new language requires a self-generating customer (SGC) to take standby service under the SS firm standby service rate schedule given certain conditions. Since interruptible standby service is an optional form of standby service, it should not be mandatory under any conditions.

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ISSUE 135a: How should the daily standby service demand be determined? (MEETER)

RECOMMENDATION: In the formula for calculating daily standby service demand, "the amount of load in KW ordinarily supplied by the customer's generation" should replace "maximized totalized customer generation output occurring in any internal between the end of the prior outage and the beginning of the current outage."

POSITION OF PARTIES

GULF: The daily standby service demand should be determined using the formula on Standby Service tariff sheet no. 6.30 with the addition of an adjustment for any seasonal variations in generation output. The addition to the formula is shown on Exhibit 247 and is reasonable and appropriate.

II: The daily standby service demand should be based on the difference between the maximum demand occurring in the on-peak hours during an outage and the corresponding maximum demand during a non-outage period of the current billing month.

STAFF ANALYSIS: The following formula is Gulf's current formula for calculating daily standby service demand on Gulf's standby service tariff: (See MFR Schedule E-17, page 39 of 50.)

Daily Standby Service (KW) =

Maximum totalized customer generation output occurring in any interval between the end of the prior outage and the beginning of the current outage.

Minus the Customer's daily generation output (KW) occurring during the on-peak period of the current outage.(1)

Minus the daily on-peak load reduction (KW) that is a direct result of the Customer's current generation outage.(1)

Staff has recommended that "maximized totalized customer generation output occurring in any interval between the end of the prior outage and the beginning of the current outage" should be replaced by "the amount of load ordinarily supplied by the customer's generation." This change would make II's requested adjustment for seasonal variation in generation output in calculating daily standby service demand. It would also ensure that SGCs are not billed for standby power when they reduce generation for purely economic

(1) The customer's daily generation output (KW) and daily on-peak period load reduction (KW) that are used in the formula must occur during the same 15 minute interval as the daily Standby Service (KW) that is used for billing purposes.

reasons. For these reasons, staff believes that these recommended changes in the formula result in a more accurate determination of standby power used. Citizen's Mr. Wright testified in response to cross examination that this language is what is prescribed, at least conceptually by Order No. 17159. (Tr. 2144) Furthermore, in its Option A, which uses the same methodology as Gulf, Florida Power Corporation calculates daily standby power on the amount of load ordinarily supplied by the customer's generation. (Pollock, Tr. 2861)

Gulf has proposed adding language to the same phrase in the formula (i.e., maximized totalized customer generation output, etc.) to implement II's requested adjustment for seasonal variations in generation output. (See Exhibit 247.) Staff believes Gulf's current and proposed formula possibly could not account for other variations. Staff agrees with Gulf that their formula is more exact but, as previously stated, believes it is less accurate in determining standby power. Staff, however, does believe Gulf's proposed formula results in a more accurate determination of standby power than the II's proposal.

The formula proposed by II has two problems.

> First, this method would not work if a customer took service with the SE rider applied. Use of SE would inflate the customer's normal usage pattern and cause the customer to pay less for standby power than actually taken. In addition, because outages can extend beyond one billing period, you may not be able to select the two wordings in the same billing period. (Haskins, Tr. 3371)

Staff agrees with Witness Haskins that II's proposed formula would result in standby power by SE rider customers not being properly billed as standby power. Additionally, staff believes the formula could and almost certainly would result in some or possibly all standby power used by nonSE customers not being billed as standby power.

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ISSUE 136: The present standby rates are based on system and class unit costs from Docket No. 840086-EI. Should the standby rate schedules (SS and ISS) charges be adjusted to reflect unit costs from the approved cost of service study (a compliance rerun) in this docket and the 1990 IIC capacity charge rates and designed in the manner specified by the Commission in Order No. 17159? (MEETER)

RECOMMENDATION: The SS charges should be designed using the compliance cost of service study and the rate design specified in Order No. 17159 with a possible exception of the forced outage rate. The forced outage rate to be used to calculate the reservation charge would be that approved in Issue 153. If the resulting charges generate either more or less revenue than the class' revenue responsibility as set by Issue 121, all charges except the customer charge should be decreased or increased by the (same) percentage required to generate the class' revenue requirement. The ISS charges should be the same as the SS charges except for the reservation and daily demand charges. The sum of the CP KW transmission unit cost plus an average IIC monthly charge rate of $6.69 should be used as the unit cost to develop these charges. If the Commission decides in Issue 138 to bill SE customers for distribution system costs on their maximum metered KW whenever it occurs, the billing KW in Exhibit 510 should be used to calculate the local facilities charges.

The company should provide the staff a compliance cost of service study and the SS rates calculated in accordance with this recommendation by August 31, 1990. A spread sheet of component costs by function (retail revenue requirements) in the format of Exhibit 509 for the compliance study should also be provided.

POSITION OF PARTIES

GULF: Yes, if at all possible.

OPC: Yes.

II: The Commission should allocate costs to the class; develop unit costs; and design rates accordingly, based on the cost of service study approved in this case. The use of system-wide average unit costs and the assumptions as to forced outage rates contained in Order No. 17159 would defeat the purpose of setting rates to all classes based on the class cost of service study, and these procedures (system costs, 10% forced outage rates) should not and need not be applied to the Rate SS class. (Pollock)

STAFF ANALYSIS: Both Gulf, the Office of Public Counsel and the staff theoretically want to design the standby service rates using the rate design specified in Order No. 17159 and a compliance cost of service study. The class' revenue responsibility would be set by the revenue generated by these rates. Since the class' revenue responsibility must be decided by August 14 and the compliance cost of service study won't be completed until two or two and a half weeks later, it is impossible to follow this preferred method in its entirety in setting the rates unless the Commission and all parties are willing to modify the class revenue responsibility later.

The II's position apparently is that the SS standby service revenue responsibility would be determined in the same manner as all other classes through the cost of service study. The rates should then be designed using the class unit costs and less than a 10 percent forced outage rate for the reservation charge. By determining the SS revenue responsibility through Issue 121, staff has used part of II's methodology.

Staff is recommending that, with the exception of establishing the revenue responsibility for the SS classes, the SS charges should be designed using the compliance cost of service study and the rate design specified in Order No. 17159 except for the forced outage rate. The reservation charge would be calculated using the forced outage rate approved in Issue 153. If the resulting charges generate either more or less revenue than the class' revenue responsibility as set by Issue 121, all charges except the customer charge should be decreased or increased by the (same) percentage required to generate the class' revenue responsibility. If the Commission decides in Issue 138 to bill SE customers for distribution system costs on their maximum metered KW, whenever it occurs, Exhibit 510 contains the appropriate billing KW for calculating the local facilities charge.

The ISS charges should be the same as the SS charges except for the reservation and daily demand charges. The sum of the CP KW transmission unit cost plus an IIC monthly charge rate of $6.69 should be used as the unit cost to develop these charges. (See Order No. 17159 at 16 and Order No. 20188 at pages 2 and 3.)

Staff is recommending that the Commission follow the rate design specified in Order No. 17159 as much as possible because there was extensive evidence in Docket No. 850673-EU on the subject and the Commission found this rate structure to be the most appropriate for recovery of costs. (Order No. 17159 at page 11)

ISSUE 137: Order No. 17568, Docket No. 850102-EI approved the experimental Supplemental Energy (SE) (Optional) Rider as a permanent rate schedule on the condition that it become a separate rate class in the company's next rate case. Has Gulf complied with Order No. 17568, and should the SE be a separate rate class? (MEETER)

RECOMMENDATION: A separate rate class consisting of LPT and PXT customers on the SE rider should not be implemented in this rate class. The question of whether a separate rate class(s) should be implemented for either PXT-SE or LPT-SE customers should be considered in the next rate case. Gulf should file its cost of service study in that case with LP/LPT and PXT each broken into SE and non-SE classes and with totals for LP/LPT and PX/PXT. Gulf did not comply with Order No. 17159 on the establishment of a separate SE rate class in this rate class.

If the Equivalent Peaker or Refined Equivalent Peaker cost of service methodology is approved for use in this docket, SE would have to be a separate class as the only no-migration study in the case has SE as a separate class.

POSITION OF PARTIES

GULF: Gulf has not complied with the order by filing a cost of service study with LPT and PXT customers on the SE rider grouped together as a separate rate class. However, customers applying the SE rider to their standard service should not be made a separate rate class.

OPC: Agree with Staff's position as stated in Order No. 23025.

II: There should be no separate class for SE customers. Supplemental Energy is provided to customers only on an as-available basis, and only on the condition that Gulf Power not be required to make any investment to accommodate that service. Therefore, there is no logical reasons to establish a separate class for SE customers because there are no costs caused by that usage. Further, the establishment of a separate class could create potential instability, due to the small size of the SE "class" and the resulting small size of the class of remaining PXT customers.

FRF: No position.

STAFF ANALYSIS: The OPC's Mr. Wright testified that,

> [T]he rate should be redesigned based on considerations of local facilities costs, and also based on considerations of potential differences between the peak demand KW characteristics and the billing demand KW characteristics of SE customers, as opposed to those in the general LP and PXT rate cases. [T. 2146]

Staff believes the <u>necessity</u> for a separate rate depends on the differences between peak demand KW characteristics and the billing demand KW characteristics of SE customers, as opposed to those in the general LP and PXT classes and considerations of local facilities costs. Mr. Wright testified that with respect to demand-related production and transmission costs it would depend on the rat[io]s of billing KW to 12 CP KW (Tr. 2151). The table below shows the relationship between billing KW and 12 CP KW and maximum billing KW and maximum metered KW for SE customers and non-SE customers by rate class.

Ratios of Billed KW to 12 CP KW
<u>and Maximum Metered KW for 1989</u>

		Ratios of on-peak Billing KW to 12 CP KW	Ratios of Maximum Billing KW to 12 CP KW	Ratio of Maximum Billing KW to Maximum Metered KW
PXT	SE	.95	1.01	.59
PXT	Non-SE	1.10	1.10	1.00
LP	SE	1.23	1.28	98
LP	Non-SE	.78	1.31	1.00

Sources: Exhibit 492 for column 1; column 2 is the maximum billed KW on Exhibit 488 divided by (the average 12 CP KW on Exhibit 487 x 12); Exhibit 488 for column 3.

Column 1 is the ratio of on-peak billing KW, which recovers cost in on-peak periods, to the 12 CP KW, which allocate demand-related production plant, transmission plant and distribution substation costs. Thus, the value of .95 for PXT-SE means that for each 12 CP KW unit of cost allocated to the class, there is only .95 on-peak billing KW to recover the cost. A similar interpretation applies to the ratios in column 2. The ratios in the second column are important to this issue because both the LPT and PXT rate schedules on which SE customers are billed include cost allocated on the 12 CP KW in the off-peak charges. (Wright, Tr. 2150) These costs are then recovered through the billing KW represented in the second column.

Staff believes that the large dissimilarity in the ratios between PXT-SE and LPT-SE, e.g., .95 to 1.23, etc., shows that PXT-SE LP-SE customers should not be combined into <u>one</u> class. The pattern of rates of return for the SE class relative to PXT and LPT in the cost of service studies is another indication to staff that this grouping of SE customers should not be implemented. Staff believes this data indicates that solving any present problem with cost recovery between the SE and non-SE customers by putting all SE customers in one class would, in fact, create a serious cost recovery problem between the LPT-SE and the PXT-SE customers.

Staff agrees with Public Counsel that the SE customers should be a separate class; however, based on the data in the above table our belief is that it should be two separate rate classes, LPT-SE and PXT-SE. Since we do not have a cost of service study in this case with SE broken into the two groups, these two rate classes cannot be implemented in this case. To expedite the evaluation of the need for a separate rate class for either PXT-SE or LPT-SE in the company's next rate case, the company should be required in its cost of service study to show LPT-SE and PXT-SE each as a separate rate class as well as the combined totals for LP/LPT-SE and LP/LPT and for PXT-SE and PXT. As specified by Order No. 17568 at page 2, the SE rate should be a cost-based, time-of-use rate; it should not be a load retention rate to prevent the economic development of cogeneration. (See Kisla, Tr. 2764, 2777-2778)

With respect to II's position in its brief that there is no logical reason to establish a separate class for SE customers because there are no costs caused by that usage, staff does not believe that the statement of no costs is supported by data. In fact, staff believes there is data in the record which indicates the company <u>has</u> incurred cost to serve the load. (1) Three new dedicated substations were built in 1989 to serve three of the six SE customers (Exhibits 511 and 517). (2) The total capacity of the substations is 130,000 KW (Exhibit 511). (3) The sum of the average billing KW for the three customers is only 68,989 KW (Exhibit 511), 53 percent of the capacity of the substations. The IIs also oppose the establishment of a separate SE class because it could create potential instability, due to the small size of the SE class and the remaining PXT customers. There have been only four customers taking service on PXT since at least 1980 (Haskins, Tr. 1977). Yet, Mr. Pollock, II's witness, in response to cross examination admitted that in the nine or ten years he had been appearing before the Commission, he had never testified on the inappropriateness of the PX/PXT class or questioned its existence because of the potential instability of a class with a small number of customers. (Tr. 2928)

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ISSUE 138: How should rates for the separate Supplemental Energy Rate Schedule be designed? (MEETER)

RECOMMENDATION: If SE remains a rider, the rates applicable to SE customers would continue to be the same as the corresponding rates applicable to non-SE customers within the same rate class. If the approved time of use rate design recovers only distribution system cost in the maximum demand charge, SE customers should be billed the maximum demand charge on their maximum metered KW whenever it occurs, i.e., the provision in the rider providing for forgiveness of demand incurred during the SE period would apply only to on-peak demand.

