
ORIGINAL

Nova Scotia Utility and Review Board

IN THE MATTER OF *The Public Utilities Act, R.S.N.S., 1989*
c. 380, as amended

- and -

IN THE MATTER OF an Application of Nova Scotia Power
Incorporated for approval of a Load Retention Rate

**BOOK OF AUTHORITIES
OF NOVA SCOTIA POWER INC.**

DATED: January 10, 2000

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NOVA SCOTIA UTILITY
AND REVIEW BOARD

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Re Incentive Rates for Electric Service

Intervenors: Oregon Department of Justice and Oregon
Department of Energy

UG 23, UE 50, Order No. 87-402
March 31, 1987

ORDER identifying permissible rate classification criteria and other legal requirements for discount rate offerings.

1. Discrimination, § 39 — Rates — Customer classes — Cost allocation.

[OR.] In determining fair and reasonable rates for utility service the commissioner has broad discretion in allocating costs among customer classes; however, the classification scheme must not result in "unjust discrimination," as defined by state statutes, O.R.S. §§ 757.310, 757.325.

2. Discrimination, § 40 — Rates — Customer classes — Basis for classification — Discounts.

[OR.] The general legal standards for discounted rate offerings are: (1) customer classes must be based on reasonable considerations, so that customers receiving "like and contemporaneous service under substantially similar circumstances" are placed in the same class; (2) customer classes must be open-ended, so that any customer meeting the criteria for the class qualifies for the rate offering; (3) discount rates can be offered only for the purpose of providing just and reasonable rates to remaining customers.

3. Discrimination, § 27 — Discount rates

— Attraction of business as a justification — Discretionary customers.

[OR.] The purpose of a discounted rate offering must be to benefit other customers by maximizing contribution to fixed costs from customers receiving the discount; therefore, discounts should be offered only to discretionary customers — i.e., those customers that: (1) use volumes large enough to justify the cost of administering a discount program, and (2) can either (a) switch fuels, (b) purchase their own supplies and install their own distribution system, or (c) are otherwise so price-sensitive that a price reduction would increase consumption enough to increase the customer's contribution to fixed costs.

4. Rates, § 339 — Electric rate design — Customer classes — Discounts — Cost of service.

[OR.] Discounted electric rates for certain customer classes must (1) be designed to maximize contribution to fixed costs from customers receiving the discount (2) be greater than variable cost plus a minimum contribution to fixed costs, and (3) reflect,

RE INCENTIVE RATES FOR ELECTRIC SERVICE

in the minimum rate, the effect of system expansion on average costs.

5. Discrimination, § 26 — Negotiated discount rates — Customer classification — Commission review.

[OR.] Negotiated rate discounts for electric service are permissible subject to the following conditions: (1) the rate must be made available to any customer meeting the criteria for the class; and (2) the commissioner must be able to change any negotiated rate.

6. Discrimination, § 40 — Rates — Customer classes — Basis for classification — Permissible criteria.

[OR.] Permissible criteria for determining customer classes include (1) volume of use, (2) end use, to the extent that differences in end use concisely describe differences in demand placed upon the utility, and (3) other factors affecting the price of utility service; past usage and social considerations unrelated to the commissioner's statutory mandate to protect the public from unreasonable rates may not be used for establishing customer classes.

Before Davis, commissioner.

By the COMMISSIONER:

INTRODUCTION

These proceedings were brought about by energy surpluses, poor economic conditions in the region, federal regulatory changes that have increased competition in the energy industry, and improved customer ability to switch fuels. Those circumstances have expanded the alternatives available to many energy users and improved the attractiveness of the alternatives. As a result, utilities have had trouble making sales to some customers at full tariff rates.

Loss of a customer results in lost contribution to fixed costs and can necessitate a rate increase for remaining customers. Persuading a would-be service

terminator to maintain service by offering a lower price can benefit other customers by continuing some contribution to fixed costs.

An unregulated energy supplier, such as a heating oil dealer, can tailor price/service packages that maximize contribution to fixed costs from individual customers. Regulated utilities are not permitted to do that because aspects of their service are "natural monopolies" and many of their customers have no viable alternative to the utility's service. Utility regulation is designed to protect those "core" customers by restricting the utility's discretion with regard to both service and pricing.

The basic restriction is the requirement of uniform service and rates for similarly situated customers. This requirement prevents utilities from unfairly offering discounts to "preferred" customers. It also limits the effectiveness of discounts as a tool for maximizing contribution because the discount must be offered to all customers in a class even though some of them would have maintained service at the higher rate. A discount that lowers total contribution from the class would disadvantage other classes of customers.

Existing criteria for classifying customers were developed when there was less need to consider customer alternatives in setting rates. The challenge facing the Commissioner is to develop new classification criteria (1) designed to isolate "discretionary" customers and (2) based on the factors that influence their purchasing decisions. Properly designed classification criteria will minimize costs for core customers by maximizing contribution from discretionary customers.

The first purpose of this order is to identify the scope of the Commissioner's discretion with respect to classifica-

tion criteria. The second purpose is to identify permissible criteria. The third is to determine whether price flexibility within a zone of reasonableness is permissible. The last is to address issues relating to fairness.

POWERS AND RESPONSIBILITIES

[1] ORS 756.040(2) empowers the Commissioner to "supervise and regulate" public utilities and to do "all things necessary and convenient in the exercise of such power and jurisdiction." The authority conferred by that statute is the broadest possible being "commensurate with that of the legislature itself." *Pacific Northwest Bell v. Sabin*, 21 Or.App. 200, 214, 8 PUR4th 159, 156 534 P.2d 984, *rev den* (1975); *American Can Co. v. Davis*, 28 Or.App. 207, 221, 559 P.2d 898, *rev den* (1977). ORS 756.040(1) requires the Commissioner to use the powers of his office to "protect [utility] customers, and the public generally, from unjust and unreasonable exactions and practices and to obtain for them adequate service at fair and reasonable rates." See *Multnomah County v. Davis*, 35 Or.App. 521, 526, 581 P.2d 968 (1977).

There are two aspects to "fair and reasonable" rates. One relates to the total revenues generated for the utility. The other relates to the way in which revenue responsibility is allocated among customers. The second aspect is the topic of this order.

Within the scope of his mandate, the Commissioner has broad discretion in allocating costs among customer classes. *American Can Corp. v. Lobdell*, 55 Or.App. 451, 462, 638 P.2d 1152 (1982). However, the classification scheme must not result in "unjust discrimination" as

that term is used in ORS 757.310 and ORS 757.325.

ORS 757.325(1) addresses in a general way the relative value received by various utility customers by prohibiting utilities from giving "undue or unreasonable preference or advantage to any particular person or locality" and from subjecting "any particular person or locality to any undue or unreasonable prejudice or disadvantage in any respect." ORS 757.310(1)(b) specifically addresses rate discrimination by prohibiting utilities from charging rates higher or lower than rates charged "any other person for a like and contemporaneous service under substantially similar circumstances". ORS 757.310 prohibits any discrimination within a customer class while ORS 757.325 prohibits only "unjust" and "undue" discrimination among classes.

PERMISSIBLE RATE CLASSIFICATIONS

In General

[2-6] The anti-discrimination policies established by ORS 757.310 and ORS 757.325 imply that customers should be grouped into classes. ORS 757.230 requires the Commissioner to adopt a classification system. However, it does not specify the criteria. It merely provides that the Commissioner "may take into account the quantity used, the time when used, the purpose for which used, and any other reasonable consideration." ORS 757.230(1). The Commissioner's first task in reviewing the legality of discounting proposals is to determine whether the new classification criteria suggested by the parties are "reasonable considerations."

The Utility Reform Project asserts

that none of the proposed classifications are reasonable because rate differences must be based on factors relating to the cost of service. However, it did not cite authority supporting that position. Regulatory principles traditionally have included value and conditions of service as additional criteria for rate classifications. Priest, *Principles of Public Utility Regulation*, Vol. 1, pages 336-7 (1969).

Inclusion of factors such as value and conditions of service is supported by ORS 757.310. The phrase "like and contemporaneous service" focuses on the characteristics of the service. The phrase "under substantially similar circumstances" focuses to [sic] the environment in which the transaction takes place.

The Department of Justice¹ asserts that equal protection clauses of the state and federal constitutions prohibit consideration of factors other than cost, value, and conditions of service. See U.S. Const. Amend. XIV; Ore. Const. Art. I, § 18 & 20. The reason is that classification criteria must have a reasonable relationship to the purpose for which the classification is made. *Kliks v. Dalles City*, 216 Or. 160, 178, 335 P.2d 366 (1959).

Kliks involved higher municipal water rates for apartment houses than other commercial users such as hotels. The Court found that the rate difference was arbitrary because the city could not point to reasonable differences in the cost, value, or conditions of service.

PGE criticizes the Department's reliance on *Kliks* because the two equal protection clauses apply only to gov-

¹The Department of Justice filed a single set of briefs on its own behalf rather than separate briefs in [sic] behalf of Staff and the Oregon Department of Energy.

ernment actions and actions of a utility are not necessarily government actions. See *Shelly v. Kraemer*, 334 U.S. 1, 13, 92 L.Ed. 1161 (1948); *Jackson v. Metropolitan Edison Co.*, 419 U.S. 345, 354, 8 PUR4th 57, 42 L.Ed.2d 477, 95 S.Ct. 449 (1974). However, the "action" in these cases is the Commissioner's classification of customers rather than implementation of rate classifications by the utility. The Commissioner concludes that government action is involved.

While the constitutional standards set forth in *Kliks* are applicable to the Commissioner, the narrow scope of permissible criteria mentioned in *Kliks* is not. Unlike the Commissioner, a municipality need only consider the impact of rate classifications on other customers. The Commissioner is required by (1) ORS 756.040 to consider impacts on the general public and (2) ORS 757.230 to consider impacts on the state's energy policy goals. As a result, a broader variety of factors may be reasonably related to the purpose for which the Commissioner classifies customers. Factors other than cost, value, and conditions of service are permissible if they are reasonably related to the Commissioner's mandate.

Volume of Use

Volume of use is a permissible criteria for two reasons. One is that the "amount used" is specifically mentioned by ORS 757.230. The other is that increased volumes magnify the impact of a customer's behavior on other customers. For example, defection of a residential space heating customer to wood as a fuel would not have a discernable impact on rates charged other customers. Defection of a large industrial customer could result in significant rate increases.

Volume of use also affects the effectiveness of discounting as a mechanism for improving contribution to fixed costs. The cost of administering a discounting program is smaller on a per-dollar-of-extra-contribution basis for a large industrial customer than a residential customer. In the case of small customers, the cost of administering the program may exceed the increased contribution.

End Use

ORS 757.230(1) provides that the Commissioner may take into account the "purpose for which [the service] is used" in classifying customers. None of the parties dispute that classifications based on end use are permissible to the extent they concisely describe differences in demands placed on the serving utility.

The contested issue was whether end-use classifications may be based on impacts on third parties or the state's energy policy goals. The specific situation of concern is the impact of discounted natural gas for cogeneration on customers of competing electric utilities. The parties requested that the Commissioner structure his decision so that an appeal on this issue would not delay pursuit of discounting proposals based on other criteria. Therefore, the "cogeneration" issue is resolved in Order No. 87-403 (83 PUR4th 619 *infra*).

Customer Alternatives

A willing buyer is necessary before a utility, or any other business, can make a sale. A key factor for an energy utility is the price of competing fuels. Another important factor is the existence of competing uses for customer re-

sources unrelated to consumption of energy.

Is the price at which individual customers will decline service a permissible classification criteria? The question will be addressed first in the context of competition from other fuels. It then will be addressed in the context of other economic circumstances that may (1) cause an existing customer to discontinue service or (2) prevent a new customer from using the service.

The propriety of discounts based on the price of competing fuels was intensively litigated before the Commissioner in a complaint proceeding brought by the Oil Heat Institute of Oregon against Northwest Natural Gas Company. See UC 23, Order No. 86-912. The Commissioner concluded that rates designed to respond to competition from other fuels are permissible. None of the parties to this proceeding dispute that conclusion.

The second question is whether competition from other uses for customer resources is a permissible criteria. A good example of this situation is the CPEX urea manufacturing plant in St. Helens. The manufacturing process for urea uses natural gas as a feed stock so substitution of other fuels is not an option. However, the market price for urea places a cap on the maximum price CPEX can pay for natural gas and remain profitable. A natural gas price above that cap will cause CPEX to close the plant and direct its resources to more profitable activities. To obtain contribution to fixed costs from the CPEX plant to the benefit of other customers, the Commissioner has allowed transportation of natural gas by Northwest Natural to CPEX at discounted rates.

In other situations, the price of en-

ergy may not dominate production costs in the way the price of natural gas dominates the cost of urea. However, energy costs may be a significant portion of total production costs and energy price discounts may be beneficial to other customers as part of a package of concessions designed to maintain load from an existing customer or attract new load to the utility's service area. The Commissioner recently authorized discounted electric service from PP&L to Nippon Kokan K. K. as a necessary part of an incentive package to attract new load. See UE 59, Order No. 87-183. The new load will reduce contribution to fixed costs required from other customers.

A variety of economic circumstances affecting individual customers may have a significant impact on a utility's ability to sell service at full tariffed rates. Since the price at which individual customers will decline service is a significant factor affecting a utility's ability to sell its service, it is a permissible criteria for distinguishing among customers.

Past Usage

The purpose of a discount for "incremental" usage is to reduce excess capacity by encouraging individual customers to consume more than they consumed in the past. The question is whether a customer's past consumption should influence the rate for present consumption.

The problem with the base/incremental approach can be illustrated by making an example of two identical lumber mills. The hypothetical situation is as follows: (1) During good times there is a market for the total output of both mills; (2) during bad times there is a market only for the output of one and

one half mills; (3) energy consumption is related to the level of production; and (4) energy costs do not have a significant impact on the amount of energy consumed.

One mill is better managed than the other and is able to operate at capacity during a recession. The other mill reduces production by one half. After the recession, the poorly managed mill increases production to capacity and qualifies for a discount on its "incremental" usage even though it would have consumed the energy at the full tariffed rate. The well managed mill, receiving the same service in the same economic environment, does not receive a discount. The result is a rate difference for two customers receiving "like and contemporaneous service under substantially similar circumstances" in violation of ORS 757.310.

Social Policies

This issue involves proposed restrictions limiting discounts to customers meeting requirements related to conservation, employment, production, or other social policy goals. Permissible classification criteria may have an impact of social policies such as economic development. However, discrimination for the *purpose* of achieving goals outside the Commissioner's mandate is not permissible because the classification would not be reasonably related to the purposes for which the Commissioner is authorized to classify customers. See *Discounts for the Low Income and Elderly*, R 23, Order No. 76-039, 1976 (Or.P.U.C.).

RATE FLEXIBILITY

The combination of circumstances

that gave rise to these proceedings has created a need for rates that focus on smaller groups of customers. Some of the parties desire the ability for individual customers to negotiate rates within a pre-approved zone of reasonableness. Under the right circumstances, greater flexibility would maximize contribution from customers with high demand elasticities. Under the wrong circumstances, the result merely would be lower rates for favored customers.

There are three problems with the zone of reasonableness concept. One is that ORS 757.205 requires each utility to file with the Commissioner schedules "showing all rates, tolls and charges which it has established. . . ." That problem could be overcome if utilities filed all negotiated rates.

The second problem is that ORS 757.325 prohibits rate discrimination within customer classes. That problem could be overcome by opening new rate groups to any customer meeting the criteria for the class. Only customers receiving service under unique circumstances would comprise a class by themselves.

The third problem is the Commissioner's statutory responsibility to ensure that rates are "just and reasonable". This actually is an issue related to the scope of regulatory review required. Development of incentives for the utility to maximize contribution from customers receiving discounts would make less intensive review appropriate. However, the Commissioner must remain able to change any negotiated rate.

FAIRNESS

The industrial customers assert that any negotiated rate within a zone rang-

ing from variable cost to fully allocated cost would be "cost based" and therefore reasonable. There are three problems with that assertion.

The first is the breadth of the range. Both electric and natural gas industries are characterized by alternating periods of surplus and scarcity and by long run incremental costs in excess of average costs. A "cost based" range from variable cost to fully allocated cost may be appropriate during periods of surplus because the objective is to lower per unit costs by more fully utilizing the system. However, as the system nears capacity, rates should begin to reflect that increased consumption will force reliance on new, more expensive resources and result in higher per unit prices. Under those circumstances, a "cost based" range will start with average cost and end with long run incremental cost.

Adoption of the industrial user's proposal would result in subsidization of industrial customers over the long term. During periods of surplus, industrial customers will contribute less than the average cost of facilities used to serve them. A failure to charge more than average cost during periods of scarcity will result in long run contribution lower than average cost.

The second problem is the suggestion that any rate within the range is reasonable. The concept of a "discount" implies that other customers pay costs properly allocated to the customer receiving the discount. A discounted rate is "fair and reasonable" only if it makes other customers better off by producing a larger contribution to fixed costs than otherwise would occur.

As a result, the only "just and reasonable" rate within the range is the rate designed to maximize contribution

to fixed costs from the customer, or class of customers, receiving the discount. Other rates result in unduly preferential treatment because they forgo contribution to the detriment of other customers.

The third problem is the implication that a range must be "cost based" to be reasonable. A "cost based" minimum price is necessary to ensure that sales to discretionary customers do not disadvantage core customers. However, in the context of competitive markets and price flexibility for discretionary customers, it is more appropriate to view value of service as the top of the range. This will minimize construction of excess capacity by ensuring that discretionary customers select the best form of energy from the alternatives available to them at future points in time. As noted, value of service is a traditional basis for spreading rates.

CONCLUSIONS

The purpose of this phase of these proceedings has been to identify permissible rate classification criteria and other legal requirements for permissible discounting concepts. The parties and Commissioner have not intended to develop the information required to determine whether specific proposals should be approved. Approval or rejection of specific permissible discounting proposals will result from a subsequent phase of the proceedings.

The Commissioner's conclusions on permissible classification criteria and other legal requirements are as follows:

1. The general legal standards for rate offerings are:

a. Classes of customers must be based on reasonable considerations, so that

customers receiving "like and contemporaneous service under substantially similar circumstances" are placed in the same class.

b. Classes of customers must be opened, so that any customer meeting the criteria for the class qualifies for the lower rate.

c. Special rates can be offered only for the purpose of providing just and reasonable rates to remaining customers.

2. The purpose of the discount must be to benefit other customers by maximizing contribution to fixed costs from customers receiving the discount. This implies that discounts should be offered only to customers with viable alternatives to the utility's service. Those "discretionary" customers are customers which:

a. Use volumes large enough to justify the cost of administering a discounting program, and

b. Can switch fuels, or

c. Can purchase their own supplies and install their own distribution system, or

d. Are otherwise so price sensitive that a price reduction would increase consumption enough to increase the customer's contribution to fixed costs.

3. The rate for discretionary customers must be designed to maximize contribution from customers receiving the discount. In addition, the rate must be greater than variable cost plus a minimum contribution to fixed costs. As the system nears capacity, the minimum rate must reflect the impact of system expansion on average costs.

4. Negotiated rates are permissible subject to the following conditions:

a. The rate must be made available to any customer meeting the criteria for the class; and

OREGON PUBLIC UTILITY COMMISSIONER

b. The Commissioner must be able to change any negotiated rate.

5. The following are permissible classification criteria:

a. Volume of use.

b. End use, at least to the extent differences in end use concisely describe differences in demands placed on the utility.

c. Other factors affecting the price the customer will pay for the utility's service.

6. The following are not permissible criteria:

a. Past usage.

b. Impacts on social policy goals unrelated to the Commissioner's mandate.

ORDER

IT IS THEREFORE ORDERED that a prehearing conference be scheduled to establish a schedule for presentation by the parties of permissible discounting proposals.

NEBRASKA PUBLIC SERVICE COMMISSION

Re Ideal-Z-Tel, Inc.

Protestant: Lincoln Telephone and Telegraph Company

Intervenor: Nebraska Telephone Association

Application No. C-694

April 14, 1987

ORDER authorizing competition among intraLATA interexchange telephone services.

THE NEW BRUNSWICK BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

IN THE MATTER OF The Public Utilities Act, R.S.N.B. 1978, Ch. P-27 as amended

IN THE MATTER OF an application by the New Brunswick Power Corporation for approval of changes in its charges, rates and tolls, in particular, for approval of an incentive rate.

Board:	David C. Nicholson	-	Chairman
	B. Fernand Nadeau	.	Vice-Chairman
	Claudette Stymiest	-	Commissioner
	Frank E. Kane	.	Commissioner

NB Power: Thomas B. Drummie, Q.C. and Karen Colpitts, Solicitors

The Large Power Users Group: E. Neil McKelvey, Q.C. and Cynthia J. Benson, Solicitors

Public Intervenors: Robert L. Kenny, Q.C. and Ivan Robichaud, Solicitors

People Against Lepreau Two Campaign: Julie Dingwell and David H. Thompson

Board: Harry G. Colwell, Solicitor

INTRODUCTION

The New Brunswick Power Corporation (NB Power) applied on Feb. 4, 1993 for a change in its rates to provide an incentive rate for large industrial customers. More particularly, this incentive rate was to promote in-province economic growth by encouraging the establishment of new industries or accelerating expansion of existing ones.

The proposed incentive is a 50% discount on the demand charge component of any new or additional loads of 2,000 KW or greater. It would be available for the period April 1, 1993 to March 31, 1998.

In July, 1993 the 440 MW Belledune Plant is scheduled to begin producing electricity for NB Power customers. Even with consideration being given to possible mothballing and early retirement of older generating plant, NB Power will have excess

capacity estimated as follows:

1993/94	-	377 MW
1994/95	-	340 MW
1995/96	-	278 MW
1996/97	-	229 MW
1997-98	-	147 MW

NB Power maintained that if, by offering this incentive rate, new industry would locate in New Brunswick, existing industry would advance start-up of unused capacity or expand capacity, this would be of benefit to all the customers of NB Power. The proposed rate would recover all of the incremental costs of producing the additional electrical energy. It would also provide a contribution to help pay for the excess generating capacity present on NB Power's system. This would mean that less revenue would be required from other sources. Therefore, the incentive rate would be of benefit to all of NB Power's customers.

As a general rule, customers who receive "a like and contemporaneous service" under similar circumstances should be charged the same rate for this service. It is rate discrimination to do otherwise. However, there has always been some

discrimination between customers in public utility rate setting. The test, both at common law and in public utility statutes, is whether or not it is "undue", "unjust", or "unlawful" discrimination.

