ONTARIO ENERGY BOARD

IN THE MATTER the *Ontario Energy Board Act*, 1998, S.O. 1998, c. 15 (Schedule B);

AND IN THE MATTER OF an application to the Ontario Energy Board by Energy+ Inc. pursuant to Section 78 of the *Ontario Energy Board Act* for approval of its proposed distribution rates and other charges effective January 1, 2019.

Toyota Motor Manufacturing Canada Inc. ("TMMC")

Response to Interrogatories

of

School Energy Coalition ("SEC")

October 25, 2018

Reference: **SEC-TMMC-1**

Preamble: [Pollock Evidence, p.48-51] With respect to Mr. Pollock's proposed standby rate design:

Questions:

a. Is Mr. Pollock aware of any other regulators who have considered a similar approach to standby rate design? If so, please provide details including copies of any regulatory decisions.

b. Has Mr. Pollock ever recommended a similar standby rate design in evidence to a regulator? If so, please provide copies of that evidence and copies of the resulting regulatory decision.

Response:

a. The Standby rate design proposed by Mr. Pollock in this proceeding is similar to rate designs approved in Florida, New York and Texas. Orders approving these rate designs are provided in links and/or attachments as noted below (be sure to temporarily turn off pop-up blocker for NYPSC links)

- New York Public Service Commission, Case No. 17-E-0238 *et al*., *Order Adopting Terms of the Joint Proposal and Establishing Electric and Gas Rate Plans* (Mar. 15, 2018). http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=202941&MatterSeq=53408
  - This Settlement incorporates the rate design as established in Case No. 14-M-0101, *Order Adopting a Ratemaking and Utility Revenue Model Policy Framework* (May 19, 2016). http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=160469&MatterSeq=44991

- Public Utility Commission of Texas, Docket No. 39896, *Order* (Sept. 14, 2012). http://interchange.puc.texas.gov/Documents/39896_806_736656.PDF
  - An *Order on Rehearing* was issued on Nov. 2, 2012, which made some technical and ancillary modifications but didn't alter the topic at hand in this proceeding. http://interchange.puc.texas.gov/Search/Documents?controlNumber=39896&itemNumber=825

- Florida Public Service Commission, Docket No. 850673-UE, *In Re: Generic Investigation of Standby Rates for Electric Utilities,* Order (Feb. 6, 1987). See **Attachment A** – SEC-TMMC-1a (begins on page 6)
  - The Feb. 1987 Order memorialized the Commission's vote on the issues and required each utility to file tariffs in conformance with same. Workshops to clarify details of the Commission's Feb. 1987 Order took place and ultimately an *Order Granting and Denying Standby Rate Tariffs and Granting Motion for Reconsideration* was issued Nov. 10, 1987. See **Attachment B** – SEC-TMMC-1a (begins on page 25)

b. Yes. Mr. Pollock has testified on standby rate design issues in numerous regulatory proceedings. Two examples of the evidence provided by Mr. Pollock are listed below. The resulting Orders are referenced in response to (a) above.

- Public Utility Commission of Texas, Docket No. 39896, *Direct Testimony and Exhibits of Jeffry Pollock* (Mar. 27 2012). http://interchange.puc.texas.gov/Search/Documents?controlNumber=39896&itemNumber=521
- New York Public Service Commission, Case No. 17-E-0238 *et al*., *Direct Testimony and Exhibits of Jeffry Pollock* (Aug. 25, 2017). http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=192499&MatterSeq=53408

Reference: **SEC-TMMC-2**

Preamble: [Pollock Evidence, p.53] Mr. Pollock states that his “recommended standby rate closely parallels the rate design approved by several state regulatory commissions in the United States.” Please provide copies of regulatory decisions and or policies approving or discussing the referenced rate design.

Questions: Please provide copies of regulatory decisions and or policies approving or discussing the referenced rate design.

Response: Please see TMMC’s response to SEC-TMMC-1.

Reference: **SEC-TMMC-3**

Preamble: [Pollock Evidence, p.51-55] SEC seeks to understand how the Board would approve the proposed standby rate design on a generic basis for other Energy+ customers with LDG.

Questions:

a. Please provide the proposed wording that Mr. Pollock and/or TMMC believes would have to be included in Energy+ tariff.

b. Please provide a step-by-step explanation of how Energy+ would determine the applicable maximum volumetric rate and daily volumetric rate.

c. Does Mr. Pollock believe there should be a minimum size of a customer's LDG facility or facilities before they should be required to pay a standby rate? If so, please explain.

d. [Exhibit 8, p.13] Energy+ has proposed that its proposed standby rate proposal be applied not just to the large user class but also to the GS> 50-999 kW and GS 1,000-4,999 kW classes. Does Mr. Pollock believe that this is appropriate or that there should be a minimum size of the class that should be charged the standby rate? If so, please explain.

e. If the answer to part (d) is yes, in full or in part, does Mr. Pollock propose any adjustments to his proposed methodology in determining the standby rate for customers in other rate classes?

Response:

a.& b. Mr. Pollock has not drafted a Standby tariff that would apply to all LDG customers. However, the approach described in Mr. Pollock's evidence for deriving a Maximum Volumetric rate and a Daily Volumetric rate (specifically on pages 49 through 54) can be applied to any rate classification. Specifically, these rates would be derived from the corresponding cost-based distribution demand-related costs functionalized between bulk, primary, and secondary.

c. Customers with LDG should be required to pay for Standby service. Mr. Pollock believes that all LDG customers equipped with demand meters should pay for Standby service.

d. Mr. Pollock does not agree with Energy+'s Standby rate proposals for any class. Accordingly, Mr. Pollock removed all of Energy+'s LDG adjustments in his revised (including the adjustments to the GS> 50-999 kW and GS 1,000-4,999 kW class load profiles) in Schedule JP-5 (both original and revised). Please see TMMC's response to subpart c.

e. Not applicable.

ATTACHMENT A

SEC-TMMC-1(a): Florida Public Service Commission, Docket No. 850673-UE
Order (Feb. 6, 1987)

KeyCite Yellow Flag - Negative Treatment
Reconsideration Granted by In Re: Generic Investigation of Standby Rates for Electric Utilities., Fla.P.S.C., November 10, 1987

87 FPSC 2:43, 1987 WL 1372507 (Fla.P.S.C.)

In Re: Generic Investigation of Standby Rates for Electric Utilities

Docket No. 850673-EU
Order No. 17159

Florida Public Service Commission

February 6, 1987

APPEARANCES: G. EDISON HOLLAND, Esquire, of the firm Beggs and Lane, Post Office Box 12950, Pensacola, Florida 32576, appearing on behalf of Gulf Power Company. JAMES D. BEASLEY, Esquire, of the firm Ausley, McMullen, McGehee, Carothers and Proctor, Post Office Box 391, Tallahassee, Florida 32302, appearing on behalf of Tampa Electric Company. MATTHEW M. CHILDS, Esquire, of the firm Steel, Hector and Davis, 200 South Monroe Street, Tallahassee, Florida 32302, appearing on behalf of Florida Power and Light Company. STEVEN A. McCLAREN, Esquire, Post Office Box 14042, St. Petersburg, Florida 33733, appearing on behalf of Florida Power Corporation. JASON BROWN, Esquire, Dade County Attorney's Office, Suite 2800, 111 Northwest 1st Street, Miami, Florida 33128-1993, appearing on behalf of Metropolitan Dade County. RICHARD A. ZAMBO, Esquire, Post Office Box 856, Brandon, Florida 33511, appearing on behalf of Conserv. Inc., Florida Crushed Stone Company, W. R. Grace and Company, International Minerals and Chemical Corporation, Monsanto Company, Occidental Chemical Company, The Royster Company, United States Steel Agricultural Chemicals, and U.S. Sugar Corporation. MICHAEL B. TWOMEY, Esquire, Florida Public Service Commission, Division of Legal Services, and SCHEFFEL WRIGHT, Class B Practitioner, Division of Electric and Gas, 101 East Gaines Street, Tallahassee, Florida 32399-0863, appearing on behalf of the Commission Staff. PRENTICE P. PRUITT, Esquire, Florida Public Service Commission, General Counsel's Office, 101 East Gaines Street, Tallahassee, Florida 32399-08961, appearing as Counsel to the Commissioners.

Before Katie Nichols, Chairman, John T. Herndon, John R. Marks, III and Michael McK. Wilson, Commissioners.

ORDER REQUIRING TARIFFS TO BE FILED AND PRESCRIBING TARIFF TERMS AND CONDITIONS

BY THE COMMISSION:

Pursuant to Notice duly issued, the Florida Public Service Commission held hearings in Tallahassee, Florida, on August 20, 21, and 22, 1986. Having considered the record herein, the Commission now enters its final order.

By its enactment of the Public Utility Regulatory Policy Act of 1978 (PURPA) the Congress of the United States required that the Federal Energy Regulatory Commission (FERC) promulgate rules implementing PURPA and further required that each state regulatory commission develop procedures by which it would implement the FERC's rules.

As a result of our 1981 and 1983 hearings designed to develop procedures by which we would implement the FERC's rules, we promulgated rules respecting Utilities' Obligations With Regard To Cogenerators and Small Power Producers, Rule 25-17.080, F.A.C. et seq.