If SE becomes a separate rate class, the time-of-use rate design approved in Issue 128 should also be used for this class. The maximum demand charge should be billed on the customer's maximum metered demand whenever it occurs.

POSITION OF PARTIES

GULF: The Supplemental Energy (SE) customers' billing determinants should be combined with non-SE customers' billing determinants for rate design purposes.

OPC: The Supplemental Energy rate should have a maximum demand charge designed to recover distribution systems costs, an on-peak demand charge to recover demand-related production and transmission costs, a non-fuel energy charge equal to the class energy unit cost, and a cost-based customer charge. The maximum demand charge should be the distribution unit cost for the SE rate class calculated using 100 percent ratcheted billing demand and assessed on maximum demand registered by the customer during an appropriate ratchet period defined in the tariff. The ratchet period should be the same as the ratchet period applied to local facilities charges for Gulf's standby customers.

II: The rates applicable to SE customers should be identical to the corresponding rate applicable to non-SE customers within the same rate class. To do otherwise could cause instability because of the small size of the SE and non-SE subclasses. (Pollock)

FRF: No position.

STAFF ANALYSIS: The SE rider presently provides forgiveness of the demands incurred during SE periods both with respect to on-peak and off-peak billing KW. Five of the six SE customers have dedicated substations (Exhibit 517). The sum of the average billing KW for the three SE customers for whom dedicated substations were built in 1989 is only 53 percent of the capacity of these substations. (Exhibit 511) However, the PXT-SE customers are billed on only 59 percent of their maximum metered KW. (Exhibit 488) Therefore, to ensure that the SE customers pay for the dedicated facilities that have been sized to serve their maximum demands whenever they occur, SE customers should be billed on their maximum <u>metered</u> demand whenever it occurs. The provision of the SE rider for forgiveness of demand in the SE period would continue to apply to on-peak demand. However, if the off-peak demand charge includes more than distribution-system costs, the present provision for forgiveness of demand in the SE rider with respect to the off-peak demand charge should be continued. This is because the ratio of maximum metered KW to 12 CP KW is 1.69 for PXT-SE customers (Maximum metered KW on Exhibit 488 divided by [12 times the average 12 CP KW on Exhibit 487).

If SE becomes a separate rate class, the time-of-use rate design approved in Issue 128 should also be used for this class because SE was approved in Order No. 17568 at page 2 as an alternate time-of-use rate with flexible designations of on-peak and off-peak hours. Regardless of the cost included in the maximum demand charge, the maximum demand charge should be billed on actual <u>metered</u> billing demand whenever it occurs to (1) ensure recovery of dedicated facilities and (2) to offset the subsidy problem caused by the dissimiliarity in ratios of on-peak billing to 12 CP KW for the two groups of SE customers.

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ISSUE 139: The applicability clause of the three demand classes (GSD, LP and PX) is stated in terms of the amount of KW demand for which the customer contracts. Is this an appropriate basis for determining applicability? (KUMMER)

RECOMMENDATION: No. In the past, contracts have not been required of all these customers, and Gulf's response to Staff's Interrogatory No. 115 (Hearing Exhibit #496) indicates that contract demand often bears little relationship to actual measured demand. As a part of this docket, tariffs should be modifed to state that the applicability for both demand and the PX/PXT 75 percent load factor should be based on measured maximum billing demand. For SE customers, this would be the actual measured billing demand in non-SE periods.

POSITION OF PARTIES

GULF: Yes. If the proposed Local Facilities Charge for rates LP, LPT, PX, and PXT is approved, Gulf will initiate a review and possible revision of existing LP/LPT and PX/PXT contracts and signing of appropriate new contracts with those LP/LPT customers who presently do not have a signed contract. For new customers, there would be no actual demand upon which to base a contract or to determine which rate would be applicable; thus, without a contract capacity, you would have no meaningful contract.

OPC: Agree with Staff's position as stated in Order No. 23025.

FRF: Agree with Staff.

STAFF ANALYSIS: Exhibit #220 shows the number of customers without current contracts. Only 37 percent of customers in the LP/LPT and PX/PXT classes currently have contracts on file. In addition, Witness Haskins stated that he did not recall any power contracts with GSD customers (TR. 1964). The applicability of the tariff for these customers is based on a nonexistent instrument. For those customers who currently have contracts on file, the relationship of actual measured demand to contract demand varies from a low of 21 percent to a high of 437 percent. In only 23 percent of the 52 contracts did measured demand fall within 10 percent of contract demand. Almost half of the contracts varied 30 percent or more from the actual measured demand.

If the applicability is based on a contract amount which does not reflect measured usage, or if there is no contract, there is the opportunity for manipulation of the rate schedule, allowing customers who would not qualify on the basis of measured demand to take service on a cheaper rate schedule or avoid payment of a minimum bill. The applicability requirements can be applied in a discriminatory manner if applicability is not based on actual measured demand.

Even if Gulf were to initiate contracts with all customers in all three demand rate classes, there are no guarantees in place that the contracted amount stated would reflect actual demand. Exhibit #220 clearly shows that in most instances, there is considerable variability between measured and contract demand. Since Gulf's current procedures for monitoring contract demand to ensure that it tracks actual demand has a very poor track record, Staff is reluctant to place any faith in their intentions to update and establish more accurate contracts demands for these customers in the future, unless such contracts are required to reflect actual measured demand.

Demand for determining applicability of tariffs should be based on historical data on measured demand where available, and any estimated demand for new customers should undergo a mandatory review at the end of the first 12 months of service, and be updated based on actual usage. Tariff references to contract demand in the applicability section and minimum bill provision of GSD/GSDT, LP/LPT and PX/PXT tariffs should be removed and replaced with reliance on actual measured demand.

ISSUE 140: The current GSD/GSDT and GSLD/GSLDT (LP/LPT) rate schedules have minimum charges equal to the customer charge plus the demand charge for the minimum KW to take service on the rate schedule for customer opting for the rate schedule. Is this minimum charge provision appropriate? (KUMMER)

RECOMMENDATION: No. It unduly penalizes customers who opt for this higher rate class because they pay for the minimum KW to qualify for the class even if their usage falls below this level. Customers who meet the class minimum even once in every 12 month period, do not pay a minimum but pay only for their actual demand, even if it falls below the minimum.

POSITION OF PARTIES

GULF: No, the minimum KW is not appropriate. However, if a change is made in the minimum KW requirement of the GSD/GSDT and LP/LPT rates, then Gulf must be allowed to redesign rates to assure recovery of any revenues lost as a result of additional crossovers to another rate and any reduction in demand (KW) useds for billing purposes.

OPC: Agree with Staff's position as stated in Order No. 23025.

FRF: Agree with Staff.

STAFF ANALYSIS: Gulf is in basic agreement with staff and other parties that the minimum bill provision is not appropriate. Staff agrees with the utility that elimination of the minimum bill must take into account the relative rates of the three classes to ensure that the cost effective breakpoint between classes does not encourage low load factor customers who appropriately belong on the lower rate schedule to opt for the GSD or LP. Such a switch would increase the cost to serve the class to which they migrate since their current rates reflect the higher cost to serve them due to lower load factor. This would defeat the goal of setting rates so as to encourage customers of like cost characteristics to remain on their appropriate rate schedule.

The substantial decrease in GS rates resulting from equalizing RS and GS rates makes it unlikely that GS customers would find it attractive to opt up to GSD unless they were very high load factor, and would more properly reflect costs of a GSD customer. The substantial difference in demand and customer charges between GSD and LP also make opting up unattractive except for extremely high load factor GSD customers.

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ISSUE 141: What is the appropriate method for calculating the minimum bill demand charge for the PX rate class? (KUMMER)

RECOMMENDATION: The minimum bill demand charge for PX should be the customer charge plus a per KW demand charge, consisting of the KW demand charge for the class plus the KWH charge times the KWH necessary to achieve a 75 percent load factor. (KW charge + 546.5 x KWH charge) = per KW minimum charge

POSITION OF PARTIES

GULF: The minimum bill demand charge for PX should be the customer charge plus a per KW demand charge, consisting of the KW demand charge for the class plus the KWH charge times the KWH necessary to achieve a 75 percent load factor, and the local facilities charge, if applicable. The minimum bill demand charge is calculated as shown below:

(KW charge + 547.5 x KWH charge) = per KW minimum demand charge

OPC: The minimum bill for PX customers should include at least the customer charge plus a local facilities charge equal to the class distribution unit cost calculated using 100 percent ratcheted billing demand and applied to the customer's highest demand in the two years ending with the current billing month. Basically agree with Staff's approach as to the other cost components of the PX minimum bill.

II: Consistent with the applicable paragraph, rate PX/PXT customers should be subject to a minimum annual billing demand charge. (Pollock)

FRF: No position.

STAFF ANALYSIS: The PXT rate is designed on the principle that higher load factor customers cost less to serve than lower load factor customers. The purpose of the minimum bill is to discourage customers from taking service on the PX rate simply to lower their individual bill, when their cost characteristics would increase the cost to serve the class as a whole. The utility's proposed minimum bill charge would require a minimum bill payment equal that which the customer would have paid if he had used sufficient KWH to generate a 75 percent load factor for the KW used. The minimum bill formula is applied to the maximum billing demand for the month to determine if the minimum bill calculation applies. This helps ensure that the actual bill would normally exceed the minimum bill if the load factor for the class is met.

Mr. Pollock, on behalf of the Industrial Intervenors, recommended using an annual billing demand charge to compute the applicability of the minimum charge. His testimony indicates that the concern is that a customer falling below a 75 percent load factor for a single month would be subject to a minimum bill charge. His proposal is that the load factor determining applicability to the minimum bill be based on an annual not monthly basis.

Witness Haskins, states, however, that under Witness Pollock's proposal, four of the six PXT customers would have paid less on their actual bill than under the minimum bill calculation. He goes on to state the modifications Gulf has made in their original language on the application of the minimum bill which staff agrees addresses Mr. Pollock's concerns (TR 3352).

Gulf modified their original language on applicability and this change was stipulated in Issue 143. In the revised proposal, each month would be evaluated on it's own merits, using the maximum demand for the month. If the monthly load factor fell below 75 percent, the rolling average annual load factor for the current and most recent 11 months would be computed. Only if both monthly and rolling average load factors fell below 75 percent would a customer be subject to a minimum bill. This appears to address Industrial Intervenors' concerns with temporary fluctuations in load factors resulting in minimum bill assessments.

OPC's proposal that a local facilities charge be included in the minimum bill provision is similar to Gulf's language in their Post Hearing Brief (p.396). In his direct testimony, Witness Wright expresses concern than a local facilities charge is necessary in order to properly recover distribution investment (TR 2089). Currently the minimum bill calculation is based on contract demand. If the contract demand understates actual demand, staff agrees that local facilities costs may be underrecovered and a local facilities charge might be appropriate.

However, staff has recommended that the language on applicability be based on actual measured maximum demand, not contract demand. If local facilities costs are properly allocated and recovered through the demand and energy charges based on actual measured maximum demand, the minimum bill would serve it's intended purpose and recover the minimum local distribution necessary to serve that level of demand. Therefore, staff does not support OPC's proposal to include a local facilities charge in the minimum bill provision.

The other point raised by Witness Wright in connection with inclusion of fuel revenues in the computation of the minimum bill (TR. 2088-9) may arise from a misunderstanding of the calculation of the provision. It is staff's understanding that a minimum bill charge is computed, using the actual measured KW, KWH, fuel and other billing adjustments, just the actual bill is computed. However, the KW billing charge is factored in at the amount stated in the minimum bill provision, which is higher than the normal KW charge. If the total actual bill is less than the calculated minimum bill, the customer is subject to the minimun bill.

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The PX/PXT rates assume a minimum relationship between KWH and KW. In general, a minimum bill charge will exceed an actual bill only if the customer's KWH usage is substantially below the required 75 percent load factor which means he used too few KWH relative to his KW demand. Fuel is considered in both the minimum and actual, therefore, there is no cost free energy as stated by Witness Wright.

