PUC BULLETIN

A Publication of the Public Utility Commission of Texas

Volume 15, No. 11 **July 1990**

TELEPHONE

ELECTRIC

MEMORANDUM DECISIONS

Public Utility Commission of Texas

7800 Shoal Creek Boulevard · Suite 400N
Austin, Texas 78757 · 512/458-0100

Jo Campbell
Commissioner

Marta Greytok
Commissioner

Paul D. Meek
Chairman

COMMISSION FORMS

Pursuant to Commission Rules, a complete list of Commission forms and publications is listed below. This list will be updated whenever an addition or deletion occurs.

You may obtain application forms by contacting the Commission Filing Clerk at the following address: Public Utility Commission of Texas; 7800 Shoal Creek Boulevard, Suite 400N; Austin, Texas 78757; telephone, 512/458-0181.

All publications are available from the Commission's Central Records Office at the same address as shown above or by phoning 512/458-0225.

There is a charge for reproduction of Commission files: 8½x11" or 8½x14"--$.85 first page, $.15 per page for each additional page. Larger material will be provided at cost.

APPLICATION FORMS

TELEPHONE & ELECTRIC
- Application for a sale, transfer or merger

ELECTRIC UTILITIES
- Electric utility application to amend certificated service area boundaries
- Application of electric utility for a certificate of convenience and necessity for proposed transmission lines and associated substations
- Application of electric utility for a certificate of convenience and necessity for proposed generating station/unit (coal fired)
- Rate filing package, Class A & B
- Rate filing package, Class C & D (electric & telephone)

TELEPHONE UTILITIES
- Application for a non-optional service upgrade with no change in existing rates
- Telephone utility application to amend a certificate of convenience and necessity
- Rate filing package, Class A & B
- Rate filing package, Class C & D (telephone & electric)

PUBLICATIONS

- Public Utility Regulatory Act ($7.50 plus tax)
- Rules of Practice and Procedure ($7.50 plus tax)
- Substantive Rules Subscription ($25.00 plus tax)
- Electric Utilities in Texas ($5.00 plus tax)
- Telephone Utilities in Texas ($5.00 plus tax)
- PUC Bulletin ($50.00 plus tax)
- News Release Subscription ($30.00 plus tax)
- PUC Digest ($75.00 plus tax, plus $3.00 shipping for mail orders)
- Public Utility Commission Annual Report ($5.00 plus tax)

MAPS

- PUC Electric service area map by COUNTY, 36" x 50" blueline copy* ($3.00 plus tax)
- PUC Telephone service area map by COUNTY, 36" x 50" blueline copy* ($3.00 plus tax)
- PUC "State of Texas" Electric service area map, 39" offset copy ($15.00 ea., plus tax)
- PUC "State of Texas" Telephone service area map, 6' x 6' color copy ($50.00 set, plus tax)
- PUC "Texas Bulk Transmission System Map", 230kv and above, 30" blueline copy ($5.00 plus tax)
- PUC "State of Texas" Telephone LATA boundary map, 36" blueline copy ($3.00 plus tax)

* County maps are sold on a per sheet basis, in some cases some counties require two or more sheets.

The PUC BULLETIN is a monthly publication of the Public Utility Commission of Texas. Subscription requests should be accompanied by payment made out to the Public Utility Commission and sent to: Public Utility Commission; Central Records--Publication Sales; 7800 Shoal Creek Boulevard, Suite 400N; Austin, Texas 78757. Subscription rate is $50.00 per year plus tax.

PETITION OF TRI-COUNTY TELEPHONE COMPANY TO IMPLEMENT MANDATORY SERVICE UPGRADE, UNBUNDLE SERVICE CONNECTION CHARGES, DETARIFF CPE AND INSIDE WIRE	**§ § § § §**	**DOCKET NO. 7598**

February 17, 1988

Commission approved stipulation addressing local exchange carrier's omnibus application.

[1] RATEMAKING--RATE DESIGN--REFUNDS, CREDITS AND SURCHARGES

Commission did not exercise its discretion to require a local exchange carrier to refund unlisted number charges collected for several years without tariff authorization because: (1) the local exchange carrier's omission of the rate from the tariff was inadvertent; (2) the local exchange carrier did not willfully violate PURA in assessing the unlawful charge; (3) the cost of refunding the unlawfully collected amounts could easily exceed the total cost of accomplishing the refund; (4) the issue of unlawful collection arose incidentally in the docket, as opposed to the result of a customer complaint in which a refund was sought; and (5) the stipulation entered into by the parties did not provide for the entry of a refund order. (p. 1989)

Public Utility Commission of Texas
7800 Shoal Creek Boulevard · Suite 400N
Austin, Texas 78757 · 512/458-0100

Dennis L. Thomas
Chairman

Jo Campbell
Commissioner

Marta Greytok
Commissioner

February 2, 1988

TO ALL PARTIES OF RECORD

Re: Docket No. 7598--Application of Tri-County Telephone Company to Implement Mandatory Service Upgrade, Unbundle Service Conection Charges, and Detariff CPE and Inside Wire

Ladies and Gentlemen:

Enclosed is a copy of my Examiner's Report and proposed final Order in the above referenced docket. The Commission will consider this case at an open meeting scheduled to begin at 9:00 a.m. on Wednesday, February 17, 1988, at the Commission offices at 7800 Shoal Creek Boulevard, Austin, Texas. Exceptions to the Examiner's Report, if any, must be filed in writing by February 8, 1988. Replies to those exceptions must be filed in writing by Friday, February 12, 1988.

Pursuant to Commission Procedural Rule 21.143, requests for oral argument must be made in writing, filed with the Commission, and served on all parties by 5:00 p.m., February 10, 1988 (the fourth scheduled working day preceding the Final Order Meeting). If all parties are present at the final order meeting, this requirement may be waived and oral argument heard at the Commissioners' discretion.

<u>Summary of Examiner's Report</u>

On July 17, 1987, Tri-County Telephone Company (Tri-County) filed an omnibus application to implement a mandatory service upgrade of all customers to one-party service; unbundle service connection charges; detariff customer premises equipment and inside wiring; implement charges for custom calling services, returned checks, and unlisted numbers; eliminate certain tariff offerings; and implement a revised tariff format. All disputed issues were resolved by stipulation of Tri-County and the staff, which were the only parties to the case. The stipulation, which is based on the staff recommendations, provides for approval of the filing on condition that Tri-County's currently tariffed Joint User Service is not eliminated, as had been proposed, and provided further that certain errors in the revised tariff noted by the staff during their review of the filing are corrected. The most significant aspect of this filing is Tri-County's request for authority to implement a mandatory upgrade of all party-line customers to one-party service. The service upgrade is necessary in order for Tri-County to comply with the pre-conditions attached to a loan from the Rural Electrification Administration which Tri-County has secured for the purpose of rebuilding its outside plant facilities and installing a digital central office switch. Under the proposal, customers will pay monthly rates of $5.60 for one-party residential service and $11.35 for one-party business service. I have recommended approval of the stipulation.

Sincerely,

Mark W. Smith
Administrative Law Judge

lsw

DOCKET NO. 7598

APPLICATION OF TRI-COUNTY TELEPHONE COMPANY TO IMPLEMENT MANDATORY SERVICE UPGRADE, UNBUNDLE SERVICE CONNECTION CHARGES, DETARIFF CPE AND INSIDE WIRE	§	PUBLIC UTILITY COMMISSION OF TEXAS

EXAMINER'S REPORT

I. Procedural History

On July 17, 1987, Tri-County Telephone Company, Inc. (Tri-County) filed an application to implement a mandatory service upgrade, unbundle; service connection charges; detariff customer premises equipment and inside wiring; implement charges for custom calling services, returned checks and unlisted telephone numbers; and effect miscellaneous tariff revisions.

By examiner's order issued on July 27, 1987, implementation of the proposed tariff revisions was suspended from the requested effective date of August 21, 1987 until January 18, 1988, pursuant to Section 43(d) of the Public Utility Regulatory Act (the Act), Tex. Rev. Civ. Stat. Ann. art. 1446c (Vernon Supp. 1987). Tri-County subsequently extended the August 21, 1987 effective date of the tariff filing from August 21, 1987, to September 20, 1987, in consideration of a postponement of the scheduled hearing date, and accordingly, implementation of the tariff revisions was again suspended until February 17, 1988, by examiner's order dated October 22, 1987.

On November 12, 1987, Tri-County filed an affidavit reflecting that individual notice of the proposed tariff changes was provided to each of its customers by billing insert, and a publisher's affidavit reflecting publication of notice of the proposed tariff changes once a week for four consecutive weeks, commencing on September 3, 1987, in the Garrison News, in compliance with the requirements of P.U.C. PROC. R. 21.22(b)(1) and (2).

On November 10, 1987, the Commission's general counsel filed a memorandum from staff telephone analyst David Featherston setting forth the staff's recommendations regarding Tri-County's tariff filing, together with a written stipulation executed by staff attorney Pam Mabry and Tri-County representative Charles D. Land requesting Commission approval of Tri-County's application as modified by the recommendations contained in Mr. Featherson's memorandum.

No protests, motions to intervene or requests for hearing were filed in this proceeding. Based upon receipt of the written stipulation between Tri-County and general counsel resolving all contested issues of fact and law raised by Tri-County's filing, the undersigned examiner issued an order on November 16, 1987, cancelling the previously scheduled hearing on the merits and advising the parties that the application would be processed administratively based upon the pleadings, staff memorandum and stipulation, pursuant to Section 13(e) of the Administrative Procedure and Texas Register Act, Tex. Rev. Civ. Stat. Ann. art. 6252-13a (Vernon Supp. 1987).

The Commission has jurisdiction over the matters raised by Tri-County's application pursuant to Sections 16(a), 18(b), and 37 of the Act.

II. Discussion and Opinion

This docket involves an omnibus application by Tri-County for Commission approval of the following:

1. Upgrading of all party-line service to one-party service and elimination of monthly mileage charges for service outside of the base rate area;

2. Unbundling of service connection charges and elimination of monthly charges for extension wiring;

3. Detariffing of multi-line customer premises equipment (CPE) and elimination of embedded single-line CPE;

4. Detariffing of installation and maintenance of inside wire and jacks;

5. Elimination of certain tariffed services which are no longer being provided to customers;

6. Establishment of a new tariff format and revision of the text of the tariff to comply with current Commission rules;

7. Implementation of rates for custom calling services;

8. Implementation of a returned check charge; and

9. Implementation of a monthly charge for unlisted numbers.

Staff witness David Featherston filed a lengthy memorandum recommending approval of Tri-County's application, with minor modifications, and the Commission's general counsel has entered into a written stipulation with Tri-County which urges approval of the filing with the modifications specified in Mr. Featherston's memorandum. A discussion of the proposed tariff changes and Mr. Featherston's recommendation with respect to each follows.

A. <u>Non-Optional Service Upgrade</u>

Tri-County proposes to implement a non-optional service upgrade to one-party service for all party-line customers, and to eliminate all mileage charges currently applicable to one-party and two-party service provided outside of the Garrison exchange base rate area. According to Tri-County witness Charles Land, elimination of party-line service and of mileage charges applicable to service provided outside of the base rate area were preconditions to obtaining a $2,100,000 loan from the Rural Electrification Administration (REA). The loan is being utilized by Tri-County to rebuild its outside plant, construct new central office facilities and install a digital central office switch. Tri-County's capital improvements program was undertaken because its outside plant facilities were in extremely poor condition, the existing central office building was structurally unsound, and demand for service exceeded the capacity of the existing electromechanical central office switch. Many of Tri-County's customers were precluded from obtaining one-party service because of the lack of sufficient system capacity.

Tri-County's current rates, net of a $0.65 credit allowed for customer provided stations, and the rates for one-party service proposed by this filing, are as follows:

Class	Current Rate	Proposed Rate
R-1	$5.60	$5.60
R-2	4.85	-
R-4	4.35	-
R-8	4.95	-
B-1	11.35	11.35
B-2	8.60	-
B-4	6.85	-
B-8	6.85	-

According to Tri-County, the elimination of mileage charges currently applicable to one-party and two-party residence and business customers located outside of the base rate area will affect 54 customers and will result in an average rate decrease for those customers of $8.39 per month.

According to Mr. Featherston, the service upgrade requested by Tri-County will permit Automatic Number Identification (ANI), which is essential to the provision of accurate toll billing and 911 emergency service.

Mr. Featherston has recommended approval of the non-optional service upgrade and the elimination of mileage charges as requested by Tri-County. However, because his recommendation is based in part upon the fact that the requested changes are preconditions to Tri-County's REA loan, Mr. Featherston has urged that approval of the non-optional upgrade in this proceeding be given no precedential value in future cases.

B. Unbundling of Service Connection Charges

Tri-County proposes to eliminate recurring rates for extension wiring and to unbundle service connections charges. The current extension wiring charges are $2.00 per month for residence extensions and $3.00 per month for business extensions. The present bundled service charges are $20 for installation of residential access lines and $25 for installation of business access lines.

Tri-County conducted a cost study based on the loaded labor rate of the emloyees performing the service order functions. In order to make this filing revenue neutral, the proposed rates were fixed at only 55 percent of the service connection costs calculated in the cost study. The proposed unbundled rates are $16.50 for primary service orders, $7.50 for secondary service orders, and $9.00 for access line connections.

According to Mr. Featherston, the methodology utilized by Tri-County to develop the unbundled service charge elements is reasonable and consistent with established precedent. Mr. Featherston believes that the pricing of service connection charges below actual cost in the manner proposed by Tri-County will minimize the customer impact associated with unbundling. Mr. Featherston has recommended approval of the unbundled service connection charges proposed by Tri-County.

C. Detariffing of CPE

Tri-County proposes to detariff all CPE consistent with the requirements of P.U.C. SUBST. R. 23.68. Although the filing reflects the Company's intention to offer its embedded multi-line CPE for sale in place, Tri-County proposes to recall all of its single-line CPE rather than conduct a sale in place program for that equipment. The recall of single-line CPE is necessary because most of the telephones have frequency ringers, which, although required for party-line service, are not compatible with the new all one-party system. According to Tri-County, the cost of modifying the current telephones would be at least $16 per telephone, which exceeds the current value of the equipment. As a consequence of the recall, customers will be offered the choice of leasing new telephones from the Company, or of purchasing new telephones from Tri-County or other vendors. The Company has agreed to modularize the jacks of each customer free of charge, in order to aid in the transition to all one-party service.

Mr. Featherston concurs with Tri-County's proposal to detariff multi-line CPE and eliminate all embedded single-line CPE.

D. Detariffing of Inside Wiring

Tri-County proposes to detariff the installation and maintenance of inside wire pursuant to the order of the Federal Communications Commission in Docket No. 79-105. The detariffing will be accomplished by removing all references to the installation and maintenance of inside wire from the current tariff. Mr. Featherston concurs with the cooperative's request to detariff inside wire.

E. Deletion of Services

Tri-County has proposed to eliminate a number of services from its current tariff. Most of the services are CPE-related and are being deleted as a consequence of the detariffing of CPE. Mr. Featherston supports the proposed service deletions with the exception of joint user service. According to Mr. Featherston, the staff opposes elimination of joint user service because that action would limit the alternatives available to the Commission if a shared tenant services provider applied for service in Tri-County's area. Pursuant to the stipulation in this docket, Tri-County has acquiesced in Mr. Featherston's recommendation and has filed revised tariff pages to include joint user service in the revised tariff.

F. New Tariff Format

The Company has proposed to implement a new tariff format which completely overhauls the existing tariff. The organization of the proposed tariff is clearly superior to Tri-County's existing tariff, and the text of the tariff has been updated to bring it into full compliance with current Commission substantive rules. It appears from Mr. Featherston's memorandum that the new tariff format, as originally filed, contained a number of errors. However, the Company filed a corrected version of the tariff on November 9, 1987, which eliminates each of the errors noted by the staff. Mr. Featherston has recommended that the corrected version of the proposed tariff, as filed on November 9, 1987, be approved by the Commission.

G. Custom Calling Features

The new digital central office switch being installed by Tri-County will enable it to offer custom calling services. When the new switch is put into service, Tri-County proposes to offer Call Waiting, Call Forwarding and Three Way Calling at a rate of $2.50 per month per feature or $6.50 per month for the three feature package. Additionally, Tri-County proposes to offer 8 Code Speed Calling for $2.50 per month and 30 Code Speed Calling for $3.50 per month. Although there are no discernable costs for these services, custom calling services have traditionally been offered at rates substantially above cost in order to generate additional contribution toward local exchange service costs. The rates for custom calling features proposed by Tri-County are approximately the same as those charged by other telephone companies. Mr. Featherston has recommended approval of the proposed custom calling services and rates as filed.

H. Returned Check Charge

Tri-County has requested authority to implement a $15 charge for returned checks. Tri-County conducted a study which revealed that the Company's service order clerk spends an estimated two hours processing and collecting each returned check. Based upon an hourly rate of $7.82, Tri-County found the cost to process and collect a check to be $15.64. Mr. Featherston has reviewed Tri-County's study and has concluded that a $15 returned check charge is appropriate. Accordingly, Mr. Featherston has recommended that Tri-County be permitted to implement a $15 returned check charge.

I. Unlisted Number Charge

Tri-County has requested authority to implement a charge of $1 per month for unlisted numbers. According to Tri-County, a monthly charge for unlisted numbers is charged by most telephone companies and is warranted in order to recover the added costs of special procedures and precautions which must be developed and followed to insure that the unlisted number is not accidentally released. Additionally, Tri-County notes that added costs are incurred in handling complaints and calls from customers that want to obtain an unlisted number. Further, the charge serves to discourage large numbers of customers from requesting unlisted numbers. Tri-County did not conduct a cost study of this particular service because it did not believe that the cost of conducting a precise cost study was justified given the very limited number of customers expected to purchase the service. The proposed rate is based upon the rates for unlisted numbers charged by other small telephone companies, which range from $.050 to $1.00 per month. Mr. Featherston has reviewed and recommended approval of the proposal to implement a recurring charge for unlisted numbers.

[1] The examiner would note that, although Tri-County's tariff does not presently authorize the collection of a recurring charge for the provision of unlisted numbers, the testimony of Company representative Land reflects that the Company has in fact been assessing the charge requested in this docket for many years. According to Mr. Land, the charge should have been included in the Company's tariff when it was first filed with the Commission in 1976, and the present filing is intended to correct that error. Mr. Land's testimony clearly gives rise to the question of whether the Commission should require the refund of all charges for unlisted number service collected by Tri-County from 1976 to present.

Although the entry of a refund order is unquestionably a Commission prerogative in this docket, the examiner does not recommend that such action be taken for the following reasons. First, where a rate has been unlawfully collected, PURA apparently leaves it to the Commission's discretion to determine the appropriate remedy; thus, PURA does not mandate a refund in this case. Second, it appears that the omission from the tariff of the charge for unlisted numbers was inadvertent and that the Company therefore was not wilfully in violation of Section 31 of PURA by its assessment of the recurring charge. Third, given the small number of customers served by the Company, the total amount of money to be refunded would likely be nominal. The cost of determining the refunds and locating the recipients could easily exceed the total refund amount. Fourth, the issue has risen incidentally in this case and not as the result of a customer complaint; thus, no one is seeking--or recommending--a refund. Fifth, the stipulation entered in this docket does not provide for a refund. General counsel has presumably weighed the equities involved based on the record and nonrecord facts of which staff may be aware and determined that a refund order is in this instance inappropriate. In the event that general counsel's execution of the stipulation does not evidence a substantive evaluation that a refund is considered by the staff to be inappropriate, the examiner submits that approval of the company's filing in this docket will not preclude general counsel from pursuing the issue in a separate proceeding should it believe such action to be warranted.

J. Conclusion

Based upon review of the Company's filing and the recommendations submitted by Mr. Featherston, the examiner finds the stipulation entered into by Tri-County and general counsel to be reasonable and accordingly recommends its adoption by the Commission.

III. Findings of Fact and Conclusions of Law

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

A. Findings of Fact

1. Tri-County Telephone Company (Tri-County) is a telecommunications utility providing local exchange and other telecommunications services within its certified service area, under Certificate of Convenience and Necessity No. 40085.

2. On July 17, 1987, Tri-County filed an application requesting authority to implement a mandatory service upgrade; unbundle service connection charges; detariff CPE and inside wiring; implement charges for custom calling services, returned checks and unlisted numbers; and effect miscellaneous tariff revisions.

3. Operation of the proposed tariff revisions has been suspended until February 17, 1988, or superseding Commission order pursuant to Section 43(d) of the Act.

4. Tri-County provided notice of this application to its customers by means of billing inserts and by publication once each week for four consecutive weeks in the Garrison News.

5. No protests or motions to intervene have been filed with the Commission in connection with this proceeding.

6. Implementation of a non-optional service upgrade to one-party service and elimination of all mileage charges currently applicable to one-party and two-party service provided outside of the Garrison exchange base rate area is necessary in order to satisfy the preconditions specified in the loan agreement between Tri-County and REA.

7. The elimination of mileage charges applicable to one-party and two-party residence and business customers located outside of the base rate area will affect 54 customers and will result in an average rate decrease for those customers of $8.39 per month.

8. The mandatory service upgrade will permit Automatic Number Identification (ANI), which is essential to the provision of accurate toll billing and 911 emergency service.

9. The proposal to implement a non-optional service upgrade and eliminate mileage charges is reasonable and should be approved, but should not constitute precedent for approval of similar requests in future rate cases.

10. Tri-County proposes to eliminate current extension wiring charges and to implement unbundled service connection charges of $16.50 for primary service orders, $7.50 for secondary service orders, and $9.00 for access line connections.

11. The methodology utilized by Tri-County to develop the unbundled service charge elements and rates is reasonable and consistent with established precedent.

12. The unbundled service charge elements and rates proposed by Tri-County should be approved, as should the request to eliminate extension wiring charges.

13. The recall of single-line CPE, as proposed by Tri-County, is necessary because most of the telephones currently in use are not compatible with a one-party system and the cost of modifying the telephones would exceed the current value of the equipment.

14. Tri-County's proposal to detariff CPE and recall its single-line CPE is reasonable and should be approved.

15. Detariffing of the installation and maintenance of inside wiring is necessary in order to bring Tri-County into compliance with the FCC's order in Docket No. 79-105. Accordingly, Tri-County's request to detariff the installation and maintenance of inside wiring is reasonable and should be approved.

16. Tri-County should not be permitted to eliminate its joint user service offering because that action would limit the alternatives available to the Commission if a shared tenant services provider applied for service in Tri-County's service area.

17. Tri-County's proposal to eliminate the services enumerated in Schedules 3 and 4 of the prefiled testimony of Mr. Land should be approved, with the exception of joint user service, because the company no longer desires to provide the services, no customers currently subscribe to the services and the services are in most instances CPE-related service which should be eliminated as a consequence of the detariffing of CPE.

18. The new tariff format proposed by Tri-County is better organized than Tri-County's current tariff and the revised text of the tariff complies with the Commission's current substantive rules.

19. Tri-County's proposed tariff format, as revised on November 9, 1987, should be approved.

20. The rates proposed by Tri-County for custom calling services are not cost-based but they are approximately the same as those charged by other telephone companies.

21. Tri-County's proposal to implement a new service offering for custom calling services should be approved at the rates proposed by Tri-County, since the services will generate additional contribution toward local exchange service costs.

22. Implementation of a $15 returned check charge is reasonable and appropriate because it places the cost of returned checks on the cost causer and the charge level is fully supported by a cost study performed by Tri-County.

23. Implementation of a recurring charge for unlisted numbers is warranted in order to recover the added costs of special procedures and precautions which must be developed and followed to provide the service, and to recover the costs incurred in handling complaints and calls from customers that want to obtain an unlisted number.

24. A monthly charge of $1.00 for unlisted numbers, as proposed by Tri-County, is reasonable based upon the rates for unlisted numbers charged by other small telephone companies.

25. Although Tri-County has been assessing an untariffed charge for unlisted numbers for a number of years, entry of a refund order is inappropriate in this docket because omission of the rate from the current tariff was inadvertent, the collection of an untariffed rate in violation of the act was not wilfull, the amount to be refunded is likely nominal in comparison to the cost of accomplishing a refund, and the stipulation does not provide for the entry of a refund order in this docket.

26. The stipulation executed by Tri-County and general counsel, which provides for approval of Tri-County's application as modified by the recommendations contained in Mr. Featherston's memorandum dated November 10, 1987, is reasonable and should be approved.

B. Conclusions of Law

1. Tri-County is a public utility as defined by Section 3(C)(2)(A) of the Act.

2. The Commission has authority and jurisdiction in this case pursuant to Sections 16(a), 18(b) and 37 of the Act.

3. Tri-County provided notice of its application in compliance with the requirements of Section 43(a) of the Act and P.U.C. PROC. R. 21.22(b).

4. Pursuant to P.U.C. PROC. R. 21.69(d), Tri-County has shown good cause for an exception to the requirement of submitting a full rate filing package.

5. Approval of Tri-County's request to detariff CPE and inside wiring is non-discretionary, as denial of the request would conflict with the rulings of the FCC in Docket No. 79-105, in contravention of Section 37 of the Act.

6. Tri-County's proposed unbundled service connection rates and its proposed charges for custom calling services, returned checks and unlisted numbers are just and reasonable, not unreasonably preferential, prejudicial, or discriminatory, and are sufficient, equitable and consistent in application to each class of customers within the meaning of Section 38 of the Act.

7. Tri-County has met its burden of proof under Section 40 of the Act with respect to the proposed changes in its tariff; therefore, the proposed tariff changes, as modified by the stipulation of the parties, should be approved.

Respectfully submitted,

Mark W. Smith

MARK W. SMITH
ADMINISTRATIVE LAW JUDGE

APPROVED on this the 1st day of February 1988.

Phillip A. Holder

PHILLIP A. HOLDER
DIRECTOR OF HEARINGS

lsw

DOCKET NO. 7598

APPLICATION OF TRI-COUNTY TELEPHONE COMPANY TO IMPLEMENT MANDATORY SERVICE UPGRADE, UNBUNDLE SERVICE CONNECTION CHARGES, DETARIFF CPE AND INSIDE WIRE	§	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 an administrative law judge 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 Tri-County Telephone Company is APPROVED to the extent recommended in the Examiner's Report, and as set forth in the agreed stipulation of the parties.

2. The proposed tariff sheets submitted with Tri-County Telephone Company's application, as corrected by subsequent filing dated November 9, 1987, are APPROVED effective the date of this Order.

3. The detariffing of inside wiring is retroactive to January 1, 1987.

4. The Commission's order in this case is based in part upon a stipulation which was reached by negotiations among the parties to this case. However, the Commission has not and should not be deemed to have endorsed, accepted, agreed to, or approved any underlying methodologies which may provide the basis for the stipulation. The results of the stipulation are found to be reasonable, and the Commission has adopted it 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 stipulation, and the Commission reserves the right to scrutinize more closely any and all such theories and methodologies in future cases.

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

SIGNED AT AUSTIN, TEXAS on this the 17th day of February 1988.

PUBLIC UTILITY COMMISSION OF TEXAS

SIGNED: Dennis L. Thomas
DENNIS L. THOMAS

SIGNED: Jo Campbell
JO CAMPBELL

SIGNED: Marta Greytok
MARTA GREYTOK

ATTEST:

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

lsw

REPORT OF ACQUISITION OF § **DOCKET NO. 8632**
CP NATIONAL CORPORATION BY §
ALLTEL CORPORATION §

June 6, 1990

Commission found the merger of ALLTEL Corporation, which wholly owns ALLTEL Texas, a Texas public utility, and CP National, which owns through its various wholly owned subsidiaries, three Texas telephone operating companies, to be in the public interest.