Most regulatory statutes in Canada bar unjust discrimination in rate setting. However, there have been no reported reviews by the Courts of regulatory decisions in Canada, as to what constitutes unjust discrimination in public utilities' rate setting. However, in the United States, the courts have dealt with this question many times. The Texas Court of Appeals discussed the subject of discrimination as follows:

"The antidiscriminatory principle is not only statutory, it is a common law principle as well... But the principle includes a permissible range of unequal treatment which, while literally discriminatory, is not unlawfully so. The dividing line is generally that drawn by the rule of reasonableness, for mere inequality is not itself unlawful discrimination. That is to say, the different treatment practiced by the public utility must be founded upon a substantial and reasonable ground of distinction between the favoured and disfavoured classes or individuals." (Amtel Communications, Inc et al v. Texas Public Utility Commission (1985), 66 PUR 4th 140, at 146.

American regulatory boards have dealt with many applications for the approval of incentive rates similar to that proposed in this application. They have generally approved

incentive rates. The reasons for approval have varied from decision to decision but a common reason is that the rates will be of benefit to all of the customers of the utility.

"Use of economic development incentive rates has generally been approved as a means of contributing to the state's efforts to promote industrial growth, of facilitating construction of new or expended industrial or commercial plant, and of strengthening utility financial bases through expansion of the customer base." (RE Joint Petition of Indiana Cities and Towns for Approval of a Standard Economic Development Tariff (1989), 104 PUR 4th 51 at 51, Indiana Utility Regulatory Commission.)

"An economic redevelopment rate was affirmed as not being unreasonably discriminatory because, by stimulating industry and increasing utility revenues it would reduce the cost of service for all utility customers over the long run..." (Re Detroit Edison Company (1985), 68 PUR 4th 241 at 253.)

Further evidence that the incentive rate applied for is in the public interest is the fact that the Government of New Brunswick passed Order-in-Council 93-50 which reads as follows:

"Pursuant to subsection 3(7) of the Electric Power Act, the Lieutenant-Governor in Council directs the New Brunswick Power Corporation to proceed with the implementation of an incentive rate for industry in the form of a discount to existing rates and to be available to "new or "additions to" loads which are 2,000 KW or greater, applicable for the period April 1, 1993 to March 31, 1998."

SPECIFIC CONSIDERATIONS

POTENTIAL BENEFITS

The incentive rate will only apply to additional loads of 2000 KW or greater. It provides for a reduction to the normal demand charge but the energy charge is unchanged. There is no additional cost to NB Power for additional demand when it has surplus generating capacity. The generating plants have been built and their fixed costs remain the same regardless of the level of demand. If demand increases but remains below the level where new facilities would be required any additional revenue from demand charges can be applied to the fixed costs of generation. This will reduce the revenue requirement from other sources.

It is possible that total revenue may be lower with the incentive rate than it would be without it. This is due to the potential for "free-riders". These are customers who would have provided additional loads even without the incentive rate and therefore would have paid more. NB Power, based on its projections, estimated that the revenue at standard rates would be \$280,000 per year more than at incentive rates. This assumes that all additional loads would have occurred even in the absence of an incentive rate. NB Power stated that only one third of the additional load need be caused by the rate incentive for it to break-even.

The reference period for determining additional loads is the last six months of 1992. NB Power stated that, as of the date of the hearing, no customer had increased load in 1993 by more

than 2000 KW compared to the last six months of 1992. Therefore, no customer will automatically receive a reduction in demand charges due to the implementation of the incentive rate. To qualify for the incentive rate, all customers must increase their demand.

The Board recognizes that there is a risk that overall revenues may be somewhat lower with the incentive rate than they would have been without it. However, on balance, the potential for increased industrial demand and energy use is significantly greater with the implementation of an incentive rate.

TIME PERIOD

NB Power proposed that the incentive rate be applicable for a five year period, from April 1, 1993 to March 31, 1998. The Corporation provided a forecast of surplus capacity for the five years. The surplus is estimated at 377 MW for 1993/94 and reduces to 147 MW for 1997/98. The Board considers that it would not be desirable to offer demand at incentive rates without a reasonable assurance that sufficient surplus capacity will exist. Given the difficulties that exist in accurately predicting future demand, the Board is concerned by a commitment to five years. However, the Board will accept NB Power's position that five years is almost the minimum time acceptable to allow for industry to respond appropriately.

AMOUNT

NB Power proposed to accept customers for the incentive rate on a first come, first served, basis to a maximum of 100 MW in the aggregate. This was based on the current load and resource analysis which NB Power stated would be reassessed on the basis of a forthcoming revised load forecast.

The Board considers this to be a reasonable limit given its concern expressed in the previous section. The proposed tariff section creating the incentive rate does not state that there will be a cap of 100 MW. Mr. Gilliss, NB Power's witness, testified that he could see merit from a customer service policy prospective, of having the limit specifically set out in the tariff as it would enhance communication and explain the situation. The Board agrees with Mr. Gilliss and considers that the maximum number of MW available under the incentive rate should be clearly stated in the tariff.

OTHER

The LPU requested the Board to direct NB Power to use normalized revenue in its cost of service studies should the Board approve the incentive rate application. The LPU stated that to do otherwise would result in a potential detriment to the large industrial class. The Board will not comment on this matter at this time but believes that it would be more appropriate to discuss the matter fully at the time of the next general rate hearing.

NB Power recommended that the incentive rate be made available to customers of both the Power Commission of the City of Saint John and the Electrical Department of the City of Edmundston as large industrial load additions to their systems would also be beneficial. To accommodate this, NB Power amended proposal page RSP N-9(a) of the tariff as filed in the application. The Board agrees that the incentive rate should be available to customers of the two wholesale customers and that the amended wording will make this clear.

CONCLUSIONS

The Board directs NB Power to amend Page RSP N-9(a) to clearly state that the incentive rate is only available to a maximum of 100 MW in the aggregate and to file the amended page with the Board for approval. The Board will, upon receipt of an acceptable page RSP N-9(a), approve the incentive rate credit, effective as of this date.

Dated at the City of Saint John, New Brunswick this 25th day of May, 1993.

..........
Douglas W. Sanders
Secretary

et seq.; 1969 PA 306, as amended, MCL 24.201 et seq.; and the Commission's Rules of Practice and Procedure, 1979 Administrative Code, R 460.11 et seq.

b. Consumers' proposed Rate S should not be approved.

THEREFORE, IT IS ORDERED that Consumers Power Company's application to implement a Primary Short-Term Power Rate S is denied.

The Commission specifically reserves jurisdiction of the matters herein contained and the authority to issue such further order or orders as the facts and circumstances may require.

Any party desiring to appeal this order must perfect an appeal to the appropriate court within 30 days after issuance and notice of this order, pursuant to MCL 462.26.

Re Gulf States Utilities Company

Docket No. 7309
— Tex PUC Bull —

Texas Public Utility Commission
May 13, 1987

OPINION and order approving experimental tariff rider offering rate discounts to large-volume electric customers with capacity for installation of cogeneration facilities.

1. RATES, § 332 — Electric rate design — Special charges — Energy cost component — Alternative cogeneration facilities.

[TEX.(P.U.C.)] An experimental "SUS" tariff rider that offered rate discounts to large-volume electric customers with the capacity to install cogeneration facilities, and which contained a below-cost energy component designed to reflect the hypothetical fuel costs that would be incurred

by a retail customer that installed cogeneration facilities to service its own electric needs, did not violate substantive Rule 23.23(b)(2)(c), which requires recovery of fuel costs through a fixed fuel factor established during a general rate case, because the rate did not constitute a cost-based mechanism designed to pass through the electric utility's fuel costs ratably to retail customers.
p. 256.

2. RATES, § 332 — Electric rate design — Special charges — Energy cost component — Fuel factor.

[TEX.(P.U.C.)] There is no legal requirement that a voluntary, noncost-based incentive electric rate should contain a fuel factor as contemplated by substantive Rule 23.23(b)(2)(c).
p. 256.

3. DISCRIMINATION, § 45 — Rates — Customer classes — Cost classification — Alternative cogeneration capacity.

[TEX.(P.U.C.)] An experimental "SUS" tariff rider that offered rate discounts to large-volume electric customers with the capacity to install cogeneration facilities, and which contained a below-cost energy component designed to reflect the hypothetical fuel costs that would be incurred by a retail customer that installed cogeneration facilities to service its own electric needs, was held not to constitute the grant of an unreasonable preference to retail industrial electric customers, even though the proposed tariff "clearly discriminated" among industrial customers, because the ability of a retail customer to utilize cogeneration as an alternative means of meeting the customer's electrical energy requirements constituted a substantial and reasonable ground of distinction among industrial customers.
p. 257.

4. DISCRIMINATION, § 45 — Rates — Customer classes — Cost classification — Industrial customers.

[TEX.(P.U.C.)] The commission has ruled, in the case of *Re El Paso Electric Co.*, Docket No. 6350, Jan. 31, 1986 (Tex.P.U.C.), that a proposed economic recovery tariff available only to certain industrial electric rate classes does not unreasonably discriminate among customers if it is shown that (1) the utility system and the general body of ratepayers are benefited by maintaining the existing industrial load, (2) existing industrial load is in serious danger of shrinking substantially or disappearing altogether, (3) unusually high in-

dustrial electric rates are a major economic factor that increase the possibility of serious load loss, and (4) approval of the rate would increase the probability that needed industrial load will continue operating on the utility's system.
p. 257.

5. RATES, § 339 — Electric rate design — Customer classes — Industrial customers — Alternative cogeneration capacity — Incentives — Load retention.

[TEX.(P.U.C.)] It is not unreasonable to offer incentive rates to certain industrial electric customers, based upon their potential ability for cogeneration of electricity, where the facts demonstrate that failure to prevent those customers from engaging in cogeneration would cause substantial harm to the local retail electric distribution utility.
p. 264.

6. COGENERATION, § 1 — Electric utilities — Rate discounts — Cogeneration development — Deferral.

[TEX.(P.U.C.)] A retail electric distribution utility was authorized to adopt an experimental "SUS" tariff rider that offered rate discounts to large-volume electric customers with the capacity to install cogeneration facilities, but only on condition that the utility would not seek the recovery of any revenue losses associated with the tariff in any present or future rate proceeding.
p. 270.

i. COGENERATION, § 1 — Electric utilities — Rate discounts — Cogeneration development — Deferral.

[TEX.(P.U.C.)] Discussion of experimental tariff rider that offered rate discounts to large-volume electric customers with characteristics such that cogeneration represents a viable alternative to regulated distribution service.
p. 253.

ii. RATES, § 332 — Electric rate design — Special charges — Energy cost component — Heat rate.

[TEX.(P.U.C.)] Discussion of heat rates contained in an experimental "SUS" tariff rider that offered rate discounts to large-volume electric customers with characteristics such that cogeneration represents a viable alternative to regulated distribution service.
p. 259.

iii. RATES, § 333 — Electric rate design — Special charges — Demand charges — Capacity rating factor.

[TEX.(P.U.C.)] Discussion of the peak demand capacity rating factor employed in designing an experimental "SUS" tariff rider that offered rate discounts to large-volume electric customers with characteristics such that cogeneration represents a viable alternative to regulated distribution service.
p. 261.

iv. COGENERATION, § 41 — Service to qualifying facilities — Rates — Incentive discount — Alternative cogeneration capacity — Viability.

[TEX.(P.U.C.)] Discussion of minimum demand and load requirements for eligibility for an experimental "SUS" tariff rider that offered rate discounts to large-volume electric customers with characteristics such that cogeneration represents a viable alternative to regulated distribution service.
p. 262.

Before Thomas, chairman, Rosson and Campbell, commissioners, and Smith, administrative law judge.

By the COMMISSION:

EXAMINER'S REPORT

I. Procedural History

On December 31, 1986, Gulf States Utilities Company (GSU) filed an application seeking authority to implement a proposed Schedule SUS Experimental Rider to Schedules LPS and LIS for Industrial Service to Qualifying Thermal Energy Users, and seeking approval of an associated contact amendment to be utilized to incorporate Schedule SUS as an applicable rate under the existing service agreements between GSU and customers electing to take power under Schedule SUS. Contemporaneously with the filing, GSU requested approval of the filing on an interim basis, pending the Com-

mission's issuance of a final order in this matter.

The Commission has jurisdiction over GSU's application pursuant to Sections 16(a), 17(e) and 37 of the Public Utility Regulatory Act (PURA or the Act), Tex. Rev. Civ. Stat. Ann. art. 1446c (Vernon Supp. 1987).

By order dated January 21, 1987, the February 4, 1987, implementation of the proposed tariff revision was suspended until July 6, 1987, being the full suspension period permitted under the terms of P.U.C. SUBST. R. 23.24(i) and P.U.C. PROC. R. 21.4.

Pursuant to P.U.C. PROC. R. 21.83, a prehearing conference was conducted on February 2, 1987, with the undersigned examiner presiding. Appearances were made by Mr. Donald Clements on behalf of GSU and Mr. George Fleming on behalf of the Commission staff. Although no movents for intervention made appearance at the prehearing conference, statements in support of GSU's application were made by Mr. Art Spencer on behalf of Chevron Corporation, and Mr. Ron Kostelny on behalf of Mobil Chemical. During the conference, a schedule was established for discovery and the prefilng of testimony. The hearing on the merits of GSU's request for both interim and permanent approval of the filing was scheduled for April 13, 1987.

By examiner's order dated February 3, 1987, GSU was directed to provide written notice of this proceeding to each of the parties to GSU's pending general rate case and to publish notice of the application once a week for two consecutive weeks in newspapers of general circulation in each county in Texas in which GSU provides utility service. On April 13, 1987, GSU filed publishers' affidavits reflecting publication of notice of GSU's filing and of the pendency of this proceeding in thirty newspapers of general circulation in GSU's Texas service area. Additionally, on April 13, 1987, GSU filed a copy of the written notice which GSU mailed to all parties to Docket No. 7195 on February 20, 1987 as well as a copy of a corrected notice which GSU mailed to all parties to Docket No.

7195 on March 20, 1987. On April 29, 1987, GSU filed a sworn affidavit attesting to the provision of notice to the parties to Docket No. 7195 on February 20, 1987 and March 20, 1987.

On April 6, 1987, the Office of Public Utility Counsel (OPC) filed a motion to intervene, which motion was granted by examiner's order dated April 9, 1987.

The hearing on the merits was conducted on April 13, 1987, with the undersigned examiner presiding. Appearances were made by Mr. Donald Clements on behalf of GSU and Mr. George Fleming on behalf of the Commission staff. Statements in support of GSU's application were again made by representatives of Chevron U.S.A. and Mobil Chemical. OPC did not make appearance at the hearing. After presentation of the respective cases of GSU and the Commission staff, the parties were directed to submit post-hearing briefs in lieu of closing argument and the hearing was adjourned. Post-hearing briefs were filed by GSU and the Commission's general counsel on April 20, 1987, and a reply brief was timely filed by GSU on April 24, 1987.

By order dated April 22, 1987, the parties were directed to file briefs by no later than April 27, 1987, on the issue of whether use of GSU's weighted average cost of gas in the steam rate energy charge, for the purpose of mirroring the variable fuel costs which an industrial customer would incur if it built a cogeneration facility, constituted a violation of PURA Section 43(g)(1). Supplemental briefs were filed on that issue on April 27, 1987 by GSU and general counsel.

On April 24, 1987, OPC filed a motion to consolidate this proceeding with Docket No. 7195 or alternatively, to reopen the record to permit OPC to present direct testimony and develop cross-examination consistent with a Statement of Position which was untimely filed by OPC on April 24, 1987. The OPC Statement of Position is attached hereto as Examiner's Exhibit No. 3. OPC's motion was denied by examiner's order dated April 29, 1987.

II. Overview

[i] Schedule SUS, attached hereto as Examiner's Exhibit No. 1, is an incentive rate which GSU proposes to offer to those customers within the Large Power Service (LPS) and Large Industrial Service (LIS) classes whose electrical and thermal energy requirements are such that cogeneration constitutes a potentially viable alternative to the continued purchase of those customers' total electrical energy requirements from GSU. According to GSU witness Donald Hamilton, Manager of Industrial Services and Cogeneration, GSU has lost 430 MW of industrial load to date as a consequence of cogeneration and approximately 185 MW of additional load is subject to loss due to cogeneration projects which are in advanced planning or engineering stages. Mr. Hamilton testified that GSU has identified a total of approximately 1800 MW of industrial capacity requirements within its service area which could potentially be served through cogeneration. The proposed SUS rider is designed to provide qualifying industrial customers with prices for power which are competitive with the power costs which those customers would experience if they chose to construct a cogeneration facility, thereby lessening the incentive for those customers to drop off of GSU's system and engage in cogeneration.

According to staff witness George Mentrup, GSU's concern over possible industrial load loss to cogeneration is warranted. In making this assessment, Mr. Mentrup notes that GSU has already experienced load loss to cogeneration, that many of GSU's LPS and LIS customers are electric intensive, high load factor customers with access to natural gas supplies, that some industrial customers are actively considering switching to cogeneration in the near future, and that LIS and LPS rates are likely to rise in the future.

According to GSU witness James Thornton, Director of Rate Research, it is economically more advantageous for GSU to recognize the reality of cogeneration by providing service to potential cogenerators under the discounted SUS rate than to do nothing because, with the SUS rider GSU

can maintain a greater revenue level than would be received were a major portion of that load lost to cogeneration. Mr. Thornton's testimony reflects that, based upon currently applicable LIS and LPS rates, adoption of Schedule SUS would reduce GSU's Texas revenues by \$3,091,202 annually. However, should GSU not implement Schedule SUS, Mr. Thornton's testimony reflects a projected annual loss of \$13,900,000 as a consequence of industrial load lost to cogeneration. GSU takes the position that any revenue reduction attributable to Schedule SUS is preferable to the permanent loss of industrial load.

If Schedule SUS is approved, GSU will not experience an immediate revenue loss as a consequence of implementation of Schedule SUS because the SUS rates will not actually commence until the period of time deemed necessary for each SUS customer to construct a cogeneration facility has passed. According to Mr. Thornton, any Schedule SUS related losses will be borne solely by GSU's stockholders and, in the event Schedule SUS is approved, GSU will not seek the recovery of any future SUS related revenue losses from its ratepayers. According to Mr. Thornton, in future rate proceedings GSU will restate its revenues as if all Schedule SUS load were being and had been billed at the LPS or LIS rates which would be applicable in the absence of Schedule SUS.

GSU has requested expedited consideration of the merits of the Schedule SUS filing and expedited consideration has been given in light of GSU's assertions that immediate implementation of the tariff is urgently needed to preclude loss of additional load.

III. Description of Schedule SUS

GSU proposes to offer Schedule SUS on an experimental basis, limiting the period in which a customer can subscribe to the offering to a one year period following the approval date of the rider. Any LPS or LIS customer with a minimum process steam

requirement of 10,000 pounds per hour or the thermal energy equivalent thereof qualifies for the Schedule SUS rate.

The Schedule SUS incentive rates do not immediately apply upon subscription to the rate by a qualifying customer. Rather, Schedule SUS requires that GSU and the customer agree upon a commencement date which reflects the reasonably achievable in-service date of a satisfactory self-generation facility, had the customer elected to proceed with a cogeneration project.

A qualifying customer must execute an amendment to its existing service agreement with GSU as a precondition to subscription to Schedule SUS. The text of the proposed service agreement amendment is attached hereto as Examiner's Exhibit No. 2. Under the terms of the proposed amendment, the customer must extend its existing service agreement for a period of no less than three years and no more than ten years. In the event that a customer desires to revert from Schedule SUS rates to standard LIS or LPS rates prior to the expiration of the agreed period, the service agreement amendment provides that the customer may do so without penalty if twelve months advance notice is given. If less than twelve months notice is given, the customer must pay the difference between past billings under Schedule SUS and the LPS or LIS rate which would otherwise have been applicable.

In the event that a customer desires to terminate the service agreement in its entirety, the service agreement amendment permits a customer to do so by making payment for the value of future charges for contract power for the remaining term of the agreement, provided that at least twelve months' notice of intent to terminate the service agreement is given. If less than twelve months' notice is given, the customer must also pay the difference between past billings under Schedule SUS and the GSU rate schedule which otherwise would have been applicable.

Schedule SUS rates are not cost based rates. Rather, they are based upon the economics of installing a gas turbine driven electric generator with a heat recovery steam

generator and in some instances, the further installation of an extraction turbine. Schedule SUS rates will vary among customers because each customer has different levels of electric demand and different ratios of electric demand to steam demand which would necessitate installation of differing sizes and types of cogeneration equipment with differing cost characteristics, were each customer actually to cogenerate. Schedule SUS rates are designed to account for those as well as other cost variables.

The optimal size of the theoretical cogeneration facility which serves as the model for calculating a customer's monthly Schedule SUS rate is determined in part by the customer's monthly average demand and in part through the use of a sizing factor. The manner of calculation of the sizing factor is set forth in the proposed service agreement amendment. For customers with an average ratio of electric energy demand to steam energy demand of 230 KWH per 1,000 pounds of steam (MLB) or less per month, the sizing factor is determined by dividing the customer's minimum actual peak energy demand for the previous year by that customer's average actual peak energy demand for the previous year. For customers with an average ratio of electric energy demand to steam energy demand in excess of 230 KWH/MLB per month, the sizing factor is calculated using minimum and average steam demand rather than minimum and average electric demand. Schedule SUS provides for periodic review of a customer's sizing factor, and provides that the factor may be subsequently adjusted should the operating conditions upon which the sizing factor is based materially change.

Once the customer's sizing factor is determined, the customer's average demand during each billing period is multiplied by the sizing factor to determine the size of the customer's load during that billing period which would be served by the theoretical cogeneration facility. Any consumption in excess of the load which would be generated by the theoretical facility during the billing period is billed at the standard LIS or LPS rates which would be applicable in

the absence of Schedule SUS. It should be noted that because both of the factors which determine the size of a customer's theoretical cogeneration facility are variables, the size of the customer's theoretical cogeneration facility can potentially vary from month to month. Schedule SUS therefore assumes that, for any given billing period, the customer has constructed the optimal size cogeneration facility to serve the load experienced by the customer during that billing period.

The SUS rate is comprised of both a demand charge and an energy charge. The SUS demand charge, referred to in the tariff as the Steam Rate Billing Load Charge, is intended to simulate the initial investment and periodic maintenance investment costs associated with the construction of a cogeneration facility. The pricing differential at various load levels reflects the customer costs related to the size of the cogeneration facility that would have been installed but for the customer's decision to utilize the SUS rider. The demand charge is comprised of two rate elements: a rate per KW and a flat dollar charge. Mr. Thornton testified that the flat dollar charge is designed to smooth out the transition from one load size to the next.

Schedule SUS has two separate demand rate schedules. Schedule A is applicable to customers who can demonstrate and contract for an average ratio of electrical energy to steam energy of 230 KWH/MLB or less per month. Schedule B is applicable to customers with electrical energy to steam energy ratios of more than 230 KWH/MLB. According to Mr. Hamilton, the purpose of having two sets of demand rate schedules is to recognize economic efficiency differences between cogeneration facilities designed to produce different electrical energy to steam energy ratios. Schedule B rates assume the addition of extraction turbines to the standard gas turbine/heat recovery steam generator configuration upon which Schedule A rates are predicated.