Among those rules is Rule 25-17.082(3), Florida Administrative Code, which provides that QFs may elect to purchase all power requirements from the utility while selling all output to the utility, or to use their output to displace purchases from the utility, selling any excess and buying any additional power required from the utility. Addressing the price the QF's shall pay for purchases under each of these options, Rule 25-17.082(3)(f), F.A.C. provides, in part:

Should a qualifying facility elect to make simultaneous purchases and sales, purchases of electric service by the qualifying facility from the utility shall be billed at the retail rate schedule under which the qualifying facility would receive service as a non-generating customer of the utility; sales of electricity by the qualifying facility to the utility shall be purchased at the utility's avoided energy and capacity rates, where applicable, in accordance with Rules 25-17.0825 and 25-17.083.

Should a qualifying facility elect to make net sales, the hourly net energy and capacity sales to the utility shall be purchases at the utility's avoided energy and capacity rates, where applicable, in accordance with Rules 25-17.0825 and 25-17.083. For those hours during which a qualifying facility is a net purchaser, purchases from the utility shall be billed at the utility's retail rate schedule under which the qualifying facility would receive service as a non-generating customer of the utility.

Thus, under our current rules, any purchases a QF makes from the purchasing utility are billed at the utility's retail rate schedule under which the QF would receive service as a non-generating customer, regardless of the use for which that power was being purchased.

FERC Rule 18 CFR 292.305(b) provides:
(b) Additional Services to be provided to qualifying facilities.

(1) Upon request of a qualifying facility, each electric utility shall provide:

(I) Supplementary power;

(II) Back-up power;

(III) Maintenance power; and

(IV) Interruptible power.

While 51 issues were identified in the Prehearing Order, the primary questions for our resolution are:
(1) Should supplemental, backup, and maintenance services be recognized as different types of services for billing purposes?;

(2) If so, what are the appropriate rates for each type of service?; and

(3) What terms, conditions, applicability criteria, and other provisions are appropriate for a standby tariff?

Including our Staff, there were seven parties to this proceeding. The four major investor-owned electric utilities, Florida Power and Light Company (FPL), Florida Power Corporation (FPC), Tampa Electric Company (Teco), and Gulf Power Company (Gulf), participated. Metropolitan Dade County (Dade County) and the Industrial Cogenerators (consisting of CF Industries, Inc.; International Minerals & Chemical Corporation; The Monsanto Company; Occidental Chemical Agricultural Products, Inc.; The Royster Company; United States Sugar Corporation; and W. R. Grace & Co.) also participated.

Our Staff conducted workshops in this docket on February 12, March 26, March 27, April 16 and May 21 of 1986. By Order No. 16011, issued April 16, 1986, we required the four investor-owned electric utilities to file illustrative standby tariffs for consideration at hearing. Formal hearings on the matter were held August 20, 21 and 22, 1986, at which time we heard the testimony of eleven witnesses. Our decisions on the various issues follow.

I. DEFINITIONS

We adopt the following definitions as being reasonable and representative of the services required:
"Standby electric service" refers to backup or maintenance service or both.

"Backup service" means electric energy or capacity supplied by the utility to replace energy or capacity ordinarily generated by a customer's own generation equipment during an unscheduled outage of the customer's generation.

"Maintenance service" means electric energy or capacity supplied by the utility to replace energy or capacity ordinarily generated by a customer's own generation equipment during a scheduled outage of the customer's generation.

"Supplemental service" means electric energy or capacity supplied by the utility in addition to that which is normally provided by the customer's own generation equipment.

II. AVAILABILITY OF SERVICE

In its Order No. 69, which adopted rules implementing PURPA, FERC found that Section 210(c) of PURPA:

> provides that the rules requiring utilities to sell electric energy to qualifying facilities shall ensure that the rates for such sales are just and reasonable, in the public interest, and nondiscriminatory with respect to qualifying cogenerators or small power producers. This section contemplates formulation of rates on the basis of traditional ratemaking (i.e., cost-of-service) concepts.

Being true to the cost-of-service concept requires a delicate balance to remain on the line between rates that "subsidize" QF's at the expense of the general body of ratepayers and those that unfairly "saddle" QF's with unwarranted costs. A primary objective of this hearing was to identify specifically those costs that are appropriate for inclusion in the rates for standby services and those that are not.

A threshold issue was whether the known or expected load characteristics of self-generating customers were sufficiently different from those of the utilities' full requirements customers to justify having different rates. FPL took the position that there was no data to substantiate known load characteristics and that expected load characteristics could be the same for both full requirements and standby customers. FPL did state, however, that a separate rate based on a different method of recovering the costs of providing standby services was justified to ensure equitable cost recovery and to provide proper price signals.

While FPC took the position that the load characteristics of self-generating customers were not presently known, it expected that they would be sufficiently different to justify different rates.

Teco took the position that the standby services were comparable to the traditional services provided to full requirements customers and argued that its modified time-of-day rate schedules were fait and reasonable for standby services.

Gulf took the position that the expected load characteristics of standby service were sufficiently different from those of full requirements customers to justify different rates.

Dade County and the Industrial Cogenerators took the position that the expected load characteristics for backup and maintenance services would be sufficiently different from existing service classes and from each other to warrant different rates. They felt that until information to the contrary was obtained, the load characteristics for supplemental service should be presumed to be the same as those of the otherwise applicable full requirements rate classes.

Based upon the record in this case, we believe and find that the expected load characteristics of self-generating customers are sufficiently different to justify different rates for backup and maintenance power. This is so because backup and maintenance services are expected to be relatively low load-factor services reflecting the low forced and scheduled outage rates expected from the self-generating customers. Supplemental service, on the other hand, is expected to vary broadly from intermittent use to nearly constant use and in this regard may be expected not to differ significantly, on average, from the characteristics of full requirements power service. Accordingly, we shall require that supplemental service be provided under the utilities' otherwise applicable full requirements service tariffs. As discussed later in this order, we shall require the collection and reporting of certain QF generation and load data that might, after sufficient operating experience and analysis, indicate that a separate rate for supplemental service is appropriate.

While we find that the expected load characteristics of both backup and maintenance power are sufficiently different from standard services to warrant separate rate schedules, we cannot, based upon the record in this case, find that backup and maintenance power are sufficiently different from each other to warrant separate cost-based rates. In theory, if maintenance power service can be scheduled to avoid a utility's peaks, it should not be assigned any cost responsibility for demand-related production and bulk transmission costs. However, there are several factors that may make it difficult or impossible to distinguish between backup and maintenance power. FPC witness William Slusser testified that backup and maintenance are difficult to distinguish from the utility's perspective because the utility must provide the same level of replacement power regardless of whether the customer's generator is out for scheduled maintenance or has been forced out. Mr. Slusser added that customers with more than one generator may simultaneously experience forced and scheduled outages. He testified that he found it difficult to distinguish any difference in the standby cost impact of the two.

We find Mr. Slusser's testimony to be persuasive. In a cost-of-service analysis using a 12 CP allocator to allocate demand-related costs, the cost responsibility will be the same for 10 MW of maintenance power taken for a full month as for 10 MW of backup power taken intermittently but only during one monthly peak hour of the year.

While we believe and find that the FERC, through 18 CFR 292.305(b), intended that the utilities offer QFs separate supplemental, backup and maintenance power services, we have also concluded that the FERC did not intend that different rates for these services were required where they were not cost-justified. Accordingly, based upon the record in this case, we find no cost-based justification for requiring different rate schedules for backup power and maintenance power. This is not to say that sufficient cost differentials between these two services cannot be recognized to justify separate rates. Rather, we simply find that there are insufficient differentials demonstrated in this record to warrant separate rates. As will be discussed below, we shall require the recording and reporting of certain QF generation and load data that might, after sufficient operating experience, warrant separate rates.

Accordingly, we find and shall order that the electric utilities shall offer QFs and other self-generating customers supplemental service under the same rates that would apply if they were non-generating customers. Furthermore, each utility shall offer cost-based rates for backup and maintenance power, which rates may be identical until such time as an evidentiary demonstration is made that different rates for these services are warranted on a cost-of-service basis.

Tariffs Applicable To Most Generating Customers in Addition to QFs

One issue in this case was whether we should mandate that non-QF standby customers would be entitled to the same services as QFs under the tariffs approved as the result of the proceedings. Both Gulf and Teco argued that we should not. Gulf took the position that we should not do so because the FERC has not mandated such services for non-QFs, while Teco argued that it would prefer to retain the option to review, or to have us review, each case on an individual basis. 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.

Accordingly, we shall require that the tariffs resulting from this proceeding shall be mandatory for all self-generating customers unless there is evidence to demonstrate that their load characteristics resemble those of normal full requirements customers. Two such possible exceptions that we recognize are: 1) customers whose generators are for emergency purposes only; and (2) customers whose total generation capacity is less than 20 percent of that customer's total electrical load.

In view of our decision on this issue, our reference to self-generating customers (SGC) shall include all cogenerators and small power producers whether or not they have obtained qualifying facility (QF) status.

Provision of Interruptible Service

All parties appear to concede that the FERC rules require the utilities to offer QF standby customers both firm backup, maintenance and supplemental service and those same services on an interruptible basis. Likewise, there appears to be no disagreement with the notion that any standby services provided on a non-firm basis should be consistent with our rule on non-firm electric service, Rule 25-6.0438, F.A.C. We concur in this assessment and find that the FERC rules do require that the utilities shall offer backup, maintenance and supplemental service on both a firm and interruptible basis. Furthermore, we find that the provision of non-firm service for standby purposes shall be consistent with Rule 25-6.0438, F.A.C.