[1] SALE OF PROPERTY AND MERGERS--MERGERS/CONSOLIDATIONS

In docket involving complex issue of the applicability of PURA §63 to transactions in which the regulated public utility is several tiers removed from the parent company, the Commission determined that the parent corporations which merged were public utilities under PURA §3(c) and the transaction was therefore governed by Section 63. (p. 2001)

Public Utility Commission of Texas
7800 Shoal Creek Boulevard · Suite 400N
Austin, Texas 78757 · 512/458-0100

May 3, 1990

TO: ALL PARTIES OF RECORD

RE: Docket No. 8632 -- Report of Acquisition of CP National Corporation by ALLTEL Corporation

Ladies and Gentlemen:

Enclosed is a copy of my Examiner's Report and Proposed Final Order in the above referenced docket. The Commission will consider this case in an open meeting scheduled to begin at 9:00 a.m. on Wednesday, June 6, 1990, at the Commission offices at 7800 Shoal Creek Boulevard, Austin, Texas. Pursuant to P.U.C. PROC. R. 21.142, exceptions if any, to the Examiner's Report must be filed in writing by noon, Monday, May 21, 1990. Replies, if any, to the exceptions must be filed in writing by noon, Monday, May 28, 1990. Please submit an original plus 15 copies of exceptions and replies.

Pursuant to P.U.C. PROC. R. 21.143, requests for oral argument must be made in writing, filed with the Commission, and served on all parties by 5:00 p.m. the fourth scheduled working day preceding the final order meeting date, or Thursday, May 31, 1990. If a request for oral argument is made, parties may call Ms. Lisa Serrano at 512/458-0266 after 9:00 a.m. on the day before the final order meeting to learn if oral argument will be allowed by the Commissioners. Although you are welcome to attend the final order meeting, you are not required to do so. A copy of the signed final order will be sent to you shortly thereafter.

<u>Summary of Examiner's Report</u>

There is no jurisdictional deadline in this docket.

On January 24, 1989, ALLTEL Corporation (ALLTEL) filed a report with the Commission disclosing the acquisition of CP National Corporation (CP National) by ALLTEL. ALLTEL exchanged 1.15 shares of its common stock for each share of common stock of CP National. The Commission staff reviewed the filing and determined that the merger of ALLTEL and CP National would have no adverse effect on the Texas public utilities that are subsidiaries of ALLTEL. Accordingly, the examiner recommends that the Commission find that the merger of ALLTEL and CP National is in the public interest.

Sincerely,

Joyce M. Phoenix

for J. Kay Trostle
Adminiatrative Law Judge

/tlg

DOCKET NO. 8632

REPORT OF ACQUISITION OF CP NATIONAL CORPORATION BY ALLTEL CORPORATION	§ §	PUBLIC UTILITY COMMISSION OF TEXAS

EXAMINER'S REPORT

I. Procedural History

On January 24, 1989, ALLTEL Corporation (ALLTEL) filed a report with the Commission pursuant to Section 63 of Public Utility Regulatory Act (PURA), Tex. Rev. Civ. Stat. Ann. art. 1446c (Vernon Supp. 1990) disclosing the acquisition of CP National Corporation (CP National) by ALLTEL effective December 30, 1988. The acquisition was effected through the exchange of 1.15 shares of ALLTEL's common stock for each share of common stock of CP National. ALLTEL is presently the sole owner of all of the capital stock of CP National, which is a "first generation" subsidiary of ALLTEL. A first generation subsidiary is a corporation whose immediate owner is the parent corporation of a group of companies.

ALLTEL is a corporation organized and existing according to the laws of the State of Ohio with its principal office in Hudson, Ohio. ALLTEL Texas, Inc. (ALLTEL Texas) is a wholly owned, "first generation" subsidiary of ALLTEL. ALLTEL Texas is incorporated pursuant to the laws of the State of Texas and is authorized by the Commission to provide telephone service to the public. ALLTEL Texas holds a Certificate of Convenience and Necessity (CCN) No. 40062.

On January 30, 1989, CP National sent a letter notifying the members of the Public Utility Commission that ALLTEL and CP National merged on December 30, 1988. CP National is a California corporation, with its principal office in San Francisco, California. Among its various, wholly owned subsidiaries is Teleco Holdings, Incorporated (Teleco), a Delaware corporation. Teleco wholly owns Great Southwest Telephone Corporation (Great Southwest), an operating telephone company incorporated in Texas and authorized by the Commission to provide telephone service to the public. Great Southwest wholly owns the following operating telephone companies which are incorporated pursuant to the laws of the State of Texas and authorized by the Commission to provide telephone service to the public in Texas: Romain Telephone Company, Inc. (Romain), CCN No. 40072; Texas-Midland Telephone Company (Texas-Midland), CCN No. 40084; and Trinity Valley Telephone Company (Trinity Valley), CCN No. 40086. CP National controls these telephone companies through the exercise of its 100 percent ownership of Teleco.

According to ALLTEL, no shares of capital stock of ALLTEL Texas , Great Southwest, or any of the previously mentioned telephone companies were exchanged, transferred, sold, or pledged, nor were any of their assets or any part of their franchises or facilities sold or pledged to effect the acquisition. Further, neither ALLTEL Texas , Great Southwest, nor any of the operating telephone subsidiaries have lost their separate corporate status as a result of the acquisition; there are no current plans to merge ALLTEL Texas with Great Southwest or any of its operating telephone subsidiaries. Based on the foregoing information, it was the opinion of ALLTEL that neither Section 63 nor any other section of PURA applied to ALLTEL's acquisition of CP National.

In Examiner's Order No. 1, the general counsel was directed to file an opinion as to whether the transaction required a public interest finding by the Commission pursuant to Section 63 of PURA. In its response to Examiner's Order No. 1 filed on February 21, 1989, the general counsel stated that it was his opinion that the Commission must make a public interest finding within the context of a Section 63 proceeding.

In Examiner's Order No. 2, the general counsel was directed to file an opinion as to whether Section 63 of PURA is applicable to this transaction. On March 14, 1989, the general counsel filed a response to Examiner's Order No. 2 and stated that the transaction between ALLTEL and CP National was a transaction involving the sale of 50 percent or more of the stock of a public utility. Therefore, the general counsel was of the opinion that Section 63 is applicable to this transaction.

On September 12, 1989, the general counsel filed a memorandum recommending approval of ALLTEL's application.

II. Discussion and Recommendation

[1] This docket involves the complex issue of the applicability of Section 63 to transactions in which the regulated public utility is several tiers removed from the parent company. In this instance, ALLTEL, which owns ALLTEL Texas (a Texas public utility), merged with CP National, which owns Teleco, which owns Great Southwest, which owns Romain, Texas-Midland, and Trinity Valley (all three Texas public utilities). The threshold issue in this docket is whether the Commission has jurisdiction over this transaction pursuant to Section 63 of PURA. It is the examiner's opinion that the Commission has such jurisdiction.

Section 3(c)(2)(A) of PURA defines "public utility" as " . . . any person, corporation . . . now or hereafter owning or operating for compensation in this state equipment or facilities for . . . the conveyance, transmission, or reception of communications over a telephone system as a dominant carrier . . . ." "Dominant carrier" is defined in Section 3(c)(2)(B) of PURA as ". . . any provider of local exchange telephone service within a certificated exchange area as to such service . . . ." Therefore, although ALLTEL is an Ohio corporation and CP National is a California corporation, both corporations are considered public utilities under PURA due to their ownership of telecommunications utilities within the State of Texas, and as such, are subject to the jurisdiction of this Commission pursuant to Section 16(a) of PURA.

Section 63 of PURA states that, "No public utility may sell, acquire, lease, or rent any plant as an operating unit or system in this state . . . or merge or consolidate with another public utility operating in this state unless the public utility reports such transaction to the commission within a reasonable time . . . ." Thus, Section 63 places an affirmative duty on a public utility to report certain specified transactions to the Commission.

In the instant case, Romain, Texas-Midland, and Trinity Valley are several tiers below the parent company CP National, and are in fact wholly owned by Great Southwest. However, ALLTEL states in its report that CP National controls Great Southwest through the exercise of its 100 percent ownership of Teleco. Therefore, CP National ultimately controls Romain, Texas-Midland, and Trinity Valley and, since the merger, ALLTEL now controls CP National and its lower-tiered subsidiaries.

Accordingly, ALLTEL and CP National are public utilities pursuant to Section 3(c) of PURA. As public utilities, their merger brings them within the ambit of Section 63 of PURA. The evidence does not support, and the examiner rejects, ALLTEL's assertion that the Commission lacks jurisdiction over this transaction. The transaction was properly reported to the Commission and is properly the subject of Commission scrutiny.

Section 63 also places on the utility a duty to report the transaction within a "reasonable time." However, the statute does not define what is a reasonable time. In this instance, the merger transpired on December 30, 1988. ALLTEL reported the transaction in January 1989, less than one month after the transaction. It is the examiner's opinion that the transaction was reported within a reasonable time, pursuant to the statute.

The next issue is whether the transaction is in the public interest. Section 63 of PURA states the following: ". . . On the filing of a report with the commission, the commission shall investigate the same with or without public hearing, to determine whether the action is consistent with the public interest." The Commission staff evaluated ALLTEL's application to determine whether the merger would adversely affect the ratepayers of Romain, Texas-Midland, or Trinity Valley. In making this determination, the staff considered four factors: 1) the methodology used to account for the transaction; 2) the immediate impact on the ratepayers of the affected companies; 3) the affected companies' access to capital as a result of the merger; and 4) how the investment community viewed the merger.

The first factor considered by the staff was the methodology used by ALLTEL to account for the transaction. ALLTEL used the pooling-of-interests method to account for the merger in this docket. In response to questions propounded by the examiner, the staff discussed the pooling-of-interests methodology and the criteria which must be met before a transaction may be accounted for using the pooling-of-interests method.

In the pooling-of-interests method, no resources are exchanged between the combining companies. The combination is effected by exchanges of shares among the shareholders. The booked assets and liabilities of the combining companies are added together to form the books of the combined company. Thus, neither goodwill nor a plant acquisition adjustment will be created as a result of a business combination accounted for under the pooling-of-interests method. A pooling-of-interests presumes that the ownership interests of the combining companies continue essentially unchanged in the new combined enterprise. Generally Accepted Accounting Principles (GAAP) require the use of the pooling-of-interests method if applicable.

The Accounting Principles Board (APB) was formed in 1959 with the responsibility of formulating accounting principles related to financial reporting. APB opinions are rules for recording financial transactions. The APB was replaced by the Financial Accounting Standards Board (FASB) in 1972.

APB No. 16 establishes twelve criteria that must be met before a combination may be accounted for as a pooling-of-interests. The criteria are listed in paragraphs 45 through 48 of APB No. 16, and are as follows:

1. Each of the combining companies is autonomous and has not been a subsidiary or division of another corporation within two years before the plan of combination is initiated.

2. Each of the combining companies is independent of the other combining companies. (Not more than 10% ownership)

3. The combination must be effected in a single transaction or is completed in accordance with a specific plan within one year after the plan is initiated.

4. A company offers and issues only common stock with rights identical to those of the majority of its outstanding voting common stock in exchange for substantially all of the voting common stock interest of another company at the date the plan of combination is consummated.

5. None of the combining companies changes the equity interest of the voting common stock in contemplation of effecting the combination either within two years before the plan of combination is initiated or between the dates the combination is initiated and consummated; changes in contemplation of effecting the combination may include distributions to stockholders and additional issuances, exchanges, and retirements of securities.

6. Each of the combining companies reacquires shares of voting common stock only for purposes other than business combinations, and no company reacquires more than a normal number of shares between the dates the plan of combination is initiated and consummated.

7. The ratio interest of individual common stockholders to those of other common stockholders in a combining company remains the same as a result of the exchange of stock to effect the combination.

8. The voting rights to which the common stock ownership interests in the resulting combined corporation are entitled are exercisable by the stockholders; the stockholders are neither deprived of nor restricted in exercising those rights for a period.

9. The combination is resolved at the date the plan is consummated and no provisions of the plan relating to the issue of securities or other consideration are pending.

10. The combined company does not agree directly or indirectly to retire or reacquire all or part of the common stock issued to effect the combination.

11. The combined company does not enter into other financial arrangements for the benefit of the former stockholders of a combining company, such as a guaranty of loans secured by stock issued in the combination, which in effect negates the exchange of equity securities.

12. The combined company does not intend or plan to dispose of a significant part of the assets of the combining companies within two years after the combination other than disposals in the ordinary course of business of the formerly separate companies and to eliminate duplicate facilities or excess capacity.

The staff indicated that Coopers and Lybrand, a Big-Eight accounting firm, audited the 1988 financial statements of ALLTEL and CP National. Coopers and Lybrand determined that the pooling-of-interests method was proper for this merger. Further, in response to staff inquiries, ALLTEL confirmed that neither goodwill nor a plant acquisition adjustment was recorded on its books to account for the merger. The examiner agrees with the staff that ALLTEL properly used the pooling-of-interests method to account for the merger of ALLTEL and CP National.

The second factor considered by the staff in reviewing this application was the immediate impact of the merger on the rate payers of Romain, Texas-Midland, and Trinity Valley. In response to the general counsel's requests for information (RFIs), ALLTEL stated that there were no plans for a rate increase for Romain, Texas-Midland or Trinity Valley. Indeed, the financial indicators for all three companies are strong. As explained by the staff, one of the primary indicators of financial health is the pretax interest coverage. When a utility company is in weak financial condition, this indicator falls below acceptable levels and a rate increase may be necessary. The pretax interest coverage in 1987 for Romain was 118.4X; for Texas-Midland was 52.2X; and for Trinity Valley was 5.8X. The Texas median in 1987 was 4.78X. Each company's pretax interest coverage ratio compares favorably to the state median. Additionally, in 1988 the pretax interest coverage ratio for Texas-Midland was 60.1X and for Trinity Valley was 6.6X. Romain did not pay interest in 1988. The examiner agrees that the pretax interest coverage ratios indicate that these utilities are in good financial health and support ALLTEL's position that a rate increase is not necessary at this time.

The third factor considered by the staff was how the merger would affect the three telephone companies' access to capital. In response to RFIs propounded by the general counsel, ALLTEL replied that it does not expect any impact on the long-term debt cost of the three companies as a result of the merger. The staff was of the opinion that any new long term debt incurred by Romain, Texas-Midland or Trinity Valley would be at lower rates relative to CP National for three reasons: 1) ALLTEL has a strong capital structure consisting of 50 percent debt and 50 percent equity; 2) ALLTEL has financed all its capital expenditures since 1986 through the internal generation of funds; and 3) ALLTEL has a credit rating of A+. The staff also stated that the companies' cost of money should decrease due to ALLTEL's larger size and greater financial flexibility. The examiner agrees that Romain, Texas-Midland, and Trinity Valley should have greater access to capital as a result of the merger of ALLTEL and CP National.

The last factor considered by the staff is how the investment community viewed the merger. In the staff's opinion, the acquisition of CP National by ALLTEL was viewed in the investment community as a positive step in the continuing growth of the company. ALLTEL reported its best year ever in 1988 with a net income increasing 15 percent to $37 million and earnings per share rising 16 percent to 86 cents per share. Further, an article in the April 17, 1989, issue of Standard and Poor's Creditweek stated that ALLTEL's proven ability to operate profitably should allow the company to continue to grow and maintain its current bond rating of A+. The examiner concurs with the staff's assessment that the merger of ALLTEL and CP National is viewed favorably in the investment community.

Based on the foregoing information, the examiner is of the opinion that the merger of ALLTEL and CP National will have no adverse impact on the ratepayers of the three telephone companies. All considerations from a financial perspective indicate that the ratepayers of Romain, Texas-Midland, and Trinity Valley will benefit from the merger of these two companies. Additionally, the company properly used the pooling-of-interests method to account for the transaction. Accordingly, the examiner recommends a finding by the Commission that the merger of ALLTEL and CP National is in the public interest.

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. ALLTEL Corporation (ALLTEL) acquired CP National Corporation (CP National) on December 30, 1988.

2. The acquisition was effected through the exchange of 1.15 shares of ALLTEL's common stock for each share of common stock of CP National.

3. ALLTEL is the sole owner of all of the capital stock of CP National and CP National is a first generation subsidiary of ALLTEL.

4. ALLTEL is a corporation organized and existing according to the laws of the state of Ohio. ALLTEL Texas , Inc. (ALLTEL Texas) is a wholly owned first generation subsidiary of ALLTEL, incorporated pursuant to the laws of the state of Texas and authorized by the Commission to provide telephone service to the public in Texas. ALLTEL Texas holds Certificate of Convenience and Necessity (CCN) No. 40062.

5. CP National is a corporation organized and existing according to the laws of the state of California. Among its wholly owned subsidiaries are Romain Telephone Company, Inc. (Roman), CCN No. 40072; Texas-Midland Telephone Company (Texas-Midland), CCN No. 40084; and Trinity Valley Telephone Company (Trinity Valley), CCN No. 40086. These three companies are incorporated pursuant to the laws of the state of Texas and are authorized by the Commission to provide telephone service to the public in Texas.

6. This transaction was properly reported to the Commission within a reasonable time.

7. The pooling-of-interests method was properly used to account for this merger. No acquisition adjustment or goodwill was recorded on the books by ALLTEL.

8. This merger will not adversely effect the ratepayers of Romain, Texas-Midland, or Trinity Valley. The financial indicators for all three companies are strong and there are no plans for a rate increase as a result of the merger.

9. Romain, Texas-Midland, and Trinity Valley should have better access to capital at lower rates due to ALLTEL's larger size, strong capital structure, and excellent credit rating.

10. The investment community views the merger of CP National and ALLTEL as positive and ALLTEL continues to grow and prosper.

11. Based on Finding of Fact Nos. 7, 8, 9, and 10 above, the merger of CP National and ALLTEL is reasonable and in the public interest.

B. Conclusions of Law

1. ALLTEL and CP National are public utilities as defined in Section 3(c) of the Public Utility Regulatory Act (PURA), Tex. Rev. Civ. Stat. Ann. art. 1446c (Vernon Supp. 1990).

2. The Commission has jurisdiction over this transaction pursuant to Section 16(a), 18(b), and 63 of PURA.

3. For the reasons stated in Finding of Fact Nos. 7, 8, 9, and 10, the merger of ALLTEL and CP National is reasonable and consistent with the public interest pursuant to Section 63 of PURA.

Respectfully submitted,

J. Kay Trostle

J. KAY TROSTLE
ADMINISTRATIVE LAW JUDGE

APPROVED on this the 6th day of June 1990.

Mary Ross McDonald

MARY ROSS MCDONALD
DIRECTOR OF HEARINGS

/tlg

DOCKET NO. 8632

REPORT OF ACQUISITION OF CP NATIONAL CORPORATION BY ALLTEL CORPORATION	§ §	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, as corrected, is hereby **ADOPTED** and made a part hereof. The Commission further issues the following Order:

1. The merger of CP National Corporation and ALLTEL Corporation is hereby found to be consistent with the public interest.

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 the 7th day of June 1990.

PUBLIC UTILITY COMMISSION OF TEXAS

SIGNED: Jo Campbell
JO CAMPBELL, COMMISSIONER

SIGNED: Marta Greytok
MARTA GREYTOK, COMMISSIONER

SIGNED: Paul D. Meek
PAUL D. MEEK, CHAIRMAN

ATTEST:

Mary Ross McDonald
MARY ROSS MCDONALD
SECRETARY OF THE COMMISSION

/tlg

JOINT FILING FOR APPROVAL OF NON-OPTIONAL TWO-WAY EXTENDED AREA SERVICE BETWEEN THE ARANSAS PASS AND INGLESIDE EXCHANGES	**§ § § §**	**PROJECT NO. 8895**

March 8, 1990

Non-optional two-way extended area service granted pursuant to P.U.C. SUBST. R. 23.49(i).

[1] PROCEDURE--MISCELLANEOUS PROCEDURAL MATTERS
MISCELLANEOUS--TELEPHONE

P.U.C. SUBST. R. 23.49(i)(3)(I) requires joint filings for extended area service to be handled administratively (i.e., informal disposition) if there are no intervenors in the proceeding and no requests for hearing are made. (p. 2022)

[2] RATEMAKING--RATE DESIGN--TELEPHONE--EXTENDED AREA SERVICE

Where the local exchange company and the affected exchanges make a joint filing for extended area service under P.U.C. SUBST. R. 23.49, no traffic analysis or data is required to be provided. (p. 2022)

Public Utility Commission of Texas

7800 Shoal Creek Boulevard · Suite 400N
Austin, Texas 78757 · 512/458-0100

Jo Campbell
Commissioner

Marta Greytok
Commissioner

Paul D. Meek
Chairman

TO: Commissioner Campbell
Commissioner Greytok
Chairman Meek
All Parties of Record

DATE: February 20, 1990

RE: Project No. 8895--Joint Filing for Approval of Non-optional Two-Way Extended Area Service Between the Aransas Pass and Ingleside Exchanges

Ladies and Gentlemen:

Enclosed is a copy of the proposed Order in the above styled and numbered project. The Commission will consider this project at an open meeting scheduled to begin at 9:00 a.m. on Wednesday, March 7, 1990, at the Commission's offices, 7800 Shoal Creek Blvd., Austin, Texas. Any corrections to the proposed order shall be filed and served on all parties of record including the Commission's general counsel no later than 3:00 p.m. on Wednesday, February 28, 1990. An original and fifteen copies of any proposed corrections shall be filed with the Commission's filing clerk.

This project represents the first joint filing for extended area service (EAS), to be administratively processed under P.U.C. SUBST. R. 23.49(i). The joint filing was made by the City of Aransas Pass, the City of Ingleside and GTE Southwest, Inc. (GTE-SW), and involves the Cities' request for approval of the provision of EAS by GTE-SW between the Aransas Pass and Ingleside exchanges. The joint filing proposes a two-way non-optional calling arrangement between the two exchanges.

Under Rule 23.49(i), if there are no intervenors in the case and if there are no requests for hearing, then the joint filing is to be handled administratively (i.e., without being docketed for hearing and final order). To help determine the necessity of docketing and a hearing in this proceeding, and in compliance with the notice requirements of the rule, the Hearings Division: (1) published notice of the proposed joint filing in the Texas Register; (2) gave written notice of the filing to the Office of Public Utility Counsel (OPC); and (3) ordered GTE-SW to provide notice to all subscribers within the Aransas Pass and Ingleside exchanges (petitioning exchanges) by publication for two consecutive weeks in a newspaper of general circulation in the area, and by inserts in customer bills. GTE-SW was also ordered to provide written notice to the governing officials and county commissions in the petitioning exchanges, and to file sworn affidavits upon completion of notice as proof thereof.

In response to the public notice, statements in support of and in opposition to the joint filing were received. In five instances it was unclear whether the respondent desired to participate in this matter by simply making a public comment or whether intervenor status was desired. Therefore, making a public comment or whether intervenor status was desired. Therefore, the Hearings Division wrote letters to those individuals detailing the difference in participation as an intervenor and participation by public comment, and asked for clarification as to the desired method of participation. Pending their responses, these individuals were added to the service list in this project and received all documents filed and orders entered herein. No further responses were received from these individuals.

A customer survey regarding the EAS proposal was conducted in the Aransas Pass and Ingleside exchanges, and the results showed that more than 50 percent of the total subscribers who will experience a rate change are in favor of this joint filing at the proposed rates. The staff has completed its review and recommends approval of the joint filing as the minimum requirements set forth in Sections 3(A)-3(J) of Rule 23.49(i) have been met.

Following receipt of the above survey results and staff recommendation, the Hearings Division entered an Order stating that there were no intervenors in this proceeding and no request for hearing had been made; therefore, absent objection, the joint filing at issue in this project would be handled administratively, with this matter being submitted to the Commission for consideration and approval. A copy of this Order was mailed to the five customers referenced above. To date no objections, requests to intervene or requests for hearing have been filed. Accordingly, informal disposition of this matter by the Commission is appropriate under Rule 23.49(i), and allowed under Section 13(a) of the Administrative Procedure and Texas Register Act (APTRA), Tex. Rev. Civ. Stat. Ann. art. 6252-13a (Vernon Supp. 1990).

The joint filing is being informally resolved without the issuance of an Examiner's Report because this matter does not involve a docketed proceeding. Rather, the enclosed proposed Order in this project was drafted by the Hearings Division in accordance with the joint proposal and the staff's recommendation of approval thereof. The staff will be prepared to address any questions the Commission may have regarding this matter.

Sincerely,

Shelia Bailey Kneip

Shelia Bailey Kneip
Administrative Law Judge

cc: Honorable Robert Earley
Texas House of Representatives

nsh

PROJECT NO. 8895

JOINT FILING FOR APPROVAL OF OF NON-OPTIONAL TWO-WAY EXTENDED SERVICE BETWEEN THE ARANSAS PASS AND INGLESIDE EXCHANGES	§ § § §	PUBLIC UTILITY COMMISSION OF TEXAS

ORDER

On March 7, 1990, in public meeting at its offices in Austin, Texas, the Public Utility Commission of Texas met to consider the following pursuant to P.U.C. SUBST. R. 23.49(i) which became effective May 15, 1989:

1. On June 16, 1989, the City of Aransas Pass (Aransas Pass), the City of Ingleside (Ingleside) and GTE Southwest, Inc. (GTE-SW) filed a joint petition pursuant to P.U.C. SUBST. R. 23.49(i)(1) seeking approval of non-optional two-way extended area service (EAS) between the local telephone exchanges serving the two cities.

2. The joint filing includes a Joint Agreement of the Parties which was executed by the Mayor or Aransas Pass, the Mayor of Ingleside, and GTE-SW the telephone company which provides local exchange service to the exchange serving the two cities. The joint filing also included separate documents executed by the Commissioners' Courts of San Patricio County and Aransas County expressing unanimous support for the requested extended area service. San Patricio County appointed both the Mayor of Aransas Pass and the Mayor of Ingleside to represent it in this matter. Aransas County appointed the Mayor of Aransas Pass to represent it in this matter.

3. Implementation of non-optional two-way extended area service between the exchanges of Aransas Pass and Ingleside will not require subscribers' telephone numbers to be changed and subscribers will not incur non-recurring service charges.

4. Aransas Pass Exchange customers will pay a flat EAS rate additive, in addition to their local exchange rate, as follows:

Class of Service	Existing Local Rate Band 2	EAS Rate Band 1	Total
R-1	$ 7.30	$1.10	$ 8.40
B-1	18.90	2.95	21.85
Key-Line	22.65	3.50	26.15
PBX Trunk	30.25	5.15	35.40

The above rates are based on rates adopted for GTE-SW in Docket No. 5610.

5. Ingleside Exchange customers will pay a flat EAS rate additive, in addition to their local exchange rate, as follows:

Class of Service	Existing Local Rate Band 1	EAS Rate Band 2	Total
R-1	$ 7.10	$1.40	$ 8.50
B-1	18.35	3.65	22.00
Key-Line	22.00	4.40	26.40
PBX Trunk	29.40	6.40	35.80

The above rates are based on rates adopted for GTE-SW in Docket No. 5610.

6. Public notice of the joint filing was given by publication for two consecutive weeks in newspapers of general circulation in San Patricio and Aransas Counties and by inserts in customers' bills. Written notice was also given to the governing officials and county commissions within the affected exchanges. Additionally, written notice was given

to the Office of Public Utility Counsel (OPC) and published in the Texas Register.