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ISSUE 142: What is the appropriate method for calculating the minimum bill demand charge for the PXT rate class? (KUMMER)

RECOMMENDATION: The minimum bill demand charge should be calculated by the methodology outlined in the company's response to Interrogatory No. 124 of Staff's Eighth Set (Hearing exhibit #272).

POSITION OF PARTIES

GULF: The minimum bill charge for rate PXT should be the customer charge plus a per KW demand charge, consisting of the PXT demand charge revenue divided by the total maximum KW and added to the PXT energy charge revenue divided by the total KW (adjusted for a 75% load factor), and the local facilities charge, if applicable. This charge should be applied to the maximum billing demand for the month in which the minimum bill is applicable.

OPC: The minimum bill for PXT customers should include at least the customer charge plus a local facilities charge equal to the class distribution unit cost calculated using 100 percent ratcheted billing demand and applied to the customer's highest demand in the two years ending with the current billing month. Basically agree with Staff's approach as to the other cost components of the PXT minimum bill.

II: While we generally agree with the staff's method, the load factor should be based on maximum on-peak demand to encourage customers to use more power during the off-peak periods. (Pollock)

FRF: No position.

STAFF ANALYSIS: The same arguments used to support staff's recommendation in Issue 141 apply here. The purpose of a minimum bill is to discourage customers from taking service on a rate which is not appropriate for their cost characteristics. The utility's proposal computes an average demand charge by summing the revenues generated by the on-peak demand charge and the maximum demand charge, then dividing this revenue total by the total maximum KW. The same procedure is used to determine an average per KWH charge (sum on and off peak and divide by total KWH). The KWH charge is then multiplied times the KWH necessary to achieve a 75 percent load factor. The KW demand charge multiplied by the measured maximum demand, and KWH calculation are added to the applicable customer charge to arrive at the minimum bill.

The same opposition was raised by Industrial Intervenors and OPC as outlined in Issue 141. The same arguments in defense of the company's proposal are valid for the PXT as well as the PX minimum bill. The applicability provision proposed by Mr. Haskins in his rebuttal testimony (TR 3351) appears to address the annual load factor usage. Staff continues to reject the local facilities charge proposed by OPC on the basis that if costs are properly allocated and billed on actual measured maximum demand, whenever it occurs, the cost of the local facilities will be recovered through the demand and energy charges.

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STIPULATED
ISSUE 143: The proposed change in the application of the minimum bill provision allows a customer who has less than a 75 percent load factor in a given month to not be billed pursuant to the minimum bill provision as long his annual load factor for the current and most recent 11 months is at least 75 percent. Is this appropriate? (KUMMER)

RECOMMENDATION: Yes. The applicability of the tariff is based on an annual load factor. It is appropriate to assess minimum billing based on an annual load factor as well, even if the monthly load factor temporarily falls below 75 percent.

POSITION OF PARTIES

GULF: The applicability clause of the tariff is based on an annual load factor. Thus it is appropriate to assess minimum billing based on an annual load factor as well, even if the monthly load factor temporarily falls below 75 percent, regardless of the monthly load factor. All parties, including staff, agree.

OPC: Agree with Staff's position as stated in Order No. 23025.

II: Yes, agree with Staff.

FRF: Agree with Staff.

STAFF ANALYSIS: The applicability as stated in the tariff refers to an annual load factor. The language proposed by the utility modifies the minimum provision to clearly reflect that applicability. In practice, if a customer falls below the minimum bill criteria for a given month, his load factor for that month and the preceding 11 months would be computed. If that load factor is at or above 75 percent, no minimum bill would be applied. This allows temporary fluctuations which may simply reflect erratic business conditions without unduly penalizing a normally high load factor customer. The rolling calculation will, however, also ensure that persistent failure to achieve the appropriate load factor will result in the customer being moved to a more appropriate rate class.

ISSUE 144: The company has proposed the implementation of a local facilities demand charge for LP/LPT and PX/PXT customers, which would be applied when the customer's actual demand does not reach at least 80 percent of the Capacity Required to be Maintained (CRM) specified in the Contract for Electric Power. Is this local facilities charge appropriate? If so, to what customer classes should it apply? (MEETER)

RECOMMENDATION: No. It is inequitable to apply the charge to the contract capacity because the contract demand for many customers bears little relationship to measured demand. Furthermore, it is an ineffective charge because no customers would have to pay the charge in the test year. The company's proposed local facilities charge should be rejected.

POSITION OF PARTIES

GULF: Yes. There has been no evidence offered to contradict the fact that this charge will protect other customers from having to subsidize those customers who, on a temporary or permanent basis, reduce their load or shut down completely. Such a customer would be obligated to pay at least the minimum monthly bill, which would include the Local Facilities Charge, if applicable, for the duration of the contract. Gulf proposes to use this Local Facilities Charge for its large customers (LP, LPT, PX, and PXT).

OPC: No. The Commission should require Gulf to implement local facilities demand charges for all of its demand-metered classes calculated and applied in the same way as the local facilities charges prescribed by the Commission for standby customers.

II: The load factor should be based on the higher of either 90% of the highest measured demand in the last eleven months or 80% of the capacity required to be maintained. (Pollock)

FRF: Agree with Staff.

STAFF ANALYSIS: Gulf has proposed the implementation of a local facilities charge for LP/LPT and PX/PXT customers. The charge would be applied when the customer's demand for a month is not 80 percent of the Capacity Required to be Maintained (CRM) specified in the Contract for Electric Power. The customer would pay the charge on the difference between the billing demand and 80 percent of the CRM. The company's proposed charges are $1.60 for GSD; $1.36 for LP/LPT; and $.68 for PX/PXT.

Staff recommends that the company's proposal should be rejected for the following reasons. First, there is a problem with using contract capacity as the basis for the charge at this time. Exhibit 220 indicates that only 52 or 37 percent of the LP/LPT and PX/PXT customers have signed a Contract for Electric Power and thus have a contracted level of CRM or contract capacity. Furthermore, for these 52 customers the annual maximum metered demand varies from zero percent to 458 percent of the CRM in 1988 and 1989. It would appear to be inequitable to base a charge on a contract demand for which there is so much variability between the contracted demand and the actual demand. Using the CRM could result in rate manipulation between customers. Second, it is an ineffective charge as no customers would have to pay the charge in the test year - the revised MFR Schedules E-16c in Exhibit for the LP/LPT and PX show no revenues generated from the charge for these classes.

The Office of Public Counsel's position is that Gulf should implement local facilities charges for all of its demand-metered classes calculated and applied in the same manner as the local facilities charges prescribed by the Commission for standby customers. Their Mr. Wright says there is "no justification for continuing to treat standby customers any differently than full requirement(s) customers when it comes to rate design and cost recovery for local distribution facilities." (Tr. 2098) Staff disagrees with Mr. Wright and Office of Public Counsel. The standby service rates (for backup and maintenance power) are based on the expected load characteristics of self-generating customers because the Commission found in the generic investigation of standby service that the expected load characteristics of self-generating customers are sufficiently different from those of full requirements customers to justify different rates. "This is because backup and maintenance services are expected to be relatively low load factor services..." Order No. 17159 at page 5. Public Counsel is advocating the use of only one component of the standby service rate design, the local facilities charge. Staff believes that since the reservation and daily demand components of the standby rate are not being implemented for full requirements customers, not implementing the standby service local facilities charge for full requirements customers is not discriminatory. One could even argue that, if the standby service local facilities charge is implemented for full requirements customers, it would be unduly discriminatory to low load factor full requirements customers not to implement the daily demand and reservation charge components as well. Staff also opposes implementing this charge when there is no evidence in the record of how this charge would impact those customers whose bills would be most greatly affected by the charge.

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ISSUE 145: The company's proposed street and outdoor lighting rates are shown on the revised MFR Schedule E-16d submitted as item no. 147 of Staff's Eighth Set of Interrogatories. Should these proposed rates be approved? (WHEELER)

RECOMMENDATION: No. The staff-recommended street and outdoor lighting rates are attached as Schedules 4 (12 CP method) and 5 (Equivalent Peaker Method). While staff and the company agree as to the basic methodology used to determine the rates for street and outdoor lighting, the actual rates recommended by staff differ due to the differing revenue increases recommended by staff for the lighting classes. The rates are also dependent on the cost of service methodology used. Staff also recommends that, prior to the next rate case, Gulf be required to obtain information which will allow for the development of cost-based rates for additional facilities pole charges.

POSITION OF PARTIES

GULF: The street and outdoor lighting rates as proposed by Gulf are contained in the revised MFR Schedule E-16d submitted as hearing exhibit no. 499.

STAFF ANALYSIS: Staff and the company agree that in designing the Street (OS-I) and Outdoor (OS-II) lighting energy charges, such charges should be set to recover the total non-fuel energy, demand, and customer-related costs at the class-approved rate of return (TR 1987). Gulf's proposed energy charges were developed using this methodology (TR 1987). The staff-recommended OS-I and II energy charges are shown in Schedules 4 (12 CP) and 5 (Equivalent Peaker). The recommended energy rates for the 12 CP method are identical to those proposed by Gulf. If the Equivalent Peaker method is used, the energy rates are different, due to the difference in the manner in which costs are allocated under this method.

It is also agreed by staff and the company that the maintenance charges should be set so as to recover the maintenance and administrative and general expenses allocated to OS-I and OS-II in the cost of service study (TR 1988). Staff recommends approval of the Gulf-proposed maintenance charges, which were developed in this manner.

Gulf agrees with staff that, following development of the energy and maintenance charges, and the additional facilities charges, the remaining OS-I and OS-II revenue requirement should be recovered through the fixture charges (TR 1988). The staff-proposed fixture charge were developed by applying a ratio to the Gulf-proposed fixture charges such that they recover the staff-recommended total revenues allocated to OS-I and OS-II, for both the 12 CP and Equivalent Peaker cost of service methodologies.

Gulf is not proposing any changes to its additional facilities pole charges of $2.00 per month for 30-foot wood poles and $4.50 per month for 30-foot concrete poles. Because Gulf's records do not reflect how many wood and concrete poles in place which are dedicated to additional facilities, it is not possible to develop cost-based pole charges (TR 1994). Prior to 1982, Gulf did not keep records which reflect the number of additional facilities poles installed. These pre-1982 customers are currently being billed for additional facilities based on the installed cost of the facilities times a fixed carrying charge (TR 1993-1993).

Staff recommends that the pole charges remain the same, since they are comparable to those of the other Florida investor-owned electric utilities. However, staff also recommends that Gulf be directed to take steps to obtain the information necessary to determine cost-based additional facilities charges by the filing of the next rate case. This would entail making a determination of the quantity of poles which are in place for additional facilities.

Staff and the company agree as to the methodology used in determining the energy rates for OS-III and the proposed OS-IV. The staff recommended energy rates differ from the Gulf proposed rates due to differences in the revenue increases allocated to the classes. Discussion of the proposed OS-IV rate is found in Issue 148.

SCHEDULE OF PRESENT AND STAFF-RECOMMENDED
STREET AND OUTDOOR LIGHTING RATES
12 CP COST STUDY

891345-EI

TYPE OF FACILITY	FIXTURE CHARGE PRESENT	FIXTURE CHARGE GULF PROP.	FIXTURE CHARGE STAFF RECOM.	MAINTENANCE CHARGE PRESENT	MAINTENANCE CHARGE GULF PROP.	MAINTENANCE CHARGE STAFF RECOM.	ENERGY CHARGE PRESENT	ENERGY CHARGE GULF PROP.	ENERGY CHARGE STAFF RECOM.	TOTAL MONTHLY CHARGE PRESENT	TOTAL MONTHLY CHARGE GULF PROP.	TOTAL MONTHLY CHARGE STAFF RECOM.
HIGH PRESSURE SODIUM (OS-I)												
5,400 LUMEN	$1.76	$1.85	$2.11	$1.65	$1.34	$1.34	$0.51	$0.74	$0.74	$3.92	$3.93	$4.19
8,800 LUMEN	$1.77	$1.86	$2.12	$1.67	$1.06	$1.06	$0.73	$1.05	$1.05	$4.17	$3.97	$4.23
20,000 LUMEN	$2.06	$2.16	$2.42	$1.77	$1.56	$1.56	$1.47	$2.13	$2.13	$5.30	$5.85	$6.11
25,000 LUMEN	$1.97	$2.71	$2.97	$1.93	$2.03	$2.03	$1.86	$2.68	$2.68	$5.76	$7.42	$7.68
46,000 LUMEN	$2.93	$3.07	$3.33	$1.99	$1.61	$1.61	$2.93	$4.24	$4.24	$7.85	$8.92	$9.18
20,000 LUMEN **	$2.06	$4.21	$4.47	$1.77	$1.79	$1.79	$1.47	$2.13	$2.13	$5.30	$8.13	$8.39
46,000 LUMEN **	$2.93	$9.09	$9.09	$1.99	$2.00	$2.00	$2.93	$4.24	$4.24	$7.85	$15.33	$15.33
20,000 LUMEN **	$2.06	$10.69	$10.95	$1.77	$1.79	$1.79	$1.47	$2.13	$2.13	$5.30	$14.61	$14.87
8,800 LUMEN **	$1.77	$6.04	$6.30	$1.67	$1.56	$1.56	$0.73	$1.05	$1.05	$4.17	$8.65	$8.91
MERCURY VAPOR (OS-I)												
3,200 LUMEN	$1.28	$1.34	$1.60	$1.26	$1.40	$1.40	$0.71	$1.03	$1.03	$3.25	$3.77	$4.03
7,000 LUMEN	$1.27	$1.33	$1.59	$1.22	$1.04	$1.04	$1.22	$1.76	$1.76	$3.71	$4.13	$4.39
9,400 LUMEN	$1.37	$1.81	$2.07	$1.38	$1.66	$1.66	$1.73	$2.50	$2.50	$4.48	$5.97	$6.23
17,000 LUMEN	$1.80	$2.12	$2.38	$1.39	$1.73	$1.73	$2.77	$4.00	$4.00	$5.96	$7.85	$8.11
48,000 LUMEN	$2.73	$5.93	$6.19	$1.83	$3.16	$3.16	$6.77	$9.79	$9.79	$11.33	$18.88	$19.14
HIGH PRESSURE SODIUM (OS-II)												
5,400 LUMEN	$1.48	$1.85	$2.11	$1.60	$0.84	$0.84	$0.51	$0.74	$0.74	$3.59	$3.43	$3.69
8,800 LUMEN	$1.67	$1.65	$1.91	$1.66	$0.79	$0.79	$0.73	$1.05	$1.05	$4.06	$3.49	$3.75
20,000 LUMEN	$2.06	$2.16	$2.42	$1.77	$1.05	$1.05	$1.47	$2.13	$2.13	$5.30	$5.34	$5.60
25,000 LUMEN	$1.97	$2.70	$2.96	$1.91	$1.50	$1.50	$1.86	$2.68	$2.68	$5.74	$6.88	$7.14
46,000 LUMEN	$2.93	$3.07	$3.33	$1.99	$1.10	$1.10	$2.93	$4.24	$4.24	$7.85	$8.41	$8.67
20,000 LUMEN *	$3.26	$4.17	$4.43	$2.05	$1.92	$1.92	$1.53	$2.21	$2.21	$6.84	$8.30	$8.56
46,000 LUMEN *	$3.39	$3.71	$3.97	$2.09	$1.79	$1.79	$3.04	$4.39	$4.39	$8.52	$9.89	$10.15
8,800 LUMEN **	$1.67	$6.05	$6.31	$1.66	$0.76	$0.76	$0.73	$1.05	$1.05	$4.06	$7.86	$8.12
MERCURY VAPOR (OS-II)												
7,000 LUMEN	$0.82	$1.31	$1.57	$1.24	$0.65	$0.65	$1.22	$1.76	$1.76	$3.28	$3.72	$3.98
17,000 LUMEN	$1.80	$2.11	$2.37	$1.50	$1.29	$1.29	$2.77	$4.00	$4.00	$6.07	$7.40	$7.66
17,000 LUMEN *	$2.56	$4.01	$4.27	$1.70	$1.84	$1.84	$2.97	$4.29	$4.29	$7.23	$10.14	$10.40

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** NEW OFFERING

SCHEDULE OF PRESENT AND STAFF-RECOMMENDED
STREET AND OUTDOOR LIGHTING RATES
12 CP COST STUDY

ENERGY RATES ($ PER KWH)

RATE	PRESENT	GULF PROPOSED	STAFF RECOMMENDED
OS-I AND OS-II	$.01821	$.02631	$.02631
OS-III	$.04581	$.03675	$.03749
OS-IV	N/A	$.03675	$.03918
OS-IV CUSTOMER CHARGE:	N/A	$10.00	$8.00

ADDITIONAL FACILITIES CHARGES

30-FOOT WOOD POLE	$2.00	$2.00	$2.00
30-FOOT CONCRETE POLE	$4.50	$4.50	$4.50

SCHEDULE OF PRESENT AND STAFF-RECOMMENDED
STREET AND OUTDOOR LIGHTING RATES
EQUIVALENT PEAKER COST STUDY
891345-EI

TYPE OF FACILITY	FIXTURE CHARGE PRESENT	FIXTURE CHARGE GULF PROP.	FIXTURE CHARGE STAFF RECOM.	MAINTENANCE CHARGE PRESENT	MAINTENANCE CHARGE GULF PROP.	MAINTENANCE CHARGE STAFF RECOM.	ENERGY CHARGE PRESENT	ENERGY CHARGE GULF PROP.	ENERGY CHARGE STAFF RECOM.	TOTAL MONTHLY CHARGE PRESENT	TOTAL MONTHLY CHARGE GULF PROP.	TOTAL MONTHLY CHARGE STAFF RECOM.
HIGH PRESSURE SODIUM (OS-I)												
5,400 LUMEN	$1.76	$1.85	$1.80	$1.65	$1.34	$1.34	$0.51	$0.74	$0.85	$3.92	$3.93	$3.99
8,800 LUMEN	$1.77	$1.86	$1.81	$1.67	$1.06	$1.06	$0.73	$1.05	$1.22	$4.17	$3.97	$4.09
20,000 LUMEN	$2.06	$2.16	$2.11	$1.77	$1.56	$1.56	$1.47	$2.13	$2.47	$5.30	$5.85	$6.14
25,000 LUMEN	$1.97	$2.71	$2.66	$1.93	$2.03	$2.03	$1.86	$2.68	$3.11	$5.76	$7.42	$7.80
46,000 LUMEN	$2.93	$3.07	$3.02	$1.99	$1.61	$1.61	$2.93	$4.24	$4.91	$7.85	$8.92	$9.54
20,000 LUMEN **	$2.06	$4.21	$4.16	$1.77	$1.79	$1.79	$1.47	$2.13	$2.47	$5.30	$8.13	$8.42
46,000 LUMEN **	$2.93	$9.09	$9.09	$1.99	$2.00	$2.00	$2.93	$4.24	$4.91	$7.85	$15.33	$16.00
20,000 LUMEN **	$2.06	$10.69	$10.64	$1.77	$1.79	$1.79	$1.47	$2.13	$2.47	$5.30	$14.61	$14.90
8,800 LUMEN **	$1.77	$6.04	$5.99	$1.67	$1.56	$1.56	$0.73	$1.05	$1.22	$4.17	$8.65	$8.77
MERCURY VAPOR (OS-I)												
3,200 LUMEN	$1.28	$1.34	$1.29	$1.26	$1.40	$1.40	$0.71	$1.03	$1.19	$3.25	$3.77	$3.88
7,000 LUMEN	$1.27	$1.33	$1.28	$1.22	$1.04	$1.04	$1.22	$1.76	$2.04	$3.71	$4.13	$4.36
9,400 LUMEN	$1.37	$1.81	$1.76	$1.38	$1.66	$1.66	$1.73	$2.50	$2.90	$4.48	$5.97	$6.32
17,000 LUMEN	$1.80	$2.12	$2.07	$1.39	$1.73	$1.73	$2.77	$4.00	$4.64	$5.96	$7.85	$8.44
48,000 LUMEN	$2.73	$5.93	$5.88	$1.83	$3.16	$3.16	$6.77	$9.79	$11.35	$11.33	$18.88	$20.39
HIGH PRESSURE SODIUM (OS-II)												
5,400 LUMEN	$1.48	$1.85	$1.80	$1.60	$0.84	$0.84	$0.51	$0.74	$0.85	$3.59	$3.43	$3.49
8,800 LUMEN	$1.67	$1.65	$1.60	$1.66	$0.79	$0.79	$0.73	$1.05	$1.22	$4.06	$3.49	$3.61
20,000 LUMEN	$2.06	$2.16	$2.11	$1.77	$1.05	$1.05	$1.47	$2.13	$2.47	$5.30	$5.34	$5.63
25,000 LUMEN	$1.97	$2.70	$2.65	$1.91	$1.50	$1.50	$1.86	$2.68	$3.11	$5.74	$6.88	$7.26
46,000 LUMEN	$2.93	$3.07	$3.02	$1.99	$1.10	$1.10	$2.93	$4.24	$4.91	$7.85	$8.41	$9.03
20,000 LUMEN *	$3.26	$4.17	$4.12	$2.05	$1.92	$1.92	$1.53	$2.21	$2.56	$6.84	$8.30	$8.60
46,000 LUMEN *	$3.39	$3.71	$3.66	$2.09	$1.79	$1.79	$3.04	$4.39	$5.10	$8.52	$9.89	$10.55
8,800 LUMEN **	$1.67	$6.05	$6.00	$1.66	$0.76	$0.76	$0.73	$1.05	$1.22	$4.06	$7.86	$7.98
MERCURY VAPOR (OS-II)												
7,000 LUMEN	$0.82	$1.31	$1.26	$1.24	$0.65	$0.65	$1.22	$1.76	$2.04	$3.28	$3.72	$3.95
17,000 LUMEN	$1.80	$2.11	$2.06	$1.50	$1.29	$1.29	$2.77	$4.00	$4.64	$6.07	$7.40	$7.99
17,000 LUMEN *	$2.56	$4.01	$3.96	$1.70	$1.84	$1.84	$2.97	$4.29	$4.97	$7.23	$10.14	$10.77

* DIRECTIONAL

** NEW OFFERING

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SCHEDULE OF PRESENT AND STAFF-RECOMMENDED STREET AND OUTDOOR LIGHTING RATES EQUIVALENT PEAKER COST STUDY

ENERGY RATES ($ PER KWH)

RATE	PRESENT	GULF PROPOSED	STAFF RECOMMENDED
OS-I AND OS-II	$.01821	$.02631	$.03052
OS-III	$.04581	$.03675	$.03749
OS-IV	N/A	$.03675	$.03918

	PRESENT	GULF PROPOSED	STAFF RECOMMENDED
OS-IV CUSTOMER CHARGE:	N/A	$10.00	$8.00

ADDITIONAL FACILITIES CHARGES

	PRESENT	GULF PROPOSED	STAFF RECOMMENDED
30-FOOT WOOD POLE	$2.00	$2.00	$2.00
30-FOOT CONCRETE POLE	$4.50	$4.50	$4.50

ISSUE 146: The company proposes to eliminate the general provisions pertaining to replacement of lighting systems on the Outdoor Service Rate Schedule (OS). Is this appropriate? (WHEELER)

RECOMMENDATION: Yes. Staff recommends that the present general provisions relating to the replacement of mercury vapor lighting fixtures with high pressure sodium fixtures be removed. Staff also recommends that a new provision be added. This new provision should require, when a customer requests replacement of a mercury vapor fixture prior to its failure, that the customer pay the company an amount equal to the undepreciated portion of the original cost of the removed fixture, plus the cost of removal, less any salvage value of the removed fixture.

POSITION OF PARTIES:

GULF: The company is proposing removal of the outdoor service replacement provisions because they are no longer relevant. They do not propose adding any new provisions regarding replacement.

STAFF ANALYSIS: The present general provisions regarding replacement of mercury vapor fixtures with high pressure sodium contain three sections. The first general provision addresses replacement of mercury vapor fixtures prior to their failure during their initial contract term. This provision requires that the customer pay to the company an amount equal to the undepreciated portion of the original cost of the removed fixtures, plus the cost of removal, less any salvage value. Since no new mercury vapor fixtures have been installed since 1982, there are no fixtures which are currently in their initial contract term. Consequently, no fixtures are currently being replaced under this provision.

The second general provision addresses replacement subsequent to the expiration of the initial term of the contract. Under this provision, if the customer requests replacement prior to failure, the company will do so without charge for up to 50 units or 10% of their existing fixtures per year, whichever is greater. Currently, all the mercury vapor replacements are being done pursuant to this provision.

The third general provision addresses replacement of mercury vapor fixtures subsequent to the approval by the commission of a cost-benefit analysis filed pursuant to order No. 10557 in Docket No. 810136-EU. Since this cost-benefit analysis was never approved by the commission, no replacements have taken place under this provision.

Removal of the current provisions without the addition of any new provisions will allow customers to request unlimited replacement of mercury vapor fixtures prior to their failure at no cost to themselves. New mercury vapor fixtures were last installed in 1982. Since these fixtures are depreciated on a 15-year useful life, there are still mercury vapor fixtures in place which are not yet fully depreciated. In order to avoid the subsidization of those customers who request replacement prior to failure, they should be required to pay the cost of removing the existing fixture, as well as the undepreciated portion of the removed fixture, less any salvage value of the removed fixture.

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STIPULATED
ISSUE 147: Should the language on OS-III be clarified so that only customers with fixed wattage loads operating continuously throughout the billing period (such as traffic signals, cable TV amplifiers and gas transmission substations) would be allowed to take service on OS-III?

STIPULATION: Yes. The cost responsibility for this class was developed in the company's cost of service study on the basis that OS-III customers' load was constant, i.e., customer usage was at the same level for all 8760 hours. Therefore, the tariff should clearly state that only customer with constant usage are to be served under this schedule.

POSITION OF PARTIES:

GULF: The language on OS-III should be classified so that only customers with fixed wattage loads operating continuously throughout the billing period (such as traffic signals, cable TV amplifiers and gas transmission substations) would be allowed to take service on OS-III.

STAFF ANALYSIS: Staff and the company agree that the language on OS-III should be clarified so that only customers who have fixed wattage loads which operate continuously will be allowed to take service on OS-III. Since the cost for this class has been developed assuming that all or almost all OS-III customers' usage is at the same level for all 8760 hours of the year, only those customers whose load is fixed and constant should be allowed to take service on OS-III to avoid under or overrecovery of cost from customers.

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ISSUE 148: Since the company's last rate case, sports fields taking service on rate schedules GS and GSD were allowed to transfer to the OS-III rate schedule. The company has now proposed an OS-IV rate for sports fields. Is this appropriate, and if so, how should the rate be designed? (WHEELER)

RECOMMENDATION: Staff recommends that sports field customers be allowed to transfer to the OS-IV rate as designed by the company. However, staff does not believe that the OS-IV rate design is based on accurate load research data. In addition, staff does not in principle advocate the creation of special rates for these and other similar types of customers. Staff recommends that the commission direct the company to require sports field customers to take service under the appropriate GS or GSD rate when the next rate case is filed.

POSITION OF PARTIES:

GULF: Gulf's position is that the proposed OS-IV rate is appropriate for sports field customers, because these customers have night-only usage patterns which justify this rate.

STAFF ANALYSIS: Currently, sports field customers are taking service on the OS-III rate. (TR 1925) This is inappropriate because the OS-III rate was designed for those customers exhibiting a constant (24-hour) load. The company is proposing that these customers be transferred to a new OS-IV rate, under which they are billed for their actual kwh usage and a customer charge which is set the same as the proposed GS customer charge. The company indicates that this is an appropriate customer charge because OS-IV customers will require the same type of meter and billing as GS customers (TR 1926).

In deriving the 12 CP and NCP allocators for OS-IV, the company assumed that all recreational lighting customers would require service at a constant rate every day of the year from sunset to 10:00 p.m. (TR 1781). A review of the customer accounting memo sheets for the sports fields customers indicate that approximately 36% of the billing months showed zero kwh usage (TR 1783). The company has no load data for sports fields, and does not intend to obtain such data using load research meters (TR 1782). The OS-IV rate was thus designed in the absence of reliable load research data.

In 1981 and 1982 the Commission eliminated special rates for sports fields, poultry farms and other uses (TR 1983). Addition of a special rate for sports fields is philosophically at odds with these past actions.

In spite of these problems, staff is recommending that the rate design for OS-IV be implemented. This is because the estimated OS-IV kilowatt hours have not been broken down into summer and winter components, and thus cannot be added to the kilowatt hours for GS and GSD to determine an accurate energy rate for those classes. In addition, the OS-IV as designed will not vary significantly from the GS rate. However, the it is recommended that when the company files its next rate case they be required to transfer their sports field customers to the appropriate GS or GSD rate schedules.

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ISSUE 149: The company's proposal for service charges are summarized as follows: (KUMMER)

	Present	Company Proposed
Initial Service	$16.00	$20.00
Reconnect a Subsequent Subscriber	16.00	16.00
Reconnect of Existing Customer after Dis-Connection for Cause	16.00	16.00
Collection Fee	6.00	6.00
Installing & Removing Temporary Service	48.00	60.00
Minimum Investigative Fee	30.00	55.00

Are these charges appropriate?

RECOMMENDATION: The service drops proposed by the company should be accepted as reasonable and cost based.

STAFF ANALYSIS: Staff has been persuaded by Gulf's argument that their proposed costs are sufficiently close to costs to accruately capture the cost of providing the service to the customer. We agree with Gulf's premise stated in their brief that "the basic ratemaking philosophies of simplicity of design, application, and administration are better served by Gulf's proposed charges."

STIPULATED
ISSUE 150: Should LP customers who have demands in excess of 7500 KW but annual load factor of less than 75 percent be allowed to opt for the PXT rate? (KUMMER)

RECOMMENDATION: No. The PXT rate as designed would underrecover the total cost to service if lower load factor customers were allowed to opt up, simply to reduce an individual customer's bill.

POSITION OF PARTIES

GULF:

OPC: No. Allowing customers to opt up based on size, rather than on usage characteristics, would reduce the homogeneity of the PXT class, resulting in potential underrecovery of costs from the customers thus opting up and in potential intra-class cross-examination.

FEA: The FEA is in general agreement with the Staff.

STAFF ANALYSIS: Cost of service studies have consistently shown that higher load factor customers cost less to serve than lower load factor customers. Essentially, high load factor customers generate more KWH per KW of investment. The PX/PXT rate was designed to be a high load factor rate and its rate is set on the principle of lower unit costs associated with high load factor. Allowing customers will a maximum demand of 7500 KW without consideration of their load factor would increase costs to all customers in the class since the capacity required would be generating proportionately fewer KWH per KW. Parties agree that the PX/PXT rate was designed as a high load factor class and should remain as such.

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ISSUE 151: Should Gulf's proposal to decrease the PXT on-peak energy charge and increase the off-peak energy charge be approved?

RECOMMENDATION: No. Although the on-peak and off-peak energy charges under the PXT rate move in the direction of unit cost, these charges should be set equal to the class energy unit cost, consistent with the time of use (TOU) design recommended by Staff in issue 128. This would send the appropriate price signals to customers served under the PXT rate.

POSITION OF PARTIES

GULF: Yes. The costs are consistent with the unit costs in the revised cost of service study.

OPC: No.

II: Yes, consistent with the unit cost study.

FRF: No position.

STAFF ANALYSIS: Consistent with our recommendation in issue 128, Staff believes that the PXT on-peak energy charge and off-peak energy charge should be set equal to class energy unit cost. This would send the appropriate price signal during the on-peak and off-peak periods because a larger share of the peak demand-related production and transmission costs would be recovered through the on-peak demand charge.

Based on the company's cost of service study and load factor methodology for designing time of use rates, the PXT on-peak energy charge would be decreased and the off-peak energy charge increased. The concepts of price stability and gradualism in the transition from previous rates is the basis of the company's proposal for setting and designing the proposed rates (TR 1907, 3178).

According to OPC's witness Wright, unless evidence was presented in the rate case that establishes variable O&M cost differences between on-peak and off-peak periods, then no pricing differential between on-peak and off-peak would be warranted for rate PXT (TR 2085).

Staff recommends the PXT on-peak and off-peak energy charges be set at unit cost in order to send the proper price signal to PXT customers, and for consistency with Staff's recommendation for time of use rates design in issue 128.

ISSUE 152: Should scheduled maintenance outages of a self-generating customer that are fully coordinated in advance with Gulf Power be subject to the ratchet provision of the SS rate? (MEETER)

RECOMMENDATION: Demands registered during fully coordinated maintenance outages should be subject to the ratchet provision for the local facilities charge. The ratchet provision of the SS rate should be waived for the reservation charge if the maintenance power is used in hours that do not include a peak hour(s) that determines Gulf's IIC payments or revenues.

POSITION OF PARTIES

GULF: Yes. Standby Service Order No. 17159 requires that the initial standby service contract demand represent the maximum backup or maintenance demand that the customer expects to impose on the utility. To insure the accuracy of the initial contract demand, the order includes a ratchet provision to increase its contract demand for a total of 24 months if the actual standby taken exceeds the contract demand.

OPC: Yes as to local facilities charges; no as to reservation charges, subject to certain conditions discussed below.

II: No. There is no reason to apply the ratchet feature if the coordination avoids incurring additional capacity-related costs. This treatment of coordination is contemplated by the Commission's general order on standby service (Order No. 17159). (Pollock, Kisla)

FRF: Agree with II.

STAFF ANALYSIS: Staff agrees with Gulf and the Public Counsel that all demands registered during maintenance outages, regardless of whether the maintenance outage is fully coordinated with Gulf, should be subject to the ratchet provision of the SS rate for the local facilities charge. The ratchet provision is appropriate because the scheduling of the outage does not affect the capacity of the local facilities to serve the customer. Scheduling the outage will not enable Gulf to avoid local facilities cost as the capacity of the local facilities, particularly dedicated substations, must be sufficient to serve the customer's maximum demand whenever it occurs. An increase in demand should properly result in an increase in the billing demand for the local facilities charge. (Wright, Tr. 3087-3088)

With respect to the application of the provision for the reservation charge, staff agrees with the Office of the Public Counsel that if (1) the maintenance outage is usefully coordinated with Gulf and (2) the maintenance is used in hours that do not include a peak hour(s) that determines Gulf's IIC payments or revenues, it would be reasonable to excuse demands registered during such periods from the ratchet provision applicable to the reservation charge. (Wright, Tr. 3088) The ratchet provision should not be waived for maintenance power used during the peak hours that determine Gulf's IIC payments or revenues because the cost impact continues for three years. Furthermore, Order No. 17159 does not require the utilities to have the ratchet provision. At page 21 the order states "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 backup demand exceeded his contractually specified maximum backup demand. Alternately, the utilities may propose other appropriate penalties instead of a ratchet provision."

ISSUE 153: Should the assumed 10% forced outage factor for self-generating customers that is built into the SS rate design be continued? (MEETER)

RECOMMENDATION: In the absence of reliable data to support a different value for the forced outage rate used to develop the reservation charge, the 10 percent forced outage rate prescribed in Order 17159 should continue to be used.

POSITION OF PARTIES

GULF: Yes. In the Standby Order No. 17159, a 10 percent forced outage rate was specified as the outage rate to be used in the calculation of the Reservation Charge and Daily Demand Charges. Further, the data from Gulf's experience with rate SS is not sufficient to warrant modifying the forced outage rate at this time.

OPC: No, but there may be no practical alternative in this docket.

II: An analysis of the forced outage rates of Gulf's self-generating customers and self-generating customers of other utilities supports the conclusion that the 10% assumed forced outage factor is too high. A more reasonable forced outage rate would not exceed 5%. (Pollock)

FRF: No position.

STAFF ANALYSIS: Order No. 17159 at page 13 states that "The reservation charge is to be calculated by multiplying an assumed 10 percent forced outage rate for SGC's generators times the utility system's unit cost per coincident peak kilowatt (CP KW) for demand-related and transmission (P&T) functions." The II's position is that the forced outage rate used should not exceed 5 percent.

Staff agrees with the Office of Public Counsel that the 10 percent forced outage rate should not be continued but that there may be no practical alternative "in the absence of sound, reliable data to support an alternative value for the forced outage rate." (Office of Public Counsel brief, page 128) Witness Pollock's analysis of forced outage data for Gulf's SGCs used data provided by only three of the four customers. One of the customers refused to either give Gulf the data or to have the data disclosed through interrogatory. (Pollock, Tr. 2928-2929) Mr. Haskins indicated that one of the three customers did not notify Gulf when he had a forced outage in September, 1989. (Tr. 1969) The overall reliability of the forced outage data is questionable in that the company was apparently accepting without review the forced outage data provided by SGCs and the SGCs may not have understood they were to report these outages. even if they signed up for zero standby power. (See cross examination of Mr. Haskins at Tr. 1968-1972 and Mr. Kisla at 2782.)

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The Office of Public Counsel has "suggest[ed] that the Commission penalize Gulf for failing to comply with Order 17159 and revisit this issue prior to Gulf's next general rate case, hopefully when Gulf files the required data." (Office of Public Counsel brief, page 129) Staff would additionally suggest that Gulf be penalized for allowing 14 months to elapse before one SGC signed his contract for standby service and not installing the metering required by Order No. 17159 on this customer's generators before February, 1990. (Haskins, Tr. 1968-1969)

ISSUE 154: Would it be appropriate to grant a rate change without allowing the redesign of rates to recover the approved revenue, run the rates in competition, and go through the same iteration process as was done in the original filing of the case and the revised portion of this case? (KUMMER)

RECOMMENDATION: No. After Staff prepares initial rates, the company should be allowed one cross-over analysis to determine migrations due to changes in rated structure. The results of this adjustment should then be given to staff for design of the final rates. Only the shortfall in revenues from the migration of customers due to changes in the rate structure in this docket should be recognized in the design of permanent rates.

POSITION OF PARTIES

GULF: No. If not allowed this opportunity, then the Company would not collect the full amount of the granted revenue increase as intended by the Commission.

OPC: Yes.

II: It would be appropriate to recognize the likelihood of migration in the designing of final rates.

FRF: No position.

STAFF ANALYSIS: All parties except OPC recognize that migrations due to changes in rate structure should be recognized in final rate design. In MFR Schedule E-16, the company estimates the migrations between customer classes based on their requested rates. If the final increase approved by the Commission differs significantly from the amount requested by the company, or if other Commission decisions in this case alter the company's assumptions about rates or rate relationships, the actual shifts in customers may change as well. Since customers will migrate only if the new schedule offers a savings over their current bill, rates based on pre-migration billing units may not allow recovery of the total increase granted.

In the most recent rate cases for all five investor owned electric utilities, the Commission has allowed the company to recompute billing units based on the initially approved rates and other changes in the rate case (TR 1985). The impact of migrations due to changes in rate structure as a result of decisions in this rate case should be the only migrations allowed. Migrations which should have occurred under existing rates and have not, should not be considered in assessing the revenue from migrations due to changes in this docket. It is the utility's responsibility to see that customers are served under the most appropriate rate schedule. Just because in the course of a rate case, some customers are found to be on a less optimum schedule, the revenue impact of placing them on the proper schedule should not be included in revenue impact of cross-overs due to changes made in the rate case.

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The company proposes not one but an indefinite number of iterations of the migration process to fine tune the rates (P.H. Brief, p. 418-9). Staff does not believe that the migration process is so precise that additional iterations would justify the time and effort. Since all the data are projected, there is a certain margin of error in all aspects - revenues, costs and billing determinants. To insist that multiple iterations of migrations are necessary to ensure proper revenue recovery ignores the magnitude of error in the original numbers. Staff continues to support a single migration analysis prior to adjusting final rates.

OPC disagrees with the concept of any migration adjustments. Staff was unable to find any support for this position in OPC testimony, transcripts or briefs. Therefore, their position is being rejected with further discussion.

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ISSUE 155: Which party to this proceeding should design the Company's final rates? (KUMMER)

RECOMMENDATION: Staff should calculate the permanent rates, subject to Commission approval. The company should be allowed one iteration to calculate the shortfall from the migration of customers due to changes in the rate structure in this docket, and the shortfall should be recognized in the permanent rates.

POSITION OF PARTIES

GULF: Any interested party to this rate case should be allowed to submit their proposal for design of the initial rates and for final rates. Then the Commission can choose the rate design proposal, or combination of proposals, it deems appropriate. However, since Gulf is the only party to this case which has the capability of running rates in competition, identifying crossovers to cheaper rates, and accounting for any revenue shortfalls, Gulf should prepare the final rates to be approved by the Commission for customer billing.

OPC: The PSC Staff.

II: Apparently, it makes sense for Gulf Power to perform the migration studies. Whether Gulf or Staff performs the final rate design, the information concerning studies, assumptions, and design methodology should be available to parties.

FRF: Company should formulate with a reviewed by Commission for conformance with order.

STAFF ANALYSIS: Prior to the 1980's, utilities calculated the final rates and submitted them to the Commission for approval. Once the Commission made a decision on the amount of increase and any rate design changes, the utility designed final rates. These rates were then submitted to staff which was responsible for determining if the design complied with Commission decisions.

Under current Commission procedures, the Commission makes a determination of policy issues which determine the total dollar of increase to be granted and any changes to rate structure or design which may have been at issue in the case. Staff then prepares rates in accordance with Commission decisions and returns to the Commission with final rates usually within two or three days. Under this scenario, the Commission makes policy decisions and sees results of those decisions in terms of rates within a very short time period. Staff is required to explain and justify all proposed rates. Any party who disagrees with the results of any part of the rate case order, including final rates, may file a petition for reconsideration.

Under no circumstances should the Commission allow Gulf to design the final rates unless Gulf is willing to waive the eight month time period for implementation of new rates, in order to allow staff adequate time to review and resolve any deviations in the rate design from the letter or intent of the Commission's order.

Gulf's concerns appear to center on recovery of the full increase in revenue granted. While this is a valid concern for any party designing rates, staff does not believe the company is in a uniquely better position to implement Commission decisions in this docket than Staff. Any party designing rates must use the billing determinants, cost allocation and rate structure approved by the Commission. Staff agrees that one migration run should be done by the Company to adjust for customer shifts due to changes in rate structure. However, as stated in Issue 154, there is a certain margin of error in all rate calculations, no matter who does the computations.

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ISSUE 156: If the Commission decides to recognize migrations between rate classes, how should the revenue shortfall, if any, be recovered? (MEETER)

RECOMMENDATION: In the absence of cost of service information on the group of migrating customers, the revenue impact of customers transferring from one rate class to another rate class due to a change in rate structure of approved rates should be allocated to the two involved classes proportional to each class's approved revenues. The revenue of migrating customers should be included in the class to which they are migrating.

POSITION OF PARTIES

GULF: The revenue shortfall should be recovered from the class to which the customers presently belong. Industrial Intervenors agree with Gulf on this issue.

OPC: Agree with Staff's position as stated in Order No. 23025.

II: Any shortfall should be made up from the class from which the customer migrates.

FRF: Migrations should be recognized, but no position at this time on how it should be done.

STAFF ANALYSIS: When a group of customers migrates from one rate class to another rate class due to a change in rate structure at the conclusion of a rate case, the cost to serve of the group of migrating customers alone is not known. It is not known whether the cost to serve of this group is that of the rate class from which they are migrating or the class to which they are migrating (Wright, Tr. 2153-2154). Intuitively, one would expect the cost to serve of this group to be somewhere between the cost to serve each of the two involved classes. (Wright, Tr. 2155)

Both Witnesses Wright and Pollock in cross examination agreed that splitting the shortfall between the two involved classes on the revenues of the two classes is a reasonable and fair method given that the cost to serve of the migrating customers is not known. Neither witness offered a more equitable method in response to cross examination. (Pollock, Tr. 2932-2933; Wright, Tr.2155)

Gulf and II's position is that the shortfall from migrations should be recovered from the class from which customers are migrating. There is no evidence in the record supporting this position. In fact, as pointed out in the previous paragraph, II's Mr. Pollock agreed that splitting the shortfall between the two involved classes is a reasonable and fair method and could not offer a more equitable method.

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ISSUE 158: Should the SE rate be modified to allow additional opportunity sales to self-generating customers who have generating capacity which is available but less economic? (MEETER)

RECOMMENDATION: No. KWH and capacity purchased to replace energy and capacity normally generated by a customer's generator which is experiencing a forced outage or an outage for scheduled maintenance, is clearly standby power and should be billed as standby power. However, to ensure that power taken to replace reduced generation for purely economic reasons is billed as supplemental power, the definitions of backup service and maintenance service should be more specific. A sentence should be added to the definition of backup service to define unscheduled outage as the loss or reduction of generation output due to equipment failure(s) or other condition(s) beyond the control of the customer. Similarly, under maintenance service a scheduled outage should be defined as the loss or reduction due to maintenance activities of any portion of a customer's generating system.

POSITION OF PARTIES

GULF: No modification is necessary. Self-generating customers may reduce generation for economic reasons under present tariffs and Commission rules and take additional capacity and energy as supplementary service, including supplementary service with the SE Rider applied.

OPC: Generally agree with Staff's position as stated in Order No. 23025.

II: Yes. The SE rate is designed to encourage opportunity sales of electric power and energy when capacity is available at a reasonable price. Such sales as described in this issue would not be in violation of the standby service tariff because the customer would have to have generating resources available. A 30 minute notice provision applicable to self-generating customers enabling Gulf to cease SE service to those customers prior to peak conditions would protect other customers from uneconomic transactions while promoting the type of sales the SE rate was designed to encourage. (Pollock, Kilsa)

FRF: No position.

STAFF ANALYSIS: This issue is whether self-generating customers who are experiencing a forced outage or an outage for scheduled maintenance of their generating system can be billed on the SE rider rather than the standby service rate for standby power taken during the outage if the customer has another generator with which he could generate but chooses not to use for economic reasons. (Pollock, Tr. 3190) In other words, the issue is whether a self-generating customer can have standby power billed under a different rate tariff than the standby service if he has additional generating capacity available but which is less economic. Under the current standby service rate schedules, self-generating customers may reduce generation for economic reasons and take additional capacity and energy as supplementary service, including supplementary service with the SE rider applied.

Order No. 17159 at page 6, in addressing the issue of whether non QF standby customers would be entitled to the same services as QFs, requires the standby tariff resulting from that proceeding to be mandatory for all self-generating customers unless there is evidence to demonstrate that their load characteristics resemble those of normal full requirements customers. The argument provided for this requirement was as follows:

> The remaining parties took the position, generally, that the services to be provided to QFs and non-QF generating customers should be based on the load characteristics and cost to serve of each. They reasoned that if each group of customers imposes similar costs on the utilities' systems, then the same services should be provided to each group at the same price.
>
> We believe that the logic of the proponents position is unassailable. Clearly, if non-QF generating customers impose similar or identical costs on the utilities for the provision of supplemental, backup and maintenance services they should be charged the same rates. In fact, utilizing cost-of-service concepts, such customers should be required to use the same rates if the cost to serve is sufficiently similar. To allow such a customer to choose a different rate because it would result in a lower bill would allow that customer to escape costs properly assigned to him. [Emphasis added]
>
> Accordingly, we shall require that the tariffs resulting from this proceeding shall be mandatory for self-generating customers unless there is evidence to demonstrate that their load characteristics resemble those of normal full requirements customers. Order No. 17159, p. 9

Besides being prohibited by Order No. 17159 there is a basic cost recovery problem if standby service is allowed to be billed on the SE rider. The standby service rates have been developed using the utility's full demand-related production and transmission unit cost per coincident peak kilowatt of demand and its energy-related production unit per kilowatt hour.

> Utilizing these [unit costs] would be expected to produce rates that require a standby customer who imposes load every day to pay the full demand-related unit cost per coincident peak KW, because it is virtually certain that his load was on at the time of the system's peak. In contrast, a standby customer who

> imposes load infrequently should and would pay a proportionately smaller amount. All standby customers would pay the actual energy unit cost for the kilowatt hours they use. We note that, in general, except for additional considerations such as rate continuity, the principles of cost-based ratemaking that we normally apply will yield rates approximately equal to unit costs. In this case, we are going as far as existing information will permit us to establish rates that will equal costs. (Order 17159, p. 12)

The standby service daily demand was calculated by dividing the utility's system production and transmission cost per CP KW by the average number of days per month that certain on-peak hours (21). (Order 17159, p. 13)

Exhibit 498 shows that the average number of days for which no portion of the on-peak hours were designated as a supplemental energy period in 1988 and 1989 was six. This means the average number of days in 1988 and 1989 for which a self-generating customer would be billed daily demand charges if standby power and were billed pursuant to the SE rider is six. Thus, if he were using standby power for maintenance every day in a given month, the customer would be paying, on average, 6/21ths of the full demand-related unit cost per coincident peak KW even though it was virtually certain that his load was on at the time of the system's peak. Clearly, Order 17159 required rates for standby service to recover the full demand-related unit cost in this scenario. Witness Wright testified that to take standby service under an SE type rate, the standby service daily demand charge would have to be recomputed to reflect the much smaller number of days with on-peak periods that count toward billing determinations. (Tr. 3123).

Furthermore, under the present terms and conditions of the SE rider, there would be a cost recovery problem for local facilities when billing standby service. This results because no cost would be recovered for local facilities for standby service demand waived by the SE rider. This could be a significant problem because five of the six SE customers have dedicated substations, substations which serve only one customer and three of these were built in 1989. (Exhibit 517)

Additionally, to allow standby power to be taken under the terms and conditions of the SE rider if the customer had generating capacity available but less economic would discriminate against self-generating customers with only one generator versus those with multiple generators. Under II's request, a self-generating customer with only one generator could not have standby power billed under the terms and conditions of the SE rider while one with multiple generators could. (Pollock, Tr. 3191)

To ensure that self-generating customers are not billed for the standby power when they reduce generation for purely economic reasons, two sentences should be added to the definition (in the tariff) of backup service and maintenance service, the two forms of standby service, to indicate more clearly what constitutes scheduled and unscheduled outages. In the definition of backup service, an unscheduled outage should be defined as the loss or reduction of generation output due to equipment failure(s) or other condition(s) beyond the control of the customer. Similarly, under maintenance service a scheduled outage should be defined as the loss or reduction due to maintenance activities of any portion of a customer's generating system.

SCHEDULE 1
JULY 27, 1990

COMPARISON OF RATES OF RETURN AT PRESENT RATES FOR VARIOUS COST OF SERVICE STUDIES

RATE CODE	COMPANY'S 12 CP &1/13 (1) PRESENT ROR / INDEX	ADJUSTED 12 CP &1/13 (2) PRESENT ROR / INDEX	STAFF-REQUESTED 12 CP & 1/13 (3) PRESENT ROR / INDEX	EQUIVALENT PEAKER (4) PRESENT ROR / INDEX	REF.EQUIVALENT PEAKER (5) PRESENT ROR / INDEX	II'S NEAR PEAK (6) PRESENT ROR / INDEX
RS	5.66% / 0.86	5.74% / 0.87	5.85% / 0.89	6.36% / 0.96	6.04% / 0.92	5.95% / 0.90
GS	13.27% / 2.01	13.45% / 2.04	13.62% / 2.06	14.05% / 2.13	13.59% / 2.06	12.21% / 1.85
RS-GS	6.16% / 0.93	6.24% / 0.95	6.36% / 0.96	6.87% / 1.04	6.54% / 0.99	6.39% / 0.97
GSD	7.22% / 1.09	7.32% / 1.11	7.07% / 1.07	6.73% / 1.02	6.66% / 1.01	6.49% / 0.98
LP/LPT	6.63% / 1.00	6.62% / 1.00	6.33% / 0.96	5.63% / 0.85	6.09% / 0.92	5.93% / 0.90
PX/PXT	8.33% / 1.26	7.49% / 1.13	7.28% / 1.10	5.56% / 0.84	7.44% / 1.13	9.95% / 1.51
SE a			7.27% / 1.10	6.11% / 0.93	6.92% / 1.05	
LP-PX-SE	7.19% / 1.09	6.92% / 1.05	6.79% / 1.03	5.73% / 0.87	6.62% / 1.00	7.14% / 1.08
OSI-II	7.43% / 1.13	6.04% / 0.91	5.96% / 0.90	5.06% / 0.77	5.94% / 0.90	8.50% / 1.29
OS-III	21.48% / 3.26	21.77% / 3.30	19.47% / 2.95	17.24% / 2.61	19.74% / 2.99	25.29% / 3.83
SS	7.29% / 1.10	7.39% / 1.12	7.76% / 1.18	11.39% / 1.73	11.57% / 1.75	11.07% / 1.68
TOT.RET	6.60% / 1.00	6.60% / 1.00	6.60% / 1.00	6.60% / 1.00	6.60% / 1.00	6.60% / 1.00

Sources: (1) Exhibit 231; (2) Exhibit 231 adjusted as explained in note below; (3) Exhibit 501; (4) Exhibit 503; (5) Exhibit 504; Exhibit 371.

Note on adjustment to Gulf's 12 CP & 1/13th cost of service study (Exhibit 231): To reflect an underallocation of cost, for the PXT and LP/LPT classes, rate base was increased by 6.84 percent and .79 percent, respectively, of the transmission and demand-related production plant rate base and the demand-related production materials and supplies. The NOI for these classes was reduced by 6.84 and .79 percent, respectively, of the total transmission and demand-related production O&M expense, production plant A&G expenses and transmission and demand-related depreciation expense. For the OS class the rate base and NOI from the staff-requested 12 CP & 1/13th cost of service study (Exhibit 501) was substituted for the values in Exhibit 231. All classes' rate base and NOI were adjusted proportionately to equal the company's filed levels of rate base and NOI.

a For the company's and the adjusted 12 CP and 1/13th cost of service studies, SE is included in LP/LPT and PX/PXT.

GULF POWER COMPANY
DOCKET NO. 891345-EI
RECOMMENDED REVENUE INCREASE BY CLASS
BASED ON COMPANY'S 12 CP AND 1/13TH COST OF SERVICE STUDY
SUMMARY OF CLASS ROR'S AND % INCREASE (000 DOLLARS)

SCHEDULE 2
JULY 30, 1990

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	
				INCREASE FROM	INCREASE FROM	TOTAL INCREASE			% INCREASE IN REV FROM SALES OF ELEC	
RATE CODE	RECOMM. RATE BASE	RECOMM. PRES.NOI	PRESENT ROR/ INDEX	SERVICE CHARGES	SALES OF ELECTRICITY	IN REVENUE	REQUIRED NOI	RECOMMENDED ROR/ INDEX	W/ADJ	BASE
RS	$506,165	$30,406	6.01% / 0.87	$47	$14,148	$14,195	$39,106	7.73% / 0.98	6.86%	10.75%
GS	$35,574	$5,010	14.08% / 2.04	$47	($5,201)	($5,154)	$1,851	5.20% / 0.66	-26.38%	-34.71%
RS-GS	$541,740	$35,417	6.54% / 0.95	$94	$8,947	$9,041	$40,958	7.56% / 0.96	3.96%	6.11%
GSD	$187,196	$14,347	7.66% / 1.11	$1	$2,087	$2,088	$15,627	8.35% / 1.06	2.30%	4.02%
LP	$111,063	$7,704	6.94% / 1.00	$0	$2,627	$2,627	$9,314	8.39% / 1.06	4.37%	9.01%
PX	$57,653	$4,520	7.84% / 1.13	$0	$500	$500	$4,826	8.37% / 1.06	1.30%	3.06%
OSI-II	$14,285	$903	6.32% / 0.91	$0	$330	$330	$1,105	7.74% / 0.98	6.85%	8.78%
OS-III	$652	$149	22.85% / 3.31	$0	($48)	($48)	$120	18.40% / 2.33	-9.58%	-14.29%
SS	$3,303	$255	7.72% / 1.12	$0	$32	$32	$275	8.33% / 1.06	3.64%	4.07%
TOT.RET	$915,892	$63,295	6.91% / 1.00	$95	$14,475	$14,570	$72,224	7.89% / 1.00	3.43%	5.82%

GULF POWER COMPANY
DOCKET NO. 891345-EI
RECOMMENDED REVENUE INCREASE BY CLASS
BASED ON EQUIVALENT PEAKER COST OF SERVICE STUDY
SUMMARY OF CLASS ROR'S AND % INCREASE (000 DOLLARS)

SCHEDULE 3
JULY 30, 1990

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	
				INCREASE FROM	INCREASE FROM	TOTAL INCREASE			% INCREASE IN REV FROM SALES OF ELEC	
RATE CODE	RECOMM. RATE BASE	RECOMM. PRES.NOI	PRESENT ROR/ INDEX	SERVICE CHARGES	SALES OF ELECTRICITY	IN REVENUE	REQUIRED NOI	RECOMMENDED ROR/ INDEX	W/ADJ	BASE
RS	$479,810	$31,946	6.66% / 0.96	$47	$11,303	$11,350	$38,902	8.11% / 1.03	5.48%	8.59%
GS	$34,443	$5,069	14.72% / 2.13	$47	($5,383)	($5,336)	$1,799	5.22% / 0.66	-27.30%	-35.92%
RS-GS	$514,254	$37,015	7.20% / 1.04	$94	$5,920	$6,014	$40,701	7.91% / 1.00	2.62%	4.04%
GSD	$195,178	$13,756	7.05% / 1.02	$1	$2,941	$2,942	$15,559	7.97% / 1.01	3.26%	5.67%
LP/LPT	$92,714	$5,465	5.89% / 0.85	$0	$2,489	$2,489	$6,990	7.54% / 0.96	5.48%	11.13%
PX/PXT	$49,110	$2,862	5.83% / 0.84	$0	$1,509	$1,509	$3,787	7.71% / 0.98	5.48%	12.89%
SE	$45,787	$2,932	6.40% / 0.93	$0	$1,400	$1,400	$3,790	8.28% / 1.05	5.48%	12.23%
LP-PX-SE	$187,611	$11,258	6.00% / 0.87	$0	$5,398	$5,398	$14,566	7.76% / 0.98	5.48%	11.86%
OSI-II	$15,540	$823	5.30% / 0.77	$0	$264	$264	$985	6.34% / 0.80	5.48%	7.03%
OS-III	$776	$140	18.04% / 2.61	$0	($48)	($48)	$111	14.30% / 1.81	-9.58%	-14.29%
SS	$2,533	$302	11.92% / 1.73	$0	$0	$0	$302	11.92% / 1.51	0.00%	0.00%
TOT.RET	$915,892	$63,295	6.91% / 1.00	$95	$14,475	$14,570	$72,224	7.89% / 1.00	3.43%	5.82%

SCHEDULE OF PRESENT AND STAFF-RECOMMENDED
STREET AND OUTDOOR LIGHTING RATES
12 CP COST STUDY

891345-EI

TYPE OF FACILITY	FIXTURE CHARGE PRESENT	FIXTURE CHARGE GULF PROP.	FIXTURE CHARGE STAFF RECOM.	MAINTENANCE CHARGE PRESENT	MAINTENANCE CHARGE GULF PROP.	MAINTENANCE CHARGE STAFF RECOM.	ENERGY CHARGE PRESENT	ENERGY CHARGE GULF PROP.	ENERGY CHARGE STAFF RECOM.	TOTAL MONTHLY CHARGE PRESENT	TOTAL MONTHLY CHARGE GULF PROP.	TOTAL MONTHLY CHARGE STAFF RECOM.
HIGH PRESSURE SODIUM (OS-I)												
5,400 LUMEN	$1.76	$1.85	$2.11	$1.65	$1.34	$1.34	$0.51	$0.74	$0.74	$3.92	$3.93	$4.19
8,800 LUMEN	$1.77	$1.86	$2.12	$1.67	$1.06	$1.06	$0.73	$1.05	$1.05	$4.17	$3.97	$4.23
20,000 LUMEN	$2.06	$2.16	$2.42	$1.77	$1.56	$1.56	$1.47	$2.13	$2.13	$5.30	$5.85	$6.11
25,000 LUMEN	$1.97	$2.71	$2.97	$1.93	$2.03	$2.03	$1.86	$2.68	$2.68	$5.76	$7.42	$7.68
46,000 LUMEN	$2.93	$3.07	$3.33	$1.99	$1.61	$1.61	$2.93	$4.24	$4.24	$7.85	$8.92	$9.18
20,000 LUMEN **	$2.06	$4.21	$4.47	$1.77	$1.79	$1.79	$1.47	$2.13	$2.13	$5.30	$8.13	$8.39
46,000 LUMEN **	$2.93	$9.09	$9.09	$1.99	$2.00	$2.00	$2.93	$4.24	$4.24	$7.85	$15.33	$15.33
20,000 LUMEN **	$2.06	$10.69	$10.95	$1.77	$1.79	$1.79	$1.47	$2.13	$2.13	$5.30	$14.61	$14.87
8,800 LUMEN **	$1.77	$6.04	$6.30	$1.67	$1.56	$1.56	$0.73	$1.05	$1.05	$4.17	$8.65	$8.91
MERCURY VAPOR (OS-I)												
3,200 LUMEN	$1.28	$1.34	$1.60	$1.26	$1.40	$1.40	$0.71	$1.03	$1.03	$3.25	$3.77	$4.03
7,000 LUMEN	$1.27	$1.33	$1.59	$1.22	$1.04	$1.04	$1.22	$1.76	$1.76	$3.71	$4.13	$4.39
9,400 LUMEN	$1.37	$1.81	$2.07	$1.38	$1.66	$1.66	$1.73	$2.50	$2.50	$4.48	$5.97	$6.23
17,000 LUMEN	$1.80	$2.12	$2.38	$1.39	$1.73	$1.73	$2.77	$4.00	$4.00	$5.96	$7.85	$8.11
48,000 LUMEN	$2.73	$5.93	$6.19	$1.83	$3.16	$3.16	$6.77	$9.79	$9.79	$11.33	$18.88	$19.14
HIGH PRESSURE SODIUM (OS-II)												
5,400 LUMEN	$1.48	$1.85	$2.11	$1.60	$0.84	$0.84	$0.51	$0.74	$0.74	$3.59	$3.43	$3.69
8,800 LUMEN	$1.67	$1.65	$1.91	$1.66	$0.79	$0.79	$0.73	$1.05	$1.05	$4.06	$3.49	$3.75
20,000 LUMEN	$2.06	$2.16	$2.42	$1.77	$1.05	$1.05	$1.47	$2.13	$2.13	$5.30	$5.34	$5.60
25,000 LUMEN	$1.97	$2.70	$2.96	$1.91	$1.50	$1.50	$1.86	$2.68	$2.68	$5.74	$6.88	$7.14
46,000 LUMEN	$2.93	$3.07	$3.33	$1.99	$1.10	$1.10	$2.93	$4.24	$4.24	$7.85	$8.41	$8.67
20,000 LUMEN *	$3.26	$4.17	$4.43	$2.05	$1.92	$1.92	$1.53	$2.21	$2.21	$6.84	$8.30	$8.56
46,000 LUMEN *	$3.39	$3.71	$3.97	$2.09	$1.79	$1.79	$3.04	$4.39	$4.39	$8.52	$9.89	$10.15
8,800 LUMEN **	$1.67	$6.05	$6.31	$1.66	$0.76	$0.76	$0.73	$1.05	$1.05	$4.06	$7.86	$8.12
MERCURY VAPOR (OS-II)												
7,000 LUMEN	$0.82	$1.31	$1.57	$1.24	$0.65	$0.65	$1.22	$1.76	$1.76	$3.28	$3.72	$3.98
17,000 LUMEN	$1.80	$2.11	$2.37	$1.50	$1.29	$1.29	$2.77	$4.00	$4.00	$6.07	$7.40	$7.66
17,000 LUMEN *	$2.56	$4.01	$4.27	$1.70	$1.84	$1.84	$2.97	$4.29	$4.29	$7.23	$10.14	$10.40

* DIRECTIONAL

** NEW OFFERING

300

SCHEDULE OF PRESENT AND STAFF-RECOMMENDED STREET AND OUTDOOR LIGHTING RATES 12 CP COST STUDY

ENERGY RATES ($ PER KWH)

RATE	PRESENT	GULF PROPOSED	STAFF RECOMMENDED
OS-I AND OS-II	$.01821	$.02631	$.02631
OS-III	$.04581	$.03675	$.03749
OS-IV	N/A	$.03675	$.03918
OS-IV CUSTOMER CHARGE:	N/A	$10.00	$8.00

ADDITIONAL FACILITIES CHARGES

30-FOOT WOOD POLE	$2.00	$2.00	$2.00
30-FOOT CONCRETE POLE	$4.50	$4.50	$4.50

SCHEDULE OF PRESENT AND STAFF-RECOMMENDED
STREET AND OUTDOOR LIGHTING RATES
EQUIVALENT PEAKER COST STUDY

891345-EI

TYPE OF FACILITY	FIXTURE CHARGE			MAINTENANCE CHARGE			ENERGY CHARGE			TOTAL MONTHLY CHARGE		
	PRESENT	GULF PROP.	STAFF RECOM.	PRESENT	GULF PROP.	STAFF RECOM.	PRESENT	GULF PROP.	STAFF RECOM.	PRESENT	GULF PROP.	STAFF RECOM.
HIGH PRESSURE SODIUM (OS-I)												
5,400 LUMEN	$1.76	$1.85	$1.80	$1.65	$1.34	$1.34	$0.51	$0.74	$0.85	$3.92	$3.93	$3.99
8,800 LUMEN	$1.77	$1.86	$1.81	$1.67	$1.06	$1.06	$0.73	$1.05	$1.22	$4.17	$3.97	$4.09
20,000 LUMEN	$2.06	$2.16	$2.11	$1.77	$1.56	$1.56	$1.47	$2.13	$2.47	$5.30	$5.85	$6.14
25,000 LUMEN	$1.97	$2.71	$2.66	$1.93	$2.03	$2.03	$1.86	$2.68	$3.11	$5.76	$7.42	$7.80
46,000 LUMEN	$2.93	$3.07	$3.02	$1.99	$1.61	$1.61	$2.93	$4.24	$4.91	$7.85	$8.92	$9.54
20,000 LUMEN **	$2.06	$4.21	$4.16	$1.77	$1.79	$1.79	$1.47	$2.13	$2.47	$5.30	$8.13	$8.42
46,000 LUMEN **	$2.93	$9.09	$9.09	$1.99	$2.00	$2.00	$2.93	$4.24	$4.91	$7.85	$15.33	$16.00
20,000 LUMEN **	$2.06	$10.69	$10.64	$1.77	$1.79	$1.79	$1.47	$2.13	$2.47	$5.30	$14.61	$14.90
8,800 LUMEN **	$1.77	$6.04	$5.99	$1.67	$1.56	$1.56	$0.73	$1.05	$1.22	$4.17	$8.65	$8.77
MERCURY VAPOR (OS-I)												
3,200 LUMEN	$1.28	$1.34	$1.29	$1.26	$1.40	$1.40	$0.71	$1.03	$1.19	$3.25	$3.77	$3.88
7,000 LUMEN	$1.27	$1.33	$1.28	$1.22	$1.04	$1.04	$1.22	$1.76	$2.04	$3.71	$4.13	$4.36
9,400 LUMEN	$1.37	$1.81	$1.76	$1.38	$1.66	$1.66	$1.73	$2.50	$2.90	$4.48	$5.97	$6.32
17,000 LUMEN	$1.80	$2.12	$2.07	$1.39	$1.73	$1.73	$2.77	$4.00	$4.64	$5.96	$7.85	$8.44
48,000 LUMEN	$2.73	$5.93	$5.88	$1.83	$3.16	$3.16	$6.77	$9.79	$11.35	$11.33	$18.88	$20.39
HIGH PRESSURE SODIUM (OS-II)												
5,400 LUMEN	$1.48	$1.85	$1.80	$1.60	$0.84	$0.84	$0.51	$0.74	$0.85	$3.59	$3.43	$3.49
8,800 LUMEN	$1.67	$1.65	$1.60	$1.66	$0.79	$0.79	$0.73	$1.05	$1.22	$4.06	$3.49	$3.61
20,000 LUMEN	$2.06	$2.16	$2.11	$1.77	$1.05	$1.05	$1.47	$2.13	$2.47	$5.30	$5.34	$5.63
25,000 LUMEN	$1.97	$2.70	$2.65	$1.91	$1.50	$1.50	$1.86	$2.68	$3.11	$5.74	$6.88	$7.26
46,000 LUMEN	$2.93	$3.07	$3.02	$1.99	$1.10	$1.10	$2.93	$4.24	$4.91	$7.85	$8.41	$9.03
20,000 LUMEN *	$3.26	$4.17	$4.12	$2.05	$1.92	$1.92	$1.53	$2.21	$2.56	$6.84	$8.30	$8.60
46,000 LUMEN *	$3.39	$3.71	$3.66	$2.09	$1.79	$1.79	$3.04	$4.39	$5.10	$8.52	$9.89	$10.55
8,800 LUMEN **	$1.67	$6.05	$6.00	$1.66	$0.76	$0.76	$0.73	$1.05	$1.22	$4.06	$7.86	$7.98
MERCURY VAPOR (OS-II)												
7,000 LUMEN	$0.82	$1.31	$1.26	$1.24	$0.65	$0.65	$1.22	$1.76	$2.04	$3.28	$3.72	$3.95
17,000 LUMEN	$1.80	$2.11	$2.06	$1.50	$1.29	$1.29	$2.77	$4.00	$4.64	$6.07	$7.40	$7.99
17,000 LUMEN *	$2.56	$4.01	$3.96	$1.70	$1.84	$1.84	$2.97	$4.29	$4.97	$7.23	$10.14	$10.77

* DIRECTIONAL

** NEW OFFERING

302

**SCHEDULE OF PRESENT AND STAFF-RECOMMENDED
STREET AND OUTDOOR LIGHTING RATES
EQUIVALENT PEAKER COST STUDY**

ENERGY RATES ($ PER KWH)

RATE	PRESENT	GULF PROPOSED	STAFF RECOMMENDED
OS-I AND OS-II	$.01821	$.02631	$.03052
OS-III	$.04581	$.03675	$.03749
OS-IV	N/A	$.03675	$.03918
OS-IV CUSTOMER CHARGE:	N/A	$10.00	$8.00

ADDITIONAL FACILITIES CHARGES

30-FOOT WOOD POLE	$2.00	$2.00	$2.00
30-FOOT CONCRETE POLE	$4.50	$4.50	$4.50

PROPOSED RATES FOR GULF POWER COMPANY - DOCKET NO 891345-EI

	CURRENT RATES	COMPANY PROPOSED	12 CP COS PROPOSED RATES		EQUIVALENT PEAKER PROPOSED RATES	
INCREASE IN REVENUES		$26,137,000	$14,475,000		$14,475,000	
RATE CLASS			STAFF TOU	LOAD FACTOR TOU	STAFF TOU	LOAD FACTOR TOU
RESIDENTIAL						
CUSTOMER CHARGE	$6.25	$8.00	$8.00	$8.00	$8.00	$8.00
ENERGY						
Oct - May	$0.03148	$0.03489	$0.03395	$0.03395	$0.03316	$0.03316
June - Sept	$0.03716	$0.04114	$0.04006	$0.04006	$0.03913	$0.03913
NON SEASONAL			$0.03653	$0.03653	$0.03567	$0.03567
RESIDENTIAL TOU						
CUSTOMER CHARGE	$9.25	$11.00	$11.00	$11.00	$11.00	$11.00
ENERGY						
ON PEAK	$0.07797	$0.08623	$0.10614	$0.08459	$0.08874	$0.08287
OFF PEAK	$0.01378	$0.01608	$0.00594	$0.01567	$0.01251	$0.01535
GENERAL SERVICE						
CUSTOMER CHARGE	$7.00	$10.00	$8.00	$8.00	$8.00	$8.00
ENERGY						
Oct - May	$0.06174	$0.05441	$0.03395	$0.03395	$0.03316	$0.03316
June - Sept	$0.06348	$0.06423	$0.04006	$0.04006	$0.03913	$0.03913
NON SEASONAL			$0.03653	$0.03653	$0.03567	$0.03567
GENERAL SERVICE TOU						
CUSTOMER	$10.00	$13.00	$11.00	$11.00	$11.00	$11.00
ENERGY						
ON PEAK	$0.14727	$0.14324	$0.10614	$0.08459	$0.08874	$0.08287
OFF PEAK	$0.02296	$0.02188	$0.00594	$0.01567	$0.01251	$0.01535
GS-DEMAND						
CUSTOMER CHARGE	$27.00	$40.00	$40.00	$40.00	$40.00	$40.00
KW DEMAND	$6.25	$4.51	$4.51	$4.51	$4.51	$4.51
ENERGY	$0.00641	$0.01424	$0.01266	$0.01266	$0.01316	$0.01316
GS DEMAND TOU						
CUSTOMER	$32.40	$45.40	$45.40	$45.40	$45.40	$45.40
KW DEMAND						
MAXIMUM	$2.96	$2.17	$2.15	$2.50	$2.15	$2.40
OFF PEAK	$3.42	$2.44	$5.00	$3.00	$3.06	$2.70
ENERGY						
ON PEAK	$0.01395	$0.03269	$0.00445	$0.02254	$0.01130	$0.02675
OFF PEAK	$0.00302	$0.00692	$0.00445	$0.00474	$0.01130	$0.00563

PROPOSED RATES FOR GULF POWER COMPANY - DOCKET NO 891345-EI

	CURRENT RATES	COMPANY PROPOSED	12 CP COS PROPOSED RATES		EQUIVALENT PEAKER PROPOSED RATES	
INCREASE IN REVENUES		$26,137,000	$14,475,000		$14,475,000	
RATE CLASS			STAFF TOU	LOAD FACTOR TOU	STAFF TOU	LOAD FACTOR TOU
LP						
CUSTOMER CHARGE	$51.00	$225.00	$225.00	$225.00	$225.00	$225.00
KW DEMAND	$6.25	$8.52	$8.50	$8.50	$6.00	$6.00
ENERGY	$0.00861	$0.00568	$0.00543	$0.00497	$0.01072	$0.01072
LP TOU						
CUSTOMER CHARGE	$51.00	$225.00	$225.00	$230.00	$230.00	$230.00
KW DEMAND						
MAXIMUM	$2.97	$4.15	$1.81	$4.14	$1.70	$2.80
ON PEAK	$3.35	$4.52	$7.26	$4.50	$4.45	$3.50
ENERGY						
ON PEAK	$0.01928	$0.01211	$0.00417	$0.01010	$0.01025	$0.02308
OFF PEAK	$0.00390	$0.00300	$0.00417	$0.00300	$0.01025	$0.00481
PX						
CUSTOMER CHARGE	$146.00	$570.00	$570.00	$570.00	$570.00	$570.00
KW DEMAND	$7.50	$8.25	$8.25	$8.25	$7.00	$7.00
ENERGY	$0.00521	$0.00445	$0.00443	$0.00443	$0.00729	$0.00729
PX TOU						
CUSTOMER CHARGE	$146.00	$570.00	$570.00	$570.00	$570.00	$570.00
KW DEMAND						
MAXIMUM	$3.56	$3.97	$0.68	$4.00	$0.56	$3.70
OFF PEAK	$3.99	$4.32	$7.75	$4.31	$5.06	$4.00
ENERGY						
ON PEAK	$0.01299	$0.00984	$0.00406	$0.00758	$0.00939	$0.01624
OFF PEAK	$0.00242	$0.00262	$0.00406	$0.00260	$0.00939	$0.00305
SE						
CUSTOMER CHARGE					$375.00	$375.00
KW DEMAND						
MAXIMUM					$0.52	$2.97
ON-PEAK		N/A	N/A	N/A	$5.75	$3.35
ENERGY						
ON PEAK					$0.06961	$0.06767
OFF PEAK					$0.01474	$0.01328

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