Under the terms of the tariff, the SUS demand charge will remain constant for the first three years that a customer is served

under the rider, and then increase by 1.5 percent each year thereafter. According to Mr. Hamilton, the annual increase is intended to reflect the increased cost of operation and maintenance associated with a gas turbine due to wear and tear and required periodic maintenance.

The SUS energy charge, referred to in the tariff as the Steam Rate Energy Charge, is intended to simulate the cost of fuel and the efficiency of the theoretical cogeneration unit which a customer would likely construct, were the customer to cogenerate. The energy charge is essentially a function of the heat rate of the theoretical cogeneration facility and of GSU's weighted average cost of gas. GSU's weighted average cost of gas is intended to represent the likely natural gas price per MMBtu which a cogenerator would have to pay. Depending upon the size of the customer's billing load and the customer's electric energy to steam energy ratio, Schedule SUS specifies a particular heat rate value to be utilized in calculating the customer's SUS energy charge. The heat rate value reflects the number of MMBtu needed to generate one MWH of electricity. Once the heat rate value is selected, the customer's energy charge is calculated by multiplying the customer's total MWH of consumption for the month by the heat rate value, and then again by GSU's weighted average cost of gas for the prior month.

The various heat rates specified in Schedule SUS are intended to reflect typical heat rates associated with different configurations and sizes of generating facilities which would be utilized by the customer. As the size of the SUS load increases, the heat rate improves, reflecting the greater efficiency of larger generating facilities in converting fuel energy input into electric and steam energy output. Under the terms of the rider, a customer's initial heat rate will increase by 1.25 percent, 1.5 percent and 2 percent at the beginning of the second, third and fourth years, respectively. The heat rate will then be reset to the initial value for the fifth, ninth and thirteenth year of SUS billing. According to Mr. Hamilton, the periodic increase in the heat rate

is intended to reflect the declining efficiency of a gas turbine over time, and the periodic resetting of the heat rate at its initial value is intended to simulate the refurbishment of a gas turbine after periodic maintenance.

Finally, it should be noted that Schedule SUS contains a minimum charge provision. The combined total SUS demand and energy charges can never be less than the monthly KWH billable under SUS rates times GSU's system average fuel cost per KWH for the preceding month, plus 8 mills per KWH. This pricing floor is intended to insure that the incentive rates achievable under SUS never fall below GSU's incremental costs of generating power.

IV. Discussion of Contested Issues

The Commission staff supports the need for GSU to implement an incentive rate designed to prevent the loss of GSU's industrial load to cogeneration. However, the staff has not endorsed Schedule SUS due to staff witness Mentrup's concerns that the filing may be deemed inconsistent with Commission Substantive Rules and that the proposed SUS rate may be deemed to be anti-competitive or unreasonably discriminatory in application. Beyond those legal concerns, staff witness Hughes has recommended that several technical modifications be made to the filing in the event Mr. Mentrup's concerns do not constitute a bar to approval of the filing. The broad threshold legal issues raised in the testimony of staff witness George Mentrup are discussed below, followed by discussion of the technical issues raised by Mr. Hughes.

A. Legal Issues

1. P.U.C. SUBST. R. 23.23(b)(2)(c)

[1, 2] Mr. Mentrup has expressed concern that schedule SUS is not subject to a fixed fuel factor and has expressed uncertainty as to whether the SUS charge should be viewed as constituting a fuel factor. To the extent that the SUS energy charge is

considered to be a fuel factor, Mr. Mentrup argues that it is inconsistent with P.U.C. SUBST. R. 23.23(b)(2)(c), which provides as follows:

(C) The utility shall recover its known and reasonably predictable fuel costs through a fixed fuel factor. The utility's fixed fuel factor shall be established during a general rate case, fuel reconciliation proceeding or interim fuel proceeding as designated in subparagraphs (D) and (E) of this paragraph, and shall be determined by dividing the utility's known or reasonably predictable fuel cost, as defined in subparagraph (B) of this paragraph, by the corresponding kilowatt-hour sales during the period in which the factor will be in effect. If, due to unique circumstances, such a calculation is not appropriate for a particular utility, a different method of calculation may be used. When approved by the Commission, the utility's fixed fuel factor:

(i) may be designed to account for seasonal differentiation of fuel costs, and

(ii) shall be designed to account for system losses and for differences in line losses corresponding to the voltage level of service.

The inconsistency noted by Mr. Mentrup lies partly in the fact that the rule does not appear to condone "fuel-type-differentiated" fuel factors, and partly in the fact that the charge is allowed to vary from month to month, and is not set in a general rate case or fuel proceeding.

GSU takes the position that the SUS energy charge does not violate P.U.C. SUBST. R. 23.23(b)(2)(c), but that should the Commission deem that it does, a good cause exception should be granted pursuant to P.U.C. SUBST. R. 23.2. In the examiner's opinion, it is not necessary to address the good cause issue because Mr. Mentrup's concern is based upon the erroneous premise

that the energy charge is in some fashion a fuel factor or the equivalent thereof.

It is important to emphasize that though the SUS rate is structured in a familiar format with a demand and an energy component, the SUS rate is not a cost based rate. Unlike a fuel factor, the energy component of the SUS rate is not designed to pass through to SUS customers the fuel costs which GSU incurs in providing service to those customers. Rather, the energy charge is designed to replicate the fuel costs which an SUS customer would have incurred had the customer actually constructed a cogeneration facility and generated the power with a gas fired turbine. Use of GSU's weighted average cost of gas is intended solely to approximate a cogenerator's likely gas costs. Clearly, the SUS energy charge does not operate like a fuel factor nor does it serve the intended purpose of a fuel factor. With respect to concern that the SUS rate contains no fuel factor, the examiner simply notes that he can find no Commission requirement that a voluntary non-cost based incentive rate contain a fuel factor.

The examiner finds that, as the SUS energy charge does not purport to constitute a cost based mechanism designed to ratably pass GSU's fuel costs through to SUS customers, it violates neither the Act nor the Commission's Substantive Rules and therefore does not constitute a legal impediment to implementation of the proposed SUS rate.

2. PURA Sections 38 and 45

[3, 4] A second legal issue raised by Mr. Mentrup is whether Schedule SUS constitutes the grant of an unreasonable preference or advantage by GSU or causes unreasonable prejudice or disadvantage, within the meaning of Section 45 of the Act, and whether Commission approval of Schedule SUS would be violative of Section 38 of the Act, which requires that rates not be unreasonably preferential, prejudicial, or discriminatory.

Staff witness George Mentrup testified

that he could foresee no disadvantage to members of any non-industrial GSU rate classes as a consequence of approval of Schedule SUS, and the examiner concurs in that conclusion. However, with regard to industrial classes, Mr. Mentrup expressed concern that certain customers within the LIS and LPS classes could be competitively disadvantaged, since industrial customers who do not qualify for the Schedule SUS incentive rate due to inability to meet the minimum thermal load requirements of the SUS rider, and industrial customers for whom Schedule SUS would not be economically attractive unless normal LIS or LPS rates increase to a certain level, would pay higher rates for utility service than those who qualify for the Schedule SUS incentive rate.

The proposed rider clearly discriminates among industrial customers, given that a preferential rate is provided to those customers which meet the minimum thermal load requirement specified in the rider. The question is whether the discrimination among LPS and LIS customers inherent in the SUS rider falls within a permissible range of unequal treatment. Whether or not the discrimination falls within that range hinges upon whether the ability of the targeted customers to utilize cogeneration as an alternative means of meeting their electrical energy requirements constitutes a substantial and reasonable ground of distinction among industrial customers.

In the examiner's opinion, use of cogeneration potential as a basis for distinguishing among LIS and LPS customers is reasonable and works no unreasonable prejudice or disadvantage to LIS or LPS customers. As noted by GSU witness James Thornton, any economic advantage to customers who qualify for service under schedule SUS does not result because of the proposed tariff, but rather from the cogeneration alternative that is presently available to those customers, regardless of whether Schedule SUS is approved or disapproved. To the extent that the proposed SUS rider is viewed as conferring upon certain industrial customers an economic ad-

vantage, it is not an unreasonable advantage since, in the event the incentive rate is not approved, the record reflects that some industrial customers will likely avail themselves of an advantage equivalent to that afforded by Schedule SUS through resort to cogeneration. So long as cogeneration is in fact a viable option for industrial customers taking service under Schedule SUS, and so long as the Schedule SUS rate reasonably approximates the cost of cogenerating electricity, the examiner believes that any preference or advantage conferred by Schedule SUS is justifiable.

The Commission recently addressed the issue of the reasonableness of discrimination inherent in incentive rates in *Re El Paso Electric Co.*, Docket No. 6350, Jan. 31, 1986 (Tex.P.U.C.). In the final Order in that docket, the Commission found that a proposed economic recovery rider (ERR) available only to certain industrial classes does not unreasonably discriminate if the evidence demonstrates: (1) that the utility system and the general body of ratepayers are benefitted by maintaining the existing industrial load; (2) that such load is in serious danger of substantially shrinking or disappearing altogether; (3) that unusually high industrial electric rates are a major economic factor which elevate this possibility of serious load loss; and (4) that approval of the ERR would increase the probability that needed industrial load will continue operating on the utility's system. While the Commission's holding pertained to discrimination among classes, it appears fully analogous to discrimination among customers within the same class as well, especially where there exists a relevant distinguishing characteristic among class members.

The evidence of record demonstrates that each of the criteria set out in Docket No. 6350 has been met. GSU witness James Thornton testified regarding the benefit to GSU and the general body of ratepayers of maintaining existing industrial load. Staff witness George Mentrup, recognizing the desirability of maintaining GSU's industrial load, testified that it would be prudent for GSU to devise as many ways as possible to

retain existing load. GSU witness Donald Hamilton testified in detail regarding the substantial loss of industrial load which has occurred to date as well as future load loss which will occur should additional industrial customers resort to cogeneration. Mr. Mentrup testified that GSU's concern regarding loss of industrial load through cogeneration is justified. Further, Mr. Mentrup cited the fact that LIS and LPS rates will likely increase in the future as a major factor contributing to loss of load to cogeneration. It is apparent from the testimony of Mr. Thornton and Mr. Hamilton that approval of the proposed SUS rider will increase the probability that load attributable to industrial customers who have the potential to cogenerate will be retained on GSU's system.

The record in this case reflects that, while the proposed SUS rider is preferential and discriminatory in application, it is not unreasonably so. There is no evidence of record demonstrating that the rider would in fact work any real prejudice or disadvantage to any customers within any GSU rate classification. The examiner finds that the discrimination inherent in the SUS rider is founded upon a substantial and reasonable ground of distinction in satisfaction of the "rule of reasonableness" established by judicial precedent, that the facts of this case satisfy the four-prong reasonableness test established by Commission precedent in Docket No. 6350, and that the unequal treatment of LPS and LIS customers based upon their potential ability to cogenerate is not only permissible but is in fact appropriate from a public policy standpoint. The examiner concludes that approval of the proposed SUS rider would not violate the broad rate structure criteria set forth in Sections 38 and 45 of the Act.

The examiner notes in passing that neither the Commission staff nor OPC has argued that Schedule SUS is violative of PURA Section 16(g), which provides that the Commission shall make and enforce rules to encourage the economical production of electric energy by qualifying cogenerators. The examiner assumes that this ar-

gument was not raised due to the belief that cogeneration does not constitute economical production of electric energy in the context of a utility with excess capacity and declining load, and the examiner concurs in that assessment.

B. Technical Issues

With respect to the technical aspects of the filing, staff witness Harold Hughes has recommended that the Commission make five specific modifications to Schedule SUS, each of which is opposed by GSU. The recommendations are as follows:

- a. The SUS heat rates should only apply to customers with steam requirements close to 265 psig-411°F. A separate heat rate schedule should be prepared for customers with higher pressure and temperature requirements.
- b. Schedule B rates should not be used.
- c. The sizing factor should not be used.
- d. Schedule SUS should contain a minimum demand requirement.
- e. Schedule SUS rates should not apply to customers with demand requirements below 10 MW.

A discussion of each of these recommendations and the examiner's analysis of the evidence relating thereto follows.

1. Heat Rates

[ii] According to Mr. Hughes, the heat rates contained in Schedule SUS should apply solely to customers with steam requirements close to 265 psig-411°F, and a separate heat rate schedule should be prepared for customers with higher pressure and temperature requirements. Mr. Hughes reached this opinion on the basis of operating data published by General Electric regarding three General Electric gas turbine

models which Mr. Hughes indicates are in wide use within the cogeneration industry. Utilizing published heat rate curves for those turbine models, as well as data published by General Electric concerning fuel chargeable to power for those turbine models at different steam pressures and temperature, Mr. Hughes calculated what he believes to be representative heat rates which would be experienced at different load levels, assuming high temperature and pressure steam requirements (895 psig-830°F) and low temperature and pressure steam requirements (265 psig-411°F). On the basis of his calculations, Mr. Hughes concluded that while the SUS heat rates proposed by GSU are appropriate for low pressure and temperature steam requirements, the heat rates are too low for use by customers with high pressure and temperature steam requirements. Accordingly, Mr. Hughes suggests that separate SUS heat rate values be calculated for use where customers require high pressure and temperature steam conditions, in order to insure that the fuel costs associated with the theoretical cogeneration facilities which those customers would deploy are not understated.

GSU asserts that the Schedule SUS heat rates are appropriate under both low pressure and temperature steam conditions and high pressure and temperature steam conditions. According to GSU witness Hamilton, Mr. Hughes' calculations overstate the heat rates levels which would be achieved under high temperature and pressure steam conditions due to Mr. Hughes' failure to consider that customers with high steam demand would utilize supplemental firing. Mr. Hamilton testified that supplemental firing involves the addition of raw fuel to the hot gases flowing from the combustion turbine to the heat recovery steam generator, resulting in a very efficient way of producing steam and the achievement of lower heat rates. Mr. Hamilton noted that the General Electric fuel chargeable to power data upon which Mr. Hughes relied in making his calculations provide separate tables for use, assuming unfired boilers or supplemental firing, respectively. Indeed, a review of the

tables in question reflects that, assuming the use of supplemental firing, the fuel chargeable to power for the three sample turbines under high pressure and temperature steam conditions approximating 895 psig-830°F will generate heat rates applicable to various load levels which are actually lower than the heat rates produced assuming the use of unfired boilers under low pressure and temperature steam conditions. Mr. Hamilton testified that GSU conducted a survey of its industrial customers at which time their steam requirements were furnished to GSU. According to Mr. Hamilton, after checking each customer's ratio of electric energy requirements to steam energy requirements, it was apparent that the ratios ranged from near 230 KWH/MLB to 110 KWH/MLB. Mr. Hamilton testified that the most economical way to serve those requirements in most cases would involve supplemental firing, and the SUS heat rates accordingly assume the use of some supplemental firing. On cross-examination, Mr. Hughes conceded that many of GSU's customers with high steam demand would utilize supplemental firing, but noted that he did not utilize data pertinent to supplemental firing in performing his calculations due to his understanding that the SUS rate was based upon a very simple configuration falling within the unfired boiler category. According to General Counsel in his post-hearing brief, it was not clear to the staff that GSU assumed the use of some supplemental firing until GSU presented its rebuttal case.

In the examiner's opinion the evidence of record supports the heat rates proposed by GSU in Schedule SUS and does not reflect the need for a separate heat rate schedule for customers with high pressure and temperature steam requirements.

2. Schedule B Rates

Mr. Hughes has recommended that the Schedule B rates, which are designed for use with LPS and LIS customers with electric energy to steam energy ratios in excess

of 230 KWH/MLB, should not be utilized because numerous cogeneration publications reflect that gas turbines with waste heat boilers are not sound economic choices for cogenerating in instances where electric energy to steam energy ratios exceed 225 KWH/MLB. According to Mr. Hughes, in such instances a cogenerator would install a reciprocating engine. However, GSU asserts that Schedule B is indeed appropriate and is designed to take into account industrial customers which would install a combined cycle unit utilizing both gas turbine and steam turbine driven electric generators. According to Mr. Hamilton, GSU's previously referenced industrial survey reflects the existence of a number of GSU customers with electric energy to steam energy ratios which were larger than could be achieved through use of an unfired gas turbine. In reviewing the equipment configuration which would provide the means of meeting higher energy demand to steam demand requirements, GSU determined that the optional configuration would involve the addition of an extraction turbine to the standard gas turbine heat recovery steam generator configuration. According to Mr. Hamilton, that configuration results in the occurrence of slightly higher capital costs and slightly better heat rates. Mr. Hamilton further testified that those customers which would potentially use the Schedule B rates have high pressure steam requirements which cannot be met using a reciprocating engine. That assertion was not challenged by the Commission staff.

Mr. Hamilton testified that a review of the Schedule B demand rates and heat rates will reveal that Schedule B contains higher demand rates and lower heat rates than Schedule A, and that those differentials are intended to reflect the use of combined cycle units to meet the needs of customers with electric energy to steam energy ratios exceeding 230 KWH/MLB. On cross-examination, Mr. Hughes testified that he was unaware that Schedule B was intended to reflect the use of combined cycle units. When asked if he felt that the Schedule B rates would be appropriate in light of that

fact, Mr. Hughes indicated that he would certainly have to take another look.

Based upon the evidence of record, the examiner finds that the SUS rates embodied in Schedule B are reasonable, appropriate and necessary in order to properly reflect the costs of operating a theoretical combined cycle cogeneration unit to meet the energy needs of those GSU customers with electric energy to steam energy ratios exceeding 230 KWH/MLB.

3. Sizing Factor

[iii] Mr. Hughes has recommended that the sizing factor concept incorporated within Schedule SUS be rejected on the basis that it does not produce a fair representation of how a cogenerator would operate. In Mr. Hughes' view, a cogenerator would not likely operate its cogeneration facility in instances where the cogenerator's peak demand falls below approximately 75 percent of the unit's rated capacity, due to the rapidly declining efficiencies of cogeneration equipment at low loads. Rather, in such instances Mr. Hughes asserts that the cogenerator would purchase its power requirements from the utility at standby power rates. Accordingly, Mr. Hughes suggests that Schedule SUS be modified to require that the customer and GSU agree upon a fixed size unit, and that any demand above 105 percent of the unit's rated capacity be considered purchased on a standby rate, and that in any month where demand is less than 75 percent of the unit's rated capacity, the customer should be required to purchase all of its power at the standard LIS or LPS firm power rate.

GSU opposes Mr. Hughes' proposal to eliminate the sizing factor. According to Mr. Hamilton, it is inappropriate to attempt to predict in advance how a cogenerator would choose to operate its facility since there are many operational constraints which would influence how the cogenerator operated the facility at any given time; but, to the extent one does so, a cogenerator would likely operate the facility at the optimum economic

output of the facility, regardless of whether the energy output is consumed by the customer or sold to a utility.

GSU argues that it is not unreasonable to use a percentage of a customer's total energy usage for a sizing factor, as opposed to the staff recommendation that a fixed-size electrical generator be used for each individual customer. Mr. Hamilton testified that the sizing factor proposed by GSU allows a consistent methodology to be applied to all customers by sizing the electrical generator in a manner which effectively allows its full capacity to be utilized to meet the customer's energy demand. According to Mr. Hamilton, individual negotiations with each customer over the size of the theoretical electric generator would increase some of the risk to the cogenerator inherent in the selection of a fixed size electrical generator without increasing the benefits to GSU or its ratepayers. In the examiner's opinion, were a fixed size generator to be used, the rate would have to recognize that realistic operation of the facility would dictate that GSU purchase excess power from the cogenerator, as necessary, at avoided cost. Use of the sizing factor proposed by GSU would appear to afford flexibility for a customer's business to expand or contract, which is a benefit which the customer would not have if it chose to cogenerate, while avoiding the need for the SUS rate to compensate for a customer's sale of theoretical excess power to GSU when the customer's load level drops. The variable sizing factor proposed by GSU appears to benefit both the SUS customer and GSU without disadvantaging either.

The examiner finds that, while the sizing mechanism proposed by Mr. Hughes is not necessarily unreasonable, adoption of his proposal would require wholesale revision of the current SUS rate structure and of the terms and conditions under which a customer could initiate and terminate the rate. As the examiner finds the current sizing factor proposed by GSU to be reasonable, it would appear preferable to utilize the sizing factor proposed by GSU rather than to require substantial restructuring of

the proposed SUS rate in order to replace a reasonable sizing factor with another reasonable but very different sizing factor. The examiner therefore recommends use of the sizing factor currently embodied in Schedule SUS.

4. Minimum Demand

[iv] Mr. Hughes has recommended that — “a minimum demand should be set in the tariff to qualify for the SUS rate” — based upon his belief that a cogenerator would not operate its cogeneration facility when the cogenerator's demand drops below 75 percent of the rated capacity of the cogeneration facility. Although the exact intent of this recommendation is not totally clear from Mr. Hughes' testimony, it appears that the recommendation is merely a restatement of Mr. Hughes' proposal that a customer be required to pay standard firm power rates in any month where the customer's demand falls below 75 percent of the rated capacity of a fixed size surrogate generating unit. As the examiner has recommended use of the sizing factor proposed by GSU, as opposed to the use of a fixed size surrogate unit, the examiner does not recommend adoption of this proposal.

5. Minimum Load Requirement

According to Mr. Hughes, there are sharply changing economies of scale for cogeneration units of between 1 MW and 10 MW in size. Within this range, as the size of the unit decreases, the installation costs per KW increase rapidly. Mr. Hughes asserts that as Schedule SUS has only two rate bands for loads smaller than 10 MW (less than 5 MW and 5 MW to 10 MW), Schedule SUS does not accurately reflect those changing economies of scale. Noting that none of the potential cogenerators identified by GSU have demand requirements of less than 10 MW, Mr. Hughes suggests that Schedule SUS not be offered to customers with demand requirements falling below that level.

Although the examiner agrees with Mr.

Hughes' assertions regarding the rapid changes in economies of scale for cogeneration units of between 1 and 10 MW, and the inability of only two rate bands for loads smaller than 10 MW to reflect those changes as accurately as might be possible, the examiner does not recommend adoption of Mr. Hughes' recommendation that Schedule SUS not be offered to customers with demand requirements falling below 10 MW.