7. The published notice and the direct notice given to customers, governing officials and county commissioners included statements regarding the project number assigned to the joint filing, the nature of the request, the Commission's mailing address and telephone number to contact in the event an individual wished to protest or intervene, and the deadline for filing a request to intervene.

8. A public comments file was established and contains comments from 26 subscribers concerning the joint filing.

9. Five of the subscribers referenced in Finding of Fact No. 8 expressed the desire to participate in this matter, but it was unclear from their comments whether they desired to participate as intervenors or of as protestants. Letters were mailed to all five individuals detailing the ways one could participate in this matter, explaining the difference between an intervenor and protestant, and requesting clarification as to the intended method of participation.

10. The five subscribers referenced in Finding of Fact No. 9 were placed on the service list pending clarification of their desired status, and as such they were served with all pleadings in this project.

11. A customer survey was conducted in this project as described in Findings of Fact Nos. 12 through 21 below. Following the receipt of the results of the survey and the Commission staff's recommendation for approval of the joint filing, a deadline of January 22, 1990, was set for objecting to the informal disposition of this proceeding and requesting a

hearing. No objection or request for hearing was filed. Additionally, no further response was received from the subscribers referenced in Finding of Fact No. 10, and there are no intervenors in this proceeding.

12. GTE-SW mailed survey cards to each of its local service subscribers in its Aransas Pass and Ingleside exchanges to determine those subscribers' interest in having EAS between those two exchanges. A total of 6,210 survey cards were mailed.

13. One side of the survey card referenced in Finding of Fact No. 12 contained text explaining the EAS proposal and the purpose of the survey. The other side of the survey card was addressed to GTE-SW and was metered with the appropriate postage.

14. The survey card requested customers who supported the provisions of EAS between the Aransas Pass and Ingleside exchanges to return the cards or to call the toll free number shown on the card. Customers not supporting EAS were informed that not responding to the survey would be counted as a vote against EAS: "Anything other than an affirmative response favoring the service will be a vote against the service".

15. The survey cards which were returned to GTE-SW were separated between the Aransas Pass and Ingleside exchanges and the responses tabulated.

16. If a survey card was returned to GTE-SW signed by the respondent but without the respondent's telephone number, GTE-SW identified said telephone number, where possible, and recorded the response. If the telephone number could not be

identified, then the survey card was counted as an invalid response.

17. After the survey responses were recorded, GTE-SW checked for duplicate responses from any one telephone number. If duplicate responses were found from a telephone number, GTE-SW deleted all but one of the telephone numbers' responses. GTE-SW then totaled the preferences indicated by the valid responses.

18. GTE-SW also determined the number of local service subscribers in the Aransas Pass and Ingleside exchanges who did not return surveys to GTE-SW. The unreturned surveys were counted as unfavorable responses for EAS between the Aransas Pass and Ingleside exchanges.

19. A positive response from at least 3,106 subscribers is required in this project to satisfy the requirements of P.U.C. SUBST. R. 23.49(i)(3)(G)(i).

20. The results of the Aransas Pass and Ingleside EAS survey are as follows:

	Aransas Pass	Ingleside	Total
Total Survey Cards Mailed	3998	2212	6210
Total Survey Cards Returned	2050	1269	3319
Favorable Response Rate	51.28%	57.37%	53.45%
Unreturned Cards	1918	929	2847
Returned a Negative Response	7	1	8
Invalid Responses	22	12	34
"Unlisted Number"	1	1	2
Total Unfavorable Responses	1948	943	2891
Unfavorable Response Rate	48.72%	42.63%	46.55%

21. The survey results set forth in Finding of Fact No. 20 reflect that more than 50 percent of the total subscribers

who will experience a rate change are in favor of this joint filing at the proposed rates.

22. Upon approval of this joint filing GTE-SW will activate the necessary central office and circuit equipment that is required to furnish two-way EAS between its Aransas Pass (758) exchange and Ingleside (776) exchange.

23. GTE-SW's Texas General Exchange Tariff, Section 13, Service Charges for residential and business service will not be changed upon approval of this joint filing.

24. The proposed rate additives identified in Finding of Fact Nos. 4 and 5 for EAS between the Aransas Pass and Ingleside exchanges recover, for GTE-SW, the appropriate cost of providing EAS including a contribution to joint costs.

25. A basic cost and revenue analysis furnished in the joint filing indicates that EAS between the Aransas Pass and Ingleside exchanges will provide a $112,357 contribution to joint and common costs in 1990 and a $106,695 contribution in 1992.

26. The City of Aransas Pass and the City of Ingleside have attempted to establish EAS between the Aransas Pass and Ingleside exchanges for a number of years.

27. GTE-SW committed to provide EAS between the Aransas Pass and Ingleside exchanges in 1984 and filed tariffs to that effect with the Commission.

28. The Commission declined to approve the tariffs referenced in Finding of Fact No. 27 due to: (a) an EAS moratorium in

effect at that time; and (b) the Commission's pending consideration of substantive rules relating to EAS.

29. Upon termination of the EAS moratorium referenced in Finding of Fact No. 28 and the Commission's adoption of EAS rules, GTE-SW conducted traffic studies between the Aransas Pass and Ingleside exchanges which failed to meet the threshold requirements for EAS set forth in the Commission's EAS rules.

30. Revisions to the Commission's EAS rules, specifically, the adoption of Commission Substantive Rule 23.49(i), exempt the traffic studies requirement in instances in which the local exchange company and the affected exchanges make a joint filing.

31. No traffic study was presented in this joint filing.

32. The long-term economic and social interests of the Aransas Pass and Ingleside exchanges will be best served by GTE-SW's provision of non-optional two-way EAS between said exchanges.

33. All necessary changes in the telephone directories resulting from the implementation of EAS between the Aransas Pass and Ingleside exchanges will be made at the earliest possible date.

34. Upon approval of the joint filing GTE-SW should file tariff documents in compliance with approved changes.

35. GTE-SW did not specifically apply for a change to tariff Section 23, Coin Telephone Service. The expanded mandatory dialing scope for the Aransas Pass and Ingleside exchanges

should be included in the existing tariff and covered by the existing rates for all classes of Coin Telephone Service.

36. The Aransas Pass and Ingleside exchanges included within the common call planning area are contained within a continuous boundary; no other exchanges are contained within that continuous bondary.

The Commission **ADOPTS** as findings of fact the propositions set forth above. The Commission further **ADOPTS** the following conclusions of law:

1. GTE-SW is a dominant carrier telecommunications utility as defined in Section 3(c)(2) of the Public Utility Regulatory Act (PURA), Tex. Rev. Civ. Stat. Ann. art. 1446c (Vernon Supp. 1990), and as such is subject to the Commission's jurisdiction under Section 18 of PURA.

2. The Commission has jurisdiction over this proceeding pursuant to Sections 16(a) and 18(b) of PURA.

3. Appropriate notice was given in this proceeding, as described in Finding of Fact Nos. 6 and 7, in accordance with P.U.C. SUBST. R. 23.49(h) and P.U.C. SUBST. R. 23.49(i)(3)(H).

4. An opportunity for hearing was given in this proceeding in accordance with Section 13(a) of the Administrative Procedure and Texas Register Act (APTRA), Tex. Rev. Civ. Stat. Ann. art. 6252-13a (Vernon Supp. 1990).

5. Section 13(a) of APTRA allows for the informal disposition of any contested case, unless precluded by law, after the opportunity for hearing has been afforded.

[1] 6. P.U.C. SUBST. R. 23.49(i)(3)(I) requires joint filings for EAS to be handled administratively (i.e., informal disposition) if there are no intervenors in the proceeding and no requests for hearing are made.

7. It is reasonable for this proceeding to be handled administratively and <u>not</u> docketed for hearing and final order for the reasons set forth in Finding of Fact No. 11 and Conclusion of Law Nos. 3, 4, 5 and 6.

[2] 8. No traffic analysis or data is required in this proceeding pursuant to P.U.C. SUBST. R. 23.49(i)(3)(B).

9. The joint filing for EAS between the Aransas Pass and Ingleside exchanges meets the minimum requirements and conditions outlined in P.U.C. SUBST. R. 23.49(i) for approval of an EAS agreement.

10. The proposed monthly EAS rate additives set forth in Finding of Fact Nos. 4 and 5 are not unreasonably preferential, prejudicial, or discriminatory, but are sufficient, equitable and consistent in application to each class of customer in each exchange, in accordance with Section 38 of PURA.

11. The proposed monthly EAS rate additives set forth in Finding of Fact Nos. 4 and 5 are just and reasonable for the reasons set forth in Finding of Fact No. 24 and Conclusion of Law No. 10.

12. The Commission may, upon proper notice and opportunity for hearing in a docketed proceeding, change the rates for any utility service, including the rate additives for EAS described in Finding of Fact Nos. 4 and 5.

13. Approval of this joint filing is consistent with the public interest for the reasons set forth in Finding of Fact Nos. 21 and 32, and Conclusion of Law Nos. 7, 9 and 11.

14. The joint filing for EAS between the Aransas Pass and Ingleside exchanges is reasonable and should be approved for the reason set forth in Conclusion of Law No. 13.

15. It is reasonable to require GTE-SW to file tariff amendments in compliance with approved changes.

The Commission further issues the following Order:

1. The joint filing for approval of non-optional two-way extended area service between the Aransas Pass and Ingleside exchanges served by General Telephone Company of the Southwest, Inc. (GTE-SW) is hereby **APPROVED**.

2. The expanded mandatory dialing scope for the Aransas Pass and Ingleside exchanges **SHALL** be included in GTE-SW's existing tariff and covered by the existing tariff and covered by the existing rates for all classes of Coin Telephone Service.

3. Within 20 days after the date of this Order, GTE-SW shall file with the Commission five copies of all pertinent tariff sheets revised to incorporate all the directives of this Order and shall serve one copy upon each party of record. No later than 10 days after the date of the tariff filing by GTE-SW, parties shall file any objections to the tariff proposal and the general counsel shall file the staff's comments recommending approval or rejection of the individual sheets of the tariff proposal. No later than 15

days after the date of the tariff filing GTE-SW, all parties and the general counsel shall file in writing any responses to the previously filed comments of other parties. The Hearings Division shall by letter approve, reject, or modify each tariff sheet, effective the date of the letter, based upon the materials submitted to the Commission under the procedure established herein. The tariff sheets shall be deemed approved upon expiration of 20 days after the date of filing, in the absence of written notification of approval, rejection, or modification by the Hearings Division. In the event that any sheets are rejected, GTE-SW shall file proposed revisions of those sheets in accordance with the Hearings Division letter within 10 days after that letter, with the review procedures set out above again to apply. Copies of all filing and of the Hearings Division letter(s) under this procedure shall be served on all parties of record and the general counsel. The tariff shall be deemed effective upon the date of implementation of the service.

4. All motions, applications, or other requests for relief general or specific not expressly granted in this order are DENIED.

SIGNED AT AUSTIN, TEXAS on this the 8th day of March 1990.

PUBLIC UTILITY COMMISSION OF TEXAS

Jo Campbell
JO CAMPBELL, COMMISSIONER

Marta Greytok
MARTA GREYTOK, COMMISSIONER

Paul D. Meek
PAUL D. MEEK, CHAIRMAN

ATTEST:

Mary Ross McDonald
MARY ROSS McDONALD
SECRETARY OF THE COMMISSION

nsh

APPLICATION OF TEXAS-NEW MEXICO POWER COMPANY FOR AUTHORITY TO CHANGE RATES § § § DOCKET NO. 8928

February 24, 1990

Commission approved rates which increase the utility's gross revenues by 2.94 percent. The utility's application for deferred accounting treatment for its first Texas generating plant, Docket No. 8880, was remanded to the Hearings Division for purposes of taking additional evidence. Motion for rehearing on some issues granted April 4, 1990.

[1] RATEMAKING--COST OF SERVICE--OPERATIONS AND MAINTENANCE--SALARIES AND EMPLOYEE BENEFITS

Pension plan expense was based upon the utility's most recent actual pension funding requirements for a twelve month period. Commission rejected utility's methodology that assumed pension costs bear a direct relationship to labor cost, and that recognized changes in market value of a pension plan's portfolio assets that do not require a cash outflow. (p. 2053)

[2] RATEMAKING--COST OF SERVICE--DEPRECIATION

Commission excluded depreciation of land rights from cost of service. Utility proposed to depreciate the cost of land rights over the period of the estimated life of the related transmission line. The Commission rejected the proposal because the record did not show that the land rights would expire upon the end of the service life of the related transmission line. (p. 2067)

[3] RATEMAKING--REVENUE ADJUSTMENTS--ELECTRIC

In a general rate case, intervenor proposed that utility switch from the meters-read method of recording revenue to the unbilled method. The switch would require a downward-adjustment to the utility's test-year revenue requirement. The Commission rejected the proposal because the adjustment would prevent the utility from recovering its cost of service. (p. 2076)

[4] RATEMAKING--INVESTED CAPITAL--USED AND USEFUL PROPERTY--GENERAL THEORY

Utility's transmission line ran from the ERCOT grid to a generating plant under construction. Utility argued that the line was used and useful because it was used for importing energy for start-up testing, exporting energy during trial generation, and for satisfying contractual commitments to the company building the generating plant. The Commission concluded that the plant was not used and useful because importing energy to the plant, and the utility's satisfaction of its commitments to the builder of the plant did not constitute service to the public. Exporting energy to ratepayers through the line could benefit the utility's customers and therefore render the line used and useful. But the record did not show that the line was actually used for such purpose. (p. 2080)

[5] RATEMAKING--INVESTED CAPITAL--USED AND USEFUL PROPERTY--PLANT HELD FOR FUTURE USE

Utility's transmission line ran from the ERCOT grid to a generating plant under construction. The Commission rejected the utility's argument that the line should be included in invested capital as plant held for future use. The future use of the line was indefinite because the future use of the generating plant was not clear. (p. 2081)

[6] RATEMAKING--INVESTED CAPITAL--POST-TEST-YEAR ADJUSTMENTS

Commission rejected proposed adjustment to accumulated depreciation that was based upon post-test-year depreciation. Intervenor proposed to reduce utility's net plant by depreciation incurred during the six months following the end of the test year. But the proposed post-test-year adjustment unreasonably relied upon test year information. Further, the adjustment incorrectly assumed that the utility's net plant steadily decreased after the end of the test year. (p. 2084)

[7] COMPLAINTS AND DISPUTES--BILLING DISPUTES

Customer argued that utility's service to the customer's computer facility was inadequate under PURA §§58(a) and 61, and that the Commission should therefore order the utility to repair portions of the distribution system. The utility's continuity of service to the customer was at 99.98 percent, but the customer sought 100 percent electric reliability. The Commission concluded that the utility was already providing adequate electric service and refused to order the utility to undertake certain repairs. (p. 2099)

[8] RATEMAKING--COST OF SERVICE--OPERATIONS AND MAINTENANCE--RATE CASE AND OTHER LEGAL EXPENSES

Commission ordered procedure by which intervenor municipalities could recover rate case attorney's fees. Reasonable fees incurred through the hearing on the merits may be recovered from the utility and included in the utility's cost of service. But the municipalities' legal fees incurred after the hearing must be recovered by a new procedure. The utility must reimburse the municipalities for all such legal fees that are reasonable and not in excess of the municipality's estimate of total rate case legal fees. Upon Commission approval, the utility may recover such legal fees from its customers by means of a surcharge. (p. 2191)

Public Utility Commission of Texas

7800 Shoal Creek Boulevard · Suite 400N
Austin, Texas 78757 · 512/458-0100

Jo Campbell
Commissioner

Marta Greytok
Commissioner

Paul D. Meek
Chairman

February 1, 1990

TO: Commissioner Campbell
Commissioner Greytok
Chairman Meek
All Parties of Record

RE: Docket No. 8880--Application of Texas-New Mexico Power Company for Approval of Deferred Accounting Treatment for TNP One, Units 1 and 2, and Adjustment to PCRF Calculation

Docket No. 8928--Application of Texas-New Mexico Power Company for Authority to Change Rates

Ladies and Gentlemen:

Enclosed is a copy of the Examiners' Report and Proposed Order in this docket. The Commission will consider this case at an open meeting scheduled to begin at 9:00 a.m., Wednesday, February 21, 1990, at its offices at 7800 Shoal Creek Boulevard, Austin, Texas. Although the parties are welcome to attend the meeting, they are not required to do so. A copy of the signed final order will be sent to the parties shortly after the meeting.

Exceptions to the Examiner's Report shall be filed by 12:00 noon, Monday, February 12, 1990. Any replies to exceptions shall be filed by 12:00 noon, Monday, February 19, 1990. An original and fifteen copies of exceptions and replies must be filed with the Commission filing clerk, and copies must be served on the Commission's general counsel.

Pursuant to Commission Procedural Rule 21.143, requests for oral argument must be made in writing, filed with the Commission, and served on all parties of record by 5:00 p.m., Thursday, February 15, 1990 (the fourth scheduled working day preceding the open meeting at which this case will be considered). If a request for oral argument is filed, parties may call Ms. Lisa Serrano at 512/458-0266 after 9:00 a.m. on Tuesday, February 20, to learn if oral argument will be allowed by the Commissioners. Even if no request for oral argument is made or even if a request for oral argument has been denied, the Commissioners may still have questions for the parties and general counsel. If oral argument is allowed, the Commissioners may delay their decision in this docket until the following day.

<u>Summary of the Examiners' Recommendation</u>

The period of suspension of rates in TNP's rate application, Docket No. 8928, ends on March 3, 1990. TNP requests the Commission's approval of proposed changes to the company's retail and wholesale rates which would increase TNP's gross revenues by $16,088,054, or 9.60 percent above the company's adjusted test year revenues. The examiners recommend that the Commission approve rates which would increase TNP's gross revenues by $8,652,365, or 2.98 percent above the company's adjusted test year revenues. (The company's original rate application stated that the company sought an increase of 5.32 percent above adjusted test year revenues. The examiners disagree with the company's methodology used to determine adjusted test year revenues and have therefore revised the adjusted test year revenues figure. This issue is discussed in section III.C.1. of the report.) The examiners' proposed rates would cause residential rates to increase by 3.08 percent, general service rates by 1.60 percent, and large general service rates by 2.35 percent. Rates charged to customers served under the industrial power schedule will not change.

The examiners recommend an overall rate of return of 11.30 percent, which is based in part upon a cost of equity of 12.86 percent.

The Company's request to include in invested capital a 345 kilovolt transmission line that connects TNP's new power plant to the Electric Reliability Council of Texas transmission grid was one of the predominant issues in the rate case. The examiners recommend that the Commission exclude the line from invested capital because the line is not yet used and useful.

TNP anticipates commercial operation of its new power plant, TNP One, in the near future. The anticipated in-service dates for Unit 1 and Unit 2 are June 1, 1990, and June 1, 1991, respectively. In Docket No. 8880, the company seeks Commission approval of deferred accounting treatment for each unit from the respective in-service date of each unit until rates reflecting that unit are implemented. The examiners conclude that the Unit 1 application should be denied because if the company fully implements its plans to finance TNP One, the company's financial integrity will be impaired whether or not the company defers Unit 1 expenses The credible evidence in the record does not show that the financing plans must be fully implemented prior to the time Unit 1 is reflected in rates. The examiners conclude that the Unit 2 application should be denied because it is premature. The proposed deferral period for Unit 2 would begin in June 1991. The Commission cannot at this time determine whether the company's financial integrity will be impaired in June 1991.

<u>Examiners' Recommendation to Take Judicial Notice</u>

In section V of the report, the examiners recommend that the Commission take judicial notice of a statement made by the company's representative, Mr. Shirley, concerning the company's anticipated filing of its next rate case. The statement was made during the Commission's Final Order Meeting of December 13, 1989. In accord with Rule 201(e) of the Texas Rules of Civil

Evidence, the parties may submit written comments concerning the proposed taking of judicial notice. The written comments must be filed no later than the deadline to file exceptions to the examiners' report.

Sincerely,

Richard S. O'Connell

Richard S. O'Connell
Hearings Examiner

Jeffrey A. Friedman
Hearings Examiner

DOCKET NO. 8880

PETITION OF TEXAS-NEW MEXICO POWER COMPANY FOR APPROVAL OF DEFERRED ACCOUNTING TREATMENT FOR TNP ONE, UNITS 1 AND 2, AND ADJUSTMENT TO PCRF CALCULATION	§ § § § §	PUBLIC UTILITY COMMISSION

DOCKET NO. 8928

APPLICATION OF TEXAS-NEW MEXICO POWER COMPANY FOR AUTHORITY TO CHANGE RATES	§ § §	OF TEXAS

INDEX TO EXAMINERS' REPORT

DOCKET NO. 8880

PETITION OF TEXAS-NEW MEXICO POWER COMPANY FOR APPROVAL OF DEFERRED ACCOUNTING TREATMENT FOR TNP ONE, UNITS 1 AND 2, AND ADJUSTMENT TO PCRF CALCULATION	§ § § § §	PUBLIC UTILITY COMMISSION OF TEXAS

DOCKET NO. 8928

APPLICATION OF TEXAS-NEW MEXICO POWER COMPANY FOR AUTHORITY TO CHANGE RATES	§ § §	PUBLIC UTILITY COMMISSION OF TEXAS

EXAMINERS' REPORT

I. Procedural History

A. Procedural Development

1. Filing of Deferred Accounting and Rate Case Applications

On June 13, 1989, Texas-New Mexico Power Company (TNP) filed an application seeking a Commission order which would permit TNP to defer the depreciation expense, operation and maintenance expense, tax expense, and carrying costs associated with its first generating plant located in Texas. The application was designated Docket No. 8880. The application stated that the generating plant, "TNP One," is scheduled for an in-service date for commercial operation of June 1, 1990, for Unit 1, and 1991, for Unit 2. TNP requested that the Commission permit TNP to defer the expenses associated with Units 1 and 2 from their respective in-service dates for commercial operation until the Commission approves rates which reflect such expenses and costs. The application also sought Commission approval of a proposed amendment to TNP's purchased power cost recovery factor (PCRF).

On July 18, 1989, TNP filed a petition for authority to change rates and a statement of intent to change rates. The application was designated Docket No. 8928. TNP requests the Commission's approval of proposed changes to TNP's retail and wholesale rates which would increase TNP's gross revenues by $16,088,054. The proposed increase is 9.60 percent above adjusted test year revenues. (See section I.C.1.a. of this report concerning the calculation of adjusted test year revenues.) All Texas customers and classes of customers over which the Commission excercises original rate jurisdiction will be affected. The test year upon which the application was based ended March 31, 1989.

Examiner's Order No. 1 in Docket No. 8928 suspended implementation of the proposed rates until January 20, 1990, or 150 days beyond their otherwise effective date. The suspension was made pursuant to Section 43(d) of the Public Utility Regulatory Act (PURA), Tex. Rev. Civ. Stat. Ann. art. 1446c (Vernon Supp. 1989). Because the hearing on the merits lasted 36 days, the period of suspension was extended by 42 days, until March 3, 1990. PURA Section 43(d).

2. Motions to Dismiss the Deferred Accounting Application, Consolidation of Rate Case and Deferred Accounting Application

A prehearing conference was held in Docket No. 8880 on July 17, 1989. During the prehearing conference, certain threshold issues were raised relating to the scope of the proceeding and whether TNP's application was premature. The following parties subsequently filed motions to dismiss TNP's application in Docket No. 8880 (the full names of the parties are set forth below in section I.C. of this report): TIEC, State of Texas, Enron, OPC, and Sterling. The movants argued the following: (1) the use of deferred accounting was eliminated by the Commission's June, 1989, revision to P.U.C. SUBST. R. 23.21(a) in which the Commission adopted the post test year adjustment (PTYA) rule; (2) the Commission does not have the authority to grant the relief requested because TNP does not have a certificate of convenience and necessity (CCN) for TNP One; (3) the fact that TNP does not yet own TNP One requires dismissal of the application; and (4) the Commission is precluded from considering the application because approval would contravene the requirement found in Section 41(a) of PURA that a utility's invested capital must be based upon original cost. The examiner ruled by order dated September 8, 1989, that the grounds for dismissal without a hearing found in P.U.C. PROC. R. 21.82(a) did not apply, and denied the motions to dismiss. The State of Texas appealed the order. The order was, however, deemed approved by the Commission. P.U.C. PROC. R. 21.106.

The examiner promulgated an order on August 15, 1989, which proposed the consolidation of Docket Nos. 8880 and 8928. The parties were allowed to submit briefs addressing whether the dockets present commmon questions of law or fact, and whether separate hearings would result in unwarranted expense, delay, or substantial injustice. P.U.C. PROC. R. 21.85. TNP, OPC, Enron, Sterling, and the State of Texas filed comments. The examiner ruled, by order dated September 8, 1989, that the dockets concern common questions of fact and that consolidation would not work any injustice upon any of the parties to either docket. The consolidation had the effect of moving the date of the hearing on the merits on the deferred accounting issues one month earlier than originally scheduled in Docket No. 8880. All of the parties in the deferred accounting case (TNP, the State of Texas, TIEC, Sterling, Enron, and the general counsel) were also parties in the rate case. Consolidation therefore did not cause any person interested solely in deferred accounting issues to attend and participate in a full rate case hearing that it would not otherwise have attended.

3. Consolidation of Appeals from City Ratemaking Ordinances

Pursuant to Sections 17 and 26 of the PURA, TNP appealed the ratemaking ordinances of the following municipalities which retained original ratemaking jurisdiction: City of Dickinson, City of League City, City of Bailey's Prairie, City of Booker, City of Holiday Lakes, City of Rio Vista, City of Whitney, City of Covington, City of LaMarque, City of Bells, City of Angleton, City of Gatesville, City of Spearman, City of Sweeney, City of Darrouzett, City of West Columbia, City of Perryton, City of Lewisville, City of Brazoria, City of Pearland, City of Texas City, City of Farmersville, City of Olney, City of Nocona, City of Fort Stockton, City of Alvin, City of Toyah, Town of Pecos City, City of Friendswood, and the City of Kermit. The appeals of the various cities have been consolidated with the consolidated Docket Nos. 8880 and 8928.

On November 9, 1989, TNP appealed the ratemaking ordinance of the City of Blum. TNP withdrew this appeal on December 15, 1989.

4. Protest Statements

Four individuals filed protest statements against TNP's proposed rate increase. The examiner sent a letter in response to each of the protestants explaining how they could participate in the rate case. None of the protestants filed further responses or appeared at the hearing.

5. Prehearing Conferences, The Hearing on the Merits, Establishment of an Outline of Issues and Scheduling of Briefs

A final prehearing conference was held in the consolidated dockets on October 19, 1989. The parties were instructed that the hearing would be separated into two phases and that they should present their witnesses during the appropriate phase. Phase I would cover the revenue requirement issues in the rate case, and all issues in the deferred accounting case. Phase II would cover the cost allocation and rate design issues in the rate case.

The hearing on the merits convened on October 24, 1989. The hearing lasted 36 days. The total includes four days where the hearing did not actually convene but the applicant TNP agreed to stipulate as days of hearing. The following parties made an appearance at the hearing on the merits: TNP, the State of Texas, TIEC, Enron, the general counsel, OPC, the Cities, and Sterling. Sterling made an appearance on only the last day of the hearing.