A related issue is whether utilities that do not offer interruptible service to their non-generating customers are required to offer interruptible standby services to their generating customers. The answer to this question appears to be no under certain circumstances. More specifically, in its Order No. 69, FERC stated that if the interruptible customers provide no savings to the electric utilities, the rate for interruptible service would not be required to be lower than the rate for firm service. The FERC noted that in such cases it would consider granting a waiver from the provision requiring interruptible service.

Rule 25-6.0438(4)(a) F.A.C. provides:

(4) Availability of service

(a) A utility may offer non-firm electric service to any customers or class of customers pursuant to tariffs or contracts approved by the Commission. Each utility that currently offers or proposes to offer non-firm electric service shall demonstrate, no later than its next rate case, that providing such service is likely to result in the cost effective deferral or avoidance of additional production plant construction by the utility or in other measurable economic benefits accruing to the utility's general body of ratepayers.

We find that the proper policy, consistent with the FERC rules and our rules, regarding the provision to SGCs of interruptible backup, maintenance, and supplemental power, is that it should be offered if it can be shown to result in demonstrable net benefits to the utility's general body of ratepayers. Absent such a demonstration, it should not be offered.

Currently, Teco and FPC offer interruptible service to both their self-generating and non-generating customers. FPL offers curtailable service but not interruptible, while Gulf offers neither.

Firm and Interruptible Services In Combination

On this issue Gulf took the position that a given customer must take service that is either firm or non-firm but not both. Teco stated that it was not possible to mix firm and non-firm service through the same meter and took the position that multiple metering had not been shown to be cost-effective. FPL, FPC and the Industrial Cogenerators took the position that firm standby and interruptible services could be provided to the same customer but only if they are supplied on electrically separate circuits and metered separately.

We agree and find that standby customers should be allowed to take interruptible supplemental power and firm backup or maintenance power, or vice versa, but only if the two services are taken on separate circuits through separate meters. In making this finding we reject Gulf's assertion that such a combination of services is neither practical nor possible.

Furthermore, while we agree with Teco and the others that it is not possible to mix firm and non-firm service through the same meter, we do not find that the cost-effectiveness of multiple meters or the lack thereof is relevant. This is so because the standby customer should be required to pay for any redundant facilities and additional metering, meter-reading and accounting costs associated with maintaining separate accounts. Accordingly, it will be up to the customers to determine if it is cost-effective to pay the additional costs in return for obtaining the separate services.

Firm and Curtailable Services In Combination

The Industrial Cogenerators raised the issue of whether the utilities should provide firm and curtailable service in combination and took the position that they should. FPL and FPC stated that the provision of these services in combination might be appropriate but that it should be consistent with the same service offered to full requirements customers and in compliance with the non-firm rates rule. Gulf and Teco took the position that this combination of services should not be required.

Currently, FPL and FPC are the only investor-owned utilities in Florida providing curtailable service. Neither FPC's witness (Slusser) nor FPL's witness (Tammy) indicated that there would be any problem in allowing self-generating customers to obtain curtailable service in combination with firm backup service.

We are of the opinion and find that curtailable service may be offered in combination with firm standby and supplemental service. Curtailable service is distinct from interruptible service in that the customer, not the utility, has the ability to reduce the load during a curtailment period called by the utility. Another distinction is that firm service with a curtailable service rider may be administered through one meter, whereas interruptible and firm service must be provided through separate meters on electrically separate circuits.

While we have found that this combination of services may be offered, we shall not require it of the utilities. Furthermore, those utilities that do offer it should ensure that this service meets the cost-effectiveness criteria set forth in the non-firm rates rule. More particularly, the utilities offering this service should ensure that the curtailment credits paid are based on the expected value of the load that they can see reduced when necessary. Normally, the curtailable loads of standby customers should be expected to have relatively lower load factors and coincidence factors than the curtailable loads of full requirements GSLD customers, which should translate into less load actually being curtailed. In turn, this would indicate that smaller credits would be appropriate for curtailable standby service than for curtailable full requirements service.

Provision of Standby Services To Loads Remote From Customer's Generator

The Industrial Cogenerators and Dade County have taken the position that we should require the utilities to provide standby service to self-served loads at locations remote from the site of the customer's generator. Dade County states that federal law mandates such service. The utilities take the position that the provision of this service is not mandated by federal law. Gulf and FPL take the position that standby service should only be applicable to the electrical load at the customer's generating site, while FPC states that all standby services required by a self-generating customer for both its generating and remote site needs can and should be provided at the generating site. FPC submitted that such a system would satisfy the requirements of PURPA and, at the same time, clearly indicate the self-generating customer's responsibility for securing wheeling services for its remote site needs.

We find that there is no PURPA requirement or other federal law that requires utilities to provide standby service to self-served loads at locations remote from the customer's generator. Whether or not this Commission has mandated self-service wheeling from a customer's generation site to a remote location, we believe that any standby service should be billed as if the standby power were received at the customer's generating site. If self-service wheeling has been ordered pursuant to Rule 25-17.0882, F.A.C., the utility may then bill the customer for wheeling the power to the remote load site. If self-service wheeling has not been ordered, then it is the customer's responsibility to provide a means for transmitting the necessary standby power from his generating site to the remote load site.

Standby Services Not Required For Loads Other Than Electrical Load Normally Served By The Customer's Electric Generator

In raising this issue, FPL asked whether a utility would have to provide standby service for a customer's mechanical or thermal loads that were in excess of the electrical load normally served by the customer's electric generator. All four of the electric utilities took the position that they should not, while the Industrial Cogenerators argued that all electric energy or capacity supplied by an electric utility resulting from scheduled or unscheduled outages of the customer's generator should be considered as standby power.

We have already determined that "supplemental service" is defined as:

> electric energy or capacity supplied by the utility in addition to that which is normally provided by the customer's own generation equipment.

We believe it follows, then, that any power supplied by a utility in excess of the capacity of the customer's generator would be supplemental power and not backup or maintenance power. Accordingly, we find that the utilities shall not be required to provide standby service to loads in excess of the capacity of a customer's generator.

Scheduling of Maintenance Power with Utilities

In its order No. 69, the FERC notes that its rules provide that:

> rates for sales shall take into account the extent to which a qualifying facility can usefully coordinate periods of scheduled maintenance with an electric utility. If a qualifying facility stays on line when the utility will need its capacity, and schedules maintenance when the utility's other units are operative, the qualifying facility is more valuable to the utility, as it can reduce its capacity requirements.

At issue here was whether standby customers should be required to schedule maintenance power service requirements. We have determined that the answer turns on how the maintenance power is billed.

If a utility's standby tariffs provide for a discount on or forgiveness for demand-related production plant charges if the customer schedules his maintenance in advance, then the standby customer should be required to schedule his maintenance with the utility. If they do not, then advance scheduling shall not be required. Furthermore, when scheduling is required, it should include sufficient advance notice to provide "useful coordination" with the utility.

Notice Requirement For Transfer From Standby Service to Full Requirements Service

At issue in this proceeding was whether self-generating customers taking backup and maintenance service under applicable rates should be required to give notice prior to transferring to full requirements service. Based on the record in this case and on our policy regarding similar transfers of non-firm customers to firm service set forth in our rule governing terms and conditions of non-firm electric service, Rule 25-6.0438(7), F.A.C., we find that requiring customers to give five years advance written notice of a desired change in service is reasonable and in the public interest (1) for transferring from interruptible standby to a firm standby tariff or to a firm full requirements service tariff; and (2) for transferring from firm standby service to firm full requirements service. Such notice is appropriate and in the public interest because it should prevent any adverse impact on a utility's generation expansion planning decisions that might result from the imposition on a utility of large increments of firm full requirements service load with insufficient notice. As we established in our Non-Firm Rates Rule, though, such transfers with less than five years notice may be permitted if it can be shown that they are in the best interests of the SGC, the utility, and the utility's other ratepayers.

Transfers from interruptible standby service to interruptible full requirements service, and from firm standby service to interruptible standby or full requirements service, will be permitted so long as they do not cause the utility to exceed its maximum level of non-firm load established by the utility's method filed and approved pursuant to Rule 25-6.0438 (5), F.A.C.

III. COST TO SERVE AND RATE DESIGN

A threshold issue in this area was whether we should prescribe a single approach to cost allocation and rate design for service supplied to self-generating customers to be adopted uniformly by all utilities, or whether we should allow each utility to price its standby service as it sees fit, provided that all costs of supplying the service are recovered. Generally, the utilities took the position that, at least initially, they should be allowed to price standby services individually and that the resulting rates should be judged on that basis. In contrast, the Industrial Cogenerators took the position that it is desirable to have a single approach applied uniformly by all utilities in the state, especially with regard to the method of determining the rate level, separation of billing units and rate design.

Having considered the record in this case, we have determined that the public interest will best be served by requiring a uniform approach to cost allocation and rate design for standby service. As will be discussed below, we believe that FPC's proposal for a reservation charge and daily demand charge, modified to incorporate time-of-use pricing, represents the best rate structure for the recovery of demand-related production and transmission costs presented in this case. There was not significant disagreement over the proper allocation and recovery of distribution facilities costs, of customer-related costs, or of energy-related costs. Based on our determination that we have identified an appropriate, equitable, cost-based approach to rate design, we shall prescribe its use by the state's four large investor-owned electric utilities. We see no reason to permit experimentation with the alternate rate designs proposed in this case, primarily because we find that the other three utilities' proposals do not accurately reflect the expected diversity of backup and maintenance power loads and that the Industrial Cogenerators' proposal may not recover an equitable contribution to the utilities' cost of maintaining continuously available reserve capacity upon which the standby customers may rely. Accordingly, we reject the notion of permitting each utility to establish its own standby rates.