The primary reason for rejecting Mr. Hughes' recommendation is that limitation of the SUS rate to customers with demand levels in excess of 10 MW will not cure the failure of the below 10 MW SUS rate bands to track cogeneration costs at that level with total accuracy, nor will it eliminate the need for rate bands below 10 MW. Under Schedule SUS, the applicable SUS rate varies from month to month. The appropriate rate band applicable in any given month is a function of the customer's average demand for the billing period times the appropriate sizing factor, the sizing factor being in most instances the ratio of the customer's minimum peak demand for the prior year and the customer's average peak demand for the prior year. The wider the disparity between a customer's historical minimum peak demand and average peak demand, the lower the sizing factor for that customer. Consequently, under Schedule SUS, a customer with a low sizing factor may in fact have monthly minimum or average demand levels well in excess of 10,000 KW yet fall within the below 10,000 KW rate bands for billing purposes under Schedule SUS. Similarly, a customer with varying monthly demand levels may in any given month fall above or below the below 10,000 KW rate band levels depending upon the customer's average demand level for the month and the customer's sizing factor. Thus, limiting the applicability of Schedule SUS to customers with demand levels exceeding 10 MW does not really serve any purpose given that customers with demand levels in excess of 10 MW will still utilize the below 10 MW rate bands at various times.

GSU takes the position that the SUS rate

should be available to all LIS and LPS customers which meet the minimum process steam or thermal energy requirements established by the SUS rider, regardless of the size of the customer's electric load and that each customer should be permitted to make its own determination as to whether Schedule SUS would constitute a beneficial rate. Finding that there is no substantial justification for limiting the applicability of the SUS rate to customers with demand levels in excess of 10 MW, given that customers with demand levels well in excess of 10 MW will still utilize the below 10 MW rate bands, the examiner recommends that Mr. Hughes' proposal not be adopted.

With respect to Mr. Hughes' underlying concern regarding the accuracy of the below 10 MW rate bands, it appears to the examiner that even if cogeneration costs are not modeled as accurately as possible in that range, little if any harm can result from that fact, given Mr. Hamilton's testimony that, in that range, the SUS rates would be higher than GSU's standard rates under any scenario, and further given that Schedule SUS is a voluntary rate. It does not appear that the problem is severe enough to warrant creation of numerous additional rate bands to capture the rapid cost variations at the below 10 MW level, nor does the problem warrant rejection of the proposed tariff.

C. OPC's Statement of Position

OPC filed a statement of position in this docket which raises a number of issues which the examiner has not attempted to address in detail, for three reasons. First, the statement was not timely filed by OPC, having been filed substantially after the close of the hearing. At the hearing, the examiner committed to the issuance of an expedited report in this docket. The failure of OPC to raise the issues contained in the statement of position in a timely fashion has deprived the examiner of the time necessary to address each of OPC's arguments in detail in this report. Second, the un-

timely filing of the statement of position has similarly precluded general counsel and GSU from responding to the arguments raised therein. Third, as OPC did not make appearance at the hearing, OPC's arguments generally lack any evidentiary support. The statement of position is attached hereto as Examiner's Exhibit No. 3, in order that the Commission may be fully cognizant of OPC's arguments against Commission approval of Schedule SUS. However, based on the record in this docket, the examiner is not persuaded that any of the arguments raised merit disapproval of GSU's filing.

OPC argues that GSU's vulnerability to load loss is due to the company's inefficient generation costs, and that if significant disallowances occur in GSU's pending rate case, GSU's prospective rates will be within a close range of cogeneration costs, thereby making Schedule SUS unnecessary. However, the record reflects that there is a significant danger that GSU will experience load loss in the near future. As final Commission action in Docket No. 7195 will not occur for many months, and the bottom line of such Commission action is by no means predictable at this time, it appears that GSU's pursuit of this filing on an expedited basis to minimize the potential for load loss to cogeneration in the near term is a prudent course of action.

OPC asserts that GSU may be proposing this filing as a political tactic aimed at decreasing opposition to the inclusion of River Bend-related costs in GSU's rates. However, there is no evidentiary support for this contention and the examiner's opinion on that matter would constitute no more than rank speculation.

OPC argues that the filing is discriminatory, and therefore violates PURA Section 38. In support of this argument, OPC notes that Schedule SUS is not a cost based rate, that different industrial customers with identical load shapes will pay different rates if they have different ratios of steam to electricity requirements, or if each customer's absolute amount of steam and electrical load is different, and that use of GSU's WACOG

in combination with a hypothetical heat rate to calculate the energy charge will result in SUS customers paying less than the equivalent cost of service paid by other LIS customers. The examiner notes that each of these contentions is true.

[5] However, it is not unreasonable to offer incentive rates to certain industrial customers based upon their potential ability to cogenerate, where the facts demonstrate that failure to prevent those customers from cogenerating would cause substantial harm to GSU. The ability to cogenerate is in this instance a valid and reasonable basis for discriminating among industrial customers, for the reasons discussed earlier in this report. Further, if it is reasonable to offer incentive rates to customers based upon their ability to cogenerate, the question of whether the incentive rate is cost based or not would appear irrelevant to the discrimination issue. Finally, Schedule SUS establishes a consistent methodology for calculating the rates applicable to each SUS customer, based upon the costs which each customer would likely incur to cogenerate. SUS customers with different ratios of steam energy to electric energy or different amounts of steam and electric load will pay different rates under Schedule SUS, because those factors affect the size, configuration and cost of the cogeneration units which customers would install.

OPC argues that the SUS rate is anti-competitive and therefore in violation of PURA Sections 38 and 46. The examiner has discussed the Section 38 arguments earlier in this report. However, with respect to PURA Section 46, The examiner cannot determine the relevance of that section to an argument regarding anti-competitive conduct. The examiner assumes that OPC intended to reference PURA Section 47, which provides that a utility may not discriminate against any person or corporation that performs services in competition with the utility, nor may the utility engage in any practice that tends to restrict or impair such competition. OPC argues that, to the extent that cogenerators are in competition with the utility for the production of

electricity, the proposed rate constitutes predatory pricing. This argument is wholly without merit. First, a customer is not in competition with the utility until it actually chooses to cogenerate. Second, the offering of an inducement to a customer not to cogenerate does not in any fashion restrict or impair the ability of that customer to cogenerate should it desire to do so. Third, from the standpoint of current cogenerators, retention of load by the purchasing utility is probably beneficial because it increases the chance that the utility will experience some avoided capacity costs.

OPC argues that Schedule SUS is not just and reasonable because it contains no apparent protection against "tariff-hopping" by industrial customers. However, this assertion is incorrect. The service agreement amendment which an SUS customer must execute contains penalties for failure to provide at least one year's notice of intent to drop off Schedule SUS.

OPC argues that Schedule SUS presents difficult problems for the regulatory process in terms of verifying the steam/KWH needs of customers, and that the tariff is therefore an open invitation for the Company to select rates that are based upon GSU's perception of competitive threat regardless of the avoided cost of the customer. In response to this argument, the examiner can only note that any tariff is susceptible to misapplication if a utility has the intent to do so. However, any such action by GSU would directly violate PURA Section 46 and subject the utility and its personnel to civil penalties and possible criminal penalties, pursuant to the terms of PURA Sections 72 and 73.

OPC argues that this filing constitutes piecemeal ratemaking. While the examiner concedes that it would have been more efficient to address this filing in conjunction with the pending GSU rate case, it appears from the record that GSU's Schedule SUS proposal was not finalized at the time GSU's rate case was initiated. PURA does not prohibit a utility from pursuing multiple filings during the pendency of a rate proceeding. The examiner notes that the issue

of consolidation of this docket with GSU's pending rate case was raised by the examiner at the initial prehearing conference in this matter. GSU opposed consolidation on the basis that expedited consideration of the filing was urgently needed, the Commission's general counsel opposed consolidation, and representatives of Chevron U.S.A. and Mobil Chemical made protest statements urging that no consolidation occur. While there is some validity to the argument that multiple proceedings before the Commission are burdensome to the parties, this filing is not in the examiner's opinion violative of either PURA Section 42 or P.U.C. PROC. R. 21.69.

OPC argues that the energy charge for the SUS rate violates P.U.C. SUBST. R. 23.23(b)(2)(c) and PURA Sections 43(9)(1) and (2). For the reasons discussed previously in this report, the examiner finds this argument to be without merit. The examiner would note, however, that OPC did not file a brief on this issue as directed in the examiner's April 22, 1987, order.

In summary, although OPC has not fully developed the arguments contained in its statement of position, or supported those arguments with evidence, it appears to the examiner that none of the arguments presented are sufficiently probative to warrant rejection of GSU's filing.

V. Recommendation

Based upon the evidence of record, the examiner finds that there is an immediate danger that GSU will experience load loss to cogeneration in the near future unless GSU takes concrete steps to prevent that loss from occurring. The examiner finds that implementation of Schedule SUS will greatly assist in preventing the loss of future load to cogeneration. The mechanics of the tariff and the associated service agreement appear to the examiner to be reasonable and the examiner finds that there is no legal bar to approval of the tariff as filed.

The examiner further finds that, although

approval of the tariff will result in a loss of revenues to GSU, failure to approve the tariff will result in an even greater loss of revenues to GSU. As GSU's shareholders will bear the burden of all SUS related revenue losses, and as GSU will not seek recovery of any such losses in future rate proceedings, GSU's non-industrial ratepayers can be harmed by this filing only to the extent that the revenue losses negatively impact GSU's financial integrity. The examiner finds in that regard that the retention of industrial load through implementation of Schedule SUS will likely have less overall negative impact on GSU's financial integrity than will failure to approve schedule SUS.

The examiner therefore recommends that the Commission approve schedule SUS and the associated service agreement amendment, as filed, effective immediately upon the entry of a final order in this matter. However, the examiner further recommends that the Commission direct, by its final order in this matter, that no revenue losses associated with implementation of Schedule SUS may be recovered from GSU ratepayers in any future GSU rate proceeding.

VI. Findings of Fact and Conclusions of Law

The examiner further recommends adoption of the following findings of fact and conclusions of law:

A. Findings of Fact

1. Gulf States Utilities Company (GSU) is a public utility providing electrical service within its certificated service area, under Certificate of Convenience and Necessity No. 30076.

2. On December 31, 1986, GSU filed an application seeking authority to implement a proposed Schedule SUS Experimental Rider to Schedules LPS and LIS for Industrial Service to Qualifying Thermal Energy Users, and further seeking approval

of a proposed contract amendment to existing service agreements between GSU and customers electing to take power under Schedule SUS.

3. The effective date of the proposed tariff revision was suspended for 150 days until July 6, 1987, or superseding order of the Commission.

4. GSU mailed individual notice of this filing to all parties to Docket No. 7195 on February 20, 1987, as well as a corrected notice on March 20, 1987, as evidenced by the sworn affidavit of Linda Werner, legal stenographer for Donald M. Clements, Jr., Manager-Business and Regulatory Law for GSU. GSU published notice of the filing and of the pendency of this proceeding in thirty newspapers of general circulation within GSU's Texas service area, as evidenced by affidavits of publication on file with the Commission.

5. The Office of Public Utility Counsel (OPC) requested and was granted intervenor status in this docket.

6. A prehearing conference was conducted on February 2, 1987, and the hearing on the merits of GSU's request for both interim and permanent approval of its filing was conducted on April 13, 1987.

7. The hearing on the merits was conducted on April 13, 1987. OPC did not make appearance at the hearing.

8. Schedule SUS is a non-cost based incentive rate available to any LPS and LIS customer with a minimum process steam requirement of 10,000 pounds per hour or the thermal energy equivalent thereof.

9. Schedule SUS is designed to provide industrial customers having the potential to cogenerate with prices for power which are competitive with the power costs which the customers would experience if they chose to construct a cogeneration facility, thereby lessening the incentive for those customers to drop off GSU's system and engage in cogeneration.

10. GSU has lost 430 MW of industrial load to date to cogeneration and has identified 185 MW of additional load which is subject to loss due to cogeneration projects

which are in advanced engineering or planning stages.

11. GSU has approximately 1800 MW of industrial capacity which can potentially be served through cogeneration.

12. GSU's concerns regarding loss of industrial load to cogeneration are warranted.

13. Implementation of Schedule SUS will cause GSU to experience some loss of revenues, but failure to implement Schedule SUS will result in an even greater loss of revenues for GSU.

14. GSU will not experience an immediate revenue loss as a consequence of implementation of Schedule SUS because the SUS rate will not actually commence until the period of time deemed necessary for each SUS customer to construct a cogeneration facility has passed.

15. GSU intends that any revenue losses incurred by GSU as a consequence of adoption of Schedule SUS will be borne solely by GSU shareholders and will not be recovered in future rate proceedings.

16. Customers will be permitted to subscribe to Schedule SUS solely during the first twelve months following approval of the rate.

17. A qualifying customer must execute an amendment to its existing service agreement with GSU as a precondition to subscription to Schedule SUS.

18. The service agreement amendment requires a customer to extend its existing service agreement for a period of no less than three years and no more than ten years and provides penalties for termination of Schedule SUS with the provision of less than one year's advance notice.

19. Schedule SUS rates are based upon the economies of installing a gas turbine driven electric generator with a heat recovery steam generator and, in some instances, the further installation of an extraction turbine.

20. Schedule SUS rates will vary among customers because each customer has different levels of electric energy and different ratios of electric energy to steam energy which would necessitate installation of differing sizes and types of cogeneration

equipment with differing cost characteristics, were each customer actually to cogenerate.

21. The optimal size of the theoretical cogeneration facility which serves as the model for calculating a customer's monthly Schedule SUS rate is determined in part by the customer's monthly average peak demand and in part through the use of a sizing factor.

22. A customer's sizing factor, which is a function of a customer's minimum actual peak energy demand to average actual peak energy demand for the prior year, or in some instances the ratio of minimum steam demand to average steam demand for the prior year, is subject to periodic review and adjustment should the operating condition upon which the sizing factor is based materially change.

23. Schedule SUS assumes that for any given billing period the customer has constructed the optimal size cogeneration facility to serve the load experienced by the customer during that billing period.

24. A customer's average demand during each billing period is multiplied by the sizing factor to determine the size of the customer's load during the billing period which would be served by the cogeneration facility. All consumption above that level is billed at the otherwise applicable LIS or LPS rates.

25. The SUS rate is comprised of a demand charge and an energy charge.

26. The SUS demand charge, which is comprised of a rate per KW and a flat dollar charge, is designed to simulate the initial investment and periodic maintenance costs associated with construction of a cogeneration facility.

27. Schedule SUS has two separate demand schedules: one for customers with an average ratio of electrical energy to steam energy of 230 KWH/MLB or less per month and one for customers with ratios in excess of 230 KWH/MLB per month.

28. The SUS demand charge remains constant for three years and then increases by 1.5 percent each year thereafter to simulate the increased cost of operation and

maintenance associated with turbine wear and tear and periodic maintenance.

29. The SUS energy charge is a function of the heat rate of the theoretical cogeneration unit and GSU's weighted average cost of gas (WACOG).

30. GSU's WACOG is used solely as a representation of the likely natural gas price per MMBtu which a cogenerator would pay.

31. Schedule SUS specifies the use of particular heat rate values, depending upon the size of the customer's billing load and the customer's electric energy to steam energy ratio.

32. The customer's energy charge is calculated by multiplying the customer's total MWH of consumption for the billing period by the appropriate heat rate value and then again by GSU's WACOG.

33. A customer's initial heat rate will increase by 1.25 percent, 1.5 percent and 2 percent at the beginning of the second, third and fourth years, respectively, and then will be reset to the initial value for the fifth, ninth and thirteenth year of SUS billing in order to reflect the declining efficiency of a gas turbine overtime and the periodic refurbishing of a gas turbine after periodic maintenance.

34. Schedule SUS contains a minimum charge provision which provides that the combined total SUS demand and energy charges can never be less than the monthly KWH billable under SUS rates times GSU's system average fuel cost per KWH for the preceding month, plus 8 mills per KWH.

35. The SUS energy charge is not a fuel factor because it is designed to replicate the fuel costs which an SUS customer would have incurred had a customer constructed a cogeneration facility and is in no way designed to pass through to SUS customers the fuel costs which GSU incurs in providing service to those customers.

36. Although Schedule SUS contains no fuel factor, there is no commission requirement that a voluntary non-cost based incentive rate contain a fuel factor.

37. The SUS energy charge is not an automatic fuel adjustment clause within the meaning of PURA Section 43(g)(1) because

it does not constitute a cost based mechanism for rateably passing GSU's fuel costs through to SUS customers.

38. The structure of the SUS energy charge does not constitute a legal impediment to implementation of Schedule SUS.

39. Schedule SUS would cause no significant disadvantage to members of any non-industrial GSU rate classes.

40. Use of cogeneration potential as a basis for distinguishing among LIS and LPS customers is reasonable and works no unreasonable prejudice or disadvantage because any economic advantage to customers who qualify for service under Schedule SUS does not result because of the proposed tariff but rather, from the cogeneration alternative that is presently available to those customers.

41. So long as cogeneration is in fact a viable option for industrial customers taking service under Schedule SUS, and so long as the Schedule SUS rate reasonably approximates the cost of cogenerating electricity, the preference or advantage conferred to qualifying customers by Schedule SUS is justifiable.

42. GSU and its ratepayers are benefited by maintaining existing industrial load.

43. There is a serious danger that GSU's industrial load will shrink substantially.

44. The likely increase in LIS and LPS rates in the near future is a major economic factor contributing to the possibility of serious load loss.

45. Approval of Schedule SUS will increase the probability that load attributable to industrial customers who have the potential to cogenerate will be retained by GSU's system.

46. The discrimination inherent in the SUS rider is founded upon a substantial and reasonable ground of distinction.

47. Mr. Hughes' recommendation that SUS heat rates should apply only to customers with steam requirements close to 265 psig-411°F, and that a separate heat rate schedule should be prepared for customers with higher pressure and temperature requirements should not be adopted because his calculations fail to consider that supple-

mental firing would be used by many customers, resulting in heat rates within the range proposed by GSU.

48. The heat rates proposed by GSU do not reflect the need for a separate heat rate schedule for customers with high pressure and temperature steam requirements.

49. Mr. Hughes' recommendation that Schedule B rates not be approved should not be adopted because Schedule B rates appropriately model the higher capital costs and lower heat rates which would result from use of a combined cycle unit to meet electric energy and steam energy requirements exceeding 230 KWH/MLB.

50. Although use of a combined cycle unit is appropriate to meet the requirements of customers with electric to steam ratios exceeding 230 KW/MLB, Mr. Hughes failed to take the fact into consideration in formulating his recommendation.

51. The sizing factor proposed by GSU is reasonable because it affords flexibility for a customer's business to expand or contract, which is a benefit the customer would not have if it chose to cogenerate, yet it avoids the need for the SUS rate to compensate for a customer's sale of theoretical excess power to GSU when the customer's load level drops. The variable sizing factor thus benefits both GSU and the SUS customer without disadvantaging either.

52. Although both are reasonable, the sizing factor proposed by GSU is preferable to that proposed by Mr. Hughes, because Mr. Hughes' proposal would require substantial restructuring of the proposed SUS rate.

53. Mr. Hughes' recommendation that a minimum demand charge be contained in Schedule SUS should not be adopted because it is inextricably tied to Mr. Hughes' fixed-size generating unit proposal which the examiner has recommended not be approved.

54. Mr. Hughes' proposal to limit applicability of the SUS rate to customers with demand levels in excess of 10 MW should not be adopted because the recommendation fails to correct the lack of totally accurate cogeneration cost tracking in the 1 MW

to 10 MW rate bands contained in Schedule SUS.

55. The problem of inaccurate modeling of cogeneration costs within the 1 MW to 10 MW range is not serious enough to warrant creation of numerous additional rate bands to capture rapid cost variations at the below 10 MW level, nor does the problem warrant rejection of the proposed tariff.

56. The SUS rate should be available to all qualifying LIS and LPS customers regardless of the size of their electric load.

57. Schedule SUS does not hamper the ability of GSU's customers to cogenerate should they desire to do so and does not adversely affect current cogenerators.

58. The terms of Schedule SUS and the associated service agreement amendment are just and reasonable.

59. Schedule SUS and the associated service agreement amendment should be approved, as filed.

60. The Commission should require that any revenue losses associated with Schedule SUS not be recoverable in future GSU rate proceedings.

B. Conclusions of Law

1. Gulf States Utilities Company (GSU) is a public utility as defined in Section 3(c)(1) of the Public Utility Regulatory Act (the Act), Tex. Rev. Civ. Stat. Ann. art. 1446c (Vernon Supp. 1987).

2. The Commission has jurisdiction over the matters raised in GSU's filing pursuant to Sections 16(a), 17(e) and 37 of the Act.

3. Implementation of the proposed tariff revision was properly suspended for 150 days pursuant to P.U.C. SUBST. R. 23.24(i) and P.U.C. PROC. R. 21.4.

4. GSU has provided notice of this proceeding in substantial compliance with the notice requirements established by the examiner under authority of P.U.C. PROC. R. 21.25(a)(3).

5. The proposed Schedule SUS Experimental Rider is not unreasonably preferential, prejudicial or discriminatory, but rather is sufficient, equitable and consistent in application, within the intended meaning of Section 38 of the Act.

6. The proposed Schedule SUS Experimental Rider does not constitute an automatic adjustment or pass-through of fuel or other costs within the intended meaning of Section 43(g)(1) of the Act.

7. The Schedule SUS Experimental Rider is not in conflict with the requirements of P.U.C. SUBST. R. 23.23(b)(2)(c).

8. GSU's implementation of the Schedule SUS Experimental Rider does not constitute the grant of an unreasonable preference or advantage to any corporation or person within any classification, nor does it subject any corporation or person within any classification to any unreasonable prejudice or advantage. The filing therefore does not conflict with Section 45 of the Act.

9. Implementation of the Schedule SUS Experimental Rider will not work any discrimination against any person or corporation performing services in competition with a public utility nor will it tend to restrict or impair such competition, within the intended meaning of Section 47 of the Act.

10. The Schedule SUS Experimental Rider and associated service contract amendment are just and reasonable within the meaning of Section 38 of the Act and should be approved.

Respectfully submitted,

MARK W. SMITH
ADMINISTRATIVE LAW JUDGE

APPROVED on this 30th
day of April 1987.

ORDER

In public meeting at its offices in Austin, Texas, the Public Utility Commission of Texas finds that the above styled application was processed in accordance with applicable statutes by an administrative law judge who prepared and filed a report containing Findings of Fact and Conclusions of Law, as well as subsequent amendments

thereto, which Examiner's Report, as amended, is ADOPTED and made a part hereof.

The Commission further issues the following Order:

1. The application of Gulf States Utilities Company for approval of Schedule SUS Experimental Rider to Schedules LPS and LIS for Industrial Service to Qualifying Thermal Energy Users, and of an associated amendment to agreements for electric service is GRANTED as filed.

2. Gulf States Utilities Company's tariff sheets comprising the Schedule SUS Experimental Rider, which are attached to the Examiner's Report as Examiner's Exhibit No. 1, are hereby APPROVED effective the date this Order is signed.

[6] 3. Gulf States Utilities Company SHALL NOT seek the recovery of any revenue losses associated with implementation of the Schedule SUS Experimental Rider in any present or future rate proceeding before this Commission.

4. This Order is deemed effective upon the date of signing.

5. All motions, applications and requests for specific findings of fact and conclusions of law, if not expressly granted herein, are DENIED for want of merit.

PUBLIC COUNSEL'S STATEMENT OF POSITION

NOW COMES the Office of Public Utility Counsel (DPC) and files this Statement of Position in lieu of testimony and briefs which would have otherwise been submitted but for the fact that OPC was effectively precluded from participation in Docket No. 7309 because of inadequate notice and preoccupation with GSU's rate case, Docket No. 7195, which is where the issue of rate schedule SUS should be raised. OPC would show:

1. GSU's vulnerability to loss of load is due, for the most part, to the Company's inefficient generation costs. Potential cogenerators are aware of the expected rates when River Bend and the Cajun buyback

are recognized in GSU's rates. The need for the incentives cannot be determined *until* the Commission's actions with respect to River Bend and the buyback are known. If significant disallowances occur, then GSU's prospective rates will be within a close range of cogeneration costs. This would be likely to preclude the need for the SUS tariff. In light of the business risks of cogeneration for industrial customers, it is not necessary for the Commission's ratemaking treatment of River Bend and the buyback to result in rates equal to cogeneration costs, but rather the significant question is the magnitude of the variable between GSU's costs and cogeneration costs.¹ If GSU is engaging in the creation of tariffs as a political tactic aimed at decreasing opposition to the inclusion of River Bend-related costs in rates, the Commission should emphatically reject such an attempt.

2. OPC takes the position that the SUS tariff is discriminatory, and therefore in violation of Sec. 38, PURA. In support of this position, OPC would point out that:

a. the proposal has *no* cost-of-service basis. The rate is based (hypothetically) upon the customer's costs, not the utility's costs. Departure from the framework of the utility's cost of service represents a precedent with far-reaching implications. GSU would argue against any attempt to base its total revenue requirement upon the market price of electricity, and certainly would label such a recommendation as "changing the rules in the middle of the game." The same holds true for tariffs based upon customers' avoided costs.

b. Under GSU's proposal, LIS customers with identical load shapes will pay different rates for the same service if: (i) the customers have different ratios of steam to electricity requirements, or (ii) the absolute amount of steam/electrical load is different.

c. Use of WACOG and a hypothetical heat rate will result in SUS customers

paying less than the equivalent cost of service paid by other LIS customers.

3. OPC believes that the SUS rate is anticompetitive and therefore in violation of Secs. 38 and 46, PURA. In support of this position, OPC would point out that:

a. If SUS customers produce identical products using different processes, those customers will face different rates based upon the steam/kWh ratios for those processes. GSU would likely argue that this economic advantage exists regardless of the existence of the tariff. But, GSU fails to mention that it is the Company's own high-cost supplier's position that has created the economic condition. GSU's response is to discriminate against certain of its industrial customers who are less capable of exploiting the situation. Moreover, this argument ignores the probability that the tariff will create incentives for industrial customers to invest in processes which maximize the SUS discount that is available, to the detriment of GSU's other customers.

b. The SUS rate is systematically biased against small LIS/LPS customers, even if the customers use the same technology and have the same load shape as larger SUS customers. This creates anticompetitive barriers to market entry by increasing the minimum size of efficient entry as a competitor.

c. To the extent that cogenerators are in competition with the utility for the production of electricity, the proposed rate constitutes predatory pricing and is, therefore, inconsistent with Sec. 46, PURA.

4. The SUS tariff does not produce just and equitable results among customers and classes of customers. There is no apparent protection against "tariff-hopping" in which industrial customers shift back to rates based upon GSU's overall embedded cost, if and when those rates become competitive with cogeneration. It is fundamentally unfair to permit selected steam customers to avoid

the cost of GSU's solid fuel production plants if those customers can demand to take service from those plants at some future time when escalating gas prices make the solid fuels economic. The Company's testimony states an objective of reducing risks to the industrial customers without transferring those risks to other customers. (DEH-5) However, if industrial customers can choose gas-only tariffs whenever they like, it is clear that GSU's other customers are immunizing steam customers against the risk associated with reliance upon gas fuel.

5. The new tariff presents difficult problems for the regulatory process in terms of verifying the steam/kWh need of customers. This is an open invitation for the Company to select rates that are based upon GSU's perception of competitive threat regardless of the avoided cost of the customer.

6. The proposed rate constitutes piecemeal ratemaking and therefore contravenes the rate change provision of Sec. 43, PURA. This argument is even more significant in light of the *pending* full rate case (Docket 7195) in which GSU could have presented this tariff. A full rate case under Sec. 43 is intended to review all of the Company's rates and tariffs as well as all of the revenue effects pertaining thereto. DPC does not understand why GSU could not have filed this tariff change as a part of its rate case — particularly when GSU has been working on these tariff proposals for several years. GSU's separate tariff filing is a blatant attempt to evade the requirements of §21.69, *PUC Rules Prac. Proc.* (pertaining to Docket 7195), which states:

Any utility filing an application, petition, or statement of intent to change its rates in a major rate proceeding must file all of its evidence, including the prepared testimony of all of its witnesses and exhibits, on the same date that such application, petition, or statement of intent to change its rates is filed with the commission.

7. OPC's position is that the energy charge

for the SUS rate violates PUC Rule 23.23 (b)(2)(C), pertaining to the fuel factor; and it further violates Sec. 43(g)(1) and (g)(2), PURA, by permitting monthly fuel rate changes without a hearing. The Company suggests that a good cause exception should be applied to the fuel rule provision; however, the use of a "good cause" exception does not cure the conflict with Sec. 43(g) of the statute. OPC would note that an exception to average fuel pricing on the basis of "competitive" reasons has precedential implications for all electric utilities. CP&L previously attempted to obtain approval of a "steam user" tariff very similar to this one, only to withdraw it when faced with opposition from OPC and other parties on similar grounds as stated in this pleading. Certainly, other electric utilities affected by cogeneration and loss of load are watching this docket very carefully to determine the ease with which a good cause exception is available. In Docket 6765, the examiners overruled a request for a good cause exception requested by OPC and the Staff with regard to depreciation because of the potential for general application of the exception. The examiners stated:

Thus, while the general counsel and OPC argue a good cause exception, they are in reality requesting a major rule change which would become the norm rather than the exception. When such a change in policy has far reaching consequences for other utilities, the examiners believe it is more appropriate to proceed by rulemaking rather than by adjudicatory hearing to formulate policy. The examiners note that the Texas Appellate Court in *Deffenbach* recognized the usefulness of a rulemaking proceeding when the agency is faced with an action which would affect more than a limited group of persons.

E.R. at p. 263.

The Commission should apply its reason-

ing consistently and for that reason must reject a good cause exception here.

Finally, OPC's review does not indicate that GSU has previously plead for a good cause exception nor has GSU's witnesses presented evidence which explicitly addresses the question of a good cause exception. In particular, GSU has not presented evidence on the uniqueness of the circumstances it faces compared to other utilities, such as HL&P and CP&L.

Respectfully submitted,

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FOOTNOTES

¹GSU alleges that the rates must be implemented immediately to avoid cogenerators from leaving the system now. OPC suspects that any cogenerator that is willing to make irreversible cogeneration decisions now, without any knowledge of the future level of GSU's rates, would probably make the investment regardless of the existence of the SUS tariff.

language that governs the formation and operation of a gas district, and the control exercised by member municipalities, we conclude that Northwest Alabama is a municipality for the purposes of the NGA.

In reaching this conclusion, we have considered the Alabama Supreme Court's decision in *Town of Hackleburg v. Northwest Alabama Gas Dist.*, 170 So.2d 792 (Ala.1964), *aff'd on rehearing*, 170 So.2d 794 (Ala.1965). In that case, Hackleburg imposed a privilege tax on the gross receipts of business done in the town by Northwest Alabama. Despite Northwest Alabama's objections, the court held that the tax was valid as an excise tax on the privilege of operating a business within the town. While the court acknowledged that Northwest Alabama was a gas district organized by several municipalities, the holding did not turn on whether Northwest Alabama was a municipality.

There is adequate support in the record before us here for finding that Northwest Alabama is a municipality under the NGA. In addition, we note that, in 1965, the Alabama Legislature amended Alabama Code § 11-50-412 to provide, in part, that "[a]ll property and all income of any [gas] district incorporated under this article and any such district itself shall be exempt from all state, county, municipal and other taxation in the state of Alabama, including, without limitation, privilege and license taxation." Thus, it appears that the *Hackleburg* case has been superseded by subsequent legislation.

The Commission orders:

Northwest Alabama is determined to be a municipality under section 2(3) of the NGA, which makes it exempt from our jurisdiction.

Haleyville and Winfield. Each community is a municipal corporation organized under the laws of Alabama.

²Under the franchise agreements, Northwest Alabama is authorized to own and operate gas systems in the communities of Beaverton, Bear Creek, Detroit, Gu-Win, and Boston-Brilliant. See Northwest Alabama's filing in Docket No. ST81-194-000.

³The wholesale customers consist of the Towns of Carbon Hill, Double Springs, Phil Campbell, Fayette, Russellville, and Decatur. See Northwest Alabama's filing in Docket No. ST81-194-000.

⁴Northwest Alabama also sells up to 2,500 Mcf of surplus gas per day on an interruptible basis to Southern that it purchases from the Beaverton Field in Lamar County.

⁵Timely, unopposed motions to intervene are granted by operation of Rule 214.

⁶Sales and Transportation by Interstate Pipelines and Distributors, Expansion of Categories of Activities Authorized Under Blanket Certificates [Regulations Preambles 1982-1985] FERC Statutes and Regulations ¶ 30,477 (1983).

⁷Certain Transportation, Sales, and Assignments by Pipeline Companies Not Subject to Commission Jurisdiction Under Section 1(c) of the Natural Gas Act [Regulations Preambles 1977-1981] FERC Statutes and Regulations ¶ 30,118 (1980).

Re Iowa Public Service Company

Docket No. RPU-88-3 (TF-88-24)

Iowa Utilities Board
May 17, 1988

OPINION and order authorizing electric tariff containing discounted rates for customer engaged in farm equipment manufacturing upon agreement to forgo installation of cogeneration or self-generation facilities.

FOOTNOTES

¹The Alabama communities that banded together to form Northwest Alabama consist of the Towns of Guin, Hackleburg, Hamilton, and Sulligent, and the Cities of

1. DISCRIMINATION, § 45 — Rates — Customer classes — Generating capacity — Preference.

[IOWA] An electric rate discount granted to a customer engaged in farm equipment manufacturing upon the customer's agreement to forgo

installation of cogeneration or self-generation facilities was held not to constitute an unreasonable preference, especially because the discount would encourage the customer to continue to purchase electric distribution service from the electric utility, thereby preserving system load and spreading recovery of fixed costs.
p. 532.

2. COGENERATION, § 1 — Development — Deferral — Special rate contracts.

[IOWA] An electric rate contract was approved that would extend a rate discount to a customer engaged in farm equipment manufacturing upon the customer's agreement to forgo installation of cogeneration or self-generation facilities.
p. 532.

DECISION AND ORDER

APPEARANCES: ALEXIS K. WODTKE, Attorney, Consumer Advocate Division of the Department of Justice, Lucas State Office Building, Des Moines, Iowa 50319; STEVEN R. WEISS, Attorney, Iowa Public Service Company, PO Box 778, Sioux City, Iowa 51102; ELIZABETH SHAW, Attorney, Deere & Company, John Deere Road, Moline, Illinois 61265-8098.

Before Nagel, chairman, and Franzenburg and Boyd, commissioners.

By the COMMISSION:

PROCEDURAL HISTORY

On January 26, 1988, Iowa Public Service Company (IPS) filed a proposed rate, identified as TF-88-24, to be offered to Deere & Company (Deere). On February 25, 1988, the Iowa Utilities Board (Board) issued an order docketing the tariff and establishing a procedural schedule. In that order, the Board stated the proposed rate should be examined in a contested case proceeding to determine if the proposed rate creates an unreasonable preference for Deere, as prohibited by IOWA CODE § 476.5 (1987).

On March 4, 1988, Deere filed a petition to intervene, and on March 15, 1988, the Board granted intervention. On March 31, 1988, a hearing was held for the purpose of cross-examination of filed testimony. All parties have filed briefs.

DISCUSSION

IPS originally filed this proposed rate and a contract incorporating the proposed rate between Deere and IPS on December 7, 1987. The proposed tariff, identified as TF-87-414, was rejected by the Board on January 6, 1988. In the order rejecting the tariff, the Board stated the proposed tariff did not comply with IOWA ADMIN. CODE 199-20.10(4) (1988) because it was not cost based. The Board suggested IPS refile the tariff as a flexible rate, pursuant to IOWA ADMIN. CODE 199-14 (1988). On January 25, 1988, IPS refiled the proposed rate, identified as TF-88-24, with a cost-of-service analysis and other supporting documentation. IPS stated it was reluctant to file the proposed rate as a flexible rate, as defined in IOWA ADMIN. CODE 199-20.14 (1988), because of the newness of the rule and its "... limited application and interpretation ...". In addition, IPS indicated Deere has plans to develop its self-generation capacity and urged the Board to expedite its investigation of the proposed rate. In the February 25, 1988, order docketing the tariff, the Board agreed with IPS that there is no statutory requirement that the proposed rate be filed as a flexible rate. However, the Board stated IPS must establish compliance with IOWA CODE § 476.5 (1987) and demonstrate that the proposed rate does not grant an unreasonable preference nor subject anyone to an unreasonable prejudice or disadvantage.

IPS contends the proposed rate does not create an unreasonable preference or advantage because the proposed rate is designed to be comparable to the alternative cost Deere would incur if it self-generated. Thus, IPS argues, Deere's competitors cannot be unreasonably prejudiced by approval

of the proposed rate because Deere could self-generate at the same cost.

Deere states no person is subjected to an unreasonable prejudice or disadvantage by the proposed rate because IPS is not proposing to transfer any costs to other customers. If Deere self-generates, other customers would be burdened with additional annual costs of not less than \$246,198.

The Consumer Advocate Division of the Department of Justice (Consumer Advocate) states other customers are being asked to contribute the amount of the discount in a proposed adjustment in the pending rate case proceeding, Docket No. RPU-87-3. According to the Consumer Advocate, the proposed rate should be filed as a flexible rate, as defined in IOWA ADMIN. CODE 199-20.14 (1988).

[1, 2] The issue for the Board to decide in this proceeding is a very narrow one. The issue is whether the proposed rate grants Deere an unreasonable preference or advantage or subjects any person to an unreasonable prejudice or disadvantage, as proscribed by IOWA CODE § 476.5 (1987), which states, in part:

No public utility subject to rate regulation shall directly or indirectly charge a greater or less compensation for its services than that prescribed in its tariffs, and no such public utility shall make or grant any unreasonable preferences or advantages as to rates or services to any person or subject any person to any unreasonable prejudice or disadvantage.

The public policy considerations involved in this decision are the protection of those customers who do not have an alternative source of supply and, in addition, the furtherance of a positive business climate in the area.

The proposed rate does not grant an unreasonable preference or advantage to Deere. The record is clear that the proposed rate matches Deere's self-generation alternative. The proposed rate does not offer Deere anything in excess of the cost to

Deere to self-generate. Any advantage to Deere is not unreasonable.

Whether the proposed rate unreasonably disadvantages other IPS customers is another question. The cost-of-service study offered as evidence in this proceeding reveals there is some subsidization occurring with the current rate and the proposed rate. The critical consideration, however, is the certain adverse impact on IPS's other customers if Deere reduces its reliance on the IPS system. Deere has demonstrated that it has the ability to self-generate and will self-generate if the proposed rate is not approved. If Deere reduces its electric purchases from IPS, there will be a projected reduced recovery of fixed costs from \$250,000 to \$400,000. Pursuant to previous Board rulings, this amount of lost revenue would, in turn, be recouped from IPS's other customers. If the proposed rate does create a disadvantage to IPS's other customers, it is not an unreasonable disadvantage since they will not have to pay this additional revenue.

The Board will approve the proposed rate. The proposed rate does not grant an unreasonable preference or advantage, nor subject any person to any unreasonable prejudice or disadvantage. It is better to sell the excess capacity available on the IPS system than to deny IPS's proposed rate for Deere and force Deere to develop its own generation capacity. However, the Board will impose conditions to this approval. IPS must offer the discounted rate to certain other customers: 1) "directly competing customers" of Deere; and 2) customers which have the same load characteristics and have an ability to cogenerate. A "directly competing customer" is one that produces the same end product as Deere. Customers that produce component parts of the same end product should not be considered directly competing customers. There has been apparent confusion as to the definition of "directly competing customers" in Board rule 20.14. The Board will amend that rule to reflect a definition consistent with this order. Second, for rate case treatment purposes, IPS's test-year revenues will be adjusted to remove the effects of the discount

by assuming that all sales were made at full tariffed rates for the customer class. In that way, IPS will absorb all costs of the discount. Fifty percent (50%) of any identifiable increase in net revenues will be used to reduce rates for all customers. The remaining fifty percent (50%) of the identifiable increase in net revenues may be kept by IPS. The approval of the proposed rate will be effective for one year.

FINDINGS OF FACT

1. Deere & Company has the ability to self-generate.

2. The proposed rate, identified as TF-88-24, is equal to the cost to Deere & Company to generate its own power.

3. If Deere & Company were to reduce its reliance on Iowa Public Service Company's system, fixed costs of from \$250,000 to \$400,000 would be collected from IPS's other customers.

CONCLUSIONS OF LAW

1. The Utilities Board has jurisdiction over the parties and subject matter of this proceeding, pursuant to IOWA CODE §§ 476.1 and 476.3 (1987).

2. The proposed tariff, identified as TF-88-24, does not grant an unreasonable preference or advantage.

3. The proposed tariff, identified as TF-88-24, does not subject any person to an unreasonable prejudice or disadvantage.

IT IS THEREFORE ORDERED:

1. The proposed tariff, identified as TF-88-24, filed by Iowa Public Service Company on January 26, 1988, is approved, subject to the following conditions:

a. Iowa Public Service Company shall offer the discounted rate to those other customers indicated in the body of this order.

b. For rate case purposes, Iowa Public Service Company's test-year revenues shall

be adjusted to remove the effects of the discount by assuming that all sales were made at full tariffed rates for the customer class. Fifty percent (50%) of any identifiable increase in net revenues will be used to reduce rates for all customers. The remaining fifty percent (50%) of the identifiable increase in net revenues may be kept by Iowa Public Service Company.

2. The approval of the proposed tariff, identified as TF-88-24, will become effective immediately and the approval of the proposed tariff will be effective for one year, commencing with the date of this order.

Re Pay Telephone Access Lines

Docket No. RMU-87-18

Iowa Utilities Board
January 22, 1988

ORDER adopting regulations requiring local exchange telephone carriers to provide access service for coin-operated telephone terminals on equal terms and conditions as access service provided for business telephone service, to ensure competitive market entry for coin-operated telephones.

1. RATES, § 565 — Telephone rate design — Coin-operated terminals — Local exchange access.

[IOWA] Telephone utilities are required to provide facilities for interconnection of coin-operated telephones with the local exchange telephone network on the same basis as for business telephone service, to ensure competitive market entry for coin-operated telephones; telephone carriers whose rates are not regulated are also required to comply with the requirement in all respects, except as to pricing of access lines for coin-operated telephones.

p. 535.

Re Northern Indiana Public Service Company

Cause No. 38365

Indiana Utility Regulatory Commission
January 20, 1988

ORDER permitting an electric utility to offer rate discounts to industrial customers who agree to defer construction of planned cogeneration facilities.

1. RATES, § 321 — Electric rate design — Rate discounts — Discrimination — Customer eligibility — Threat of load loss — Anticogeneration rates.

[IND.] A proposed experimental tariff rider that would permit an electric utility to sell power at negotiated discount rates to certain customers that agree to defer on-site generation for five years and further agree to purchase all of their electric power requirements (except for that power which has historically been supplied by internal generation) from the utility during that five-year period was determined to be not unreasonably discriminatory as between customer classes or individual customers even though (1) eligibility for the discount rates would be restricted to those large industrial customers that have the capability to leave the utility system, and (2) eligible customers could negotiate differing rate discounts; the commission found that the threat of significant load loss was a legitimate consideration for determining eligibility for the discount rates, and that differences in the rates negotiated by those customers eligible for the discounts would result from reasonable considerations based upon the unique circumstances of the service provided to each.

p. 391.

2. COGENERATION, § 1 — Rate discounts for potential cogenerators — Anticogeneration rates — Deferral of construction of cogeneration facilities.

[IND.] Neither the Public Utility Regulatory Policies Act nor state laws governing the development of cogeneration prohibit a potential cogenerator and its utility from jointly planning the timing and capacity of a qualifying facility;

accordingly, a proposed experimental tariff rider that would permit an electric utility to sell power at negotiated discount rates to certain customers that agree to defer on-site generation for five years and further agree to purchase all of their electric power requirements (except for that power which has historically been supplied by internal generation) from the utility during that five-year period was found to be consistent with both PURPA and state law.

p. 395.

3. COGENERATION, § 1 — Rate discounts for potential cogenerators — Anticogeneration rates — Deferral of construction of cogeneration facilities.

[IND.] The commission approved a rate contract under which an electric utility agreed to supply power to an industrial customer at a discount rate in return for the customer's promise to defer the construction of a planned cogeneration facility and remain a customer of the utility; it was found that (1) absent the rate discount the customer would have left the utility system, thereby causing the utility to lose approximately \$4 million in annual revenues, and (2) revenues produced under the discount rate would make a substantial contribution to the fixed costs of the utility.

p. 400.

Before Duvall, chairman, Corban, Bailey, Zagrovich, and O'Lessker, commissioners, and Jones, administrative law judge.

By the COMMISSION:

On August 28, 1987, Northern Indiana Public Service Company ("Petitioner" or "NIPSCO") filed its verified Petition with the Commission requesting approval of its Generation Alternative Rider ("Rider GA") and a new electric service contract with R.R. Donnelley & Sons Company ("Donnelley") to be entered into under terms and conditions of Rider GA if Rider GA is approved. Concurrently with the filing of the Petition, Petitioner, Donnelley and the Office of Utility Consumer Counselor ("UCC" or "Public"), filed a Stipulation of Pre-filing Dates, Other Procedural Matters and Waiver of Prehearing Conference. On October 5,

1987, Bethlehem Steel Corporation ("Bethlehem") filed its Petition to Intervene, which was granted by docket entry on October 5, 1987.

Pursuant to notice of public hearing published as required by law, proof of which was incorporated into the record by reference, a public hearing in this Cause was held on November 12 and 13, 1987, in Room 907 of the State Office Building, Indianapolis, Indiana. At that hearing, evidence was presented by Petitioner, Donnelley, Intervenor Bethlehem Steel Corporation ("Bethlehem") and the Public. Intervenor Cogeneration Systems, Inc. did not appear at the hearing. The Commission has considered all of the evidence admitted into the record and the cross-examination of the witnesses in making the following findings.

Based upon applicable law and the evidence presented herein, the Commission now finds:

1. *Statutory Notice and Commission Jurisdiction.* Notice of the public hearing conducted by the Commission in this Cause was given and published as required by law. Petitioner is a public utility within the meaning of the Public Service Commission Act, as amended, and is subject to the jurisdiction of the Commission in the manner and to the extent provided by the laws of the State of Indiana, and the Commission has jurisdiction over Petitioner and the subject matter of this Cause.

2. *Petitioner's Characteristics.* Petitioner is a public utility incorporated under the laws of the State of Indiana operating electric properties and supplying electric energy to approximately 360,000 customers in 21 counties in northern Indiana. Petitioner has charter authority to engage in the business of supplying electric energy to the public in the area it serves in the State of Indiana.

3. *Relief Requested.* Petitioner requests approval of Rider GA and the proposed new electric service contract that Petitioner has entered into with Donnelley under Rider GA.

A. Rider GA. Exhibit A of Petitioner's

Petition filed August 28, 1987 (Petitioner's Exhibit 1-A) is a tariff for an experimental rider "available to customers who intend on installing on-site generation technology as an energy source and who agreed to postpone the installation and receive service" under Rate schedules 824, 825, 826, 832 and 833. Pursuant to Rider GA Petitioner will, under appropriate circumstances, agree to sell electric power at a negotiated, discounted rate to a customer which agrees to defer on-site generation for five years and further agrees to purchase all of its electric power requirements, except that which historically has been supplied by internal generation of the customer, from Petitioner during the five year contract period. The rider provides that:

(a) Each qualifying potential project must have a minimum capacity of 500 KW at each location.

(b) Maximum eligible capacity under Rider GA is limited to 300 MW, allocated on a first come, first served basis.

(c) Rider GA customers must be able to utilize the total electric output of the potential on-site generation facility for at least 4,500 hours per year.

(d) Rider GA contracts are to be for a five year term with no application for Rider GA service to be accepted after September 1992.

(e) A Rider GA contract customer will be required to show evidence of the viability and economics of potential on-site generation. On the acceptance of such evidence by NIPSCO Petitioner will negotiate with the customer the specific terms of the contract.

(f) Each proposed Rider GA contract must be submitted for IURC review and approval or rejection.

B. Donnelley Contract. Petitioner also requests approval of the proposed electric service contract to be entered into between Petitioner and Donnelley (Exhibit B to Petitioner's 1-A). Petitioner states that this is the standard form of contract entered into between Petitioner and most of its industrial customers and that most of the provisions are identical to those contained in the existing contract with Donnelley for electric service for Donnelley's printing plant in Warsaw, Indiana. The new provisions in the proposed contract and those pertinent to Petitioner's request for relief are set forth in the second, third and fourth paragraphs on page 2 of the contract under "Such special terms and conditions of service, if any, as are herein set forth, are made a part of this agreement." In consideration for Donnelley's deferring the installation and utilization of electrical generating equipment for the five year contract period, Petitioner agrees that it will bill Donnelley under the applicable rate schedule (currently rate 824) and will credit each month's billing by \$.02 per KWh billed but that such credit will be limited to the first 69,089,000 KWh billed annually. Thus, the maximum credit during a twelve month period will be \$1,381,780. In the event the customer does not use 69,089,000 KWh in any one year there shall be no credit carry over to a future year occasioned by such short fall in consumption. Additionally by reason of the customer making an initial payment to Petitioner of \$3,800,000, Petitioner will credit the customer's electric bill by \$63,333.34 each month for 60 months commencing with the first month of service under the contract. This provision returns to the customer its initial payment of \$3,800,000 without any interest or additional return. Finally at any time after the initial two years of the contract either party has the option of initiating negotiations for delivery of energy to the customer after the five year period of the contract.

4. Circumstances Prompting the Proposal of Rider GA. NIPSCO's witness, Mr. Joel A. Nieting, Petitioner's Director of Rates, testified that Rider GA was developed because certain of Petitioner's industrial customers are seriously considering the installation of on-site generation capacity to meet all or a substantial portion of the respective electric loads currently served by Petitioner. (Petitioner's Exhibit 1, page 2) He testified that loss of these loads would cause a reduction in Petitioner's revenue which would ultimately cause additional rate increases for the remaining ratepayers. Further the loss of such customers who are generally high load factor customers would impact adversely the operating characteristics of Petitioner's system. He testified that Petitioner currently has and will in the future have sufficient generating capacity to meet its projected loads and that installation of on-site generation capacity in the near term would constitute a needless duplication of facilities and decreased utilization of Petitioner's system. He also testified that NIPSCO might be required to purchase electricity from those on-site generation projects which are "qualified facilities" at times when NIPSCO does not need such electricity and when it would not be in the best interest of its ratepayers to do so.

Mr. Nieting testified that the purpose of Rider GA is essentially four-fold: (1) Deferral of additional on-site generation capacity within NIPSCO's service territory until additional generating capacity is required; (2) Retention of industrial customers which have the potential of installing on-site generation capacity so that such customers continue sharing in the system costs; (3) Provision of an alternative in the decision making process for potential on-site generation customers; and (4) Realization by such customers of a portion of the benefits of on-site generation capacity during the period in which on-site generation is deferred.

Mr. Nieting explained that Rider GA will allow NIPSCO sufficient pricing flexibility to negotiate retention of electric loads which might otherwise be replaced by on-site generation projects. He stated that NIPSCO would accept revenues that were more than sufficient to cover incremental production costs but lower than full retail rates. In answer to a question he testified that incremental costs (essentially variable costs i.e. average fuel cost plus variable operating and maintenance expenses) were in the range of 2.5¢ to 2.7¢ per KWh. He also testified that it was not NIPSCO's intent to discourage cogeneration and other alternate energy supplies but to defer such supplies until the NIPSCO system needs additional capacity.

When questioned about the potential loss of customers Mr. Nieting testified that NIPSCO had lost customers in all classes in the past and that in subsequent rate cases fixed costs had been reallocated to other customers to make up for the lost revenue.

On cross-examination Mr. Nieting also testified regarding the magnitude of potential load loss from present customers installing internal generation or adding to present facilities. He stated that he had talked to Rollcoater, Abitibi and Inland Steel. The first two customers represent potential projects larger than 500 KW but less than 10 MW. He estimated that the Inland Steel project might be in the range of 80 to 130 MW. He also stated that projects which had very favorable economics (ones which had cost even less than NIPSCO's incremental cost) would probably result in load loss in any case. In reply to Intervenor Bethlehem's contention that Inland Steel had a long term contract with NIPSCO and therefore could not utilize Rider GA, Mr. Nieting stated that Inland's contract required payment of the demand charge for 75% of contracted demand and no energy charge if it reduced its NIPSCO load. Under these conditions, he said installation and operation of added cogeneration capacity might still be economic.

Mr. Nieting stated on rebuttal that NIPSCO had asked for and had received

approval of economic development type rates to deal with load loss but this was primarily to obtain customers or secure new load to utilize existing capacity reserves. The Donnelley project and similar situations were different than normal load loss in his opinion because the customer's facility would still be in NIPSCO's territory but the facility would no longer be a customer.

5. *Evidence of Bethlehem and the Public.* Mr. Michael L. Brosch, Principal in the firm of Dittmer, Brosch & Associates, testified for the Office of the Utility Consumer Counselor. Mr. Brosch did not deal specifically with the potential for or the magnitude of load loss but did support the concept of flexible rates because as he stated on page 16 of Public's Exhibit No. 1, the deferral of self-generation projects to prevent unnecessary duplication of generation facilities is a valid consideration. He recommended that assuming the Commission is legally empowered to do so, it should approve the concept of flexible pricing where competition can replace the role of regulation. Mr. Brosch did warn that "the Commission should act to ensure that economic self-generation by a utility's customer is not discouraged." (Public's Exhibit No. 1, page 13) He defined economic self-generation as a project that produces power at less than the utility's marginal cost. However he also recommended that Rider GA only be approved if certain conditions were satisfied, including specific changes in the future pricing of firm service provided to customers that self-generate or contract for service under Rider GA and later wish firm service from Petitioner. Mr. Brosch also testified on what he felt was proper future ratemaking treatment of Rider GA discounts negotiated by NIPSCO. He recognized that Rider GA was a departure from traditional cost of service, rate of return regulation but believed it was necessary to depart from traditional treatment because

of the potential adverse affects on other ratepayers.

Mr. Richard J. Rudden, President of R.J. Rudden & Associates, Inc., testified for Intervenor Bethlehem Steel. Mr. Rudden recommended that the Commission reject Rider GA because the proposed Rider does not address what he felt was the real problem, NIPSCO's industrial rates which are very high relative to market prices; the exposure to a risk of higher long-term costs for NIPSCO ratepayers as a result of Rider GA; the failure to demonstrate a real threat of load loss; the discriminatory and non-cost based nature of Rider GA; and the failure to consider other alternatives to solving the problem of high rates.

In support of his contention that the real problem are the high industrial rates on the NIPSCO system, he testified the cost of electricity at Bethlehem Burns Harbor Plant is between 27% and 85% higher than the costs of electricity at its other plants across the country. Upon cross-examination Mr. Rudden did say that Burns Harbor used other energy forms in addition to electricity (including natural gas purchased from NIPSCO) but he did not know the relative total energy costs at Burns Harbor compared to other Bethlehem plants. Subject to check, he also accepted that in the last six months Bethlehem produced internally 71% to 80% of all its needs for electricity.

Mr. Rudden contended that Rider GA is discriminatory because it does not meet the statutory and judicial requirements as being a "different service" provided to a customer or class of customers under different conditions than service provided to other customers for a different rate. He stated that a customer with a thermal load which made cogeneration feasible might be eligible for Rider GA but one which had no thermal load would not be eligible. As a result, the two customers could be paying a different amount for service even though their electrical load profiles were identical. Further he contended that Rider GA contained no objective standards by which to judge the feasibility of deferred on-site generation project and/or to determine the appropri-

ate discount for such deferral. In addition he suggested as an alternative to NIPSCO's proposal a "split the savings" approach to encourage more sales to customers with existing cogeneration and other on-site facilities.

Dr. Albert Chang, Assistant Chief - Technical Section, Economics and Finance Division of the Commission testified in his staff report (Public's Exhibit No. 3) that theoretically cogeneration facilities constructed in NIPSCO's territory could in the long run defer the need for new capacity. However he agreed with the other witnesses that NIPSCO presently has excess generating capacity. Further he stated that NIPSCO had no new capacity planned in the period during which the Rider GA would be in effect and as a result additional cogeneration facilities would not defer any NIPSCO construction and that consequently deferral of construction and coordination of the addition of cogeneration facilities would produce greater benefits than current construction of cogeneration.

Mr. Jeffrey R. Bailey, Assistant Chief Engineer, Engineering Division of the Commission stated in his report (Public's Exhibit No. 2) that there was little doubt that cogeneration would benefit NIPSCO's system in the long run but at this time when NIPSCO has plentiful capacity, lost load would adversely affect its efficiency of operations as well as its cash flow. He opined that rejection of proposed Rider GA puts the ratepayers in NIPSCO under a considerable amount of short-term risk. He estimated that a load loss of 100 KW from on-site generation could reduce NIPSCO's gross operating profit \$22,000,000 per year, a potential increase in costs assigned to other ratepayers.

From the evidence it seems clear that Petitioner has sufficient capacity to meet the needs of all of its existing customers and that loss of existing customers such as Donnelley could have an immediate adverse impact on NIPSCO and ultimately could transfer more costs to the remaining customers. Therefore we find that methods to

retain existing load are appropriate to consider.

6. *Discriminatory Rates and Rider GA.* Witnesses appearing on behalf of the Public and Intervenor Bethlehem expressed concern about a perceived discriminatory effect Rider GA could have upon NIPSCO's customers if the rate is approved. Staff witness Dr. Albert Chang indicated that the proposed rider, if approved, should not cause NIPSCO ratepayers to absorb the associated revenue loss, indicating that I.C. 8-1-2-44 and I.C. 8-1-2-103 may operate to prevent such subsidization of Rider GA customers by the remaining customer classes. (Public's Exhibit No. 3, page 8). The Public's witness Mr. Michael Brosch also expressed this concern (Public's Exhibit No. 1, page 12). Intervenor Bethlehem's witness Mr. Rudden identified several aspects to the proposed rate which, in Mr. Rudden's opinion, render it discriminatory. First, Mr. Rudden notes that NIPSCO does not propose to offer similar types of discounts to customers who may be considering other non-generating alternatives, such as conservation investments, load management, gas fired heating and air conditioning, and similar items. Second, the Rider is not available to potential cogeneration plants which would operate for less than the equivalent of 4,500 hours of minimum capability per year. Also, each customer seeking to negotiate a discount under Rider GA would be in a different bargaining position than the others. Each, would therefore, exert different economic and other pressures on NIPSCO and thereby achieve different Rider GA discounts. Finally, Mr. Rudden indicated that two customers could have very similar electric load profiles, and therefore would impose the same costs on the NIPSCO system. Yet, if one customer had a thermal load that made cogeneration feasible, and the other did not, the customer with the thermal load would be eligible for

service under Rider GA and the other would not.

Three closely related statutes pertain to the proper regulatory treatment of discriminatory rates. I.C. 8-1-2-103, states, in pertinent part, that:

No public utility, ... as defined in this chapter, may charge, demand, collect, or receive from any person a greater or less compensation for any service rendered or to be rendered, or for any service in connection therewith, than that prescribed in the published schedules or tariffs then enforced or established as provided herein, or than it charges, demands, collects or receives from any other person for like and contemporaneous service.

I.C. 8-1-2-68(a) provides:

Whenever, upon an investigation, the Commission shall find any rates, tolls, charges, schedules or joint rate or rates, to be unjust, unreasonable, insufficient or unjustly discriminatory, or to be preferential or otherwise in violation of any of the provisions of this Act, the Commission shall determine and by order fix just and reasonable rates, tolls, charges, schedules or joint rates to be imposed, observed and followed in the future. In lieu of those found to be unjust, unreasonable, insufficient or unjustly discriminatory or preferential or otherwise in violation of any of the provisions of this Act.

On the other hand, I.C. 8-1-2-46 provides that:

The commission shall provide for a comprehensive classification of such service for each public utility and such classification may take into account the quantity used, the time when used, the purpose for which used and other reasonable consideration. Each public utility is required to conform its schedule of rates, tolls, and charges to such classification.

On the same subject, but with more specificity, I.C. 8-1-2-24 provides:

Nothing in this Act shall be taken to prohibit a public utility from entering into any reasonable arrangement with its customers or consumers, or with its employees, with any municipality in which any of its property is located, for the division or distribution of its surplus profits, or providing for a sliding scale of charges or other financial device that may be practicable and advantageous to the parties interested. No such arrangement or device shall be lawful until it shall be found by the Commission, after investigation, to be reasonable and just and not inconsistent with the purpose of this Act. Such arrangement shall be under the supervision and regulation of the Commission.

Finally, I.C. 8-1-2-25 provides that:

The commission shall ascertain, determine and order such rates, charges and regulations as may be necessary to give effect to such arrangement, but the right and power to make such other and further changes in rates, charges and regulations as the commission may ascertain and determine to be necessary and reasonable, and the right to revoke its approval and amend or rescind all orders relative thereto, is reserved and vested in the commission, notwithstanding any such arrangement and mutual agreement.

Intervenor and the Public have expressed concerns about conflicts between the design of Rider GA and I.C. 8-1-2-68 and 103. However, statutes pertaining to the same subject matter must be read together, as they are in *pari materia* *Schrenker v. Clifford*, — Ind. —, 387 N.E.2d 59 (1979), *Woodring v. McCaslin*, 183 Ind. 134, 104 N.E.2d 759 (1914). A single statute which is part of a related group should not be read in isolation. *Holland v. King*, — Ind.App. —, 500 N.E.2d 1229 (1986), *Park*

100 Development Co. v. Indiana Dept. of State Revenue, — Ind. —, 429 N.E.2d 220 (1981). For example, I.C. 8-1-2-68 and 103 place restrictions on rate design which would raise concerns about unlawful discrimination in certain instances, but for a further reading of the related provisions found at I.C. 8-1-2-24, 25 and 46, which permit certain types of differences in rates. We will, therefore, review proposed Rider GA for unlawful discrimination while keeping in mind all of the related statutes, consistent with the authorities cited above.

[1] The Public and Intervenor Bethlehem have identified two levels of discrimination which may result if Rider GA is approved. First, the rates might be discriminatory as between those customers qualifying for the rate and those who do not, contrary to I.C. 8-1-2-68 and 103. Second, Intervenor Bethlehem notes that customers qualifying for the Rider could negotiate different rates, resulting in discrimination between qualifying customers as well.

As noted above, Public's witnesses Dr. Chang and Mr. Brosch expressed concern that to the extent the proposed Rider is not cost-based, it could have a discriminatory impact between customer classes. Petitioner's witness Mr. Nieting testified that the rate has been designed to recover the variable cost associated with customer service, as well as a portion of NIPSCO's embedded costs. Thus, to the extent a negotiated rate under Rider GA would not recover NIPSCO's fully embedded costs, it is not "cost-based" in the traditional sense in which that term is typically employed. However, because the rate is based upon the goal of retaining certain industrial customers and some recovery of NIPSCO's embedded cost, it is cost-related, and certainly not arbitrarily derived. As a matter of regulatory policy, we try to adhere to cost of service principles. However, Indiana law prohibiting rate discrimination does not prohibit utilities from earning more or less profit from different classes of customers. See I.C. 8-1-2-24, 25 and 46. Thus, the fact that NIPSCO's cost recovery under Rider GA would be less than under other indus-

trial rate schedules does not make Rider GA discriminatory. It is reasonable, however, to investigate the impact upon the various classes of NIPSCO's customers, and NIPSCO's shareholders of recovery of less than fully embedded cost under Rider GA. These are policy considerations which are discussed in a separate finding, as failure to fully recover embedded costs, does not in and of itself make a rate discriminatory and thus inappropriate as a matter of law.

Intervenor Bethlehem's witness Richard Rudden expressed additional concerns that the proposed Rider would discriminate between customer classes. Mr. Rudden observes that NIPSCO does not propose to offer the Rider to customers who may be considering other non-generating alternatives, such as conservation investments, load management, gas-fired heating and air-conditioning and similar items. In addition, Mr. Rudden observes that the Rider is not available to potential cogeneration plants that would operate for less than the equivalent of 4,500 hours of minimum capability per year. Finally, if one customer had a thermal load that made cogeneration feasible and the other did not, the customer with the thermal load would be eligible for service under Rider GA and the other would not, even though the electrical load profiles, and therefore the costs of service, were identical for the two.

Within the statutory framework concerning discriminatory rates, customers may be charged different rates if they receive different service under different conditions or circumstances. Because a great variety of circumstances or conditions may exist in a utility's customer base, discretion must be exercised in setting the lines between customer classes. Thus, while I.C. 8-1-2-103 prohibits charging different rates for the same services under the same conditions, I.C. 8-1-2-68 permits reasonable differences in rates, not in violation of I.C. 8-1-2-103, I.C. 8-1-2-24 provides for any reasonable arrangement between a utility, its customers, employees or any municipality in which its property is located, for the division or distribution of its surplus profits, or for the

provision of a sliding scale of charges or other financial device that may be practicable and advantageous to the parties interested and I.C. 8-1-2-46 provides that the Commission shall provide for classifications which may take into account the quantity used, the time when used, the purpose for which used, and any other reasonable consideration. The Commission has been given great latitude in balancing the interests of the various parties when drawing lines between customer classes, and the Court of Appeals of Indiana has given deference to this Commission's expertise in making this determination of the reasonableness of rate discrimination. *Capital Improv. Board v. Indiana Pub. Service Commission*, — Ind.App. —, 375 N.E.2d 616, 633 (1978).

Intervenor Bethlehem's witness Rudden considers as one class all customers who may be contemplating alternatives to purchase of their full load requirements through firm rates, whether through conservation, load management, or other devices. Considering such a broad customer class, and assuming that conditions and circumstances of service to this broad class is substantially similar for all of its members, Mr. Rudden concludes that the rate is discriminatory because it does not encompass all the members of his chosen customer class. However, Petitioner has not focused on such a broad group. Petitioner's witness Mr. Nieting testified that the purpose of the Rider is to prevent loss of existing industrial customers due to the installation of on-site generation capacity. The loss of such customers, who are generally high load factor customers, Mr. Nieting testified, would impact adversely the operating characteristics of NIPSCO's system, would constitute a needless duplication of facilities, and a decrease in utilization of NIPSCO's system and ultimately cause additional rate increases for the remaining ratepayers. (Petitioner's Exhibit No. 1, page 2).

The Commission recognizes that load loss is not a new phenomenon. We assume, and Petitioner's witness Mr. Nieting agreed upon cross-examination, the size of Petitioner's various classes is variable as members enter

and leave the system for a variety of reasons. Just as industrial customers may consider various forms of on-site generation, Petitioner's residential customers may consider various forms of home heating. It is evident that Petitioner's concern in proposing Rider GA is to reduce the significant load losses presented by industrial on-site generation by its existing customers at a time when additional capacity is not needed. We find this threatened load-loss to be a legitimate concern of the type contemplated by I.C. 8-1-2-24, 25 and 46, and thus an appropriate distinction in determining customer classes. We note that the proposed Rider does not discriminate between the various forms of on-site generation. One existing customer may consider a means of on-site generation in which all of the resulting electricity would be used by that customer. Another may contemplate a form of on-site generation which would qualify as a cogeneration facility under Federal and State laws, including this Commission's rules. Both would qualify for Rider GA if they meet other conditions. The "other conditions" reasonably distinguish between those customers who fall within the group which can exercise considerable market power in selecting energy sources and those who cannot. While a homeowner selecting solar heating and going off Petitioner's system would represent exercise of some market power and resulting loss to Petitioner, Petitioner chooses to limit the applicability of Rider GA to those customers requiring at least 500 KW and full use of its on-site generating capacity for at least 4,500 hours per year, thereby targeting those customers having significantly large load factors. As Mr. Rudden observes, conservation efforts would not qualify a customer for Rider GA. However, while conservation efforts can provide economies to the customers, they do not defer cogeneration units or on-site generation, which is a purpose of Rider GA. Further, the impact of conservation is much less quantifiable than construction of on-site generation, thus rendering conservation a vague basis upon which to draw a customer class line.

Rider GA is somewhat remedial in nature as it is designed to defer on-site industrial generation at a time when NIPSCO's system has excess capacity. It is clear that in the absence of Rider GA, on-site generation would be constructed resulting in unnecessarily duplicative expenditure of resources for a period of time. As designed, the risk of loss produced by Rider GA is placed on NIPSCO's shareholders from date of the approval of the rider to NIPSCO's next general rate proceeding. It is only reasonable for Petitioner to limit this risk by narrowing the class to large industrial customers having the capability of leaving the system.

With these concerns in mind, we turn to Bethlehem's argument that Rider GA would unlawfully discriminate between these customers having high thermal load factors and those who do not. The classic inquiry as to whether a circumstance constitutes discrimination involves a consideration of whether the act or practice under scrutiny would purport to treat those similarly situated in a similar fashion. If those similarly situated are treated in a dissimilar fashion, the act or practice may then be discriminatory. This consideration is often before the Commission in the area of utility ratemaking and rate design. Certainly the physical and technological capabilities of a customer for electricity are taken into account when determining rate classifications. The energy user whose business and facilities require a 10 MW load with a high load factor is treated differently and will pay a different amount per Kwh than that customer whose requirements amount to only 10,000 Kwh per month. Further, customers who have the ability to utilize off-peak and interruptible service are treated differently and pay a different amount for their electricity from those customers whose physical requirements and technology do not allow for such load characteristics. We do not consider these differentiations to be discriminatory in nature because these rate classifications are open to all such similarly situated customers. The inquiry at hand as to whether the proposed Rate GA constitutes discrimi-

natory treatment of customers without thermal load characteristics is similar in nature to the type of inquiries outlined above. NIPSCO has defined the requirements for its Rate GA to make that rate available only to those customers whose physical and technological characteristics are such that their existing thermal load would make economically feasible self-generation. Rate GA would be available to any such customers similarly situated. Assuming the policy considerations for the design of a rate classification are determined to be appropriate by this Commission, the inquiry then is limited to whether all potential customers coming within that definition may avail themselves of the rate. Certainly the customer using 10,000 Kwh per month as firm service would rather pay the same price per kilowatt hour as a customer provided 10 MW of interruptible service. The fact that the 10,000 Kwh per month customers physical and technological load characteristics are dissimilar from those of the 10 MW customer does not make differing prices per kilowatt hour discriminatory. The fact that a customer has a thermal load which would make self-generation economically feasible and pose a threat to NIPSCO's load makes that customer dissimilar from one with the same load characteristics but no thermal load. Therefore, to offer customers with dissimilar characteristics differing rates does not mean that discrimination exists.

Thus, we disagree with Bethlehem's witness Rudden when he infers that the proposed rate is discriminatory between those customers having thermal loads and those who do not. While the dollar cost of service for both customers could be the same, Mr. Rudden has failed to note that the conditions and circumstances of service to the two are dissimilar. In one case, Petitioner is faced with competition and the attendant loss of market power, producing ramifications which may impact all of its customer classes, as well as investors, while in the other case, this element is not present due to technical and physical realities discussed above. Other states have recognized the threat of load loss as a circumstance which

may be considered in defining customer classes. See, for example, *Re Arkansas Power & Light Co.*, 83 PUR4th 12 (Ark.P.S.C.1987) and *Re Incentive Rates for Electric Service*, 82 PUR4th 624 (Or.P.U.C.1987), *Re Pacific Gas & E. Co.*, Resolution E-3017, Jan. 28, 1987 (Cal.P.U.C.); *Re Pacific Gas & E. Co.*, Resolution E-3021, March 25, 1987 (Cal.P.U.C.); *Re Kansas Gas & E. Co.*, Docket No. 86-KGE-273, Sept. 30, 1986 (Kan.S.C.C.); *Re Kansas Gas & E. Co.*, Docket No. 85-KGE-495, Feb. 10, 1986 (Kan.S.C.C.); *Re Arizona Pub. Service Co.*, Decision 55696, Aug. 31, 1987 (Ariz.C.C.); *Re Gulf States Utilities Co.*, Docket No. 7309, May 13, 1987 (Tex.P.U.C.); *Re Pacific Power & Light Co.*, Order No. 87-183, Feb. 12, 1987 (Or.P.U.C.). Based upon the foregoing, we conclude that the proposed Rider GA is not discriminatory between Petitioner's customer classes. Therefore, the proposed Rider GA is certainly not "unreasonably discriminatory" within the meaning of the statute.

As noted earlier, the proposed Rider GA is negotiable, and so NIPSCO's customers qualifying would not necessarily each receive the same rate. Bethlehem's witness Rudden testified that such discrimination between customers within the proposed class renders the rate unduly discriminatory, and hence illegal. We perceive two factors which provide motivation for a negotiable rate. First, and obviously, since NIPSCO's shareholders bear the burden of loss resulting from a successfully negotiated rate under Rider GA, it follows that NIPSCO's management would want to minimize its shareholders exposure to such risk. On the other hand, the economics of each individual cogeneration or other on-site generation project will dictate the market power which each respective industrial customer may bring to bear in negotiations. A set rate would thus attract certain of NIPSCO's industrial customers, while others would leave the system. By creating a margin within which a rate may be negotiated, more customers would stay on the system, while providing NIPSCO with an opportunity to reduce the loss to its shareholders to the extent practicable given the relative econo-

ies of the proposed cogeneration or other on-site generation system. While it is acknowledged that Mr. Rudden is correct in stating that this is a discriminatory pricing scheme, the Commission observes that it is responsive to the specific facts which each unique customer may be able to present and hence not unreasonably discriminatory. As Mr. Nieting noted, testifying on behalf of NIPSCO, some generating systems will be so economic as to render Rider GA inappropriate. By providing a margin within which a rate may be negotiated, NIPSCO proposes to balance the risk to its shareholders with the efficiencies and economies of the proposed on-site generation projects which it anticipates its customers will develop. The Commission finds that these considerations provide reasonable guides for pricing. While each customer would presumably receive a different rate, the Commission finds that those differing rates would result from reasonable considerations based upon the unique circumstances of service provided to each large industrial customer considering the economies of on-site generation. The resulting rates negotiated under Rider GA differ from each other in a manner which benefits all of the parties concerned by balancing the interests of the customer, the ratepayers as a whole, and NIPSCO's shareholders in a manner consistent with the provisions of I.C. 8-1-2-24, 25 and 46. We therefore find that the proposed Rider GA is not unreasonably discriminatory as between members of the proposed customer class.

7. Rider GA and the Encouragement of Cogeneration. Several witnesses expressed concern that deferral of cogeneration projects by mechanisms such as the proposed Rider GA conflicted with the National goals of the Public Utility Regulatory Policies Act ("PURPA") and that the result might be cancellation rather than simply deferral. Bethlehem's witness, Mr. Rudden, contended that deferral of economic cogeneration projects could result in discouraging development because management momentum is lost when projects are deferred since cogeneration is a major philosophical de-

parture from the normal business of the potential cogenerator, because project stops and starts tend to increase project costs and because the capital funds currently available for cogeneration may not be available at some future date. He contended that the addition of cogeneration facilities was a benefit to the NIPSCO system and that because deferral might well mean cancellation such deferral could result in higher long run costs for NIPSCO customers.

Public's witness, Dr. Chang, stressed that both federal and state law encouraged the development of cogeneration and small power facilities and he questioned whether deferral, even though voluntary, was consistent with the laws and this Commission's regulations. On the other hand, Public's witness, Mr. Brosch, testifying on a flexible pricing proposal, which is discussed *infra*, testified that the threat of a higher than standard demand charge could discourage abandonment of existing self-generation and encourage completion of cogeneration plans. Donnelley's witness, Mr. Kispert, testified that Donnelley was willing to enter into the agreement with NIPSCO despite the potential for greater savings if Donnelley were to proceed with its project. He acknowledged that there would be less risk for Donnelley in accepting the savings under the NIPSCO proposal but he also indicated that Donnelley had evaluated the savings from the cogeneration project on a twelve year life but really thought that twenty years of operation was more reasonable. He indicated that if Rider GA were not approved Donnelley would proceed with the project. Petitioner's witness, Mr. Nieting, also testified that it was not NIPSCO's intention to discourage cogeneration because they did realize the future benefits of customer-owned facilities. However he also pointed out that arrangements such as Rider GA give NIPSCO the flexibility to "correct" its resource plan if in fact another unit was required sooner or later than their present estimate.

[2] A review of the statutes and regulations cited by Dr. Chang does indicate a need to encourage cogeneration. This Com-

mission has established procedures for determining avoided cost rates and for standard energy and capacity repurchase contracts in an effort to encourage cogeneration without unduly burdening other customers of the purchasing utility. However it is also clear that a potential cogenerator is not required to install facilities even if economic. PURPA and Public Law 72-1982 do require a utility to purchase electricity generated by a qualifying facility but our Indiana Statute and this Commission's rules implementing that statute do allow a utility and a cogenerator to negotiate a repurchase agreement subject to the review and approval of this Commission. [See I.C. 8-1-2.4-4(f)] We find nothing in the law that would prohibit a potential cogenerator and its utility from jointly planning the timing and capacity of a qualifying facility such as a new cogeneration facility. The obligation of every public utility to furnish reasonably adequate service and facilities at reasonable and just charges is certainly not questioned. Further this Commission in acting on any Petition for the construction, purchase or lease of facilities for the generation of electricity is required to consider other methods of furnishing reliable, efficient, and economical electric service including cogeneration. We would expect the utility requesting the approval of new generating facilities to have a full evidentiary record concerning efforts to develop economic cogeneration in their service territory and possibly elsewhere. Therefore we find that joint planning to provide cogeneration or other alternate energy facilities in a timely manner is consistent with federal and state law and the regulations of this Commission.

8. *Alternatives to Rider GA.* Even though we have found, *supra*, that it is appropriate to take steps to avoid load loss and that there is no legal impediment to utilizing a rate such as Rider GA, evidence was presented contending that NIPSCO should consider other approaches to dealing with this problem. Bethlehem's witness, Mr. Rudden stated that NIPSCO's real problem is its very high rates for industrial service. He cited the Edison Electric Institute's

ranking of industrial rates for the 208 utilities reporting which shows NIPSCO's industrial rates ranking between the 10th and 26th highest of all rates. (Intervenor Bethlehem's Exhibit 1, page 7) Therefore, he contended that NIPSCO cannot compete for new business and cites the recent decision of a new steel mill to locate in the Public Service Company of Indiana territory. He contended further that Rider GA discriminates for a few select customers and deviates from cost of service principles and therefore does not answer the problem. Mr. Rudden discussed by way of example several possible alternatives. He points out that NIPSCO is not proposing to offer similar types of discount to customers considering non-generating alternatives, e.g. conservation investments or load management, or is it considering rates which would benefit existing cogenerators such as a "retail economy energy tariff". Under a retail economy energy tariff, the rate might be a price halfway between the variable operating costs respectively of the cogenerator and of NIPSCO. Such a rate would be similar to the economy energy transactions which NIPSCO and other utilities undertake to reduce their costs. Mr. Rudden stated that neither of these alternatives were specific proposals with all the supporting evidence but were examples of things which NIPSCO might consider to deal with what he considered the real problem. Further, he stated that NIPSCO's Rate 832.2 is not comparable because that rate applies only to interruptible service.

Public's witness, Mr. Brosch also argued that the proposed rate was not cost based but expressed the opinion that a departure from embedded cost of service rates was appropriate and necessary to deal with the present problems of the utility industries. He favored flexible pricing to deal with the potential for load loss, the installation of additional on-site generation and the competition of other energy sources. However, he expressed great concern that under our present regulatory methods, a customer which installed its own self-generation equipment and left the system could then

take advantage of changing energy and operating costs to discontinue its own operation at any time when its variable operating costs exceeded the utility's tariffed rate for service. He argued that the ability of the customer to "game" the system in this manner gave it unfair advantage over the utility with its obligation to serve under cost of service rates. He proposed that customers who left the system as a result of installing on-site generating capacity should be required to pay the "market" price for service if the customer chose to return to the system at some later time. Because discounts are non-traditional, Mr. Brosch contended that the treatment of customers receiving discounts should be non-traditional. He said that the PURPA avoided cost at that time would be a reasonable representation of the market price. He indicated that the PURPA price might be higher or lower than the current tariff but would be appropriate to providing service for a returning customer. On cross-examination he stated that the rate to be charged a customer who had left the system and then returned would be established by negotiation between customer and utility but that any such rate should be within the defined range between the tariffed rate and a PURPA rate.

Petitioner's witness, Mr. Nieting, stated that he did not believe the retail economy energy alternative addresses the question of load retention or deferral of new capacity. He pointed out that Rate 832.2 is available for customers with existing on-site generation and economic development rates have been approved to promote better utilization of existing capacity. He contended that Rider GA was designed specifically to deal with potential load loss from existing customers. He also agreed that Rider GA could be provided for customer classes other than those cited in Rider GA but he was unaware of customers in any other class which might meet the size and load factor requirements.

Mr. Nieting responded to Mr. Rudden's criticism of Petitioner's rates for industrial service by pointing out that the current

rates were approved by this Commission in July of 1987 as just and reasonable and by contending that the rates approved by the Commission did not cover Petitioner's costs. He also replied to Mr. Brosch's charge that NIPSCO had not looked at some of Mr. Brosch's suggestions from Cause No. 38045 to reduce its costs. He stated that NIPSCO had looked at sale and lease back of facilities and found that the life cycle cost was higher than NIPSCO's present policy; however, he stated on cross-examination that he did not know the details of the study. He also stated that he thought Mr. Rudden's suggestion of a retail economy energy rate mixed embedded and incremental cost and was not cost-based, a factor Mr. Rudden had objected to in consideration of Rider GA.

The Commission recognizes that Mr. Rudden is not asking for approval of a retail economy energy rate. We note, however, that such a rate deals with a different problem than one which we found, *supra*, i.e. retention of current load. The economy rate concept, even if proved and accepted, does not deal with a clear and current possibility of load loss but with the more nebulous concept of "competitive electric rates". Mr. Rudden's contention that Petitioner's industrial rates are too high illustrates a constant concern in utility regulation. A utility is required to provide reasonably reliable and adequate service and is allowed to charge just and reasonable rates related to the prudently undertaken investment and properly controlled operation of these facilities but those rates also must not confiscate the utility's investment. The cost of investment and operation can and does legitimately vary from geographic area to geographic area and from time period to time period and these variations can result in one utility's rates being significantly different (higher or lower) than the rates of other utilities. In other words, we believe that a rate may be "just and reasonable" in a regulatory sense and still not "competitive" with other locations and/or utilities. No one in this hearing questioned Mr. Rudden's

evidence that NIPSCO's rates are high, however, the Commission fails to see why a proposal which might maintain capacity utilization and/or load factor should be rejected because NIPSCO may have other problems as well. Approval or rejection of Rider GA should depend on whether it is legal and whether it deals effectively with the problem of load loss.

Similarly, Mr. Brosch's proposal of flexible rates for customers who leave the NIPSCO system and later wish to return seems premature. The current proposal does not deal with customers leaving the system but rather encouraging customers not to leave the system. Mr. Brosch did argue that his concept of flexible pricing should apply to any customer who avoids payment of full retail rates including contracting under the proposed Rider GA. At that time the customer should no longer be guaranteed return to firm service under normal retail tariffs. As the Public recognized in its proposed Order filed in this Cause, the Commission requires a more fully developed record before approving and mandating such a major change in utility regulation. We do not, on the other hand, accept Public's representation concerning the lack of record evidence contrary to the ideas advanced by the Public on the question of flexible pricing. Public's evidence was introduced over the objection of Petitioner and Intervenor Donnelley but the presiding Administrative Law Judge in ruling directed the parties to address the need for an additional hearing on this subject in proposed Orders. Public's primary argument in requesting a policy decision related to matters beyond NIPSCO's and Donnelley's immediate concern is that the emergence of special rates designed to respond to competition have provided the opportunity to "game" the system by certain large customers. Mr. Brosch contended that this ability to jump on and off the system disadvantaged captive ratepayers. The Commission recognizes this possibility for customers who actually make the investment or take other actions to leave the system and thereby obligate the remaining custom-

ers for recovery of a greater share of the fixed costs. In this Cause, Public has proposed that NIPSCO be allowed to use the Rider GA as long as the negotiated rate recovers all the variable costs but additionally Public proposes that any under-recovery of fixed costs be absorbed totally by the shareholders. If under-recovery of costs resulting from discount rates approved pursuant to Rider GA are the sole responsibility of the shareholders, other ratepayers will not be disadvantaged as they might be in the case of load loss and therefore should be indifferent to the rate treatment of such customers. Public's argument for additional hearings on flexible pricing also is based on the consistent application of either marginal cost or average embedded cost pricing for customers having market alternatives to service from NIPSCO. The evidence of this Cause does not support the contention that rates negotiated under Rider GA are marginal cost because they do include some proportion of embedded cost in excess of variable cost and that amount is dependent upon the specific advantages being foregone by the customer with the potential of on-site generation. Therefore we find that the record in this Cause does not support the need for additional hearings on flexible pricing.

9. *Apportionment of Risk of Loss.* The Commission also must consider the assignment of revenue shortfalls as a result of allowing Rider GA application. The record supports the contention that Petitioner's shareholders will bear the full revenue deficiency until a rate case is considered. Public's argument that the allowed return test under I.C. 8-1-2-42 fuel cost adjustment might permit some recovery of revenue is unconvincing. Petitioner must incur actual fuel costs before an adjustment will be approved by this Commission and it must demonstrate that increased fuel costs have not been offset by decreases in other expenses. With these safeguards, over-recovery is unlikely. The consideration of revenue shortfall in a future rate proceeding is a more difficult question. No one knows at this time how extensively Rider GA will be used, when

the next rate case will be and what the revenue and expense changes will result from Rider GA. Arguably, there may be potential benefits to ratepayers as a result of Rider GA but no evidence in support of or opposition to sharing the shortfall will be available until that future rate case. Therefore, we find that a decision on assignment of revenue shortfall should be deferred until Petitioner's next rate case. However, in the absence of clear and convincing evidence to the contrary, Petitioner's shareholders should continue to bear the total risk of loss due to Rider GA.

10. *Additional Terms and Conditions.* Petitioner has proposed that the length of contract under Rider GA be limited to five years, but extensions might be available if conditions warrant, subject to approval by this Commission. Further deferral of on-site generation might be appropriate if NIPSCO still does not have a need for additional capacity at the time a Rider GA contract is to expire. Because one of the purposes of Rider GA is to avoid uneconomic duplication of facilities, the Commission finds that the possibility of extension should be allowed in Rider GA.

As discussed above, some potential on-site generation involves customers being served under long-term contracts. The Commission knows administratively that Petitioner has renegotiated contract demand levels with various customers in recent years, either reducing the contract demand level or substituting interruptible service for some portion of the previous contract demand level. No evidence of such renegotiation was presented in this Cause but the Commission shares Intervenor Bethlehem's concern about on-site generation potential by a customer with a long-term contract. Because Rider GA is to preserve load which would be lost if on-site generation were added, it is not appropriate to apply it to contract demand which would not be lost whether or not on-site generation were added. Therefore, the Commission finds that contract demand under Rider GA should not replace contract demand under an existing non-cancellable contract.

The proposed Rider GA allows anyone eligible for service under certain firm service rates to request and negotiate for service under Rider GA. As discussed previously, the intent is to encourage deferral of on-site generation until added capacity is needed on the NIPSCO system. Under these circumstances we should consider whether Rider GA should be limited to customers currently receiving service under a firm service tariff or whether a new customer with the potential for on-site generation should be allowed to request service under Rider GA. There is agreement of the parties that Petitioner has capacity in excess of reasonable reserve requirements and therefore deferral of some on site generation is in the best interest of other ratepayers and the utility. On one hand allowing a new customer to apply for service under Rider GA could assure a reasonable rate of load growth but on the other hand allowing new service under Rider GA might accelerate the date of additional capacity requirement. If service for new customers were allowed under Rider GA, there is the potential for sharing fixed costs among more customers because even under Rider GA there is some contribution towards fixed costs. However, the Commission also realizes that if Rider GA service were allowed for a new customer it would be necessary to carefully compare the penalties of more rapid utilization of existing reserves and the benefits of the added sales. Therefore the Commission finds that Petitioner should be able to offer service under Rider GA to new customers with the proven potential for on-site generation but that the term of contract may be restricted to less than five years after consideration of the then current estimate of needed capacity additions.

Petitioner also proposed a limit of 300 MW for total contracts under Rider GA. On cross-examination Mr. Nieting indicated that the benefits to Petitioner might be as great for deferring potential on-site generation in excess of 300 MW as they were for the first 10 MW under the current proposal. Therefore we find that there should be no arbitrary limit to the total service

which might be provided under Rider GA. The Commission will consider on a case-by-case basis whether a particular proposal under Rider GA will result in excessive deferral. In that connection, the Public's witness Mr. Bailey recommends that the availability of Rider GA be terminated December 31, 1992, unless Petitioner files a detailed economic evaluation on or before June 30, 1991, showing continuation of Rider GA benefits for Petitioner's system and ratepayers. During the hearing, Mr. Nieting agreed to Mr. Bailey's proposal. The Commission finds that such economic evaluation should be submitted on or before June 30, 1991, if Petitioner intends to continue the availability of Rider GA beyond December 31, 1992. Public's Witness Bailey recommended that any contract already in effect as of December 31, 1992, be terminated if new construction has begun, but the economic evaluation has not been filed as described above. We do not believe that it is appropriate to shorten the term of any agreements reached through Rider GA as such treatment would introduce an unreasonable element of uncertainty to the negotiation process. Mr. Bailey also recommended that each proposed contract be submitted to the Commission for prior approval, accompanied by an economic analysis not more than six months old. We find that all proposed contracts, accompanied by the economic analysis, should be submitted to the Commission's Engineering Division for ultimate approval via our thirty-day filing procedure pursuant to I.C. 8-1-2-42.

[3] 11. *Donnelley Contract*. In early 1986, Donnelley notified Petitioner of its plans to proceed with a cogeneration project at Donnelley's printing plant in Warsaw, Indiana. Donnelley's witness Kispert described the proposed project as consisting of two gas turbines, each with the capability of producing 3.9 MW, and a steam turbine capable of producing 5.3 MW. (Donnelley Ex. 1, p. 8.) Thus, the maximum output of the project would be 13.1 MW. Mr. Kispert said the average demand at the Warsaw plant is between 7 and 8 MW, with a peak demand between 9 and 10 MW. *Id.* Thus, if the

cogeneration project were constructed, Donnelley would not be required to purchase any electricity from Petitioner, even during maintenance periods.

When told that Donnelley would be constructing a cogeneration facility which would displace Petitioner's sales of electricity to Donnelley, Petitioner requested that Donnelley provide Petitioner with the data which convinced Donnelley that it could generate its own electricity cheaper than it could purchase the electricity from Petitioner. After reviewing that data, Petitioner became convinced that the Donnelley cogeneration project was indeed a viable project and that Donnelley would construct the project and leave Petitioner's system unless Petitioner could somehow reduce the cost of electricity sold to Donnelley. Following lengthy arms-length, good faith negotiations, Petitioner and Donnelley agreed upon the contract presented for approval in this proceeding.

No party disputed the fact that the proposed Donnelley cogeneration project is a viable project which could be built by Donnelley and which would reduce its total energy costs at the Warsaw plant. Indeed, Mr. Bailey updated Donnelley's economic studies and concluded that the project was still viable under present conditions. (Public's Ex. 2, pp. 67.) Nor did any witness dispute Mr. Kispert's testimony that Donnelley is prepared to pursue its plan to construct and operate the proposed cogeneration facility at its Warsaw plant if the Donnelley Contract is not approved by the Commission.

The only criticism of the Donnelley Contract was submitted by Mr. Rudden. He said that in his opinion, the 2¢ per kwh discount "may be excessive." Bethlehem Ex. 1, p. 24. During cross-examination, he said that, in his opinion, any discount was too large. That, of course, was based upon his view that there should not be any Rider GA or contracts thereunder. The overwhelming evidence, however, is that absent a 2¢ per kwh discount, Donnelley would never have agreed to defer its cogeneration project and remain a customer of Petitioner.

ven with that discount, Mr. Kispert said that the savings under the Donnelley Contract were not as great as the savings would have been had Donnelley proceeded to construct and operate the proposed cogeneration project.

Furthermore, the 2¢ per kwh credit is in fact reduced by virtue of Petitioner receiving the \$3.8 million initial deposit which it will repay, without interest, over a 60-month period. Mr. Nieting testified that Petitioner's having use of Donnelley's initial payment reduces the discount to an effective discount of 1.8 cents per kwh. We find Petitioner's insistence upon an up-front payment and repayment without interest as a demonstration of the customer's good faith of going forward absent an agreement to have been appropriate.

If Petitioner were to lose Donnelley as a customer, it would lose revenues of approximately \$4 million annually. (Bailey Direct, Public's Ex. 2, pp. 7-8; Nieting Direct, Petitioner's Ex. 1, p. 10.) With the 2¢ per kwh discount, Donnelley would still provide Petitioner with annual revenues of approximately \$2.6 to \$2.7 million. (Nieting Direct, Petitioner's Ex. 1, p. 10.) Furthermore, the evidence clearly established that even at the discounted rate, Donnelley will be making a substantial contribution to Petitioner's fixed costs. Mr. Nieting testified that Petitioner's variable operating and maintenance costs, including fuel costs, are between 2.5 and 2.6 cents per kwh. The evidence further established that under Rate 824, Donnelley would be paying about 6.4 cents per kwh for electricity purchased from Petitioner. Thus, with the 2¢/per kwh discount, Donnelley would still be paying Petitioner approximately 4.4 cents per kwh, or 1.8 to 1.9 cents per kwh toward Petitioner's fixed costs. Clearly, all of Petitioner's ratepayers benefit from Donnelley's continued contribution to Petitioner fixed costs. Donnelley receives the benefits of (1) receiving a portion of the savings that would have been realized had the project been completed, (2) avoiding the risks of generation construction based on assumptions which may not turn out to be accurate, and (3)

having the use of freed-up funds for investing in its primary business of printing.

In light of the benefits generated by the Donnelley Contract to Petitioner, its ratepayers and Donnelley, we find that the Donnelley Contract is reasonable and just, in the public interest and should be approved.

12. *Conclusion.* The Commission finds that Rider GA is a reasonable and appropriate method of avoiding excessive load loss. Subject to the additional conditions found above, the Commission finds that Rider GA as proposed should be approved.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. Petitioner's proposed Rider GA should be, and is hereby, approved, subject to the conditions found just and reasonable and in the public interest in Finding No. 10 hereof.

2. The Donnelley Contract should be, and is hereby, approved.

3. Within ten days of the issuance of this Order, Petitioner shall file revised tariff sheets with the Commission's Engineering Department in accordance with the Commission's rules for the filings of tariffs which reflect the rates, herein approved, and subject to the terms and conditions prescribed herein.

4. The revised tariff sheets filed in accord with Ordering Paragraph 3 shall be effective on the date of approval by the Commission's Engineering Department.

5. On or before December 31, 1991, Petitioner shall file an economic analysis with the Commission's Engineering Department as outlined in Finding No. 10.

6. Any future contract filings under Rider GA shall be filed under the Commission's thirty-day filing procedures and shall be accompanied by an economic analysis as described in Finding No. 10.

7. All other proposed terms and conditions raised in the instant proceeding shall be, and hereby are, rejected, consistent with the foregoing findings.

8. This Order shall be effective on and after the date of its approval.

suant to its authority to regulate telecommunications rates and to effectuate the public interest pursuant to RCW 80.16.020, RCW 80.36.140 and RCW 80.36.300, and pursuant to powers granted under RCW 80.16.050, to review the reasonableness of the consideration exchanged pursuant to the contracts at issue in this proceeding and to attribute revenue to the parties for rate-making purposes accordingly.

4. The publishing fee proposed by the applicant is unreasonable and not in the public interest pursuant to RCW 80.16.020. An appropriate compensation for PNB should be determined when the approval of the contracts and the fees are considered in the next Pacific Northwest Bell general rate proceeding, pursuant to RCW 80.16.050. Alternate remedies, including treatment of the transfer of directory publishing as a sale, will be considered. Temporary approval of the contracts at issue in this proceeding to permit publication of telephone directories is in the public interest.

ORDER

NOW THEREFORE, IT IS HEREBY ORDERED That Pacific Northwest Bell Telephone Company and US West Direct Company are authorized to enter into publishing agreements which are the subject matter of this proceeding to the extent necessary to provide for the continuing publication of telephone directories until full review of the contracts and the rate issues involved can occur at the next Pacific Northwest Bell general rate proceeding, and

IT IS FURTHER ORDERED That because the publishing fee at issue in this proceeding is not shown to be in the public interest, and may have a substantial effect upon the cost and availability of telecommunications service, it will not be approved in this proceeding. The contracts and the compensation proposed by the applicant will be reviewed in the next Pacific Northwest Bell general rate proceeding, when appropriate publishing fees will be determined

and given appropriate ratemaking effect by the Commission, and

IT IS FURTHER ORDERED THAT The Commission retains jurisdiction pursuant to RCW 80.16.050 to effectuate the provisions of this order and to ensure that public policy with respect to the availability and cost of telecommunications service is carried out.

FOOTNOTES

¹PNB now operates under the d/b/a of U.S. West Communications. To avoid confusion in this order, the original name as it appears on the application will be used.

Re Arkansas Power and Light Company

Docket No. 88-072-TF
Order No. 6

Arkansas Public Service Commission
September 15, 1988

ORDER authorizing an electric utility to reduce its rates for service to a large-load industrial customer in return for the customer's grant of an option to install utility-owned cogeneration facilities and agreement to defer the operation of on-site electric generation.

1. COGENERATION, § 1 — Electric utilities — Rate discounts — Large-load industrial customer with cogeneration or self-generation alternative.

[ARK.] An electric utility was authorized to reduce its rates for service to a large-load industrial customer in return for the customer's agreement to (1) defer the operation of on-site electric generation for at least four years and (2) provide the utility with a ten-year option to install utility-owned on-site cogeneration facilities; it was found that the agreement would benefit both the utility and its ratepayers by maintaining a contribution to fixed costs that otherwise would be lost to self-generation, and that the agreement would not adversely affect other customers because the utility had agreed that any revenue loss associated with the agreement would be

borne by its stockholders; moreover, it was found that the option to install utility-owned cogeneration facilities would provide the utility with flexibility in meeting increased demand while eliminating much of the risk associated with the possible need to construct additional large central station generating units.
p. 431.

2. DISCRIMINATION, § 45 — Concessions to particular customers — Discount electric rates — Large-load industrial customers with self-generation alternatives.

[ARK.] Discount electric rates offered to a large-load industrial customer in return for its agreement to defer operation of on-site electric generation were found to be just and reasonable and not unduly discriminatory where the rates would (1) produce a savings to the customer of less than the amount it could have saved by implementing self-generation and (2) maintain a contribution to the fixed costs of the utility.
p. 431.

Before Johnston, chairman, and Qualls and Kearney, commissioners.

By the COMMISSION:

ORDER

On May 19, 1988, Arkansas Power & Light Company (AP&L) filed a letter application and proposed tariff in the above-styled docket pursuant to Rule 11.01(d) of the Commission's Rules of Practice and Procedure. The tariff is applicable to one customer, Mid-America Packaging, Inc. (Mid-America), an existing customer of AP&L, and consists of a May 1, 1988, Agreement for Electric Service between AP&L and Mid-America (the Agreement).

In its letter application, AP&L stated that Mid-America engages in the manufacture of paper products at its paper mill and bag plant located near Pine Bluff, Arkansas and operates twenty-four (24) hours a day, seven (7) days a week, with high thermal and electrical load factors. AP&L also stated that Mid-America has studied and considered

the use of steam producing facilities and the installation of co-generation equipment to partially offset its purchases of electricity from AP&L. According to studies conducted by AP&L and Mid-America, Mid-America has a viable option to construct and operate an on-site electric generation facility capable of displacing a substantial portion of AP&L's current sale of electricity to Mid-America.

On June 7, 1988, Mr. Chris Benson of the Commission Staff filed Prepared Testimony requesting that the proposed tariff be suspended for purposes of further investigation. Also on June 7, 1988, Arkansas Electric Energy Consumers (AEEC) filed a Petition to Intervene, stating that it wished to be heard on the issue of how any revenue shortfalls resulting from the Agreement would be treated in AP&L's next general rate case with respect to AP&L's other ratepayers. AEEC is an association of approximately forty (40) large industrial electric energy consumers located in Arkansas. Mid-America, a member of AEEC, did not join in the Petition to Intervene.

By Order No. 1 entered on June 17, 1988, the Commission suspended the proposed tariff, set a procedural schedule for filing testimony and a hearing, and granted intervenor status to AEEC. In response to an AP&L Motion filed June 24, 1988, the procedural schedule was expanded by Order No. 4, entered on July 8, 1988, to provide AP&L an opportunity to file surrebuttal testimony. Order No. 4 clearly specified that the granting of the AP&L Motion was not to be considered precedent in any other proceedings before the Commission and did not constitute Commission endorsement of a change in the normal procedural schedule in Commission proceedings.

On June 20, 1988, Mid-America filed a Petition to Intervene. Said Petition was granted by Commission Order No. 2, entered on June 28, 1988.

The Commission entered Order No. 3, styled as a Protective Order, on July 1, 1988, in response to petitions filed by AP&L and Mid-America on June 14 and June 20, 1988, respectively. The Protective Order

found that certain information related to the analyses made by AP&L, Mid-America and its consultants concerning the feasibility of Mid-America's co-generation of its electric requirements should be filed under seal, to be disclosed only to the Commissioners and their staff, APSC General Staff members, and experts retained by the Staff. The Protective Order also protects certain information about other AP&L customers who may also have co-generation potential and other customer-specific information relative to individual customer loads, service, usage, payment history and installed equipment. The Protective Order was expanded by Order No. 5, entered July 20, 1988, to include information requested by the Staff from Mid-America in Staff's Request for Information, Amended E-2.

Prepared Testimony was filed in this case by Mr. Kenneth R. Breeden, Mr. Alan C. Hardy and Mr. Kelton Grubbs on behalf of AP&L. Mr. Ray C. Dillion, Mr. Tracy K. King and Mr. John A. Tillinghast filed Prepared Testimony on behalf of Mid-America. The Staff filed Prepared Testimony by Mr. John Strode. AEEC did not file testimony nor did it present any witnesses.

THE AGREEMENT

The Agreement obligates Mid-America to purchase from AP&L all electricity required for its operations until the April 30, 1992, termination date of the Agreement. The demand and energy rates to be paid by Mid-America will escalate at the rate of one percent (1%) per year. Under the Agreement, Mid-America must pay a minimum demand charge of sixty seven thousand five hundred dollars (\$67,500) a month, to be escalated at one percent (1%) per year.

Mid-America agrees to defer the operation of on-site electric generation for the term of the Agreement. AP&L is provided a ten (10) year option, which expires April 30, 1998, to propose the construction of AP&L-owned co-generation facilities in the event Mid-America plans to install new or

increased boiler or thermal energy capacity or on-site electric generation facilities.

Section 9 of the Agreement, as initially filed by AP&L, contained a provision stating that Commission approval of the rates contained in the Agreement would designate the appropriate rate design and revenue level (when applied to test year billing determinants) for Mid-America at the time of AP&L's next general Arkansas retail rate proceeding. The revenue requirement for the other Arkansas retail customers would then be determined by subtracting Mid-America's revenue requirement from the total Arkansas retail revenue requirement.

Following Mr. Strode's criticism of Section 9 and his proposal of different Section 9 language in his Prepared Testimony, filed August 12, 1988, AP&L and Mid-America amended the initial Agreement on August 19, 1988, to incorporate the Staff's proposed language in Section 9 of the Agreement. The amended Section 9 of the Agreement provides that Commission approval of the proposed Agreement rates designates the appropriate revenue requirement for Mid-America "at this time". There is no language specifying the appropriate Mid-America revenue requirement at the time of AP&L's next general Arkansas retail rate proceeding. In the event the Commission imputes a revenue requirement to Mid-America in connection with AP&L's next general Arkansas retail rate proceeding in an amount greater than that actually realized pursuant to the Agreement, AP&L has the right to terminate the Agreement.

The August 19, 1988, amendment also recognized the merger of Mid-America with and into Gaylord Container Corporation, a corporation affiliated with Mid-America by common ownership.

DISCUSSION

[1, 2] AP&L and Mid-America support approval of the Agreement. As a result of the August 19, 1988, amendment to the Agreement, the Staff now recommends approval of the Agreement. Also as a result

of the amendment, AEEC, the other party to this matter, does not oppose approval. Thus, the amended Agreement is unopposed.

However, the Commission must make its own independent determination based on the evidence presented. The issue is whether this tariff is just and reasonable for Mid-America and AP&L and in the best overall interests of the public, including Mid-America, AP&L and all other AP&L customers.

1. *Mid-America's Alternative.* Mr. Breeden testified that AP&L's motivation to enter into the Agreement was the existence of a viable co-generation alternative available to Mid-America. The available alternative would enable Mid-America to partially reduce its electricity purchases from AP&L and to no longer be a full requirements customer of AP&L. AP&L is convinced that a portion of Mid-America's load would be lost without approval of the Agreement and that the result would be a loss of contribution to AP&L's fixed costs.

Mid-America's alternative is the installation of on-site co-generation equipment. Mr. Hardy testified that Mid-America was the only paper mill served by AP&L that did not generate a portion of its own electrical requirements. Three co-generation experts testified in this matter, one on behalf of AP&L and two on behalf of Mid-America. All stated that Mid-America does have a viable option to install co-generation. The Staff reviewed the testimony of the experts and studied information supplied by Mid-America. Mr. Strode testified that the Staff was convinced that co-generation is a viable alternative for Mid-America.

The Commission is also persuaded that Mid-America has a viable alternative to co-generate a portion of its electrical requirements. Further, Mr. Dillon stated that a Mid-America management decision has already been made to co-generate electricity at the paper mill if the Agreement is not approved.

If Mid-America were to pursue its co-generation alternative its current contribution to AP&L's fixed costs would decrease. Mr. Strode testified that other ratepayers

would be affected by such a decrease, even outside the context of an AP&L general retail rate proceeding, due to the operation of the Grand Gulf Rider M-33.

Approval of the Agreement would prevent Mid-America from exercising its co-generation alternative for at least the next four years thus preventing the resultant loss of contribution to AP&L's fixed costs.

2. *Agreement Rates.* The rates negotiated between AP&L and Mid-America incorporate sufficient incentives to prevent Mid-America from pursuing its co-generation alternative. Both AP&L and Mid-America witnesses testified that the Agreement rates were developed in a way which would emulate Mid-America's co-generation alternative (i.e. Mid-America's avoided cost). Mr. Hardy testified that Mid-America will continue to make a substantial contribution to AP&L's fixed costs under the rates provided for in the Agreement.

Mr. Strode testified that the Agreement is not unduly discriminatory because it allows Mid-America to achieve a savings approximating the savings it would have received by pursuing its co-generation alternative, while still making a contribution to AP&L's fixed costs and rate riders. The Commission is of the opinion that the rates are not unduly discriminatory.

AP&L stated in its letter application that the Agreement is expected to reduce the overall level of revenues which AP&L would otherwise receive if Mid-America continued to purchase its full electrical requirements from AP&L at standard retail rates. Mid-America and Staff witnesses testified that due to the Agreement's larger minimum demand charge, Mid-America could potentially pay more than under the current standard retail rates if Mid-America's production were reduced.

3. *Regulatory Treatment.* Mr. Hardy stated that any difference between revenues produced under the Agreement and revenues which would have been produced by applicable standard rate schedules until the conclusion of AP&L's next general retail rate case, will be permanently borne by AP&L stockholders and will never be collected

from AP&L ratepayers. Mr. Strode correctly pointed out that this is not unusual in that AP&L stockholders always gain the benefit or suffer the detriment any time load is added or lost between rate cases.

By approval of the Agreement, the Commission would designate the Agreement rates as the appropriate revenue requirement for Mid-America "at this time". As to the development of Mid-America's revenue requirement at the time of the next AP&L general retail rate proceeding, the Agreement is silent. The question is, of course, moot if there is no AP&L general rate case until after the termination of the Agreement. In the event such a rate proceeding does occur during the life of the Agreement, the Commission will be free to make a determination at *that* time, based on the facts and circumstances then presented, of the appropriate Mid-America revenue level.

4. *Co-generation Option.* Mr. Breeden stated that AP&L's option to make a proposal to install, own and operate co-generation plant(s) at the Mid-America mill provides AP&L and its customers a benefit due to the lead time involved in constructing a central station coal-fired generating unit as compared to the construction of a co-generation facility. A co-generation facility can be installed with a relatively short construction lead time and can be built in discreet increments. Thus, AP&L asserts that the option to construct co-generation facilities provides AP&L with flexibility and eliminates much of the risk associated with large central station generating units.

5. *Assignability.* Mr. Strode expressed concern over AP&L's ability to assign its rights under the Agreement (including its co-generation option) to an unregulated entity. Mr. Hardy testified that AP&L was willing to seek Commission approval prior to assigning its rights to develop co-generation facilities under Agreement.

CONCLUSION

Based on the evidence presented, the Commission finds that substantial evidence

has been presented that the Agreement is in the best overall interest of the public, AP&L, Mid-America and AP&L's other customers. It has been shown that:

1. Mid-America now has a viable co-generation alternative.

2. Failure to approve the Agreement could cause Mid-America to pursue its co-generation alternative, thereby causing the loss of a significant contribution to AP&L's fixed costs. The Agreement provides a significant contribution to fixed costs. The retention of Mid-America as a full requirements customer thus benefits AP&L and its remaining customers.

3. The Agreement rates are just and reasonable to Mid-America and AP&L and are not unduly discriminatory. The rates produce a savings to Mid-America of less than the amount it could have saved by exercising its option. The rates maintain a contribution to fixed costs.

4. By approval of the Agreement, the Commission is not precluded from determining the appropriate revenue requirement for Mid-America at the time of the next AP&L general retail rate proceeding based on the facts and circumstances then presented.

Accordingly, for the reasons set forth hereinabove, we find that the Agreement is in the best overall interest of the public, AP&L, Mid-America and all other AP&L customers. We also find and hereby direct that AP&L shall seek prior Commission approval before attempting to assign *any* of its rights under the Agreement. Further, we specifically reserve judgment at this time regarding the appropriate regulatory treatment of any potential generation facility that may be constructed pursuant to the terms of this Agreement.

IT IS, THEREFORE, ORDERED:

(1) That the May 1, 1988, Agreement for Electric Service between AP&L and Mid-America filed on May 19, 1988, as amended on August 19, 1988, and filed on August 22, 1988, should be and hereby is approved

in accordance with the foregoing provisions and directives of this Order; and

(2) That all documents filed in this docket with the Secretary of the Commission under protective seal shall continue to be maintained in accordance with the Protective Orders entered previously in this docket.

Re Diamond State Telephone Company

Docket No. 86-20 Phase IA
Order No. 2970

Delaware Public Service Commission
August 16, 1988

PETITION by local exchange telephone carrier for approval of a range of equity returns under an "incentive regulation" proposal; rejected as filed but replaced with a "rate stability" plan.

1. RETURN, § 4 — Commission powers — Penalties and rewards.

[DEL.] The commission is empowered to impose a penalty on equity returns for poor management as well as rewards on equity returns for superior performance.
p. 437.

2. RATES, § 170 — Factors affecting reasonableness — Surplus — Excessive return.

[DEL.] The fact that a utility's authorized rates result in a return in excess of that authorized does not in itself mean that those rates are patently and automatically unreasonable.
p. 437.

3. RETURN, § 5 — Regulatory incentive plan — Sliding scale — Range of returns — Commission duties.

[DEL.] The commission rejected an "incentive regulation" proposal that would have provided a range of equity returns for a local telephone carrier, within which the commission could not in-

vestigate and adjust the carrier's rates; specifically, the proposal would have prompted a freeze on rates with no rate increase requests unless the carrier's equity return fell below 12%, in exchange for the commission's promise not to reduce the carrier's rates unless its equity return exceeded 15%; the commission found that approval of such a range of returns would improperly abridge its duty and authority to set just and reasonable rates.
p. 437.

4. RETURN, § 20 — Amount to be allowed — Specific versus range of returns — Incentive regulation versus rate stability.

[DEL.] The commission replaced a telephone carrier's "incentive regulation" proposal, which espoused a range of authorized returns, with a "rate stability" plan, under which a specific return on equity was authorized in conjunction with a rate reduction, but with assurances from the commission that it was unlikely that rates would be reduced further even if the actual return exceeded the authorized figure, an event that was found to be possible given market, technical, and managerial improvements.
p. 439.

Before Norling, chairman, Lester, vice chairman, and Twilley and McClelland, commissioners.

By the COMMISSION:

FINDINGS, OPINION AND ORDER

AND NOW, to-wit, this 16th day of August 1988, the Commission, for the reasons set forth herein, makes the following findings, files the following opinion and enters the following Order.

1. PROCEDURAL HISTORY

1. This matter arose during the latter stages of the proceedings in Phase I of PSC Docket No. 86-20 with a request by Commissioner John R. McClelland that the parties to the Docket address the concept of incentive regulation. During the Commis-