At the final prehearing conference and during the hearing on the merits the parties were advised that the examiners presiding over the consolidated dockets would promulgate an outline of the issues. The parties were advised that they would be ordered to organize briefs, reply briefs, exceptions to the examiners' report, and replies to exceptions, according to the outline. This examiners' report has been organized according to the same outline with some revisions. The parties are directed to organize their exceptions to the examiners' report, and replies to exceptions, according to the outline used in this report. The purpose of the outline is to assist the parties, the examiner and the Commissioners in expeditiously locating the parties' arguments and the examiners' conclusions on each issue.

B. Notice

Administrative Law Judge's Order No. 2 in Docket No. 8880 ordered TNP to complete the following notice concerning TNP's application for deferred accounting: (1) publish notice for two consecutive weeks in newspapers of general circulation in TNP's service area, and (2) give direct notice to the parties in TNP's last rate case, Docket No. 8095. TNP filed on October 13, 1989, and on October 25, 1989, publisher's affidavits certifying that notice had been published as directed above. TNP filed on August 23, 1989, a certificate of service that stated that the required direct notice had been completed.

As required by P.U.C. PROC. R. 21.22(b)(1), TNP published notice of its rate case application once each week for four consecutive weeks, prior to the effective date of the proposed change, in newspapers of general circulation in TNP's service area. TNP provided publisher's affidavits to that effect. TNP also notified affected municipalities and its customers individually of the proposed changes as required by P.U.C. PROC. R. 21.22(b)(2) and (3). Finally, Examiner's Order No. 1 in Docket No. 8928 required TNP to give direct notice to the commissioners' court of each county which would be affected by the proposed rate changes. TNP filed on September 1, 1989, an affidavit certifying that direct notice to the commissioners' courts had been completed. The affidavits certifying that notice has been completed were admitted into the record as TNP Exhibit No. 66.

C. Presiding Examiners, Parties, Acronyms, Attorneys

Docket No. 8880 was at its outset assigned to Administrative Law Judge Shelia Bailey Kneip. The docket was reassigned to Examiner Richard O'Connell on or about August 1, 1989. Docket No. 8928 was at its outset assigned solely to Examiner O'Connell. The rate design portion of Docket No. 8928 was assigned to Examiner Jeffrey Friedman on or about October 10, 1989. The reassignment of Docket No. 8880 was made pursuant to Section 15 of the Administrative Procedure and Texas Register Act (APTRA), Tex. Rev. Civ. Stat. Ann. art. 6252-13a (Vernon Supp. 1989) and P.U.C. PROC. R. 21.102(b).

The following parties and their representatives appeared during the hearing on the merits:

Party	Representative
Texas-New Mexico Power Company (TNP)	Michael Shirley John Bucy Patricia Bowers James McNally
Enron Gas Pipeline Company (Enron)	Marianne Carroll Jim Boyle Taylor Davis
Texas Industrial Energy Consumers (TIEC)	Alton Hall
State of Texas	Rupaco Gonzalez
Office of Public Utility Counsel (OPC)	Carlos Higgins Lanetta Cooper
Intervenor Cities (Cities)	Don Butler
Sterling Chemicals, Inc. (Sterling)	Cathy Lee Jordan
General Counsel	Walter Muse

Herring Marathon Group, Inc. (Herring Marathon) was represented by Stephen Fenoglio at the first prehearing conference in Docket No. 8928. Herring Marathon did not make an appearance at the hearing on the merits. By order dated September 13, 1989, MGHerring Group, Inc. was granted intervenor status and grouped for all purposes with Herring Marathon. Both MGHerring Group, Inc. and Herring Marathon are represented by Mr. Fenoglio.

The following cities, which are all represented by Mr. Butler, intervened in Docket No. 8928: City of Fort Stockton, City of Lewisville, City of Alvin, City of Angleton, City of Aubrey, City of Blossom, City of Bogata, City of Booker, City of Brazoria, City of Celeste, City of Crawford, City of Darrouzett, City of Farmersville, City of Friendswood, City of Gordon, City of Kermit, City of Krugerville, City of Morgan, City of Nocona, City of Olney, City of Pearland, Town of Pecos City, City of Perryton, City of Petrolia, City of Princeton, City of Spearman, City of Strawn, City of Sweeney, City of Talco, City of Texas City, and City of Toyah. The City of Friendswood withdrew its intervention on December 12, 1989.

II. Jurisdiction

TNP is a public utility, as that term is defined in section 3(c)(1) of the PURA. The Commission has jurisdiction over TNP's deferred accounting application by virtue of Sections 16(a) and 27 of the PURA. The Commission has jurisdiction over TNP's application to change rates and the consolidated appeals by virtue of Sections 16(a), 17(d), 17(e), 37, and 43 of the PURA.

III. Introduction

A. <u>Description of TNP</u>

1. The Company

The utility TNP is one of three subsidiaries of TNP Enterprises, Inc. (TNPE). TNPE is a Texas corporation. As of January 31, 1989, non-affiliates of TNPE held 7,981,651 shares of the common stock of TNPE with an aggregate market value of $159,633,036. TNPE became the parent and owner of all common stock of TNP on October 3, 1984, and designates TNP as its "principal operating subsidiary." TNP Exhibit No. 4 (TNPE 1988 Form 10-K). TNPE's other two subsidiaries are TNP Operating Company and Bayport Cogeneration, Inc. (Bayport). TNPE established TNP Operating Company in 1984 for purposes of seeking non-utility business acquisitions, but the subsidiary has not yet acquired any businesses. Bayport formerly owned a 50 percent general partnership interest in Capitol Cogeneration Company, Ltd. (Capitol). Capitol owned and operated a 375-megawatt cogeneration facility in Pasadena, Texas. Capitol, however, sold the facility to Clear Lake Cogeneration Limited Partnership (Clear Lake) on May 3, 1988. Since that time, Bayport's only activities have been in connection with the completion of the final affairs related to Capitol. During 1988, TNP purchased energy from the cogeneration facility from Capitol until May 3 and purchased energy from the facility from Clear Lake on and after May 3. In 1988, TNP purchased 48.7 percent of the energy required for its Texas service areas from the cogeneration facility. TNP Exhibit No. 4 (TNPE 1988 Annual Report at 12).

The utility TNP and the parent TNPE have the same directors. The three executive officers of TNPE are also among the 12 executive officers of TNP. TNP Exhibit No. 4 (TNP, TNPE 1988 Form 10-Ks). The corporate headquarters for both TNP and TNPE is located in Fort Worth.

The utility TNP has five service areas. Four service areas are located in Texas. During the test year, 77 percent of the total kilowatt hours (kwh) sold by TNP was sold to TNP's customers in the Texas service areas. The other service area is located in New Mexico. Examiners' Attachment A is a copy of the service area map found in TNP's current Energy Efficiency Plan. According to TNP's 1988 Form 10-K, TNP operates with little direct competition throughout most of its service territory because it is the only utility certificated to serve particular areas. Consolidated operations of TNP for the twelve months ended March 31, 1989, provided operating revenues of $365,073,851 and earnings available for common stock of $14,523,160.

At the end of the test year, TNP served 161,683 customers in Texas. TNP's Texas customers had the following test year characteristics:

	Percent of Total Customers	Percent of Total KWHs sold
Residential	84.4%	35%
Commercial and Industrial	15.5%	62%
Municipal and Wholesale	.1%	3%

TNP is a distribution utility. TNP does not generate power in Texas but rather purchases power for resale to its customers. TNP's Texas service areas and the entities from which TNP buys power to serve the particular service area are listed below:

Service Area	Power Suppliers
Southeast Division	Houston Lighting and Power Company Union Carbide Clear Lake Cogeneration, Ltd. Texas Municipal Power Agency
Western Division	West Texas Utilities Texas Utilities Electric Company
Central Division, Northern Division	Southwestern Public Service Company Texas Utilities Electric Company

The Southeast Division produced 47.5 percent of TNP's total consolidated revenues in 1988. The other three Texas service areas together produced 31.8 percent of total consolidated revenues. The remaining portion of revenues is attributable to New Mexico operations. TNP Exhibit No. 4 (TNP Form 10-K at 4).

On June 6, 1988, TNP organized a wholly owned subsidiary, Texas Generating Company (TGC). According to TNP's 1988 Form 10-K, TGC's only transaction has been the issuance of stock to TNP. According to TNP Vice President and Chief

Financial Officer, Mr. D. R. Barnard, and TNP Vice President, Manager - Generation, Mr. Rickey J. Wright, TGC was created so that it would own TNP's first generating plant, discussed below. Tr. at 331, 1873.

2. TNP's First Texas Generating Facility, TNP One

TNP has contracted with a consortium of companies composed of H. B. Zachry Company, Westinghouse Electric Corporation, and Combustion Engineering/Lurgi, to construct two units of a four unit electric generating plant in Robertson County, Texas. The electric generating plant is referred to collectively as TNP One. Units 1 and 2 of TNP One are being constructed on a turn-key basis such that ownership of each unit does not pass to TNP until the unit meets certain performance criteria. Unit 1 construction began in December 1987; it is scheduled for commercial operation on June 1, 1990. Unit 2 construction began in November 1988 and is scheduled for commercial operation on July 1, 1991. TNP does not have definite dates for the beginning of construction of Units 3 and 4. TNP Exhibit No. 1 at 19.

TNP plans that TNP One will provide base load power to any of TNP's service areas within the Electric Reliability Council of Texas (ERCOT) transmission system. Each unit is nominally rated at 150 megawatts (MW) and utilizes circulating fluidized bed (CFB) boiler technology that staff witness Gordon H. Van Sickle characterized as "experimental." Unit 1 will be the first generating plant to utilize CFB technology that is rated at more than 100 MW. Tr. at 4258. TNP One is designed to operate while burning natural gas, lignite, or western coal. Assuming that TNP obtains title to Units 1 and 2, TNP's plant in service amount will increase from $350 million to $950 million. Tr. at 2341.

B. Summaries of Prior Commission Orders Concerning TNP

1. Rate Cases

Prior to Docket No. 8928 TNP filed six rate cases. TNP filed five rate cases during the period 1980 to 1984. The applications were filed approximately twelve months apart. TNP filed its sixth rate case, Docket No. 8095, on April 29, 1988, seeking a rate increase of $12,575,887, or a 4.47 percent increase over adjusted test year revenues. TNP stipulated to a rate increase of $4,600,000, or 1.16 percent over adjusted test year revenues. TNP's post hearing brief states that TNP agreed to the stipulated rate increase in Docket No. 8095 based upon receiving the rates early. TNP Brief at 25. The stipulated rates went into effect on September 1, 1988. Absent an extended hearing, had the docket remained contested, the Commission would have had to rule on TNP's application in Docket No. 8095 no later than November 2, 1988.

2. The NOI and CCN Proceedings Concerning TNP One

On July 17, 1985, TNP filed, pursuant to Section 54(d) of the PURA, a notice of intent (NOI) to apply for Commission certification of TNP One. Docket No. 6397, Notice of Intent of Texas-New Mexico Power Company for a Coal-Fired Generating Plant in Robertson County, 12 P.U.C. BULL. 131 (February 7, 1986). The examiner recommended denial of the NOI. The Commission, however, approved the NOI. The Commission concluded that TNP had demonstrated that the plant was appropriate in light of the alternatives of cogeneration and purchased power.

On August 15, 1986, TNP filed, pursuant to Section 54 of the PURA, an application for certification of Units 1 through 4 of TNP One. Docket No. 6992, Application of Texas-New Mexico Power Company for Certification of a Lignite Fired Electrical Generation Station in Robertson County, Texas, ______ P.U.C. BULL. ____ (August 17, 1987). The administrative law judge recommended approval of the application. The Commission approved the application. TIEC, Houston Lighting & Power Company (HL&P), and Cogen Lyondell and Cogen Lynchburg appealed the Commission's Order in Docket No. 6992. By letter ruling dated April 10, 1989, and by Order of Dismissal dated May 17, 1989, Judge Harley Clark of the 250th District Court ruled that the Commission's Order in Docket No. 6992 lacks "finality." He therefore concluded that the Final Order is not susceptable to judicial review and that the docket remains pending at the Commission. TNP appealed the District Court's ruling to the Court of Appeals.

The record in this docket does not reflect the status of the appeal. On December 13 and 14, 1989, the Commission in an open meeting heard argument from the parties to Docket No. 6992 concerning a motion of the Commission's general counsel. The Commission granted the general counsel's motion requesting that the Commission remand the proceedings in the docket back to the Commission's Hearings Division for further evaluation of TNP's application.

C. TNP's Applications (Summary of Relief Requested)

1. The Rate Case (Docket No. 8928)

a. Description of Rate Application. As previously stated, TNP seeks an increase in gross revenues of $16,088,054, or 9.60 percent above adjusted test year revenues. The company's application states that the increase is 5.32 percent above adjusted test year revenues. The examiners, however, disagree with the company's calculation of adjusted test year revenues. Adjusted test year revenues should be increased to reflect any increases in the rates charged by TNP's wholesale suppliers. Increases in wholesale rates are passed through to the company's customers by means of a purchased power cost recovery factor (PCRF), therefore increasing the company's revenues. But the company's adjusted test year revenues figure is based in part upon the wholesale rates proposed by HL&P in its current rate case, Docket No. 8425. The proposed rates in Docket No. 8425 are not a known and measurable change. TNP's test year revenues should not be adjusted according to charges in rates that are not yet known and measurable. The examiners have accordingly revised the company's adjusted test year revenues figure. See Schedule VII. TNP Exhibit No. 21 at 14. Staff Exhibit Nos. 15 at 2, and 20 at 4. TNP seeks an overall revenue requirement of $318,690,386. The proposed increase would affect TNP's rates in all of its Texas service areas. The amount of the proposed rate increases to the various customer classes, however, would differ depending upon each class's existing contribution to the overall return and TNP's proposed changes for each class. TNP seeks an overall return on invested capital of 11.91 percent. In calculating the return on invested capital, TNP utilized a 14.1 percent return on common equity.

TNP proposes to include in invested capital several items classified as construction work in progress at the end of the test year, and a new transmission line. The items classified as construction work in progress as of March 31, 1989, but reclassified to plant in service by September 30, 1989, total $439,775. The new transmission line was completed prior to the end of the test year, but runs from the ERCOT system to TNP One, which is not in service. TNP seeks to include in invested capital the $11,890,506 cost of the transmission line.

b. Need for Rate Relief; Effect of TNP One on Application. According to TNP Vice President - Contracts and Regulation, Mr. Jack V. Chambers, there are four primary reasons for TNP's request for an increase in rates: (1) to avoid further deterioration of TNP's financial integrity; (2) to meet required transmission and distribution construction programs; (3) to fulfill TNP's financial needs; and (4) to continue providing a reliable quality of service to TNP's customers. TNP Exhibit No. 1 at 4. TNP asserts that because its capitalization will increase threefold by the end of 1991, it is imperative that TNP maintain its financial integrity so that it may continue to have access to the capital markets. Id. at 7. TNP's goal is to increase its bond ratings. Tr. at 45. For these reasons TNP filed this rate application and intends to file annual rate cases for the next several years. TNP Exhibit No. 1 at 8.

Enron asserts that the primary purpose of this application is to position TNP so that it will be able to assume the financial obligations related to TNP One once ownership passes to TNP from the construction consortium. Enron Brief at 9. OPC and TIEC concur with Enron's position. OPC Brief at 2; TIEC Brief at 5. The intervenors argue that TNP should not receive rate relief for costs or expenses related to TNP One because the plant is not used and useful. TNP does not at this time own the plant, or have a CCN to construct or operate the plant. The intervenors especially take issue with TNP's application because during the 1987 hearing concerning TNP's application for a CCN for TNP One, TNP Vice President Barnard testified that "[t]he method of financing and constructing [TNP One] by a Consortium's use of project financing should not require increased rates to the ratepayer during the period of construction." Enron Exhibit No. 50 at 15. Further, he testified that "the financing plan allow[s] the company to build [TNP One] without adversely affecting the company's financial position." Id. at 24. TNP responded that this rate application would have been filed whether or not TNP One was under construction. Tr. at 53.

2. The Application for Deferred Accounting (Docket No. 8880)

The description of the deferred accounting application is in Section V of this report.

VI. The Rate Case

A. Cost of Service (Expenses and Taxes)

1. Purchased Power

Listed below are the various recommendations concerning the appropriate purchased power expense that should be included in TNP's cost of service:

Test year	TNP Request	Staff Recommendation	Examiners' Recommendation
$199,127,617	$205,760,104	$193,136,288	$198,520,645

TNP witness Mr. Garry M. Johnson explained TNP's proposed purchased power expense. TNP Exhibit Nos. 21 and 63. The parties that reviewed this portion of TNP's application generally supported TNP's request. There was, however, one issue which affected several calculations that contribute to TNP's total purchased power expense. Both Mr. Johnson and Cities' witness Mr. Jack E. Stowe, Jr. testified that that portion of the purchased power expense attributable to power purchased from HL&P should be based upon HL&P's current bonded rates. TNP Exhibit No. 63 at 5; Cities Exhibit No. 3 at 14; TNP Brief at 33. HL&P is itself in the midst of a rate case, Docket No. 8425, and has put into effect bonded rates as of June 9, 1989, pursuant to Section 43(e) of the PURA.

Staff witness Ms. Rhonda McClellan reviewed purchased power expenses and recommended four adjustments. Staff Exhibit No. 15. First, she recommended that the power expense attributable to Southwestern Public Service Company (SPS) should be based in part upon SPS's monthly fuel adjustment factor applicable at the end of the test year rather than the factor applicable in February 1989. TNP agreed with Ms. McClellan. TNP Brief at 33.

Ms. McClellan's remaining three recommendations are based upon her position that that portion of the power expense attributable to HL&P should be based upon HL&P's rates as approved in its last rate case, Docket No. 6765. She testified that if the power expense calculations are based upon HL&P's rates in Docket No. 6765, then the purchased power expense attributable to HL&P and Clear Lake Cogeneration Company (because CLC's contract with TNP provides that CLC's rates are 98 percent of HL&P's rates) should be reduced. Further, the lower HL&P rates affect the year-end customer adjustment to purchased power expense because the adjustment is based in part on the cost of purchased power.

The examiners agree with the staff's position. Commission Substantive Rule 23.21(a) provides that a utility's rates are to be based upon its cost of rendering service during the test year, adjusted for known and measurable changes. The rule explicitly permits exceptions where other substantive rules dealing with fuel expenses are applicable. But the examiners find that there are no other substantive rules which authorize the relief sought by TNP. <u>See</u> P.U.C. SUBST. R. 23.23. HL&P's bonded rates went into effect after the end of TNP's test year. The bonded rates are not a known and measurable change from the rates approved by the Commission in Docket No. 6765 because the amount and the effective date of the rates which the Commission will approve in Docket No. 8425 are unknown. The fact that HL&P implemented bond rates that are comparable to the staff's recommendations in Docket No. 8425 does not mean that the Commission will ultimately approve rates equal to the bonded rates. The examiners note that TNP will recover from its customers the full cost of purchased power, whether it is through base rates or through its PCRF.

The examiners recommend approval of TNP's proposed purchased power expense, as adjusted by staff witnesses McClellan and Ms. Kathleen J. North. Ms. McClellan recommended a purchased power expense of $193,136,288. During the hearing on the merits, she concurred that one of her calculations was incorrect, causing her calculation to be too low by $5,384,357. TNP Exhibit No. 63 at 4; Tr. at 4405. Ms. McClellan's corrected recommended purchased power expense is $198,520,645. Ms. North pointed out that purchased power expense should be reduced by $107,760 to reflect a company input error during the test year. The company's test year revenues reflect August 1988 billing demand expenses attributable to HL&P in excess of such expenses actually incurred. Staff Exhibit No. 20 at 4. The examiners therefore recommend purchased power expense of $198,412,885.

2. Operations and Maintenance

Included as Schedule II is the examiners' recommendation regarding operations and maintenance expense.

a. <u>O&M Not Adjusted</u>. The test year O&M expenses that TNP did not adjust totalled $13,898,622. The examiners recommend an adjustment to outside services expense in the amount of negative $23,605, as discussed in section IV.A.2.d.v. of this report. The examiners recommend an adjustment to advertising expense in the amount of negative $14,616, as discussed in section VI.A.d.viii.4. The examiners recommend an adjustment to Texas Atomic Energy Research Foundation dues in the amount of negative $16,660, as discussed in section VI.A.d.viii.5. The examiners' recommended unadjusted O&M expense is found on Schedule II.

b. <u>Standby Expense</u>. Listed below are the various recommendations concerning the appropriate standby power expense that should be included in TNP's cost of service:

Test Year	TNP Request	Staff Recommendation	Examiners' Recommendation
$1,784,216	$1,999,229	$1,999,229	$1,999,229

There are two congeneration facilities located in TNP's service area. Each facility contracts with TNP to provide standby power in the event the facility incurs a forced outage or a maintenance outage. TNP in turn contracts with HL&P for standby power. TNP did not incur standby power expense during the first month of the test year, April 1988. The adjustment made by TNP consists of an annualization of the test year standby power expense, as explained in the testimony of TNP witness Johnson. TNP Exhibit No. 21 at 18. Staff witness McClellan concurred with the adjustment. Staff Exhibit No. 15 at 4. TNP witness Ms. Barbara K. Ellis made adjustments to present and proposed revenues received from the congenerators to match Mr. Johnson's adjustment. TNP Exhibit No. 20 at 10. The examiners conclude that Mr. Johnson's adjustment appropriately reflects known and measurable changes to the test year expense, and therefore recommend approval of standby power expense of $1,999,229.

c. Labor Expense and Labor-Related Expense.

i. Allocation Factor. TNP's payroll system automatically allocates labor and labor-related expenses among TNP and its affiliates based on the percent of time a TNP employee works on affiliate operations. Employees record all time attributable to affiliate operations on their daily time sheets. TNP Exhibit No. 5 at 27.

TNP uses several allocation factors to develop the labor and labor-related expense. TNP Exhibit No. 19 at 3. An allocation factor is used to predict the amount of total labor cost for Texas operations that is expensed. (The portion of labor cost that is not expensed is capitalized or is attributable to non-utility operations. Tr. at 1627.) This factor is .681871. A second factor is used to predict the amount of the total general office (Fort Worth) labor cost that is expensed. This factor is .811127. A third factor is used to predict the amount of general office labor that is attributable to Texas operations. This factor is .797103. The general office labor cost is multiplied by both the second and third allocation factors to determine the general office labor expense. Staff witness Foreman testified that the allocation factors are reasonable. Staff Exhibit No. 5 at 8. The examiners recommend approval of the allocation factors used by the company.

ii. Labor Expense. TNP's adjustment to the test year labor expense consists of four components. First, the wage rates at the end of the test year were annualized. In addition, wages were adjusted for board-approved promotions and wage increases for employees who report to TNP's president. Second, wage progressions anticipated during the period April 1, 1989, through September 30, 1989, were added. Third, additional overtime wages for non-exempt employees were added. Fourth, wages for new employees, net of retirees, anticipated during the period April 1, 1989, through September 30, 1989, were added. Each adjustment was multiplied by the appropriate allocation factor. TNP Exhibit No. 19 at 4.

The only criticism of TNP's labor adjustment methodology came from Cities' witness Mr. Jack E. Stowe, Jr. Mr. Stowe testified that the most current available salary information concerning TNP is the second quarter of 1989, ending June 30, 1989. TNP's labor expense adjustments go beyond this period and are therefore not currently known and measurable. Cities Exhibit No. 3 at 16. TNP witness Mr. Gary L. Spooner sponsored TNP's labor expense adjustment. Mr. Spooner could have submitted information which showed that the expenses projected through September 30, 1989, had actually occurred and were therefore known and measurable. His rebuttal testimony, however, did not respond to Mr. Stowe's argument. The examiners agree with Mr. Stowe and conclude that TNP's adjustment does not consist of a known and measurable change to test year labor expense.

Mr. Stowe's own proposed labor expense adjustment is based on salary expense and employee levels that occurred during the second quarter of 1989. Mr. Stowe's calculation annualized the base payroll and added an overtime factor. Cities Exhibit No. 3, JES-17. He testified that he used company payroll information from the most recent quarter available, rather than from the most recent month available, due to the instability from month to month displayed in actual labor costs. The examiners conclude that Mr. Stowe's analysis is more reasonable than the staff's analysis, which proposed an adjustment based upon June 1989 wage data because it mitigates the effect of monthly fluctuations. Staff Exhibit No. 5 at 6. The examiners recommend approval of Mr. Stowe's recommended labor expense of $20,060,988.

[1] iii. Labor-Related Expense. Labor-related expense consists of (1) pension plan costs, (2) workers' compensation and public liability insurance, (3) thrift plan costs, and (4) group life insurance. Listed below are the various recommendations concerning the appropriate labor-related expense that should be included in TNP's cost of service:

Test Year	TNP Request	Staff Recommendation	Examiners' Recommendation
$2,744,443	$2,851,424	$2,589,624	$2,775,987

TNP witness Spooner calculated the adjusted pension plan expense of $1,202,057 by adding to the test year pension plan expense the product of the following formula:

$$\frac{\text{Test year pension cost}}{\text{Test year labor cost}} \times \text{(TNP recommended adjusted labor expense)} \times \text{(Expense allocator)}$$

Commission staff witness Foreman disagreed with TNP's methodology because pension cost does not bear a direct relationship to labor cost. Further, she pointed out that TNP calculated its pension costs using Financial Accounting Standards Board (FASB) 87, which recognizes changes in the market value of a pension plan's portfolio assets that do not require a cash outflow. She recommended that TNP be allowed to recover from its ratepayers only those amounts that were actually funded. Staff Exhibit No. 5 at 9. Her recommendation is in accord with the Commission's decision in Docket No. 8363, Application of El Paso Electric Company for Authority to Change Rates, 14 P.U.C. BULL. 2834 (May 5, 1989). The examiners therefore recommend that pension expense be based upon the 1989 actual pension funding requirements incurred by TNP. Pension funding costs for all TNPE operations during 1989 totalled $1,990,273. TNP Exhibit No. 48 at 4. The examiners followed the allocation formula used by staff witness Foreman and recommend a pension plan expense of $1,147,963. Staff Exhibit No. 5 at 11. The portion of total TNPE pension cost allocable to TNP is calculated as follows:

(1,990,273)(.652638)(.681871) + (1,990,273)(.203807)(.811127)
(.797103).

TNP witness Spooner calculated adjustments to test year workers' compensation and public liability insurance expense, thrift plan expense, and group life insurance expense, using calculations similar to TNP's proposed pension plan expense adjustment shown above. Both staff witness Foreman and Cities' witness Stowe agreed with the methodology but stated that their own calculation of adjusted labor expense should be used in the calculation of the labor-related expenses. The examiners agree with the method of calculation used by the parties and recommend its adoption. The examiners further recommend utilizing the examiners' recommended level of labor expense, $20,060,988, in the calculations of the components of labor-related expense. The calculation of total labor-related expense shown below is based upon TNP's requested labor-related expense (TNP Exhibit No. 3, Schedule A at 5), the examiners' recommended pension expense, and the calculations shown on Exhibit JES-18 of Mr. Stowe's testimony (Cities Exhibit No. 3):

Pension expense	$1,147,963
Workers' compensation and liability insurance ($759,464 - $6901)	$752,563
Thrift expense ($756,190 - $12,320)	$743,870
Group insurance ($133,713 - $2,122)	$131,591
Total	$2,775,987

The examiners did not find credible the testimony of OPC witness Mr. Randy Allen on labor-related expense. Mr. Allen proposed adjustments based upon the most recent monthly data available. But as Mr. Allen points out, the proportionate relationships he relies upon change from month to month. The examiners find more reasonable the testimony of the other parties that relied upon data from a twelve month period because the monthly fluctuations are mitigated. OPC Exhibit No. 11 at 16.

d. <u>Miscellaneous</u>.

i. General Office Expense. TNP's corporate general office is located in Fort Worth, Texas. Costs incurred by the general office are not accounted for under a separate line item as "general office expense." Instead, each expense category is treated separately and included with other similar costs incurred by TNP. TNP Brief at 42.

ii. General Office Rent. General office rent during the test year totalled $575,571. TNP proposed an adjustment of $110,188 due to a rent increase effective May 1989. TNP Exhibit No. 17 at 3. The rent increase is contained in TNP's September 1984 lease of the premises. The parties did not contest the rent increase or the methodology used to allocate a portion of the increase to TNP. The examiners recommend approval of general office rent of $685,759.

iii. Factoring Expense. TNP sells its daily billed accounts receivable to CSW Credit, Inc. The factoring cost consists of an interest component (because receivables are sold at a discount), and a bad debt component (because receivables are sold without recourse). TNP demonstrated that factoring results in a net benefit to ratepayers. TNP Exhibit No. 16 at 6.

The factoring expense is determined by multiplying TNP's cost of service by a factoring expense effective rate. TNP formulated the rate by dividing test year factoring expense by test year total Texas revenues. Staff witness Foreman's analysis of information obtained from the Company led her to recommend an updated factoring expense rate based on information from the 12 months ending August 1989. She recommended a rate of .00955413. Staff Exhibit No. 5 at 14. OPC witness Allen concurred. OPC Exhibit No. 11, RMA-7 schedule 2. The factoring expense rate developed by Cities' witness Stowe is unreliable because it is based on financial information occurring on one day, September 19, 1909. Cities Exhibit No. 3 at 15.

The examiners conclude that the rate used by staff and OPC reflects the latest factoring expense rate that is known and measurable and therefore recommend its adoption. The examiners' recommended factoring expense is found on Schedule II.

The testimony of both staff witness Foreman and OPC witness Allen discussed the overall benefit of factoring to ratepayers. Both concluded that at this time factoring does benefit TNP's ratepayers and therefore factoring should be a recoverable expense.

iv. Rate Case Expense. Under the procedure established by Examiner's Order No. 2 in Docket No. 8928, the company and the Cities filed invoices for rate case expense periodically throughout the proceeding. The order provided the parties the following guidelines:

1. The testimony of each witness offered to support rate case expenses must expressly state that the witness has informally audited the invoices and other documentation. A cursory review in not sufficient. Expense items will not be presumed to be reasonable.

2. The evidence must demonstrate that:

   * the individual charges and rates are reasonable (<u>e.g.</u>, by comparison with the usual charges for similar services);

   * the hours spent on each service are reasonable;

* the calculation of the charges is correct;

* there is no double-billing of charges;

* none of the charges for rate case expenses has been recovered through reimbursements for other expenses.

TNP witness Ms. Sheryl A. Benoit filed testimony in support of the Company's estimated rate case expenses. TNP Exhibit Nos. 9, 9a, and 9b. TNP witness Mr. Philip F. Ricketts testified as to the reasonableness of the rates charged and hours billed by TNP's representative before the Commission, the firm of Johnson & Gibbs. Staff witnesses Foreman and Mr. Paul C. Bellon filed testimony concerning rate case expenses. They concluded that, to a great extent, the rate case expenses actually incurred by TNP in the consolidated dockets were reasonable and recommended their inclusion in cost of service. Staff Exhibit Nos. 11 and 22.

TNP's request consists of two elements, TNP's own rate case expenses and the rate case expenses incurred by the Cities. TNP must reimburse the Cities for rate expenses incurred by the Cities to the extent the expenses are found reasonable by the Commission. PURA Section 24(a). Concerning TNP's own rate case expenses, during the hearing and in the initial briefs in Phase I of this case, the staff and TNP disagreed on several issues. The staff recommended disallowance of those expenses that were billed to TNP under a formula because those expenses are not supported by original receipts and are therefore not known and measurable. The staff recommended disallowance of those portions of Johnson & Gibbs bills that were not supported by original receipts. Finally, the staff testified that estimated expenses are not known and measurable, and therefore recommended disallowance of all expenses incurred after November 30, 1989, because this is the last day for which TNP had submitted invoices for the staff's review.

TNP's final position on rate case expense was that the evidence supported the staff's recommendation. The staff submitted a late-filed exhibit on December 15, 1989, which showed the staff's final evaluation of TNP's rate case expense. Staff Exhibit No. 23. The late-filed exhibit was admitted into the record. Tr. at 5711; Examiners' Order No. 17. The staff increased its recommendation to $905,240. The increase was based upon the staff's review of additional receipts for services billed by Johnson & Gibbs. TNP concluded that "the evidence supports the inclusion of the updated [staff] expense figures in TNP's cost-of-service." TNP Phase I Reply Brief at 19. The examiners note that the staff's expense recommendation is in excess of the company's request but is less than the expenses actually incurred by TNP on or before November 30, 1989.

The Cities' rate case expense remained a contested issue. The Cities' representative, Mr. Butler, did not contest the staff's adjustments to the Cities' expenses that were incurred by November 30, 1989, the last day for which the Cities had submitted invoices for the staff's review. But he argued that the staff's recommendation to disallow all costs not yet incurred was an arbitrary standard that is inconsistent with Sections 23 and 24 of PURA. Cities Reply Brief at 3.

The staff recommended approval of expenses attributable to expert witnesses Stowe and Mr. Jack Hopper in excess of the Cities's, original estimated amounts for these witnesses. Cities Exhibit No. 4A. Staff Exhibit No. 23 at PB-4. The only information in the record concerning the Cities' request for expenses in excess of the staff recommendation for these two witnesses is the staff's late-filed exhibit. The information in Schedule PB-4 is presented in a confusing manner because it is not clear what meaning should be attributed to totals under the "expenses not yet incurred" column that are in brackets as opposed to totals that are not in brackets. The examiners therefore recommend approval of the staff's recommended expense for witnesses Stowe and Hopper that is based upon "expenses incurred to date," a total of $87,116.

The Cities estimated that expenses attributable to the firm of Butler & Casstevens would total $55,053. Staff recommends allowance of $17,267, based upon expenses incurred through November 30, 1989. The examiners agree with Mr. Butler that under Section 24 of the PURA, that the Cities are entitled to reimbursement from the utility for the reasonable costs of expenses incurred after the hearing on the merits. The staff's position that reasonable legal expenses incurred after the hearing on the merits cannot be recovered is contrary to Section 24 of the PURA. Further, the Cities are entitled to the same treatment as the utilities. The Commission has previously rejected staff's argument that a utility may not recover estimated rate case expenses. Docket No. 5610, Application of GTE Southwest, Incorporated for a Rate Increase, 15 P.U.C. BULL. 1, 118-9 (February 23, 1989). The examiners conclude, however, that the Cities' estimate of legal expenses is excessive. The record does not provide sufficient evidence that, with six days remaining in the hearing on the merits, the Cities reasonably anticipate that 69 percent of total legal expenses will be incurred after that date. The examiners therefore recommend approval of Cities' legal expenses of $22,267.

v. Outside Services. TNP did not propose adjustments to its test year outside services expense of $1,464,174. OPC witness Allen, however, testified that certain outside services incurred during the test year are not of a recurring nature, and he therefore recommended a reduction to test year expense for known and measurable changes. OPC Exhibit No. 11 at 36. TNP Assistant Treasurer Mr. Robert F. Horton responded to Mr. Allen's recommendations. TNP Exhibit No. 45 at 10. Mr. Horton's response shows that three of five of Mr. Allen's recommendations are incorrect because the outside services were properly accounted for, and the services are in fact recurring. The examiners agree with Mr. Allen that the record shows that the services provided by the firms of Stone & Webster and Isham, Lincoln & Beale are not of a recurring nature. The examiners' conclusion is based upon TNP's representation that it intends to file a new rate case soon after this rate case is completed, and upon the fact that Mr. Horton's rebuttal testimony gave no definite indication that these services would be needed during the period that the rates approved in Docket No. 8928 will be in effect. The examiners therefore recommend disallowance of $13,318 attributable to Stone & Webster, and $10,287 attributable to Isham, Lincoln & Beale. (The amount attributable to Isham, Lincoln & Beale is the test year expense of $13,176, less amounts allocated to New Mexico and TNPE operations.)

vi. Mr. Tarpley's Airplane. Mr. J.M. Tarpley is the chief executive officer of both TNP and TNPE. Mr. Tarpley flies his own plane to TNP's service territories on company business and charges TNP $146 per hour flight time. During the hearing TNP witness Horton was questioned concerning the reasonableness of the $146 per hour rate (Tr. at 467), but no party recommended disallowance of any portion of this expense.

vii. Directors Fees. Staff witness Foreman recommended a decrease of $35,209 to TNP's unadjusted O&M because one member of the board of directors is paid annual fees far in excess of the other members. Staff Exhibit No. 5 at 5. Enron supported the staff's adjustment. Enron Reply Brief at 14. The rebuttal testimony of TNP witness Horton shows, however, that Mr. R. D. Woofter is paid $72,000 in annual fees, as compared to the other members that are paid $9,000 in annual fees, because Mr. Woofter is the former chief executive officer of TNP. Further, Mr. Woofter is the agent of the board of directors, and has a policy of meeting weekly with Mr. Tarpley. TNP Exhibit No. 45 at 12. The evidence shows that Mr. Woofter's duties are in excess of those of the other board members, justifying a greater fee for his services. There is no credible evidence in the record to support the allegation that his fees are unreasonably greater than the fees paid to the other board members. The examiners therefore recommend that the Commission not adopt the staff's adjustment to TNP's unadjusted O&M expense.

viii. Dues, Contributions, and Advertising. During the test year TNP made contributions to approximately 13 organizations that totalled $42,082 to TNP's donations and contributions expense. TNP Exhibit No. 3, Schedule G-4, 2-1. Enron witness Mr. Lane Kollen argued that the donations are not a cost of service, that ratepayers do not have a voice in the determination of recipients, and that ratepayers do not receive an individual tax deduction benefit for contributions made on their behalf. Enron Exhibit No. 69 at 23. TNP must appreciate Mr. Kollen's second point. A letter in the record signed by TNP's president says that HL&P (a wholesale supplier to TNP) should not include contributions to a particular entity in its wholesale rates because TNP "should have the option of determining for itself" whether it wishes to make contributions. TNP Exhibit No. 1, JVC-3. TNP's argument that the contribution expense is below the maximum contribution amount allowed by the Commission's substantive rules misses the point that all expenses must be reasonable and necessary. P.U.C. SUBST. R. 23.21(b)(2)(J). Contributions are not a reasonable cost of service, given TNP's position that it must receive a rate increase to maintain its financial integrity. The examiners therefore recommend that the Commission disallow TNP's adjusted "Donations" expense, as shown on Schedule II.

(1) EEI dues. TNP is a member of the Edison Electric Institute (EEI). The parties all agreed that some portion of EEI dues are just and reasonable but could not agree on the allowable amount. TNP witness Dudley E. Craig and staff witness Foreman disagreed concerning the portion of total EEI dues that are attributable to Texas operations. TNP Exhibit No. 47 at 10; Staff Exhibit No. 5 at 16. The witnesses' allocation methodologies were equally unexplained. The examiners therefore adopt the staff's recommendation of $96,998 because it is the lower figure.

The witnesses Craig, Foreman, and OPC witness Allen then disallowed a portion of EEI dues that are attributable to EEI activities that are not allowable expenses under P.U.C. SUBST. R. 21.21(b). The witnesses all relied upon the National Association of Regulatory Utility Commissioners' <u>Audit Report on the Expenditures of the Edison Electric Institute</u>. The report is dated November 1, 1988. The witnesses agreed that the portion of EEI dues attributable to EEI legislative advocacy (15.28%), club dues (.07%), and publications which promote consumption of electricity (.08%), should be disallowed. The examiners agree with Mr. Allen's recommendations that dues attributable to legislative policy research (5.22%) and political activity contributions (.34%) should also be disallowed. The two additional activities are not allowable expenses because they are directly or indirectly related to legislative advocacy. P.U.C. SUBST. R. 23.21(b)(1)(E)(iv). The examiners therefore recommend disallowance of 20.99 percent of EEI dues attributable to Texas operations, and recommend EEI expense of $76,638.

(2) EPRI dues. On March 23, 1989, TNP became a member of the Electric Power Research Institute (EPRI). EPRI implemented a new policy in April 1989 that requires a utility to be a member of EPRI before EPRI will provide to the utility advice, assistance, and the results of EPRI studies. TNP witness Mr. James Johnson, the Manager of the South Central Region of EPRI, testified that enforcement of the new policy in Texas poses a special problem because EPRI dues are based upon a utility's retail sales. In most instances a utility's EPRI dues are recovered through retail sales because the Federal Energy Regulatory Commission does not permit recovery of EPRI dues through wholesale rates. In Texas, however, HL&P and TU Electric recover a portion of EPRI dues through wholesale rates. TNP purchases power from these utilities and therefore pays EPRI dues through its purchased power expense. But EPRI's revenues from HL&P and TU Electric are no greater because EPRI dues are not based, even in part, upon wholesale sales. Tr. at 4823.

TNP requests EPRI dues expense of $364,396, based upon two conflicting arguments made by TNP Vice President Mr. Jack V. Chambers. First, he stated that the Company will not continue to be a member of EPRI if TNP must continue to pay wholesale electric rates to HL&P and TU Electric that include EPRI dues. TNP Exhibit No. 1 at 13. Because the consolidated dockets 8928 and 8880 do not concern a review of the rates of HL&P or TU Electric, the examiners respond that TNP's argument is misplaced.

Second, he stated that TNP wants to continue to be an EPRI member and pay dues directly to EPRI so that it can obtain the "direct benefits" of EPRI programs. TNP and its ratepayers will not be double charged for EPRI dues because EPRI agrees to adjust its dues assessment against TNP downward to reflect the fact that TNP is making indirect payments to EPRI. TNP Exhibit No. 61 at 4. If this is the case, then the Commission staff, OPC, and Enron would likely recommend approval of the EPRI expense. These parties did not contest the reasonableness of EPRI membership but did recommend disallowance of all EPRI expense, based upon the understanding that TNP and its ratepayers would be double charged for EPRI dues if TNP paid dues direct to EPRI.

To rebut this charge, Mr. Chambers pointed out that during the year 1989, EPRI granted TNP a "special credit" of $437,000 to reflect indirect payments, so that TNP's direct payment to EPRI was only $2,797. Mr. Johnson testified that EPRI agrees to grant the special credit until TNP no longer pays EPRI dues indirectly. TNP Exhibit No. 49 at 18. TNP's 1990 EPRI dues that are allocated to Texas operations total $364,396. TNP Exhibit No. 21, GMJ-8. The credible evidence in the record shows that the 1990 special credit will be equal to the 1989 credit, which is in excess of 1990 dues attributable to Texas. The examiners therefore recommend excluding all EPRI dues expense.

(3) Chambers of commerce dues. OPC witness Allen recommended disallowing $8,550 of TNP's O&M expense attributable to chambers of commerce dues. OPC Exhibit No. 11 at 29. The examiners conclude that the credible evidence in the record shows that the dues are expended in support of, or membership in, professional or trade associations that contribute toward the professionalism of their membership. The conclusion is based upon the fact that TNP employees improve their professional skills as they work towards the goals of the particular chamber of commerce. TNP Exhibit No. 45 at 9. The expenses are therefore allowable under P.U.C. SUBST. R. 23.21(b)(1)(E)(iv). The Commission should not adopt Mr. Allen's recommendation, but should include the $8,550 in chambers of commerce dues in O&M expense.

(4) Advertising. OPC witness Allen recommended disallowing $16,849 of TNP's O&M expense attributable to advertising. Mr. Allen recommended disallowing a portion of the test year advertising expense in the amount of $2,233 because Mr. Allen thought the particular ads were "related to institutional or image building" advertising. OPC Exhibit No. 11 at 31. But such advertisements are ordinary advertising that is an allowable expense under P.U.C. SUBST. R. 23.21(b)(1)(E). Mr. Allen recommended disallowing another portion of the test year advertising expense in the amount of $14,616 because the advertisements promote the use of special security lights. TNP did not

contest the dollar amount Mr. Allen attributed to such advertising. TNP Exhibit No. 45 at 9. TNP argues that the advertisements are an allowable expense because TNP's purpose is to improve load management. This argument ignores the fact that the advertisements seek to create a demand for electricity where there was none before. The examiners conclude that such advertising is not an allowable expense because the advertising promotes increased consumption of electricity. P.U.C. SUBST. R. 23.21(b)(2)(F). The examiners therefore recommend that the Commission disallow $14,616 of TNP's O&M expense that is attributable to advertising expense.

(5) Texas Atomic Energy Research Foundation. OPC witness Allen and Cities witness Stowe recommened disallowing $16,660 of TNP's O&M expense attributable to dues paid during the test year to the Texas Atomic Energy Research Foundation. Cities Exhibit No. 3 at 17. TNP argues that the expense is "used and useful" to TNP's ratepayers because two of TNP's wholesale suppliers have nuclear facilities. If TNP's membership in the foundation brings about any benefits to the nuclear industry, then TNP's ratepayers will be in a position to indirectly benefit. TNP Reply Brief at 25. TNP's argument is, of course, incorrectly based upon the standard for determining a utility's invested capital. PURA Section 41(a). This expense is not a reasonable or necessary cost of service. P.U.C. SUBST. R. 23.21(b)(2)(J). The Commission should adopt the recommendation of Mr. Allen and Mr. Stowe and disallow $16,660 of TNP's O&M expense attributable to dues paid to the Texas Atomic Energy Research Foundation.

(6) Civic club dues. OPC witness Allen recommended disallowing $11,425 of TNP's O&M expense that is attributable to civic club dues. OPC Exhibit No. 11 (Exhibit RMA-7, Schedule 5). Civic club dues are listed together with professional dues in TNP's schedules. The total expense for both types of dues during the test year was $15,908. TNP Exhibit No. 3, schedule G-4.2-2. The examiners conclude that the credible evidence in the record shows that the dues are expended in support of, or membership in, professional or trade associations that contribute toward the professionalism of their membership. The conclusion is based upon the fact that TNP employees improve

their professional skills as they work towards the goals of the particular civic club. TNP Exhibit No. 45 at 9. The expenses are therefore allowable under P.U.C. SUBST. R. 23.21(b)(1)(E)(iv). The Commission should allow this amount in TNP's O&M expense.

(7) Other dues. OPC witness Allen recommended disallowing $8,076 of TNP's O&M expense attributable to "other less than $50" dues and subscriptions. TNP Exhibit No. 3, Schedule G-4.2-2. TNP witness Horton's rebuttal to Mr. Allen's recommendation consists of a response that is intended to apply equally to Mr. Allen's recommendations concerning chambers of commerce dues, civic club dues, and other dues. TNP Exhibit No. 45 at 9. TNP failed to explain to whom and why "other dues" are paid. The examiners cannot assume that TNP employees will improve their professional skills as a result of being members of groups that have not been identified. The credible evidence in the record therefore does not show that "other less than $50" dues contribute toward the professionalism of their membership. The Commission should adopt Mr. Allen's recommendation and disallow TNP's O&M expense of $8,076 attributable to "other less than $50" dues expense.

ix. Interest on Customer Deposits. OPC witness Allen recommended an increase of $13,752 to TNP's O&M expense attributable to interest on customer deposits. OPC Exhibit No. 11, Exhibit RMA-7, Schedule 10. TNP witness Dudley E. Craig testified that the company's proposed expense is based upon test year end customer deposits, multiplied by the interest rate on customer deposits prescribed by the Commission at the time Mr. Craig prepared his direct testimony (July 1989). TNP Exhibit No. 17 at 8. The examiners conclude that the credible evidence in the record does not support Mr. Allen's recommendation, and recommend that the Commission not adopt it.

x. Field Collection Costs. OPC witness Allen recommended a decrease of $113,637 to TNP's O&M expense attributable to costs related to TNP employees making trips to customers' homes to collect overdue bills. Mr. Allen argued that if the Commission grants TNP's request in the rate case to implement a direct charge to customers, then TNP's field collection costs will decrease.

The credible evidence indicates that the costs will remain the same. The examiners recommend that the Commission not adopt Mr. Allen's recommendation.

xi. Energy Efficiency Programs. The examiners recommend an increase of $82,400 to the company's operation & maintenance expense to reflect costs related to the company's energy efficiency programs, as discussed in section VI.F of the report.

3. Depreciation

Listed below are the various recommendations concerning the appropriate depreciation expense that should be included in TNP's cost of service:

Test Year	TNP Request	Staff Recommends	OPC Recommends	Cities Recommend
$12,353,250	$13,000,878	$13,000,878	$12,710,307	$12,585,246

TNP witness William K. Strand presented TNP's proposed depreciation expense. TNP Exhibit No. 7. Staff witness N. S. Parate concurred with TNP's proposed depreciation expense. Staff Exhibit No. 9. As discussed below in section IV.C.1.a. of this report, the examiners recommend excluding from invested capital TNP's 345 kilovolt (KV) transmission line that connects TNP One with the Electric Reliability Council of Texas (ERCOT) grid. The examiners therefore recommend disallowing depreciation expense that is attributable to the line, $290,571. TNP Exhibit No. 48 at 8. OPC witness Allen, Enron witness Kollen, and Cities witness Stowe all recommended disallowance of this expense.

As discussed below in section IV.C.1.b. of this report, the examiners recommend excluding from invested capital TNP's proposed reclassification of CWIP to plant in service. The examiners therefore recommend disallowing the depreciation expense of $12,089 that is attributable to the CWIP projects. Tr. at 1616.

[2] Cities witness Mr. B. C. Sarma recommended disallowing depreciation expense of $122,437 attributable to TNP's depreciation of transmission plant land rights. Cities Exhibit No. 2 at 6. The examiners agree with Mr. Sarma. First, the examiners note the definition of depreciation used by Mr. Strand:

> "Depreciation," as applied to depreciable utility plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities.

TNP Exhibit No. 7 at 3.

Depreciation expense recognizes the loss in service value of an asset as a cost of providing service. Depreciation expense is also a mechanism by which the utility's investment in assets dedicated to serving the public is returned to the utility.

TNP's land rights consist of the company's purchased rights-of-way for transmission lines. TNP proposed to depreciate the cost of the rights-of-way over the period of the estimated life of the related transmission line. In rebuttal testimony, Mr. Strand objected to Mr. Sarma's proposal, but gave no information suggesting that TNP will abandon the rights-of-way upon the end of the useful life of the related transmission line. TNP Exhibit No. 53 at 3. TNP witness Spooner also did not say that TNP intends to abandon the rights-of-way. TNP Exhibit No. 48 at 7. There is no credible evidence in the record establishing that the rights-of-way will lose their value upon the end of the service life of the related transmission line. TNP's rebuttal testimony left unanswered the question whether, at the end of the useful life of the first transmission line, TNP might build a new transmission line on the same right-of-way, or might sell the right-of-way to a third party such as an electric or telephone utility.

For purposes of comparison, the examiners note that land is generally considered to be nondepreciable because overtime does not suffer a "loss in service value." The examiners conclude that TNP's land rights also do not suffer a loss in service value over time. Similar to the regulatory treatment of land, TNP's ratepayers should pay a reasonable return on TNP's investment in land rights, but should not reimburse TNP for the investment itself through depreciation expense.

Mr. Strand incorrectly states that TNP's current ratepayers will enjoy the use of the land rights without cost if the land rights are not depreciated. TNP Exhibit No. 53 at 5. TNP's investment in the land rights is dedicated to serving the public. It is therefore included in TNP's invested capital, for which the ratepayers pay TNP a reasonable return. The examiners recommend depreciation expense of $12,587,870, based upon the recommendations of witnesses Allen and Sarma.

4. Taxes Other than Income Taxes

The examiners' recommended taxes other than income tax expense is found on Schedule III. The examiners discussed below the various tax expenses that comprise "taxes other than income taxes" only if a party recommended an adjustment to TNP's requested amount:

a. Payroll Taxes. Cities witness Stowe recommended an adjustment to payroll taxes based upon his own calculation of labor expense. Cities Exhibit No. 3, JES-24. TNP's labor expense, which was discussed earlier in this report, affects the calculation of payroll tax expense. TNP witness Spooner disagreed with the labor expense total used by Mr. Stowe in his calculation of payroll taxes but did not object to the methodology used by Mr. Stowe. TNP Exhibit No. 48 at 5. Because the examiners have recommended that the Commission adopt Mr. Stowe's calculation of labor expense, the examiners also recommend that the Commission adopt Mr. Stowe's calculation of payroll tax expense.

b. Environmental Taxes. No party proposed an adjustment to TNP's proposed environmental tax expense of $15,262. The examiners find this amount reasonable and recommend its inclusion in cost of service.

c. State Franchise Taxes. Listed below are the various recommendations concerning the appropriate Texas state franchise tax expense that should be included in TNP's cost of service:

Test year	TNP Request	Staff Recommends	OPC Recommends	Examiners Recommend
$724,906	$756,754	$692,957	$756,754	$756,754

OPC witness Allen and staff witness Foreman recommended adjustments based upon the decrease in the franchise tax rate that is effective May 1, 1990. Mr. Allen's adjustment for estimated 1990 tax expense reflects the fact that the new, lower rate will not go into effect until May. OPC Exhibit No. 11 at 42. Ms. Foreman's adjustment simply adopts the new rate. During cross examination, Ms. Foreman admitted that the calculation of tax expense should reflect that TNP will continue to pay franchise tax at the higher rate through April 1990. Tr. at 3523. TNP concurred with Mr. Allen's adjustment. TNP Exhibit No. 47 at 7. Ms. Foreman proposed a second adjustment to franchise tax expense based upon a refund of such taxes received by TNP during the years 1984 through 1987. This proposed adjustment is discussed in section IV.B.2. of the report. The examiners recommend that the Commission adopt Mr. Allen's proposed adjustment, and recommend a state franchise tax expense of $756,754.

d. Ad Valorem Taxes. Listed below are the various recommendations concerning the appropriate ad valorem tax expense that should be included in TNP's cost of service:

Test year	TNP Request	Staff Recommends	OPC Recommends	Examiners Recommend
$3,253,675	$3,454,382	$3,329,004	$3,105,509	$3,450,497

TNP witness Craig explained that TNP's adjustment is based upon a uncomplicated formula. First, an effective rate of taxation is determined, based upon 1988 ad valorem taxes as a ratio of 1988 gross plant. Second, the effective rate is applied to the gross plant total at the end of the test year.

Finally, the estimated tax is reduced by the portion allocated to TNPE operations and New Mexico opertions. TNP Exhibit No. 17 at 5. OPC argues that the tax expense should total TNP's 1988 ad valorem tax bill because TNP's proposed formula does not provide "known and measurable" taxes. OPC Brief at 7. OPC's argument confuses the determination of a test year expense with proposed adjustments to that expense for known and measurable changes, and would have the Commission determine TNP's cost of service based upon a period ending before the end of TNP's test year.

The credible evidence in the record shows that TNP's formula is a reasonable estimate of ad valorem tax expense. TNP's request should, however, be reduced by $3,885 to exclude taxes related to construction work in progress. TNP Exhibit No. 17 at 6. Staff witness Foreman testified that, according to generally accepted accounting principles, all costs, including ad valorem taxes, associated with construction work in progress should be capitalized rather than expensed. Staff Exhibit No. 5 at 20. The examiners therefore recommend an ad valorem tax expense of $3,450,497.

e. Texas Gross Receipts Taxes. The examiners' recommended gross receipts tax expense is shown on Schedule III. This expense is determined by multiplying the recommended revenue requirement by an effective tax rate. TNP, OPC, and staff used their own recommended revenue requirement to determine the proposed gross receipts tax expense. OPC witness Allen and staff witness Foreman also disagreed with TNP's effective tax rate. Mr. Allen argued that the calculation of the rate should not be based in part upon TNP's "other revenues" (i.e., revenues collected for reasons other than sales) because such revenues are not subject to the gross receipts tax. OPC Exhibit No. 11, RMA-7, Schedule 14. The examiners respond that the proportionate level of taxable revenue to non-taxable revenue will remain roughly equal over time. Ms. Foreman argued, and the examiners agree, that it is preferable to use actual taxes paid during the test year rather than TNP's use of test year taxes accrued. Staff Exhibit 5 at 26. TNP witness Craig testified that tax accruals are not estimates, but rather are based upon the particular month's revenues. TNP Exhibit No. 47 at 12. But this fact does not challenge the reasonableness of Ms. Foreman's reliance upon the test year actual taxes paid. The examiners therefore recommend that the Commission rely upon Ms. Foreman's calculations of the effective tax rate.

f. Street Rental Tax Rate. The examiners' recommend street rental tax expense as found on Schedule III. This expense, like the gross receipts tax expense, is determined by multiplying the recommended revenue requirement by an effective tax rate. OPC witness Allen and staff witness Foreman disagreed with TNP's effective tax rate. Mr. Allen argued that the calculation of the rate should not be based in part upon TNP's "other revenues" (i.e., revenues collected for reasons other than sales) because such revenues are not subject to street rental tax. OPC Exhibit No. 11 at 45, RMA-7 schedule 14. The examiners respond that the proportionate level of taxable revenue to non-taxable revenue will remain roughly equal over time. The examiners do not recommend adoption of Ms. Foreman's calculation of the effective tax rate because it is based upon actual taxes paid during a period other than the test year. The examiners therefore recommend that the Commission rely upon TNP's effective tax rate.

g. Texas PUC Assessment. The examiners's recommended PUC assessment expense is shown on Schedule III.

This expense, like the gross receipts tax and the street rental tax expenses discussed above, is determined by multiplying the recommended revenue requirement by an effective tax rate. Mr. Allen recommended the use of his recommended revenue requirement in the calculation of the expense, but he did not propose other adjustments. Staff witness Foreman recommended an adjustment to TNP'a proposed effective tax rate. The recommendation was not, however, based upon test year information. The examiners recommend that the Commission rely upon TNP's proposed effective rate.

5. Federal Income Taxes

Listed below are the various recommendations concerning the appropriate federal income tax expense that should be included in TNP's cost of service.

Included as Schedule V is the examiners' recommendation regarding federal income tax expense:

Test Year	TNP Request	Staff Recommends	OPC Recommends
$4,009,329	$7,936,752	$6,726,092	$2,952,828

a. Return Method. Three parties calculated a federal income tax expense for the company, and all utilized the return method for this calculation. This is a means of deriving federal income tax expense based upon the return dollars allowed a company. From an accounting perspective, the return included in cost of service represents the anticipated net income from operations of the utility after federal income tax in the rate year. The elements of a utility's revenue requirements, other than return and the federal income tax expense, are directly associated with tax deductable expenses. The return element and tax expense together are therefore roughly equivalent to pre-tax net income. After the adjustments are made to the return component, it is "grossed-up" to a before-tax number to which the tax rate of 34 percent is applied. These two calculations can occur together through utilization of the gross-up factor of 0.515151.

TNP witnesses Mr. Robert E. Williams, Jr. and Mr. John A. Jeter discussed the company's calculation of tax expense. TNP Exhibit Nos. 15, 50, and 58. Staff witness Ruth R. Runyon presented the staff's calculation of tax expense. Staff Exhibit Nos. 7 and 23. Mr. Allen presented OPC's calculation of tax expense. OPC Exhibit No. 11 at 47. Enron witness Kollen proposed one adjustment. Enron Exhibit No. 69 at 24. Cities witness Stowe proposed several adjustments. Cities Exhibit No. 3 at 20.

b. Calculation of Tax Expense.

i. Non-tax issues. The return methodology for calculating tax expense begins with the requested return and deducts an interest expense based upon the recommended invested capital and weighted cost of debt. The calculation on Schedule V begins with the return dollars recommended by the examiners. From that figure the interest expense, based upon the examiners' recommended weighted cost of debt times the examiners' recommended invested capital, is deducted.

ii. Amortization of Investment Tax Credits (ITCs). Staff witness Runyon explained her adjustment as follows: "Because amortization of ITC's is not an expense for which revenues are provided but is a reduction to the revenue requirement, the amortization will reduce revenues and thus will reduce TNP's return. This reduction is not reflected in return and therefore must be deducted." Staff Exhibit No. 7 at 15. Her adjustment was slightly larger than TNP's own proposed ITC deduction. TNP did not contest Ms. Runyon's adjustment. The examiners therefore recommend adoption of Ms. Runyon's recommended ITC deduction of $736,519, as shown on Schedule V.

iii. Amortization of Excess Deferred Taxes. As explained by Enron witness Kollen, TNP's accumulated deferred income tax balance consists of collections from ratepayers of taxes payable by the company in the future. The balance is increased to reflect current period tax benefits not yet returned to the ratepayers, and decreased as the tax benefits from prior periods are returned to the ratepayers. Future taxes are collected from ratepayers at current tax rates, and ultimately paid by the company at the future tax rate. The process is synchronized if a constant tax rate is assumed. But, of course, the federal income tax rate has declined twice in recent years. Consequently, as Mr. Kollen explains, a portion of the accumulated deferred tax balance became "excess." The excess deferred taxes belong to the ratepayers because they represent prepayments to the company for taxes that will never be owed or paid. Enron Exhibit No. 25 at 24.

TNP's accumulated excess deferred taxes consists of "protected" and "unprotected" amounts. As explained by staff witness Runyon, the "protected" amounts refers to excess taxes for which Section 203(e) of the Tax Reform Act of 1986 requires specific treatment if TNP is to continue to use accelerated depreciation for computing current federal income taxes. No party contested the company's proposed method of amortizing the protected amounts. Ms. Runyon, however, testified that there are no Internal Revenue Service regulations which control the amortization of excess "unprotected" amounts. She proposed amortizing the excess taxes ratably over the remaining lives of the items which generated the difference. According to Ms. Runyon, this is the only equitable amortization period. She characterizes both excess taxes and taxes as expenses that should be normalized in order to match benefits with costs. Staff Exhibit No. 7 at 9. TNP proposed amortization of the unprotected amounts using the average rate assumption method, which is explained in the testimony of Mr. Williams. TNP Exhibit No. 15 at 15. But Mr. Williams' and Mr. Jeters' rebuttal testimony did not object to the staff's use of remaining lives or rateable amortization methods, rather than the average rate assumption method original proposed by TNP.

Mr. Williams and Mr. Jeters did, however, provide testimony in opposition to the recommendation of Enron witness Kollen and OPC witness Allen. Mr. Kollen and Mr. Allen recommended the return of excess deferred taxes to ratepayers over a three year period by means of a reduction to the estimated federal income tax expense. TNP argues that the excess deferred taxes are a "tax benefit" that should be spread over the life of the related asset, and that deferred taxes are an interest-free loan from the government to the company. TNP Exhibit Nos. 50 at 5 and 58 at 15. The examiners are not persuaded by TNP's arguments, but rather rely upon the testimony of Ms. Runyon and Cities' witness Stowe, and conclude that the unprotected excess deferred taxes should be amortized over the remaining lives of the items which generated the difference. Ms. Runyon pointed out that TNP does not have the funds in cash that are represented by the excess deferred tax account. Amortization of the account over a three year period would cause an unexpected cash demand at a time when the company's financial integrity has been called into question. TNP Exhibit No. 45 at 17. Further, the unamortized portion of the account will, of course, continue to serve as a reduction to the company's invested capital, upon which the company's return is calculated.

The examiners recommend adoption of Ms. Runyon's calculation of the amortization of excess deferred taxes, as shown on Schedule V. Further, the

Commission should adopt Ms. Runyon's recommendation to require the company to set forth accounts and procedures to reconcile the amortization of the "protected" excess deferred taxes. The company should be ordered to create accounts as set forth in Staff Exhibit No. 7 at 14. The Commission adopted a similar recommendation in Docket No. 5610, Application of GTE Southwest Incorporated For a Rate Increase, 15 P.U.C. BULL. 1, 109 (February 23, 1989).

iv. Additional Depreciation; Environmental Tax; Disallowed Business Meals. The parties agreed on the adjustments for additional depreciation, environmental tax, and disallowed business meals. Staff witness Runyon proposed an adjustment to the additional depreciation expense, which was not contested by the company. Staff Exhibit No. 7 at 15. The examiners therefore recommend adoption of the staff's proposed adjustments, as shown on Schedule V.

v. Consolidated Tax Return Savings; Below the Line Expenses. Consolidated tax savings were not in issue in this case because TNPE did not incur consolidated tax return savings during the test year.

OPC witness Allen and Cities witness Stowe recommended adjusting the calculation of federal income tax expense to incorporate the tax effects of expenses not allowed in TNP's cost of service. The proposed adjustments reflect the tax effects of the following five disallowed expenses: country club dues, political activities expense, club memberships, Texas Atomic Energy Foundation dues, and the disallowed portion of EEI dues. Based upon the examiners' recommendations concerning disallowance of the particular expenses, the adjustment would increase tax deductions by $141,451, and reduce tax expense by $48,093.

The Commission recently held that PURA Section 43(c)(3) prohibits the consideration of disallowed expenses in the computation of income taxes. Docket No. 5610, Application of GTE Southwest Incorporated For a Rate Increase, 15 P.U.C. BULL. 1, 244 (February 23, 1989). Based upon Commission precedent, the examiners recommend that the Commission reject the recommendations of Mr.

Allen and Mr. Stowe. The examiners are concerned, however, that this precedent is inconsistent with the directive found in PURA Section 39(a) that a utility may be allowed rates to recover only its reasonable and necessary operating expenses. The effect of Commission precedent is that ratepayers pay 34 percent of the company's disallowed expenses. The examiners note that Mr. Jeter called into question whether calculation of income tax expense based in part upon disallowed expenses would violate normalization rules. Normalization rules concern the matching of costs to related revenues. Normalization rules were also an issue discussed in Docket No. 5610, in which Mr. Jeter, who is a partner in the accounting firm of Arthur Anderson & Co., testified on behalf of GTE Southwest Incorporated. But in the consolidated Docket Nos. 8928 and 8880, Mr. Jeter admits that his opinion that there would be a normalization violation is based in part upon IRS letter rulings that do not discuss the inclusion in a federal income tax expense calculation of disallowed expenses. TNP Exhibit No. 58 at 12.

B. <u>Revenue Issues</u>

[3] 1. Conversion from Meters Read Method to Unbilled Revenues Method

TIEC witness Ms. Theodora S. Carlson proposed a reduction to TNP's revenue requirement of $2,173,000. TIEC Exhibit Nos. 3 and 3A. Her proposal is based upon her opinion that the company should switch from the meters-read method of recording revenue to the unbilled method. According to Ms. Carlson, her proposal would result in a closer matching of revenues and expenses, and the accounting switch would provide an offset to the company's revenue requirement, lowering the company's need for a rate increase. OPC and Enron supported Ms. Carlson's proposed adjustment.

TNP's books for financial reporting purposes record revenues on a meters-read basis. Due to the lag between the provision of electric service and the subsequent meter reading and billing, revenues lag behind the related provision of service. For example, TNP's test year revenues is based upon electric service provided over a 12 month period that ended roughly 15 days before the end of the test year. But under the unbilled method, TNP's revenue total for a particular period would be based upon electric service provided during the period.

Adoption of Ms. Carlson's proposal would require two adjustments to the company's books. First, Ms. Carlson proposes an adjustment to test year revenues to reflect the change to the unbilled method. This adjustment would cause test year revenues to reflect revenues from a period that is roughly 12 and one-half months long. Second, revenues for each future period must be adjusted on an on-going basis. During a particular period revenues are estimated, and then adjusted to subtract billed revenues attributable to the previous period.

One of Ms. Carlson's goals is to better match revenues with expenses. TNP witness Jeter acknowledged that the unbilled method does work toward this goal. But he characterized as "completely wrong" the proposed adjustment to reflect the switch from the meters-read to the unbilled method. TNP Exhibit No. 58 at 22. The Tax Reform Act of 1986 required the company to switch to the unbilled method for tax purposes, resulting in the company making an adjustment to the tax books based upon December 1986 unbilled revenues. Ms. Carlson proposes to rely upon this same figure because it is easily verified, and to add it to test year revenues. She proposes the amortization of the excess revenues over a four year period, causing a reduction to the company's revenue requirement. But as Mr. Jeter points out, if the proper adjustments were made to revenues and expenses in connection with implementing Ms. Carlson's adjustment, the effect on test year revenue would be immaterial.

Ms. Carlson's second goal is to reduce TNP's need for a rate increase. Ms. Carlson recently testified in an El Paso Electric Power Company rate case and proposed that that company should also switch to the unbilled method. The administative law judge concluded that "Ms. Carlson's proposed adjustment would be an inappropriate adjustment to reflect what is, in effect, only a bookkeeping entry for which the company received no cash." The Commission rejected Ms. Carlson's proposal. Docket No. 8363, Application of El Paso Electric Company for Authority to Change Rates, 14 P.U.C. BULL. 2834, 3044

(May 5,1989). TIEC in brief states that the administrative law judge confused Ms. Carlson's recommendation with that of another witness in a prior El Paso Electric rate case. TIEC Reply Brief at 5. But the examiners find the same problems with Ms. Carlson's proposal in this case as was discussed by the administrative law judge concerning Ms. Carlson's proposal in Docket No. 8363. TNP witness Craig pointed out that the proposed reduction to revenues would set rates at a level which would not allow the company to recover its cost of service. TNP Exhibit No. 47 at 3. The examiners agree with Mr. Craig and recommend that the Commission not adopt Ms. Carlson's recommendation.

2. Franchise Tax Refunds.

Staff witness Foreman and OPC witness Allen recommend adjustments to TNP's revenue requirement, based upon a refund by the State of Texas in June 1989 of $1,034,099 in overcollected franchise taxes. Ms. Foreman also recommends an adjustment based upon the related $86,981 interest expense refund. The examiners recommend that the Commission not rule upon this issue at this time. As discussed in the section of this report concerning the application for deferred accounting treatment for TNP One, TNP will soon file its next rate case based upon a test year ending September 30, 1989. The Commission will then have the opportunity to consider the appropriate regulatory treatment for this nonrecurring revenue received during the test year.

3. Billing Determinants

OPC witness Allen adjusted the company's proposed billing determinants. He testified that the most important impact of these adjustments is on rate design, and went on to say that revenue at present rates should be "priced-out." OPC Exhibit No. 11 at 106. But Mr. Allen did not propose any specific adjustments. The examiners' recommendations concerning billing determinants are found in the rate design section of this report. The examiners recommend that the Commission reject Mr. Allen's proposed revenue adjustments that are based upon his proposed adjustments to billing determinants.

C. Invested Capital

Listed below are the various recommendations concerning the appropriate invested capital. Included as Schedule IV is the examiners' recommendation regarding invested capital:

Test Year	TNP Request	Staff Recommends	OPC Recommends	Cities Recommend
$235,353,182	$231,950,909	$232,722,857	$209,988,470	$206,963,938

1. Plant in Service

a. 345 KV Line. TNP Vice President, Manager - Generation, Mr. Rickey J. Wright testified that the company completed construction of, and put into service by the end of the test year a 345 KV transmission line that runs from TNP One to the Twin Oak substation owned by TU Electric. TNP Exhibit No. 2 at 6. The transmission line and related substation addition would increase TNP's plant in service by $11,890,506. The Commission's general counsel supports the inclusion of the line in plant in service. TIEC, Enron, OPC, and the State of Texas oppose its inclusion. The examiners recommend that the line not be included in the company's plant in service.

The record shows that the line was completed and energized on March 22, 1989. The double-circuit line runs approximately 18 miles and is designed to place the output of TNP One onto the ERCOT grid. The company evaluated alternative transmission line projects both for providing testing and startup power for TNP One, and for delivering the output from TNP One. The company could have constructed a smaller temporary line to provide testing and startup power to TNP One, or could have utilized nearby existing transmission lines. The problems presented by the alternatives were, however, greater. Greater costs were associated with building and later tearing down a line intended only for providing testing and startup power. The nearby existing transmission lines are connected to power sources that are inadequate for testing and startup purposes. TNP Exhibit No. 12 at 10; Tr. at 1314. The examiners note that intervenor parties who seek the disallowance of the line from plant in service do not argue that the construction of the line was unreasonable. The examiners conclude that the credible evidence in the record shows that the 345 KV line was the most reasonable alternative.

[4] The intervenors do, however, argue that the line is not "used and useful in rendering service to the public." PURA Section 39(a). TNP argues that the line was "used and useful" in March 1989 for the following activities: (1) providing the means for construction and start-up testing, (2) exporting energy during performance testing and trial operation, and (3) satisfying contractual commitments to the construction consortium that is constructing TNP One. Neither activities (1) nor (3) consist of TNP rendering service to the public. Activity (2) could benefit the public if the TNP One energy exported during testing of the plant was provided to TNP customers, or if the energy were sold by TNP to a third party. But by the end of the hearing there was no evidence in the record that TNP had actually sold any TNP One energy. Further, it was not clear whether TNP has contemplated whether TNP or the construction consortium building TNP One would own the energy exported during the testing of the plant. Tr. at 1870. In any case, TNP does not have any firm plans concerning who will buy the power. Tr. at 1155.

The credible evidence in the record shows that the 345 KV line exists solely for the purpose of connecting TNP One with TNP's customers. Because the TNP One plant is not at this time in commercial operation, it is not used and useful in rendering service to the public. A transmission line that serves no purpose but to transmit power from TNP One is similarly not used and useful. Mr. Wright could have rebutted the intervenors' arguments that the line is not currently used and useful. Mr. Wright was not, however, called as a rebuttal witness. TNP in brief, therefore, relied in part upon the testimony of staff witness Mr. N. S. Parate. During the hearing on the merits, Mr. Parate testified that the transmission line is currently useful. Tr. at 3624. But upon further examination, it was clear that he was testifying "from a technical point of view" when he responded that the line was useful. When asked whether a particular capital item was "used and useful," Mr. Parate's focus turned to whether the item provides service to customers. Tr. at 3674. Mr. Parate's testimony is therefore consistent with excluding the 345 KV line from plant in service because the line does not, at this time, provide service to the public.

[5] TNP's initial post-hearing brief argues in the alternative that the 345 KV line should be allowed in invested capital as plant held for future use. Enron and TIEC responded that there is nothing in the record to support this alternative argument, and that the intervenors were not given the opportunity]o respond to TNP's alternative argument on the record. The alternative argument is on its face questionable, given that the line's usefulness is so closely tied to TNP One. The future use of the line is indefinite because the status of TNP One is not clear. The reader is reminded that title to TNP One will pass from the construction consortium to TNP only if certain power plant performance criteria are met, and that the Commission docket related to TNP's application for a CCN for TNP One (Docket No. 6992) has been remanded to the Commission's Hearings Division. The examiners recommend that both of the company's arguments should be rejected and that the company's investment in the 345 KV line and related substation improvements not be included in invested capital.

b. <u>Reclassification of Construction Year-End Balances</u>. TNP seeks the inclusion in plant in service of eight construction projects that were at the end of the test year classified as construction work in progress (CWIP). The projects were all completed on or before September 30, 1989. TNP's adjustment would increase plant in service by $439,775, which represents the CWIP balance related to the projects as of the end of the test year. The general counsel approved of the reclassification, based upon the testimony of staff witness Parate. Enron recommends disallowance of the proposed adjustment. The examiners concur with Enron and recommend that the Commission deny the proposed adjustment.

TNP does not rely upon the Commission's post-test year adjustment (PTYA) rule. TNP Brief at 82. That rule was adopted by the Commission in Spring 1989 and became effective June 26, 1989. P.U.C. SUBST. R. 23.21(a). OPC witness Allen testified that TNP's proposed adjustment to plant in service may be made under this rule because it provides in part that post-test year adjustments may be made to invested capital for known and measurable changes. The rule, however, provides that post-test year adjustments will be considered only where the attendant impacts on all aspects of a utility's operations can, with reasonable certainty, be identified, quantified, and matched.

There is insufficient credible evidence in the record concerning the "attendant impacts" of the eight construction projects. For example, one project consists of the provision of electric service to a new shopping mall. But TNP did not adjust its estimated kilowatt-hour sales to reflect its customers at the mall. TNP Exhibit No. 21 at 7.

Because TNP does not rely upon the PTYA rule, it must rely upon Commission precedent. The relevant Commission precedent is, however, the "Big Cajun" rule found in Docket No. 5560. The rule provides that "reclassification of test year CWIP to plant in service is not allowed," and that "it does not matter whether the subject CWIP relates to generation or non-generation, or growth related or non-growth related plant." Docket No. 5560, <u>Application of Gulf States Utilities for a Rate Increase</u>, 10 P.U.C. BULL. 405, 421, 545 (July 13, 1984). The examiners in that docket, in formulating the Big Cajun rule, relied in part upon a Texas-New Mexico Power Company rate case where a proposed reclassification of CWIP was disallowed. Docket No. 4985, <u>Application of Texas-New Mexico Power Company</u>, 10 P.U.C. BULL. 963 (September 28, 1983). Post-test year CWIP reclassification contravenes Commission policy because it violates the matching of costs and revenues, and because, under certain circumstances, it circumvents the requirement found in PURA Section 41 that CWIP should be included in invested capital only upon a showing that the reclassification is necessary to the financial integrity of the utility. 10 P.U.C. BULL. 405, 421. The examiners note that the examiners' report in Docket No. 5560 also states that post-test year CWIP reclassification contravenes Commission policy because it is not a "measurable change" because it includes estimated completion costs. This is not the case in TNP's current rate application because TNP only seeks inclusion of CWIP costs as of the end of the test year. Commission precedent is clear, however, that post-test year CWIP reclassification is not permitted, except within the guidelines set forth in the PTYA rule discussed above. The credible evidence in the record does not support the reclassification of TNP's eight projects pursuant to the PTYA rule. The examiners therefore recommend disallowance of TNP's proposed adjustment to plant in service.

2. Accumulated Depreciation

TNP witness Spooner sponsored the company's proposed provision for accumulated depreciation of $77,893,853. TNP Exhibit No. 19. The examiners recommend adoption of TNP's proposed accumulated depreciation figure.

OPC witness Allen recommended an adjustment to accumulated depreciation. His adjustment consisted of increasing accumulated depreciation by one half of TNP's annual depreciation expense. OPC Exhibit No. 11 at 84. Mr. Allen argued that the adjustment is needed so that ratepayers do not pay an excessive return on TNP's investment. If the total net plant (plant in service less accumulated depreciation) figure used by the company is adopted then ratepayers will pay a return on TNP's net plant as of the end of the test year. But in the six months after the end of the test year TNP has continued to collect through its rates depreciation expense. Because depreciation expense represents the recovery of TNP's investment, TNP's current net plant investment is less than it was at the end of the test year. Mr. Allen's recommendation therefore requires increasing accumulated depreciation by the amount of depreciation expense incurred in the six months after the end of the test year.

TNP apparently misunderstands Mr. Allen's proposal. In its brief, TNP argues that its proposed CWIP reclassification is not a post-test year adjustment and therefore Mr. Allen's proposed post-test year adjustment should not be adopted. TNP Reply Brief at 53. Mr. Allen's proposed adjustment, however, goes to TNP's total net plant at the end of the test year.

Mr. Allen argued that the Commission "has not required this adjustment because until recently it did not allow for post-test year known and measurable change adjustments to invested capital." OPC Exhibit No. 11 at 89. Because the Commission has adopted the PTYA rule, the company's invested capital should be adjusted to reflect the reduction to net plant occuring after the end of the test year. TNP argues that the "post-test year adjustment was only recently adopted and has not yet been applied in any case by the Commission. As a result, all ramifications of its use are unknown and, frankly, the issue with regard to plant in service is better left to a case which unquestionably puts the application of the new rule at issue." TNP Reply Brief at 54. The examiners respond that that is what Mr. Allen has done in this case.

[6] Mr. Allen is correct that the Commission has rejected adjustments to accumulated depreciation as improper post-test year adjustments to invested capital. Docket No. 8363, Application of El Paso Electric Company for Authority to Change Rates, 14 P.U.C. BULL. 2834 (May 5, 1989); Docket Nos. 7195 and 6755, Application of Gulf States Utilities Company for Authority to Change Rates and Inquiry into the Prudence of River Bend Nuclear Generating Station, 14 P.U.C. BULL. 1943 (May 16, 1988); Docket No. 7510, Application of West Texas Utilities Company for Authority to Change Rates, 14 P.U.C. BULL. 620 (November 30, 1987). Now that the PTYA rule has been adopted by the Commission it would seem that the Commission should adopt his recommendation. But Mr. Allen has forgotten the other infirmities of his recommendation that are not reconciled by the Commission's adoption of the PTYA rule. First, test year depreciation expense does not necessarily reflect depreciation expense that occurs during the six month period immediately following the test year. This is so because test year depreciation expense reflects in part some capital items that were added during the test year, and reflects in part capital items retired during the test year. The depreciation expense actually booked during the test year therefore may not accurately represent the ratable depletion of the service lives of the capital items in service as of the end of the test year. Second, the proposed adjustment assumes that the ratepayers' return of the company's investment through depreciation expense is not reinvested by the company in capital items. This assumption is demonstrably wrong, given that

TNP intends in the near future to acquire generation facilities. Finally, Mr. Allen previously recommended this adjustment as a Commission staff witness. The weaknesses of the proposal were discussed at that time. Docket Nos. 5640 and 5661, Application of Texas Utilities Electric Company for a Rate Increase, 10 P.U.C. BULL. 659, 678 (November 19, 1984).

Under P.U.C. SUBST. R. 23.21(a), post-test year adjustments to invested capital will be considered only where the attendant impacts on all aspects of a utility's operations can, with certainty, be indentified, quantified, and matched. The examiners conclude that the credible evidence in the record shows that the proposed adjustment has not met this test, because post-test year depreciation expense does not necessarily match test year depreciation expense, and because the adjustment incorrectly assumes that the company's net plant steadily decreases after the end of the test year. The examiners therefore recommend that the Commission not adopt Mr. Allen's proposed adjustment.

3. Working Capital

TNP witness Michael L. Cunningham explained that the company's invested capital should include, in addition to net plant in service, other assets used in supplying utility service to the consumer. One such asset is working capital, which includes a working cash allowance, materials and supplies, and prepaid insurance and taxes. No party proposed adjustments to the company's prepaid insurance and taxes total. Working cash allowance, and materials and supplies are discussed below.

a. Working Cash Allowance (Lead Lag Study). The company's working cash allowance represents cash on hand used to meet the company's day-to-day needs. Prior to the company's 1988 rate case, the company assumed, for regulatory purposes, that the receipt of its revenues are delayed for 45 days, which is roughly one-eighth of a year. The company therefore requested as an addition to invested capital a working cash allowance of one-eighth of its operations and maintenance expense. Tr. at 4722.

According to Mr. Cunningham, the Commission now requires utilities to establish their working cash allowance using methods other than by reliance upon the "one-eighth rule." The Commission's substantive rules provide for such a requirement. P.U.C. SUBST. R. 23.21(c)(2)(B)(iii). Mr. Cunningham's testimony concerning working cash allowance is therefore supported by a "lead lag study." The study measures the difference between the date a utility receives goods and services and the date it pays for them, and the difference between the date of rendering service and the receipt of revenues from its customers. The revenue lag days reflect that period of time from when the company renders service to the time when it receives payment. The expense lag days reflect that period of time from when the utility receives goods or service to such time when payment is rendered. TNP Exhibit No. 16.

The company continuously collects revenues from ratepayers. To the extent this cash is on hand prior to its disbursement to pay for the costs of providing service, the cash represents cost-free capital to the company. The effect of ratepayers providing cost-free capital to the company is offset in the ratemaking process by a reduction to the company's invested capital. The examiners note that the company's lead lag study produced a result of $14,964,381, which the company subtracted from its calculation of invested capital.

A lead lag study prepared by staff witness Ms. Linda D. Taylor closely follows the methodology used by Mr. Cunningham. Staff Exhibit Nos. 6 and 23. TNP disagreed with Ms. Taylor's study on only one major point, concerning the calculation of federal income tax lead days, on which, as discussed below, the examiners recommend adoption of Ms. Taylor's methodology. The examiners recommend rejection of the various recommendations made by Enron, TIEC, OPC, and the Cities, as discussed below. The examiners therefore recommend that the Commission adopt the lead lag study prepared by Ms. Taylor, as revised and attached to this report as Schedule VI. The revisions are based upon the examiners' recommendations concerning operations and maintenance expense, which affect the lead lag study.

A review of Schedule VI shows that there are two predominant factors in the lead lag study. The lag associated with TNP's receipt of revenues is entered at the top of the page. The "dollar days" figure under column five represents a positive figure, which, if taken alone, would indicate that the company's invested capital should be increased to reflect investor-supplied cash that is needed to meet the company's cash needs prior to the time ratepayers pay for service that the company has already provided. The next line on Examiners' Attachment B shows the other predominant factor. The lead associated with TNP's receipt of service from its wholesale electric power providers before TNP pays for the service shows a negative figure, which, if taken alone, would indicate that the company's invested capital should be decreased.

The lead lag studies prepared by TNP and staff exclude from consideration the lead associated with TNP's payment of interest expense on long term debt and payment of dividends on preferred stock. OPC, Enron, and TIEC recommended that the lead lag study include these lead items. The examiners recommend rejection of the proposal because it is inconsistent with the methodology used by the company. The company's methodology consisted of a "cash-only" lead lag study. The first predominant feature of the study is, as discussed above, the lag associated with revenues. The cash-only lead lag study methodology excludes from this figure the revenue that is used to pay interest on long term debt and preferred stock dividends. TNP Exhibit No. 16, Exhibit MLC-1, Schedule 1a at 11. It would be inconsistent and inequitable to then include in the study the lead associated with the company's subsequent payments related to these items. The intervenors' point that the company's payments for interest on long term debt and preferred stock dividends are made in cash is irrelevant. The examiners' recommendation is consistent with Commission precedent. Docket No. 7510, Application of West Texas Utilities Company for Authority to Change Rates, 14 P.U.C. BULL. 620, 895 (November 30, 1987).

As previously discussed in this report, TNP sells its accounts receivable to the factoring firm of CSW Credit, Inc. OPC witness Allen recommends the exclusion of factoring costs from the lead lag study because TNP seeks to include factoring costs in its operation and maintenance expense. TNP responded that factoring costs should be included, and noted that staff witness Taylor used factoring costs in her lead lag study. TNP Reply Brief at 59. The examiners recommend approval of the methodology used by Ms. Taylor, which includes and separately lists factoring costs, and designates zero lead days with this cost.

TNP and Ms. Taylor added to their respective lead lag studies an allowance to reflect the company's average cash held in banks. OPC witness Allen argues that inclusion of this figure to the lead lag study amounts to double counting, because cash in banks merely amounts to the net of various components of the lead lag study. OPC Brief at 16. But TNP witness Jeter testified that a lead lag study determines cash requirements as if a company could provide funds from investors precisely when needed and could use funds received from ratepayers precisely when received. Because as a practical matter this is not the case, the company must also have cash on hand in addition to the amounts indicated in the lead lag study. TNP Exhibit No. 58 at 19. The examiner concurs with Mr. Jeter and recommends that the Commission reject Mr. Allen's recommendation.

Ms. Taylor's determination of 101.12 lead days associated with the period between the date federal income taxes are incurred and the date they are paid is based upon actual payment information from 1988. TNP's determination of 58.95 lead days is based upon the statutory federal income tax payment schedule of 22.5 percent due each quarter, with the remaining 10 percent due the following March 15. Ms. Taylor did not follow the company's methodology because the company's schedule "is not reflective of the percentages of actual taxable income paid." Staff Exhibit No. 6 at 7. TNP witness Cunningham's rebuttal testimony offered two reasons the lead lag study should rely upon the statutory schedule. TNP Exhibit No. 46 at 13.

First, because the lead lag study ignores the seasonal fluctuations of revenues, the study should also ignore the seasonal fluctuations of income taxes paid. Mr. Cunningham states that "[u]se of the statutory dates are the only way to prevent a mismatch in the lead lag study." The examiners respond that no matter what lead day is used in the study, the study will ignore the seasonal payment of federal income taxes. There is no basis for using a statutorily-derived figure where there is at hand a figure that reflects reality.

Second, Mr. Cunningham argues that the statutory figure should be used because the company follows the statutory payment requirements. Again, the fact that the company complies with federal law is no basis for using a statutorily-derived figure where there is at hand a figure that reflects reality. The examiners therefore recommend approval of the methodology used by staff witness Taylor.

Finally, several witness, including staff witness Taylor, used the check clearing date, as opposed to the date TNP issued the check. TNP did not, however, disagree with Ms. Taylor's use of the check clearing date because her study was consistent in its methodology by its use of a cash in banks figure (discussed above) that is per bank, as opposed to per book. TNP Reply Brief at 64.

b. <u>Materials and Supplies</u>. Cities witness Stowe proposed an adjustment to this element of working capital. Cities Exhibit No. 3 at 8. But TNP witness Cunningham showed that the calculation upon which Mr. Stowe based his recommendation was incorrect. TNP Exhibit No. 46 at 1. The examiners' recommended materials and supplies is shown on Schedule IV.

4. Deferred Federal Income Taxes

OPC witness Allen proposed an adjustment that was based upon the company's proposed post-test year CWIP reclassification. OPC Brief at 17. The examiners have recommended disallowance of TNP's proposed CWIP reclassification and therefore recommend that the Commission not adopt Mr. Allen's recommendation. The examiners' recommended Deferred Federal Income taxes is shown on Schedule IV.

5. Customer Deposits, Customer Advances for Construction

Again, Mr. Allen recommended an adjustment based on the company's proposed post-test year CWIP reclassification. The examiners have recommended disallowances of TNP's proposed CWIP reclassification and therefore recommend that the Commission not adopt Mr. Allen's recommendation.

D. Rate of Return

The examiners recommend a rate of return of 11.3 percent. The recommendation is based on the examiners' recommended cost of debt, cost of preferred stock, cost of equity, and capital structure. The rate of return calculation is as follows:

	Percent of Total	Cost	Weighted Average Cost
Long Term Debt	46.32	9.87	4.57
Preferred Stock	5.03	9.37	.47
Common Equity	48.65	12.86	6.26
			11.30

1. Cost of Debt

The examiners recommend a cost of long term debt of 9.87 percent. TNP and OPC recommended 9.89 percent. The staff recommended 9.74 percent, Enron 9.5 percent, and the Cities 9.2 percent.

The staff's recommendation is based upon the "yield to maturity" method that is required by the Commission's rate filing package form. Staff Exhibit No. 14. TNP witness Dennis R. Bolster prepared the company's calculation of the cost of long term debt, and rebutted the staff's recommendation. TNP Exhibit No. 52 at 4. He testified that if the staff's calculation had correctly included the costs related to the unamortized premium on bond redemptions, the staff's calculation would have indicated a cost of debt of 9.87 percent. The staff did not challenge Mr. Bolster's correction. Mr. Bolster's own calculation was based upon an embedded cost methodology.

Although TNP argues in brief that the Commission may properly rely upon this method, the examiners note that Mr. Bolster provided no legal basis for the examiners to rely upon a methodology other than the one required in the Commission's rate filing package. The examiners therefore recommend adoption of the staff's proposal, as corrected by Mr. Bolster.

Enron witness Kollen noted that the company's bond ratings have been down-graded since early 1988. He testified that the bond down-gradings are due to the magnitude of TNP's future financing requirements related to the purchase of TNP One. In his view, the company's customers therefore should not at this time pay a higher rate of return that reflects plant not yet in the company's rate base. The company is no longer rated "single A," but Mr. Kollen recommends that the company's cost of debt should be 9.5 percent, based upon the average cost of debt for a "single A" rated company. Mr. Kollen relies upon a "Moody's Corporate Bond Yield Averages" chart for July 1989. Enron Exhibit No. 69 at 11. Mr. Kollen would have the Commission ignore the cost of debt studies prepared by the other witnesses. Such studies determine cost of debt based upon the weighted cost of TNP's nine bond issues dating back to July 1963. See Staff Exhibit No. 13, schedule RH-XVI. The Commission should reject Mr. Kollen's recommendation.

The recommendation of Cities witness Mr. Jack Hopper is based upon a methodology which included a debt acquisition premium in the cost of debt calculation. His recommendation is related to the recommendation of Cities witness Stowe to include the debt acquisition premium as an expense item. The examiners recommend rejection of Mr. Stowe's proposal and therefore also recommend rejection of Mr. Hopper's methodology.

2. Cost of Preferred Stock

TNP witness Bolster testified that TNP's cost of preferred stock is 9.43 percent. TNP, however, recommends adoption of staff witness Rebecca T. Hathhorn's calculation of cost of preferred stock. TNP Brief at 90. The credible evidence in the record shows that TNP's cost of preferred stock is

9.37 percent, as shown in the testimony of Ms. Hathhorn. Staff Exhibit No. 13B. The examiners therefore recommend adoption of a cost of preferred stock of 9.37 percent.

3. Cost of Equity

The examiners recommend a cost of equity of 12.86 percent. This recommendation is based upon portions of the testimony of Enron witness Mr. Jay B. Kennedy and staff witness Hathhorn. TNP requested a cost of equity of 14.1 percent. The staff and the Cities both recommended a cost of equity of 12.6 percent. OPC recommended 12.67 percent. Enron recommended 12.38 percent.

All of the witnesses used a discounted cash flow (DCF) analysis to support their recommended rates. DCF analysis is based on the premise that the value of a financial asset is determined by its ability to generate future net cash flows. The future cash flows from common stock take the form of dividends and appreciation in price. The value of the stock to investors is the discounted present value of future cash flows. The analysis consists of adding the company's expected dividend yield and the company's expected growth rate. The sum represents the rate of return expected by investors. All of the parties relied upon stock information pertaining to TNPE because the stock of TNP is not traded on the open market.

TNP's cost of equity request was based upon the testimony of Mr. Dennis R. Bolster. TNP Exhibit Nos. 8 and 52. Enron witness Kennedy pointed out that there are several weaknesses in the various methodologies used by Mr. Bolster to arrive at his recommended cost of equity figure. Concerning Mr. Bolster's determination of expected dividend growth, Mr. Kennedy testified that he had "never seen an old forecast used to forecast an event that is to occur beyond the end of the old forecast." Mr. Bolster's determination of expected growth rates were substantially in excess of the projected growth rates for TNPE prepared by Solomon Brothers (an investment banking house) and the Institutional Broker's Estimating System (IBES) (a survey of brokers concerning earnings growth forecasts). The methodologies used by all of the cost of equity witnesses included a DCF analysis of electric utilities comparable to TNPE. The twelve utilities selected by Mr. Bolster were "inappropriate" according to Mr. Kennedy because, in part, most of the twelve utilities had better Value Line (an investment research firm) safety rankings and bond ratings than TNPE. Further, some of the companies "are not even close to the same size as TNP." Enron Exhibit No. 68 at 39. The examiners point out that Mr. Bolster's rebuttal testimony did not respond to Mr. Kennedy's criticisms. Nor were Mr. Kennedy's criticisms explored, much less proved incorrect, during cross examination. Tr. 2731. The credible evidence in the record therefore indicates that the Commission should not rely upon the cost of equity testimony of Mr. Bolster.

The examiners next review the testimony of Enron witness Kennedy, staff witness Hathhorn, and Cities witness Hopper. Enron Exhibit Nos. 67 and 68; Staff Exhibit Nos. 13, 13A, 13B, and 13C; Cities Exhibit No. 4. OPC witness Dr. Carol A. Szerszen also presented cost of equity testimony. OPC in brief, however, supported the staff's calculation. The staff's final recommendation is very close to the final recommendation of Dr. Szerszen. OPC Reply Brief at 13.

As previously discussed, the first element in the DCF analysis is the determination of the expected dividend yield. Dividend yield is derived by dividing stock price by the dividend. Obviously, the particular time period from which the stock price and dividend information is taken is important. Too short a time period approaches an analysis of TNPE's spot price. Too long a historical period may not reflect the future expectations of investors. Mr. Kennedy used an average per month stock price figure during the period April through September 1989. Ms. Hathhorn picked a representative price for TNPE stock based upon market prices following an August 1989 price decline. Mr. Hopper used the average stock price on each Wednesday during a six week period in August and September 1989. Each witness anticipated dividend growth in the near future. The examiners conclude that the dividend yield method used by Mr. Kennedy is the most reasonable because it determines dividend yield based upon average stock prices during a six-month period. Mr. Kennedy's method will best avoid producing a cost of equity figure that is based upon price fluctuations during the period August through September 1989.

The second element in the DCF analysis is the determination of the expected growth rate. The three witnesses each used information pertaining to TNPE's dividend per share growth (DPS), book value per share growth (BVPS), earnings per share growth (EPS), and current growth projections prepared by independant investment companies. The examiners agree with TNP that the averages of TNP's DPS, BVPS, and EPS increase in the most recent five year period instead of the most recent 15 and 10 year periods) and the most recent five year growth data should be used. TNP Brief at 100. The examiners therefore do not rely upon the analyses of Mr. Hopper and Ms. Hathhorn because they relied in part upon DPS, BVPS, and EPS growth information that is more than five years old. Staff Exhibit No. 13, schedule RH-VI at 4. Mr. Kennedy's analysis relied upon only such data from the past five years. Further, his analysis utilizes a weighted average method that gives greater weight to the projections of TNPE's growth during the period rates set in this case will be in effect.

As discussed above, each of the three witnesses also conducted a DCF analysis of comparable electric utilities. Ms. Hathhorn noted that TNP is facing a major construction program, that none of the comparable companies selected by her have similar construction programs, and that TNP's DCF analysis produces a somewhat higher result. She therefore used the comparable DCF analysis only for purposes of checking the reasonableness of the DCF analysis for TNPE. Staff Exhibit No. 13B at 35. The examiners agree with Ms. Hathhorn and conclude that the results of the DCF analysis of comparable companies should not be averaged with the results of the DCF analysis of TNPE. The examiners also conclude that Mr. Kennedy's DCF analysis of TNPE, which produced a cost of equity of 12.86 percent, should be relied upon, rather than Mr. Kennedy's final recommendation which represents an average of the TNPE and comparable company DCF analyses.

The calculations discussed above determine TNP'S "bare cost of equity." TNP witness Bolster and staff witness Hathhorne recommended that various "market-to-book adjustments" should be made to the bare cost of equity to arrive at their total recommended cost of equity.

According to Mr. Bolster, TNP's bare cost of equity of 13.25 percent should be adjusted upward by 10 percent of his expected dividend yield figure to arrive at his recommended cost of equity of 14.1 percent. The adjustment is needed given the fact that TNP will have to finance two 150 megawatt generating plants, each of which costs more than the company's current total capitalization. Since the first unit is expected to come on line June 1, 1990, the company must be in a strong financial position so that it can sell common stock without diluting the investment of its existing shareholders, and can market its debt on reasonable terms. TNP Brief at 93. The Commission's general counsel argues that Ms. Hathhorn's recommendation incorporates all the market-to-book adjustments that should be made. General Counsel Reply Brief at 7.

According to TNP, there is a distinction between its request and its position that it is not asking for rate relief in this case based upon TNP One. According to Mr. Horton, TNP's Assistant Treasurer, TNP does not seek rate relief related to the construction of TNP One. But TNP does need rate relief in the form noted above because of the Company's two recent bond down-gradings. Those bond down-gradings are the result of regulatory risk, not the impending capital needs of the company related to financing TNP One. Tr. at 698. Without exploring this distinction, the examiners recommend that the Commission deny the proposed "market-to-book adjustment." As discussed in the direct testimony of TNP witness Chambers, because the company is a distribution utility with comparatively little invested capital, an increase in expenses greatly affects the company's return on equity. According to Mr. Chambers, this is an argument to allow expenses in the cost of service. Much less testimony was dedicated to exploring ways to limit expenses. Further, the examiners conclude that this adjustment is not justified in light of the examiners' recommendation that the Commission adopt the staff's recommendation concerning the DCF analysis. As the reader will recall, the staff recommended a return on equity that was not partly based upon a DCF analysis of comparable companies (that indicated a lower rate of return) because TNP "is facing a major construction program."

Staff witness Hathhorn proposed two additional market-to-book adjustments. First, according to Ms. Hathhorn, the bare return on equity should be increased to reflect that the company, upon the issuance of new stock, does not receive the allowed return on equity. The dilution in equity values is attributable to flotation costs and market pressure. (Flotation costs relate to underwriting, distribution, and various other stock issuance costs.) Ms. Hathhorn's flotation market-to-book adjustment would increase the return on equity by only .81 percent. The examiners do not recommend its adoption because the calculation requires one to predict the number of new shares of stock TNPE will issue in the future. Ms. Hathhorn assumes TNP will require $90 million in new equity but gives no basis for her assumption.

Second, Ms. Hathhorn testified that the return on equity should be adjusted to reflect market pressure, or the drop in market price of a stock that accompanies new issuances. The examiners recommend that the Commission not adopt this adjustment because it is based upon information concerning the effect of market pressure on the day the stock is issued. Based upon the credible evidence in the record, it is unreasonable to assume that market pressure will have a long-term effect upon TNP's return on equity. In response to the argument that the day of issuance is the only relevant day because this is when the company actually sells the new stock, the examiners reply that the proposed adjustment unreasonably revalues all of the company's stock. The company suffers no immediate cash effects due to the devaluation of its already outstanding shares of stock.

4. Capital Structure

TNP recommends adoption of the staff's recommended capital structure of 46.32 percent long-term debt, 5.03 percent preferred stock, and 48.65 percent common equity. The staff's recommendation is based upon TNP's capital structure as of August 31, 1989. Staff Exhibit No. 13C, schedule RH-XVIII. The examiners recommend adoption of the staff's recommended capital structure.

The examiners note that Enron recommended a capital structure that reflected the company's lower common equity percentages in its capital structure prior to the commencement of the TNP One construction. Enron argued that the imputed capital structure is necessary to remove the effects of TNP One from the rate case. The examiners do not recommend adoption of an imputed capital structure.

E. Quality of Service

1. General Conclusions

In fixing a reasonable return on invested capital, the Commission must consider the quality of the utility's services, the efficiency of the utility's operations, and the quality of the utility's management. PURA Section 39(b).

TNP witness Mr. Randy Ownby testified that the company received 16 customer complaints during the test year. TNP Exhibit No. 10. TNP witness Mr. Allan B. Davis testified that the company complies with its own policy of providing safe, adequate, and reliable electric service. TNP Exhibit No. 12.

The preponderance of the evidence in the record shows that the quality of the management of the company does not indicate that the company's rate of return should be adjusted either higher or lower. The examiners note that Enron complained of management's "collective amnesia" on the stand and recommended that the Commission closely investigate the company's management during its next rate case. Enron Reply Brief at 32.

The examiners conclude that the company's rate of return should not be adjusted based upon the company's quality of service, efficiency of operations, and quality of management.

2. Texas Instruments

Mr. Charles Arthur Correll, the Site Facilities Manager of Texas Intruments' (TI) Lewisville plant testified concerning the need for modifications to TNP's distribution system to alleviate the system defects that lead to two electric outages at the plant. TIEC Exhibit No. 4. According to Mr. Correll, the Lewisville plant, which is northwest of Dallas, houses TI's primary computing facility. The computer is interconnected with TI sites worldwide and relates to TI's defense industry business. TI's representative, TIEC, requests that the Commission order TNP to install one new circuit breaker each at the West and South substations serving the TI plant, and to install adequate static wires used to ground lightning strikes to protect the transmission lines running to the substation located at the TI plant.

TIEC relies upon PURA Sections 58(a) and 61(1). Those sections provide:

> Section 58(a). Except as provided by this section or Section 58A of this Act, the holder of any certificate of public convenience and necessity shall serve every consumer within its certified area and shall render continous and adequate service within the area or areas.
>
> Section 61. After notice and hearing, the commission may: (1) order a public utility to provide specified improvements in its service in a defined area, if service in such area in inadequate or is substantially inferior to service in a comparable area and it is reasonable to require the company to provide such improved service.

TNP responded that it is already providing TI with a reasonable, generally acceptable, and typical level of electric service. TNP Brief at 106. TNP's continuity of service to TI is at 99.980 percent, compared to TNP's systemwide continuity of service of 99.978 percent. TNP Exhibit No. 54 at 2. In the past two years, TI has suffered two service interruptions that were related to TNP's distribution system. Both interruptions occurred during early Sunday mornings and both interruptions were initiated by lightning strikes on the transmission lines running to the substation at the TI plant. The first outage occurred on June 26, 1988, and lasted 1 hour and 56 minutes. The second outage occurred on June 7, 1989, and lasted 1 hour and 4 minutes.

Staff witness Mr. John B. Gordon testified that there was a defect in the design of the network of switches that serve the TI substation. Staff Exhibit No. 4. The problem can be solved by installing an oil circuit breaker (OCB) at the West substation. TNP agrees to install a new circuit breaker at the West substation at TNP's expense, and has included this project in its 1990 construction budget. TNP Exhibit No. 54 at 9. TNP believes that this design improvement will provide a net reliability benefit to all of the customers served from the TI substation, not just TI itself. TNP estimates the cost of the new OCB will be $202,000. TIEC Exhibit No. 4, appendix C.

Mr. Gordon testified that "eventually" an OCB also should be installed at the South substation. His recommendation, however, is only that an OCB should be installed as soon as possible at the West substation. TNP estimated that the cost of installing both OCBs is $532,000. TIEC Exhibit No. 4, appendix C. TIEC argues on behalf of TI that TNP should be required to install both OCBs at TNP's expense. TNP should pay for both OCBs because TNP's inadequate service in the past has caused TI damages in excess of the cost of the two OCBs. Second, TNP should pay because TI has already payed additional amounts to TNP to obtain the service TI requires. Finally, TIEC argues that "broader policy considerations" weigh in favor of requiring TNP to pay the full cost. This final argument is bolstered by information concerning the size of TI.

[7] The examiners disagree with TIEC. The credible evidence in the record shows that TNP has provided TI with adequate electric service. TI's electric requirements are exceptional, in that TI requires 100 percent electric reliability. In the past, TI has recognized that its electric requirements are exceptional and therefore has expended some of its own resources in its efforts to obtain its goal of 100 percent electric reliability. The Commission should reject TI's new position that TNP should pay to provide this type of service. The additional expenses and investment incurred by TNP to provide TI with exceptional service would subsequently be charged to all of TNP's ratepayers. The fact that TI is a large company is further reason to require TI to pay for its own exceptional electric needs.

Finally, TIEC argues that the Commission should at least require to TNP to conduct a study of the quality of protection afforded by the existing static wire on the single pole, double circuit transmission line that runs to the TI substation. TNP has already studied the static line improvements suggested by TI. The expected tripout rate due to lightning strikes on the existing line with the existing static wire is once every 5.6 years. TNP concluded that the existing static line is adequate. TNP Exhibit No. 54 at 9. The examiners agree with TNP and conclude that TI's request for a Commission order requiring certain actions by TNP should be denied.

F. Energy Efficiency Plan

1. Reporting Requirements

The Commission's substantive rules require that an electric utility filing for approval of a major rate change must submit its most recent energy efficiency plan. P.U.C. SUBST. R. 23.22(c). TNP accordingly filed its energy efficiency plan and the testimony of Mr. Douglas A. Landry in support of the plan. TNP Exhibit Nos. 13, 13A, 14, and 56. The Commission's substantive rules provide that the plan and related testimony must indicate:

1. the extent to which the goals of the utility's plan have been reached as of the date of filing;
2. the status of programs and studies undertaken pursuant to the plan;
3. the costs expended and benefits achieved pursuant to the plan; and
4. the extent the company's achievements through the plan have offset the need for new generating facilities, or permitted the company to reduce its reliance upon less efficient generation facilities.

Mr. Landry explained that the company's primary energy efficiency goal is annual system load factor improvement. The company is achieving this goal through implementation of programs that reduce peak load and increase off-peak energy sales. Mr. Landry also noted that the company seeks to improve the energy efficiency of its customers by providing customers with energy conservation information.

TNP currently has two energy efficiency programs, an "Energy Checked Efficiency Home Program" and an interruptible irrigation service rate. According to Mr. Landry, the home efficiency program has achieved nine megawatts of peak load reduction and saved 36,580 megawatt hours of energy during the period 1975 through 1989. The interruptible irrigation rate currently reduces irrigation load by 2.1 megawatts. The other load management plan activities the company has been involved with include the Residential Conservation Service Program. This was a federally mandated program that was discontinued in June 1989. Other TNP activities include energy "audits," and providing information to customers. TNP plans to undertake two new plans. They are the "Good Cents Home Program" and the "High Efficiency Air Conditioning and Heat Pump Plan."

Staff witness Mr. Nat Treadway reviewed the company's energy efficiency plan. Staff Exhibit No. 8. Mr. Treadway testified that the plan meets the reporting requirements of P.U.C. SUBST. R. 23.22. But Mr. Treadway also had various critical remarks about TNP's energy efficiency goals and the presentation of the information in the plan. TNP should closely review Mr. Treadway's remarks prior to submitting its next energy efficiency plan. Finally, the examiners note that Mr. Treadway recommended no adjustment to the company's rate of return based upon the company's energy conservation programs. P.U.C. SUBST. R. 23.22(d). The examiners conclude that the company has met the Commission's requirements concerning the filing of an energy efficiency plan. Further, the examiners conclude that the fixing of TNP's return on invested capital should not be adjusted based upon TNP's efforts to comply with the Commission's statewide energy plan, and TNP's achievements in the conservation of resources. PURA Section 39(b).

2. COS Treatment for Demand Side Programs

There are two cost of service issues that relate to the company's demand side programs. First, as previously mentioned, TNP's participation in the federally mandated Residential Conservation Service Program ended upon the termination of the program in June 1989. Mr. Treadway therefore recommended an adjustment to TNP's unadjusted operations and maintenance expense to reflect that the related test year expenses would not be incurred in the future. TNP witness Landry responded that the company will continue to offer a service that is similar to the federally mandated program. The examiners agree with the company that test year expenses that are of a recurring nature should not be disallowed simply because the name of the related energy efficiency plan has changed. The Commission should not adjust TNP's unadjusted O&M expense based upon Mr. Treadway's recommendation.

Second, TNP requests a post-test year adjustment to O&M expense related to TNP's plans to implement its Good Cents Home Program and High Efficiency Air Conditioning and Heat Pump Plan. TNP requests allowance of expenses of $237,600 for programs that have not yet been implemented. Mr. Treadway recommends rejection of the company's expense adjustment. The examiners recommend that the Commission include in operations and maintenance expense the June 1989 partial payment to the firm that markets the Good Cents Home Program. This partial payment is the only cost related to the two programs that is known and measurable. The other costs have not yet been incurred. The examiners note that the partial payment was for purposes of purchasing the core package and the training services package which do not appear to be recurring expenses. But because the company intends to file its next rate case in the near future the company will not recover this expense item more than once. The Commission should allow TNP's good cents home program June 1989 expense of $82,400.

G. <u>KW Hour Sales Adjustment, Weather Adjustment</u>

Staff witness Ms. Denise L. Rosenblum reviewed TNP's two adjustments to test year kilowatt hour sales. She found that the adjustments are reasonable because they accurately reflect the company's number of customers at the end of the test year. Staff Exhibit No. 10 at 15. The examiners recommend approval of the company's two adjustments to test year kilowatt hours sales.

The company did not propose an adjustment to test year kilowatt hour sales based upon a weather adjustment. Weather adjustments increase or decrease test year kilowatt hour sales to reflect that unusual weather occurred during the test year. Such adjustments were proposed by seven of the nine largest utilities in the state in their most recent rate cases. Staff Exhibit No. 10, schedule 3. Staff witness Rosenblum recommended that the Commission require the company to implement a weather adjustment methodology, and to incorporate a weather adjustment into its next rate case.

According to Ms. Rosenblum, the staff has developed a policy which has been consistently supported by the Commission. According to the policy, an electric utility applying for approval of a major change in rates need not make a weather adjustment if one or more of the following are true:

1. the utility has never proposed adjustments to test year KWH sales in previous Commission dockets;
2. weather during the test year was normal; or
3. the utility establishes that the relationship between weather and electricity consumption cannot be determined, or that the utility does not serve a weather-sensitive load.

TNP states that it last received a weather adjustment in Docket No. 4240, which was based upon a test year that ended September 1, 1981, but that it has neither sought nor received a weather adjustment since that time. TNP Reply brief at 93. Ms. Rosenblum testified that in both Docket No. 3370 and Docket No. 4985 (which was, of course, after Docket No. 4240) the company proposed weather adjustments. In both dockets, the staff found the supporting information acceptable but poorly prepared. Staff Exhibit No. 10 at 6. In response to an RFI, TNP stated that it will not implement a weather adjustment methodology until the Commission staff is consistent in their criteria for acceptance of weather adjustments, or until the magnitude of the adjustment is such that, without the adjustment, test year billing determinants would be misrepresented. Id. at 11.

Weather adjustments serve two purposes. An adjustment to kilowatt hour sales during a test year with unusual weather may be made so that during the period rates will be in effect the company will not under or overrecover. And as discussed by TNP in its RFI response, weather adjustments affect rate design. Rate design is based upon billing determinants which are in turn based upon adjusted kilowatt hour sales.

The examiners point out that, according to the staff's test set forth above, TNP cannot take the position that a weather adjustment is not appropriate under reason (3) above because the weather information cannot be determined. TNP has prepared weather studies in the past and can presumably prepare them now. But TNP may simply take the position that, pursuant to reason (2) above, weather during the test year was normal (which TNP has done in this case) and therefore weather adjustments are not required. Ms. Rosenblum's testimony shows that it would be difficult within the constraints of a rate case to challenge TNP's claim. Unless the staff can obtain the needed information from TNP, the staff would have to collect and digest weather information from the four disparate areas of Texas that constitute TNP's service area.

The Commission therefore finds itself in the position that it is dependent upon TNP to decide whether and when a weather adjustment is needed, knowing that TNP's motivation to propose a weather adjustment will depend upon the type of unusual weather that occurred during the test year. There is, however, insufficient credible evidence in the record to determine the cost and usefulness of weather adjustment calculations. The examiners therefore recommend that the Commission reject Ms. Rosenblum's proposal.

V. The Deferred Accounting Application

A. Description of Deferred Accounting

Staff witness Ms. Diana Kellerman Lay described deferred accounting by means of a comparison with accounting for plant under construction. Staff

Exhibit No. 17 at 6. During the period of construction of a plant, a company may capitalize operating and carrying (financing) costs. The company may seek to include the capitalized costs in rate base when it seeks rate base treatment for the plant. But financial accounting standards prohibit the capitalization of operating and carrying costs incurred once the plant is in commercial operation. The company may no longer book the operating and carrying costs to a balance sheet account. The company must book the costs to expense accounts that affect the income statement. The booked expenses reduce the company's net income. The new plant has a negative impact on the income statement until the company can charge rates that reflect the new plant. "Deferred accounting" refers to the capitalization of plant operating and carrying costs incurred during the period from commercial operation of the plant to the date the plant is reflected in the company's rates.

The Financial Accounting Standards Board's (FASB's) Statement of Financial Accounting Standards (SFAS) No. 71 provides an exception to the above rule. The actions of a regulatory authority can provide reasonable assurance of the existence of an asset (the deferred and capitalized plant costs). A company may therefore capitalize for financial reporting purposes the deferred costs of a new plant if there is a probability that the costs will be recovered in a future rate proceeding. A company seeking to defer costs will accordingly seek an order from the regulatory authority establishing the "probability of recovery" of the deferred costs. TNP, the general counsel, Enron, and the State of Texas agreed that Commission precedent indicates that the Commission will grant an application for a deferred accounting order if a two part test is met:

1. The company's current financial integrity is so fragile that it would not have access to the capital markets on reasonable terms unless it is allowed to continue to accrue AFUDC (allowance for funds used during construction) and defer the expenses associated with a new plant during the period of operation before rates are in effect that reflect the cost of plant.

2. The accounting treatment proposed by the company accords with generally accepted accounting practices (GAAP).

Docket No. 8230, Application of Houston Lighting and Power Company for Approval of Deferred Accounting Treatment for Limestone Unit 2 and the South Texas Project Unit 1, 14 P.U.C. BULL. 2752 (April 19, 1989); Docket No. 7560, Application of Central Power and Light Company for Approval of Deferred Accounting Treatment of Certain Costs Related to the South Texas Nuclear Project Unit 1, 14 P.U.C. BULL. 2669 (April 19, 1989). As discussed below, TIEC, and the State of Texas each contended, on different bases, that the Commission does not have authority to grant TNP's request for a deferred accounting order.

B. TNP's Application

TNP requests to defer and capitalize the costs associated with TNP One, Units 1 and 2, from their respective commercial in-service dates until the time rates are in effect that reflect such costs. TNP seeks the deferral of the operation and maintenance expenses, depreciation, taxes, and carrying costs associated with each unit. The estimated deferred charges for Unit 1 are approximately $5,148,773 per month at the beginning of the deferral period, but increase to $6,156,130 per month at the end of the projected 12-month deferral period. Total Unit 1 estimated deferred charges are $66,693,297. The estimated deferred charges for Unit 2 are approximately $4,302,713 per month at the beginning of the deferral period, but increase to $4,711,487 per month at the end of the projected 12-month deferral period. Total estimated deferred charges for Unit 2 are $53,837,005. TNP Exhibit No. 24, Exhibit REW-2, REW-5.

The total estimated cost of Unit 1 is $331,385,000. The total estimated cost of Unit 2 is $268,880,000. TNP Brief at 131.

TNP does not at this time own TNP One. As discussed at the beginning of this report, a construction consortium is currently building TNP One, Units 1 and 2. The consortium organized a corporation specifically for purposes of owning Unit 1 during its construction. The corporation, Project Funding Corporation, owns Unit 1 and is the entity that borrowed funds for constructing Unit 1. According to the contract between TNP and the consortium, ownership of

Unit 1 will pass from Project Funding Corporation to TNP upon TNP's "preliminary acceptance" of Unit 1. Enron Exhibit No. 60. The preliminary acceptance date (PAD) occurs at the time Unit 1 meets certain performance criteria. TNP anticipates that preliminary acceptance of Unit 1 will occur on June 1, 1990. On that date, the obligation to pay the interest due on debt associated with the plant will also pass to TNP. TNP must repay or refinance the debt held by Project Funding Corporation according to the following schedule: one third of the debt 15 months after the unit's PAD, one third of the debt 27 months after the PAD, and one third of the debt 39 months after the PAD. TNP's therefore anticipates that it must refinance one third of Unit 1 by September 1991, the second third by September 1992, and the final third by September 1993. Under the contract with the consortium, TNP's "final acceptance" of Unit 1 does not occur until 12 months after TNP's preliminary acceptance of Unit 1. During this period, TNP may return ownership of Unit 1 to Project Funding Corporation if the plant does not meet certain performance criteria.

The contract between the consortium and TNP has similar provisions concerning Unit 2. The record reflected, however, that the consortium, not Project Funding Corporation, owns and finances Unit 2. TNP anticipates preliminary acceptance of Unit 2 on June 1, 1991. TNP must therefore refinance Unit 2 according to the following schedule: one third of the debt by September 1992, one third by September 1993, and the final third by September 1994.

The above discussion must be corrected on one important point. The credible evidence in the record shows that upon the respective PADs related to Units 1 and 2, ownership and the related debt obligation will pass to Texas Generating Company (TGC), TNP's subsidiary. During the hearing, and even in brief, TNP could never definitely state whether TNP or its subsidiary TGC will take ownership of Units 1 and 2. But the credible evidence in the record shows that TNP has taken the necessary preliminary contractual steps so that ownership will pass to TGC. Enron Exhibit Nos. 55, 56, and 57. Further, TNP has no current plans to change its position that ownership of Units 1 and 2 will pass to TGC. Tr. at 2025. TNP will, however, be the guarantor of TGC's debt. And TGC will pass an undivided interest in each unit to TNP in proportion to the amount of permanent debt related to the unit that is retired by TNP. Tr. at 2023. The sole purpose behind the creation of TGC is to provide lenders a first lien on the generating plant. If TNP were to own Units 1 and 2 outright, then the units would, under TNP's original indenture, become part of the company's trust estate. TNP could not then offer lenders first liens on Units 1 and 2. The ability to offer lenders a first lien means that the debt may be obtained at a lower cost. Tr. at 2043.

The Commission staff recommend approval of deferred accounting treatment for Units 1 and 2. OPC, Enron, TIEC, and the State of Texas oppose the company's application. The Cities did not participate in the deferred accounting portion of the consolidated dockets.

C. Examiners' Evaluation

1. The Unit 2 Application

The examiners begin by focusing on the company's request for deferred accounting treatment for Unit 2. Based upon the discussion below, the examiners conclude that the application is premature and therefore recommend that the Commission reject TNP's application for deferred accounting treatment for Unit 2.

Commission precedent indicates that the pertinent question is the status of the company's "current financial integrity." TNP anticipates that commercial operation of Unit 2 will closely follow its anticipated June 1, 1991, PAD. Commercial operation of Unit 2 is therefore planned to begin 15 months after the Commission will rule upon TNP's request in this case. The Commission cannot at this time determine what TNP's financial integrity in June 1991 will be, or whether TNP's financial status at that time will justify deferred accounting for Unit 2. Between the Commission's ruling in this case and June 1991, the costs of financing will vary; TNP may or may not take ownership of Unit 1; and the Commission will most likely rule on TNP's next application for a change in rates, expected to be filed in March 1990. Deferred accounting treatment is not explicitly authorized in the PURA. It is therefore inadvisable to stretch its application to the extent of TNP's request. Mr. Barnard, TNP's Chief Financial Officer, testified:

> Since the in-service dates are at the beginning of the last month of a calendar quarter, it is important that deferred accounting be granted prior to the in-service date to avoid reporting results of operations which would reflect the absence of deferred accounting for even one month. These reported results would likely have a negative impact on TNP's bond ratings. As previously discussed, any downgrading of these ratings would result in increased cost per issue of from 50 to 100 basis points. In addition, TNP further requests that the accounting order be issued prior to January 1, 1990. This timing would provide reassurance to the rating agencies and possibly avoid any downgrading of TNP's bond ratings prior to the in-service date of the plants.

TNP Exhibit No. 22 at 31. The examiners respond that Mr. Barnard's second reason for granting deferred accounting so early, to "provide reassurance to the rating agencies and possibly avoid any down-grading," is insufficient justification for granting TNP's request. Mr. Barnard would have the Commission expand the scope of deferred accounting by leaps and bounds. He proposes that the Commission create a regulatory asset not only when a company's financial integrity is fragile, but also when a company's financial integrity might be fragile in the future. Mr. Barnard's concern that the order be approved prior to the in-service date of Unit 2 is similarly an insufficient basis to grant TNP's request. There is sufficient time in the next 15 months to review a new application for deferred accounting concerning Unit 2 so that, if appropriate, deferred accounting may be granted before June 1, 1991. The examiners are aware that the actual in-service date may be earlier or later than June 1, 1991. Given the experience the company will by that time have had with placing Unit 1 into operation, the company will be able to file a new application in enough time to guarantee its review prior to the in-service date of Unit 2.

2. The Unit 1 Application

Based upon the discussion below, the examiners recommend that the Commission reject TNP's application for deferred accounting treatment for Unit 1.

Staff witness Lay described TNP's current financial condition as "relatively stable." Staff Exhibit No. 17 at 5. Rating agencies currently rate TNP as follows:

Duff & Phelps	D&P-6
Standard & Poors	BBB+
Moody's	A3

The Moody's rating of A3 represents a downgrading from A2 as of June 30, 1989. The company's return on equity (ROE) for the years 1987 and 1988 was 12.93 percent and 12.23 percent, respectively. TNP's 1988 ROE was below the 1988 median industry average and below the median for utilities holding an "A" bond rating. Ms. Lay's chart shows a range of 11.7 percent to 13.7 percent, rather than a single median figure for utilities holding a triple "B" bond rating. TNP's 1988 ROE is within this range of the median ROE earned by triple B rated utilities in 1988. Staff Exhibit No. 17, Schedule DL-III.

Ms. Lay reviewed the company's ability to issue new first mortgage bonds and preferred stock. According to Ms. Lay, the company's inability to issue these basic types of securities during the period when it will be refinancing the consortium debt would cause the refinancing to be much more difficult. TNP's indenture agreement requires that net earnings available for interest equal 2.5 times the aggregate amount of annual first mortgage bond interest, including the pro forma interest of new bond issues. The company's restated articles of incorporation require that gross income available for payment of interest charges must equal 1.5 times the aggregate amount of annualized interest on all indebtedness and annualized dividends on all preferred stock.

Prior to investigating the company's financial needs during the proposed period of deferral of Unit 1, the examiners note that TNP's application is materially different from the applications reviewed in Docket Nos. 7560 and 8230 concerning deferred accounting treatment for Unit 1 of the South Texas Project. In these dockets, the companies (HL&P and Central Power and Light) argued that operating and carrying costs related to the new plant incurred during the period of regulatory lag would damage the company's financial integrity. TNP's application also seeks to defer and capitalize operating and carrying costs related to a new plant during the period of regulatory lag. But in this case, TNP does not yet own the plant. The company argues that it must finance the plant during the proposed deferral period. It is primarily the new financing obligations that both strain the company's financial integrity and require the company to maintain its current financial status. This point was made in brief by TNP.

> Because the debt assumed by TNP will have to be refinanced within thirty-nine months after each unit's preliminary acceptance date as described above, it will be necessary for TNP to enter the capital markets to permanently finance each unit beginning in 1990. Although the financing schedule provides flexibility, TNP must have the flexibility to enter the capital markets and to refinance the debt shortly after it assumes ownership of each unit. In order to ensure that it, and ultimately its ratepayers, will pay the lowest capital costs available, TNP must be ready to enter the markets and take advantage of favorable market conditions whenever they occur as soon after each unit's PAD as possible.

TNP Brief at 134. TNP admits that the urgency to finance Unit 1 is not based upon its contractual obligations to Project Financing Corporation. Assuming the preliminary acceptance date for Unit 1 is June 1, 1990, TNP is obligated to retire or refinance the first one-third of the debt related to Unit 1, or roughly $110 million, by September 1991, three months after TNP estimates that Unit 1 will be in rate base. Further, Mr. Barnard testified that the company will not begin retiring or refinancing the debt related to any unit until TNP's final acceptance of the unit:

> Examiner: And TNP, once there's preliminary acceptance, will not until final acceptance move towards financing the plant with long-term debt?
>
> Mr. Barnard: I would think not, until some event -- that would be my estimate now -- that some event has occurred such as final acceptance, I would think that no long-term debt would be issued to fund out the credit facility.

Tr. at 2183. As previously discussed, under the terms of the agreement between the consortium and TNP, final acceptance of a particular unit may occur up to 12 months after preliminary acceptance.

There is a second distinction between TNP's application and prior applications by other utilities for deferred accounting treatment. As previously discussed in this report, the Commission recently adopted the post-test year adjustment rule, which in part permits rate base treatment for assets added to plant in service after the end of the test year. The distiction is important because the company intends to rely upon the new PTYA rule in its next rate case. The examiners come to this conclusion based upon the statements of the company's representative, Mr. Shirley, made during a recent Commission Final Order Meeting:

> Mr. Shirley: . . . TNP is preparing a rate case based upon September 30, 1989, test year under the recently passed post test year adjustment rule. And we intend to file that rate case requesting rate base treatment of Unit 1 hopefully in February, but certainly within the first quarter of 1990.

Commission Final Order Meeting of December 13, 1989, at 278. The examiners propose that the Commission take judicial notice of this statement pursuant to Rule 201 of the Texas Rules of Evidence. The company has already prepared projections of its financial indicators based upon the assumption that it will file its Unit 1 rate case no later than March 31, 1990, using a test year ending September 30, 1989. The projections further assume that the company will rely upon the post-test year adjustment rule and that rates reflecting Unit 1 will be effective January 1, 1991. State of Texas Exhibit Nos. 5 and 8. A copy of the projections assuming no deferred accounting is attached to this report as Examiners' Attachment B. A copy of the projections assuming deferred accounting for Unit 1 and Unit 2 is granted in this case is attached to this report as Examiner's Attachment C.

Prior to discussing the projections, the examiners note that TNP has, pursuant to PURA Section 43(e), implemented bonded rates on a systemwide basis in Docket No. 8928. If TNP files its next rate case on March 30, 1990, (the last business day of the period Mr. Shirley predicted TNP would file its next rate case) then TNP may implement bonded rates on October 1, 1990, that reflect Unit 1.

Examiners' Attachments B and C both show under the columns "long term debt issued," "preferred stock issued," and "common stock issued" the company's plans to retire or refinance total debt of $500 million during the period 1989 through June 1992. The examiners focus on the company's financing plans and financial ratios during the period before TNP may implement bonded rates that reflect Unit 1. With deferred accounting, the company's return on equity remains stable but below the median range for a triple B rated utility. Without deferred accounting, the company's return on equity is identical until it plummets upon the company issuing $35 million worth of stock in March 1990. The company's indenture coverage, both with and without deferred accounting, remains above the required 2.5 times net earnings available for interest above aggregate annual first mortgage bond interest. The company's preferred stock coverage ratios fall below the required 1.5 level, both with and without deferred accounting, in June 1990.

The examiners limit their review of TNP's financial integrity to the period during which the alternative of implementing bonded rates is not available. The examiners do so because Mr. Barnard testified that the company does not request deferral of Unit 1 expenses at the same time that interim or bonded rates reflecting Unit 1 are in place. Tr. at 2165. The examiners note, however, that the company's financial indicators will be low even after TNP implements bonded rates that reflect Unit 1, assuming the company implements its financing program according to the schedule shown on Examiner's Attachments B and C.

Staff witness Lay recommended approval of deferred accounting for both Units 1 and 2. Ms. Lay's testimony, however, contemplated in only general terms what the company's financial integrity might be if the company filed a rate case seeking rate base treatment of Unit 1 using the post-test year adjustment rule. Staff Exhibit No. 17 at 18. This is not surprising, of course, because the company's projections estimated that Unit 1 would not be in rate base until June 1991. Ms. Lay's testimony did not investigate the company's financial integrity assuming both the use of a post-test year adjustment and the implementation of bonded rates to obtain rate base treatment for Unit 1.

The examiners conclude that the credible evidence in the record shows that TNP One Unit 1 will enter commercial operation on June 1, 1990. The company will file its next rate case which will seek rate base treatment for Unit 1 no later than March 30, 1990. The company will then have the right to implement bonded rates that reflect Unit 1 on October 1, 1990. From March 1990 through September 1990 the company's financial integrity will be so fragile that it will not have access to the capital markets on reasonable terms if the company implements the financing program shown on Examiners' Attachements B and C. This financial impairment will occur whether or not the Commission grants or denies TNP's application for deferred accounting for Unit 1. The company has not carried its burden of proof to show its financial condition during the period March 1990 through September 1990 if the company does not implement the financing program shown on Examiners' Attachments B and C. The Commission should therefore deny TNP's application for deferred accounting treatment for Unit 1.

3. Proposed PCRF Amendment

TNP seeks approval of an amendment to its PCRF that would cause the company to collect from its ratepayers both purchased power costs and purchased power costs avoided due to power dispatched from TNP One. The company proposes to offset the purchased power savings against TNP One fuel costs. If purchased power savings exceed TNP One fuel costs, then the excess savings will offset the deferred amounts for Units 1 and 2. P.U.C. SUBST. R. 23.23(b)(3)(A) provides in part:

> An electric utility which purchases electricity at wholesale pursuant to rate schedules approved, promulgated, or accepted by a federal or state authority, or from qualifying facilities may be allowed to include within its tariff a purchased power cost recovery factor (PCRF) clause which authorizes the utility to charge or credit its customer for the cost of power and energy purchased to the extent that such costs varies from the purchased power cost utilized to fix the base rates of the utility.

TNP acknowledges that its proposal violates this Commission rule but requests a good cause exception to the rule. All of the parties, including the staff, recommend rejection of the proposal. TIEC witness Mr. Maurice Brubaker testified that the proposal is inappropriate because TNP proposes to offset energy and demand savings against TNP One costs which represent only demand costs. This is improper from the standpoint of both cost allocation and rate design. TIEC Exhibit No. 10. TNP argues that the PCRF amendment is imperative to maintain the company's cash flow. Further, the amendment eliminates the need for an interim fuel adjustment clause.

Staff witness McClellan testified that the Commission should disallow TNP's PCRF clause entirely because the company will not be a "distribution utility" upon the in-service date of TNP One; substantive rule 23.23(b)(3) authorizes the use of a PCRF only for distribution utilities. She recommends that the Company charge for both purchased power and purchased power costs avoided due to energy dispatched from TNP One through a fixed fuel factor. The general counsel acknowledges that Ms. McClellan's recommendation violates Commission rules and states that, if the recommendation were adopted, the Commission would have to grant a good cause exception to P.U.C. SUBST. R. 23.23(b)(2)(B)(ii). TNP made the point that Ms. McClellan's recommendation is also improper from the standpoint of both cost allocation and rate design, as explained by TIEC witness Brubaker.

The examiners conclude that TNP's proposal violates the PURA and should therefore be rejected. The Commission cannot, of course, make good cause exceptions to the PURA. The Company's proposal would violate section 43(g)(4)(B) of the PURA which provides that the Commission may authorize appropriate methods for the adjustment of the cost of "purchased electricity." TNP's proposal would have the company charge its customers for electricity that it has not purchased.

The examiners also recommend that the Commission not adopt Ms. McClellan's recommendation. Ms. Clellan proposes that the Commission make a good cause exception to the following Commission substantive rule:

> Purchased power capacity costs, fuel handling costs, costs associated with the disposal of fuel combustion residuals, railcar maintenance costs, railcar taxes, and coal brokerage fees will not be included as known or reasonably predictable fuel costs to be recovered through the fixed fuel factor as defined in subparagraph (C) of this paragraph, unless the utility demonstrates that such treatment is justified by special circumstances.

P.U.C. SUBST. R. 23.23(b)(2)(B)(ii). Ms. McClellan would have the company collect (through a fixed fuel factor) purchased power capacity costs, purchased power energy costs, and purchased power costs that have not been incurred. The examiners recommend that the Commission permit TNP to continue to use its PCRF to recover purchased power costs that have actually been incurred. Further, TNP should be required to file a new application seeking approval of an interim fuel adjustment clause designed to recover TNP One fuel costs. This recommendation is consistent with the Commission's substantive rules. TNP will collect its purchased power costs through a purchased power clause, and will collect fuel costs through a fuel factor clause.

4. Other Issues

The State of Texas contends that deferred expenses cannot properly be included in invested capital, because they are not part of the original cost of the plant as required by section 41(a) of the PURA, and therefore the Commission is precluded from considering this application. The Commission has previously reviewed this argument in Docket No. 7560 and has ruled that this section of the PURA does not prohibit deferred accounting.

TIEC argues that the Commission does not have authority to grant TNP's application for deferred accounting because TNP does not yet have a CCN for TNP One. As previously discussed in this report, Docket No. 6992, which concerns TNP's application for a CCN for TNP One, has been remanded to the Commission's Hearings Division. TIEC argues that deferred accounting treatment is a "rate," and that the Commission cannot confer rate treatment upon an asset that is not used and useful in rendering service to the public. TNP One does not yet have a CCN and is therefore not used and useful. The examiners respond that TNP seeks deferred accounting treatment for Units 1 and 2 beginning with the units' respective commercial operation dates. The respective commercial operation dates necessarily follow the date the Commission grants the related CCN because the plants cannot enter commercial operation without a CCN. Section 50(1) of the PURA. The Commission could approve TNP's application for deferred accounting, conditioned upon a Commission final resolution in Docket No. 6992. A non-final order where conditioned upon the entry of another order can become final on the entry of the second order. Big Three Industries, Inc. v. Railroad Commission of Texas, 618 S.W.2d 543, 548 (Tex. 1981).

VI. Cost Allocation

The purpose behind a cost-of-service study is the assignment to each class of customers its appropriate amount of the utility's cost to provide electric service. All of the parties have agreed that the rates should be based on a cost-causation basis. Assigning costs to the class causing the expense to be incurred entails a three-step process: functionalization, classification, and allocation.

Functionalization is the process of grouping costs into several categories. TNP uses four categories: production (purchased power), transmission, distribution, and administration and general expense. The functional groups are then classified into demand, energy, and customer related costs. These costs are then allocated to the various classes of service by allocators which relate to demand, energy, and number of customers. TNP, TIEC, and Staff used this approach in preparing their respective cost allocation studies. OPC also prepared a cost-of-service study, but it is materially different from those of the other parties. OPC's study will be discussed below in the discussion of distribution plant and expenses.

A. Functionalization

During the functionalization process, costs are assigned to four functional categories used in delivering electrical service. These are production (purchased power), transmission, distribution, and administration and general expense. None of the parties challenged TNP's functionalization.

1. Dual-Use Substations

TNP has twenty-two substations with costs associated with both transmission and distribution functions. In TNP's last rate case, Application of Texas-New Mexico Power Company for Authority to Change Rates, