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Public Utility Commission of Texas
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INQUIRY INTO PRICING PRACTICES OF SOUTHWESTERN BELL TELEPHONE COMPANY UNDER THE ESSX CUSTOM TARIFF § § § **DOCKET NO. 6771**

March 22, 1989

This case is an inquiry into the method by which Southwestern Bell Telephone Company determines its prices for ESSX (PLEXAR) custom service. The Commission approved the incremental unit cost model used by the company to determine the minimum prices for ESSX custom service. It rejected the fully distributed cost model proposed by an intervenor.

[1] RATEMAKING--RATE DESIGN--TELEPHONE--PRICING CONCEPTS--MARGINAL COST

The incremental-unit-cost model developed by the applicant correctly determines the minimum rates it may charge pursuant to customer-specific contracts to provide ESSX (PLEXAR) service. (p. 2466)

[2] RATEMAKING--RATE DESIGN--TELEPHONE--PRICING CONCEPTS--MARGINAL COST

The applicant's incremental-unit-cost (IUC) model was correctly applied to determine the minimum prices in customer-specific contracts. However, to ensure that other customers do not subsidize the competitive service, the applicant must separately account for prorated plant costs, the expense of processing unsuccessful bids, and all other expenses that are causally related to the class of service, but that are excluded from the IUC studies for individual customers. (p. 2481)

DOCKET NO. 6771

INQUIRY INTO PRICING PRACTICES OF SOUTHWESTERN BELL TELEPHONE COMPANY UNDER THE ESSX CUSTOM TARIFF § § § PUBLIC UTILITY COMMISSION OF TEXAS

TABLE OF CONTENTS

DOCKET NO. 6771

INQUIRY INTO PRICING PRACTICES OF SOUTHWESTERN BELL TELEPHONE COMPANY UNDER THE ESSX CUSTOM TARIFF	§ § §	PUBLIC UTILITY COMMISSION OF TEXAS

EXAMINER'S REPORT

I. Introduction

Overview.--This case does not involve the approval of any tariff or rates. Rather, ROLM Corporation is challenging the method by which Southwestern Bell Telephone Company ("Bell" or "the company") determines its prices for ESSX Custom service. In particular, Bell uses an incremental unit cost (IUC) model to determine the minimum prices for ESSX Custom service, and ROLM maintains that the minimum prices should instead be determined by a fully distributed cost (FDC) model.

State Purchasing and General Counsel support Bell's use of the IUC model. The ALJ concludes that (1) Bell's model is the appropriate method for determining whether the company recovers the costs of providing service to ESSX Custom subscribers and (2) Bell is correctly applying the model to determine the floor for prices in ESSX Custom service contracts. Accordingly, the ALJ recommends approval of Bell's cost model.

Description of service.--Bell's central-office-based switching services fall into two main categories: Centrex and ESSX (ESSX has been renamed PLEXAR^{sm}, but is referred to in this Report as ESSX). The distinguishing feature of ESSX is its use of electronic-switching-system techology, which enables the company to provide more service features than are available with Centrex.

From the user's point of view, Centrex and ESSX systems emulate a PBX (private branch exchange) system. Unlike a PBX system, however, each individual station is directly connected to the central office by a dedicated access line (local loop) in the same manner used for individual subscribers. The customers have direct inward and outward dialing capability plus intercom calling. Other calling features, such as call forwarding or three-way calling, are also available.

There are several categories of ESSX service. The ESSX-30 and ESSX-400 services are provided at tariffed rates to customers with up to 30 and 400 stations, respectively. ESSX Custom service--which is the subject of this case--is available only to customers with more than 400 stations and is provided pursuant to customer-specific contracts negotiated by Bell. The rates for ESSX Custom service thus vary from customer to customer.

Bell received approval from the Commission to provide ESSX Custom service in January 1985 (Tariff Control No. T-151-4), and its authorization to provide the service pursuant to customer-specific tariffs is not being challenged. Interim approval has been granted to service contracts with nearly 30 customers pending resolution of this case. Even though Bell's ESSX Custom service is regulated, it is undisputed in this case that the service faces substantial competition from unregulated PBX vendors.

II. Procedural History

Jurisdiction.--This case originated out of the intervention by ROLM in a case involving the approval of an ESSX Custom tariff to provide service to Shell Oil Company. Once it was determined that ROLM did not oppose the contract with Shell Oil, its challenge to Bell's costing and pricing methods was severed to be considered in this case. *See Southwestern Bell Telephone Co.*, Docket No. 6555, Order Severing Issues (Mar. 24, 1986).

The Commission has jurisdiction and authority in this case pursuant to sections 16(a) and 18(a)-(b) of the Public Utility Regulatory Act, Tex. Rev. Civ. Stat. Ann. art. 1446c (Vernon Supp. 1989) (PURA).

Notice.--Because this case does not involve a request to change rates, the ALJ and the parties agreed that proper notice consisted of (1) published notice in two consecutive issues of *Telephony* (a telecommunications industry weekly trade journal) and (2) direct notice by mail to PBX vendors, all of Bell's Centrex customers, the Office of Public Utility Counsel, the representative of the Cities in Bell's previous rate case, and the representative of the State Purchasing and General Services Commission ("State Purchasing").

Bell filed affidavits affirming that notice was provided and published as directed. State Purchasing moved to intervene, and its motion was granted on April 25, 1986. There were no other intervenors.

Hearing.--The hearing on the merits in this case was originally scheduled for July 15, 1986. At the request of the parties, the hearing was rescheduled three times: September 9, 1986; October 21, 1986; and December 4, 1986. The hearing began on December 4, 1986, and adjourned on December 17, 1986.

III. Preliminary Matters

A. Scope of Case

Pursuant to order, the parties filed pleadings setting forth the issues they believed to be properly resolvable in this case. In Order No. 5, the ALJ limited the scope of this case to the following two issues: (1) Whether Bell is properly measuring the cost of providing ESSX Custom service to individual customers, and (2) whether Bell's prices for that service recover its actual costs. The scope therefore includes the issue of allocating common costs, but only for the purpose of determining whether ESSX Custom rates recover appropriate costs. The issue of whether rates for other services recover more than the costs of providing those services was held to be outside the scope of this case, so that attention could be focused on ESSX Custom costs and rates.

B. Burden of Proof

During the hearing, the ALJ ruled on the parties' burden of proof with respect to the issues. Tr. at 1604-09. At the time of the hearing, section 40 of PURA was not applicable to this case, because the section applied only to rate increases requested by a utility or rate decreases requested by a complainant. Common law standards thus controlled: The party with the affirmative of an issue has the burden of proof with respect to that issue, unless the facts lie peculiarly within the knowledge of another party. *See Dessommes v. Dessommes*, 505 S.W.2d 673 (Tex. Civ. App.--Dallas 1973, writ ref'd n.r.e.). The party that would lose if no evidence were presented is the party with the affirmative. *See Union City Transfer v. Adams*, 248 S.W.2d 256 (Tex. Civ. App.--Fort Worth 1952, writ ref'd n.r.e.).

Utilities have the burden of proving that the method by which they calculate their rates results in just and reasonable rates. Bell has the affirmative of the issue and is in possession of the facts; therefore, it has both the burden of persuasion and the burden of production. However, with respect to any allegations that Bell's ESSX Custom service rates damage Bell's competitors in the PBX market, ROLM has the affirmative of the issue because if no evidence were presented, ROLM would lose. Moreover, ROLM is in possession of the facts with regard to any alleged damage it may have suffered. ROLM therefore has the burden of persuasion and the burden of production with respect to allegations of damage to competitors.

ROLM's attorney stated that ROLM had chosen not to present a case for relief based on injury to ROLM as a competitor of Bell's. Therefore, ROLM had not and would not offer evidence that ESSX Custom prices damage competition in the marketplace. Rather, ROLM's case was based on the theory that the manner in which Bell prices ESSX Custom service has a harmful effect on the rates for local exchange service. Tr. at 1614-15.

C. Implications of Senate Bill 444

After the hearing in this case, Senate Bill 444 amended several provisions of PURA, effective September 1, 1987, and December 31, 1988. In particular, section 18(e)(3)(B) requires the Commission to approve customer-specific contracts for central-office-based switching systems of more than 200 stations upon receiving certification that certain requirements are met, including that the local exchange company is recovering "appropriate costs."

Section 18(g) requires the Commission to balance the public's interest in an advanced communications system with concerns for preserving universal service, prohibiting anticompetitive practices, and preventing subsidization of competitive services with revenues from regulated monopoly services. Section 18(h) requires that competitive services recover their appropriate costs. Finally, section 18(j) prohibits contracts approved pursuant to section 18(e)(3)(B) from pricing services in a discriminatory manner.

By posthearing briefs, the parties stated that Senate Bill 444 did not control the resolution of this case. The elements of proof for approval of customer-specific contracts pursuant to section 18(e)(3)(B) are different from those in the ESSX Custom tariff. Moreover, it was the parties' view that section 18(e)(3)(B) does not supersede or otherwise invalidate Bell's ESSX Custom tariff. ROLM noted that the provisions added by Senate Bill 444 list factors that the Commission had to consider even before enactment of the statute.

D. Previous ESSX Service Cases

The Commission has not separately reviewed Bell's ESSX Custom service tariff in a contested case. However, there have been two cases involving the company's ESSX-400 service tariff. *See Southwestern Bell Telephone Co.*, Docket No. 7394, 13 P.U.C. Bull. 1313 (1987); *Southwestern Bell Telephone Co.*, Docket No. 6146 (Oct. 30, 1985).

Docket No. 6146 involved Bell's original application for approval to offer ESSX-400 service. ROLM intervened in the case, contending that the rates were discriminatory and that the service was unnecessary for Bell to be competitive with PBX vendors. Significantly, the proposed rates were based on incremental unit costs. The Commission approved the ESSX-400 tariff, finding that the rates were not discriminatory so long as Bell continued to offer Centrex service.

Docket No. 7394 involved Bell's application for an overall reduction of the rates for ESSX-400 service and for a revision of the structure of rates for the service. The company noted that even though the tariff had been in effect for 18 months, there were no subscribers to ESSX-400 service. The main intervenor was AT&T Information Systems, which opposed the changes on the grounds that they would unlawfully discriminate against PBX vendors. Again, the proposed rates were based on incremental unit costs. The Commission approved Bell's application with minor changes, finding that the IUC study provided an appropriate basis for setting ESSX-400 rates. The Commission's order is presently on appeal before district court.

The rates in the two ESSX-400 cases were based entirely on IUC studies. The cases thus establish a precedent for basing rates for ESSX service on incremental unit costs and finding that such rates recover appropriate costs and are not unreasonably discriminatory.

IV. Measuring the Cost of ESSX Custom Service

A. Incremental Versus Fully Distributed Costs

Incremental cost is the change in costs caused by changing the number of units of service provided. (Marginal cost, a related concept, is the change in cost caused by *one* unit's change of service provided.) Incremental cost thus measures the direct cost a company incurs to provide an additional amount of service. An IUC study for a potential ESSX Custom subscriber measures the additional cost Bell would incur to provide ESSX Custom service to that subscriber.

As described by Bell witness David Ho, IUC models are a practical application of marginal cost principles. Mr. Ho is the district Staff Manager--Regulatory and is responsible for developing the company's cost studies to verify that they appropriately reflect the costs incurred in providing service and are consistent with previous decisions of the Commission.

Fully distributed cost is a broader measure of cost that includes common costs. In a typical FDC study, as many costs as possible are first directly assigned to specific activities on a causal basis. Remaining costs are then allocated, using various allocators to achieve a full distribution of total costs to all services. An FDC study would thus allocate to ESSX Custom service common costs that would be incurred whether or not the ESSX Custom service is provided.

B. Southwestern Bell's IUC Model

1. Economic Theory

Bell sponsored the testimony of John Wenders, professor of economics at the University of Idaho, to present the economic theory supporting the use of the company's IUC model. Bell Exh. 1. This section summarizes his testimony.

Prices for ESSX Custom service should be set in a manner that maximizes the cash contribution from the service. This goal can be attained by applying the marginal-revenue-equals-marginal-cost concept from economics. The proper measure of costs is therefore some type of marginal cost.

From both the company's and the Commission's points of view, it is appropriate to make as much money as possible from a competitive service such as ESSX Custom. Maximizing the contribution from ESSX Custom service will accomplish the Commission's goal of keeping the revenue requirements for local service as low as possible.

Bell should base the prices of ESSX Custom service on marginal costs. The amount of cost that is includible in the marginal cost of serving a potential customer depends on several factors, including the amount of service the customer orders, the facilities available to serve the customer, and the amount of time the customer will commit to using the facilities.

In general, any cost that the company will incur--either at the time service begins or any time during the contract for service--must be included in calculation of marginal cost. For example, presently unused facilities may be available to serve a potential ESSX Custom customer. If forecasts of demand show that the facilities will otherwise remain idle during the term of the contract, providing ESSX Custom service to the customer will not add to the capacity costs of the company, and the marginal cost of the service may be very low. However, if the demand forecasts show that providing ESSX Custom service will require the company to add to its capacity during the term of the contract, the present value of the additional required capacity must be reflected in the marginal cost of serving the customer.

Even though fully distributed costs are higher than marginal costs, the other customers of the company are not subsidizing ESSX Custom service as long as Bell recovers its relevant direct cost of providing the service. The marginal cost is thus the appropriate price floor for ESSX Custom service, and the company should use its knowledge of the marketplace to price its service as far above that floor as possible without losing the business.

Just as important, if Bell were required to base its prices for ESSX Custom service on fully distributed costs, it might lose some business from which a contribution could otherwise be obtained to benefit the general body of ratepayers. And since the capital costs would continue, they remain part of the company's revenue requirement that is borne by the residual ratepayers.

Prof. Wenders testified that he had reviewed Bell's costing procedures and pricing objective. In his opinion, the company has developed a reasonable practical application of the optimal pricing strategy.

2. Application of the IUC Model

Bell witness Ho explained how the company applies the theoretical principles discussed by Prof. Wenders. SWB Exh. 4. Bell witness Jerry Melson, District Manager--Marketing Administrative, described the process of gathering market information for determining an ESSX Custom subscriber's price on the basis of willingness-to-pay. SWB Exh. 2. Finally, Bell witness Eugene Springfield, Division Staff Manager--Rate Administration, testified that his department uses the IUC studies and the marketing information to set the prices in individual ESSX Custom service contracts. SWB Exh. 5. This section summarizes their testimony.

Incremental costs measure the direct cost Bell will incur in providing a product or service. They are based on the principle of cost causation and are prospective in nature. Incremental costs are similar to marginal costs except that they reflect changes in quantity greater than one unit. When the company's incremental costs are expressed on a unit basis, they are called incremental unit costs and are generally considered to be equivalent to marginal costs.

IUC studies include the two general categories of direct cost: capital costs and operating expenses. The studies are particularly appropriate for pricing ESSX Custom service, because the company can take into account information pertaining to each individual customer, such as the requested term of contract, calling characteristics, station size, and central-office and outside-plant facility requirements. These factors determine the recurring and nonrecurring costs of serving the customer for the contract period.

Bell's Network Department furnishes customer-specific data to Mr. Ho's department, which reviews it to determine consistency and reasonableness. The data is used to determine the customer's network requirements. From this information, the incremental recurring and nonrecurring costs of providing the particular ESSX Custom service are calculated. The costs are directly related to the specific customer's service needs and are provided to the rates and tariffs organization as an input to the pricing decision for that customer's service.

The marketing organization in Bell provides the customer willingness-to-pay information that serves as an additional benchmark in determining the price in an ESSX Custom contract. According to Mr. Melson, Bell's sales employees are held accountable not only for stimulating product sales but also for generating revenue on a set of accounts. They therefore have an incentive not to underestimate willingness-to-pay simply to accomplish a sale.

Mr. Springfield explained that the IUC studies are the foundation for the rates in the customer-specific tariffs that Bell files with the Commission: in each ESSX Custom service contract, the service must cover its relevant incremental unit cost. In addition, the company's goal is to maximize the contribution above incremental unit cost, given the competition it faces as judged by the marketing personnel.

C. ROLM's Proposal: An FDC Model

ROLM witness Walter Bolter, a telecommunications consultant, reviewed the costing and pricing practices used by Bell to set rates for ESSX Custom service. In addition, Dr. Bolter proposed the development of a costing model to determine stand-alone costs for monopoly services to ensure that these services do not subsidize competitive services. This section summarizes his proposed costing model.

If Bell's costing and pricing practices favor certain customers, there could be serious adverse effects on its other customers. In particular, if the company underprices ESSX Custom service, the resulting revenue shortfall would necessarily be borne by Bell's other services--in particular, residually priced basic exchange service. Moreover, the company has an incentive to keep rates for regulated competitive services as low as possible and to make up any cost deficiencies by raising residually priced monopoly service rates. Therefore, it is important for the Commission to have cost-of-service information available to evaluate the company's pricing strategies.

Several factors determine the choice between alternative costing and pricing methods: equitable treatment of all customers, efficiency and innovation, and managerial accountability are foremost. In addition, the Commission should foster fair competition between Bell and its competitors and otherwise promote an orderly market. From the point of view of monopoly-service ratepayers, a critical concern is the maintenance of universal service and avoidance of cross-subsidization and discrimination.

To protect the subscribers of monopoly services, the Commission may wish to develop accounting safeguards for distributing costs to these services in a manner that prevents Bell from exploiting them to further the company's ambitions in future competitive and deregulated markets.

The Federal Communications Commission (FCC) has investigated the allocation of costs between regulated and unregulated services, and the dichotomy there is similar to that between competitive and noncompetitive services in Texas. Specifically, CC Docket No. 86-111 is a generic proceeding initiated to address cost allocation between competitive and noncompetitive services.

While there is more than one method of fully allocating costs, the methods considered have significant common characteristics. The first step is to directly assign the maximum amount of operating expenses and investment costs. Any costs that cannot be directly assigned are treated as common costs, which are allocated in a second step using either indirect measures of cost causation or general allocators.

In Dr. Bolter's opinion, Bell failed to show that its ESSX Custom service is recovering its cost; thus, it is likely to harm basic service subscribers.

The company has not justified its cost allocation method, and it relies on inconsistent data, applications, and procedures. Accordingly, Dr. Bolter recommended that the Commission reject Bell's approach and develop costing guidelines and a costing manual that would reasonably allocate overhead and common costs to all services, including ESSX Custom service. Revenue-requirements allocation rules would limit the burdern of basic services to their stand-alone costs.

D. Position of State Purchasing and General Counsel

State Purchasing supports Bell's IUC model, noting that the company's approach to pricing ESSX Custom service is conservative and may overstate the cost of providing ESSX Custom service. In addition, State Purchasing takes the position that the State may not be charged rates for ESSX Custom service that exceed the actual cost of providing the service or that are used to subsidize other classes of private customers.

General Counsel witness David Featherston, a telephone rate analyst, also supported Bell's use of IUC studies. In his opinion, the company assigns the relevant portion of costs to each ESSX Custom customer. As a result, rates for ESSX Custom are above costs and provide a contribution to common costs. Mr. Featherston therefore recommended that Bell's IUC cost model be approved.

E. Discussion and Recommendation

[1] In the ALJ's opinion, the IUC model developed by Bell correctly determines the minimum rates Bell may charge in an ESSX Custom service contract. Approving the IUC model in this case would be consistent with the Commission's approval of ESSX-400 rates, which were set on the basis of incremental unit costs plus a contribution. Accordingly, the Commission should continue to allow Bell to use an IUC model to determine the floor for ESSX Custom rates.

1. The FDC Model

With respect to the FDC model proposed by ROLM, the ALJ is persuaded by the testimony of Wenders and Ho that such a model is entirely inappropriate for determining whether a competitive service such as ESSX Custom is recovering its costs.

The FCC cost manual.--In brief, ROLM notes that the FCC has prescribed a cost manual that fully allocates costs between regulated and nonregulated services. *Separation of Costs of Regulated Telephone Service from Costs of Nonregulated Activities*, CC Docket No. 86-111 (adopted Dec. 23, 1986; released Feb. 6, 1987). However, the FCC's order expressly disclaims any attempt to attribute costs to unregulated activities for the purpose of establishing a relationship between cost and price. *Id.* at para. 41.

Thus, although the FCC's model allocates costs to nonregulated competitive activities, it is up to the company competing in the marketplace to recover (or fail to recover) those costs. *Id.* at para. 115. The distinguishing circumstance of this case is that ESSX Custom service remains regulated, and Bell must be allowed to recover its reasonable costs through regulated rates. The pricing issue therefore cannot be set aside in this case as it was (quite properly) set aside by the FCC for the purpose of separating the costs of regulated and nonregulated activities.

In posthearing pleadings, ROLM also contends that in CC Docket No. 86-111, Southwestern Bell filed comments and a cost allocation manual that (1) take a position contrary to the telephone company's position in this case and (2) demonstrate the feasibility of ROLM's recommendation in this case. In the order, however, the FCC clearly noted that Bell "asserts its objection to [the] use of fully distributed costing for pricing purposes, but states that it has filed a manual proposing fully distributed costing because it believes that is what we want to see." *Id.* at para. 100. Bell's position before the FCC therefore appears to be consistent with its position in this case.

Dr. Bolter's incremental-cost test.--Remarkably, ROLM's own witness Dr. Bolter agreed on cross-examination that incremental costs should be used to determine whether one service is subsidizing another. Tr. at 1588-90. The cross-examination referred to a discussion of the issue in a book coauthored by Dr. Bolter:

> A service (or group of services) is *not* receiving a subsidy, *i.e.*, is *compensatory*, if gross incremental revenues at least recover the gross incremental cost of the service. . . . A service which passes the incremental cost test involves no cross-subsidy, since ". . . under these circumstances the revenues contributed by purchasers of [the service] must at least cover the costs imposed upon the supplier in the course of serving them."

W. Bolter, J. Duvall, F. Kelsey & J. McConnaughey, *Telecommunications Policy for the 1980s: The Transition to Competition* 96 (1984) (emphasis in the original) (quoting Baumol, *Minimum and Maximum Pricing Principles for Residual Regulation*, 5 E. Econ. J. 242 (1979)), Examiner's Exh. 9. Thus, according to Dr. Bolter's own book, the Commission should examine incremental costs, not fully distributed costs, to determine whether ESSX Custom service is receiving a subsidy or compensating other services.

2. The IUC Model

The controlling principle is cost-causation: so long as a competitive service produces more revenues than costs, there is a contribution to common costs that will lower the burden borne by users of residually priced services. And that burden will be lower even if the rates charged for the competitive service do not cover its fully distributed costs.

Contrariwise, to the extent that common costs are "allocated" to a competitive service, the Commission will not have an accurate measure of the effect of continuing or terminating that service. The question is not whether each service receives a "fair" or "equitable" allocation of common costs. Indeed, the practical result of focusing on the distribution of common costs is that revenue-maximizing activity is inhibited. As a result, imposing an FDC standard would mean a smaller contribution from the competitive service and an increased burden on residually priced services.

It is appropriate for the Commission to approve a costing method that fosters competition. Section 2 of PURA states that public regulation of utilities should operate as a substitute for competition. Moreover, section 18(e) grants the Commission authority "to allow local exchange companies to respond to significant competitive challenges."

ESSX Custom service is offered in a competitive market, and the IUC model enables Bell to emulate an unregulated firm in pricing ESSX Custom service. As explained by the Bell witnesses and by General Counsel witness Featherston, the IUC model and customer-specific contracts provide the company with the flexibility to respond to the market for PBX-type switching services. Moreover, as explained by Prof. Wenders, economic theory supports the use of an IUC model, because it is a straightforward application of the profit-maximizing principles that guide unregulated firms in competitive markets. The model thus prevents anticompetitive behavior by the telephone company. By contrast, the FDC model would impose on Bell the traditional constraints of regulation, preventing it from effectively competing with unregulated firms.

Allowing Bell to use an IUC model also satisfies other objectives and requirements set forth in PURA. By setting incremental costs as the minimum price for ESSX Custom service, the company should be able to sell the service to more customers, thereby increasing the contribution from the service. The contribution above incremental cost will be used to hold down the rates for residually priced basic service.

Accordingly, the ALJ recommends that the Commission continue to allow Bell to use an IUC model to set the floor for ESSX Custom prices.

V. Recovering the Cost of ESSX Custom Service

A. Introduction

ROLM contends that even if the IUC model were correct, Bell's application of the model is so faulty that the company cannot demonstrate that ESSX Custom service would recover its costs. Specifically, ROLM argues that (1) Bell has failed to correctly identify and attribute certain costs to ESSX Custom service, (2) Bell does not in fact use individual customer cost studies to determine incremental cost, and (3) there are other specific defects in Bell's cost-identification procedures.

General Counsel argues that Bell should not be allowed to recover costs that should have been recovered by ESSX Custom rates but that were not recognized in the studies. In particular, the company apportions certain capital costs to future ESSX Custom customers. General Counsel contends that the other ratepayers should not be required to bear these costs if such customers do not materialize.

Bell defends its procedures as the proper application of the theoretical incremental cost model. In particular, Bell argues that it includes all costs properly includible in incremental costs. The company concedes that it uses average cost data and rates from other tariffs in its IUC model, but contends that in each instance, the use of such data tends to overstate costs. With respect to General Counsel's recommendation, Bell contends that its forecasts are as accurate as possible and that so long as ESSX Custom is a regulated service, the company should be allowed to recover the reasonable costs.

Bell provided extensive evidence during the 10 days of hearing to support its procedures. The ALJ is persuaded by the evidence and the testimony of Bell's witnesses that the company properly applies the IUC model to determine the cost of providing ESSX Custom service to individual customers.

Although ROLM showed that some costs attributable to ESSX Custom service are not included in the cost studies, Bell demonstrated that the costs are sunk rather than incremental costs and should not be considered in determining the floor price. These costs should be periodically reviewed to determine whether ESSX Custom should be continued, but such a review is beyond the scope of this case.

General Counsel's recommendation raises a proper concern about the reasonableness of the costs Bell incurs to provide ESSX Custom service and the need to determine whether ESSX Custom service is paying its way as a class of service. However, Bell must be allowed to recover the reasonable and necessary expenses of ESSX Custom service so long as ESSX Custom service, taken as a whole, is generating a net contribution.

B. The Issue of Individualized Cost Studies

Much of Bell's direct case was devoted to demonstrating that the company determines the cost of providing ESSX Custom service on a customer-by-customer basis. ROLM contended in its direct case that the telephone company in fact uses average costs and other nonindividual data in estimating costs.

1. Simulated Access Lines

ROLM witness Fred Kelsey, a telecommunications consultant, testified that Bell analyzes only a small portion of the costs associated with serving an individual customer. ROLM Exh. 28. at 3. In particular, the company does not study all network costs that would be caused by a prospective customer. Instead, the total rate is built up from a combination of individually studied costs and a standard rate element. As a result, ROLM contends that, at best, Bell estimates the cost of serving an average customer of the proposed customer's size and location.

Mr. Kelsey pointed out examples of Bell's use of nonindividualized data. One of the most significant charges for ESSX Custom service is that for simulated access lines (SALs), which are not physical lines but rather a software-based blocking of access to the ESSX Custom customer. SALs are a feature of ESSX Custom service that allows it to be tailored to the customer's needs and operating budget; the charges for SALs can compose from around 20 to 40 percent of the customer's monthly rate.

In costing ESSX Custom service to determine its minimum price, however, Bell does not determine the cost of providing SALs to the proposed customer; rather, the company simply uses the standard rate element for SALs. According to ROLM witness John Williams, a telecommunications consultant, there is no cost-study support for such rates and no rational basis for using them. ROLM Exh. 27 at 8.

In response, Bell notes that its ESSX Custom costing procedures result in its accounting for both the cost of the loops and the SAL charge. Thus, the ESSX Custom service subscribers pay the same loop cost as PBX customers and then pay again for loop costs through their ESSX Custom service rates. On cross-examination, ROLM witness Williams conceded that the procedure appeared to result in Bell's charging for "something that is not there." Tr. at 877.

In the ALJ's opinion, it does not appear that Bell is improperly ignoring a cost by accounting for a SAL charge. In addition, Mr. Ho explained on cross-examination that the company calculates the cost of installing the number of cables the prospective ESSX Custom customer will require plus a five percent allowance for spare capacity. Tr. at 529-30. The company's procedures appear to be a proper application of the IUC model.

2. Loop Costs

In a related area, Kelsey and Williams testified that Bell's calculations do not reflect a proper allocation of loop costs. Loop costs are estimated on the basis of the cost of installing new loop facilities sufficient to provide the requested service, rather than on the basis of the existing loop facilities. Dr. Williams pointed out that Bell's costing procedures thus favors existing Centrex customers with shorter-than-average loop lengths, because by switching to ESSX Custom service, these customers can negotiate a lower price. *Id.* at 14.

Moreover, the company ignores noninvestment costs, such as maintenance and administration expenses. In Mr. Kelsey's opinion, a true customer-specific costing method would develop outside subscriber plant costs on a stand-alone basis. On cross-examination, Mr. Kelsey conceded that factors other than loop length affect the cost of loops. Tr. at 955.

Bell contends that such factors, such as cost of easements and the expense of laying trunk lines, explain the apparent inconsistencies in loop cost that Mr. Kelsey perceived, since the company bases its cost estimate on the cost of installing facilities for the prospective customer.

The ALJ concludes that Bell's procedures do not underestimate the incremental cost of the loops used to serve ESSX Custom customers.

3. Traffic Studies and Switch-Related Costs

According to ROLM, the most important fault in Bell's method of identifying switch costs is the general lack of individual traffic studies. Traffic studies have been performed for some customers but not for others. ROLM contends that Bell cannot know the proper amount of switch-related costs to attribute to an individual customer unless it knows how much traffic the customer will present to the serving switch.

In addition, ROLM noted that Bell identifies switch costs by using the installed costs of the particular switch used to provide the service, rather than the replacement cost that would be consistent with its other costing practices.

Bell concedes that the average traffic data it uses is not customer-specific, but notes that it is usually higher than data provided by customers. Tr. at 1750 (cross-examination of Ho). Thus, using the average traffic data would usually produce a higher cost figure for ESSX Custom service. Mr. Ho testified that if valid customer data is available, Bell uses it; however, time constraints usually do not allow for the collection of data.

The ALJ concludes that under the circumstances, Bell's use of average traffic data is reasonable and is unlikely to result in the underpricing of ESSX Custom service.

4. Selling and Marketing Expenses

Mr. Kelsey pointed out also that Bell includes selling and marketing costs in a general category of administrative expenses that are based on a factor applied to investment. ROLM Exh. 28 at 8. ROLM contends that such expenses, rather than being related to plant, are more responsive to the nature of the service and the demands of the customers. Mr. Kelsey expected such costs to be greater than average for ESSX Custom service, so the use of average factors would underassign costs to ESSX Custom service.

On cross-examination, Mr. Kelsey acknowledged that he had performed no studies to support his assumption that selling and marketing expenses are higher for ESSX Custom service. Tr. at 964. In addition, he conceded that if ESSX Custom investment is greater than average investment, applying the same factor would yield a higher allowance for these expenses.

Bell witness Melson described the duties of the account executives, explaining that while they meet with larger subscribers more frequently, part of the contacts would be for the purpose of selling additional services, not just supporting the ESSX Custom service. Tr. at 167.

In the ALJ's opinion, Bell's procedures for estimating selling and marketing expense are consistent with the IUC model.

C. Other Alleged Defects in Bell's Procedures

1. Preparation Costs

ROLM points out that to the extent that Bell focuses on the cost of serving an individual customer, it will ignore costs that are attributable solely to the class of ESSX Custom customers. One example of such a cost would be the legal and executive costs incurred in this case. Another such cost would be the preparation cost incurred to prepare quotes for requested ESSX Custom service. The preparation cost of a bid is included in the cost of service to the requesting customer. However, the cost of unsuccessful bids is never included in the cost assessment. According to Mr. Kelsey, the costs of the unsuccessful bids will fall on the residual ratepayers unless they are assigned to ESSX Custom service.

Bell responds that it is properly applying the incremental cost model: the costs of preparing unsuccessful bids are not properly included in the incremental cost of serving any customer, because once the costs are incurred they are sunk costs.

The ALJ agrees with Bell that the cost of preparing unsuccessful bids should not be allocated among ESSX Custom customers. However, the company may not properly ignore these costs. As is explained below in the section discussing General Counsel's recommendation, costs attributable to ESSX Custom service that are not included in the incremental cost of service must be offset by the contribution from ESSX Custom service.

2. Spare Capacity

In addition, Mr. Kelsey testified that Bell's costing procedures do not assign sufficient excess loop capacity to ESSX Custom subscribers. ROLM Exh. 28 at 20-21. In calculating the loop cost for ESSX Custom, Bell allows for a 5 percent spare capacity. Total outside plant for all services, however, is planned with a 15 percent spare capacity. According to Mr. Kelsey, the company's method therefore shifts the costs of excess capacity to residually priced services.

According to Mr. Ho, the company's method of costing cables often builds in substantial spare capacity, because cables are sized in discrete increments and the cost will generally be based on a greater number of pairs than is necessary to serve the customer. Mr. Kelsey acknowledged that the company's procedure is a reasonable way of allowing for spare capacity. Tr. at 1132-33.

The ALJ concludes that Bell's procedure does not underestimate the cost of providing ESSX Custom service.

3. Administrative Costs

ROLM contends that Bell attributes an inadequate portion of administrative costs to ESSX Custom service. For one customer, the cost studies were based on an administrative-expense-cost-factor study performed in 1984, using data from 1983. Moreover, ROLM notes that the study purports to allocate only about one third of Bell's administrative expenses. According to ROLM, Bell must be understating the amount of administrative expense that should be attributed to the services it offers. Mr. Kelsey testified that since these expenses are incurred to serve all service offerings, a fair share of the costs should be assigned to ESSX Custom.

Bell responds that ROLM's allegation is simply a criticism of the IUC model used to develop the cost of ESSX Custom service. As a result, it does not demonstrate that Bell did not correctly apply the model.

The ALJ agrees with Bell. The purpose of the IUC model is to determine the minimum price that a competitive service such as ESSX Custom must earn in order to provide a contribution to common costs. It does not purport to fairly assign costs; moreover, as explained above, if principles of fair distribution of costs are applied to the model, it would no longer serve its purpose.

4. Maximization of Revenues

a. ESSX Custom versus Centrex.--ROLM notes that according to Bell witness Melson, a Bell sales person would not want to sell ESSX Custom service to an existing Centrex customer (thus lowering the customer's rates) unless the customer is "competitively vulnerable." Tr. at 143-44. Mr. Springfield also testified that Bell should not try to get existing Centrex customers to convert to ESSX Custom; rather, the company should determine which customers are in a competitive situation and respond to requests from customers for the service. Tr. at 633.

According to ROLM, however, Bell does sell ESSX Custom service to existing Centrex customers without any reasonable foundation for believing that the customers are competitively vulnerable. Three ESSX Custom customers testified why they chose Bell's ESSX Custom service. Richard Riker testified on behalf of M.D. Anderson Hospital in Houston. Mr. Riker stated that early in the decision process, his organization determined not to purchase or lease a PBX system; it converted from Centrex to ESSX Custom to obtain lower rates. State Purchasing Exh. 14 at 3-4. Steve Rosenfeld testified for the University of Texas at El Paso (UTEP). Mr. Rosenfeld stated that UTEP had initially spoken to both Bell and AT&T, but solicited an ESSX Custom proposal only after deciding not to buy a PBX. Tr. at 763-67. Finally, Robert Whipple testified for Texas Tech University. He stated that Texas Tech had never issued a request for competitive proposals at the time Bell informed his office of ESSX Custom service.

ROLM argues that if Bell were truly attempting to maximize its revenues from Centrex-type services, it would have insisted on selling its tariffed Centrex service to these customers, who had decided to choose nothing other than Centrex. At the least, Bell would have charged these invulnerable customers a high markup over its identified costs. But the identified markup for Texas Tech is 20 percent, or much lower than the 50 percent markup for Shell Oil. Thus, ROLM concludes that ESSX Custom service is reducing Bell's revenues from all Centrex services, and thus the company is not maximizing its revenues.

Bell responds that it cannot be expected to know which customers who inquire about service alternatives are considering the purchase of a PBX system. The company points out that large customers--the only type that qualify for ESSX Custom service--are in most cases talking to Bell's competitors about service alternatives. It is reasonable for Bell's account executives to present ESSX Custom service offerings to these customers, and it is unreasonable to conclude that Bell is not maximizing profits simply because these customers pay less for ESSX Custom than they paid for the previous Centrex service.

Bell contends that in general, it has no way of knowing for certain whether its customers will stay with Centrex. It points out that Centrex revenues have fallen substantially. Mr. Springfield testified that Centrex annual revenues as a category (excluding ESSX Custom service) fell from about $32 million in 1984 to about $17 million in August 1986. Tr. at 690. At the time of the hearing, ESSX Custom service annual revenues were about $5 million. ROLM Exh. 5.

Finally, Bell reiterates that the determination of ESSX Custom's service effect on other regulated service ratepayers must be based on whether the service is recovering costs as properly measured. The question of whether Bell might still be collecting Centrex revenues in isolated instances is irrelevant.

The testimony of the state agency witnesses also supports Bell's contention that large customers are well aware of their telecommunications options. Unless the telephone company is allowed to respond to competition, such customers can be expected to leave the regulated telephone system.

The ALJ agrees with Bell's analysis. The decline in Centrex revenues is a strong indication that the service category is vulnerable to competition. Even if ESSX Custom service revenues are added to the Centrex revenues, there is still a significant decline.

b. ESSX Custom versus PBX.--ROLM points out that Centrex and ESSX services are inefficient in terms of the telephone company facilities employed--

particularly when compared with a PBX system. If a Centrex and ESSX customer converts to a PBX system, hundreds and usually thousands of access lines are freed for other uses and additional revenues.

For example, ROLM notes that M.D. Anderson would pay Bell about $59,000 in monthly revenues if it converted to a PBX. While this is substantially less than the $113,000 a month it pays in ESSX Custom service rentals, nearly 5,900 lines would be freed for use. According to ROLM, if these lines were all re-used at the single-line business rate, Bell would receive about $297,000 in monthly revenue, or much more than it receives from the ESSX Custom service. Moreover, as Bell's forecasts indicate, all but a small portion of the lines are classified as reusable--meaning that the company expects a demand for the facilities within five years. Tr. 331-34.

ROLM's calculations may accurately describe the future--in which PBX systems replace central-office-based systems. According to Bell witness Melson, ESSX Custom prices are generally significantly higher than PBX prices. Tr. at 129-30. However, even if customers do convert to PBXs, there would still be the question of how the adjustment should be made. ROLM did not suggest that Bell is capable of immediately reusing the facilities that are idled when Centrex customers switch to PBXs. Mr. Bearden, the Bell witness who testified about the reusability forecasts, could not say when in the five-year forecast period the facilities would be reusable. Tr. at 333. The ESSX Custom service contracts of record in this case have a term of two to three years. Thus, even if eventual conversion to PBXs were certain, ESSX Custom service would serve an important role as a transition service, enabling the telephone company's facilities to provide earnings until there are other demands for them. And if ROLM is not correct about the conversion to PBXs, profits from Bell's ESSX Custom service would continue to reduce the common costs borne by other ratepayers.

VI. Recommendations

A. ROLM

ROLM notes that the central inquiry in this case is the amount of costs for which ESSX Custom service should be responsible so that regulated ratepayers are protected from the burden of cross-subsidization. Once the "cost responsibility" is determined, Bell may price ESSX Custom service as the market requires. That is, ROLM does not advocate using the cost allocation to determine a price floor; rather, it would use it to determine the share of Bell's revenue requirement that would be excluded from the responsibility of Bell's regulated ratepayers.

In its opening argument, ROLM argued that Bell should be prohibited from offering ESSX Custom service to new customers until it can propose a "demonstrably fair and easily auditable costing model." Alternatively, the Commission should require Bell to develop a new pricing scheme that would insulate monopoly-service subscribers from any losses Bell may incur as a result of its ventures into competive markets.

ROLM contends that the Commission should undertake to identify means of protecting regulated ratepayers, and it offers two alternatives for consideration. One, the Commission could determine the stand-alone cost for the monopoly services it must protect, set rates for those services on the basis of their costs, and then allow rates for other services to be set as Bell wishes. Two, all costs could be identified and cost responsibility assigned to the various services.

B. State Purchasing

State Purchasing contends that regardless of the Commission's decision with regard to the pricing of ESSX Custom service to private subscribers, the rates charged to state agencies for the service may not be based on a method that allocates costs in excess of direct costs. Since Bell's cost model accurately identifies these direct costs, existing state agency ESSX Custom subscribers should be allowed to obtain the service under the present arrangements, without restriction.

C. General Counsel

General Counsel urges that the resolution of this case not include an endorsement of any specific cost model over another for general ratemaking purposes. This case deals only with the cost support for Bell's ESSX Custom service, and the record in it is not a suitable basis for a general ratemaking cost model. Thus, General Counsel recommends that the Commission approve Bell's cost model only for ESSX Custom service.

General Counsel believes that the public interest is best served if Bell retains its Centrex customers by offering ESSX Custom service. Pricing ESSX Custom service to at least recover incremental costs is necessary to provide Bell the flexibility to compete in the PBX market. General Counsel recognizes that ESSX Custom service enables individual customers to obtain service at less than average cost, so Bell will lose some Centrex revenues. The choice, however, is between losing some or all Centrex revenues, because Centrex is a competitive service.

General Counsel recommends that Bell be required to separately account for certain plant used to provide ESSX Custom service. Specifically, Bell's cost model does not apportion all of the plant costs to a current ESSX Custom subscriber if it expects there will be a future demand for the plant after the current subscriber's contract expires. At the same time, since the company does not include sunk costs in its calculation of incremental costs, General Counsel notes that the plant costs would not be included in the cost studies for the future customers. As a result, General Counsel is concerned that monopoly services may wind up bearing these plant costs. A separate accounting would make it possible to disallow plant that the company chose for competitive reasons not to recover from the initial customer.

In addition, General Counsel recommends that the ESSX Custom tariff include a statement that IUC studies are conducted to develop rates and that the rates are subject to Commission review.

Bell's response.--Bell notes that the cost of plant prorated to the future is a necessary expense of providing ESSX Custom service. A requirement that the cost of inaccurate forecasts be borne by Bell's shareholders is inappropriate. Such a requirement would impose on the shareholders the risk of offering the service, even though the shareholders' benefit is limited to a regulated rate of return. Bell contends that the General Counsel's proposal would be appropriate only if ESSX Custom service were deregulated (which no one has advocated). Only then would there be a balancing of the risks and the benefits to the shareholders.

D. Discussion and Recommendation

In the ALJ's opinion, Bell's IUC model is the appropriate theoretical method of determining the minimum price that the company may charge for ESSX

Custom service to a customer. In addition, the company is appropriately applying the model to determine minimum prices. The ALJ therefore recommends that the Commission approve the use of the IUC model with Bell's ESSX Custom tariff. As recommended by General Counsel, this approval should not be construed an endorsement of IUC models for general ratemaking purposes.

Moreover, it should be understood that approval of the IUC model in this case is solely for the purpose of determining minimum prices and that in the event that ESSX services are deregulated, the ESSX Custom cost of service will be subject to full review by the Commission for the purpose of allocating costs between regulated and unregulated services.

General Counsel recommends that Bell separately account for all plant that is prorated to future ESSX Custom customers and that any costs that were incorrectly excluded from the rates for current ESSX Custom service contracts be disallowed in future rate cases. In the ALJ's opinion, the recommendation as stated by the General Counsel is inconsistent with the law and with economic theory of the cost studies. However, with a modification it provides an appropriate guide for the Commission.

ESSX Custom service is a regulated service. Section 39(a) of PURA requires that rates be set in a manner that allows the utility to recover its reasonable and necessary operating expenses. The omission of a cost from a cost study would not make that cost unreasonable or unnecessary and thus unrecoverable through rates. Indeed, omission from a cost study does not even imply that the cost is not recovered by ESSX Custom service, because the cost studies are used only for setting the *minimum* price of the service to an individual customer. According to Bell, the company makes every effort to earn as much contribution from each contract that it can. As long as the overall contributions from ESSX Custom service exceed any omitted costs, there is no burden on monopoly services and no rationale for disallowing the costs as recommended by General Counsel.

This is not to say that the prorated costs can be ignored. Bell's own witness Prof. Wenders acknowledged that the company must periodically review its ESSX operations in Texas to determine whether the service is contributing to the company's regulatory revenue requirement. He noted that if it does not, it should be abandoned.

Such a review is necessary because of the nature of IUC pricing: prorated costs and processing costs are not properly considered when determining the minimum price to an individual subscriber even though they are causally related to ESSX Custom service (as a class of service). The class of service must therefore be periodically reviewed to determine that it generates enough revenues to cover the costs excluded from the IUC studies for individual subscribers.

[2] In the ALJ's opinion, Bell should be held accountable to Prof. Wenders's standard. The company should be required to separately account for the prorated plant costs, the expense of processing unsuccessful bids, and all other expenses that are causally related to the class of ESSX Custom service, but that are excluded from the IUC studies for individual customers. In the company's current rate case and in future rate cases, Bell should present evidence regarding the profitability of ESSX Custom service as a class. If ESSX Custom service as a class has not generated a net contribution to common costs, the amount of costs exceeding revenues would be subject to being disallowed as an imprudent, unreasonable, and unnecessary expense. This is not to suggest that the lack of a net contribution would be sufficient evidence to demonstrate that any ESSX-Custom-related expenses should be disallowed. Rather, the lack of a net contribution would make Bell's ESSX Custom activities more susceptible to challenge.

The ALJ therefore recommends that the Commission adopt the following findings and conclusions, which would support an order implementing the ALJ's recommendations.

VII. Findings of Fact and Conclusions of Law

A. Findings of Fact

1. Bell is a telephone utility certified to provide local exchange telephone service to areas in Texas under Certificate No. 40079.

2. This case was initiated on March 24, 1986, by an order severing ROLM's challenge to Bell's costing model for ESSX Custom service from Docket No. 6555. In this case, Bell has not proposed to change any of its rates, and no challenge to any of the company's rates has been raised.

3. Bell provided and published notice as described in section II of this Report. ROLM and State Purchasing are the only intervenors in this case.

4. ESSX Custom service is a central-office-based PBX-type service for systems of more than 400 stations that is provided pursuant to customer-specific contracts. Bell received approval from the Commission to provide ESSX Custom service in January 1985.

5. ESSX Custom service is a regulated service subject to significant competition.

6. For the reasons discussed in section IV of this Report, an IUC study determines the amount of costs that must be recovered by a contract to provide ESSX Custom service without a subsidy from regulated monopoly service. Any revenues collected in excess of that amount constitute a contribution from that contract to common costs.

7. By using an IUC model to determine a floor for prices in ESSX Custom contracts, Bell emulates a competitive firm's behavior in the market for PBX-type service.

8. For the reasons discussed in section IV of this Report, a fully distributed cost study does not determine the appropriate amount of costs that must be recovered by a contract to provide ESSX Custom service.

9. For the reasons discussed in section V of this Report, Bell is correctly using the IUC studies to determine a floor for prices in ESSX Custom contracts.

10. If the incremental revenue generated by an ESSX Custom contract equals or exceeds the incremental cost of providing service pursuant to that contract, the rates in the contract are not preferential or discriminatory, subsidized by regulated monopoly service, or anticompetitive.

11. As discussed in section VI of this Report, the costs of prorated plant, the expense of processing unsuccessful bids, and other similar expenses are properly attributable to the class of ESSX Custom service, but are properly ignored in incremental cost studies. These costs must be considered to determine whether ESSX Custom service as a class of service is providing a net contribution to common costs.

B. Conclusions of Law

1. Bell is a public utility as that term is defined by section 3(c) of PURA.

2. Pursuant to sections 16(a) and 18(a)-(b) of PURA, the Commission has jurisdiction and authority in this proceeding to review and approve the method by which Bell determines the minimum price it will charge in an ESSX Custom service contract.

3. This proceeding does not involve a change in any of Bell's regulated rates as that term is defined by section 3(d) of PURA.

4. Notice of this proceeding was properly provided in accordance with the requirements of P.U.C. Proc. R. 21.25.

5. Rates in a contract for ESSX Custom service determined on the basis of incremental costs plus a contribution will recover appropriate costs and will not be unreasonably preferential, prejudicial, or discriminatory; subsidized by regulated monopoly services; or predatory or anticompetitive.

6. If in Bell's current rate case or in future rate cases, the Commission determines that ESSX Custom service as a class is not generating a net contribution to common costs, the amount of costs exceeding revenues should be subject to disallowance as imprudent, unreasonable, and unnecessary expenses. Such a determination is not being made in this case.

7. The IUC cost model used by Bell to determine a floor for prices in ESSX Custom service contracts should be approved by the Commission.

Respectfully submitted,

Charles J. Smaistrla

CHARLES J. SMAISTRLA
ADMINISTRATIVE LAW JUDGE

APPROVED on the 3d day of March 1989.

Phillip A. Holder

PHILLIP A. HOLDER
DIRECTOR OF HEARINGS

DOCKET NO. 6771

INQUIRY INTO PRICING PRACTICES OF SOUTHWESTERN BELL TELEPHONE COMPANY UNDER THE ESSX CUSTOM TARIFF § PUBLIC UTILITY COMMISSION OF TEXAS

ORDER

In public meeting at its offices in Austin, Texas, the Public Utility Commission of Texas finds that after statutory notice was provided, the application in this proceeding was processed in accordance with applicable statutes and rules by an administrative law judge who prepared and filed an Examiner's Report containing findings of fact and conclusions of law. The Examiner's Report is ADOPTED and incorporated by reference into this Order. Accordingly, the Commission issues the following orders:

1. The use of the incremental unit cost model by Southwestern Bell Telephone Company ("Bell" or "the company") to determine the minimum price chargeable for service provided under an ESSX Custom service contract is APPROVED.

2. Bell shall separately account for prorated plant costs, the expense of processing unsuccessful bids, and all other expenses that are causally related to the class of ESSX Custom service, but that are excluded from the incremental cost studies for individual customers.

   Notwithstanding the approval granted in this Order, in Bell's current rate case and in future rate cases, the profitability of ESSX Custom service as a class will be subject to review. If the company fails to demonstrate that ESSX Custom service as a class has not generated a net contribution to common costs, the amount of costs exceeding revenues may be subject to disallowance as an imprudent, unreasonable, and unnecessary expense.

3. This Order applies to Bell's ESSX Custom service tariffs and, unless otherwise provided by the Commission, any Bell tariffs replacing ESSX Custom tariffs. This Order does not constitute Commission approval of incremental cost models for any other service or for general ratemaking purposes.

4. Motions, requests for relief, and proposed findings of fact and conclusions of law not granted by the Commission or by ALJ's order are DENIED for lack of merit.

SIGNED IN AUSTIN, TEXAS, on the 19th day of April 1989.

PUBLIC UTILITY COMMISSION OF TEXAS

SIGNED: Marta Greytok
MARTA GREYTOK

SIGNED: William B. Cassin
WILLIAM B. CASSIN

ATTEST:

Phillip A. Holder
PHILLIP A. HOLDER
SECRETARY OF THE COMMISSION

(cont.)

APPLICATIONS OF WATERWOOD COMMUNICATIONS, INC. CONCERNING THE PURCHASE OF TRI-QUEST COMMUNICATIONS, INC. AND SUBSIDIARY TRI-COUNTY TELEPHONE COMPANY, INC. § § § § §

DOCKET NO. 8043

February 15, 1989

Commission determined that corporate restructuring is consistent with the public interest, pursuant to PURA Section 63.

[1] CERTIFICATION--TRANSFER OF CERTIFICATES

Applicant purchased 100 percent of the stock of a utility but did not request the transfer of the utility's CCN. PURA Section 59 does not apply to the transaction because there is no sale, assignment, or lease of a CCN. (p. 2491)

DOCKET NO. 8043

APPLICATION OF WATERWOOD COMMUNICATIONS, INC. CONCERNING THE PURCHASE OF TRI-QUEST COMMUNICATIONS, INC. AND SUBSIDIARY TRI-COUNTY TELEPHONE COMPANY, INC.	§ § § § §	PUBLIC UTILITY COMMISSION OF TEXAS

EXAMINER'S REPORT

I. Procedural History

On March 17, 1988, Waterwood Communications, Inc. (Waterwood) filed an application for sale, transfer, or merger. The application reports Waterwood's purchase of Tri-Quest Communications, Inc. (Tri-Quest). The purchase, effective December 31, 1987, provides for the immediate liquidation of Tri-Quest and the continued operation of Tri-Quest's subsidiary, Tri-County Telephone Company, Inc. (Tri-County). Both before and after the transaction the two utilities, Waterwood and Tri-County, are owned in their entirety by two individuals, Gene Hunziker and Doyle Rogers.

An Order dated December 8, 1988, notified the parties that this case would be handled administratively unless a request for a hearing was filed by December 19, 1988. No party requested a hearing. There were no motions to intervene or protest statements filed. This case was therefore handled administratively without a hearing, pursuant to Section 13(e) of the Administrative Procedure and Texas Register Act. Tex. Rev. Civ. Stat. Ann. art. 6252-13a (Vernon Supp. 1988).

The staff submitted its recommendation on June 6, 1988. The staff recommended approval of the application and the general counsel concurred.

II. Discussion

A. Description of the Transaction

The reader may wish to refer immediately to Examiner's Attachment A, which is an organizational chart intended to assist the reader's understanding of the effects of the applicant's corporate restructuring.

Waterwood is a telecommunications utility that serves San Jacinto and Walker counties pursuant to its Certificate of Convenience and Necessity (CCN) No. 40091. Waterwood is owned in its entirety by H & R Properties, a partnership equally owned by the individuals Hunziker and Rogers.

Tri-County is a telecommunications utility that serves Nacogdoches and Rusk counties pursuant to its CCN No. 40085. Prior to the reorganization Tri-County was a wholly-owned subsidiary of Tri-Quest. Tri-Quest was a corporation owned in its entirety by Hunziker and Rogers.

In response to the Examiner's Order dated April 7, 1988, Waterwood filed a pleading that asserted there were two reasons to reorganize the companies owned by Hunziker and Rogers, the first being to "streamline the management and operations of the two separate telephone companies."

Second, the owners wished to refinance the debt owed by Tri-Quest that was related to the original acquisition of Tri-County. The Texas Bank for Cooperatives had a banking relationship with Waterwood and was willing to consolidate the Tri-Quest debt with the long-term indebtedness of Waterwood. (The Texas Bank for Cooperatives, located in Austin, was created pursuant to federal law. According to the Farm Credit Act of 1971, cooperatives eligible for loans from the Rural Electrification Administration may also obtain loans from the Texas Bank for Cooperatives. The Texas Bank for Cooperatives was reorganized in 1988 and is now part of the National Bank for Cooperatives.) According to Waterwood's response, the Texas Bank for Cooperatives can only loan to an operating telephone company or its subsidiary. Since Tri-Quest was not a telephone company, the Texas Bank for Cooperatives offered the refinancing only if Tri-County became a subsidiary of Waterwood.

Accordingly, on December 31, 1987, Tri-Quest transferred "all of its assets, business, goodwill, liabilities, contracts, and obligations" to Waterwood in exchange for shares of Waterwood stock. The transaction resulted in the following: the shares of Waterwood stock held by Tri-Quest were distributed to Hunziker and Rogers, Tri-Quest was liquidated, and Tri-County became the wholly-owned subsidiary of Waterwood.

B. Staff Recommendation

Commission staff member Mr. Blake Herndon, "based on an accounting review," recommended approval of the proposed transaction. He noted that there will not be an accounting acquisition adjustment in connection with this transaction and that no gain or loss will be recognized. Further, he noted that:

1. Waterwood and Tri-County will maintain separate accounting records.

2. Because management and ownership remain the same, customer deposits should not be affected.

3. There are no tax consequences. Waterwood and Tri-County may, however, file a consolidated tax return.

4. Waterwood and Tri-County will operate separately under their separate CCNs.

5. The transaction does not affect the tariff of either Waterwood or Tri-County.

6. The transaction does not affect customer rates.

Finally, Mr. Herndon recommended approval of the proposed journal entry to reflect Waterwood's acquisition of Tri-Quest. The proposed entry is shown on Examiner's Attachment B.

C. Hearings Examiner's Recommendations

Waterwood filed this application pursuant to P.U.C. SUBST. R. 23.12(d), and Sections 63 and 64 of the Public Utility Regulatory Act (PURA). Tex. Rev. Civ. Stat. Ann. art. 1446c (Vernon Supp. 1988). The various issues that are raised by this application are discussed separately:

1. Compliance with Section 64

Section 64 provides that, upon a public utility's purchase of voting stock in another public utility doing business in Texas, the purchasing utility must report the transaction to the Commission. The application in this case serves as adequate notice of Waterwood's purchase of Tri-Quest and its public utility subsidiary, Tri-County.

2. Section 63

Pursuant to PURA Section 63 and P.U.C. SUBST. R. 23.12(d), a utility must report to the Commission the sale of 50 percent or more of the stock of a utility. The corporate restructuring here includes this type of transaction because Waterwood obtained 100 percent of the stock of Tri-Quest and its public utility subsidiary, Tri-County. The Commission has the duty to investigate the transaction and to determine whether the transaction is "consistent with the public interest." In reaching its determination, the Commission must take into consideration the reasonable value of the property, facilities, or securities to be acquired, disposed of, merged or consolidated.

If the transaction is not in the public interest, the transaction must be taken into consideration in the next rate case. Further, the effect of the transaction will be disallowed if it would unreasonably affect rates or service.

An analysis of the facts of this case leads the examiner to recommend that the Commission find that the December 31, 1987 corporate restructuring is consistent with the public interest. There is little evidence to suggest that operations and customer service will be affected: the same two individuals own the Waterwood and Tri-County utilities after the reorganization, and the operations of the two utilities will remain separate. On the other hand, the reorganization permits the consolidation of debt and permits The Bank for Cooperatives to refinance on more favorable terms the debt related to the purchase of Tri-County. The reorganization also eliminates the Tri-Quest entity, which may save expenses previously dedicated to maintaining the corporation.

3. <u>No Transfer of Certificate Rights</u>

[1] This case was not analyzed pursuant to Article VII of the PURA ("Certificates of Convenience and Necessity" (CCNs)) because Waterwood did not request to transfer or amend a CCN. Section 59 of the PURA concerns the sale, assignment or lease of a CCN. But in the present case there is no sale, assignment or lease of a CCN. Certificate 40085 is held by Tri-County and will continue to be held by Tri-County no matter who its shareholders are. See <u>Application of Sandy Mountain Development Company, Inc.</u>, Docket No. 4065, 7 P.U.C. BULL. 628 (December 22, 1981); <u>Application of Century Telephone Enterprises, Inc.</u>, Docket No. 3304, 6 P.U.C. BULL. 68 (September 11, 1980).

4. <u>Customer Deposits</u>

Upon the sale of a public utility, the seller must file a list showing the names and addresses of all customers who have to their credit a deposit.

P.U.C. SUBST. R. 23.43(i). But, as the staff pointed out, customer deposits will not be effected by this reorganization. The examiner therefore did not require Waterwood to submit the list of customers.

5. Notice

As discussed above, this case did not concern the transfer of CCN rights. The notice requirements for licensing proceedings were therefore not imposed.

Further, there were no affected persons that were not already parties in this case. Upon the examiner's request, Waterwood submitted an affidavit that asserted that the reorganization would not directly affect neighboring utilities, cities, political subdivisions, or other parties. The balance of the record also indicated only the applicant itself was an "affected person" in this case. The purpose behind the reorganization was to obtain a favorable debt restructuring. There was nothing in the record, however, to suggest that the financial integrity of Waterwood or Tri-County is at stake or that the quality of service is threatened. The examiner therefore did not require Waterwood to publish notice or give direct notice to its customers.

The Commission published notice in the Texas Register concerning the evaluation of this case at the February 7, 1989, final order meeting. P.U.C. PROC. R. 21.25.

6. Approval of Journal Entry

The proposed journal entry to Waterwood's books concerning the acquisition of Tri-Quest records the assets, liabilities, and equity of Tri-Quest at book value. The staff approved of the entry. The examiner therefore recommends that the Commission order Waterwood to record the purchase of Tri-Quest using the journal entries attached to this report as Examiner's Attachment B.

III. Findings of Fact and Conclusions of Law

The examiner recommends that the Commission adopt the following Findings of Fact and Conclusions of Law:

A. Findings of Fact

1. There were no motions to intervene or protest statements filed in this case. The parties did not request a hearing within the time specified by the examiner. The case was therefore handled administratively without a hearing.

2. Waterwood provides local exchange telephone service within its certificated service area, under CCN No. 40091.

3. Tri-County provides local exchange telephone service within its certificated service area, under CCN No. 40085.

4. Prior to the corporate reorganization, Waterwood was owned by H & R Properties, a partnership; Tri-County was a wholly-owned subsidiary of Tri-Quest; Tri-Quest was a non-utility corporation. Both H & R Properties and Tri-Quest were owned in their entirety by the individuals Gene Hunziker and Doyle Rogers.

5. On March 17, 1988, Waterwood filed an application for sale, transfer, or merger. The application reports the December 31, 1987 corporate restructuring and seeks Commission approval.

6. The December 31, 1987, corporate restructuring effected the following changes: Tri-Quest transferred all of its assets, business, goodwill, liabilities, and obligations to Waterwood in exchange for shares of Waterwood stock; the shares of Waterwood stock held by Tri-Quest were distributed to Hunziker and Rogers; Tri-Quest was liquidated; and Tri-County became the wholly-owned subsidiary of Waterwood.

7. The reorganization will not affect Waterwood or Tri-County operations or customer service. The same two individuals own Waterwood and Tri-County before and after the reorganization. The reorganization does, however, allow the refinancing on more reasonable terms of the debt related to the original purchase of Tri-County.

8. The reorganization is in the public interest.

9. Waterwood did not request to amend its CCN nor Tri-County's CCN.

10. Customer deposits held by Waterwood or Tri-County will not be affected by the reorganization.

11. The reorganization will not directly affect neighboring utilities, cities, political subdivisions, or other parties.

12. The proposed accounting entries to record the reorganization on the books of Waterwood, identified here as Examiner's Attachment B, are reasonable.

B. Conclusions of Law

1. Waterwood and Tri-County are public utilities as defined by Section 3(c)(2) of the PURA.

2. The Commission has jurisdiction over the matters raised in this case pursuant to Sections 16(a) and 18(b) of the PURA.

3. The Commission has the authority to review the sale of 100 percent of the stock of a company and its wholly-owned public utility subsidiary, and the authority to determine whether such transaction is consistent with the public interest. Section 63 of the PURA.

4. The corporate reorganization that is the subject of this case is consistent with the public interest, within the meaning of Section 63 of the PURA.

5. The application filed in this case constitutes adequate notice that Waterwood purchased voting stock in Tri-County, within the meaning of Section 64 of the PURA.

6. Section 59 of the PURA concerns the sale, assignment or lease of a CCN. In this case there is no sale, assignment or lease of a CCN. Certificate 40085 is held by Tri-County and will continue to be held by Tri-County no matter who its shareholders are. See Application of Sandy Mountain Development Company, Inc., Docket No. 4065, 7 P.U.C. BULL. 628 (December 22, 1981); Application of Century Telephone Enterprises, Inc., Docket No. 3304, 6 P.U.C. BULL. 68 (September 11, 1980).

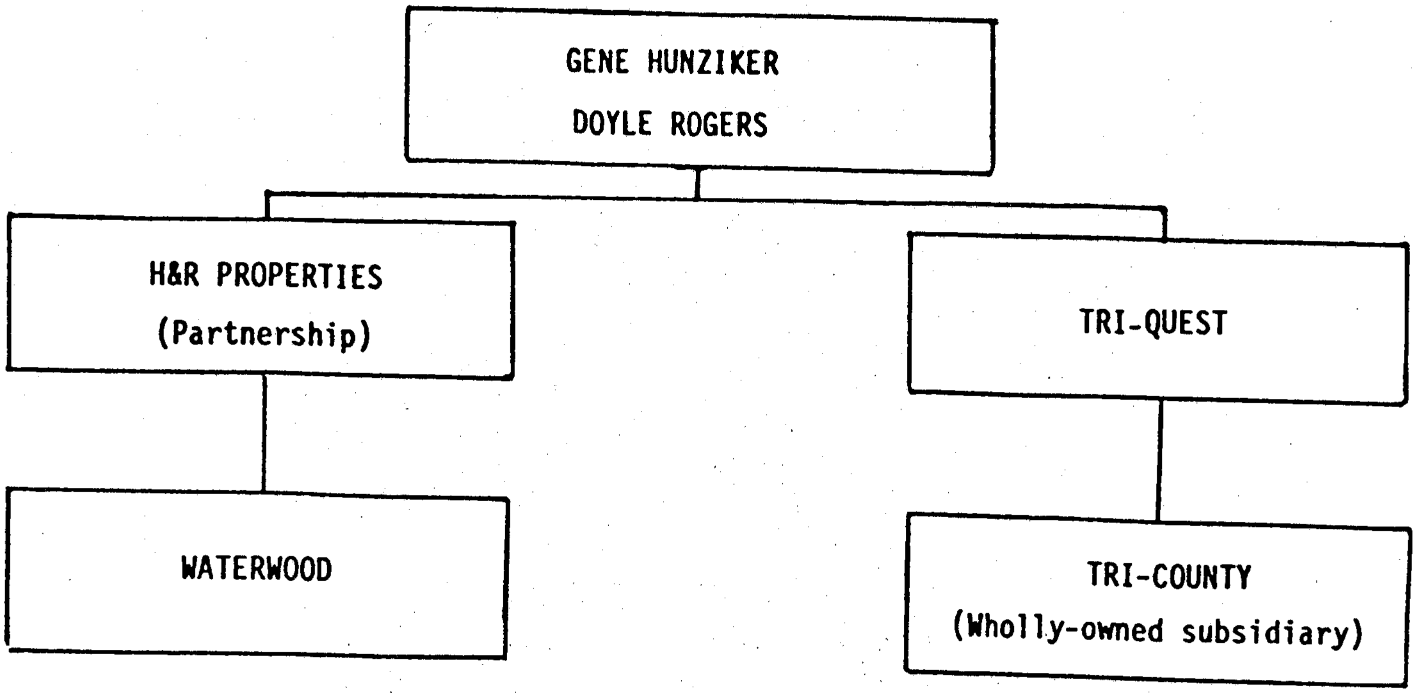
7. Waterwood was not directed to publish or give direct notice in this case because the reorganization that is the subject of this case will not affect other parties.

Respectfully submitted,

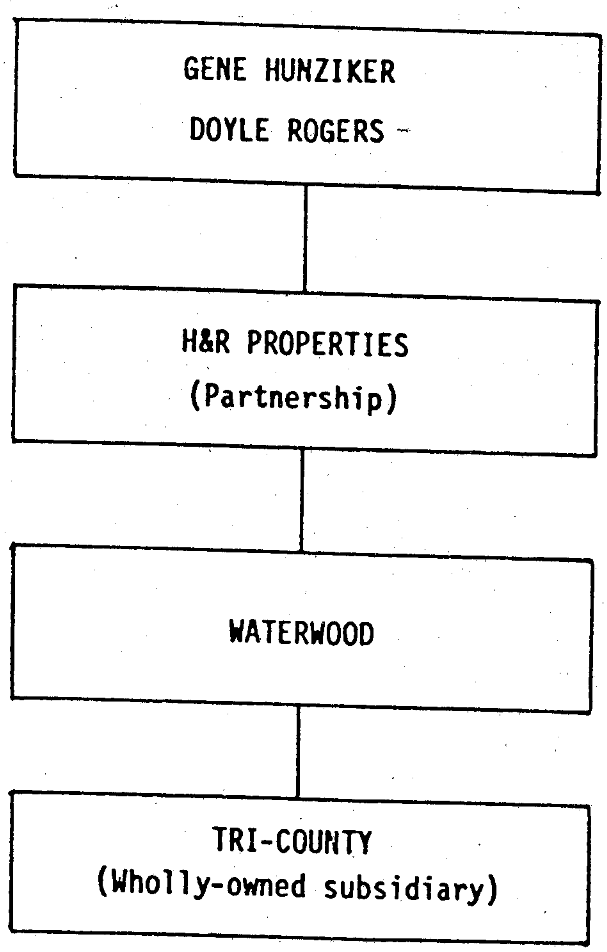
Richard S. O'Connell
RICHARD S. O'CONNELL
HEARINGS EXAMINER

APPROVED on the 23d day of January 1989.

Elizabeth Hagan Drews for
PHILLIP A. HOLDER
DIRECTOR OF HEARINGS



organization effective December 31, 1987



EXAMINER'S ATTACHMENT A

Cash	$ 1,674	
Accounts receivable - affiliates	19,856	
Vehicles (book value)	1,226	
Investment in Tri-County Telephone Co., Inc.	1,137,922	
Investment in Waterwood Mobile Telephone	5,100	
Accounts payable - affiliates		$ 205,664
Accounts payable - trade		222
Federal income tax payable		3,875
Other taxes payable		475
Notes payable		520,083
Capital stock (additional shares issued by Waterwood Communications)		1,990
Additional paid-in capital		161,020
Retailed earnings		272,449

This entry reflects the acquisition of Tri-Quest Communications, Inc., under the "pooling of interests" method of accounting whereby all of Tri-Quest's assets, liabilities, and equity are recorded at book value on Water Communications' books.

EXAMINER'S ATTACHMENT B

DOCKET NO. 8043

APPLICATION OF WATERWOOD COMMUNICATIONS, INC. CONCERNING THE PURCHASE OF TRI-QUEST COMMUNICATIONS, INC. AND SUBSIDIARY TRI-COUNTY TELEPHONE COMPANY, INC.	§ § § § §	PUBLIC UTILITY COMMISSION OF TEXAS

ORDER

In public meeting at its offices in Austin, Texas, the Public Utility Commission of Texas finds that the application in this case was processed by a hearings examiner in accordance with Commission rules and applicable statutes. An Examiner's Report containing Findings of Fact and Conclusions of Law was submitted, which report is hereby ADOPTED and made a part hereof. The Commission further issues the following Order:

1. Waterwood Communications, Inc. is ORDERED to record the purchase of Tri-Quest Communications, Inc. in accordance with the journal entries attached to the Examiner's Report as Examiner's Attachment B.

2. All motions, applications, and requests for entry of specific Findings of Fact and Conclusions of Law and any other requests for relief, general or specific, if not expressly granted herein are DENIED for want of merit.

SIGNED AT AUSTIN, TEXAS on this the 15th day of February 1989.

PUBLIC UTILITY COMMISSION OF TEXAS

SIGNED: Marta Greytok
MARTA GREYTOK

SIGNED: William B. Cassin
WILLIAM B. CASSIN

I respectfully dissent. The proposed corporate reorganization should not be approved because there is insufficient information in the record to conclude that the reorganization will not in the future detrimentally affect the capital structure of Waterwood Communications, Inc. or Tri-County Telephone Company, Inc.

SIGNED: Jo Campbell
JO CAMPBELL

ATTEST

Phillip A. Holder
PHILLIP A. HOLDER
SECRETARY OF THE COMMISSION

INQUIRY INTO THE RATES OF RAYBURN COUNTRY ELECTRIC COOPERATIVE, INC. AND APPLICATION FOR A CERTIFICATE OF CONVENIENCE AND NECESSITY § § § § **DOCKET NO. 7361**

March 9, 1989

Commission approved stipulation of the parties which provided a 1.59 percent increase in revenues over test year revenues, and approved of CCN application for utility's sole transmission line.

[1] PROCEDURE--NOTICE--NOTICE BY APPLICANT--WHEN REQUIRED

Direct notice to municipalities was not required, notwithstanding utility sought to change rates under PURA Section 43 because the applicant utility only provides wholesale electric service to distribution cooperatives and therefore its rates only indirectly affect municipalities. Further, no municipalities have jurisdiction over the applicant. (p. 2504)

[2] CERTIFICATION--SERVICE/FACILITIES THAT REQUIRE CERTIFICATION

Utility asserted that its sole electric line, a 36 foot 12.5 kv tie-line, need not be certificated because it was a distribution line operating below 60 kv. P.U.C. SUBST. R. 23.31(a)(1). Held: the tie-line is a transmission line because it does not serve end-use customers. Utility must apply for a CCN for the line. (p. 2530)

DOCKET NO. 7361

INQUIRY INTO THE RATES OF RAYBURN COUNTRY ELECTRIC COOPERATIVE, INC. AND APPLICATION FOR A CERTIFICATE OF CONVENIENCE AND NECESSITY	§ § § §	PUBLIC UTILITY COMMISSION OF TEXAS

SUPPLEMENTAL EXAMINER'S REPORT

I. Procedural History

A. Introduction

An Examiner's Report was issued in this docket on October 28, 1988. The report recommended that the Commission deny Rayburn Country Electric Cooperative, Inc. (Rayburn Country) status as a public utility and that the Commission deny approval of Rayburn Country's proposed rates. Following the Commission's November 22, 1988, Final Order Meeting, this docket was remanded to the hearings division. At the meeting the Commission considered and elected not to adopt the recommendations in the Examiner's Report. This Supplemental Examiner's Report is issued pursuant to the Order of Remand, dated November 22, 1988, which directed the hearings division to issue a "supplemental examiner's report with findings of fact and conclusions of law that would support approval of rates for Rayburn Country Electric Cooperative, Inc." The case was reassigned to the undersigned examiner on November 28, 1988.

This description of the procedural history of the docket is intended to supplement the procedural history portion of the October 28, 1988, Examiner's Report. The following discussion explains generally the procedure leading to the Commission's Order of Remand, and describes the subsequent procedure leading to this Supplemental Examiner's Report.

B. Nature of the Case

Rayburn Country Electric Cooperative, Inc. (Rayburn Country) initiated this docket on January 16, 1987. On that date Rayburn Country began operation of its only transmission line (Rayburn Country does not own generating facilities) and filed with the Commission its original tariff for electric service. The nature of the case has changed several times since that original tariff was filed. First, the case consisted of a review of an initial tariff filing. Second, the Commission's general counsel filed in July 1987 a request for a hearing. Examiner's Order No. 13 concluded that the request invoked the Commission's authority to conduct a hearing to inquire into the reasonableness of Rayburn Country's rates. Public Utility Regulatory Act (PURA), Section 42, Tex. Rev. Civ. Stat. Ann. art. 1446c (Vernon Supp. 1988). Finally, in response to the PURA Section 42 inquiry, Rayburn Country and the other parties agreed that Rayburn Country should prepare a rate filing package. The rate package, filed on April 4, 1988, included a statement of intent to change rates pursuant to PURA Section 43(a).

Examiner's Order No. 13 also concluded that Rayburn Country must obtain a certificate of convenience and necessity (CCN) for its transmission line. Rayburn Country therefore filed in this docket on December 11, 1987, an application for a CCN for its transmission line.

C. Intervenors, Protest Statements

There were two intervening parties in this docket. Hunt-Collin Electric Cooperative, Inc. (Hunt-Collin) intervened in this docket and later took the position that the Commission should deny approval of the rates proposed by Rayburn Country. (The customers of Rayburn Country consist entirely of seven electric distribution cooperatives (the customer cooperatives). Upon the initial filing in this docket each customer cooperative was also a member of Rayburn Country. Hunt-Collin, however, is a customer of Rayburn Country but is no longer a member of Rayburn Country.) As subsequently described in this report, Rayburn Country and Hunt-Collin were engaged in litigation outside of this docket. As part of a settlement of disputes between Rayburn Country and

Hunt-Collin, Hunt-Collin agreed to withdraw its intervention in this docket. The examiner granted the motion to withdraw as an intervening party on December 5, 1988.

The six electric distribution cooperatives that are both customer cooperatives and members of Rayburn Country are Fannin County Electric Cooperative, Inc.; Farmers Electric Cooperative, Inc.; Grayson-Collin Electric Cooperative, Inc.; Kaufman County Electric Cooperative, Inc.; Lamar County Electric Cooperative Association; and New Era Electric Cooperative, Inc. (the member co-ops). The member cooperatives were granted intervenor status as a single party. The member cooperatives supported the rates proposed by Rayburn Country.

There were no protest statements in this docket.

D. Interim Approval of Rates

The rates filed by Rayburn Country on January 16, 1987, were approved on an interim basis on February 10, 1987. Rayburn Country filed an amended Purchased Power Cost Recovery Factor (PCRF) schedule on May 4, 1987. The amended PCRF schedule corrected errors made in the original PCRF schedule that were the result of mistakenly double counting a transmission credit. The amended PCRF schedule was approved on an interim basis on May 19, 1987. Examiner's Order No. 13, dated November 9, 1987, concluded that the initial tariff filing in this docket was not subject to Commission review under PURA Section 43(a) and that interim approval was not appropriate. The Order therefore rescinded the interim approval of the rates filed January 16, 1987. Interim approval of the amended PCRF schedule was retained because it was subject to Commission review under PURA Section 43(g).

After the Order of Remand, on December 15, 1988, Rayburn Country filed a motion seeking interim approval of revised tariff sheets. Both the general counsel and the intervenor member cooperative group supported the motion. The principal features of the motion were:

1. Revised wholesale power and PCRF schedules. Both the rates already granted interim approval and the proposed rates pass through the entire costs of purchased power to the customer cooperatives. But the proposed schedules would reduce rates due to a recalculation and reduction of non-purchased power revenue requirements.

2. A request that the proposed interim rates be declared "approved after hearing by the Public Utility Commission of Texas." The customer cooperatives' PCRF clauses permit the cooperatives to pass through only charges by Rayburn Country that reflect Rayburn Country rates that have been approved by the Commission.

3. A request for permission to forward economy energy savings to the customer cooperatives. Examiner's Order No. 13 prohibited Rayburn Country from passing on to the customer cooperatives savings obtained through economy energy purchases. Approximately $2.2 million accrued during the period November 1987 to September 1988. The motion sought approval of the payment of the accrued savings plus interest earned over a twelve month period.

After an open meeting during which Rayburn Country called two witnesses in support of the motion, the motion was granted on January 20, 1989.

E. Notice; Suspension of Operation of Proposed Rates

[1] Notice of the CCN application was required pursuant to the Commission's authority under PURA Section 54(a). Rayburn Country submitted an affidavit that established that notice was published in accordance with P.U.C. PROC. R. 21.24(c)(1). Rayburn Country Exhibit No. 1. (Exhibit cites in this Supplemental Examiner's Report refer to the evidence taken at the hearing on the merits that began on July 26, 1988.) Rayburn Country was not required to mail notice of the CCN application to the other utilities that were located within five miles of the transmission line. P.U.C. PROC. R. 21.24(c)(2). Direct notice of the CCN was not necessary because the "neighboring utilities" consisted of the customer cooperatives. The customer cooperatives participated in this docket and had actual notice of the CCN application.

PURA Section 43(a) requires Rayburn Country to give notice of its April 4, 1988, statement of intent to change rates. Rayburn Country submitted affidavits on November 10, 17, and 22, 1988, that established that notice had been published for four consecutive weeks in the sixteen counties served by the customer cooperatives.

Notice of the statement of intent to change rates also must include direct notice to affected municipalities. PURA Section 43(a). There were, however, no "affected municipalities" in this docket because there were no municipalities within the service area of the customer cooperatives that may have jurisdiction over the proposed rates and because the municipalities will be indirectly affected if the proposed rates are approved.

The determination of which municipalities are "affected" should turn upon the two purposes behind the requirement of notice to municipalities. First, notice must be given to municipalities that may have jurisdiction to regulate the proposed rates. Municipalities may regulate local utility service within their boundaries. PURA Section 22. The PURA makes no distinction between regulating service that is retail service or, as is the case in this docket, wholesale service. Rayburn Country does not, however, have any service area of its own. The bills paid by the municipalities located within the 16 counties served by the customer cooperatives are determined according to the rates set by the customer cooperatives. Those rates are not the subject of this docket. The municipalities also may have jurisdiction over utilities with facilities located within municipal boundaries. But Rayburn Country's only transmission line is not located within the boundaries of a municipality.

Second, notice must be provided to affected municipalities, just as notice must be provided to affected individuals, so that the affected municipalities may choose to participate in the Commission's evaluation of the proposed rate changes.

The examiner concludes that the published notice in this docket was sufficient notice to the municipalities located within the 16 counties served by the customer cooperatives. The municipalities do not have jurisdiction over the proposed rate changes and will be indirectly affected if the proposed rates are approved. The municipalities in the sixteen counties served by the customer cooperatives are therefore not "affected municipalities" and direct notice to them is not required.

Examiner's Order No. 23 suspended the operation of Rayburn Country's proposed rates for 150 days beyond the date publication of notice was completed, until March 20, 1989.

F. Agreement of the Parties that Would Resolve By Stipulation Every Contested Issue in the Docket

A "Stipulation of Parties" was filed on January 30, 1989. A copy of the Stipulation of Parties and its Exhibits A and B are attached to this Supplemental Examiner's Report. The stipulation was signed by the representatives of Rayburn Country, the member cooperatives, and general counsel, and asserts that the stipulation is intended to resolve all matters raised in this docket. The parties' principal agreements consisted of the following:

1. Rayburn Country is a utility, as defined by PURA.
2. Rayburn Country's transmission line should be granted a CCN.
3. Rayburn Country's revenue requirements, excluding purchased power costs, are $550,000. (The rate filing package requested annual revenue, excluding purchased power costs, of about $1.1 million.)
4. The proposed rates, attached to the Stipulation of Parties as exhibits "A" and "B," should be approved. The proposed rates are identical to the rates approved on an interim basis on January 20, 1989. Two of the four schedules require amendments to reflect that Hunt-Collin has agreed to no longer be a customer of Rayburn Country. The dollar amounts received by the remaining customer cooperatives pursuant to the two schedules will not change.

Following the next section, "Description of Utility," the remaining portions of this report evaluate both the positions of the parties prior to the Order of Remand, and the Stipulation of Parties.

II. Description of Utility

A. Membership and Purpose

Rayburn Country is a federation of six member cooperatives and one nonmember cooperative that serve about 200,000 retail customers in a 16-county area east of Dallas. Rayburn Country has no retail customers, and its only utility service is to resell power at wholesale to the customer cooperatives. Its only service facility is a 36-foot, 12.5-kV tie-line, which is one of about 100 tie-lines connecting its power suppliers to the customer cooperatives.

Rayburn Country was formed in 1979 by seven co-ops that split from the Tex-La Electric Cooperative of Texas (Tex-La) because of a disagreement over participation in the Comanche Peak Nuclear Plant. The customer cooperatives opted not to participate in the nuclear power plant and formed their own group. Until summer 1986, Rayburn Country existed only as a shell corporation, with no offices or employees. It was operated primarily through the part-time efforts of the general manager of Kaufman County Electric Cooperative, Inc., Mr. Ray Raymond, who drew no salary.

In 1986, Rayburn Country hired a full-time manager, Mr. John Kirkland, whose main objective has been to obtain alternative sources of bulk power for Rayburn Country. When he began as manager, Rayburn Country received all of its load requirements from Texas Utilities Electric Company (TU Electric) and Denison Dam. Currently, Rayburn Country obtains power through five power arrangements: (1) TU Electric; (2) Denison Dam, South Unit; (3) Denison Dam, North Unit; (4) Pickton delivery point; and (5) economy energy.

Before January 1987, Rayburn Country did not own or operate facilities to provide electric utility service; therefore, it was not a public utility pursuant to section 3(c) of PURA. At that time, however, Rayburn Country assumed ownership of a 12.5-kV tie-line at the Pickton delivery point. When the Pickton tie-line was energized, Rayburn Country became a public utility.

B. Firm-Power Arrangements

In splitting off from Tex-La, the customer cooperatives obtained a share of an allocation of 35 megawatts (MW) of relatively inexpensive hydroelectric capacity from the Denison Dam, operated by the Southwestern Power Administration (SWPA). In 1983 and 1984, Rayburn Country negotiated agreements to purchase that allocation of power and an additional 35 MW of hydroelectric capacity. In addition, it is negotiating to obtain firm power from Houston Lighting & Power Company (HL&P), and it expects to obtain power from other power producers, such as qualifying facilities.

In addition to the above activities, Rayburn Country is renegotiating its contract with TU Electric. The contract expired on June 30, 1987, and has been renewed on a month-to-month basis since then. Rayburn Country's peak load is about 300 MW, and TU Electric provides whatever capacity and energy is not supplied from the other arrangements. TUEC also delivers power over its lines from the Denison Dam units to the customer cooperatives and schedules the generation with SWPA.

The tie-line at Pickton enabled Rayburn Country to obtain its first power from outside TU Electric and the Energy Reliability Council of Texas (ERCOT) interconnect system. The Pickton delivery point is part of the SWEPCO system (and thus outside ERCOT). A part of the area served by Farmers Electric Cooperative, Inc. was isolated to receive the power. Under the arrangement, Rayburn Country receives a 1.6-MW allocation of power from SWPA to serve the isolated area; the balance of its load is provided by SWEPCO.

C. Economy Energy Arrangements

Rayburn Country has negotiated agreements with TU Electric, HL&P, and West Texas Utilities Company (WTU) that enable it to purchase economy energy from HL&P or WTU if the energy is offered at a rate lower than TU Electric energy charges. Under the arrangements, Rayburn Country pays TU Electric the full demand charge under the wholesale rate for all energy that is delivered to the customer cooperatives.

Each month, HL&P and WTU submit offers to sell economy energy to Rayburn Country for the calendar month. If Rayburn Country accepts an offer, it provides a schedule to TU Electric showing the amounts and timing of the economy energy to be purchased. TU Electric acts as Rayburn Country's agent and schedules the delivery of the power from the supplying utility to Rayburn Country. Rayburn Country receives a monthly credit from TU Electric that reduces its power costs by an amount equal to the difference between the cost of delivering the economy energy and the cost that would have been incurred under TU Electric's wholesale rate.

According to Rayburn Country, having alternative economy energy arrangements creates competition among the power suppliers and provides alternative sources of power in the event of curtailments because of transmission limitations or other reasons. Unfortunately, Rayburn Country will probably not be able to negotiate additional economy energy arrangements, because TU Electric has refused to enter into any more scheduling-agent agreements for economy energy.

D. <u>Litigation and Lobbying</u>

For much of the time since 1984, Rayburn Country has been involved in litigation. In one case (the "Brazos" case), it intervened on behalf of SWPA to prevent a reallocation of the Denison Dam power. According to Rayburn Country, its efforts in the case preserved all of the benefits from the Denison Dam arrangements, which otherwise would have been lost. In addition, Rayburn Country intervened in TU Electric's last rate case, <u>Application of Texas Utilities Electric Company for a Rate Increase</u>, Docket No. 5640, 10 P.U.C. BULL. 659 (November 19, 1984).

Apparently because of Rayburn Country's growing expenses, one of the co-ops, Hunt-Collin, withdrew from membership in July 1987 and sought also to withdraw from its wholesale power contract with Rayburn Country and to take with it a portion--about 900 kW--of the Denison Dam allocation of hydro-electric power. Rayburn Country sought a declaratory judgment in federal court enforcing the wholesale power supply contract and declaring that Rayburn Country held the hydroelectric power allocation. Hunt-Collin counterclaimed for actual and punitive damages, control of the hydroelectric power allocation, and annulment of the wholesale power contract. Rayburn Country considered its continued existence to be at stake in the litigation; the litigation expenses for the lawsuit against Hunt-Collin make up a significant portion of its requested administrative and general expenses in this case. The litigation was, however, resolved by an agreement reached by Rayburn Country and Hunt-Collin after the July 1988 hearing on the merits in this docket.

Rayburn Country took the lead in lobbying efforts against several recreation associations and the North Texas Municipal Water District. The associations attempted to restrict the use of water in Lake Texoma for electric power production at Denison Dam. Rayburn Country contends that its efforts are largely responsible for preserving the allocation for power production. To resolve the battle against the water district, Rayburn Country negotiated an amendment to its contract with SWPA that provides for a monthly credit (reduction) to its invoice from SWPA for the Denison Dam power. The credit is a negotiated compensation for a reallocation of water in Lake Texoma to the water district. According to Rayburn Country, it must continue to monitor the situation because of the competing uses for the lake water.

E. Summary

According to Rayburn Country, the savings from its various alternative power arrangements totaled about $7.4 million in 1987. About 58 percent of this amount, or $4.3 million, is attributable to the Denision Dam power. The economy energy purchases accounted for about $3.0 million of the savings (beginning April 1987), and the Pickton interconnection with SWEPCO accounted for about $115,000.

It was the cost associated with searching for and arranging the alternative power supplies and protecting its hydroelectric power that apparently led Rayburn Country to file this case. In 1984, Rayburn Country's annual budget was about $314,000, which it paid out of assessments against the customer cooperatives. The annual budget jumped to about $831,000 in 1985 and

$854,000 in 1986. In 1987, Rayburn Country collected from the customer cooperatives a total of about $1.2 million (excluding purchased-power costs).

III. Evaluation of Proposed Rates and Stipulation of Parties

A. Introduction

The rate changes proposed by Rayburn Country would affect all of the customer cooperatives and would produce a rate increase of $1,305,074 or 2.69 percent over actual test year revenues. The Commission staff and general counsel recommended a rate increase that totalled $444,074 or .91 percent over actual test year revenues. The difference of positions taken by Rayburn Country and the Commission staff relates entirely to the proper determination of non-purchased power expenses. The information in Rayburn Country's rate filing package was based upon a test year that ended December 31, 1987.

B. Invested Capital

The parties took the following positions concerning Rayburn Country's rate base:

INVESTED CAPITAL

	Co-op Request	Staff Adjustment	Staff-Recommended Amount
Plant in Service	$ 61,809	$(5,326)	$56,483
Accumulated Depreciation	(7,285)	0	(7,285)
Net Plant in Service	$ 54,524	$ (5,326)	$49,198
Working Cash Allowance	127,576	(78,844)	48,732
Prepayments	21,373	0	21,373
Total Invested Capital	$203,473	$(84,170)	$119,303

Rayburn Country witness Mr. Carl N. Stover is a financial analyst employed by C. H. Guernsey. He asserted that Rayburn Country, unlike other cooperatives, has essentially no rate base. According to Rayburn Country, its total adjusted rate base is $203,473. Staff witness Mr. Raymond Orozco made two adjustments to Rayburn Country's proposed adjusted rate base. The adjustments totalled $5,326. Mr. Orozco subtracted from plant in service an I.D. camera and computer equipment purchased after the end of the test year. He did not adjust the figures for accumulated depreciation and for prepayments. The Stipulation of Parties reflects Mr. Orozco's position on these three elements of rate base. The remaining element of Rayburn Country's rate base, working cash allowance, is discussed below.

C. Rate of Return (Working Cash Allowance)

Mr. Stover asserted that, in determining the rate of return on Rayburn Country's invested capital, the primary consideration is to maintain a satisfactory cash reserve. Because Rayburn Country is a new organization it is difficult to predict the appropriate cash reserve. Further, the nature of its business activities is changing and expanding, which requires an adequate cash reserve. Mr. Stover testified that the cash reserve fund at the end of the test year was approximately $600,000. This amount is adequate and therefore Rayburn Country sought a rate of return that would produce zero cash margins. In other words, Rayburn Country sought a rate of return that would neither increase or decrease its current cash reserve. According to Rayburn Country, the appropriate rate of return is 10 percent.

Staff witness Orozco pointed out that Rayburn Country does not service a debt, and has an extremely small rate base relative to its revenues. He therefore recommended a zero rate of return. During rebuttal, Mr. Stover argued that Rayburn Country intends to purchase land and a building for a headquarters. Rayburn Country must also purchase Supervisory Control and Data Acquisition and telemetering equipment (SCADA). The SCADA equipment shall be used to monitor remotely the energy delivery points. These purchases will reduce the cash reserve to less than $268,000. A zero rate of return would cause Rayburn Country to continuously draw down on its cash reserve. He concluded that drawing down the cash reserve too far would be imprudent and impractical.

The parties stipulated to a cash reserve of $152,270. During the negotiations leading to the Stipulation of Parties, Rayburn Country stated that the land and building for a headquarters had already been purchased. The parties therefore agreed that the cash reserve should only reflect Rayburn Country's cash needs pertaining to the purchase of the SCADA equipment. Schedules RO-6 and RO-7 attached to Mr. Orozco's testimony filed in support of the stipulation show that the parties agreed to permit the funding of 10 percent of the purchase with cash. The cash expended plus the annual debt service on the related loan is $152,270.

The parties stipulated to a rate of return of zero percent. A zero rate of return is reasonable because Rayburn Country has no outstanding debt and therefore no debt coverage requirements. A rate of return greater than zero would produce excess cash that Rayburn does not need. Rayburn Country has no plans to invest in new transmission or generating plant in the next five years, and already has a cash reserve sufficient to finance the purchase of the SCADA equipment.

D. Reasonable and Necessary Expenses

In fixing the rates of a utility, the rates shall be fixed to permit the recovery of the utility's reasonable and necessary operating expenses. PURA Section 39(a). Rayburn Country requested recovery of its operating expenses as shown below:

	Test Year	Adjustment	Adjusted Test Year
Purchased Power	47,396,724	1,410,205	48,806,929
Operations & Maintenance	861,022	184,843	1,045,865
Depreciation	9,007	1,201	10,208
Taxes	5,892	735	6,627
Total Operating Expenses	$48,272,645	$ 1,596,984	$49,869,629

1. Purchased Power Expenses

Rayburn Country witness Mr. Michael Moore, a power systems analysis engineer with C.H. Guernsey & Company, explained that to calculate the adjusted purchased power expense, he corrected the test-year cost for billing errors, annualized the power costs from the Pickton delivery point and the economy energy purchases to reflect a full year of operation, and adjusted TUEC's fuel factors to current rates. Prior to the hearing on the merits the Commission staff accepted the Rayburn Country purchased power calculations. The Stipulation of Parties also concludes that the proposed purchased power expense of $48,806,929 is appropriate. The examiner concludes that a purchased power expense of $48,806,929 is just and reasonable. The calculation offered by Rayburn Country is based upon the test year purchased power expense, adjusted to annualize expenses and to reflect new TU Electric rates.

2. Operations and Maintainance Expenses

Rayburn Country requested recovery of operations and maintainance expenses as presented below:

	Test Year Amount	Co-op Adjustment	Co-op Request
O & M Expense Not Adjusted	$111,890	$ 0	$ 111,890
Payroll	83,563	10,198	93,761
Medical Insurance	4,325	737	5,062
Dental Insurance	762	64	826
Life Insurance	622	24	646
Long-Term Disability Insurance	312	(40)	272
Savings Plan	5,600	684	6,284
General Liability Insurance	3,254	796	4,050
Workers Compensation Insurance	704	(331)	373
Automobile Insurance	890	39	929
Sick Leave Accrual	4,221	(313)	3,908
Load Research Data	0	7,500	7,500
Accounting	38,444	(8,424)	30,020
Engineering	127,168	94,340	221,508
Rate Case	89,458	(31,125)	58,333
Legal	295,102	205,401	500,503
Legislative Advocacy	94,707	(94,707)	0
Total Operations and Maintenance	$861,022	$184,843	$1,045,865

2.1 Payroll

Rayburn Country witness Ms. Judy Lambert, an electrical rate analyst for C.H. Guernsey, testified that the adjusted payroll was calculated using estimated 1988 wage rates for Rayburn Country's two full-time employees and one part-time employee. The Commission staff recommended a reduction of $9,081 from the Rayburn Country figure because Rayburn Country planned to employ only the two full-time employees after June, 1988. During its rebuttal case Rayburn Country increased its estimate to $106,100 because it had increased its payroll to three full-time employees. Staff accountant Mr. Paul Bellon testified that the parties stipulated to a total payroll expense of $106,104. The stipulated amount includes wage increases to the President and the Administrative Director and the salary of an additional employee hired on July 1, 1988.

2.2 Employee Benefits

The following discussion concerns adjustments to the expense estimates for medical insurance, dental insurance, life insurance, long-term disability insurance, savings plan, general liability insurance, workers compensation insurance, automobile insurance, and sick leave accrual. Ms. Lambert used 1988 premium rates or contribution rates and, where appropriate, adjusted base wages, to adjust the test year employee benefits expense estimates. Mr. Bellon made several adjustments based upon the position that Rayburn Country would in the future have only two full-time employees. Notwithstanding the fact that the parties stipulated to payroll expenses adjusted to reflect employment of three full-time employees, the parties stipulated to all of the employee benefits expenses according to the staff's position reflected in the testimony of Mr. Bellon.

2.3 Load Research Data

According to Ms. Lambert, the estimated expense was increased from zero to $7,500 to reflect the cost of raw demand data for the Rayburn Country purchased power delivery points. The staff did not adjust this estimate. The parties stipulated to the $7,500 figure.

2.4 Accounting

This category includes expenses related to preparation of the annual audit report, monthly accounting services, and changes to accounting software. Ms. Lambert adjusted downward the expense estimate by $8,424 to $30,020 to reflect the current costs of these services. The staff did not adjust this estimate. The parties stipulated to the $30,020 figure.

2.5 Engineering

Rayburn Country paid $127,168 for engineering services during the test year. Mr. Kirkland, the president of Rayburn Country, testified that the services are not the conventional engineering services performed for an electric utility, because Rayburn Country owns only one 36 foot tie-line. Rather, the services are related to power planning and power supply activities. The activities generally consist of investigating potential sources of power supply, evaluating proposals for alternative power supply arrangements, negotiating power supply agreements, and administering current agreements. In addition, the services include associated activities such as processing and analyzing load data.

Rayburn Country adjusted upward the engineering services estimate by $94,340 to $221,508. Since Rayburn Country's long-term contract with TU Electric has expired, it will be necessary for Rayburn Country to negotiate another power supply agreement with TU Electric. Because of the technical nature of the arrangements, engineering services will be necessary in the negotiating and computer modeling of the agreements. Further, according to Rayburn Country witness Moore, the upward adjustment reflects the cost of projects that have been approved by Rayburn Country's Board. New power supply planning activities, including the investigation of alternative power supply arrangements, will require additional engineering services.

Staff witness Bellon made the following adjustments to the figure proposed by Rayburn Country for engineering services:

Engineering Project	Co-op Request	Staff Adjust.	Staff Recomm.
Transmission Planning	$ 2,620	$ (2,620)	$ 0
Interval Load Data	(2,494)	37,817	35,323
TU Electric Contract	19,900	(16,196)	3,704
Alt. Power Supply Arrangements	136,778	(60,264)	76,514
Hunt-Collin Litigation	13,882	(13,882)	0
Load Forecasting Model	28,490	(12,563)	15,927
Miscellaneous Services	22,332	(4,833)	17,499
Total	$221,508	$(72,541)	$148,967

Mr. Bellon explained that he reviewed the invoices provided by C.H. Guernsey to substantiate the work performed for Rayburn Country. According to Mr. Bellon, the general descriptions of the services performed provide little or no specific information about the services actually provided, the time spent, the individual performing the services, the hourly billing rates, or the purpose of out-of-pocket expenses. The disallowance of all of these expenses would, however, prevent Rayburn Country from performing its functions. Further, the engineering services appear to be consistent with Rayburn Country's obligations. Mr. Bellon therefore believed that Rayburn Country should be allowed to recover the amounts recommended in the above chart, which are the actual expenses incurred for the 12 months ending May 1988.

According to Mr. Bellon, all of the engineering services related to the Hunt-Collin litigation should be disallowed. Rayburn Country had failed: (1) to demonstrate that the potential financial harm from Hunt-Collin's claim was sufficient to offset such large expenditures, (2) to show how long the litigation would take, (3) to demonstrate that the expenses are recurring in nature, or (4) to estimate for the general counsel the annual hours of work the litigation is expected to require.

In response to Mr. Bellon's testimony, Rayburn Country submitted invoices showing in considerable detail the engineering services to be provided and the associated charges. Mr. Moore asserted that the known and measurable engineering services would cost $260,287, or $38,779 more than requested in the rate filing package. The increase was due to an error in Rayburn Country's original workpapers.

The stipulated amount for engineering services reflects the position taken by Mr. Bellon, adjusted to reflect more recent data. The stipulated amount of $163,173 is comprised of the actual engineering expenses incurred from August 1987 through July 1988. Expenses related to the Hunt-Collin litigation were excluded.

2.6 Rate Case

Rate case expenses during the test year totalled $89,458. Rayburn Country estimated that the total expense for this docket would be $175,000, and proposed to amortize the expense over a three year period. The annual rate case expense would be $58,333.

Mr. Bellon recommended the disallowance of all estimated expenses. Further, he noted that Rayburn Country had requested $18,750 for annual rate case expenses in its testimony supporting its initial tariff filing. In his opinion, Rayburn Country will therefore have been recovering these expenses for 20 months by the time its new rates are approved. The inclusion of these expenses in cost of service would permit a double-recovery. He recommended that Rayburn Country be permitted to recover only its actual rate case expense incurred from January through May 1988. According to his calculations, actual expenses totalled $56,634, which Mr. Bellon recommended be amortized over a three-year period for an annual rate case expense of $18,878.

During Rebuttal, Rayburn Country responded to Mr. Bellon's testimony that concerned double-recovery. According to Ms. Lambert's calculations, the total unrecovered rate case expense was $166,990, which included $20,000 of estimated expenses. Amortized over three years, the expense is $55,663.

The parties stipulated to an annual rate case expense. The figure is based upon the total actual rate case expense for this docket, $210,700, less rate case expenses previously recovered through current rates, $35,938. The remaining $174,762 was then amortized over a three-year period, for an annual expense of $58,254. The Stipulation of Parties does not discuss why the total actual rate expense is more than $50,000 greater than Rayburn Country's April 1988 estimate. Expenses related to the remand of this case may be responsible for a majority of the difference.

2.7 Legal

Rayburn Country paid $295,102 for legal services during the test year. The test year amount was adjusted upward $205,401 to $500,503. Mr. Kirkland, the president of Rayburn Country, explained that the legal services were directed towards the litigation with Hunt-Collin, negotiations with TU Electric, and arranging economy energy purchases. Mr. Phillip Ricketts, an attorney who specializes in regulatory law, testified for Rayburn Country. He asserted that the legal services provided by four law firms were reasonable and prudent and that the increases in legal services reflected in the adjustment to the test year were also necessary, reasonable, and prudent. Expenses for legislative advocacy were not included under the legal services category.

Staff witness Bellon recommended a 96 percent reduction to Rayburn Country's adjusted test year figure. According to him, only a small portion of the legal services were adequately supported by invoices. He recommended the following adjustments:

Law Firm or Project	Co-op Request	Staff Adjustment	Staff Recomm.
Verner Liipfert	$392,553	$(392,553)	$ 0
McGinnis, Lochridge & Kilgore	103,209	(85,566)	17,643
Payne & Vendig	1,628	(1,628)	0
Stanley Harris Rice	221	(221)	0
Sheey Lovelace	157	(157)	0
Denison Dam/Tex-La	2,735	(2,735)	0
Total	$500,503	$(482,860)	$17,643

He recommended disallowing all of the fees paid to the law firm of Verner, Liipfert because the invoices for legal services were too general to determine the reasonableness of the services, and because the invoices did not clearly specify whether all legislative advocacy expenses were excluded.

He recommended disallowing a large portion of the fees paid to the law firm of McGinnis, Lochridge & Kilgore. According to Mr. Bellon, only the months of January through March 1987 were adequately supported by invoices. This prevented him from concluding that the legal services for the other months during the test year and the estimated expenses are recurring in nature and necessary to providing utility service. Further, the estimated expenses were not known and measurable, as required by P.U.C. SUBST. R. 23.21.

He recommended disallowing all of the fees paid to the law firm of Payne & Vendig. All of the legal services provided related to the Hunt-Collin litigation. In Mr. Bellon's opinion, none of the Hunt-Collin litigation expenses were properly recoverable through rates, based upon the same enumerated reasons Mr. Bellon recommended disallowance of the engineering expenses related to the Hunt-Collin litigation.

With respect to the remainder of the requested legal expenses, Mr. Bellon stated that Rayburn Country failed to provide any information to support the amounts, despite the staff's discovery requests. Accordingly, he recommended that the amounts not be allowed.

During Rebuttal Rayburn Country contested the conclusions of Mr. Bellon. Mr. Kirkland asserted that the staff position would prohibit Rayburn Country from performing legal services necessary to secure lower cost power. According to both Mr. Kirkland and Mr. Ricketts, the Hunt-Collin litigation is necessary. Mr. Ricketts asserted that annual fees of $286,800 are reasonable for the litigation.

Rayburn Country also contested Mr. Bellon's conclusions concerning the adequacy of the invoices. According to Rayburn Country, sufficient invoices were provided with the same degree of detail that is generally provided by law firms.

The staff's recommendation for the adjusted test year was $17,643. The parties stipulated to $58,208. According to Mr. Bellon, the stipulated amount reflects the total legal fees paid to the firm of McGinnis, Lochridge & Kilgore for general legal services rendered during the test year. According to Mr. Ricketts, this law firm performed work clearly of a recurring nature. The firm negotiates transmission service agreements and power supply agreements, attends board meetings, and other general corporate work. As previously stated, the Hunt-Collin litigation was concluded through a settlement among the parties. There was therefore no reason to anticipate future legal expenses for litigation against Hunt-Collin.

2.8 Legislative Advocacy

Legislative advocacy expenses may not be considered for ratemaking purposes. PURA Section 41(3)(A). Legislative advocacy work performed by the firm of Verner Liipfert was separated from other legal work performed by the firm. The entire amount attributed to legislative advocacy, $94,707, was deducted from the test year operations and maintenance expenses. The Stipulation of Parties also reflects this elimination of legislative advocacy expenses. During the hearing on the merits the only issue raised concerning legislative advocacy expenses was whether additional "legal services" provided by outside counsel should be classified as legislative advocacy expenses. According to Mr. Ricketts, it was clear that McGinnis, Lochridge & Kilgore did not perform any legislative advocacy services for Rayburn Country. Because this firm is the only firm whose legal services are included in the Stipulation of Parties, no legislative advocacy expenses are included in operations and maintainance expenses.

2.9 Travel

Rayburn Country sought $41,102 of travel expenses in the adjusted test year operations and maintenance expenses. Mr. Bellon sought to exclude $20,581 of this amount because $18,209 of the expenses were better categorized as legislative advocacy expenses and $2,372 of the expenses were better categorized as rate case expenses. The Stipulation of Parties adopts the position taken by Mr. Bellon.

2.10 Miscellaneous Expenses

Mr. Bellon recommended the disallowance of $4,853 associated with the writing off of a video brochure because Rayburn Country had not demonstrated that the expense was reasonable and necessary to provide utility service. Concerning the Stipulation of Parties, Mr. Bellon explained that the $4,058 increase to the staff's recommended other miscellaneous expenses of $2,262 represents miscellaneous expenses which the parties agreed to include in Rayburn Country's cost of service for settlement purposes.

2.11 Summary of Operations and Maintenance Expenses

The staff's recommendation for adjusted operations and maintenance expenses was $415,112. Rayburn Country sought $1,045,865. As discussed above, the Stipulation of Parties indicated a stipulated amount for each of the categories under operations and maintenance expenses. The stipulated amounts total $534,741 for operations and maintenance expenses. The examiner concludes that the record supports the stipulated amounts and indicates that they are just and reasonable. Each of the sections above note how the record supports the stipulated amount. Further, the stipulated amounts reflect that Rayburn Country's expenses will be more moderate now that the Hunt-Collin litigation has been settled.

3. Depreciation Expense

Rayburn Country sought approval of an adjusted test year depreciation expense of $10,208. Schedule G-5.1 in the rate filing package shows that Rayburn Country's depreciable assets consist mostly of office equipment and transportation equipment. The assets are depreciated at an annual rate of 3.2 percent. Mr. Bellon recommended decreasing the requested amount by $1,065 to remove amounts associated with a computer and I.D. camera purchased after the end of the test year. During rebuttal Ms. Lambert asserted that the $1,065 in depreciation expense is incurred in connection with property that is used and useful by Rayburn Country in providing service, and the expense should be included in the revenue requirement. The parties stipulated to an expense of $9,143, which was the position of staff witness Bellon.

4. Taxes Other Than Income Taxes

Rayburn Country sought approval of an adjusted test year expense of $6,627. Schedules G-9.0 through 11.0 in the rate filing package show that property tax is the only expense under this category that is not related to Rayburn Country's wage base. Mr. Bellon asserted that the expense should be adjusted according to his determination of the wage base. He recommended a $511 decrease to Rayburn Country's request, based upon the staff's recommended annual wage base. The parties stipulated to an expense of $6,116, which is the position taken by Mr. Bellon.

E. Summary of Revenue Requirements

The parties stipulated to an adjusted test year figure for each of the elements of Rayburn Country's revenue requirement: return on invested capital, purchased power, operations and maintenance expense, depreciation, and taxes other than income taxes. The record supports each of the stipulated figures. Staff member Orozco's testimony showed that a zero return on invested capital is appropriate because a higher return would produce an unnecessary cash reserve. Mr. Moore's testimony concerning purchased power expenses was uncontested and showed that Rayburn Country's expenses in this category would be comparable to the test year figure, after consideration of several adjustments to reflect more current information. The preceding discussion in this report showed the reasonableness of each of the operations and maintenance expenses. Concerning depreciation expense, Mr. Bellon's testimony showed that the expense relates only to those assets that were owned by Rayburn Country during the test year. Mr. Bellon's testimony concerning taxes shows that the stipulated figure is, except for small adjustments, identical to the tax expense during the test year. The examiner therefore concludes that the revenue requirement stipulated to by the parties, $49,356,929, is just and reasonable.

F. Rate Design; Proposed Rate Schedules

Rayburn Country witness Moore testified that a cost of service study was not prepared because Rayburn Country serves only one customer class. He asserted that the proposed rates were designed to meet three objectives: the rates must provide revenue to meet purchased power costs, and to meet non-purchased power costs. The rates must also allocate to the customer cooperatives the benefits arising from the rights to less expensive hydro-electric power. The variances in demand and energy costs attributable to the separate customer cooperatives are recovered through separate demand and energy components.

The Stipulation of Parties seeks the Commission's approval of two exhibits that consist of the proposed rate schedules. Exhibit A is a copy of the rates approved on an interim basis on January 20, 1989. Exhibit B is a copy of two rate schedules with the necessary amendments to reflect the withdrawal of Hunt-Collin as a Rayburn Country customer.

1. Rate WP

Exhibit A consists of Rate WP, Rider PCRF, and schedules SUA and NUA. Mr. Moore pointed out that Rate WP is similar to TU Electric's Rate WP because Rayburn Country obtains most of its load obligations from TU Electric. Staff witness Kelso King testified that Rate WP is designed to recover Rayburn Country's entire revenue requirement.

The demand component was set according to the demand cost of adjusted test year purchased power cost. As previously stated, the determination of the adjusted test year purchased power cost was uncontested. The parties therefore all agreed that the appropriate demand charge was $6.33/kw. Schedule KMK-1 attached to Mr. King's direct testimony illustrates the calculation.

The energy component is designed to recover energy purchased power costs and non-purchased power expenses. Because the non-purchased power expenses were contested in this docket, the related energy component was also contested. In the rate filing package Rayburn Country sought a rate of .025818/kwh. General counsel's position was that a rate of .025244/kwh was most appropriate. The proposed rates in the Stipulation of Parties utilizes a rate of .025408/kwh. The examiner notes that if the stipulated operating expenses, $550,000, are used in Mr. King's calculation at KMK-1, the energy component should be slightly lower than the stipulated rate. The examiner's calculation produces a figure of .025338/kwh.

The examiner concludes that the Rate WP included in Exhibit A of the Stipulation of Parties is just and reasonable. The record contains information to support each of the parties' calculations. The demand component is identical to the rate uncontested in the hearing. The energy component reflects a settlement figure between the positions taken by the parties.

2. Rider PCRF

Rider PCRF is designed to flow through to the customer cooperatives changes in purchased power costs, as compared to the purchased power costs during the test year which were used to formulate the rates in Rate WP. Similar to Rate WP, Rider PCRF has both a demand and energy component.

The Rider PCRF energy component formula is adjusted in part due to savings from economy energy purchases during the test year. The rates of HL&P through which Rayburn Country purchased economy energy were not approved by the Commission at the time Rayburn Country filed the rate filing package. Examiner's Order No. 13 in this docket, which was affirmed by the Commission, prohibited the savings from economy energy purchases from passing through Rayburn Country's PCRF to the customer cooperatives. The PCRF clause could not be used to pass through changes in power costs due to rates that were not approved by the Commission. The examiner concludes that Rayburn Country should not be permitted to adjust its PCRF formula based upon HL&P rates that have not been approved by the Commission. This question is, however, moot here because the rate for HL&P economy energy has now been approved by the Commission in Docket No. 8231, Application of Houston Lighting & Power Co. for Approval of Economy Energy Sales Contracts.

The examiner concludes that the Rider PCRF in Exhibit A of the Stipulation of Parties is just and reasonable. The components of Rider PCRF are based upon the rates determined appropriate for Rate WP. The record supports the calculation of both rate schedules. Further, the Rider PCRF adopts the recommendations of the Commission staff.

3. Rider SUA and Rider NUA

Rider SUA allocates the power cost savings accociated with the south unit of Denison Dam to the five customer cooperatives that received benefits from the south unit prior to Rayburn Country gaining utility status.

Part of the settlement of litigation between Rayburn Country and Hunt-Collin is that Hunt-Collin will no longer be a customer of Rayburn Country. This portion of the settlement shall take effect in mid-March, 1989. Hunt-Collin shall, however, continue to receive benefits from Denison Dam power arrangements that are attributable to it. The Stipulation of Parties is not clear on this point, but it appears that Rayburn Country shall be the agent of Hunt-Collin. Rayburn Country shall directly receive the benefits of Denison Dam Power and the portion attributable to Hunt-Collin shall be paid to Hunt-Collin. Because Hunt-Collin shall no longer be a customer of Rayburn Country the tariff cannot be used to pass the savings through to Hunt-Collin.

The Stipulation of Parties seeks approval of two versions of Rider SUA. Exhibit A includes the Rider SUA that was approved on an interim basis on January 20, 1989. Exhibit B includes Rider SUA with the references to Hunt-Collin deleted; this version of Rider SUA also revises the allocation factor for the remaining customer cooperatives under the schedule. According to Mr. Moore, the customer cooperatives will not be affected by the amendments to the schedule.

Rider NUA is simular to Rider SUA, but provides for the allocation of power cost savings attributable to the north unit of Denison Dam. The Rider NUA in Exhibit A was approved on an interim basis on January 20, 1989. The Rider NUA in Exhibit B is revised to reflect the withdrawal of Hunt-Collin as a customer of Rayburn Country.

The examiner concludes that Riders SUA and NUA in Exhibit A of the Stipulation of Parties are just and reasonable. Further, the Riders SUA and NUA in Exhibit B are just and reasonable and should be approved; Rayburn Country should be directed to put them into effect the first day Hunt-Collin is no longer a Rayburn Country customer, or April 3, 1989, whichever date is earlier.

IV. Refunds

A. Refund of Excess Cash Reserve

Staff witness Bellon stated in his supplemental testimony that Rayburn Country's available cash reserve was $434,190 as of November 30, 1988. As previously discussed, the parties have stipulated that the appropriate cash reserve is $152,270. Rayburn Country therefore has excess cash reserves of $281,920. In the Stipulation of Parties Rayburn Country agrees that as soon as a Final Order in this Docket implementing the Stipulation of Parties is promulgated, "Rayburn Country's Board of Directors will approve a rotation of capital credits that have previously been assigned by Rayburn Country to its customers in the amount of $281,920."

B. Refund of Lake Texoma Storage Reallocation Credit

As previously discussed, through its lobbying efforts that lead to a settlement with the North Texas Municipal Water District, Rayburn Country obtained a monthly credit to its invoice from SWPA for Denison Dam power. The credit is a negotiated compensation for a reallocation of water in Lake Texoma to the water district. In the future the credits will be received each month and distributed to the customer cooperatives. But Rayburn Country received one lump sum payment for prior months' credits. As of December 31, 1988, the lump sum plus interest held by Rayburn Country totalled $216,991.90. Examiner's Attachment A is a copy of Mr. Kirkland's JWK-2 (Stipulation Document). The attachment shows the amount of the proposed refund to each of the seven customer cooperatives. In the Stipulation of Parties Rayburn Country agrees that as soon as the Final Order implementing the Stipulation of Parties is approved, Rayburn Country will refund the accumulated storage reallocation credit plus interest based upon the allocation factor in Rider NUA.

C. Refund of Savings From Economy Energy Purchases

Rayburn Country collected in an escrow account money saved from economy energy purchases that it, due to Examiner's Order No. 13, could not pass through its PCRF to the member cooperatives. This situation existed from November 1987 through September 1988. According to Mr. Kirkland, the escrow account holds a principal amount of $2,181,672. The principal amount is earning interest at a variable rate. The parties agree that the principal and interest should be refunded to the customer cooperatives.

The witnesses Moore and Kirkland both asserted that the most equitable method to refund the money in the escrow account to the customer cooperatives was a month-to-month refund plan over a twelve month period, with the first actual refunds to be included in the billings mailed in early February 1989. The month-to-month refunds shall return the escrowed amounts in the same calendar month in which they were first escrowed one year earlier. For example, Rayburn Country proposes to refund the January 1988 economy energy savings in January 1989; the actual refund of savings would occur with the billings sent out in early February 1989. The economy energy savings accrued in November and December 1987 shall be refunded to the customer cooperatives in November and December 1989.

The refunds will be in proportion to the amount of the customers' monthly bill. For example, the greater proportion of the winter months refunds will be returned to the customer cooperatives who have the larger winter months bills. Rayburn Country asserts this is equitable because the customer cooperatives who receive the greatest refunds are the same customer cooperatives who one year ago suffered the most because of the bar against passing the economy energy savings to the customer cooperatives.

The refunds to the customer cooperatives of the savings from economy energy purchases were put into effect on an interim basis pursuant to Examiner's Order No. 27. Examiner's Attachment B is a copy of Mr. Kirkland's attachment JWK-1 (Stipulation Document). The attachment shows the principal and interest that Rayburn Country agrees to return to each of the customer cooperatives according to the above-described method of returning the funds.

D. Written Report of Refunds Made

Rayburn Country has agreed to make the above-described refunds as soon as the Commission approves the Stipulation of Parties. The Commission should order Rayburn Country to file a sworn written report with the Commission confirming that the refunds have been made, and demonstrating the details of their calculation. The rotation of capital credits and the refund of the reallocation credit, should not take more than 45 days. With respect to the refund of the economy energy savings, Rayburn Country should file a report no later than February 1990 to confirm that the refunds have been made. The proposed order attached hereto so provides.

V. The CCN Case

[2] Examiner's Order No. 13 required Rayburn Country to submit an application for a CCN for Rayburn Country's transmission line. Rayburn Country opposed the Order, asserting that PURA Section 50(1) did not apply to the transmission line and that the Commission's substantive rules also indicated that Rayburn Country need not apply for a CCN. Rayburn Country pointed out that the Commission's substantive rules provide that a CCN is necessary for construction of a transmission line, not a distribution line. P.U.C. SUBST. R. 23.31(c)(1)(C), (c)(2)(E). The rules also define "transmission line." A transmission line includes all lines operated at 60 kv or above. P.U.C. SUBST. R. 23.31(a)(1).

Any public utility must, however, obtain a CCN prior to rendering service directly or indirectly to the public. PURA Section 50(1). The Commission's substantive rules provide that all lines operated at above 60 kv or above are transmission lines. Rayburn Country operates its one line at 12.5 kv. The line therefore is not on the basis of voltage necessarily a "transmission line." The line is, however, not used to serve end-use customers, and therefore on this basis the line is a "transmission line" that must be licensed by the Commission.

The Commission may grant a CCN for the line only if the Commission finds that the CCN is necessary for the service, accomodation, convenience, or safety of the public. PURA Section 54(b). The Commission must consider the adequacy of existing service, the need for additional service, the effect of the granting of a certificate on the recipient of the certificate and on any public utility of the same kind already serving the proximate area, and on such factors as community values, recreational and park areas, historical and aesthetic values, environmental integrity, and the probable improvement of service or lowering of cost to consumers in such area resulting from the granting of such certificate. PURA Section 54(c).

Rayburn Country's transmission line is a 36 foot, 12.5 kv overhead tie-line connecting Farmers Electric Cooperative, Inc. to SWEPCO. Staff witness Mr. Mel Eckhoff reviewed Rayburn Country's application for a CCN. He noted that the tie-line is in the unincorporated community of Pickton, in Hopkins County, and is in the right-of-way of and parallel to State Highway 11 near the intersection of that road and Farm to Market Road 269.

According to Mr. Eckhoff, the cost of the Pickton tie-line (about $360) was reasonable. In addition, he reviewed the effect of the tie-line on the surrounding area. There are three businesses, four church buildings, and three residences within 500 feet of the line. Mr. Eckhoff noted, however, that the tie-line is farther from the structures than are the distribution facilities of SWEPCO and Farmers Electric Cooperative, Inc. Given the size of the tie-line, he concluded that the tie-line does not adversely affect the structures. Similarly, he concluded that the tie-line does not affect any television transmitters or similar electronic facilities, registered airstrips, pastures or croplands, parks, camps, or other recreation areas, or historical or archealogical sites. He therefore recommended approval of the application.

Rayburn Country witness Mr. Pete Montes is the engineering manager of Farmers Electric Cooperative, Inc. He testified that the tie-line lies in the most direct and economical route. Further, the tie-line does not affect recreational, park, or historical sites, or environmental or aesthetic values. He noted that while the tie-line does not improve service in the area, it does lower the cost of service to consumers.

Rayburn Country witness Mr. Kirkland explained the need for the line from the perspective of power supply. Rayburn Country is obligated to provide to the customer cooperatives all of their bulk power requirements. To provide its customers with the cheapest power, Rayburn Country arranged to buy power from SWEPCO, which is part of the Southwest Power Pool. The Southwest Power Pool is isolated from the delivery system the customer cooperatives are connected to, ERCOT. Rayburn Country determined, however, that a portion of the Farmers Electric Cooperative, Inc. service area could be isolated and transferred from ERCOT to the Southwest Power Pool. Accordingly, the tie-line was constructed to transmit power from SWEPCO to the isolated portion of the Farmers Electric Cooperative, Inc. service area. According to his calculations, the transfer of load from TU Electric to SWEPCO saved the customer cooperatives about $98,000 during the period January through September 1987.

The examiner concludes that the Rayburn Country tie-line is necessary for the service, accomodation, convenience, and safety of the public. The tie-line runs a distance of only 36 feet. It does not affect community values, recreational and park areas, historical and aesthetic values, or the environmental integrity of the area. The two other utilities that serve the area, SWEPCO and Farmers Electric Cooperative, Inc., will not be adversely affected. The tie-line permits SWEPCO to serve a new customer, Rayburn Country. Farmers Electric Cooperative, Inc., along with the other customer cooperatives, will receive less expensive power. Finally, the tie-line does not promise more or less reliable service but does promise to provide less expensive power.

VI. Findings of Fact and Conclusions of Law

The examiner recommends that the Commission adopt the following Findings of Fact and Conclusions of Law:

A. Findings of Fact

1. Rayburn Country is a federation of six member cooperatives and one nonmember cooperative that serve about 200,000 customers in a 16-county area east of the City of Dallas. Rayburn Country has no retail customers, and its only utility service is to resell power at wholesale to the customer cooperatives.

2. Rayburn Country operates one transmission line. The line is a 36 foot, 12.5 kV overhead tie-line that connects the facilities of SWEPCO to the facilities of Farmers Electric Cooperative, Inc. The line is located in the unincorporated community of Pickton, in Hopkins County.

3. On January 16, 1987, Rayburn Country filed its original tariff with the Commission. On that date Rayburn Country began operating its transmission line.

4. The Commission's general counsel filed in July 1987 a request for a hearing to review the materials filed by Rayburn Country in this docket.

5. On April 4, 1988, Rayburn Country filed a rate filing package and a statement of intent to change rates pursuant to PURA Section 43(a).

6. A hearing on the merits was held in this case beginning on July 26, 1988.

7. An Examiner's Report was issued in this docket on October 28, 1988. The report recommended that the Commission deny Rayburn Country status as a public utility and that the Commission deny Rayburn Country's proposed rates. At the November 22, 1988, Final Order Meeting the Commission elected not to adopt the recommendations. The Commission therefore remanded the case to the hearings division to prepare findings of fact and conclusions of law that would support approval of rates for Rayburn Country.

8. The case was reassigned to the undersigned hearings examiner on November 28, 1988. The undersigned hearings examiner has read the record.

9. Hunt-Collin intervened in this case and opposed Rayburn Country's proposed rates. Pursuant to an agreement between Rayburn Country and Hunt-Collin, Hunt-Collin moved to withdraw its intervention on November 15, 1988. The motion was granted on December 6, 1988.

10. The member cooperatives (Fannin County Electric Cooperative, Inc.; Farmers Electric Cooperative, Inc.; Grayson-Collin Electric Cooperative, Inc.; Kaufman County Electric Cooperative, Inc.; Lamar County Electric Cooperative, Association; and New Era Electric Cooperative, Inc.) were granted intervenor status as a single party. The member cooperatives supported the rates proposed by Rayburn Country.

11. There were no protest statements in this docket.

12. The rates filed by Rayburn Country on January 16, 1987, were approved on an interim basis on February 10, 1987. Rayburn Country amended its Rider PCRF on May 4, 1987. The amended Rider PCRF was approved on an interim basis on

May 19, 1987. Examiner's Order No. 13, dated November 9, 1987, concluded that the initial tariff filing in this docket was not subject to Commission review under PURA Section 43(a) and that interim approval was not appropriate. The Order therefore rescinded the interim approval of the rates filed January 16, 1987. Interim approval of the amended Rider PCRF was not rescinded because it was subject to Commission review under PURA Section 43(g).

13. On December 15, 1988, Rayburn Country filed a motion seeking interim approval of revised tariff sheets. The revised tariff sheets reduced rates due to a recalculation and reduction of non-purchased power revenue requirements. The revised tariff sheets were granted interim approval on January 20, 1989.

14. On December 11, 1987, Rayburn Country filed an application for a CCN. Notice was published in Hopkins County for two consecutive weeks. The neighboring utilities providing the same utility service within five miles of the requested facility had actual notice of the CCN application.

15. Rayburn Country submitted affidavits that established that notice of the April 4, 1988, statement of intent to change rates, had been published for four consecutive weeks in the sixteen counties served by the customer cooperatives.

16. Examiner's Order No. 23 suspended the operation of Rayburn Country's proposed rates for 150 days beyond the date publication of notice was completed, until March 20, 1989.

17. Direct notice of the April 4, 1988, statement of intent to change rates was not given to the municipalities located in the sixteen counties served by the customer cooperatives.

18. On January 30, 1989, Rayburn Country, the intervenor member cooperatives, and the general counsel filed a "Stipulation of Parties." The agreement was submitted for purposes of resolving by stipulation every contested issue in the docket.

19. Pursuant to paragraph 16 of the Stipulation of Parties, the parties agreed that the supplemental testimony of witnesses Kirkland, Moore, Orozco, and Bellon filed in support of the Stipulation of Parties should be admitted into evidence. The parties waived their right to cross-examination.

20. Rayburn Country's proposed rates would produce a rate increase of $1,305,074 or 2.69 percent over actual test year revenues. The Commission staff and general counsel recommended a rate increase that totalled $444,074 or .91 percent over actual test year revenues. The Stipulation of Parties provides for a rate increase of $772,027 or 1.59 percent over actual test year revenues.

21. Rayburn Country has total invested capital, excluding working cash allowance, of $70,571, based on the original cost of property used and useful in providing service, as set forth in the testimony of staff witness Bellon.

22. The parties stipulated to a cash reserve of $152,270. The stipulated amount reflects Rayburn Country's cash needs with respect to the purchase of SCADA equipment. The SCADA equipment shall be used and useful in providing service to the customer cooperatives.

23. The parties stipulated to a zero rate of return. A zero rate of return is reasonable because Rayburn Country has no outstanding debt and therefore no debt coverage requirements. A rate of return greater than zero would produce excess cash that Rayburn Country does not need. Rayburn Country has no plans to invest in new transmission or generating plant in the next five years, and already has a cash reserve sufficient to finance the purchase of the SCADA equipment.

24. The parties stipulated to $48,806,929 for purchased power. The figure was uncontested during the hearing on the merits. It was adjusted to annualize expenses and to reflect new TU Electric rates. The stipulated figure is just and reasonable.

25. The parties stipulated to $534,741 for operations and maintenance expenses. The stipulated amount is just and reasonable, and reflects that Rayburn Country's expenses will be more moderate now that the Hunt-Collin litigation has been settled.

26. The parties stipulated to a depreciation expense of $9,143. The stipulated figure reflects the position taken by staff witness Bellon and is just and reasonable.

27. The parties stipulated to an expense for taxes other than income taxes of $6,116. The stipulated figure reflects the position taken by staff witness Bellon and is just and reasonable.

28. The rates set forth in the Stipulation of Parties Attachments A and B are designed to meet three objectives. The rates provide revenue to meet purchased power costs, and to meet non-purchased power costs. The rates also allocate to the customer cooperatives the benefits arising from the rights to less expensive hydro-electric power costs. The variances in demand and energy costs attributable to the separate customer cooperatives are recovered through separate demand and energy components.

29. The rates set forth in the Stipulation of Parties Attachment A are appropriate to recover the cost of service. The rates do not make unreasonable differences or preferences with respect to rates or service provided to the customer cooperatives.

30. The rates set forth in the Stipulation of Parties Attachment B are appropriate to allocate the power cost savings associated with the north and south units of Denison Dam, upon the withdrawal of Hunt-Collin as a customer of Rayburn Country. The member cooperatives will not be affected by the amendments to Schedules NUA and SUA found in Stipulation of Parties Attachment B.

31. The rates set forth in the Stipulation of Parties Attachments A and B are fair and equitable, clear, understandable, and predictable. In addition, the rates would generate sufficient revenue to enable Rayburn Country to recover its cost of service as determined in the preceding findings of fact.

32. The rates set forth in the Stipulation of Parties Attachments A and B conform with the terms of the Stipulation of Parties.

33. Rayburn Country's cash reserve as of November 30, 1988, was $434,190. The appropriate cash reserve for Rayburn Country is $152,270. Rayburn Country therefore has excess cash reserves of $281,920 that should be returned to the customer cooperatives through a rotation of capital credits.

34. Pursuant to the Stipulation of Parties, Rayburn Country agrees that as soon as the Commission's Final Order implementing the Stipulation of Parties is signed, Rayburn Country will approve a rotation of capital credits in the amount of $281,920.

35. Rayburn Country received a lump sum payment and subsequent monthly payments from SWPA to compensate Rayburn Country for the reallocation of water in Lake Texoma. As of December 31, 1988, the lump sum plus interest held by Rayburn Country totalled $216,991.90. Examiner's Attachment A illustrates the portion of this sum attributable to each customer cooperative. This sum should be returned to the customer cooperatives according to the amounts attributable to each of the customer cooperatives, as set forth in Examiner's Attachment A. The sum should be returned in a single lump sum payment to each of the customer cooperatives.

36. Pursuant to the Stipulation of Parties, Rayburn Country agrees that as soon as the Commission's Final Order implementing the Stipulation of Parties is signed, Rayburn Country will refund to the customer cooperatives the accumulated storage reallocation credit plus interest, based upon the allocation factor in Rider NUA.

37. Rayburn Country collected in an escrow account money saved from economy energy purchases that it, due to Examiner's Order No. 13, could not pass through its Rider PCRF to the member cooperatives. This situation existed from November 1987 through September 1988. The principal and interest should be returned to the customer cooperatives.

38. Examiner's Attachment B shows the principal and interest from economy energy savings that Rayburn Country should return to each of the customer cooperatives. The most equitable method to refund the money to the member cooperatives is a month-to-month refund plan over a twelve month period. The month-to-month refunds shall return the escrowed amounts in the same calendar month in which the economy energy savings were first escrowed one year earlier. The refund should be based upon the historical kilowatt hour usage of each customer in the month in which the economy energy savings occurred. The refund plan was put into effect on an interim basis pursuant to Examiner's Order No. 27.

39. Pursuant to the Stipulation of Parties, Rayburn Country intends to continue to pay to the customer cooperatives the accrued economy energy savings plus interest in the manner outlined in Examiner's Order No. 27.

40. Rayburn Country's transmission line does not adversely affect nearby structures. The tie-line does not affect any television transmitters or similar electronic facilities, registered airstrips, pastures or croplands, parks, camps, or other recreation areas, or historical or archaelogical sites.

41. The tie-line follows the most direct and economical route and permits Rayburn Country to purchase power from SWEPCO. The transfer of load at the Pickton tie-line from TU Electric to SWEPCO saved the customer cooperatives about $98,000 during the period January through September 1987.

42. The tie line does not affect community values, recreational and park areas, historical and aesthetic values, or the environmental integrity of the area.

The two other utilities that serve the area, SWEPCO and Farmers Electric Cooperative, Inc., will not be adversely effected. The tie-line does not promise more or less reliable service but does promise to provide less expensive power.

43. The Rayburn Country tie-line is necessary for the service, accommodation, convenience, and safety of the public.

B. Conclusions of Law

1. Rayburn Country is a public utility as that term is defined by PURA Section 3(c)(1).

2. The Commission has jurisdiction and authority to evaluate and approve Rayburn Country's proposed rates. PURA Sections 16(a), 17(e) and 37.

3. Rayburn Country's rate filing package meets the requirements for a statement of intent. PURA Section 43(a).

4. This docket was reassigned to the undersigned examiner pursuant to Section 15 of the Administrative Procedure and Texas Register Act, Tex. Rev. Civ. Stat. Ann. art. 6252-13a (Vernon Supp. 1988).

5. Proper notice was given to all affected persons in compliance with PURA Section 43(a).

6. Proper notice was given to all affected persons concerning the application for a CCN. P.U.C. PROC. R. 21.24.

7. The operation of the proposed rate schedules was suspended in accordance with PURA Section 43(d).

8. The methods of calculating and rates recovering allowable expenses, which were approved by the staff and accepted in the Stipulation of Parties, are proper and adequate and have been uniformly and consistently applied.

9. The invested capital stipulated to by the parties is based on the original cost of property used and useful to Rayburn Country in providing service. PURA Section 39(a).

10. The return on rate base stipulated to by the parties constitutes a reasonable return on Rayburn Country's invested capital used and useful in rendering service to the public. PURA Section 39(a).

11. The overall revenue stipulated to by the parties will permit Rayburn Country a reasonable opportunity to earn a reasonable return over and above its reasonable and necessary operating expenses. PURA Section 39(a).

12. Rayburn Country has met its burden of proof to show that rates producing the base rate revenue stipulated to by the parties are just and reasonable. PURA Section 40.

13. The rates labeled as Attachments A and B of the Stipulation of Parties are just and reasonable and are not unreasonably preferential, prejudicial, or discriminatory. PURA Section 38.

14. The rates and services of Rayburn Country set forth in Attachments A and B of the Stipulation of Parties do not grant an unreasonable preference or advantage to any customer or subject any customer to unreasonable prejudice or disadvantage. PURA Section 45.

15. The rates and services of Rayburn Country set forth in Attachments A and B of the Stipulation of Parties are just and reasonable and otherwise comply with the ratemaking mandates of Article IV of the PURA.

16. Rayburn Country has met its burden of proof to show that its 12.5 kv tie-line located in Pickton, Hopkins County, is necessary for the service, accomodation, convenience, and safety of the public. PURA Section 54(b). The record shows sufficient consideration of the adequacy of existing service, the need for additional service, the effect of granting a CCN on the recipient of the CCN and on any public utility of the same kind already serving the proximate area. The tie-line will not adversely affect community values, recreational and park areas, historical and aesthetic values, or environmental integrity. The tie-line does not promise more or less reliable service but does promise to provide less expensive power. PURA Section 54(c).

Respectfully submitted,

Richard S. O'Connell

RICHARD S. O'CONNELL
HEARINGS EXAMINER

APPROVED on the 23rd day of February 1989.

Elizabeth Hagan Drews for

PHILLIP A. HOLDER
DIRECTOR OF HEARINGS

BEFORE THE
PUBLIC UTILITY COMMISSION OF TEXAS

APPLICATION OF RAYBURN COUNTRY ELECTRIC COOPERATIVE, INC. FOR APPROVAL OF WHOLESALE RATES	§ § § §	DOCKET NO. 7361

STIPULATION OF PARTIES

TO THE HONORABLE PUBLIC UTILITY COMMISSION OF TEXAS:

NOW COMES Rayburn Country Electric Cooperative, Inc. ("Rayburn Country"), Office of the General Counsel ("General Counsel") and the Member Cooperatives ("Members"), collectively referred to as "Parties" and makes and files this their Stipulation of Parties ("Stipulation") and respectfully would show the Honorable Public Utility Commission of Texas ("PUC" or "Commission") as follows:

1. It is the intent of the Parties that this Stipulation resolve all matters raised by this Docket, and the Parties hereto acknowledge that no precedential effect is to be given to this Stipulation and that this Stipulation is entered into solely on the basis of the facts of this Docket.

2. The Parties agree that Rayburn Country is a utility as that term is defined in the Public Utility Regulatory Act ("PURA"), TEX. REV. CIV. STAT. ANN. art. 1446c. As a result, the PUC has jurisdiction over the rates and charges of Rayburn Country.

3. The Parties hereto agree that since January 16, 1987, Rayburn Country has owned and operated 36 feet of 12.5 KV tie-line connecting Southwestern Electric Power Company ("SWEPCO") and Rayburn Country at the Pickton delivery point.

4. The Parties hereto agree that the 12.5 KV tie-line is necessary for the service, accommodation, convenience and safety of the public and that the granting of a Certificate of Convenience and Necessity ("CCN") will not have any adverse effect on any public utility of the same kind already serving the proximate area, nor does the granting of a CCN have any adverse effect on community values, recreational, park areas, historic and aesthetic values, the environment and environmental integrity, and that the tie-line would improve service and lower the cost to consumers in the area. Therefore, the Parties agree that Rayburn Country's request for a CCN should be granted.

5. On January 16, 1987, Rayburn Country filed initial tariffs with the PUC, and since that date Rayburn Country has been charging only rates consistent with those tariffs as amended.

6. The Parties agree that Rayburn Country's revenue requirements excluding purchased power costs are $550,000.

7. The design of Rayburn Country's rates to recover the revenue requirements, excluding purchased power, as set forth in paragraph 6 above will be based on the billing determinants as shown in Rayburn Country's April 4, 1988 filing with the Commission, except that the billing determinants

will be reduced to exclude the billing determinants of Hunt-Collin Electric Cooperative, Inc. ("Hunt-Collin").

8. A copy of the rates as designed in accordance with paragraphs 6 and 7 above is attached to this Stipulation as Exhibit"A."

9. Hunt-Collin has agreed to terminate its service from Rayburn Country no later than mid-March 1989. As a result of Hunt-Collin no longer receiving any power and energy from Rayburn Country, the Parties agree that it is necessary to adjust Riders NUA and SUA to exclude Hunt-Collin from the calculation. A copy of Riders NUA and SUA as designed, excluding Hunt-Collin, are attached to the Stipulation as Exhibit "B" and shall be effective as of the date Hunt-Collin no longer is a customer of Rayburn Country and will supercede Riders NUA and SUA as they appear in Exhibit "A."

10. The Parties to the Stipulation agree that it is reasonable for Rayburn Country to have an available cash balance of $152,270 as of November 30, 1988.

11. Rayburn Country agrees that as soon as the Final Order implementing the Stipulation is approved, Rayburn Country's Board of Directors will approve a rotation of capital credits that have previously been assigned by Rayburn Country to its customers in the amount of $281,920.

12. Rayburn Country agrees that as soon as the Final Order implementing the Stipulation is approved, Rayburn Country will refund the

accumulated storage reallocation credit plus interest based upon the allocation factor in Rider NUA.

13. As a result of the interim rates approved on January 20, 1989, Rayburn Country has begun to refund to its customers the collections for purchased power that have accumulated as a result of Examiner's Order No. 13 in this Docket. As a result of the Final Order, the refunds with accumulated interest will continue to be paid in a manner and form such that the refunds will, as near as practical, match the month in which the payment was made.

14. The Stipulation is a result of a negotiated settlement which is reasonable and in the public interest of all the issues of fact in this Docket. The Stipulation is offered only in the spirit of compromise and neither Staff, Members nor Rayburn Country do intend for the Stipulation to be regarded as an expression about the appropriateness or correctness of any assumption in respect to the calculation of revenue requirements or any underlying ratemaking principals.

15. Staff, Members and Rayburn Country further agree that no Findings of Fact or Conclusions of Law adopted pursuant to this Stipulation shall be binding upon the Parties in any other proceeding before this Commission, any other regulatory agency, court or other governmental authority.

16. The Parties to the Stipulation agree that the supplemental testimony of John W. Kirkland, Michael Moore, Raymond R. Orozco and Paul Bellon shall be admitted into evidence in support of this Stipulation and that

the Parties hereto agree to waive any cross-examination of the witnesses on this testimony.

17. Staff, Members and Rayburn Country agree that each of them reserves the right to withdraw and demand a full public hearing at any time prior to the expiration of the period for filing Motions for Rehearing in the event the Commission enters, or plans to enter, a Final Order that materially deviates from this Stipulation and the attached Proposed Findings of Fact and Conclusions of Law. The Parties further agree that Rayburn Country reserves the right to appeal in the event the Commission enters a Final Order that materially deviates from this Stipulation.

18. Each of the parties warrants that the person whose signature appears below has the authority to enter into this Stipulation.

ENTERED INTO this 30th day of January, 1989.

By: Paula Mueller
Paula Mueller, Attorney for Public Utility Commission of Texas

By: Richard C. Balough
Richard C. Balough, Attorney for Rayburn Country Electric Cooperative, Inc.

By: Bruce Pauley (by RCB by Permission)
Bruce Pauley, Attorney for Member Cooperatives

RATE WP
WHOLESALE POWER

APPLICABILITY:

This rate schedule is applicable to power and energy delivered by RCEC to its members, in the quantities and at the locations as agreed between RCEC and its members, for resale to consumers of members' systems. Not applicable to temporary, standby, or supplemental service.

MONTHLY RATE:

Customer Charge: $240.00 per point of delivery

Demand Charge: $ 6.33 per kW of billing demand,
plus $ 1.00 per kW for each kW of billing demand in excess of the contract kW.

Energy Charge: $0.025408 per kWh for all kWh.

Transmission Service Credit: $1.35 per kW of billing demand, plus $0.000552 per kWh when service is provided at 69,000 volts or higher.

Plus an amount calculated in accordance with Rider PCRF,
Plus an amount for the South Unit Adjustment calculated in accordance with Rider SUA,
Plus an amount for the North Unit Adjustment calculated in accordance with Rider NUA.

Payment: Bills are due when rendered and are past due if not paid within 16 days thereafter.
Bills are increased 3% if not paid within 20 days after being rendered.

DEMAND DETERMINATION:

Billing demand for calculation of the monthly bill shall be calculated as the largest of the following:

(1) the highest 15-minute kW recorded during the current month;
(2) 80% of the on-peak kW;
(3) 50% of the contract kW; or
(4) 50% of the highest 15-minute kW recorded at the point of delivery in the 12-month period ended with the current month.

RATE WP
WHOLESALE POWER

DEFINITIONS:

On-peak kW is the highest 15-minute kW recorded during the billing months of June through September in the 12-month period ended with the current month. For a Customer contracting for new service, on-peak kW is the current month kW until Customer establishes such demand through on-peak use, unless, in RCEC's sole judgment, sufficient data exists for RCEC to estimate on-peak kW until Customer establishes on-peak history through actual use.

Contract kW is the maximum kW specified in the Agreement for Electric Service.

Current month kW is the highest 15-minute kW recorded during the current month.

NOTICE:

Service hereunder is subject to the orders of regulatory bodies having jurisdiction and to RCEC's Tariff for Electric Service.

RIDER PCRF

POWER COST RECOVERY FACTOR

APPLICABILITY:

This rider is applicable to billing demand and energy delivered by RCEC to its members under Rate WP.

MONTHLY RATE:

Demand Adjustment

$$PCRF_{kW} = (A - B \pm C)/D$$

Where:

$PCRF_{kW}$ = Power Cost Recovery Factor (expressed in $ per kW) to be applied to member's monthly billing demand.

A = Total customer charges and demand costs incurred by RCEC from all suppliers for power purchases, other than purchases associated with the North and South Units at the Denison Dam and including power cost savings associated with short-term purchases which Rayburn Country may enter into from time to time; plus transmission service demand credits paid and less delivery point revenue received by RCEC pursuant to Rate WP.

B = Total customer charges and demand costs incurred by RCEC from all supplier for power purchases, other than purchases associated with the North and South Units at the Denison Dam, which are included in RCEC's base rates in the Rate WP. The base demand cost is computed as:

$$B = (6.33)(D)$$

C = Adjustment to be applied to the current monthly billing to account for differences in actual customer charges and demand costs and actual $PCRF_{kW}$ revenues recovered in previous periods.

D = Total estimated monthly billing demand for all members.

RIDER PCRF
POWER COST RECOVERY FACTOR
(Continued)

Energy Adjustment

$$PCRF_{kWh} = (E - F \pm G)/H$$

Where:

$PCRF_{kWh}$ = Power Cost Recovery Factor (expressed in \$ per kWh) to be applied to member's monthly kWh.

E = Total energy charges and fuel costs incurred by RCEC from all suppliers for purchases, other than purchases associated with the North and South Units at the Denison Dam and including power cost savings associated with short-term purchases which Rayburn Country may enter into from time to time; plus transmission service energy credits paid by RCEC pursuant to Rate WP.

F = Total energy charges and fuel costs incurred by RCEC from all supplier for power purchases, other than purchases associated with the North and South Units at the Denison Dam, which are included in RCEC's base rates in Rate WP. The base energy cost is computed as:

$$F = (.024955)(H)$$

G = Adjustment to be applied to the current monthly billing to account for differences in actual energy charges and fuel costs and actual $PCRF_{kWh}$ revenues recovered in previous periods.

H = Total estimated monthly kWh for all members.

RIDER SUA
DENISON DAM SOUTH UNIT ADJUSTMENT

APPLICABILITY:

This rate schedule is applicable to each of the following RCEC member-cooperatives:

Fannin County Electric Cooperative, Inc.
Farmers Electric Cooperative, Inc.
Grayson-Collin Electric Cooperative, Inc.
Hunt-Collin Electric Cooperative, Inc.
Kaufman County Electric Cooperative, Inc.

MONTHLY ADJUSTMENT:

RCEC billing to member-systems shall be adjusted monthly to reflect the difference between costs and revenues for RCEC in connection with RCEC's delivery to TUEC of capacity and energy from the South Unit of Denison Dam, and for RCEC's purchases of withdrawal capacity and energy from TUEC, pursuant to Contract No. DE-MS75-84SW-00102, between the United States of America and Tex-La of Texas and Rayburn Country, dated February 29, 1984, as it may be amended from time to time, or its successor, as it may amended from time to time, and the Scheduling Agent Agreement between TUEC and Tex-La of Texas and Rayburn Country, dated October 30, 1984, as it may be amended from time to time, or its successor, as it may be amended from time to time. The monthly South Unit Adjustment for each member-cooperative shall be determined as follows:

$$SUA = (SUC - SUR - WPS) * SUAF$$

Where:

SUA = Member's South Unit Adjustment.

SUC = RCEC cost for South Unit capacity and energy from SWPA for the second preceding calendar month.

SUR = Total revenue received by RCEC for South Unit capacity and energy for the second preceding calendar month.

WPS = Withdrawal power savings, calculated as the difference between RCEC's total cost for withdrawal power and the total cost for that same power under the applicable TUEC rate.

SUAF = Members' South Unit allocation factor, as follows:

Fannin County Electric Cooperative, Inc.	6.07%
Farmers Electric Cooperative, Inc.	36.94%
Grayson-Collin Electric Cooperative, Inc.	24.02%
Hunt-Collin Electric Cooperative, Inc.	3.12%
Kaufman County Electric Cooperative, Inc.	29.85%

RIDER NUA
DENISON DAM NORTH UNIT ADJUSTMENT

APPLICABILITY:

This rate schedule is applicable to each of the following RCEC member-cooperatives:

Fannin County Electric Cooperative, Inc.
Farmers Electric Cooperative, Inc.
Grayson-Collin Electric Cooperative, Inc.
Hunt-Collin Electric Cooperative, Inc.
Kaufman County Electric Cooperative, Inc.
Lamar County Electric Cooperative, Inc.
New Era Electric Cooperative, Inc.

MONTHLY ADJUSTMENT:

RCEC billing to member-systems shall be adjusted monthly for all costs and benefits to RCEC in connection with RCEC's entitlements to the North Unit of Denison Dam pursuant to Contract No. DE-MS75-84SW-00102, between the United States of America and Tex-La of Texas and Rayburn Country, dated February 29, 1984, as it may be amended from time to time, or its successor, as it may amended from time to time, and the Scheduling Agent Agreement between TUEC and Tex-La of Texas and Rayburn Country, dated October 30, 1984, as it may be amended from time to time, or its successor, as it may be amended from time to time. The monthly North Unit Adjustment for each member-cooperative shall be determined as follows:

$$NUA = (NUC - NUR) * NUAF$$

Where:

NUA = Member's North Unit Adjustment.

NUC = Total RCEC cost for North Unit capacity and energy for the second preceding calendar month.

NUR = Total revenue received by RCEC for North Unit energy for the second preceding calendar month.

NUAF = Member's North Unit Allocation Factor, as follows:

Fannin County Electric Cooperative, Inc.	4.68%
Farmers Electric Cooperative, Inc.	26.85%
Grayson-Collin Electric Cooperative, Inc.	18.20%
Hunt-Collin Electric Cooperative, Inc.	2.34%
Kaufman County Electric Cooperative, Inc.	21.98%
Lamar County Electric Cooperative, Inc.	7.93%
New Era Electric Cooperative, Inc.	18.02%

RIDER SUA
DENISON DAM SOUTH UNIT ADJUSTMENT

APPLICABILITY:

This rate schedule is applicable to each of the following RCEC member-cooperatives:

Fannin County Electric Cooperative, Inc.
Farmers Electric Cooperative, Inc.
Grayson-Collin Electric Cooperative, Inc.
Kaufman County Electric Cooperative, Inc.

MONTHLY ADJUSTMENT:

RCEC billing to member-systems shall be adjusted monthly to reflect the difference between costs and revenues for RCEC in connection with RCEC's delivery to TUEC of capacity and energy from the South Unit of Denison Dam, and for RCEC's purchases of withdrawal capacity and energy from TUEC, pursuant to Contract No. DE-MS75-84SW-00102, between the United States of America and Tex-La of Texas and Rayburn Country, dated February 29, 1984, as it may be amended from time to time, or its successor, as it may amended from time to time, and the Scheduling Agent Agreement between TUEC and Tex-La of Texas and Rayburn Country, dated October 30, 1984, as it may be amended from time to time, or its successor, as it may be amended from time to time. The monthly South Unit Adjustment for each member-cooperative shall be determined as follows:

$$SUA = (SUC - SUR - WPS - HCSUB) * SUAF$$

Where:

SUA = Member's South Unit Adjustment.

SUC = RCEC cost for South Unit capacity and energy from SWPA for the second preceding calendar month.

SUR = Total revenue received by RCEC for South Unit capacity and energy for the second preceding calendar month.

WPS = Withdrawal power savings, calculated as the difference between RCEC's total cost for withdrawal power and the total cost for that same power under the applicable TUEC rate.

HCSUB = RCEC net benefit payment to Hunt-Collin Electric Cooperative, Inc. for the South Unit.

SUAF = Members' South Unit allocation factor, as follows:

Fannin County Electric Cooperative, Inc.	6.27%
Farmers Electric Cooperative, Inc.	38.13%
Grayson-Collin Electric Cooperative, Inc.	24.79%
Kaufman County Electric Cooperative, Inc.	30.81%

RIDER NUA
DENISON DAM NORTH UNIT ADJUSTMENT

APPLICABILITY:

This rate schedule is applicable to each of the following RCEC member-cooperatives:

Fannin County Electric Cooperative, Inc.
Farmers Electric Cooperative, Inc.
Grayson-Collin Electric Cooperative, Inc.
Kaufman County Electric Cooperative, Inc.
Lamar County Electric Cooperative, Inc.
New Era Electric Cooperative, Inc.

MONTHLY ADJUSTMENT:

RCEC billing to member-systems shall be adjusted monthly for all costs and benefits to RCEC in connection with RCEC's entitlements to the North Unit of Denison Dam pursuant to Contract No. DE-MS75-84SW-00102, between the United States of America and Tex-La of Texas and Rayburn Country, dated February 29, 1984, as it may be amended from time to time, or its successor, as it may amended from time to time, and the Scheduling Agent Agreement between TUEC and Tex-La of Texas and Rayburn Country, dated October 30, 1984, as it may be amended from time to time, or its successor, as it may be amended from time to time. The monthly North Unit Adjustment for each member-cooperative shall be determined as follows:

$$NUA = (NUC - NUR - HCNUB) * NUAF$$

Where:

NUA = Member's North Unit Adjustment.

NUC = Total RCEC cost for North Unit capacity and energy for the second preceding calendar month.
NUR = Total revenue received by RCEC for North Unit energy for the second preceding calendar month.
HCNUB = RCEC net benefit payment to Hunt-Collin Electric Cooperative, Inc. for the North Unit.
NUAF = Member's North Unit Allocation Factor, as follows:

Fannin County Electric Cooperative, Inc.	4.80%
Farmers Electric Cooperative, Inc.	27.49%
Grayson-Collin Electric Cooperative, Inc.	18.63%
Kaufman County Electric Cooperative, Inc.	22.51%
Lamar County Electric Cooperative, Inc.	8.12%
New Era Electric Cooperative, Inc.	18.45%

RAYBURN COUNTRY ELECTRIC COOPERATIVE, INC.
HYDRO REALLOCATION REFUND -- TOTAL

	HYDRO PRINCIPAL	INTEREST EARNED*	TOTAL REFUND
FANNIN	$9,783.56	$371.65	$10,155.21
FARMERS	$56,130.06	$2,132.25	$58,262.31
GRAYSON-COLLIN	$38,047.22	$1,445.33	$39,492.55
HUNT-COLLIN	$4,891.78	$185.83	$5,077.61
KAUFMAN	$45,949.32	$1,745.50	$47,694.82
LAMAR	$16,577.73	$629.75	$17,207.48
NEW ERA	$37,670.90	$1,431.02	$39,101.92
TOTAL	$209,050.57	$7,941.33	$216,991.90

*INTEREST CALCULATED AS OF DECEMBER 31, 1988

RAYBURN COUNTRY ELECTRIC COOPERATIVE, INC.
ECONOMY ENERGY REFUND -- TOTAL

	ECONOMY ENERGY PRINCIPAL	INTEREST EARNED*	TOTAL REFUND
FANNIN	$100,084.58	$5,365.51	$105,450.09
FARMERS	$609,556.02	$32,725.12	$642,281.14
GRAYSON-COLLIN	$394,233.06	$21,232.81	$415,465.87
HUNT-COLLIN	$51,727.79	$2,778.37	$54,506.16
KAUFMAN	$485,627.61	$26,034.11	$511,661.72
LAMAR	$158,048.68	$8,463.95	$166,512.63
NEW ERA	$382,395.04	$20,310.06	$402,705.10
TOTAL	$2,181,672.78	$116,909.93	$2,298,582.71

*CALCULATIONS AS OF DECEMBER 31, 1988

DOCKET NO. 7361

INQUIRY INTO THE RATES OF RAYBURN COUNTRY ELECTRIC COOPERATIVE, INC. AND APPLICATION FOR A CERTIFICATE OF CONVENIENCE AND NECESSITY	§ § § §	PUBLIC UTILITY COMMISSION OF TEXAS

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 and rules by a hearings examiner, who prepared and filed a report containing Findings of Fact and Conclusions of Law. The Supplemental Examiner's Report, as amended by the examiner on March 6, 1989, is ADOPTED and made a part hereof. The Commission further issues the following Order:

1. The application of Rayburn Country Electric Cooperative, Inc. (Rayburn Country) for rate changes is GRANTED to the extent recommended in the Supplemental Examiner's Report.

2. Exhibit A of the January 30, 1989, Stipulation of Parties consists of the proposed tariff. The proposed tariff is hereby APPROVED and effective the date of this Order. Rayburn Country is ORDERED to file five copies of Exhibit A with the Commission's tariff clerk. The tariff in Exhibit A shall be substituted for the tariff currently on file with the Commission.

3. Exhibit B of the January 30, 1989, Stipulation of Parties consists of proposed revised tariff Riders SUA and NUA. The revisions reflect the mid-March 1989 withdrawal of Hunt-Collin Electric Cooperative, Inc. (Hunt-Collin) as a customer of Rayburn Country. The Riders SUA and NUA in Exhibit B are APPROVED. Rayburn Country is ORDERED to file with the Commission's tariff

clerk five copies of the Exhibit B Riders SUA and NUA on the first day Hunt-Collin is no longer a Rayburn Country customer, or April 3, 1989, whichever date is earlier. Rayburn Country shall note at the top of each page of the Riders SUA and NUA the effective date of Hunt-Collin's withdrawal as a customer of Rayburn Country.

4. Rayburn Country is ORDERED to file a sworn written statement with the Commission no later than 45 days after the date of this Order. The statement shall confirm that the rotation of capital credits in the amount of $281,920, and that the refund of the Lake Texhoma reallocation credit have both been paid to the Rayburn Country customer cooperatives. The statement shall demonstrate the details of the calculation of the rotation of capital credits and the details of the calculation of the refund.

5. Rayburn Country is ORDERED to file a sworn written statement with the Commission no later than February 1990. The statement shall confirm that Rayburn Country has refunded to the Rayburn Country customer cooperatives savings from economy energy purchases held in an escrow account. Rayburn Country created the escrow account to hold savings related to economy energy purchases made from November 1987 through September 1988. The statement shall detail the calculation and timing of payments from the escrow account of the principal plus interest.

6. The application of Rayburn Country for a certificate of convenience and necessity for its transmission line located in the unincorporated community of Pickton, Hopkins County, is GRANTED. The Certificate of Convenience and Necessity is numbered 30187.

7. The Commission's Order in this case is based upon stipulations which were reached by negotiations among the parties in this case; however, the Commission has not and should not be deemed to have endorsed, accepted, agreed to, or approved any ratemaking or underlying methodology which provides the basis for the stipulations. The results of the stipulations as a whole are found to be reasonable, and the Commission has adopted them for that reason alone. This Order is not to be regarded as a binding or precedential holding as to the appropriateness of any theories or methodologies underlying the stipulations, and the Commission reserves the right to scrutinize more closely any and all such theories and methodologies in future cases.

8. All motions and requests for entry of specific findings of fact and conclusions of law or for any other form of relief, general or specific, if not expressly granted herein are DENIED for want of merit.

SIGNED AT AUSTIN, TEXAS on this the 9th day of March 1989.

PUBLIC UTILITY COMMISSION OF TEXAS

SIGNED: Marta Greytok
MARTA GREYTOK

SIGNED: Jo Campbell
JO CAMPBELL

SIGNED: William B. Cassin
WILLIAM B. CASSIN

ATTEST:

Phillip A. Holder
PHILLIP A. HOLDER
SECRETARY TO THE COMMISSION

APPLICATION OF HOUSTON LIGHTING & POWER COMPANY FOR APPROVAL OF ECONOMY ENERGY SALES CONTRACTS § § § **DOCKET NO. 8231**

February 24, 1989

Generic tariff for sale of economy energy by Houston Lighting & Power Company (HL&P), as well as specific contracts with three electric cooperatives, approved.

[1] RATEMAKING--RATE DESIGN--ELECTRIC--WHOLESALE RATES
RATEMAKING--RATE DESIGN--ELECTRIC--FUEL AND PURCHASED POWER

Section 31 of PURA makes it unlawful for any utility to charge, collect, or receive any rate that is not provided for under the authority of PURA, yet the short-term nature of economy energy transactions renders prior approval of specific sales unfeasible. Approval of a generic tariff constitutes approval of the rates charged for economy energy transactions occurring under the terms of the generic tariff and thereby satisfies Section 31 of PURA. (p. 2565)

[2] RATEMAKING--RATE DESIGN--ELECTRIC--WHOLESALE RATES
RATEMAKING--RATE DESIGN--ELECTRIC--FUEL AND PURCHASED POWER

The economy energy market in Texas is competitive. (pp. 2568, 2586)

[3] RATEMAKING--RATE DESIGN--ELECTRIC--INCENTIVE RATES

It is appropriate to design the price floor for economy energy to cover the short-run incremental cost of providing the service. It is not appropriate to include non-incremental costs in the design of the price floor. (pp. 2568, 2586)

[4] RATEMAKING--RATE DESIGN--ELECTRIC--WHOLESALE RATES
RATEMAKING--RATE DESIGN--ELECTRIC--FUEL AND PURCHASED POWER

There are reasonable public policy reasons for approving generic tariffs for the sale of economy energy, namely the preservation and legalization of a utility's participation in an economy energy market that is saving money for all participating utilities. (pp. 2581, 2587)

[5] RATEMAKING--RATE DESIGN--ELECTRIC--WHOLESALE RATES
RATEMAKING--RATE DESIGN--ELECTRIC--FUEL AND PURCHASED POWER

Approval of a generic tariff for the sale of economy energy constitutes approval after a hearing by the Commission and thereby satisfies the requirements of section 43(g)(4)(A) of PURA. (pp. 2588, 2589)

DOCKET NO. 8231

APPLICATION OF HOUSTON LIGHTING AND POWER COMPANY FOR APPROVAL OF ECONOMY ENERGY SALES CONTRACTS AND GENERIC TARIFF	§ § § §	PUBLIC UTILITY COMMISSION OF TEXAS

EXAMINER'S REPORT

I. Procedural History

On June 21, 1988, Houston Lighting & Power Company (HL&P) filed three agreements providing for the sale of economy energy to three electric utilities -- Tex-La Electric Cooperative, Inc. (Tex-La), Rayburn Country Electric Cooperative, Inc. (Rayburn Country), and Cap Rock Electric Cooperative, Inc. (Cap Rock). The agreements were filed pursuant to section 32 of the Public Utility Regulatory Act (PURA), Tex. Rev. Civ. Stat. Ann. art. 1446c (Vernon Supp. 1988).

A prehearing conference was held on July 14, 1988, with Administrative Law Judge Charles Smaistrla presiding. Appearances were made on behalf of HL&P and the Commission staff. It was decided at the prehearing conference that hearings on the merits would be scheduled for consideration of both interim and final approval of the three agreements, and that the company would file a generic tariff for economy energy sales which would be considered for approval at the final hearing on the merits.

The three economy energy agreements initially filed were granted interim approval by ALJ Smaistrla on August 3, 1988, following an interim hearing and stipulation of all the parties (HL&P, Tex-La, Rayburn Country, and the Commission's general counsel).

HL&P filed a generic tariff on August 29, 1988. Implementation of the proposed tariff change was suspended for 150 days beyond the otherwise effective date of October 3, 1988, to March 2, 1989, pursuant to P.U.C. SUBST. R. 23.24(i).

On September 20, 1988, this case was reassigned to the undersigned hearings examiner. Intervention was granted to Occidental Chemical Corporation

(Occidental), Dow Chemical Company (Dow) and CoGen Lyondell, Inc. (CoGen) on September 22, 1988. The hearing on the merits was convened on October 31, 1988. Appearances were entered on behalf of all the parties previously mentioned, as well as the Office of Public Utility Counsel (OPC). (The OPC representative left shortly after the hearing was convened and did not reappear.) All of the parties except CoGen and OPC entered into a written stipulation which settled all disputed issues. (The stipulation is attached to this report as "Attachment No. 1." The exhibits are not included due to their bulk.) Because an agreement with all the parties could not be reached, a full hearing on the merits was conducted. The hearing was adjourned on November 2, 1988. Post-hearing briefs were filed by all parties except OPC, which did not participate in the hearing anyway. Reply briefs were filed by HL&P, Rayburn Country, and CoGen.

II. Jurisdiction

HL&P, Tex-La, Rayburn Country, and Cap Rock are public utilities as the term is defined in section 3(c) of PURA. The Commission has jurisdiction and authority in this proceeding pursuant to sections 16(a), 17(e), 32 and 37 of PURA.

III. Background and Overview

Economy energy transactions involve the off-system sale and purchase of energy between utilities at prices that are economically efficient for both the seller and the purchaser. The transactions occur voluntarily and on a short-term basis when one utility can generate, or otherwise acquire, energy at an incremental cost that is less than the incremental cost of production, or acquisition, of another utility. Through the testimony of one of its witnesses, Charles F. Ham, HL&P demonstrated that economy energy sales have been occurring within Texas for over 25 years, and that the Commission has been encouraging economy energy sales since 1977. (HL&P Exh. No. 5, Ham Testimony.)

Perhaps because of the the short-term nature of these transactions, they have gone virtually unregulated by the Commission. Utilities in Texas routinely negotiate transactions over a short time frame for the sale and purchase of short-term firm and non-firm energy. Under such conditions, regulation has apparently been deemed unfeasible.

On December 17, 1987, the Commission affirmed, on appeal, Examiner's Order No. 13 in Docket No. 7361, Filing by Rayburn Country Electric Cooperative, Inc. of Initial Rates and Inquiry into Rates Pursuant to Section 42. In part, Order No. 13 held that the member coops of Rayburn Country could not use their PCRF (purchased cost recovery factor) clauses to automatically pass through variations in purchased power costs resulting from the rates charged by Rayburn Country. This was because Rayburn Country's rates had not been approved by the Commission after a hearing or accepted by a federal regulatory authority, and therefore, under section 43(g)(4)(A) of PURA, the member coops' PCRF clauses would not be applicable to increases or decreases in the cost of electricity purchased from Rayburn Country.

Rayburn Country began purchasing economy energy from HL&P in April of 1987. For the period from April of 1987 through August of 1988, receipts of economy energy from HL&P accounted for 63.7 percent of Rayburn Country's total sales of energy to its customers, and allowed the cooperative to save $5,356,200 in purchased power expense. Yet, because the economy energy transactions had not been approved by the Commission after a hearing or accepted by a federal regulatory authority, neither Rayburn Country nor its member coops could pass the saving through to their own customers until August 3, 1988, when interim approval, after a hearing, was granted in this docket to Rayburn Country's economy energy agreement with HL&P.

In light of section 43(g)(4)(A) of PURA and the Commission's affirmance of Order No. 13 in Docket No. 7361, it would seem that approval of economy energy transactions after a hearing is necessary in order to enable purchasing utilities [eligible under P.U.C. SUBST. R. 23.23(b)(3)] to pass through the costs/savings that they incur from the transactions.

[1] Section 31 of PURA makes it unlawful for any utility to charge, collect, or receive any rate that is not provided for under the authority of PURA. To the extent that utilities have been selling economy energy in Texas without prior Commission approval of the rates charged, it appears that they have been doing so illegally. In fairness to the utilities, the Commission has long been aware of the industry practice of engaging in economy energy transactions and, as was stated earlier, has encouraged the practice. The Commission seems to have acquiesced with the industry practice concerning economy energy transactions insomuch as the Commission has not formally regulated such transactions.

Because of the nature of these transactions, prior approval of specific transactions is not feasible. Having reviewed the application of HL&P and the evidence developed at the hearing, the examiner suspects that the best course of action to deal with this industry-wide situation would be to encourage utilities which sell economy energy in Texas file generic tariffs, similar to the one proposed in the partial stipulation admitted at the hearing in this docket. Those utilities with approved tariffs would be able to legally sell economy energy in Texas in accordance with PURA. Furthermore, utilities with PCRF clauses would be able to pass through to their customers any costs/savings realized from purchases of economy energy from utilities with approved tariffs. Industry-wide action cannot properly be taken in this docket, however. Therefore, the examiner recommends that the Commission have its staff review the situation and recommend a proposal.

IV. Three Cooperative Agreements

Before discussing the proposed generic tariff, the examiner will briefly discuss HL&P's agreements with the three cooperatives. Each of these agreements was approved in August on an interim basis, and no party has any opposition to final approval of these three agreements.

The terms of the three agreements are almost identical, although the maximum level of MWH delivery that HL&P will offer monthly differs for the three cooperatives. (See Joint Exh. No. 1, Final Stipulation, Exhs. A-1 through A-3.) Under the agreements, HL&P may quote a price per MWH to the cooperatives each month, and the cooperatives have the option of accepting or rejecting the offer. The prices remain fixed for the duration of any calendar month in which the cooperatives elect to receive deliveries. The cooperatives are responsible for maintaining wheeling arrangements for the transfer of the energy from HL&P's system to their own. Additionally, the cooperatives are responsible for retaining scheduling agreements with Texas Utilities Electric Company which maintains the control area for each of the cooperatives.

The evidence shows that past economy energy sales to Rayburn Country and Tex-La have been economically efficient. HL&P has received marginal revenues from the sales that have been well above its marginal costs. Rayburn Country was the only one of the three cooperatives that presented evidence of its savings resulting from the purchase of economy energy from HL&P. Rayburn Country reduced its purchased power expense by $5,356,200, or 7.1 percent, during the period from April of 1987 through August of 1988 as a result of purchases from HL&P. (Rayburn Exh. No. 1, Moore Testimony, p. 5.) Although there is no direct evidence of the savings experienced by the other two cooperatives, if one merely assumes that Tex-La and Cap Rock behaved rationally in making their purchase decisions (that is, they purchased energy from HL&P only when the price was lower than that of the next source available to them), it follows that they too were able to reduce their purchased power expense by buying economy energy from HL&P.

Staff rate analyst George Mentrup reviewed the three agreements and recommended approval. (General Counsel Exh. No. 1-A, Mentrup Supplemental Testimony, p. 2.) The evidence shows that the agreements are beneficial to the ratepayers of all four utilities involved insomuch as the savings experienced by each utility can be expected to lower the cost for service of each utility. The record also reflects HL&P's intention of proposing, in its next rate case (which was filed shortly after the hearing on the merits in this case was adjourned), that all revenues from its economy energy sales be booked to reconcilable fuel accounts and be subject to a fuel reconciliation proceeding. Mr. Mentrup testified that if HL&P were to make sales for less than its marginal cost, the Commission could disallow the expenses associated with those sales. For these reasons, the examiner recommends that final approval be given to these agreements.

V. Generic Tariff

The three agreements with the cooperatives discussed in the previous section are based upon a type of economy energy transaction known as Economy B. Guidelines for this type of transaction were first adopted by the Electric Reliability Council of Texas (ERCOT) in 1985. (HL&P Exh. No. 5, Ham Testimony, p. 5.) Economy B sales are energy sales that are firm for each twenty-four hour period of sale. If approved, the generic tariff proposed in the partial stipulation would permit HL&P to legally offer Economy B energy, as well as the other types of economy energy services provided for in ERCOT guidelines. Other types of economy energy services specified in the proposed tariff are Economy A and Broker, and Economy C. Economy A and Broker energy are hour to hour interruptible sales that are based upon oral agreements between utilities and take place less than twenty-four hours at a time. Economy C energy sales are firm for more than four but less than twenty-four hours. (HL&P Exh. No. 1, Standish Testimony, p. 2; Joint Exh. No. 1, Final Stipulation, Exh. B-1.)

The tariff, which is attached to this report as "Attachment No. 2", does not specifically identify any other type of service, but does state that sales are not limited to the services that are specified. (See Attachment No. 2, EES tariff, p. 1, section titled "Billing".) Sales must be per ERCOT guidelines, however, and all economy energy sold under the tariff must comport with the restrictions and limitations therein. For reasons to follow, the examiner recommends that the stipulation and the proposed generic tariff be adopted.

A. Pricing

The tariff specifies a price floor for each of the economy energy services. Services must be priced to cover HL&P's projected marginal fuel cost, adjusted for line losses of one percent when averaged over the time period of the transaction. Additionally, Economy B and C prices must include a margin of not less than 1.2 mills per kwh to cover incremental variable O&M (operation and maintenance) cost. Actual prices will result from agreements between HL&P and the purchasing utility. The evidence shows that the economy energy market is
[2] competitive, with West Texas Utilities being the major competitor of HL&P. (10/31/88 HOM Tr., pp. 72-73.) Because the market is competitive, it will serve to set effective ceilings on the prices at which HL&P may successfully offer these services. HL&P witness Thomas Standish, manager of HL&P's rate and economic research department, testified that in response to the market the company is currently seeking margins of 10 to 15 percent on its Economy A sales, and margins of 10 to 25 percent on its Economy B sales. (10/31/88 HOM Tr., pp. 71-72.)

[3] In testimony, both Messrs. Standish and Mentrup explained why the price floor proposed in the tariff is appropriate. In order to make a profit on the sales, HL&P would have to sell its economy energy at a price greater than its extra production costs. In economic terms, this extra production cost is referred to as short-run incremental cost (also commonly referred to as marginal cost) and includes the additional fuel cost, line losses, and O&M cost associated with the production of the additional energy sold. The proposed tariff is designed to cover each of these components of incremental cost, although the 1.2 mills per kwh does not apply to Economy A and Broker sales because any incremental O&M costs associated with this service is de minimis.

The major component of short-run incremental production cost for economy energy is, of course, the fuel cost. HL&P projects incremental fuel cost hourly through the use of its computerized production dispatch model, GENSOM D.

Production dispatch models are commonly used by major electric utilities in Texas to project incremental cost for economy energy sales. (HL&P Exh. No. 6, p. 5; 10/31/88 HOM Tr., p. 521.) Using GENSOM D to project the hourly incremental fuel cost associated with an economy energy transaction should result in the most accurate projection possible because GENSOM D is the same program that determines, hourly, the actual dispatch of units within HL&P's generating system. (10/31/88 HOM Tr., pp. 41, 307.)

HL&P will add a one percent (1%) loss factor above the calculated incremental fuel cost to offset for possible energy losses on its lines resulting from expanded use of its transmission system for economy energy sales. In HL&P's last rate case, Docket No. 6765, the Commission found that HL&P's average line loss was .08%. The evidence shows that a 1 percent (1%) additive is sufficient to cover line losses associated with economy energy sales. (10/31/88 HOM Tr., p. 243; HL&P Exh. No. 6, Meyer Testimony, pp. 7-8.)

The generic tariff also requires HL&P to include a 1.2 mills per kwh additive in the calculation of short-run incremental cost for Economy B and C energy to cover incremental variable O&M expense. The evidence shows that an additive of 1.2 mills/kwh is more than sufficient to cover incremental variable O&M expense. HL&P witness Thomas Standish testified that, in his opinion, incremental O&M cost for these sales is zero because the sales can be used to reduce cycling (the starting and stopping of generating units in response to changes in system load) and thereby <u>lower</u> incremental O&M expense. (HL&P Exh. No. 1, Standish Testimony, p. 5; 10/31/88 HOM Tr., pp. 89-90, 240-241.) Staff analyst George Mentrup did not dispute this possibility, but since Mr. Standish had not offered any quantifiable support for his opinion, Mr. Mentrup recommended an additive of 1 mill/kwh in order to cover the possibility of positive incremental variable O&M cost. (General Counsel Exh. No. 1, Mentrup Testimony, p. 9.) On cross-examination, CoGen witness Thomas Edmonds admitted that an incremental O&M expense of .88 mills/kwh was reasonable. (10/31/88 HOM Tr., pp. 374-377.) The <u>average</u> variable O&M expense found reasonable in the company's last rate case, Docket No. 6765, was 1.2 mills/kwh. (HL&P Exh. No. 2, Standish Testimony, p. 9.)

The additive for O&M expense does not apply to Economy A and Broker sales. Economy A and Broker energy are sold out of on-line spinning reserves which are in excess of the utility's spinning reserve obligation. Thus, no additional units are committed, nor does additional cycling of units occur, in order to make these sales. Incremental O&M cost is, therefore, de minimis.

B. Purchaser Obligations

Purchasers of economy energy under the generic tariff must have firm purchase power arrangements in place or capacity available as required by ERCOT guidelines, but not necessarily on line, to back up this service. (See Attachment No. 2, section titled "Services Provided".) Additionally, purchasers are responsible for maintaining scheduling and wheeling arrangements necessary to complete deliveries. TU Electric currently provides these services to Rayburn Country and Tex-La in connection with the existing agreements which have been given interim approval. (Rayburn Exh. No. 1, Moore Testimony, p. 4; 10/31/88 HOM Tr., pp. 102, 292.)

Per ERCOT operating guidelines, service under the tariff may be terminated if the purchasing utility fails to maintain back-up capacity. Rayburn witness Michael Moore identified one instance when such a termination occurred. Mr. Moore testified that when a fire in April of 1987 took two of TU Electric's generating units out of service, economy energy deliveries from HL&P to Rayburn Country were terminated because Rayburn Country no longer had back-up capacity available. (10/31/88 HOM Tr., pp. 292-293.)

The proposed generic tariff would continue HL&P's participation in Broker, Economy A, Economy B, and Economy C transactions as they are currently conducted under the auspices of the ERCOT organization. Contract periods under the proposed generic tariff are not to exceed twenty-one (21) days. Agreements with contract periods greater than twenty-one (21) days (such as the agreements with the three cooperatives) must be submitted to the Commission for review and approval.

VI. ERCOT Practices

The three cooperative agreements, as well as the proposed generic tariff, are designed to comport with the industry practices concerning economy energy as developed by ERCOT members. Approval of agreements and generic tariffs, such as the ones proposed here, should enable economy energy transactions to continue as they have for a number of years under ERCOT guidelines. A summary of some of the testimony which describes the existing ERCOT practices should therefore be useful.

At the hearing, Mr. Meyer described how Economy A and Broker transactions are handled. Economy A and Broker sales are non-firm hourly sales that are interruptible by the buyer or the seller at any time upon notice. The transactions are handled through ERCOT, which acts as an agent for each of the participants. Any utility wishing to participate in the brokerage program must submit buy and sell bids with ERCOT five minutes before the hour. ERCOT matches buyers and sellers to maximize split savings for the each buyer and seller. Transactions are then immediately finalized by ERCOT without further input from the individual utilities. The program is designed to match buyers and sellers to maximize savings for the participants and the industry as a whole. Mr. Meyer estimates that an entire transaction takes less than five minutes to complete. (10/31/88 HOM Tr., pp. 496, 506-509.) Because these transactions do occur within such a short time frame it is obvious that prior approval of each specific transaction is not feasible. Requiring prior Commission approval of the specific rate charged for economy energy sold under this system would be unworkable and would destroy a program which has served the ERCOT utilities well since at least 1985. (HL&P Exh. No. 5, Ham Testimony, p. 6.)

Mr. Meyer also described the mechanics of an Economy B transaction. Economy B sales are energy sales that are firm for twenty-four hours. Economy B transactions are used by utilities for daily planning purposes. As ERCOT members develop their daily generation plans, they may utilize their production dispatch models to look at such things as projected system loads, projected incremental production costs, and projected incremental costs of producing additional energy for sale in the economy energy market. They may then decide whether to submit a bid to ERCOT for the sale of firm energy the following day. Submitted bids are posted on the ERCOT "bulletin board" for transactions to be completed the following day. Utilities may then review the bulletin board and decide whether to purchase. If they decide to purchase, wheeling arrangements are made, and with the help of ERCOT personnel, the transaction is usually finalized in about an hour.

There is no testimony describing the Economy C transactions, but they are presumably handled similarly to the Economy B transactions since Economy C is essentially equivalent to Economy B, except that the duration of the Economy C sale is for less than 24 hours.

ERCOT began reporting total savings figures for the electric industry as a result of these transactions in May of 1987. For the first fifteen months, over $15 million dollars has been saved, for an average of over $1 million per month. (HL&P Exh. No. 5, Ham Testimony, p. 6.) At present, HL&P accounts for about thirty percent (30%) of the ERCOT economy energy market. (HL&P Exh. No. 6, Meyer Testimony, p. 11.)

VII. CoGen Lyondell's Position

As stated earlier, OPC and CoGen are the only parties that have not signed the stipulation. Although OPC intervened, the agency has not participated in the case. At the hearing, counsel for CoGen stated for the record that CoGen does not oppose final approval of the three cooperative agreements, but CoGen does oppose approval of the generic tariff proposed in the stipulation of the other parties. The examiner has carefully considered the matters raised by CoGen during the three-day hearing and in its post-hearing briefs, and is nevertheless persuaded that the evidence shows that approval of the proposed generic tariff is in the public interest and should be approved. The examiner will discuss the arguments made by CoGen and explain why she believes the arguments are without merit and that HL&P has met its burden of proof in this case.

A. Recovery of Wheeling Costs

CoGen argues that the proposed tariff should be denied because it will not recover any revenues from purchasing utilities for the use of HL&P's transmission system. The evidence shows, however, that it is proper to price economy energy at short-run incremental cost, and that there are no significant incremental transmission costs associated with the sale of economy energy. As described earlier, the incremental O&M costs associated with economy energy sales are related to generation, not transmission.

Staff analyst George Mentrup explained why it is inappropriate to design the minimum rate for these economy energy transactions to include the recovery of embedded costs. Embedded costs are investment costs that are usually fixed and which have already been incurred and allocated to the native system ratepayers. HL&P's generation and transmission system was built, and embedded costs incurred, for the purpose of providing service to HL&P's native customers. The presence or absence of economy energy sales in no way alters the size or cost of the existing system. Those costs are "sunk" costs and are not properly considered for recovery in economy energy sales. (General Counsel Exh. No. 1, Mentrup Testimony, pp. 7-8.)

Because economy energy sales are sales of opportunity, whereby the company may utilize its existing spare capacity and available transmission to sell off-system energy at a profit (marginal revenue above marginal cost), the company has in the past used the extra revenue derived from economy energy sales to reduce the fixed cost burden of the native ratepayers. The benefit to HL&P ratepayers will continue in the future. As explained earlier, the company intends, with Commission approval, to book the revenues from these transactions to reconcilable fuel accounts. Thus, the savings can be used to offset known or reasonably predictable fuel costs allocated to HL&P ratepayers.

For these reasons, the examiner finds that CoGen's argument is misplaced, and that the only transmission costs that the generic tariff should be designed to recover are incremental transmission costs, which the evidence shows are zero.

B. O&M Cost Recovery

CoGen also argues that HL&P has not shown that the proposed generic tariff will recover all O&M costs to be incurred with the sale of economy energy, and that the tariff should be denied for this reason.

As was stated earlier, the 1.2 mills per kwh additive for Economy B and C is greater than the figures supported by the evidence for recovery of incremental O&M. The evidence simply does not support CoGen's assertion that there will be an underrecovery of O&M costs. CoGen's own witness testified on cross-examination that a figure of .88 mills/kwh would be a reasonable additive for O&M cost recovery. The examiner finds CoGen's challenge to be without merit.

C. Incremental Fuel Cost Recovery

CoGen also argues that the proposed generic tariff should be denied because of its reliance on GENSOM D to calculate incremental fuel costs. HL&P's witnesses, as well as the staff analyst, testified that use of GENSOM D is proper because the closer the incremental costing model reflects the company's dispatch behavior, the closer the projection of incremental costs will be to true incremental costs. (10/31/88 HOM Tr., p. 307.) The evidence shows that use of dispatch models for projecting incremental fuel costs is common throughout the electric industry.

CoGen asserts that the GENSOM program is complex, and therefore cannot be successfully audited. (CoGen Brief, p. 14.) The evidence, however, will not support the conclusion that the use of GENSOM D for purposes of this tariff cannot be successfully audited. HL&P has been using the program for some time now, and its use has not been challenged in previous rate cases or fuel reconciliation proceedings. (10/31/88 HOM Tr., pp. 384-385, 442-443.) Mr. Mentrup expressed confidence in the Commission staff's ability to accurately determine reconcilable fuel cost. (10/31/88 HOM Tr., p. 319.) Evidence concerning HL&P's use of the GENSOM program to determine its incremental fuel cost would certainly be relevant and discoverable in any rate case or fuel reconciliation proceeding. For these reasons, the examiner concludes that use of the program is auditable and rejects CoGen's argument.

D. Discriminatory/Anti-Competitive Issues

Finally, CoGen argues that the proposed tariff should be denied because it is discriminatory and anti-competitive in nature. CoGen correctly points out that the tariff sets only a price floor and that the actual price charged to utilities purchasing economy energy from HL&P will likely vary with each transaction. CoGen is incorrect, however, in its conclusion that this fact demonstrates that the proposed tariff does not satisfy section 38 of PURA, which requires that rates not be unreasonably preferential, prejudicial, or discriminatory. There is no evidence to show that a utility will be economically disadvantaged, or otherwise harmed, either from its own purchase of economy energy from HL&P, or from another utility's purchase of economy energy from HL&P. Indeed, these transactions were described by some witnesses as a "win-win" situation because not only does HL&P sell at a profit, but purchasing utilities buy at a price lower than the cost of their next available source of energy.

Section 38 of PURA is designed to protect consumers against discriminatory rates of a utility with monopoly power. HL&P, however, does not have monopoly power in the economy energy market. Rates charged to purchasers of economy energy will be voluntary, as well as responsive to market pressures. The differences that will result among the prices paid by purchasing utilities under this tariff will result not from any superior bargaining power or leverage on the part of HL&P, but rather from the competitive pressures that exist in the economy energy market.

For the reasons just given, the examiner does not believe that the existence of a price floor within a tariff designed for a competitive market allows for unequal treatment of customers by the utility operating under the tariff. However, even if the tariff does allow for unequal treatment of customers, the examiner believes that allowing for such unequal treatment does not constitute unreasonable, or unlawful, discrimination. The courts have held that unequal treatment of customers is not unlawful if there are reasonable public policy reasons for it. Texas Alarm & Signal Assoc. v. Public Utility Commission, 603 SW2d 766 (Tex. 1980); Amtel Communications, v. Public Utility Commission, 687 SW2d 95 (Tex. App. -- Austin 1985, no writ). The preservation and legalization of HL&P's participation in an economy energy market that is saving money for all participating utilities is surely a reasonable public policy objective.

CoGen also argues that the proposed tariff violates sections 45 and 47 of PURA. Section 45 prohibits utilities from establishing or maintaining any unreasonable differences as to rates or services between localities or classes of service. Section 47 prohibits utilities from discriminating against competitors, or engaging in any other practices that tend to restrict or impair competition.

Mr. Mentrup testified that pricing above short-run incremental cost precludes anti-competitive pricing (pricing below cost to win sales away from competitors), as well as cross-subsidization (pricing services to one group of customers below cost and "making up the difference" by over-pricing another group of customers). (General Counsel Exh. No. 1, Mentrup Testimony, pp. 6-8.) The evidence has shown that the price floors within the tariff are designed to ensure that each of the economy energy services is priced above short-run incremental cost. Thus, the tariff will prevent the possibility of violations of sections 45 and 47 through pricing.

As was discussed on page 12 of this report, CoGen has objected to the fact that the tariff is not designed to recover wheeling costs from purchasing utilities. CoGen includes this objection in its discrimination argument. CoGen argues that since qualifying facilities (QFs) must pay wheeling charges to HL&P if they transport electricity over HL&P's lines to make an economy energy-type sale, HL&P should have to include its own wheeling cost in the price it charges for economy energy. CoGen argues that for HL&P to charge QFs for the use of its transmission system, while not charging itself, constitutes discrimination. This argument does not make sense. There are fundamental differences between the two situations. The QFs are competitors of HL&P and may or may not be native system customers of HL&P. Why should HL&P offer its competitors free use of its system which was build for and paid by HL&P's native system customers? When HL&P makes an economy energy sale, however, it is doing so with the use of spare generation and transmission capacity, and it is doing so with the objective of earning revenues that can be used to offset embedded costs previously incurred. Why should HL&P risk the loss of a profitable sale by including non-incremental costs in the price?

Anti-competitive pricing is, of course, not the only means by which a utility might violate sections 45 and 47 of PURA. Discriminatory practices are also a concern. Several of the intervenors in this docket were concerned that the generic tariff might facilitate such practices, but all except CoGen were satisfied that the revised tariff and stipulation adequately addressed those concerns. In brief, Dow Chemical explained why it is satisfied that the proposed tariff will not permit HL&P to "unduly affect competition."

Originally, Dow was concerned that the tariff would create "backdoor" capacity contracts that would unfairly disadvantage cogenerators who compete for such capacity sales. The tariff provision that requires purchasers to have firm purchased power, or capacity, in place to back-up the sale, as well the provision that HL&P will not be obligated to provide firm energy for more than a twenty-four hour period, assures Dow that there will be no "backdoor" capacity agreements. Dow was also satisfied by the requirement, added to the final version of the proposed tariff, that contract periods may not exceed twenty-one (21) days, and that Commission approval must be obtained for additional contracts of five days or more when the additional contract is made within ninety (90) days from the beginning of the 21 day contract. Dow is confident that this will give any aggrieved party an opportunity to demonstrate that HL&P is, in fact, using the tariff as a means of making capacity sales. Finally, Dow is reassured by the testimony of Mr. Standish that HL&P will not include economy energy sales in the calculation of its capacity reserve margins. (HL&P Exh. No. 2, Standish Testimony, p. 4.)

Dow's second concern was that HL&P would give preference to economy energy sales over wheeling agreements with QFs. The stipulating parties agreed, however, to include the following language in their stipulation:

> It is further understood and agreed that no economy energy sales are or shall be utilized by the Company in evaluating the available capacity on its transmission system for planning purposes. Furthermore, off-system economy energy sales shall not be made if the effect of such sales is to limit the availability of transmission capacity for firm capacity transfer by cogenerators <u>when ACW</u> (available capacity wheeling) <u>or PCW</u> (planned capacity wheeling) <u>service has been scheduled</u>. (Stipulation, p. 2; emphasis in original.)

Concerning the treatment of new wheeling agreements, Mr. Standish testified that in deciding whether to make an economy energy sale or to sell wheeling to cogenerators, the company will undertake whichever transaction returns the greater amount of revenues to its ratepayers. That is, if the company determines that more revenues can be collected from selling wheeling -- and allowing a cogenerator to make the economy sale -- than from HL&P making the economy sale directly, then the company will take the revenue from the wheeling transaction. (HL&P Exh. No. 2, Standish Testimony, p. 12.)

Dow's final concern was that economy energy sales might create an economic incentive to interrupt native interruptible customers, such as Dow, prior to interruption of economy energy purchasers. This concern, shared by other intervenors, was addressed to the satisfaction of the signatories to the stipulation with the adoption of the following language in the stipulation:

> HL&P will not interrupt interruptible sales within its retail service area for economic reasons in order to continue off-system economy energy sales . . . . [T]he Company reserves the right to interrupt any interruptible customer(s) should HL&P determine that the continuation of interruptible sales will threaten to create or contribute to an emergency situation within the ERCOT system. Should an emergency condition arise while the Company is making economy energy sales, the Company will initiate the following actions in order of priority as may be necessary to remedy the emergency: 1) interrupt Economy A and Brokerage sales, 2) attempt to schedule Emergency power, 3) request interruption of Economy B and Economy C sales, and 4) interrupt interruptible sales within the Company's retail service area. (Stipulation, pp. 5-6.)

The examiner believes that the safeguards present in the tariff and in the stipulation will prevent the possibility of HL&P engaging in discriminatory or anti-competitive practices.

VIII. "Rate" Approval

The nature of the tariff being recommended here is unusual, at least among electric tariffs, in that no customer's actual rate can be identified on the face of the tariff. The price floor is identified in the tariff, as well as certain requirements designed to prevent abuse, but because the tariff gives HL&P price flexibility to competitively participate in the economy energy market, the actual rates that will be charged cannot be determined from the tariff. The examiner has already discussed the practical reasons and public policy concerns that justify the existence of such flexibility in the tariff. She has also concluded that the proposed tariff does not violate sections 38, 45 or 47 of PURA. A separate legal question is whether there are any legal impediments to approving a generic tariff which identifies a process by which a rate will be determined, rather than identifying the rate(s) within the tariff itself.

The definition of "rate" in PURA is broad. The term is defined in section 3(d) as follows:

> (d) The term "rate," when used in this Act, means and includes every compensation, tariff, charge, fare, toll, rental, and classification, or any of them demanded, observed, charged, or collected whether directly or indirectly by any public utility for any service, product, or commodity described in Subdivision (c) of this section, and any rules, regulations, practices, or contracts affecting any such compensation, tariff, charge, fare, toll, rental or classification.

The Commission is considering, as part of the evidence in this docket, the process by which HL&P -- or ERCOT acting as HL&P's agent -- will set specific rates under the generic tariff. That process will be subject to retrospective review during any HL&P general rate case or fuel reconciliation proceeding. In light of this, the examiner submits that approval of the proposed generic tariff will constitute approval of a practice affecting the specific rate actually charged under the tariff, and will therefore satisfy PURA's definition of "rate".

There is considerable Commission precedent for approval of tariffs that do not set specific rates, but which establish a process or methodology for determining the actual rates to be charged. Tariffs for the sale of interruptible-type services, for example, often define the rate to be charged in terms of mark-ups to either the utility's incremental fuel or energy costs, or to the utility's average weighted cost of fuel or gas. (<u>See</u> ISB tariffs approved in Docket No. 7788, <u>Gulf States Utilities</u>, Docket No. 7720, <u>Central Power & Light</u>, Docket No. 7044, <u>Houston Lighting & Power</u>, and Docket No. 6765, <u>Houston Lighting & Power</u>.

The difference between these tariffs and the one proposed here is, of course, that there is no set margin (other than in the price floor) to be added to HL&P's incremental fuel cost in this tariff. The actual margin will be determined by competition. Because the market is competitive and the participants are all utilities, the examiner does not believe that this distinction between the proposed tariff and tariffs previously approved by the Commission is significant.

[4] Section 2 of PURA describes the legislative policy that is to be applied to the administration of the Act. To summarize the section, PURA was enacted to protect the public interest and to regulate public utilities, which are natural monopolies in the areas they serve, with the objective that regulation operate as a substitute for competition. The examiner submits that approval of the proposed generic tariff is consistent with this legislative directive. The evidence clearly shows that HL&P is not, and cannot, participate as a natural monopoly in the economy energy market. Rather than operating as a substitute for competition, price regulation of HL&P's participation in this market would greatly hinder the utility's ability to compete. The generic tariff will allow HL&P to continue its competitive participation in an economy energy market which the evidence shows is in the best interest of HL&P, its ratepayers, and the electric industry. The examiner concludes that approval of the generic tariff is in the public interest and consistent with the legislative intent of PURA.

IX. Conclusion

For the reasons stated in this report, the examiner recommends approval of each of HL&P's agreements with Rayburn Country, Tex-La, and Cap Rock. The evidence shows that the agreements are in the best interest of all four utilities and their ratepayers. The three cooperatives will benefit because the agreements have lowered, and should continue to lower, the cooperatives' purchased power costs. Final approval of the three cooperative agreements will enable the cooperatives to pass these savings along to their members through the mechanism of PCRF clauses, as they have been doing on an interim basis.

HL&P benefits from the agreements with the cooperatives because profits from the sales can be used to offset HL&Ps revenue requirement. HL&P stated in this docket that it will propose in its next rate case, which has now been filed, to book revenues from all economy energy sales to reconcilable fuel accounts. The transactions will be subject to audit during any HL&P general rate case or fuel reconciliation proceeding. Furthermore, HL&P will have the burden of proving, among other things, that it has generated electricity efficiently. To the extent that it fails to meet that burden, the Commission may disallow unreasonable expenses. If, however, the transactions generate savings, as the evidence overwhelmingly suggests they will, the revenues will offset the company's reasonable and necessary fuel costs.

The examiner recommends approval of the generic tariff because the evidence shows it, too, is reasonable and in the public interest. The evidence shows that economy energy transactions handled through ERCOT save the electric industry an average of $1 million per month. HL&P is a major participant in that economy energy market. Although the transactions have been beneficial to Texas ratepayers, they have taken place without formal Commission approval and in violation of section 31 of PURA. Approval of a tariff legalizing these economy energy transactions is needed. Because to the short-term nature of the transactions, prior approval of specific rates is not feasible. The examiner believes that the stipulating parties have proposed a desirable and workable solution to this situation. The examiner recommends approval of the stipulation and proposed generic tariff.

X. Findings of Fact and Conclusions of Law

A. Findings of Fact

1. On June 21, 1988, Houston Lighting & Power Company (HL&P) filed three agreements providing for the sale of economy energy to three electric utilities -- Tex-La Electric Cooperative, Inc. (Tex-La), Rayburn Country Electric Cooperative, Inc. (Rayburn Country), and Cap Rock Electric Cooperative, Inc. (Cap Rock).

2. The agreements were filed pursuant to section 32 of the Public Utility Regulatory Act (PURA), Tex. Rev. Civ. Stat. Ann. art. 1446c (Vernon Supp. 1988).

3. A prehearing conference was held on July 14, 1988, with Administrative Law Judge Charles Smaistrla presiding. Appearances were entered on behalf of HL&P and the Commission staff. It was agreed that HL&P would file a generic tariff which would be considered at a final hearing on the merits.

4. An interim hearing was convened on August 3, 1988. Motions to intervene filed by Rayburn Country and Tex-La were granted, and the three agreements originally filed by HL&P were granted interim approval following the hearing and stipulation of all the parties.

5. HL&P filed a generic tariff on August 29, 1988. Implementation of the proposed tariff change was suspended for 150 days beyond the otherwise effective date of October 3, 1988, to March 2, 1989, pursuant to P.U.C. SUBST. R. 23.24(i).

6. On September 20, 1988, this case was reassigned to the undersigned hearings examiner.

7. Intervention was granted to Occidental Chemical Corporation (Occidental), Dow Chemical Company (Dow) and CoGen Lyondell, Inc. (CoGen) on September 22, 1988.

8. A hearing on the merits was convened on October 31, 1988 for final consideration of the three cooperative agreements, as well as the subsequently filed generic tariff.

9. All of the parties except the Office of Public Counsel (OPC) and CoGen entered into a written stipulation which was presented to the examiner at the start of the hearing. The stipulation (minus exhibits) is attached to this

report as "Attachment No. 1." The generic tariff proposed by the stipulating parties is attached to this report as "Attachment No. 2."

10. All parties except OPC participated in the hearing. The hearing was adjourned on November 2, 1988.

11. Economy energy transactions involve the voluntary off-system sale and purchase of energy between utilities, at prices that are economically efficient for both the sellers and the purchasers.

12. Economy energy transactions have been occurring within Texas for over 25 years, and the Commission has been encouraging the transactions since 1977.

13. Under each of the three cooperative agreements, HL&P may quote a price per MWH to the cooperatives each month, and the cooperatives have the option of accepting or rejecting the offer. Prices remain fixed for the duration of any calendar month in which the cooperatives elect to receive deliveries. The cooperatives are responsible for maintaining wheeling and scheduling arrangements.

14. Rayburn Country reduced its purchased power expense by $5,356,200, or 7.1 percent, during the period from April of 1987 through August of 1988 as a result of economy energy purchases from HL&P.

15. HL&P has received marginal revenues from sales of economy energy to the cooperatives that are well above marginal costs of providing the service.

16. Staff rate analyst George Mentrup reviewed the three cooperative agreements and recommended approval.

17. The generic tariff proposed in the partial stipulation admitted at the hearing on the merits specifically covers Economy A, Broker, Economy C, and Economy B transactions. The tariff is not limited to these services, but any

service offered under the tariff must satisfy the restrictions and limitations of the tariff, such as the ones described in Findings of Fact Nos. 21-25.

18. Economy A and Broker energy are hour to hour interruptible sales that are based upon oral agreements between utilities and take place less than twenty-four hours at a time.

19. Economy C energy sales are firm for more than four but less than twenty-four hours.

20. Economy B sales are energy sales that are firm for twenty-four hours.

21. HL&P is prohibited under the proposed generic tariff from obligating itself to supply economy energy for periods greater than twenty-four hours on a firm basis.

22. Contract periods under the proposed generic tariff are not to be greater than 21 days. In the event another sale of five or more days is made to the same customer within a ninety day period from the beginning of the 21-day contract period, then the second sale to the same customer must be manifested by a written contract and submitted to the Commission for review.

23. Purchasers of economy energy under the proposed tariff must have firm purchase power arrangements in place or capacity available as required by ERCOT (Electric Reliability Council of Texas) guidelines, but not necessarily on line, to back up the service.

24. Under the proposed tariff, purchasers are responsible for maintaining scheduling and wheeling arrangements necessary to complete deliveries. Service may be terminated if the purchasing utility fails to maintain back-up capacity.

25. Services for economy energy sold under the proposed tariff must be priced to cover HL&P's projected marginal fuel cost, adjusted for line losses of one percent when averaged over the time period of the transaction. Additionally, Economy B and C prices must include a margin of not less than 1.2 mills per kwh to cover incremental variable O&M (operation and maintenance) cost.

26. The prices identified in Finding of Fact No. 26 represent the minimum prices that HL&P must charge for services under the tariff. Actual prices will result from agreements between HL&P and the purchasing utilities.

[2] 27. The economy energy market in Texas is competitive.

28. It is appropriate to design the price floor for economy energy to cover [3] the short-run incremental cost of providing the service. It is not appropriate to include non-incremental costs in the design of the price floor.

29. HL&P will utilize its computerized production dispatch model, GENSOM D, to project the incremental fuel cost of economy energy transactions.

30. Utilizing GENSOM D to project incremental fuel cost for an economy energy sale is reasonable and should give the most accurate projection possible.

31. The 1.2 mills per kwh additive to the price floor of Economy B and C is adequate to cover incremental O&M costs associated with making those sales.

32. There are no significant O&M costs associated with the sale of Economy A and Broker energy which are sold from excess on-line spinning reserves.

33. HL&P incurs no incremental wheeling costs with making economy energy sales under the proposed tariff.

34. The price floor contained in the generic tariff and described in Finding of Fact No. 25 is reasonable.

35. No utility will be economically disadvantaged, or otherwise harmed, either from its own purchase of economy energy from HL&P, or from another utility's purchase of economy energy from HL&P under the terms of the generic tariff.

[4] 36. There are reasonable public policy reasons for approving the proposed generic tariff for the sale of economy energy, namely the preservation and legalization of HL&P's participation in a economy energy market that is saving money for all participating utilities.

37. Because the services under the proposed tariff will be priced above short-run incremental cost, anti-competitive pricing (pricing below cost to win sales away from competitors), as well as cross-subsidization (pricing services to one group of customers below cost and "making up the difference" by over-pricing another group of customers) will be avoided.

38. Adoption of the stipulation would result in HL&P's not being allowed to use economy energy sales in evaluating the available capacity on its transmission system for planning purposes.

39. Adoption of the stipulation would result in HL&P's not being allowed to make off-system economy energy sales if the effect of such sales is to limit the availability of transmission capacity for firm capacity transfer by cogenerators when PCW (planned capacity wheeling) or ACW (available capacity wheeling) has been scheduled.

40. Adoption of the stipulation would result in HL&P's not being allowed to interrupt interruptible sales within its retail service area for economic reasons in order to continue off-system economy energy sales.

41. Adoption of the stipulation would result in HL&P's being allowed to interrupt interruptible customers if the company determines that the continuation of interruptible sales will threaten to create or contribute to an emergency situation within the ERCOT system.

42. Adoption of the stipulation would result in HL&P initiating the following actions in order of priority as may be necessary to remedy an emergency situation: 1) interrupt Economy A and Brokerage sales, 2) attempt to schedule Emergency power, 3) request interruption of Economy B and Economy C sales, and 4) interrupt interruptible sales within the HL&P retail service area.

43. Based upon the above Findings of Fact, the cooperative agreements, as well as the proposed stipulation and generic tariff are reasonable and in the public interest.

B. Conclusions of Law

1. HL&P, Rayburn Country, Tex-La, and Cap Rock are public utilities as the term is defined in section 3(c)(1) of PURA.

2. The Commission has jurisdiction and authority over this application, including the subsequently filed generic tariff, pursuant to sections 16(a), 17(e), 32 and 37 of PURA.

3. None of the three cooperative agreements, nor the generic tariff proposed by the stipulating parties, is unreasonably preferential, prejudicial or discriminatory, but rather each of the agreements and the tariff is sufficient, equitable and consistent in application, within the meaning of section 38 of PURA.

[5] 4. The interim approval granted to the agreements between HL&P and the three cooperatives on August 3, 1988 constitutes approval after a hearing by the Commission and thereby satisfies the requirements of section 43(g)(4)(A) of PURA.

[5] 5. Approval of the proposed generic tariff will constitute approval after a hearing by the Commission and thereby satisfy the requirements of section 43(g)(4)(A) of PURA.

6. HL&P's implementation of any of the three cooperative agreements or the proposed generic tariff will not constitute the grant of an unreasonable preference or advantage to any corporation or person within any classification, nor will it subject any corporation or person within any classification to any unreasonable prejudice or advantage. The agreements and the proposed tariff therefore do not conflict with section 45 of PURA.

7. Implementation of the three cooperative agreements or the proposed generic tariff 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 meaning section 47 of PURA.

8. The three cooperative agreements and the proposed generic tariff are just and reasonable within the meaning of section 38 of PURA and should be approved.

Respectfully submitted,

Becky Bruner
BECKY BRUNER
HEARINGS EXAMINER

APPROVED on this the 30th day of January 1989.

Phillip A. Holder
PHILLIP A. HOLDER
DIRECTOR OF HEARINGS

BB/sm

Attachment No. 1 [redacted]

DOCKET NO. 8231

APPLICATION OF HOUSTON LIGHTING & POWER COMPANY FOR APPROVAL OF ECONOMY ENERGY SALES CONTRACTS	* * * *	PUBLIC UTILITY COMMISSION OF TEXAS

FINAL STIPULATION AND AGREEMENT

The undersigned signatories hereby state that they agree on the final resolution of this Docket as set forth below and that they have full authority to enter into this Final Stipulation and Agreement on behalf of the entities they represent.

1. It is the agreement of the parties that this Final Stipulation and Agreement resolves all matters raised by those certain Agreements for Sale of Economy Energy executed by and between Houston Lighting & Power Company and (i) the Tex-La Electric Cooperative of Texas, Inc. as of February 10, 1986 (including revisions thereto dated November 1, 1986); (ii) Rayburn Country Electric Cooperative, Inc. as of February 11, 1987; and (iii) Cap Rock Electric Cooperative, Inc. as of April 18, 1988 (referred to herein collectively as the "Agreements" and individually as an "Agreement"), true and correct copies of which are attached hereto as Exhibits A-1, A-2 and A-3, respectively.

2. The parties hereto further agree that as a part of the Final Order in this Docket, the Public Utility Commission of Texas ("Commission") find reasonable and approve in all

respects the Agreements and all such portions, provisions, duties and obligations contained therein, including the Agreements' terms, conditions, and pricing provisions.

3. The signatories likewise agree that the Rate Schedule designated "Economy Energy Sales - EES," Sheet No. D7.5, attached hereto as Exhibit B-1, be found reasonable and approved by the Commission and incorporated into Houston Lighting & Power Company's ("HL&P" or "Company") Tariff for Electric Service.

4. It is further understood and agreed that no economy energy sales are or shall be utilized by the Company in evaluating the available capacity on its transmission system for planning purposes. Furthermore, off-system economy energy sales shall not be made if the effect of such sales is to limit the availability of transmission capacity for firm capacity transfers by cogenerators <u>when ACW or PCW service has been scheduled</u>.

5. The signatories further agree that HL&P will not interrupt interruptible sales within its retail service area for economic reasons in order to continue off-system economy energy sales. Anything <u>herein</u> to the contrary notwithstanding, the Company reserves the right to interrupt any interruptible customer(s) should HL&P determine that the continuation of interruptible sales will threaten to create or contribute to an emergency situation within the <u>ERCOT</u> system. Should an emergency condition arise while the Company is making economy

energy sales, the Company will initiate the following actions in order of priority as may be necessary to remedy the emergency: 1) interrupt Economy A and Brokerage sales, 2) attempt to schedule Emergency power, 3) request interruption of Economy B and Economy C sales, and 4) interrupt interruptible sales within the Company's retail service area.

6. The undersigned further stipulate that the prefiled testimony of Thomas R. Standish (July, 1988), Thomas R. Standish (August, 1988), Michael K. Moore, ~~and~~ & George Mentrup (Direct and Supplemental) and ~~Thomas R. Standish~~ Rebuttal Testimony for Thomas R. Standish attached hereto as Exhibits C-1, C-2, C-3, C-4, ~~and~~ & C-5, and C-6 be admitted into evidence in this proceeding without cross-examination by any of the signatory parties. All signatories hereto preserve any rights they may otherwise have in the event that the Commission does not incorporate this Final Stipulation and Agreement into the final order in Docket No. 8231. In addition, all parties to this Final Stipulation and Agreement preserve the right to file exceptions, present oral argument, and otherwise defend the terms of this Stipulation in the further event the Examiner's Report fails to endorse the terms of this Final Stipulation and Agreement.

7. The signatories enter into this Final Stipulation and Agreement for the purposes of this proceeding only and subject to further order of the Commission in subsequent proceedings.

~~8. It is further agreed that HL&P's ratepayers will incur no additional costs associated with its transmission~~ STRIKE

~~system as a result of off-system economy energy sales under the Tariff agreed to in this Stipulation.~~

STRIKE

GWS
pm
mc
JR
AMH

8. ~~9.~~ It is recognized and agreed that the parties hereto, by filing this Final Stipulation and Agreement, do not express agreement or concurrence with any specific methodology, finding or conclusion expressed herein; and that this Final Stipulation and Agreement is made and filed solely for the purposes of compromising on and settling the issues in this proceeding.

JR
AMH

9. ~~10.~~ Upon approval of the attached exhibits A-1, A-2, A-3, B-1, C-1, C-2, C-3, C-4, ~~and~~ C-5 and C-6 by the Commission, this Final Stipulation and Agreement shall be a full and complete settlement of all claims made by the parties hereto in this docket.

EXECUTED this ______ day of ______________, 1988.

THE GENERAL COUNSEL OF THE PUBLIC
UTILITY COMMISSION OF TEXAS

By: Paula Mueller
(Signature)

Paula Mueller
(Name-printed or typed)

Assistant General Counsel
(Title-printed or typed)

HOUSTON LIGHTING & POWER COMPANY

By: George W. Schalles III
(Signature)

George W. Schalles III
(Name-printed or typed)

ATTORNEY FOR HL&P
(Title-printed or typed)

TEX-LA ELECTRIC COOPERATIVE OF TEXAS, INC.

By: Fernando Rodriguez
(Signature)

Fernando Rodriguez
(Name-printed or typed)

Atty. for Tex-La
(Title-printed or typed)

RAYBURN COUNTRY ELECTRIC COOPERATIVE, INC.

By: [signature]
(Signature)

RICHARD C. BALOUGH
(Name-printed or typed)

Attorney for Rayburn Country Electric Cooperative, Inc.
(Title-printed or typed)

OCCIDENTAL CHEMICAL CORPORATION

By: Marianne Carroll
(Signature)

MARIANNE CARROLL
(Name-printed or typed)

Attorney for Occidental Chemical Corp.
(Title-printed or typed)

COGEN LYONDELL, INC.

By: ______________________
(Signature)

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(Name-printed or typed)

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(Title-printed or typed)

DOW CHEMICAL COMPANY

By: Allen H. King
(Signature)

Allen H. KING
(Name-printed or typed)

Haman, Howell, Smith & Lee
Attorney for Dow Chemical Co.
(Title-printed or typed)

OFFICE OF PUBLIC UTILITY COUNSEL

By: ______________________________
(Signature)

____
(Name-printed or typed)

____
(Title-printed or typed)

ECONOMY ENERGY SERVICE - EES

AVAILABILITY

From 345,000 volt and 138,000 volt, three phase, 60 hertz, alternating current, overhead lines at the points where the Company is interconnected with other electric utilities.

APPLICATION

Applicable to economy energy supplied by the Company to electric utilities, including municipally owned utilities. The practices presented herein are based upon the ERCOT Operating Guides and are in accordance with Public Utility Commission of Texas (PUCT) Substantive Rules.

SERVICES PROVIDED

The services provided under this schedule are for economy energy transactions for which the Customer must have firm purchase power arrangements in place or capacity available as required by ERCOT guidelines, but not necessarily on-line, to back up this service such that Customer is capable of providing the full amount of power taken hereunder from such back-up source(s) upon proper notice. Likewise, the Customer shall be responsible for any necessary scheduling and other ancillary arrangements which may be required to effectuate transactions hereunder.

BILLING

Charges for services provided shall be as mutually agreed by the parties, but in no case will the charges be lower than the Company's projected marginal cost based upon the Company's production cost dispatch model including estimated transmission line losses of one percent (1%), when averaged over the contract period, which in no event shall be longer than 21 days. The rate agreed to by the parties does not violate this rate schedule if the rate differs from the Company's actual marginal cost at the time of delivery.

In establishing charges for economy energy service provided hereunder sales shall be per ERCOT guidelines and shall include, but not be limited to, the following:

(1) Economy A and Broker service is interruptible upon notification, non-firm energy transferred between utility control areas by mutual agreement for mutual economic advantage.

(2) Economy B service is daily firm energy transferred between utility control areas by mutual agreement for mutual economic advantage. Customer must have capacity available (but not necessarily on-line) upon 24 hours notice to back up this service, as detailed in the "Services Provided" section above.

(3) Economy C service is firm energy transferred between utility control areas for periods of less than 24 hours but at least 4 hours by mutual agreement for mutual advantage. Customer must have capacity available (but not necessarily on-line) upon 24 hours notice to back up this service, as detailed in the "Services Provided" section above.

(4) Economy B and Economy C energy shall be priced at the Company's projected marginal fuel cost (adjusted for 1% line losses) plus a margin of not less than 1.2 mils per kwh.

PAYMENT

Bills are due when rendered. A bill for service is delinquent if not received by the Past Due Date shown on the Electric Service Bill. The Past Due Date will not be less than sixteen (16) day from the date the bill is mailed to Customer.
If the total amount due is not received on or before the Past Due Date, a one time late payment charge will be assessed. The charge will be equal to a percentage of the total amount due exclusive of sales tax for each day, up to a maximum of fourteen days, after the Past Due Date that payment is received. The percentage will be the daily non-compounded equivalent to the prime interest rate effective at Texas Commerce Bank, National Association, Houston, Texas at the end of the billing period, plus two percentage points, or, if the end of the billing period falls on a holiday or weekend, the preceding business day. If the total amount due is not received on or before the fourteenth (14) day after the Past Due Date, the late payment charge to be assessed will become 5% of the total bill exclusive of sales tax. In no case will the late payment charge exceed 5% of the total bill exclusive of sales tax.

WHEELING

The Company assumes no responsibility for the wheeling arrangement(s) required to effectuate economy energy deliveries hereunder. All required wheeling arrangement(s) and the costs associated therewith will be the responsibility of the Customer.

CONTRACT PERIOD

The contract period shall be mutually agreed between the Customer and the Company, but in no case will the Company obligate itself to supply economy energy herein for periods greater than twenty-four (24) hours on a firm basis. In no event shall the contract period for EES service exceed 21 days. In the event another sale of five or more days is made to the same customer within a ninety day period from the beginning of the 21 day EES contract period then that second sale to the same customer shall be manifest by written contract and submitted to the PUCT for review.

OTHER TERMS AND CONDITIONS

Other terms and conditions shall be as mutually agreed by the parties.

DEFINITIONS

The term electric utility as used herein is defined as in the Public Utility Regulatory Act (PURA) of Texas, Article I, s 3 (c) and includes municipally owned and co-operatively owned electric utilities, as well as river authorities.

The term economy energy as used herein is defined as in PUCT Substantive Rule No. Subsection 23.3.

The term control area as used herein is defined as in the ERCOT Operating Guide.

NOTICE

Service furnished under this schedule is subject to any change authorized by law, and to the provisions of applicable Company Service Specifications.

DOCKET NO. 8231

1989 FEB 24 PM 2:12

APPLICATION OF HOUSTON LIGHTING AND POWER COMPANY FOR APPROVAL OF ECONOMY ENERGY SALES CONTRACTS AND GENERIC TARIFF	§ § § §	PUBLIC UTILITY COMMISSION OF TEXAS

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 a hearings examiner who prepared and filed a report containing Findings of Fact and Conclusions of Law, which Examiner's Report is ADOPTED and made a part hereof. The Commission further issues the following Order:

1. The application of Houston Lighting & Power Company (HL&P) is hereby GRANTED to the extent recommended in the Examiner's Report.

2. HL&P's agreements with Rayburn Country Electric Cooperative, Inc. (Rayburn Country) Tex-La Electric Cooperative, Inc. (Tex-La), and Cap Rock Electric Cooperative, Inc. (Cap Rock) are APPROVED as of August 3, 1988.

3. The stipulation admitted at the hearing on the merits as "Joint Exhibit No. 1" is ADOPTED.

4. The generic tariff proposed by the stipulation is APPROVED.

5. Within twenty (20) days after the date of this Order, HL&P SHALL file the three agreements identified in paragraph 2 of this Order and the generic tariff identified in paragraph 4 of this Order, in accordance with the directives of this Order. HL&P SHALL serve one copy upon the general counsel. No later than ten (10) days after the date of the tariff filing by HL&P, the general counsel SHALL file

the staff's comments recommending approval or rejection of the filings. No later than fifteen (15) days after the date of the filing by HL&P, HL&P SHALL file in writing any responses to the previously filed comments of the general counsel. The Hearings Division SHALL by letter approve, modify or reject each tariff sheet, effective the date of the letter, based upon the materials submitted to the Commission under the procedures established herein. The tariff sheet(s) shall be deemed approved and shall become effective upon expiration of twenty (20) days after the date of filing, in the absence of written notification of approval, modification or rejection by the Hearings Division. In the event that any sheet(s) is/are modified or rejected, the Company SHALL file proposed revisions of that/those sheet(s) in accordance with the Hearings Division letter within ten (10) days after the date of that letter, with the review procedures set out above once again to apply. Copies of all filings and of the Hearings Division letter(s) under this procedure SHALL be served on all parties of record and the general counsel.

6. All motions, applications, and requests for entry of specific findings of fact and conclusions of law and any other requests for relief, general or specific not expressly granted herein are DENIED for want of merit.

7. The Commission staff is **INSTRUCTED** to review the status of participation in the economy energy market by utilities operating under this Commission's jurisdiction. The staff SHALL report its findings to the Commission in an administrative meeting and propose a plan, if necessary, for bringing the participation of utilities into

compliance with the Public Utility Regulatory Act (PURA), Tex. Rev. Civ. Stat. Ann. art. 1446c (Vernon Supp. 1988).

SIGNED AT AUSTIN, TEXAS on this the 23rd day of February 1989.

PUBLIC UTILITY COMMISSION OF TEXAS

SIGNED: Marta Greytok
MARTA GREYTOK

SIGNED: Jo Campbell
JO CAMPBELL

SIGNED: William B. Cassin
WILLIAM B. CASSIN

ATTEST:

Elizabeth Hagan Drews for
PHILLIP A. HOLDER
SECRETARY OF THE COMMISSION

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APPLICATION OF GULF STATES UTILITIES COMPANY FOR APPROVAL OF AN AMENDMENT TO SCHEDULE SUS § § §

DOCKET NO. 8329

February 23, 1989

Request of Gulf States Utilities Company (GSU) for amendments to Schedule SUS (Steam User Service) approved in part and denied in part.. Renewal of schedule approved. Request for authority to negotiate customer specific contracts denied. Motion for rehearing denied by operation of law.

[1] MISCELLANEOUS--ELECTRIC

The Commission will not sanction a utility's practice of requiring its customers to purchase a non-utility service in order to retain eligibility for a particular utility service. (pp. 2607, 2622)

[2] RATEMAKING--RATE DESIGN--DISCRIMINATORY RATES

A negotiated ratemaking process which allows discrimination among customers based upon such factors as the level and expertise of the negotiators, the size of the customer's electrical load, the utility's desire to retain a customer's electrical load, and the honesty of negotiators constitutes discrimination not based upon substantial and reasonable grounds of distinction. (pp. 2618, 2627, 2628)

[3] RATEMAKING--RATE DESIGN--ELECTRIC--INCENTIVE RATES

It is appropriate to require industrial customers who receive incentive rates (designed to keep them on the system) to revert to paying otherwise applicable standard rates when the utility's reserve capacity margin drops to the level at which the utility will have to bring new generating units on line. (p. 2649)

DOCKET NO. 8329

APPLICATION OF GULF STATES UTILITIES COMPANY FOR APPROVAL OF AN AMENDMENT TO SCHEDULE SUS	§ § §	PUBLIC UTILITY COMMISSION OF TEXAS

EXAMINER'S REPORT

I. Procedural History

On August 31, 1988, Gulf States Utilities Company (GSU) filed an application for approval of certain amendments to its existing Schedule SUS (Steam User Service). Schedule SUS is an experimental rider which offers incentive rates to industrial customers with the potential to cogenerate. The rates, which were approved on May 13, 1988, are designed to approximate the costs of cogeneration. The objective is to encourage industrial customers to remain on the GSU system, rather than leaving and cogenerating their own electricity. The amendments proposed in this application would primarily do two things. They would extend the application period for the rate through 1991, and would add a new subsection allowing GSU to negotiate customer specific contracts with those applicants for whom the existing rate structure is not suited.

Pursuant to P.U.C. SUBST. R. 23.24(i), implementation of the tariff revisions proposed in this application was suspended for 150 days beyond the otherwise effective date, until March 4, 1989. The suspension was made in order to give the Commission sufficient time to review the application.

A prehearing conference was held on September 22, 1988. Appearances were entered on behalf of GSU, the Office of Public Counsel (OPC), and the Commission's staff and general counsel. OPC's motion to intervene was granted. The question of the applicability of section 43(a) was discussed at the conference, but no party took the position that the application constitutes a request for a change in rates. No existing rates are proposed to be changed and the provision for customer specific contracts is voluntary, as is the entire SUS rate structure. The examiner concluded that section 43(a) does not apply here. GSU was ordered to provide individual notice of its application to existing SUS customers, potential customers that might be eligible for SUS, and all parties in its last general rate case. On September 28, 1988, GSU filed an affidavit verifying its compliance with the the examiner's directive.

Gulf Coast Cogeneration Association, Inc. (GCCA) and CoGen Lyondell, Inc. (CoGen) filed motions to intervene on October 17, 1988. GSU opposed the motions. Following a review of the pleadings, the examiner granted both motions to intervene on November 18, 1988.

The hearing on the merits was convened, as noticed, on December 8, 1988. Appearances were entered on behalf of GSU, OPC, GCCA, CoGen, and the staff and general counsel. Evidence was presented in the form of direct testimony and exhibits by all parties except OPC. The hearing was adjourned on December 9, 1988. Briefs and reply briefs were filed by all parties.

II. Jurisdiction

GSU is a public utility as the term is defined in section 3(c) of the Public Utility Regulatory Act (PURA), Tex. Rev. Civ. Stat. Ann. art. 1446c (Vernon Supp. 1988). The Commission has jurisdiction and authority in this matter pursuant to sections 16(a), 17(e) and 37 of PURA.

III. Existing Schedule SUS

The rates designed under Schedule SUS differ from those normally found in electric utility tariffs. Rates under Schedule SUS are not cost based. Rather, the rates are designed to approximate the costs that a customer would incur if that customer were to construct a cogeneration project to supply part or all of its electrical requirements. The tariff, including the proposed amendments, is attached to this report as "Attachment No. 1." The examiner will discuss the proposed amendments in subsequent sections of this report. This section of the report is devoted to describing Schedule SUS as it currently exists.

A. Eligibility and General Terms and Conditions

The Commission first approved Schedule SUS on May 13, 1987, when it adopted the Examiner's Report in Docket No. 7309, Application of Gulf States Utilities Company for Approval of Experimental Rider to Schedules LPS and LIS. 13 P.U.C. BULL. 1629. Billing under Schedule SUS is available to qualifying customers already receiving service from GSU within the LPS (Large Power Service) or LIS (Large Industrial Service) classes. In GSU's last general rate case, Docket No. 7195, Schedule LIS was replaced with Schedule HLFS (High Load Factor Service). The change was inadvertently left out of the compliance tariffs approved following the Commission's Final Order in that docket. GSU proposes to change references to Schedule LIS to HLFS. The change is merely an update and is non-substantive.

To qualify for SUS, customers within the LPS and HLFS classes must have minimum process steam requirements of 10,000 pounds per hour or the thermal energy equivalent thereof. The minimum requirements may not include requirements satisfied by cogeneration facilities that are or will be operational.

Qualifying customers do not begin receiving incentive rates under Schedule SUS until the date that their cogeneration project would have been completed and in-service had the customer chosen to proceed with construction instead of agreeing to SUS rates. This date, of course, is an estimate and the tariff states that GSU and the applicant must agree upon the date.

As a precondition to subscription, customers must execute an amendment to their existing service agreement which requires that the term of their service agreement be extended for a period of not less than three years and no more than ten years to implement SUS rates. Should a customer desire to revert back to LPS or HLFS rates prior to the expiration of the SUS agreement, the customer may do so without penalty if twelve months 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 HLFS rate which would otherwise have been applicable. Should a customer desire to terminate the service agreement in its entirety, that customer must make payment for the value of future charges for contract power for the remaining term of the agreement. If less than twelve months notice of the intent to terminate is given, however, the customer must also pay the difference between past billings under Schedule SUS and the GSU rate schedule that would otherwise have been applicable.

[1] Another provision under the service agreement amendment to Schedule SUS has generated some controversy in this docket. That provision states that GSU has the option to supply steam or thermal energy to the customer at "economically neutral" prices, defined as prices "whereby the customer's cash flow will not be different due to steam or thermal energy purchases" from GSU. The provision further states that if the customer declines the offer, SUS service will be terminated eighteen months after GSU makes the offer to supply steam or thermal energy. Although the service agreement amendment was approved along with approval of Schedule SUS in Docket No. 7309, it does not appear that attention was given to this particular provision. There was no discussion of the provision in the Examiner's Report.

On cross-examination, Mr. Sandberg testified that the intent of the steam provision is to give GSU the opportunity to provide the customer's steam supply requirements at any future time when a cogeneration project might become more attractive to the customer than the SUS incentive rates. (HOM 12/9/88, Tr., pp. 245-246). The provision, however, says that GSU may make an offer to supply steam at any time. There is nothing in the language that ties the timing of the offer to a change in the economics of cogeneration. Furthermore, having GSU provide steam energy at an "economically neutral" price would not alter the economics of cogeneration for the customer. It is difficult to see what purpose this provision has in GSU's service agreements other than to force steam sales upon SUS customers. The examiner does not believe this practice should be sanctioned by the Commission.

GSU has not demonstrated to the examiner how it will pay for the costs of supplying steam. Presumably the costs would be borne below the line, but no evidence on this question was presented, nor did GSU offer any evidence comparing its projected costs of supplying steam with the customers' own costs. The examiner recommends that the provision not be included in any future agreements with SUS customers. The examiner also recommends that the Commission order that GSU not exercise its option under existing agreements. Alternatively, if the option is allowed to be exercised, the Commission should order that costs associated with supplying steam (under terms of agreements which have already been executed) be borne below the line by shareholders.

B. Rate Design and Billing

Schedule SUS rates are based upon the economics of installing a cogeneration facility consisting of a gas turbine driven electric generator with a heat recovery steam generator producing steam from the gas turbine exhaust. The billing provision under the tariff, section IV, has two distinct parts, steam billing and the remaining firm electric billing. The steam billing portion is the part that is designed to approximate the costs of cogeneration that the customer would have incurred had the customer proceeded with construction and installation of the type of cogeneration facility described above. The remaining firm electric billing applies to the amount of electric load and energy that would still have been served by GSU had the customer proceeded with construction and installation of the facility. Other relevant schedules from GSU's tariffs would be applied to these demand and energy determinants. The billing determinants for the remaining firm electric billing are calculated simply by subtracting the steam billing load from the total electric billing load (to get the demand determinant) and subtracting the steam energy from the total monthly metered energy (to get the energy determinant). (GSU Exh. No. 2, Thornton Testimony, pp. 5 - 7.)

As one might expect, the steam billing is more involved. The rate structure for steam billing is designed to reflect the costs the customer would incur by investing in, and owning and operating, a cogeneration facility consisting of a gas turbine driven electric generator with the gas turbine exhaust used to produce steam in a heat recovery steam generator. (The steam produced in the heat recovery steam generator would be used for the production process requirements of the customer's plant.) While the rate concept is unusual, it is applied in the conventional manner in that there is a demand charge, an energy charge and a minimum charge. The demand charge, referred to on page 3 of 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. (GSU Exh. No. 1, Sandberg Testimony, Exh. TRS-1, Examiner's Rpt. from Docket No. 7309.) There are two separate schedules for calculating the demand charge. A customer who can demonstrate and contract for an average ratio of electrical energy to steam energy of 230 KWH/MLB or less per month will be billed under Rate Schedule A. Rate Schedule B is applicable to customers with an average ratio of electrical energy to steam energy in excess of 230 KWH/MLB per month. The purpose for having two sets of demand charges (Schedules A and B) is to recognize economic efficiency differences between cogeneration facilities designed to produce different electrical energy to steam energy ratios.

The rate structure under the billing load (demand) charge is also designed to recognize variations in cost that would be associated with different size cogeneration units. GSU attempts to match the customer's actual energy usage with the optimal size unit. Each customer is assigned a "sizing factor" which represents the amount of the customer's required electrical power that would have been provided by the optimal size unit. The monthly billing load used to calculate the customer's steam billing demand charge takes this sizing factor into consideration. The sizing factor is subject to periodic review and will be adjusted if the operating conditions upon which it is based materially change. That is, if the customer's thermal or electric demand usage changes to the degree that a different size unit would be optimal, the customer's sizing factor -- and resulting monthly billing load and demand charge -- will be adjusted to reflect this. Such flexibility would not be present in the real world and, as GSU witness Kenneth Sandberg observed, this flexibility is a benefit of the SUS rate versus installation of a cogeneration system. It is also, however, a deviation from the stated rate design goal of replicating cogeneration costs.

As page 3 of the tariff indicates, the steam rate demand charge is calculated by multiplying the customer's billing load times the relevant charge per KW ($/KW), and then adding the relevant dollar charge ($ constant) applicable to that range of billing load. Both schedules A and B reflect the economy of scale savings that are available to customers that qualify for simulated use of larger units. These economies reverse at approximately the thirty megawatt level. (GSU Exh. No. 1, Sandberg Testimony, p. 9.) The purpose of the additional dollar charge (the constant) is to smooth the transition from one load size to the next. (GSU Exh. No. 2, Thornton Testimony, p.8.)

Within each billing load range, the steam billing demand charge will increase over the life of the rate. The level remains constant for the first three years that a customer is served on the schedule, but increases by 1.5 percent each year thereafter. This escalation is intended to reflect the increased cost of operations and maintenance associated with a gas turbine due to wear and tear and the periodic maintenance required. (GSU Exh. No. 1, Sandberg Testimony, p. 8.)

The energy charge, shown on page 4 of the tariff, is intended to simulate the cost of fuel and energy efficiency of the theoretical cogeneration unit. Whichever of schedules A or B is established for the demand steam billing is also used in the energy steam billing. The energy charge is similar to the demand charge in that it, too, is structured to reflect the same economic concepts of differences in sizing and efficiency. These economic differences are reflected within the energy charge schedule through changes in applied fuel heat rate values. (GSU Exh. No. 2, Thornton Testimony, p. 9.) The heat rate value reflects the number of MMBtu needed to generate one MWH of electricity. 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. (GSU Exh. No. 1, Sandberg Testimony, exh. TRS-1, Examiner's Report from Dkt. 7309.) The heat rate schedule also has a provision for annual heat rate increases, reflecting increasing inefficiencies in a cogeneration unit over time, as well as periodical corrective maintenance. (GSU Exh. No. 2, Thorton Testimony, p. 9.)

Finally, the tariff contains a minimum charge provision. The total SUS monthly rate may not be less than the result achieved by multiplying GSU's system average fuel cost for the preceding month, plus 8 mills per KWH, by the current months steam energy determinants. GSU witnesses testified that the company has always received rates well above this minimum, but should the minimum ever be applied, GSU will receive 8 mills over the variable cost to supply the power. (Id., p. 10.) CoGen challenged the adequacy of the minimum charges, but the examiner finds that it is adequate to recover GSU's variable cost.

C. Shareholder Responsibility

When GSU requested approval of Schedule SUS in Docket No. 7309, it proposed that the company's shareholders would accept all revenue losses associated with providing SUS. The company promised that it would not seek the recovery from ratepayers of any future SUS related revenue losses. The proposal was that GSU would restate its revenues in rate proceedings as if all Schedule SUS load were being, and had been, billed at the otherwise applicable standard rates. (GSU Exh. No. 1, Thornton Testimony, Exh. TRS-1, Examiner's Report in Dkt. No. 7309, p. 4.)

In this proceeding, GSU witnesses have testified that while the company will not seek recovery of revenue losses occurring during the initial terms of SUS agreements, it may seek Commission approval to have ratepayers bear part or all of subsequent revenue shortfalls associated with Schedule SUS. The examiner supposes there would be no harm in GSU's asking, but notes that the Commission took the company at its word in Docket No. 7309 when the Commission issued the following order:

> 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.

IV. Proposed Amendments

A. Availability

Schedule SUS was approved in Docket No. 7309 as an experimental rider, and the tariff specified that applications would only be accepted for a one-year period. That time period expired in May of 1988. GSU is proposing to amend the availability section to allow acceptance of applications through December 31, 1991. None of the intervenors has taken a position on this proposal. Staff rate analyst Jeffrey Rudolph endorsed the proposal. (HOM 12/9/88, Tr. pp. 236 - 237.)

Although the examiner stated at the prehearing conference, and again in a prehearing order issued following the conference, that the entire SUS tariff would be subject to review in this proceeding to determine if it should be renewed, GSU and the Commission staff were the only parties to address the question of renewal. The objective presented for renewing Schedule SUS is the same one that was presented to the Commission for original approval in Docket No. 7309 -- to minimize the potential loss in load, and the resulting revenue impact, due to cogeneration. In adopting the Examiner's Report in Docket No. 7309, the Commission adopted several Findings endorsing this objective. The Examiner's Report, including proposed Findings of Fact and Conclusions of Law, and the Commission's Final Order, were admitted as evidence in this proceeding. The Findings of Fact, Conclusions of Law, and the Final Order, are attached to this report as "Attachment No. 2." The examiner notes Findings Nos. 12, 13, 42 and 45 as evidence that the Commission has endorsed GSU's objective of retaining industrial load in order to benefit both the company and its ratepayers.

GSU's industrial accounts manager Kenneth Sandberg testified that since the approval of Schedule SUS in May of 1987, GSU has discussed its application with approximately ten customers. Four of the ten are currently being billed under SUS. Three reviewed the schedule but opted to remain on the company's standard LPS or HLFS rates. One customer evaluated SUS, but decided to build a cogeneration unit. The two other customers, Mr. Sandberg testified, are candidates for service under the proposed revision that will allow customer specific contracts. (GSU Exh. No. 1, Sandberg Testimony, p. 14.)

The load lost in Texas by GSU as a result of customers producing their own electricity is about 130 MW. GSU estimates that, as a result of being able to offer Schedule SUS, it has been able to retain over 160 MW of industrial load in Texas, and corresponding revenues, that would otherwise have been lost to cogeneration. (Id.) On an annualized basis, the revenues received in Texas from industrial customers billed under SUS are approximately $4,321,000 less than revenues that would have been received from those same customers if they remained on the system and were billed under the standard HLFS. (GCCA Exh. No. 3.) Of course, had the customers left the system, GSU would not have received any revenues from them. GSU has identified approximately 58 MW of capacity that is subject to further potential loss to cogeneration, but the company says the existing SUS rates are not technically and economically suited for this load. GSU is requesting authority to negotiate customer specific contracts to attract this load.

Mr. Rudolph testified that load retention is still a viable objective for GSU for three reasons: 1) GSU has an ample supply of production capacity, 2) GSU's projected short-run system load growth is low, and 3) GSU operates within an environment where cogeneration is competitive. Mr. Rudolph examined projected capacity and reserve margins for GSU through the year 1997. The company is not expected to experience a capacity margin below 18 percent until 1997, when the capacity margin is projected to be 17.40 percent during August. Mr. Rudolph concluded that any type of load retention program is unlikely to burden GSU's production or capacity resources now or in the near future.

The evidence shows that Schedule SUS has been effective in reducing load loss to cogeneration, which was the objective of the company and of the Commission in approving the tariff in May of 1987. Ironically, GSU did not present any testimony to prove that there is still industrial load which is subject to potential loss to cogeneration and for which the existing schedule SUS would be competitive. As stated earlier, GSU did identify 58 MW of load that is subject to potential loss because of cogeneration, but the company says the existing

No. 7309 ("GSU has approximately 1800 MW of industrial capacity which can potentially be served through cogeneration") to support the conclusion that there is still industrial load subject to potential loss and for which the existing SUS rates would be competitive. Also, the evidence shows that several customers have signed up for SUS during 1988 which suggests that the likely possibility that there is still an interest in the incentive rates. The examiner concludes that the objective of load retention would be further served by renewal of SUS, and therefore, the examiner recommends approval of GSU's proposal to extend the time period for accepting applications to December 31, 1991.

GSU is also proposing to amend the availability section of the tariff to expressly reserve the right to refuse requests for service under SUS when the company's projected capacity margin for the next calendar year is less than 18 percent. The evidence shows that GSU will require additional power resources when its capacity margin falls below 15.25 percent. This led Mr. Rudolph to recommend that service under Schedule SUS should be terminated when GSU's capacity margins equal or fall below 15.25 percent. (General Counsel Exh. No. 1, Rudolph Testimony, p. 9.) The examiner finds that such action termination of existing service would be a violation of the utility's duty to provide service to its customers, and therefore rejects this recommendation. The examiner does, however, recommend that GSU be prohibited from accepting applications for billing under SUS when the company's capacity margin falls below 18 percent. That is, the examiner does not think GSU should have the discretion to offer SUS rates when capacity margins are close to the point at which the company will need to acquire additional power sources to serve its customers. GSU's current situation of having excess capacity is being used to justify the continuation of this rider.[1] When that situation changes, the justification will no longer exist.

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1 According to the staff's estimates, GSU's capacity margin is currently about 40 percent. (See General Counsel Exh. No. 1, Rudolph Testimony, Sch. I.)

B. Customer Specific Contracts

The most litigated issues in this case revolve around GSU's proposal for adding a new section to its existing Schedule SUS. Mr. Sandberg testified that GSU has determined, based on its experience with the existing schedule, that it is not competitive with some cogeneration projects. The new section, Section VIII, is intended to enable GSU to compete with potential cogeneration customers having smaller electric loads -- less than 30 MW -- than the existing rate is designed for. (General Counsel, Rudolph Testimony, p. 10.) The amendment would permit GSU to make modifications to provisions of Schedule SUS (except for the minimum charge provision described on page 8) when the technical and economic aspects of a customer's proposed cogeneration project are such that the billing application of Schedule A or B would not be competitive with the economics of the the proposed project. Under the proposed amendment, GSU could enter into negotiations for specific contracts with customers and the agreements would then be submitted to the Commission for expedited administrative review; GSU proposes a twenty day review by the staff.

Although the staff recommended some modifications to GSU's proposal -- such as a longer review period -- its recommendation is in basic agreement with GSU's proposal. Nevertheless, Mr. Rudolph did testify that he believed GSU could have presented a standardized set of rates (similar to the structure in the existing tariff) and that such an approach would be less of a regulatory burden. (HOM 12/9/88, Tr., p.228.) GCCA and CoGen opposed adoption of the proposal. The examiner recommends that the proposal be rejected.

GSU's proposal presents the Commission with some difficult policy and legal issues. Trying to balance the Commission's policy of encouraging economical cogeneration with the Commission's objective of retaining GSU's industrial load base is not easy. There are also some thorny legal issues concerning discrimination raised by the proposal. Finally, there is a legitimate concern that the proposal will place a heavy regulatory burden on the Commission. The examiner believes that each of these issues and concerns would be much easier to resolve in the context of a proposal for approval of standardized rates designed to compete with smaller cogeneration projects (e.g., a modification to the existing rate structure), and both Mr. Rudolph and GSU's own witness, Mr. Sandberg, have testified that such a proposal is feasible. (12/9/88 HOM, Tr., pp. 45 - 46.)

1. Encouraging Cogeneration vs. Preventing "Death Spirals"

The objective of retaining GSU's industrial load is an important one. GSU's generation and transmission system was constructed for the purpose of serving all of its customers, and the fixed cost burden associated with that construction is borne by all customers. If some industrial customers leave the system in favor of cogeneration, then the remaining customers will have to bear a larger share of the fixed cost burden than they would have otherwise borne. As the cost burden for the remaining customers increases, then still more industrial customers with the capacity to cogenerate will decide to leave the system, thereby again increasing the cost burden of remaining customers. The sequence has been described somewhat horrifically as a "death spiral". Keeping industrial customers on the system is, as the company argues, in the interest of all GSU ratepayers, and one way to encourage industrial customers to remain on the system is to offer them incentive rates.

Section 16 of PURA directs the Commission to encourage the economical production of electric energy by qualifying cogenerators and small power producers. Allowing utilities to compete with the economics of cogeneration, which is luring away some utility customers, is not inconsistent with this legislative directive. Section 16 refers to the encouragement of economical production. It is not economical for society as a whole to encourage new cogeneration in areas where excess generating capacity already exists. In order to strike the proper balance between a utility's interest in retaining its industrial load base and the legislative directive found in section 16, the Commission must find a way to allow the utility to compete with cogeneration in a way that is designed to prevent the possibility of abuse by the utility. The examiner believes that the approach taken by the Commission in Docket No. 7309 is such a balanced approach and is unconvinced by the evidence presented in this docket that the Commission should deviate from that approach.

2. Discriminatory Issues.

There is reason to be concerned that the amendment proposed by GSU violates the discriminatory prohibitions of PURA. Both GCCA and CoGen make this argument, while GSU contends that these issues were decided by the Commission in Docket No. 7309 and that the same reasoning adopted there still applies.

In Docket No. 7309, Judge Smith found that Schedule SUS does discriminate among industrial customers insofar as the incentive rate is only available to those industrial customers which meet the minimum thermal and electrical load requirements. He concluded, however, that the discrimination is not unreasonable (which would violate sections 38 and 45 of PURA) because the distinction between those industrial customers who could cogenerate exists independently of Schedule SUS. As Judge Smith explained it:

> . . . [A]ny 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 advantage, 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.

GSU argues that its current proposal is consistent with this reasoning. The company acknowledges that the proposed amendment could result in two customers with the same thermal and electrical energy requirements paying different rates under the proposed amendment because separate negotiations with the two customers might produce different agreements. GSU argues, however, that this would not constitute unreasonable discrimination because the two customers might also receive different prices from negotiations with a cogeneration developer. Negotiations between industrial customers and GSU are likely to be influenced by different factors than are negotiations between those same customers and a cogeneration developer, however. Also, this Commission does not regulate cogeneration developers and, as far as the examiner is aware, cogeneration developers are free to practice price discrimination among customers. GSU is not.

GSU argues that the existing rate structure of SUS is not technically designed to fit the electrical and thermal requirements of some customers, but has identified only two customers, having a combined load capacity of 58 MW, for whom the rate structure is not suited. The company contends that individual negotiations with these customers will produce rates better suited to each of these customer's needs. Admittedly, the existing rate structure does not have the flexibility that would allow it to accurately replicate the costs of all potential cogenerators, but it does have the desirable feature of applying the same rate to customers with the same thermal and electrical energy requirements. Furthermore, the examiner does not agree with GSU that customer negotiations are likely to produce a more accurate estimate of the costs of each customer's potential cogeneration project. Negotiations between GSU and applicates under the proposed amendment are likely to be influenced by many factors other than information about the design and size of a potential cogeneration project. The level and expertise of the participants' negotiating skills, the size of the customer's electrical load and GSU's desire to retain it, and the honesty of the participants are but a few examples of factors that could influence the outcome of negotiations. [Nor would abuses be as easy to discover as GSU promises. The regulatory concerns raisen by GSU's proposal will be discussed in the next section of this report.]

[2] In the interest of helping GSU keep industrial customers on its system, the Commission concluded in Docket No. 7309 that discriminating between industrial customers on the basis of their ability to cognerate was not unreasonable discrimination because the ability to cogenerate was a pre-existing condition. The examiner recommends against amending Schedule SUS as proposed by GSU

because there is a risk that discrimination among customers will be based upon other factors that will necessarily influence the rate-making process that GSU has proposed. Allowing discrimination among customers based upon factors such as the ones mentioned in the above paragraph will not, in the examiner's opinion, satisfy the standards established by Texas courts that discrimination be based upon substantial and reasonable grounds of distinction. Texas Alarm & Signal Assoc. v. Public Utility Comm., 603 SW2d 766 (Tex. 1980); Amtel Communications v. Public Utility Comm., 687 SW2d 95 (Tex. App. -- Austin 1985, no writ).

The examiner only very recently issued a report in another case, Application of Houston Lighting & Power Company for Approval of an Economy Energy Tariff, Docket No. 8329, in which many of these same issues were raised. In that case the examiner found that there was no risk of discrimination in allowing the competitive market to determine the margin above HL&P's incremental costs for pricing economy energy. The facts in that case are distinguishable from the facts here, however. In the HL&P case, a real service -- economy energy -- was being priced. Here, GSU is attempting to price something that doesn't even exist -- a hypothetical cogeneration project. Also, the mechanisms and practices for pricing economy energy are sophisticated and well understood by all participants. Many of HL&P's routine economy energy sales do not even involve negotiation, but are processed and administered by ERCOT personnel without any direct involvement from HL&P. There are no such institutional safeguards to prevent the possibility of intentional or unintentional abuse in negotiations between GSU and its industrial customers. Finally, all of HL&P's economy energy sales are made to other public utilities. Sections 38 and 45 of PURA are probably not intended to protect public utilities from economy competition with other public utilities. Those sections are, however, intended to protect GSU's customers against the sort of unreasonable discrimination that can arise, intentionally or otherwise, within the rate-making process proposed by the company.

3. Regulatory Burden

Another reason that the examiner has decided to recommend rejection of the proposed new section to SUS is that the process proposed by GSU for reviewing the agreements is unworkable. GSU proposes that the Commission staff have twenty days in which to review the customer specific contracts submitted under Section VIII. GSU proposes that staff's review be submitted to the Hearings Division, and that the Hearings Division shall issue an order approving or disapproving the contract and rate modifications within ten days. GSU's proposal for review of the contracts is unacceptable. Testimony at the hearing revealed that negotiations for these contracts can take as long as a year. In reviewing the contracts, the staff would have to go through the same analysis that GSU would had to have gone through, but staff's review would have to be independent in order to determine whether the rates negotiated do approximate the cost of cogeneration for the customer.

The staff, like GSU, would have to first determine whether the customer's proposed cogeneration project is indeed one that the customer would likely build were the customer to cogenerate. Second, the staff, like GSU, would have to determine whether the company's standard LPS or HLFS rates are an adequate alternative to the proposed cogeneration project. Third, the staff, like GSU, would have to determine whether the existing SUS rates could approximate the customer's hypothetical cogeneration project since the proposed amendment only permits modifications to the existing rate structure when it is not competitive with the proposed project. Fourth, the staff, like GSU, would have to determine what modifications, if any, could and should be made to the criteria in Schedule SUS. Finally, the staff, like GSU, would have to make sure that the resulting rate was above the price floor of GSU's system average fuel cost plus 8 mills. Mr. Rudolph testified that the staff would need more than twenty days to do its review, and the examiner certainly agrees.

Based upon some of the testimony offered by GSU witnesses at the hearing, it seems that GSU believes that third parties should not be permitted to participate in the Commission review process. The examiner does not believe that the Commission can, or should, preclude persons from intervening in a

Commission review of these contracts provided intervenors are able to show a justiciable interest. There are a number of reasons that can result in an application being docketed. In particular, there are a number of reasons why the customer specific contracts that GSU is proposing to submit might be docketed: 1) because so much analysis would have to be undertaken by the staff before making a recommendation, 2) because the staff might recommend docketing or disapproval, 3) because the tariff examiner or director hearings might decide that the contracts raise legal questions that should be addressed, or 4) because the contracts might generate third party challenges.

GSU's proposal for administrative review is unreasonable and would impose an unrealistic administrative burden upon the Commission.

GSU has, from the date it filed this application, pushed for an expedited review of this filing, explaining that it has already negotiated an agreement for modified SUS rates with one customer, Ameripol Synpol, and is waiting for Commission approval of this application to finalize the agreement and submit the contract for approval by the Commission. The examiner believes the Commission should not be pressured to make a decision based on GSU's setting of the agenda. GSU should have sought Commission approval of its proposal before negotiating rates with any customers and heightening expectations of those customers.

V. Recommendation

To summarize, the examiner makes the following recommendations:

1. GSU's proposal to amend the existing Schedule SUS to refer to the HLFS (High Load Factor Service) class instead of the LIS (Large Industrial Service) class is a non-substantive change and an update to accurately reflect the service eligibility requirements. The examiner recommends approval.

2. GSU's proposal to renew the existing Schedule SUS until December 31, 1991 should be approved.

3. GSU's proposal that it have discretion to offer Schedule SUS when its capacity margins fall below 18 percent should be rejected. The company should not be allowed to accept applications when its capacity margin is 18 percent or below.

4. GSU should be ordered to not include any provision regarding the sale of steam or thermal energy to its SUS customers in service agreements with those customers.

[1] 5. GSU should be ordered not to exercise the option of selling steam or thermal energy that exists in service agreements already executed with SUS customers.

6. GSU's proposal to add Section VIII to Schedule SUS should be rejected. Should the Commission approve GSU's proposal for customer specific contracts, the examiner makes the following recommendations concerning Section VIII:

Subsection C of Section VIII, concerning the time period for Commission review of customer contracts, should be deleted. GSU's applications for approval of customer contracts should be treated consistent with the normal tariff procedures under SUBST. R. 23.24.

VI. Findings of Fact and Conclusions of Law

A. Findings of Fact

1. On August 31, 1988, Gulf States Utilities Company (GSU) filed an application for approval of amendments to its Schedule SUS (Steam User Service). Schedule SUS is an experimental rider which offers incentive rates to industrial customers with the potential to cogenerate.

2. The time period for accepting applications under Schedule SUS was one year, beginning May 13, 1987.

4. In compliance with the examiner's orders, GSU provided individual notice of this filing to all current customers of SUS and identified potential customers, as well as to all parties in its last general rate case.

5. A prehearing conference was held on September 22, 1988. Appearances were entered on behalf of GSU, the Office of Public Counsel (OPC), and the Commission's staff.

6. Intervention was granted to Gulf Coast Cogeneration Association (GCCA) and CoGen Lyondell, Inc. (CoGen) on October 17, 1988.

7. A hearing on the merits was convened on December 8, 1988, and adjourned the following day.

8. GSU proposes to amend the tariff to accurately reflect the fact that the service is available to qualifying customers within the LPS (Large Power Service) class and the HLFS (High Load Factor Service) class. The amendment is non-substantive and should be approved.

9. To qualify for Schedule SUS, existing LPS or HLFS customers must have minimum process steam requirements of 10,000 pounds per hour or the thermal equivalent thereof. The minimum requirements may not include requirements satisfied by cogeneration facilities that are or will become operational.

10. SUS rates are designed to approximate the costs of cogeneration that the customers would experience were they to install an optimal size cogeneration facility at their production sites.

11. Qualifying customers do not begin receiving incentive rates under Schedule SUS until their cogeneration project would have been completed and in-service had the customer chosen to proceed with construction instead of agreeing to SUS rates.

11. Qualifying customers do not begin receiving incentive rates under Schedule SUS until their cogeneration project would have been completed and in-service had the customer chosen to proceed with construction instead of agreeing to SUS rates.

12. As a precondition to subscription, customers must execute an amendment to their existing service agreement. One of the provisions under that amendment states that GSU has the option to supply steam or thermal energy to the customer at "economically neutral" prices. The provision states that if the customer declines the offer, SUS service will be terminated eighteen months after GSU makes the offer to supply steam or thermal energy.

13. GSU did not offer any evidence showing how it would pay the costs of supplying steam or thermal energy to SUS customers; nor did the company offer any evidence comparing its projected costs of supplying steam with the customers' own costs.

14. The provision regarding the sale of steam or thermal energy described in Finding of Fact No. 12 should not be included in future SUS service agreements. GSU should be ordered not to exercise the option under its present agreements with customers.

15. Schedule SUS rates are based upon the economics of installing a cogeneration facility consisting of a gas turbine driven electric generator with a heat recovery steam generator producing steam from the gas turbine exhaust.

16. The billing provision under Schedule SUS has two distinct parts, steam billing and the remaining firm electric billing. The steam billing is the part that is designed to replicate the costs of a hypothetical cogeneration facility for the customer. The remaining firm electric billing applies to the amount of electric load and energy that would still have been served by GSU had the customer proceeded with a cogeneration project. Other standard tariffs would apply to this portion.

17. The steam billing consists of a demand charge and an energy charge. There is also a minimum charge that is designed to recover GSU's variable cost of providing power to the customer.

18. The demand charge is intended to simulate the initial investment and periodic maintenance investment costs associated with the construction of a cogeneration facility.

19. There are two separate schedules, Schedule A and B, for calculating the demand charge. The ratio of a customer's electrical energy to steam energy requirements determines which schedule applies.

20. The rate structure under the demand charge is designed to recognize variations in cost that would be associated with different size cogeneration units. GSU attempts to match the customer's actual energy usage with the optimal size unit which will help determine the customer's billing load for purposes of calculating the demand charge.

21. Within each billing load range, the steam billing demand charge will increase over the life of the rate. This escalation is intended to reflect the increased cost of operations and maintenance associated with a gas turbine.

22. The steam billing energy charge is intended to simulate the cost of fuel and energy efficiency of the theoretical cogeneration unit. Like the demand charge, the energy charge is structured to reflect the economic concepts of differences in sizing and efficiency. These are reflected through changes in the applied heat rate values.

23. The minimum charge under Schedule SUS is the result achieved by multiplying GSU's system average fuel cost for the preceding month, plus 8 mills per KWH, by the current month's steam energy determinants. This amount has, and will, cover GSU's variable cost to supply power to its SUS customers.

24. Since Schedule SUS was approved in May of 1987, GSU has discussed its application with ten customers. Four of the ten are currently being billed under SUS. Three reviewed the schedule but opted to remain on the company's standard LPS or HLFS rates. One customer decided to build a cogeneration project. The other two customers are candidates for service under the proposed revision that would allow customer specific contracts.

25. The load lost in Texas by GSU as a result of customers producing their own electricity is about 130 MW. GSU estimates that Schedule SUS has allowed it to retain about 160 MW of industrial load.

26. On an annualized basis, GSU estimates that the revenues received in Texas from industrial customers billed under SUS are approximately $4,321,000 less than revenues that would have been received from those same customers if they remained on the system and were billed under the standard rates.

27. GSU has identified 58 MW of load that is subject to further loss due to the threat of cogeneration. The proposed provision for customer specific contracts is aimed at this load.

28. Load retention is a viable objective for GSU. It is an objective which was endorsed by the Commission when it first approved Schedule SUS in Docket No. 7309.

29. GSU proposes that the deadline for accepting applications for Schedule SUS tariff be extended until December 31, 1991. The proposal is reasonable.

30. GSU's current situation of having excess capacity is being used to justify the continuation of Schedule SUS. That justification will no longer exist when the excess capacity is dwindling. Therefore, GSU should not be permitted to accept applications when its capacity margin falls below 18 percent.

31. GSU proposes that a new section, Section VIII, be added to Schedule SUS which would allow the company to enter into customer specific contracts to modify the existing provisions of the tariff (except for the minimum charge) when the technical and economic aspects of a customer's proposed cogeneration project are such that the billing application of Schedule A or B would not be competitive with the economics of the proposed project.

32. The customer specific contract provision is aimed at potential cogenerators having electric loads less than thirty MW.

33. Rates developed from negotiations between potential cogenerators for service under the proposed Section VIII would likely be influenced by factors other than the economics of the cogeneration project that the customer would build but for the opportunity to receive incentive rates under Schedule SUS.

[2] 34. It would constitute unreasonable discrimination for GSU to charge different rates under the proposed amendment to Schedule SUS to customers with the same thermal and electrical energy requirements.

35. GSU proposes that the Commission staff review customer specific contracts, submitted under the provisions of the proposed amendment, within twenty days and that the Hearings Division approve or disapprove the contracts within ten days after receipt of staff's recommendation.

36. GSU's proposal for an expedited administrative review of customer specific contracts is inconsistent with the policies of the Commission and would, if adopted, impose an unreasonable regulatory burden on the Commission.

37. GSU's proposal for adding a new section to the existing SUS tariff providing for expedited review of customer specific contracts is unreasonable because it would allow unreasonable discrimination and limited Commission review.

B. Conclusions of Law

1. GSU is a public utility as defined in section 3(c) of the Public Utility Regulatory Act (PURA), Tex. Rev. Civ. Stat. Ann. art. 1446c (Vernon Supp. 1988.)

2. The Commission has jurisdiction over this application pursuant to sections 16(a), 17(e) and 37 of PURA.

3. 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).

4. The existing Schedule SUS is not unreasonably preferential, prejudicial or discriminatory, but rather is sufficient and equitable within the intended meaning of section 38 of PURA.

5. Renewing the existing Schedule SUS 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. Renewal therefore does not conflict with section 45 of PURA.

[2] 6. Renewal of Schedule SUS 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 meaning of section 47 of PURA.

7. GSU's proposal for a new Section VIII to be added to the existing Schedule SUS does not satisfy the standards of sections 38 and 45 or PURA.

SIGNED AT AUSTIN, TEXAS on this 6th day of February 1989.

PUBLIC UTILITY COMMISSION OF TEXAS

Becky Bruner
BECKY BRUNER
HEARINGS EXAMINER

APPROVED:

Phillip A. Holder
PHILLIP A. HOLDER
DIRECTOR OF HEARINGS

BB/sm

GULF STATES UTILITIES CO.
Electric Service
Texas

SECTION NO.: III
SECTION TITLE: Rate Schedules and Charges
SHEET NO.: 1
EFFECTIVE DATE: Proposed
REVISION: 7
APPLICABLE: Entire Texas Service Area
PAGE: 1 of 1

INDEX TO SCHEDULES

*Refer to Section II for list of Cities
**Closed to New Business
***Experimental Tariff

GULF STATES UTILITIES CO.
Electric Service
Texas

SECTION NO.: III
SECTION TITLE: Rate Schedules and Charges
SHEET NO.: 51
EFFECTIVE DATE: Proposed
REVISION: 1
APPLICABLE: Unincorporated Areas of Texas Service Area
PAGE: 1 of 8

SCHEDULE SUS

EXPERIMENTAL RIDER TO SCHEDULE LPS AND HLFS FOR INDUSTRIAL SERVICE TO QUALIFYING THERMAL ENERGY USERS

I. Applicability

This rider is applicable under the Regular Terms and Conditions of the Company to existing Customers in unincorporated areas who qualify for service under Schedules LPS or HLFS, on or prior to the date this rider is approved by the regulatory authority having jurisdiction thereof. The Customers must have minimum process steam requirements of 10 M#/hour or the thermal energy equivalent. These minimum requirements exclude all such requirements satisfied by cogeneration facilities that are operational or will be operational or satisfied by other steam or heat that has been or will be used to generate electrical power internally. Other riders to Schedules GS, LGS, LPS and/or HLFS are applicable only to that portion of the Customer's load served under such Schedules.

II. Availability

Requests for service under Schedule SUS will be accepted through December 31, 1991, however, the Company reserves the right to not accept requests for service under this Schedule if the Company's projected capacity margin for the next calendar year, as determined by Company, is less than 18%.

III. Determination of Total Electric Contract Power and Total Billing Load

The total contract power under Schedule SUS will be determined in accordance with the "Determination of Contract Power and Billing Load" provision contained in the respective rate Schedules LPS or HLFS. The establishment of the total billing load within the "Determination of Contract Power and Billing Load" provision shall be modified such that the total billing load shall be the greater of actual created KW, as adjusted by the power factor provision, or 75 percent of contract power.

IV. Determination of Monthly Billing

A. Billing Determinants Under Steam Rate

1. Contracted Sizing Factor (SF): The SF will be subject to a periodic review by the Company and will be adjusted if the operating conditions upon which the SF is based have materially changed.

2. Billing Load: The monthly Steam Rate Billing Load calculated by multiplying the monthly measured KWH used by the contracted sizing factor (SF) divided by the period hours:

$$\text{Steam Rate Billing Load} = \frac{\text{KWH x SF}}{\text{Period Hours}}$$

3. Energy: The monthly KWH for billing the Steam Rate calculated by multiplying the monthly measured KWH used by the contracted sizing factor (SF):

Steam Rate KWH = KWH x SF

4. The monthly measured KWH used in the above Billing Load and Energy shall exclude KWH associated with Schedule MSS.

B. Billing Determinants Under Applicable Firm Electric Rate Schedule

1. Billing Load: The monthly maximum KW load for billing under the applicable firm electric rate schedule is calculated by subtracting the monthly Steam Rate Billing Load from the Total Billing Load, as established in Section III, Determination of Total Electric Contract Power and Total Billing Load.

The monthly maximum KW load, calculated as described above, will be the basis for determining contract power and billing load under the applicable firm electric rate schedule. The interval for measuring the monthly maximum KW load (ie., 15-minute or 30-minute) will be as defined by the applicable firm electric rate schedule. All other provisions of the applicable firm electric rate schedule will remain in force and unchanged.

2. Energy: The monthly KWH used, for billing the energy charge under the applicable firm electric rate schedule, is calculated by subtracting the monthly Steam Rate KWH from the monthly measured KWH.

SCHEDULE SUS (Cont.)

C. Net Monthly Bill shall be the sum of the following:

1. Billing Determinants billed under the applicable firm electric rate schedule.

2. a. Steam Rate Billing Load Charge

Total Monthly Steam Rate Billing Load		Rate Schedule A		Rate Schedule B	
At Least	But Less Than	$/KW	$ Constant	$/KW	$ Constant
	5,000 KW	27.70	0	31.00	0
5,000 KW	10,500 KW	23.70	20,088	25.32	33,393
10,500 KW	15,500 KW	17.70	83,092	19.20	97,669
15,500 KW	19,500 KW	15.80	112,535	13.58	187,131
19,500 KW	20,500 KW	15.80	112,535	13.58	187,131
20,500 KW	22,500 KW	11.80	194,533	13.58	187,131
22,500 KW	23,000 KW	11.80	194,533	12.28	219,740
23,000 KW	23,500 KW	0.09	469,706	12.28	219,740
23,500 KW	24,000 KW	0.09	469,706	0.10	506,000
24,000 KW	24,500 KW	0.09	469,706	0.10	506,000
24,500 KW	25,500 KW	0.09	469,706	0.10	506,000
25,500 KW	26,500 KW	0.09	469,706	0.10	506,000
26,500 KW	27,500 KW	0.09	469,706	0.10	506,000
27,500 KW	28,500 KW	0.09	469,706	0.10	506,000
28,500 KW	29,500 KW	0.09	469,706	0.10	506,000
29,500 KW	31,500 KW	0.09	469,706	0.10	506,000
31,500 KW	32,000 KW	15.00	0	0.10	506,000
32,000 KW		15.00	0	16.00	0

Rate Schedule A is applicable to Customers who can demonstrate and contract for an average ratio of electrical energy to steam energy (or equivalent steam energy) of 230 KWH/Mlb or less per month.

Rate Schedule B is applicable to Customers who can demonstrate and contract for an average ratio of electrical energy to steam energy (or equivalent steam energy) in excess of 230 KWH/Mlb per month.

The charges contained under Rate Schedules A and B will remain constant for a Customer's first 3 years of service under the rider, after which the charges will escalate at a rate of 1.5 percent annually.

b. Steam Rate Billing Load Charge Calculation

Total Steam Rate Billing Load Charge = (Billing Load x $/KW) + $ Constant

3. Steam Rate Energy Charge

a. Fuel Heat Rate Schedule (FHRS)

Total Monthly Steam Rate Billing Load		Fuel Heat Rate Schedule (MMBtu/MWH)	
At Least	But Less Than	A	B
	5,000 KW	7	6.7
5,000 KW	10,500 KW	7	6.7
10,500 KW	15,500 KW	7	6.7
15,500 KW	19,500 KW	7	6.6
19,500 KW	20,500 KW	7	6.5
20,500 KW	22,500 KW	6.9	6.4
22,500 KW	23,000 KW	6.8	6.3
23,000 KW	23,500 KW	6.8	6.2
23,500 KW	24,000 KW	6.7	6.2
24,000 KW	24,500 KW	6.6	6.1
24,500 KW	25,500 KW	6.5	6
25,500 KW	26,500 KW	6.4	5.9
26,500 KW	27,500 KW	6.3	5.8
27,500 KW	28,500 KW	6.2	5.8
28,500 KW	29,500 KW	6.1	5.8
29,500 KW	31,500 KW	6	5.8
31,500 KW	32,000 KW	6	5.8
32,000 KW		6	5.8

Fuel Heat Rate Schedule A is applicable to Customers which have contracted for Rate Schedule A of the Steam Rate Billing Load charge.

Fuel Heat Rate Schedule B is applicable to Customers which have contracted for Rate Schedule B of the Steam Rate Billing Load Charge.

The initial FHRS will increase by 1.25%, 1.5% and 2% at the beginning of the second, third and fourth years respectively after billing at the initial FHRS one year. The FHRS will reset to the initial value for the fifth, ninth and thirteenth year of SUS billing.

b. Natural Gas Price (NGP) will be the Gulf States Utilities Company Weighted Average Cost of Gas ($/MMBtu) from the month preceding the Schedule SUS billing month.

c. Energy Charge Calculation

$$\text{Total Steam Rate Energy Charge} = \frac{\text{Steam Rate KWH}}{1000} \times \text{FHRS} \times \text{NGP}$$

d. The combined total billing for the Steam Rate Billing Load Charge and the Steam Rate Energy Charge shall not be less than the current billing month steam rate KWH times the Company's System Average Fuel Cost (¢/KWH) from the preceding month, plus 8 mills per KWH.

SCHEDULE SUS (Cont.)

V. Definitions

A. Total Electric Contract Power
The total monthly amount of power served to the Customer as adjusted under the Determination of Contract Power and Billing Load provision contained in the respective Schedules LPS or HLFS, as well as any applicable adjustment associated with service under Schedule MSS or Schedule PM.

B. Firm Electric Contract Power
The total firm electric contract power under the applicable rate for firm service billing.

C. Thermal Energy
The energy used in the production process of plant products, excluding heat energy or steam that has been or will be used to generate electrical power. The thermal energy consumed in transferring heat energy to process streams for the production of Customer's products, excluding thermal energy converted to electric energy.

D. Period Hours
The total hours in a billing month.

E. Contracted Sizing Factor
A factor to determine the optimum size of the electrical generator based on the Customer's actual thermal and electric energy usage.

F. Company's System Average Fuel Cost
The result, to the nearest one hundredth of a mill, of dividing the System Fuel Costs by the System Sales.

Where:

System Fuel Cost - is determined for the immediately preceding month and consists of the total cost of fossil and nuclear fuel used in Company's generating stations plus Company's share of such fuel used in jointly owned or leased plants, plus the net energy cost of energy purchases (exclusive of capacity and demand charges) on an economic dispatch basis, plus the actual identifiable fossil and nuclear fuel costs associated with intersystem purchases, plus non-fuel costs associated with purchased economic power as defined below, less the cost of fossil and nuclear fuel recovered through intersystem sales (including fuel costs related to economic dispatch basis intersystem sales).

System Sales - are the KWH sold in the immediately preceding month determined by the sum of (a) Company's net generation, and (b) intersystem purchases, including economy energy received, less (c) intersystem sales, including economy energy delivered and, less (d) system losses.

Non-fuel purchased economic power costs - All non-fuel costs incurred in buying economic power and having such power delivered to the Company's system. Such costs include, but are not limited to, capacity or reservation charges, adders, and any transmission or wheeling charges associated with the purchase. Purchased economic power is power or energy purchased over a period of twelve months or less where the total cost of the purchase is less than the Company's total avoided variable cost and the purchase is not necessary to meet reserve requirements. The Company's system reserve capacity criteria is that established by the Southwest Power Pool and is subject to change from time to time. At the present, the Company's minimum reserve criteria is to maintain an 18% reserve margin.

VI. Meters

A. Electric Meters
The service under this Schedule shall be supplied through a single electric service meter. Service not supplied under this Schedule shall be metered separately.

VII. Conditions of Service

An amendment to the existing firm power contract to provide Schedule SUS service is required. In order to receive service under Schedule SUS, the Customer must extend the term of the existing service contract by the period of time agreed in the Amendment. Actual Schedule SUS service will not commence immediately following amendment execution. The Company and the Customer will agree to terms which will specify this commencement date based upon the reasonably achievable in-service date of a satisfactory self-generation facility, should that option have been chosen instead of this rider.

Certain items pertinent to the application of Schedule SUS will be established by the executed amendment to the firm power contract. These are the Contracted Sizing Factor, the Rate Schedule (A or B), the Fuel Heat Rate Schedule (A or B), the conversion factor for converting thermal energy to equivalent steam energy, and the Electric/Thermal Energy Ratio.

The Customer on a monthly basis must provide a record of thermal energy actually used. The information contained in the record must be such that the Company can verify the reasonability of the reported usage.

GULF STATES UTILITIES CO.
Electric Service
Texas

SECTION NO: III
SECTION TITLE: Rate Schedules and Charges
SHEET NO.: 54
EFFECTIVE DATE: Proposed
REVISION: 1
APPLICABLE: Unincorporated Areas of Texas Service Area

Schedule SUS (Cont.)

VIII. Contractual Modifications of Schedule SUS Provisions

A. Some provisions of Schedule SUS may be contractually modified where the technical and economic aspects of a customers proposed cogeneration project are such that the billing application of Schedule A or Schedule B would not be competitive with the economics of the proposed project. The customer must provide the Company with the project economic evaluation which will, to the Company's satisfaction, clearly demonstrate an economic advantage of the customer's proposed project over the billing under Schedules A and B. Such evaluation shall include but not be limited to the following information:

1. Fuel price projections.
2. Requirements for standby and maintenance service
3. Operating and Maintenance cost of project
4. Thermal and electrical (KW & KWH) load projections
5. Project major equipment performance data
6. Projected energy sales to Company
7. Capital cost of project
8. Finance cost of project
9. Depreciation expense
10. Leasing cost if applicable

A confidentiality agreement will be executed upon customer request to protect customer proprietary data. Contractual modifications to Schedule SUS will only be made to the specific provisions which require change in order to be competitive with the customer's proposed project economics. Such changes shall be made at the sole discretion of the Company. All other provisions of Schedule SUS shall remain applicable. In no case will a contract modification lower the minimum billing contained in Section IV.C.3.d.

B. Company Annual Review

The Company and customer will contractually establish specific items to be annually reviewed as well as levels of reasonability. The annual review will compare actual value with the assumptions used to modify Schedule SUS. When such Company review deems the assumptions unreasonable, the contractual modifications to Schedule SUS will be revised. Contractual revision will be completed within thirty days of Company notification to customer. Where such revision is not completed in thirty days, the customer will be served under schedule A or B or under a regular service schedule, whichever is applicable.

C. Data Filing

As stated above, the Company and customer may by contract modify the application of Schedule SUS to meet the particular economic needs or requirements and conditions of service for an individual customer. All contracts providing for modification shall be filed with the Public Utility Commission of Texas. Upon such filing, the Staff of the Public Utility Commission of Texas shall review the modifications to Schedule SUS to ascertain whether or not such modifications are consistent with the purposes and provisions of this rate, including the provisions of Sections VIII.A. hereof. The Staff shall conduct such review within 20 days from the date of the filing of such contract. During such time, if Staff so requests, the Company shall provide to the Staff on a confidential basis copies of the supporting technical and economic data provided by the customer to the Company.

Upon the conclusion of its review, the Staff shall issue its recommendation to the Commission recommending that such contract and the modification therein be approved or not approved, as the case may be. The recommendation made by the Staff shall be considered by the Hearings Division of the Public Utility Commission of Texas and the Hearings Division shall, within 10 days after receiving the recommendation of Staff, issue an order approving or disapproving the contract and the modifications to the SUS rate therein.

Supersedes SUS (5-13-87)

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 revenues 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 an 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 conduct 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 four

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 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.

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 customers 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 peak 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 LIP 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 benefitted 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 discrimintion 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^{o}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 supplemental 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 demand and steam demand requirements exceeding 230 KW/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 and does not adversely affect current cognerators.

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 properly 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 Schedle 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

MARK W. SMITH
ADMINISTRATIVE LAW JUDGE

APPROVED on this the 30th day of April 1987.

Phillip A. Holder

PHILLIP A. HOLDER
DIRECTOR OF HEARINGS

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DOCKET NO. 8329

APPLICATION OF GULF STATES UTILITIES COMPANY FOR APPROVAL OF AN AMENDMENT TO SCHEDULE SUS	§ § §	PUBLIC UTILITY COMMISSION OF TEXAS

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 a hearings examiner who prepared and filed a report containing Findings of Fact and Conclusions of Law, which Examiner's Report is **ADOPTED** as revised and made a part hereof. The Commission further issues the following Order:

1. Finding of Fact No. 30 is **MODIFIED** to read as follows:

   30. GSU's current situation of having excess capacity is being used to justify the continuation of Schedule SUS. That [3] justification will no longer exist when the excess capacity is dwindling. Therefore, GSU should not be permitted to accept applications when its capacity margin falls below 18 percent. In addition, the tariff, as well as future service agreements for SUS, should specify that billing under the terms of Schedule SUS will cease when GSU's capacity margin falls below 18 percent.

2. The application of Gulf States Utilities Company (GSU) for approval of amendments to Schedule SUS is **GRANTED** only to the extent recommended in the Examiner's Report.

3. Within twenty (20) days after the date of this Order, GSU SHALL file a revised tariff in accordance with the directives of this Order. GSU SHALL serve one copy upon the general counsel. No later than ten (10) days after the date of the tariff filing by GSU, the general counsel SHALL file the staff's comments recommending approval or rejection of the filing. No later than fifteen (15) days after the date of the filing by GSU, GSU SHALL file in writing any responses to the previously filed comments of the general counsel. The Hearings

Division SHALL by letter approve, modify or reject each tariff sheet, effective the date of the letter, based upon the materials submitted to the Commission under the procedures established herein. The tariff sheet(s) shall be deemed approved and shall become effective upon expiration of twenty (20) days after the date of filing, in the absence of written notification of approval modification or rejection by the Hearings Division. In the event that any sheet(s) is/are modified or rejected, the Company SHALL file proposed revisions of that/those sheet(s) in accordance with the Hearings Division letter within ten (10) days after the date of that letter, with the review procedures set out above once again to apply. Copies of all filings and of the Hearings Division letter(s) under this procedure SHALL be served on all parties of record and the general counsel.

4. GSU SHALL NOT include any provisions in its service agreements with SUS customers regarding the sale of steam or thermal energy. GSU SHALL NOT exercise options to sell steam or thermal energy in its existing service agreements with SUS customers.

5. GSU 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. In any GSU rate proceeding, GSU's revenues MUST be restated as if all Schedule SUS load were being, and had been, billed at the otherwise applicable standard rates for the SUS customers.

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

7. 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.

SIGNED AT AUSTIN, TEXAS on this 23rd day of February 1989.

PUBLIC UTILITY COMMISSION OF TEXAS

SIGNED: Marta Greytok
MARTA GREYTOK

SIGNED: Jo Campbell
JO CAMPBELL

SIGNED: William B. Cassin
WILLIAM B. CASSIN

ATTEST:

Elizabeth Hagan Drews for
PHILLIP A. HOLDER
SECRETARY OF THE COMMISSION

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APPEAL BY RURAL RATEPAYERS	**§**	**DOCKET NO. 8481**
CONCERNING THE CITY OF LAMPASAS'	**§**	
NOVEMBER 14, 1988, MUNICIPALLY	**§**	
OWNED UTILITY RATE CHANGE	**§**	

February 9, 1989

The Commission granted the petitioner group's motion to withdraw its appeal of city-owned utility rate change.

[1] PROCEDURE--PREHEARING PROCEEDINGS--DISMISSAL WITHOUT HEARING

Where dismissal does not go to the merits of the case, dismissal must be without prejudice. (p. 2657)

DOCKET NO. 8481

APPEAL BY RURAL RATEPAYERS CONCERNING THE CITY OF LAMPASAS' NOVEMBER 14, 1988 MUNICIPALLY OWNED UTILITY RATE CHANGE	§ § §	PUBLIC UTILITY COMMISSION OF TEXAS

EXAMINER'S REPORT

I. Dispute Between the City of Lampasas and Rural Ratepayers

On November 14, 1988, the City Council of the City of Lampasas passed an ordinance which changed the rates charged by Lampasas Public Utilities. According to the statement of Mr. H. E. Gubbels at the December 28, 1988, prehearing conference, the City of Lampasas would not divulge the information necessary to evaluate the reasonableness of the rate change. Mr. Gubbels lives outside the city limits of the City of Lampasas, is a Lampasas Public Utilities customer, and is the representative of the petitioner group.

The petitioner group therefore appealed the November 14, 1988, ordinance to the Commission. A petition, signed by 45 individuals, was filed with the Commission. The petition asserted that the signatories were rural ratepayers of Lampasas Public Utilities; the signatories requested the Commission to conduct an appeal hearing concerning the rate change. The Commission is authorized to hear such appeals. Public Utility Regulatory Act (PURA), Tex. Rev. Civ. Stat. Ann. art. 1446c, Section 26(c) (Vernon Supp. 1988).

II. Subsequent Understanding Between the Parties

Prior to the first prehearing conference, the City of Lampasas shared with the petitioner group all of the information necessary to evaluate the reasonableness of the rate change. According to Mr. Gubbels, it was then clear that rural ratepayers had been treated fairly. The ordinance raised the energy rate for all customers. The rural ratepayers classification was simultaneously eliminated, however. This meant that the rural ratepayers would be charged according to the lower energy schedule previously applied only to the customers located within the city limits. The combined effect of the rate changes is that the rural ratepayers receive a small rate reduction.

III. Procedural History

The petition signed by the rural ratepayers was filed with the Commission on December 7, 1988. A prehearing conference was held on December 28, 1988. Just prior to the beginning of the prehearing conference a motion to dismiss was filed. The motion was signed by the City of Lampasas and Mr. Gubbels.

During the prehearing conference the examiner set a procedural schedule leading to a hearing on the merits. As discussed below, the Commission must evaluate appeals of municipal rate changes in a short time period. The procedural schedule was therefore immediately set. If the motion to dismiss were withdrawn or were not unanimously supported by the petitioner group then the case would be in a position to proceed.

This case concerned the adjudication of the rights of a large group of individuals who had each signed a petition that requested the intervention of the Commission. The prehearing conference discussion did not supply sufficient information to conclude that the motion to dismiss was supported by all of the petitioner group. The examiner therefore ordered the parties to submit a second motion to dismiss. The second motion to dismiss was filed on December 30, 1988, and contained the following:

1. A request to dismiss the case without prejudice.

2. A statement that the members of the petitioner group agreed at the time they signed the petition that Mr. Gubbels would represent the group.

3. A statement that Mr. Gubbels notified by mail each member of the petitioner group that he had filed a motion to dismiss the petition filed with the Commission. The notice informed the members of the petitioner group that they could file objections to the motion to dismiss. The objections could be filed with the Commission on or before January 9, 1989.

The second motion to dismiss was executed by Mr. Gubbels, the City of Lampasas, and the Commission's general counsel. No objections to the motions to dismiss were filed. The Office of Public Utility Counsel (OPC) appeared at the prehearing conference. OPC voiced its approval of the motion to dismiss filed on December 28, 1988, but did not move to intervene in this case.

Mr. Jess Totten appeared on behalf of the Commission's general counsel at the prehearing conference. He indicated that there were defects in the petitions. For example, each signature page must contain a concise description of the action of the municipality the group seeks to appeal and the date of that action. P.U.C. PROC. 21.62(g). Examiner's Attachment A is a copy of one page of the petition. The attachment shows that the petition does not meet this requirement. The Commission cannot conduct an appeal hearing under PURA Section 26(c) without a valid petition invoking the jurisdiction of the Commission. The examiner did not pursue a final resolution of the issue because the parties had already moved to dismiss the case.

IV. Rationale Behind the Issuance of Examiner's Report

A. Introduction

An applicant may withdraw its application without prejudice any time prior to the signing of a final order by the Commission. P.U.C. PROC. R. 21.82(b).

The term "applicant" includes parties who seek an available remedy from the Commission through an appeal. P.U.C. PROC. R. 21.41. The examiner has the authority to dismiss a case where the applicant has withdrawn the application, no other requests for final relief in the docket are pending, and dismissal amounts to a ministerial function. Even then, a party to the case may appeal the order granting the motion to dismiss. Application of Tel-Paging, Inc. For a Certificate of Convenience and Necessity Within Dallas and Surrounding Counties, 5 P.U.C. BULL. 151 (October 25, 1979); Application of Central Power and Light Company to Amend Certificate of Convenience and Necessity Within Victoria County, 3 P.U.C. BULL. 660 (December 6, 1977). Rather than grant the second motion to dismiss, the examiner elected to issue this Examiner's Report. The decision was based upon the three considerations discussed below.

B. Protection of Petitioner Group's Rights

As previously mentioned, a large group of individuals sought the intervention of the Commission. The Commission's consideration of the motion to dismiss further guarantees the protection of the petitioner group's rights.

C. Present Discussion for Commission's Consideration Concerning the Commission's Authority to Dismiss PURA Section 26(c) Initiatives

1. The Commission May Grant the Motion to Dismiss

According to PURA Section 26(c), ratepayers of a municipally owned electric utility outside the municiple limits may appeal any action of the governing body that affects rates. The ratepayers must file a petition with the Commission. But the PURA does not fully set forth the rights and obligations of the petitioner group as litigants. Section 26 does not explain whether and how the petitioner group may withdraw the petition. This is an important question, where, as is the case here, the applicant is not an individual but rather is a group of individuals that may have divergent interests. In the instance where the representative of a petitioner group files a motion to dismiss, other members of the petitioner group who do not want the petition dismissed could argue that the Commission does not have the authority to dismiss the petition.

The Commission has previously confronted the issue whether a Section 26(c) petitioner group may withdraw its petition. The Commission granted the petitioner group's motion to dismiss even though the intervenors in the case opposed the motion. Petition of City Park Neighborhood Association for Relief from Rates Set by the City of Austin for Electric Service Outside the City Limits, Docket No. 3960 (November 5, 1982). In the present docket there is an even stronger factual basis to grant the petitioner group's motion to dismiss. In this docket all of the parties support the motion to dismiss. Further, each member of the petitioner group was afforded the opportunity to object to the motion to dismiss. None did so. The examiner therefore concludes that the Commission may grant the petitioner group's motion to dismiss and enter a judgment of dismissal.

2. Judgment of Dismissal Without Prejudice

[1] Both the December 28, 1988, motion to dismiss and the second motion to dismiss seek a judgment of dismissal "without prejudice." A judgment of dismissal with prejudice would bar the petitioner group from again appealing to the Commission based upon the same facts that are the subject of this case.

It is improper to dismiss a case with prejudice where dismissal does not go to the merits of the case. Calaway v. Gardner, 525 S.W.2d 262 (Tex. Civ. App.-Houston [14th Dist.] 1975, no writ); McMinn v. Department of Public Safety, 307 S.W.2d 283 (Tex. Civ. App.-Austin 1957, no writ). The merits of the case have not been developed. A judgment of dismissal must necessarily be based upon the petitioner group's motion to dismiss. Dismissal without prejudice is therefore the only proper means by which to dismiss this case.

If the Commission grants the motion to dismiss without prejudice the question then arises what rights the petitioner group have if in the future they appeal to the Commission the November 14, 1988, ordinance. The question is moot because at this time all parties and the entire petitioner group support the motion to dismiss.

For purposes of advising the petitioner group, however, the examiner points out that there may be two possible interpretations of their rights to appeal the ordinance after the motion to dismiss is granted:

1. The dismissed case is in no way an adjudication of the rights of the parties; it merely places the parties in the position they were in before the Commission's jurisdiction was invoked, as if the petition had never been filed. Crofts v. Court of Civil Appeals for the Eighth Supreme Judicial District of Texas, 362 S.W.2d 101 (Tex. 1962); United States Fidelity and Guaranty Company v. Beuhler, 597 S.W.2d 523 (Tex. Civ. App.-Beaumont 1980, no writ). The dismissed case does not toll the "statute of limitations," which in this case is the PURA Section 26(d) requirement that the petition seeking an appeal must be filed within 30 days of the ordinance. The petitioner group therefore cannot appeal the November 14, 1988, ordinance because the deadline to file the petition has passed.

2. The petitioner group may move the Commission to reinstate the dismissed case. The motion to reinstate must be timely and effective. According to the Commission's procedural rules, motions for rehearing on final orders of the Commission (in this case, the judgment of dismissal) must be filed within 15 days of the final order. P.U.C. PROC. R. 21.161.

D. Opportunity to Discuss the Effect of PURA Section 26 on the Commission's Evaluation of Appeals of Municipal Rates

If the motion to dismiss were denied, PURA Section 26 would impose upon the Commission a comparatively short period of time to evaluate the rates of Lampasas Public Utilities. Further, the evaluation would be based upon a record prepared by parties that have comparatively less experience before the Commission.

In a major rate case initiated by an investor-owned utility, the Commission must issue a final order within 185 days after the statement of intent to change rates is filed. Otherwise, the rates are deemed to have been approved. PURA Sections 43(a), (d). Similarly, the Commission must evaluate an appeal by ratepayers outside the municipal limits concerning rates set by a municipally owned utility within 185 days after the petition is filed. PURA Section 26(e)(1).

But the similarities quickly end. Concerning the procedure leading to a final resolution of the case, an investor-owned utility that files a statement of intent to change rates must simultaneously file its evidence in support of the rate change. Much of this evidence must be filed in the form of a "rate filing package." P.U.C. PROC. R. 21.69. The timing of the rate filing package where there is an appeal by ratepayers outside the municipal limits concerning rates set by a municipally owned utility is much different. The municipality is not expected to file a rate filing package the same day the ratepayers file a petition with the Commission. The municipality may not know of the incipient rate appeal, and is often without the appropriate data in organized form that PURA Section 26(e) implicitly assumes is readily available.

At the first prehearing conference in this docket (held on the 21st day after the petition was filed) the examiner set the City of Lampasas' deadline for submitting a rate filing package for January 26, 1989 (50 days after the petition was filed). The effect of having the rate filing package submitted 50 days after the 185 day period begins would have consisted of shorter subsequent periods for the parties to evaluate the other parties' testimony and to prepare their own.

The compact procedural schedule in an appeal of rates set by a municipally owned utility demands that the parties have the expertise to quickly prepare and evaluate testimony concerning utility rates. But in this docket neither the City of Lampasas, the petitioner group, nor their representatives had previously appeared before the Commission. Before the first prehearing conference the City of Lampasas and the petitioner group filed a joint motion requesting that the conference be postponed at least 15 days. The parties, of course, may have already anticipated the dismissal of the docket, but the motion itself did not say so. The examiner concludes that the motion may have evidenced the unfairness of expecting inexperienced parties to immediately go into high gear towards resolving the appeal to the Commission.

V. Examiner's Recommendation

The examiner recommends that the Commission grant the motion to dismiss filed December 30, 1989, and enter a judgment of dismissal without prejudice. All the parties support the motion to dismiss. Each member of the petitioner group was given the opportunity to object to the motion to dismiss but did not do so. Further, the Commission may not have the authority to conduct an appeal hearing in this case due to the defects in the petition. Because the recommendation to dismiss the case is not based upon the merits of the case, the judgment of dismissal must be "without prejudice."

VI. Findings of Fact and Conclusions of Law

The examiner recommends that the Commission adopt the following Findings of Fact and Conclusions of Law:

A. Findings of Fact

1. Lampasas Public Utilities is owned by the City of Lampasas, Texas. Lampasas Public Utilities distributes electricity to its customers both within and outside the City of Lampasas.

2. The City Council of the City of Lampasas passed an ordinance on November 14, 1988. The ordinance changed the rates charged by Lampasas Public Utilities.

3. A group of rural ratepayers of Lampasas Public Utilities filed a petition with the Commission on December 7, 1988. The petition requested the Commission to conduct an appeal hearing concerning the City of Lampasas ordinance passed on November 14, 1988.

4. A prehearing conference was held on December 28, 1988. Shortly before the conference began the City of Lampasas and the petitioner group filed a joint motion to dismiss the docket.

5. On December 30, 1988, the City of Lampasas, the petitioner group, and the Commission's general counsel filed a second motion to dismiss the docket without prejudice.

6. The petitioner group agreed to have Mr. H. E. Gubbels represent them.

7. Upon the filing of the second motion to dismiss, the individuals belonging to the petitioner group were informed that they had one week to object to the second motion to dismiss. No objections were filed with the Commission.

8. OPC made an appearance at the prehearing conference. OPC supported the motion to dismiss filed on December 28, 1988.

B. Conclusions of Law

1. The Commission's authority to hear appeals of actions of municipal governing bodies affecting the rates of a municipally owned electric utility arises under PURA Sections 16(a) and 26.

2. An applicant may withdraw its petition without prejudice. P.U.C. PROC. R. 21.82(b). "Applicant" includes parties that have by written petition, including appeals, applied for or sought an available remedy from the Commission. P.U.C. PROC. R. 21.41.

3. The petitioner group, through its appointed representative, requested the withdrawal of its petition by filing the second motion to dismiss.

4. In a case initiated by a petition filed pursuant to PURA Section 26(c), the petitioner group may file a motion to dismiss. The Commission is authorized to grant the motion to dismiss and enter a judgment of dismissal. Petition of City Park Neighborhood Association for Relief from Rates Set by the City of Austin for Electric Service Outside the City Limits, Docket No. 3960 (November 5, 1982).

PUBLIC UTILITY COMMISSION OF TEXAS

Richard S O'Connell
RICHARD S. O'CONNELL
HEARINGS EXAMINER

APPROVED on the 27th day of January 1989.

Phillip A. Holder
PHILLIP A. HOLDER
DIRECTOR OF HEARINGS

PETITION

WE , THE UNDERSIGNED RURAL RATE PAYERS OF LAMPASAS PUBLIC UTILITIES, CITY OF LAMPASAS, TEXAS, CONSTITUTING MORE THAN FIVE PERCENT (5%) OF THE RURAL RATE PAYERS, REQUEST THE TEXAS PUBLIC UTILITY COMMISSION CONDUCT AN APPEAL HEARING FOR THOSE CUSTOMERS RESIDING OUTSIDE THE CITY LIMITS OF THE CITY OF LAMPASAS, TEXAS

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PUBLIC UTILITY COMMISSION
FILING CLERK

Bert/
H. E. /Gubbels
Printed Name

P.O. Box 948
LAMPASAS, Texas 76550
Full Printed Address

11993
Voter Registration Number or D.L. #

0904400900
Lampasas Public Utilities Account #

H. E. Gubbels
Signature

LARRY W. Scevers
Printed Name

Rt. 1 - Box 23 - B
LAMPASAS, TEXAS 76550
Full Printed Address

7544
Voter Registration Number or D.L. #

0904401000
Lampasas Public Utilities Account #

LW Scevers
Signature

EXAMINER'S ATTACHMENT A

DOCKET NO. 8481

APPEAL BY RURAL RATEPAYERS CONCERNING THE CITY OF LAMPASAS' NOVEMBER 14, 1988 MUNICIPALLY OWNED UTILITY RATE CHANGE	§ § §	PUBLIC UTILITY COMMISSION OF TEXAS

ORDER

In public meeting at its offices in Austin, Texas, the Public Utility Commission of Texas finds that the application in this case was processed by a hearings examiner in accordance with Commission rules and applicable statutes. An Examiner's Report containing Findings of Fact and Conclusions of Law was submitted, which report is hereby ADOPTED and made a part hereof. The Commission further issues the following Order:

1. The motion to dismiss filed on December 30, 1988, is GRANTED. The appeal is dismissed without prejudice.

2. All motions, applications, and requests for entry of specific Findings of Fact and Conclusions of Law and any other requests for relief, general or specific, if not expressly granted herein are DENIED for want of merit.

SIGNED AT AUSTIN, TEXAS on this the 9th day of February 1989.

PUBLIC UTILITY COMMISSION OF TEXAS

SIGNED: Marta Greytok
MARTA GREYTOK

SIGNED: Jo Campbell
JO CAMPBELL

SIGNED: William B. Cassin
WILLIAM B. CASSIN

ATTEST

Phillip A. Holder
PHILLIP A. HOLDER
SECRETARY OF THE COMMISSION

MEMORANDUM DECISIONS

TELEPHONE

United Telephone Company of Texas, Inc., Docket No. 8222. Examiner's Report adopted April 13, 1989. Stipulated settlement approved. The case concerned general counsel's inquiry into the effects of the Tax Reduction Act on the utility's rates.

Southwestern Bell Telephone Co., Docket No. 8345. Examiner's Report adopted May 10, 1989. Application for base rate area revision in Nacogdoches Exchange approved.

Southwestern Bell Telephone Co., Docket No. 8347. Examiner's Report adopted May 10, 1989. Application for base rate area revision in Taylor Exchange approved.

Southwestern Bell Telephone Co., Docket No. 8359. Examiner's Report adopted May 10, 1989. Application for a base rate area revision in Elgin Exchange approved.

GTE Southwest, Inc., Docket No. 8388. Examiner's Report adopted April 21, 1989. Applicant's request for 350 CentraNet station lines approved.

Contel of Texas, Inc., Docket No. 8408. Examiner's Report adopted May 10, 1989. Application to amend Certificate of Convenience and Necessity within Hopkins County approved.

Poka-Lambro Telephone Cooperative, Inc., Docket No. 8441. Examiner's Report adopted May 10, 1989. Application to amend Certificate of Convenience and Necessity in Borden County approved.

Eastex Telephone Cooperative, Inc., Docket No. 8450. Examiner's Report adopted April 21, 1989. Applicant's request to increase depreciation rates on ste-by-step central office equipment which is being replaced by digital switches was approved.

Panhandle Telephone Cooperative, Inc., Docket No. 8452. Examiner's Report adopted May 10, 1989. Application to amend Certificate of Convenience and Necessity in Hansford County approved.

Southwestern Bell Telephone Company, Docket No. 8466. Examiner's Report adopted May 11, 1989. Applicant's request to revise its access service tariff to give interexchange carriers an additional option in the provision of originating 800 access service was granted.

Santa Rosa Telephone Cooperative, Inc., Docket No. 8524. Examiner's Report adopted May 10, 1989. Applicant's request to provide custom calling and hot line alert services and to waive associated installation charges granted.

Eastex Telephone Cooperative, Inc., Docket No. 8526. Examiner's Report adopted May 10, 1989. Application to amend Certificate of Convenience and Necessity in Polk County approved.

Guadalupe Valley Telephone Cooperative, Inc., Docket No. 8564. Examiner's Report adopted May 10, 1989. Application to amend Certificate of Convenience and Necessity in Comal County approved.

Contel of Texas, Inc., Docket No. 8689. Examiner's Report adopted May 10, 1989. Application to amend Certificate of Convenience and Necessity in Harris County approved.

ELECTRIC

South Texas Electric Cooperative, Docket 7754. Examiner's Report adopted May 11, 1989. Application approved to exempt generating and transmission co-op from obligation to sell power to qualifying facilities and to exempt its member co-ops from obligation to purchase power from qualifying facilities.

Southwestern Electric Power Company, Docket No. 7932. Examiner's Report adopted April 21, 1989. SWEPCO's standard avoided cost calculation and terms and conditions for the purchase of firm energy and capacity from qualifying facilities was approved.

Texas Utilities Electric Company, Docket No. 7935. Examiner's Report adopted April 21, 1989. Texas Utilities' standard avoided cost calculation and terms and conditions for the purchase of firm energy and capacity from qualifying facilities was approved.

Lea County Electric Cooperative, Docket No. 8115. Examiner's Report adopted April 21, 1989. Application approved to extend experimental levelized purchased-power-cost-recovery-factor clause.

Texas Utilities Electric Co., Docket No. 8284. Examiner's Report adopted May 10,1989. Application for transmission lines and associated substation in Dallas County approved.

Greenbelt Electric Cooperative, Docket No. 8298. Applicant's request to withdraw petition alleging that West Texas Utilities interfered with the co-op's distribution lines was granted May 5, 1989.

Navarro County Electric Cooperative, Docket No. 8316. Examiner's Report adopted May 11, 1989. Navarro's application to institute a returned check charge was approved subsequent to the co-op's completion of Section 43(a) notice as ordered by the Commission in the Order of Remand.

Wood County Electric Cooperative, Inc., Docket No. 8348. Examiner's Report adopted May 10, 1989. Application for a transmission line in Franklin County granted.

South Texas Electric Cooperative, Inc., Docket No. 8378. Examiner's Report adopted May 10, 1989. Application for a transmission line in Live Oak County approved.

Brazos Electric Power Cooperative, Inc., Docket No. 8379. Examiner's Report adopted April 7, 1989. Applicant's request for a 138 kV transmission line within Johnson County granted.

Brazos Electric Power Cooperative, Inc., Docket No. 8396. Examiner's Report adopted on May 11, 1989. Applicant's request to temporarily reduce rates to reflect its withdrawal from Comanche Peak granted.

Brazos Electric Power Cooperative, Inc., Docket No. 8401. Examiner's Report adopted May 10, 1989. Application for a transmission line in Johnson County granted.

Southwestern Electric Power Co., Docket No. 8429. Examiner's Report adopted May 10, 1989. Application for a transmission line in Cass County approved.

Tri-County Electric Cooperative, Inc., Docket No. 8437. Examiner's Report adopted May 11, 1989. Tri-County's petition to decrease residential rates during the winter billing months of January through April 1989 was approved.

Brazos Electric Power Cooperative, Inc., Docket No. 8443. Examiner's Report adopted May 10, 1989. Application for a transmission line in Grayson County approved.

Farmers Electric Cooperative, Inc., Docket No. 8483. Examiner's Report adopted April 21, 1989. Applicant's request to amend certificated service area boundaries within Hunt County granted.

Texas Utilities Electric Co., Docket No. 8699. Examiner's Report adopted May 10, 1989. Application to amend service area boundary in Fannin County approved.