Cost Allocation and Rate Design for Production and Bulk Transmission Costs for Firm Back-up and Maintenance Service

For any customers, both standby and full requirements alike, fair, appropriate, cost-based rates will reflect the diversity and coincidence characteristics of the customers, because it is these characteristics that determine the level of demand-related costs incurred by the utility to serve them. In common electric utility usage, coincidence refers to the degree to which a customer's or class's maximum demand occurs at the time of the utility's system peak. Again, this is significant because it is a utility's need or obligation to serve its maximum peak demand that causes it to incur demand-related production and transmission costs. In order to meet the requirements that standby rates neither subsidize nor discriminate against self-generating customers, it is necessary that these customers be allocated demand-related production and transmission costs on the basis of their diversified demands at the time of system coincident peaks in the same way that these costs are allocated to full requirements rate classes.

In each utility's next rate case, we expect that standby customers would be treated as a separate class and be assigned costs consistent with the appropriate data in the new cost-of-service study. Until those cases are filed and processed, and until the data necessary for new cost-of-service studies is collected, the cost study approved by the Commission in each utility's last rate case should be the foundation for the cost components that will be used to develop rates for backup and maintenance service.

We believe that the use of these cost studies is appropriate because the classification of demand versus energy-related production and transmission costs should be the same for both standby and full requirements customers. Accordingly, we believe that appropriate backup and maintenance rates can be developed using each utility's full demand-related production and transmission unit cost per coincident peak kilowatt of demand and its energy-related production unit cost per kilowatt-hour. Utilizing these 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.

We find that, of the approaches presented by the parties to this proceeding, the daily demand charge and reservation charge proposal of FPC, modified to incorporate time-of-use pricing, is clearly superior to the others. Specifically, we find that FPC's approach can be expected to match revenue recovery and cost responsibility for demand-related production and transmission costs better than a system incorporating demand, energy and customer charges. We find this approach superior to those advocated by FPL, Gulf and Teco, because the FPC approach produces rates that fairly recognize the diversity and coincidence of individual customers. By comparison, the proposals of the other three utilities base the demand charges on the assumption of the average coincidence of their full requirements rate classes. For example, evidence was introduced into the record of this case that showed that the demand-related unit costs that went into the development of FPL's on-peak demand charges for backup and maintenance (and supplemental) service were based on average coincidence factors on the order of 60 to 70 percent, and that Teco's proposed rates are based on average coincidence factors of approximately 79 percent for firm standby service and approximately 66 percent for interruptible standby service. We find these to be beyond the bounds of reasonableness when considered in light of the low expected coincidence of backup and maintenance power service. Significantly, we observe that under the FPC proposal (as modified) that we herein adopt, customers with a high degree of coincidence, i.e., customers whose demands are certain to have occurred at the time of the utility's peak, will pay greater demand charges for production and transmission costs than they would under the other utilities' proposals, while customers with a low degree of coincidence, i.e., those whose infrequent demands are unlikely to have occurred at the time of the utility's peak demand, will pay less than under the other three proposals. We also believe this approach is preferable to that proposed by the Industrial Cogenerators, because theirs, with an assumed 95% availability factor, might result in an inequitable underrecovery of the costs associated with providing and maintaining reserve capacity.

As stated above, we find that a combination of a reservation charge and a daily demand charge incorporating time-of-use pricing are most appropriate for the recovery of demand-related production and transmission costs for firm backup and maintenance services. The reservation charge is to be calculated by multiplying an assumed 10 percent forced outage rate for SGCs' generators times the utility system's unit cost per coincident peak kilowatt (CPKW) for demand-related production and transmission (P&T) functions. For example, if a utility's monthly unit cost per CPKW for demand-related P&T costs, calculated using the cost of service study most recently approved by the Commission, is $10 per KW, the reservation charge would be $1 per KW per month (10 percent of $10 per KW). We note with interest that using alternate approaches, both Gulf and FPL derived similar charges for the reserve function provided by a utility. We find that the reservation charge described above will equitably recover the cost incurred by the utility in standing continuously ready to serve the backup and maintenance power needs of self-generating customers.

The daily demand charge is to be calculated by dividing the utility's system P&T unit cost per CPKW by the average number of days per month that contain on-peak hours. For example, if the utility's P&T unit cost is $10 per KW, and if there are 21 days containing on-peak hours per month, the daily demand charge would be $10 per KW divided by 21 days, or $0.48 per KW per day. This charge would be applied to the maximum demand recorded by an SGC during the on-peak period of each day when backup or maintenance power is used, and the charges for these days would be summed to obtain the monthly charge.

In combination, the reservation charge and the daily demand charge would work as follows. First, both amounts would be calculated. For all KW up to the level of maximum backup and maintenance demand actually registered each month, the customer will pay the greater of the daily demand charge or the reservation charge. For all KW, if any, in excess of the maximum level of combined backup and maintenance demands in the month, the customer will pay the reservation charge. We explicitly recognize that this amounts to crediting the reservation charge against the daily demand charge. We find this to be appropriate because, in addition to recovering a fair contribution to the cost of reserve capacity continuously available to serve standby customers, the reservation charge is designed to recover the costs of serving customers with a 10 percent forced outage rate -- that is, whose loads are expected to be present 10 percent of the time -- as those costs would be determined using traditionally accepted cost of service methods. Thus, in a month when the customer's load is present on 10 percent or fewer of the on-peak days, he should not be required to pay more than the reservation charge. In practice, this will mean that an SGC may use backup or maintenance power for up to two on-peak days out of the approximately 20 on-peak days of each month without the daily demand charge exceeding the reservation charge.

Florida Power Corporation proposed a seasonal adjustment factor to be applied to the daily demand charges each month. FPC's specific proposal is to charge 1.2 times the daily demand charges in the peak months of January, February, July, and August, 1.0 times these charges in the “shoulder” months of June, September, October and December, and 0.8 times those charges in the off-peak or “valley” months of March, April, May, and November. The purpose of this adjustment factor is to reflect seasonal variations in cost that are attributable to seasonal fluctuations in peak demands and to encourage SGCs to schedule maintenance outages in the utility's valley months when reserve capacity is not at a premium. We find such a seasonal adjustment factor to be appropriate, and we will generally approve such an adjustment factor for backup and maintenance rates if a utility proposes it. However, we shall not require a seasonal adjustment factor if a utility elects not to propose one.

Based on the record before us in this proceeding, we find that the combination of the reservation charge and daily demand charge constitutes an appropriate cost-based rate structure that fairly reflects the expected diversity and coincidence of backup and maintenance power service loads imposed on the utility. We find that it better reflects costs imposed on the utility than any of the rates proposed by FPL, Gulf and Teco. The demand charges in these other proposals reflect the average diversity of different classes or groups of demand-metered full requirements customers, and we simply believe that the expected diversity of backup and maintenance power loads is so different as to warrant the recommended treatment. Additionally, we note that the rate structure that we herein endorse and require will, in general, produce less revenue than the other proposals from standby customers who use power less frequently than average full requirements customers and more revenue from standby customers who use power more frequently than average full requirements customers. In fact, for a customer who uses no power during a month, our approved rate structure will recover only a fair contribution to the cost of reserve capacity continuously available to serve him, while a customer who uses a certain amount of KW continuously throughout the month will pay the full system unit cost per coincident peak KW for his service. This is clearly more sensible than a fate structure that recovers the same flat amount per KW from a customer who uses power for 30 minute during a month as it recovers from a customer who uses power continuously for 30 days in the month.

In the cost of service analyses that we have approved for the subject utilities, some proportion of generation plant costs has been classified as energy-related, allocated to classes on the basis of their total energy (KWH) usage, and recovered through the non-fuel energy charge. The charge is also designed to recover variable operations and maintenance costs of generating electricity. This charge is expressed in cents per KWH and is paid on each KWH used. The rate structure for backup and maintenance power service shall include a non-fuel energy charge set equal to the system energy unit cost, i.e., the total energy-related costs of the utility divided by total energy sales, with appropriate adjustments to reflect different line losses at different service voltage levels, if applicable.

We recognize that low-load-factor full requirements customers are subject to some potential inequities under current demand-energy-customer charge rate structures. That is, by being charged rates based on average load and usage characteristics for their rate classes, they may pay more than the cost responsibility that would be assigned to them if they were treated as a separate class. However, the plight of low-load-factor customers is not the subject of this proceeding. We are aware of this potential problem and we will address it in due time and in the appropriate proceedings. We will not let such considerations prevent us from requiring appropriate cost-based rates for SGCs in this docket.

Additionally, we are not persuaded by FPL's argument or contention that the combination reservation charge-daily demand charge rate structure will virtually never permit the utility to recover its cost of providing service. FPL alleges that only under special circumstances--e.g., continuous use or equal on-peak demands every on-peak billing day of the month--will the SGC pay the cost of providing the service. Under the FPC proposal that we approve with modifications, those are simply the circumstances under which the cost recovered from a high-usage standby customer will approximate the cost responsibility imposed by that SGC. It is not necessary to recover the full P&T unit cost per KW from customers who use intermittently, because their cost responsibility--as determined using traditional cost of service methods--will be less than that amount. It is our determination that the approved rate structure will recover from any SGC approximately the demand-related production and transmission costs that his actual power usage imposes on the utility system as determined by traditionally accepted cost of service methods. The unit cost that is the foundation of the modified FPC rate structure is the utility's cost for demand related production and transmission per coincident peak kilowatt. If the customer is not imposing a load at the time of the utility's monthly system peak, then he should not and would not be assigned any demand-related P&T costs using traditional cost of service principles and methods. Accordingly, the modified FPC rate design that we approve herein for backup and maintenance service will assure recovery of the full cost per CP KW from the customer who is known to be imposing load at the time of the peak, it will recover appropriately and equitably less from SGCs who use power less frequently, and it will recover an equitable amount for the provision of reserve standby capacity from customers who use no power at all in a given month.

Cost Allocation and Rate Design for Interruptible Backup and Maintenance Service

In generation expansion planning, interruptible service differs from firm service in that utilities do not include the peak demands of interruptible customers in determining the need to add generating capacity. Accordingly, no peak-demand-related production, costs are assigned to interruptible service. In keeping with the FERC rules and with our own rules on non-firm electric service, we shall require the provision of interruptible backup and maintenance service only where such service results in a demonstrable benefit to a utility's general body of ratepayers.

When interruptible backup and maintenance service is offered, it will be offered under a combination reservation charge and daily demand charge rate structure analogous to that approved for firm backup and maintenance service. The difference is that the rates will be based on only the system common transmission unit cost per coincident peak kilowatt, rather than the total demand-related production and transmission unit cost per CPKW. Thus, the reservation charge will be 10 percent of the utility's common transmission unit cost per CPKW. The daily demand charge for backup and maintenance power taken will be the same unit cost value divided by the average number of days per month that contain on-peak billing periods. The charges will be applied as described in the preceding section.

Although the idea of requiring or permitting SGCs who desire interruptible standby service to take service under the otherwise applicable full requirements interruptible service rates may at first seem appealing, we find that this would be inappropriate (1) because it would not result in the fair, appropriate recovery of the costs of local transmission and distribution facilities installed to serve large customers who only used power intermittently, and (2) because a better rate design, as described above, can be fashioned for the recovery of common transmission costs.

Other costs allocated to interruptible service and the rates designed to recover them will be handled in the same way as they are handled with respect to full requirements interruptible service. Interruptible standby customers will pay the otherwise applicable fuel charges, conservation cost recovery charges, and oil backout cost recovery charges, all stated in cents per kilowatt hour, for all KWH that they use. They will also pay a non-fuel energy charge set equal to the utility's system energy unit cost. This cost and the associated charge include variable operations and maintenance costs of generating electricity plus that portion of generation plant costs that we determine to be energy-related--i.e., capital costs incurred to obtain fuel savings justified by the energy loads to be served by the generating capacity. The customer charge for interruptible standby service will be set equal to the customer charge for the utility's full requirements interruptible rate schedule, plus $25 per month to cover additional metering and billing costs.

Recovery of Dedicated Local Facilities Costs

It is essential that sufficient local transmission and distribution capacity be in place to serve the maximum demand of each standby customer. Likewise, equity demands that the customers pay for the costs of these facilities. The failure of standby customers to pay these costs would ultimately result in a utility's general body of ratepayers having to bear them. To prevent this from happening, we shall require the utilities to submit tariffs that include a recurring monthly charge per KW of maximum combined backup and maintenance demand and also provide that standby customers shall not be permitted to take backup or maintenance power on the otherwise applicable full requirements rate schedule. This is necessary because permitting a standby customer to take backup and maintenance power service on the otherwise applicable rate schedule could result in his avoiding payment for the costs of the dedicated local facilities installed to serve him. This is especially critical for interruptible customers, for whom the demand charge is composed primarily of subtransmission and distribution costs.

FPL, Gulf and Teco submitted that the distribution demand or local facilities charge should apply to a self-generating customer's maximum load including supplemental power. While this treatment might be appropriate for all customers, or at least all demand-metered customers in the future, our decision that supplemental power service shall be billed under the otherwise applicable rate obviates the need to take this step now. This is so because the demand charge component of the otherwise applicable rate includes an element of cost recovery for local facilities. We plan to investigate and consider imposing ratcheted charges for dedicated local facilities for all customers in future rate cases.

We find that the costs of dedicated local facilities for serving the backup and maintenance power loads 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. We believe that calculating the charge in this manner will result in a rate which appropriately reflects any economies or diseconomies of scale that may exist as a result of serving customers with different size loads.

Recovery of Local Facilities Costs From a Self-Generating Customer Who Takes Both Standby Service and Wheels Power

Some QF customers will require both standby (backup and maintenance) service and wheeling service for the export of excess power to other utilities. If separate charges are imposed for each service for the recovery of local facilities costs, a customer could pay more than the revenue requirement of the local facilities installed to serve him. This problem may be obviated by such a customer leasing or buying all local facilities up to the interconnection with the utility's high voltage transmission system. Gulf, FPL and Dade County recognized the advantages of this solution, and we encourage QFs who both purchase standby services and wheel excess power to consider buying or leasing the local facilities necessary to serve them. Where a customer elects not to buy or lease his local facilities, the serving utility shall examine the specific local facilities costs of providing standby services, as well as wheeling service, and provide case-by-case adjustments, if necessary, to avoid overrecoveries for local facilities costs. Where a utility and a customer cannot agree on a reasonable case-by-case adjustment, the customer may bring the dispute to the Commission for resolution.

Allocation and Recovery of Customer-Related Costs of Backup, Maintenance, and Supplemental Service

All parties to this proceeding, except Gulf, agreed that the appropriate customer-related costs are those associated with meters, service drops, customer accounting, billing and customer service and information. They also agreed that these costs should be recovered through a fixed monthly charge.

While Gulf's illustrative standby tariff includes a customer charge equal to its current customer charge for its LP and LPT customers, the utility's witnesses advocated the use of a Minimum Distribution System concept in allocating costs to standby customers. We have consistently rejected the use of a Minimum Distribution System for classifying and allocating costs and do so again. We note that aside from Gulf's stated position favoring the use of the Minimum Distribution System concept, there was no evidence in the record to support the use of such a concept. Accordingly, we will not approve its use in the development and implementation of standby rates.

To recover the identified customer costs, all parties, except FPC, supported the use of the specific customer charge on the otherwise applicable general service large demand rate schedule. FPC proposed setting the customer charge on their standby tariff at $25 above its CS-1 (curtailable rate schedule) rate of $175. FPC reasoned that metering and billing are the primary cost determinants in a customer charge and concluded that the metering required for standby customers was expected to be similar to that of its curtailable customers. FPC proposed the additional $25 charge to reflect and recover the greater billing analysis expected to result from having separate rates for supplemental, backup and maintenance service.

We agree with FPC that the customer charge for standby service should reflect the higher billing costs that will be occasioned by separate standby rates. Accordingly, we find that the customer charge for standby services shall be the utility's customer charge for the otherwise applicable curtailable rate schedule plus $25. If a utility 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. Those customers taking interruptible standby service shall pay the otherwise applicable interruptible customer charge plus $25.

“Other Costs” of Serving Standby Customers and the Recovery of Those Costs

“Other costs” associated with serving standby customers besides customer and capacity-related costs are fuel, oil backout, energy conservation, non-fuel energy-related costs, revenue-related costs, net general and intangible plant, plant held for future use, working capital and administrative and general expenses. All parties agreed that energy-related costs should be recovered on an energy basis through a KWH charge. We agree. Energy-related costs are allocated in cost of service studies in this manner and it is reasonable and consistent that energy-related costs for standby power service should be recovered in the same manner.

We find that revenue-related costs (regulatory assessment fees, gross receipts taxes and working capital associated with these) shall be recovered uniformly on all rate charges because that is the manner in which the utilities are assessed these taxes and how they, in turn, allocate them to the various rate classes. Energy conservation and oil backout charges should be billed to standby customers in the same manner as all other classes. Fuel should be priced on an average basis as it is for all other customers because base rates are developed on average embedded costing. However, where a customer takes service on a time-of-use rate, his fuel charges should be time differentiated.

Gulf proposed that standby customers should be required to pay for certain benefits they receive simply as a result of being interconnected with a utility, and identified these benefits as including voltage regulation, frequency stabilization, fault current limitation and transient stability. However, on cross-examination, Gulf's witnesses could not identify any specific costs associated with the provision of these benefits. Accordingly, we reject for now Gulf's assertion that standby customers should be billed for receiving these benefits.

A related issue, raised by FPL, asked whether it was appropriate to identify and recover certain administrative and general costs related to the utility's obligation to provide service which are not affected by the customer's source of generation. FPL described such costs as “Independent of Supply Source” (ISS) costs and characterized them as costs that are incurred by the utility because of its obligation to serve but which are not directly related to the production and delivery of electric power. More specifically, FPL proposed that these “Independent of Supply Source” administrative and general expenses be “unbundled” and recovered from standby customers via fixed monthly “access charges” so that they would not be shifted to the general body of ratepayers.

The Industrial Cogenerators argued that attempting to recover costs from QFs which are not similarly recovered from all of the ratepayers of a utility would be contrary to 18 CFR 292.305(1)(ii) and the Florida Energy Efficiency and Conservation Act (FEECA) because such rates would discriminate against QFs in comparison to rates for sales to other customers served by an electric utility.

Based upon the record in this case, as well as our consistent policy set forth in general electric utility rate cases, we find that the allocation and recovery of all costs should be accomplished on a consistent basis. Peak demand-related costs should be allocated using a peak demand responsibility allocation factor and recovered through a demand charge; energy-related costs should be allocated according to the classes' energy usage and recovered through energy (¢ per KWH) charges; and customer-related costs should be allocated according to the number of utility customers (weighted or unweighted) and recovered through a monthly customer charge. This is the manner in which costs are allocated to and recovered from all of FPL's other customers and all of the customers of the other utilities. Similarly, although they are not directly related to the production and delivery of electric power, A&G expenses have traditionally been allocated to rate classes using indirect usage-based allocators and recovered in the utilities' demand, energy, and customer charges. In opposition to this methodology, FPL has proposed the use of substantial “access” charges which it states are necessary to recover certain “non-usage sensitive” administrative and general costs.

We are not persuaded by the record in this proceeding that these costs are truly non-usage-sensitive. However, if FPL believes that they are, they may introduce evidence to that effect in future rate cases. If these costs are ultimately determined to be non-usage-sensitive, then both the total cost of service study, in which those costs are allocated among all rate classes, and rates designed to recover them should reflect that determination on a consistent basis. FPL has not proposed such an integrated approach in this case.

While there may be some costs that standby customers will not be billed for that they might otherwise be billed for if they were full requirements customers, this situation is not unique to standby customers. On cross-examination, FPL's witness Edward Tammy agreed that full requirements time-of-use customers who shift load from on-peak to off-peak, for example, customers who shift load from on-peak to off-peak by installing thermal ice storage systems, should pay the same amount for A&G costs that they paid before shifting their load. Despite the fact that these load shifting situations are analogous to the expected usage patterns of standby customers, no Florida electric utility, including FPL, has proposed to charge these customers “access” charges to recover the costs no longer billed.

We believe and find that singling out standby customers alone for this type of cost recovery would be unduly discriminatory and would be in violation of both state and federal law. Accordingly, we decline to require the inclusion of any access fees or charges designed to recover revenues that previously paid for administrative and general expenses.

Recognition of Time-of-Use Cost Differentials

Currently FPL and Teco require standby service to be taken on a time-of-use (TOU) basis while FPC has a similar requirement for its standby customers that are not QFs. Teco and FPL have proposed tariffs with standby rates based on TOU pricing. The Industrial Cogenerators advocate the incorporation of TOU pricing for backup and maintenance service; Gulf and FPC do not oppose the use of TOU pricing in structuring rates for backup and maintenance service.

TOU pricing reflects the cost impact upon a utility of supplying electric power at different times, that is, during peak periods and during off-peak periods. This, in turn, should provide a price signal that will encourage standby customers to shift power taken for backup and maintenance power service to off-peak periods when the cost of providing it is less. Accordingly, we find that TOU pricing is appropriate and cost-based and shall require that it be utilized in the development of backup and maintenance power rates.

IV. METERING, MEASURING, AND BILLING FOR STANDBY SERVICE

In order to administer the approved rate structure for backup, maintenance, and supplemental power service to self-generating customers, it will be necessary to distinguish backup and maintenance service from supplemental service. Our policy on this matter is straightforward: both backup and maintenance power service and supplemental service should be properly measured and billed under the applicable rates. We find that this can and should be satisfactorily accomplished (1) by the installation of appropriate metering on the generating unit or units of SGCs and on power demand (KW) and energy (KWH) supplied to SGCs by the utility, and (2) by appropriate contracting for and monitoring of the power service taken by SGCs.

Metering and Interpretation of Metered Data

Self-generating customers taking service under approved standby rates will be required by the tariffs to permit the installation by the utility of metering equipment to measure both the output of their generating unit or units and the power taken from the utility. The utility will be responsible for analyzing the metered data to determine what amount of the customer's service was supplemental and what amount was backup or maintenance power. Consistent with our definitions, power taken from the utility in addition to what the customer normally generates will be supplemental power billed under the otherwise applicable full requirements service rate. Power taken to replace power normally generated by the customer will be backup or maintenance power billed under the applicable rate.

We would make two comments by way of clarifying our intent. First, the load of an SGC whose electrical generation fluctuates with or follows the level of other plant processes should be treated as supplemental power under normal conditions when his generator is operating. Similarly, if the SGC's demand on the utility remains at a constant level both preceding and following an outage, that power should be regarded as supplemental power. Second, in determining the billing units for a customer who takes both supplemental and backup or maintenance service, the utility must diligently analyze the customer's generator operation and power usage for the period immediately preceding an outage. This analysis, performed with care and reason, should enable the identification of backup power taken to replace the customer's normal generation and supplemental power taken in excess of normal generation. Utilities should require by tariff appropriate and sufficient notification of outage events to permit the fair and accurate administration of the tariffs.

Contract Demands For Reservation Charges and Local Facilities Charges

To enable the initial specification of billing units for the reservation charge and the local facilities charge, the standby tariffs shall provide for an initial contract demand (KW) level to be established by mutual agreement of each SGC and the utility serving him. This amount should represent the maximum backup or maintenance power load that the customer expects to impose on the utility. Tariffs should also provide for the periodic renegotiation of this contract level, again subject to the mutual agreement of both parties. 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.

Load Research Data

We find that the utilities and the SGCs should undertake such data collection and reporting activities as are necessary to permit analysis of the load and usage characteristics of backup, maintenance, and supplemental electric service. This data and the analysis of it are necessary to assure, on a continuing basis, that the rates that we approve for these services are fair and cost-based. At a minimum we shall require that each subject utility collect and report annually the following data for its standby customers.

I. Billing Data

A. Monthly billing KW for purposes of billing for local transmission and distribution facilities, if applicable

B. Monthly billing KW for purposes of billing for production and bulk transmission plant

C. Total KWH, by month

D. On-peak and off-peak KWH, by month

II. Load, Coincidence and Load Factor Data

A. Annual Data - For each of the 12 monthly system peak hours and for each of the 200 hours with the highest system demand levels for each year, provide:

1. Total standby customer load

2. Customer supplemental load, if measured

3. Customer backup and maintenance load, if measured

B. Coincidence and Load Factor Data

1. Average coincidence factor for total, supplemental and backup/maintenance loads for the 12 monthly system peak hours

2. Customer annual CP load factor and customer 12 CP load factor

3. Plots of individual customer load factors vs. coincidence factors for supplemental loads and for backup/maintenance loads, for the year and for each month

III. Customer Generation and Availability Data

A. Annual generation availability factor, %

B. Annual generation capacity factor, %

C. Annual generation load factor, %

Additional data deemed necessary for proper cost of service analyses and rate design may be collected and reported by any utility or customer or group of SGCs. We expect that issues relating to the confidentiality of load and usage data will be resolved amicably by the utilities and their customers.

We believe that the rate schedules, availability, and terms and conditions for standby electric service required by this Order are fair and reasonable and fully comply with the intent of PURPA and the applicable FERC rules. While we recognize that, once additional load research data is obtained, refinements to the standby tariffs required by this Order may be warranted, we find that these tariffs represent the most equitable, cost-based and non-discriminatory rate schedules possible based upon the record of this proceeding.

In view of the above, it is

ORDERED by the Florida Public Service Commission that Florida Power & Light Company, Florida Power Corporation, Tampa Electric Company, and Gulf Power Company shall file standby tariffs consistent with the provisions of this Order within forty days of its effective date.

By ORDER of the Florida Public Service Commission, this 6th day of FEBRUARY, 1987.

STEVE TRIBBLE, Director Division of Records and Reporting

(SEAL)

NOTICE OF JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.59(4), Florida Statutes (1985), to notify parties of any administrative hearing or judicial review of Commission orders that may be available, as well as the procedures and time limits that apply to such further proceedings. This notice should not be construed as an endorsement by the Florida Public Service Commission of any request for judicial review, nor should it be construed as an indication that such request will be granted.

Any party adversely affected by the Commission's final action in the matter may request judicial review by the Florida Supreme Court by the filing of a notice of appeal with the Director, Division of Records and Reporting and the filing of a copy of the notice and the filing fee with the Supreme Court. This filing must be completed within 30 days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

As printed in Florida Public Service Commission Reporter

End of Document

ATTACHMENT B

SEC-TMMC-1(a): Florida Public Service Commission, Docket No. 850673-UE
Order Granting and Denying Standby Rate Tariffs and Granting Motion for Reconsideration (Nov. 10, 1987).

87 FPSC 11:188, 1987 WL 1372141 (Fla.P.S.C.)

In Re: Generic Investigation of Standby Rates for Electric Utilities.

Docket No. 850673-EU
Order No. 18418

Florida Public Service Commission

November 10, 1987

Before Katie Nichols, Chairman, Thomas M. Beard, Gerald L. Gunter, John T. Herndon and Michael McK. Wilson, Commissioners.

ORDER APPROVING AND DENYING STANDBY RATE TARIFFS AND GRANTING MOTION FOR RECONSIDERATION

By the Commission:

The Commission opened this generic standby rates docket in 1985. Several staff workshops were held in early 1986 for the purpose of defining, clarifying and discussing the issues. Hearings were held in August of 1986 focusing on the rate structure for standby service and the method by which the rates would be calculated.

Order No. 17159 was issued on February 6, 1987, memorializing the Commission's vote on the issues in this docket at its special agenda conference on December 1, 1986. Order No. 17159 required Florida Power Corporation (FPC), Florida Power and Light Company (FPL), Gulf Power Company (Gulf) and Tampa Electric Company (TECO) to file tariffs conforming to the Commission's decisions by March 18, 1987. Several staff workshops were held to clarify the meaning of the order and to discuss the filed tariffs. In general, the actual rates had been computed correctly and the rate structures embodied in the tariffs conformed to the order, but several complicated issues arose with respect to the determination of standby and supplemental billing units.

The subject of greatest controversy raised at this implementation stage is the proper method for distinguishing between standby and supplemental power service. This is especially difficult for customers whose electrical usage and generator output vary with fluctuations in the level of their industrial processes, i.e., customers whose electrical usage and generator output are normally "load following". Standby power is defined in Order No. 17159 as electric energy or capacity supplied by the utility during a scheduled or unscheduled outage of the customer's generator to replace power ordinarily generated by the customer's own generating equipment. Supplemental power is defined as electric energy or capacity supplied by the utility in addition to that which is normally provided by the customer's own generation equipment.

FLORIDA POWER CORPORATION

Florida Power Corporation's proposed standby tariffs have been designed and the specific rates have been computed in accordance with Order No. 17159. FPC has added one billing option not contemplated by the order and has also proposed a single local facilities charge rather than the class-specific charges specified in the order.

In its SS-1 (Firm Standby) and SS-2 (Interruptible Standby) tariffs, FPC offers two options, A and B, for determining standby power service requirements. Option A entails the analysis of metered load and customer generation data for this determination as contemplated by Order No. 17159. Option B embodies a "generation deficiency approach" by which the customer specifies his maximum generation capacity and any power taken from the utility when his generator is operating below this capacity is billed as standby power (up to the generator's capacity). Customers have the option of changing methods one time during their contract term.

This “generation deficiency approach” is a standard method for treating standby power service supplied by one utility to another. It was discussed in the staff workshops in early 1986 but was generally opposed by cogenerators because it may not provide adequate recognition of supplemental power requirements imposed when the cogenerator's electrical output varies in response to fluctuations in industrial process levels. There was no testimony presented on this methodology at the hearing. Even so, because of its optional nature and because it does represent a standard, workable methodology, we approve its inclusion in the tariffs.

Order No. 17159 requires the local facilities charges for backup and maintenance power service to be set at the distribution unit cost, based on a 100% ratcheted billing demand, for the class to which the customer would otherwise belong. FPC has proposed to collect the same charge, $1.60 per KW per month, from customers who would otherwise be in either the GSD or GSLD classes. In support of its proposal, FPC has shown that the calculated charges are quite similar, $1.60 per KW per month for GSLD and $1.48 per KW per month for GSD. FPC further asserts that the load characteristics of GSD standby customers are more likely to resemble those of GSLD customers than those of other members of the GSD class. This seems reasonable considering that: 1) the GSLD class load factor is greater than the GSD class load factor and 2) the higher load factor customers would have a greater incentive to install cogeneration. For these reasons we approve FPC's proposed unified local facilities charge.

The Industrial Cogenerators have identified a potential problem with FPC's proposed tariffs involving the possible overrecovery of local facilities costs. They point out that, if a customer pays for a certain amount of local facilities on an on-going basis through the established local facilities charge, and if the customer also uses supplemental power in such a pattern that his total load in a given billing period does not exceed his established standby capacity, then he may pay too much for local facilities. While this is possible, we will not disapprove FPC's tariffs on that ground for the following reasons:

(1) This problem has been discussed with the personnel of FPC and the utility has stated that their intent is to avoid overrecovery. If problems do arise, FPC has agreed to make appropriate adjustments in customers' bills on a case-by-case basis.

(2) FPC plans to modify all of its tariffs subsequent to its pending rate case (Docket No. 870220-EI) so that all customers will pay for local facilities costs on the same basis. This is a timely solution to the problem raised by the Industrial Cogenerators and it is unlikely that any overrecovery will occur in the three-to-five-month period prior to the new tariffs' going into effect.

(3) Even if the customer paid both charges, because the rates are based on average costs for the class, it is not clear that he would be paying more than the revenue requirement for the local facilities installed to serve him.

For the above reasons, we approve FPC's proposed SS-1 and SS-2 tariffs with an effective date of February 1, 1988.

TAMPA ELECTRIC COMPANY

TECO's proposed standby tariffs and charges have generally been designed in accordance with Order No. 17159. However, there are three specific variances from Order No. 17159: (1) the computations of the demand and energy charges for standby power service reflect the treatment given demand and energy costs in TECO's last rate case; 2) a unified local facilities charge for customers who would otherwise be in the GSD or GSLD classes reflecting the unified cost and ratemaking treatment applied to these classes in TECO's last rate case and 3) an alternative method for calculating standby demand and energy billing units. Additionally, TECO inadvertently entered outdated 1986 non-fuel energy charge values in the tariffs.

In computing its reservation charges, daily demand charges, and energy charges for firm backup and maintenance service under rate schedule SBF, TECO has followed the ratemaking treatment applied to the demand and energy unit costs established in its last rate case. This varies from the requirements of Order No. 17159 which states that the standby rates will be based on the approved unit costs. Because of the significant change in the cost of service study adopted by the Commission (Equivalent Peaker Cost Study) in TECO's last rate case, and because the company's treatment here matches that approved in the last rate case, we approve the charges as filed.

Order No. 17159 requires that local facilities costs 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.” In TECO's last rate case, the Commission combined the GSD and GSLD classes for determining demand and energy charges, maintaining only separate customer charges. Order No. 15451 at 39. Consistent with this treatment, TECO has in this proceeding proposed a single unified local facilities charge for standby customers who would otherwise belong to either the GSD or GSLD class. We believe this to be reasonable and approve it.

TECO's proposed billing methodology might be characterized as a “supplemental demand threshold” approach. Under this method a customer would first establish his maximum expected supplemental power demand. Then, power used below this level would be billed at the applicable rate for supplemental power, and any power above the maximum supplemental “threshold” would be billed at the standby (backup and maintenance) rates, SBF, SBI-1 or SBI-3.

TECO asserts that this method will be easier and less costly to administer than a method which requires detailed analysis of customer loads and customer generator output throughout the billing period. Further, TECO is of the opinion that allowing the standby customer more input into the determination of his billing treatment will result in fewer billing disputes.

There is the possibility that standby customers could manipulate their specified maximum supplemental demand levels so as to obtain lower bills. This could be done either by obtaining backup or maintenance power at the supplemental rate by specifying the maximum supplemental demand at a level higher than the true value or by obtaining low-load factor supplemental power at the standby rate by setting the maximum supplemental demand at a level lower than the true value.

TECO believes that this possibility can be prevented by monitoring the customer's usage of utility-supplied power compared to the customer's generator output. Additionally, TECO's tariff provides that the utility can require the standby demand to be modified at the utility's request to more accurately reflect the customer's metered usage. We are satisfied that TECO is committed to preventing any abuse of its billing method, and in view of its belief that this method will be easier to administer, we approve it.

Due to an error in preparing the tariffs, the actual non-fuel energy charges shown on the June 5th SBF tariff sheets reflect the rates that were in effect from December 4, 1985 until January 31, 1987. Order No. 15451 granted TECO a slight rate increase on January 31, 1987, and provides for another on January 31, 1988. The standby rate schedules SBF, SBI-1 and SBI-3 should have the non-fuel energy charges set at the currently applicable 1987 rates. For this reason, we disapprove the SBF, SBI-1 and SBI-3 tariffs filed with this Commission.

GULF POWER COMPANY

The standby service tariffs submitted by Gulf on May 21, 1987, deviated from the requirements of Order No. 17159 in two respects: (1) structure of the local facilities charge and (2) treatment of standby customers whose supplemental loads fluctuate with their industrial processes.

Gulf's SS tariff submitted on May 21st included a local facilities charge based on the unit cost for all of Gulf's demand-metered customers in the aggregate. Order No. 17159 requires that local transmission and distribution costs should appropriately 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.” While a single local facilities charge has been approved for FPC and TECO, Gulf's GSD, LP, and PX classes are so disparate that a single rate would be inappropriate and inequitable.

Gulf's currently proposed tariff, submitted on October 8, 1987, has class-specific local facilities charges and is therefore consistent with Order No. 17159.

The Industrial Cogenerators have raised the issue of voltage level metering credits and transformer ownership discounts for supplemental power service in Gulf's supplemental and standby service tariffs. Gulf has included appropriate credits and discounts in its currently proposed supplemental tariffs. However, with regard to standby service, the specific method for computing the standby local facilities charge prescribed by Order No. 17159 does not include transformer ownership credits or voltage level metering discounts; the charge is simply to be set at the distribution unit cost for the class. While it might be appropriate to provide these credits and discounts to standby customers, it is not clear that this would result in a more accurate recovery of the costs of local facilities serving those customers. For this reason, neither transformer ownership credits nor voltage level metering discounts are necessary to properly implement Order No. 17159.

As originally submitted on May 21st, Gulf's SS tariff incorporated a “supplemental demand threshold” approach to billing determination whereby the customer would set his expected maximum level of supplemental demand and would be billed at the supplemental power rate for usage up to that level. Power taken above that level would then be billed as standby power. The tariff made no explicit provision for recognizing process-following electrical loads, with the result that customers could be billed for actual standby power at the supplemental rate or for actual supplemental power at the standby rate.

Under the May 21st tariff it would have been possible to take backup or maintenance power without exceeding the specified maximum supplemental power level, thus obtaining backup or maintenance service at the supplemental rate, or to take low-load factor supplemental power at the standby rate. Either of these actions would have resulted in the customer underpaying for the service actually provided to him. Conversely, it would have been possible for customers to be billed for backup power use at the potentially higher supplemental rate. Finally, customers could have been billed incorrectly since they were unable to change the specified maximum supplemental level as their processes changed.

Gulf's currently proposed tariffs specifically comply with Order No. 17159 in the determination of standby and supplemental power billing units. This is done by means of a metered data analysis method by which the customer's actual usage and generator output data are analyzed to determine whether power supplied by the utility is standby or supplemental power. This method is similar to FPC's method approved above. Gulf is no longer proposing to use a “supplemental demand threshold” methodology.

Order No. 17159 provides that customers who wish to transfer from firm standby service to firm full requirements service must give five years' advance notice to the utility, unless it can be shown that shorter notice is not detrimental to the utility or the utility's general body of ratepayers. In putting this requirement into its proposed SS tariff, Gulf has treated it as a “Term of Contract” similar to those in its other tariffs.

The differences between the Term of Contract provision in the standby tariff and those in the full-requirements tariffs are: (1) that transfers from the standby rate requires five years' notice instead of one year notice and (2) that the standby tariff would obligate the customer for the payment of the customer charge, the standby reservation charge, and the standby local facilities charge for five years from the inception of service.

This matter was not addressed at the hearing. While the Industrial Cogenerators are correct that the provision “appears to go beyond” the requirements of the order, it is not necessarily inconsistent with the order. It seems reasonable for a utility to include terms and conditions of service in its standby tariffs that are comparable to those in its other tariffs. Additionally, it seems reasonable in this instance for the utility to attempt to assure recovery of part of the costs for local facilities installed to serve a standby customer and the costs of part of the production plant planned and installed to serve him by means of a minimum contract period of five years. This can also be viewed as providing some protection for the utility's general body of ratepayers because they would ultimately bear the cost of abandoned facilities. And, as a practical matter, the only time this requirement would pose a problem is when the customer closed down his facility on short notice or disconnected from the utility entirely. In light of all these factors, we approve the inclusion of this Term of Contract provision in Gulf's current tariff filing.

Based on the above, we approve the SS Rate Schedule for standby and supplemental service filed by Gulf Power Company on October 8, 1987.

FLORIDA POWER AND LIGHT COMPANY

Florida Power and Light Company's proposed standby rate schedule SST-1 and Standby and Supplemental Service Agreement filed on May 22, 1987, generally comported with Order No. 17159. There were two exceptions to the order, however. First, in its May 22nd tariffs FPL did not express customer charges and distribution demand (local facilities) charges on a rate class basis but on a voltage level basis. Second, FPL has proposed an alternative method for determining standby and supplemental billing units.

Order No. 17159 provides that local facilities costs should be recovered via a charge equal to “the distribution unit cost, calculated using 100% ratcheted billing KW as the billing determinant, for the class to which the customer would otherwise belong.” While voltage level rates for local facilities costs may be intuitively appealing, they are not provided for by the order and their implementation would require a detailed cost of service analysis of a utility's distribution plant. For this reason we reject this approach to local facilities costing.

FPL's currently proposed SST-1 and Standby and Supplemental Service Agreement tariff submitted on November 6, 1987, calculate distribution demand charges on a rate class basis rather than on a voltage level basis. The November 6th tariff comports with Order No. 17159 and is approved in this regard.

With regards to local facilities costs, Metropolitan Dade County (Dade) has raised concerns that relate to the potential for overpayment of local facilities plant costs. Dade is concerned that overpayment could occur where the customer pays for part or all of his dedicated local facilities and O&M costs pursuant to an interconnection agreement. We are not persuaded that there is a problem. If the customer owned all of his local facilities up to and including the interconnection facilities with FPL's 69 KV (or higher voltage) transmission system, he would pay no distribution demand or local facilities charge. If he were interconnected at the low side of a distribution substation (69 KV to 13 KV or 115 KV to 13 KV), owned and maintained by FPL, he would properly pay the distribution unit cost for his class. If a customer had previously entered into a contract requiring him to pay for O&M costs on a substation owned and maintained by the utility, there could be an overrecovery problem. We believe, however, that such problems should be addressed on a case-by-case basis if they arise. Should the customer be unable to reach a satisfactory resolution of the problem with the utility, the Commission is available to adjudicate the dispute.

In its May 22nd tariff, FPL proposed customer charges which were based on voltage level groupings matched to its different curtailable service (CS-1, CS-2, CS-3) customer charges with $25 added as required by Order No. 17159. The charges themselves are correct but they should have been applied on a rate class, rather than a voltage level, basis. This problem has been corrected in FPL's November 6th proposed tariff.

In both its May 22nd and November 6th tariffs, FPL has proposed an alternate method to that contemplated by the order for determining standby and supplemental service billing units. FPL's proposed method might be characterized as a modified or adjusted generation deficiency method. In FPL's method, the customer would specify his contract standby demand and the minimum normal operating level of his generator in KW. The customer would also specify an amount of "process-following load", that is, load that the company would not have to serve in the event of an outage of the customer's generating equipment. As long as the generator was operating at or above the minimum normal level, all power supplied by the company would be billed as supplemental power service. When his generator output fell below the minimum normal level, the standby demand would be "the lesser of (1) the contract standby demand minus the customer's load being served by the customer's generation, but not less than zero, or (2) the level of demand being supplied by the company."

We believe that this method is acceptable and approve it. Because FPL requires that a customer's generation output be metered, it should provide for fair and acceptably accurate determination of standby and supplemental power service requirements and make adequate provision for customers whose electrical generation and usage vary with fluctuations in industrial processes. Further, this method appears to be easily administrable and does not lend itself to manipulation by FPL's customers.

Commission Order No. 17159 provides that standby tariffs shall require customers to give five years' written notice before transferring from firm standby service to firm full-requirements service. FPL's May 22nd tariff and its November 6th tariff both require five years' written notice before the customer may transfer to "an applicable retail rate schedule", with the added provision that earlier transfers may be permitted if they are in the best interests of the standby customer, the utility, and the utility's other ratepayers.

Dade objects to this provision because they believe it could be construed to prohibit transfers from firm standby (SST-1) to an interruptible rate schedule at such time as FPL offers service under an interruptible rate. Dade's concern that Qualifying Facilities (QF) not be arbitrarily denied access to interruptible service because of a transfer provision in the standby tariff is legitimate.

Staff points out that the proper construction of FPL's SST-1 tariff language would permit QFs to transfer to interruptible standby service whenever interruptible service was offered pursuant to the Commission's Non-Firm Rates Rule, Rule 25-6.0438, Florida Administrative Code. This is so because Section (4)(a) of the rule provides that interruptible service may be offered if it can be shown to be cost-effective for the utility's general body of ratepayers or result in "other measurable economic benefits". Should FPL propose to offer interruptible service, then, by the requirements of Rule 25-6.0438 it would have to prove that such service would benefit the utility's general body of ratepayers. That is, the requirements imposed on the standby customer by FPL's proposed SST-1 tariff would already have been met by the utility.

We adopt Staff's construction of the language of our rule and FPL's proposed tariff. Any customer who is on the standby service rate will be entitled to transfer to interruptible service, should FPL offer such service, notwithstanding the five years' notice requirement if he is otherwise qualified to do so.

Based on the above rationale, we approve Florida Power and Light's SST-1 tariff as submitted on November 6, 1987.

MOTION FOR RECONSIDERATION

Commission Order No. 17159 requires self-generating customers to permit the utility to install metering equipment to measure the customer's generation output and the power service taken from the utility. The order also requires each utility to collect and report annually: (1) billing data; (2) peak load, coincidence and load factor data; and (3) customer generation and availability data "for its standby customers." The order is not specific as to whether this means aggregate data for all of a utility's standby customers as a group or data for each standby customer individually,

By their motion of February 23, 1987, the Industrial Cogenerators ask that this Commission enter an order clarifying this matter. Specifically, they ask that Order No. 17159 be modified as follows:

(1) treat as confidential the data of individual self generating customers (collected as required by Order 17159) and

(2) reflect only aggregated customer data in reports provided to the Commission.
Motion for reconsideration at 3.

We find that this request is consistent with the intent of Order No. 17159 and therefore grant the motion for reconsideration.

Therefore, it is

ORDERED by the Florida Public Service Commission that Florida Power Corporation's proposed SS-1 and SS-2 tariffs be and are hereby approved as filed with an effective date of February 1, 1988. It is further

ORDERED that Tampa Electric Company's proposed SBF, SBI-1 and SBI-3 tariffs be and are hereby disapproved because they do not use the currently applicable non-fuel energy charges. It is further

ORDERED that Gulf Power Company's SS Rate Schedule for Standby and Supplemental Service submitted on October 8, 1987, be and is hereby approved. It is further

ORDERED that Florida Power and Light Company's SSI-1 tariff and Standby and Supplemental Agreement of November 6, 1987, be and are hereby approved as interpreted in the body of this order. It is further

ORDERED that the Motion for Reconsideration filed by the Industrial Cogenerators on February 23, 1987, be and is hereby approved as outlined in the body of this order.

By ORDER of the Florida Public Service Commission, this 10th day of NOVEMBER, 1987.

STEVE TRIBBLE, Director Division of Records and Reporting

by: Kay Flynn Chief, Bureau of Records

(SEAL)

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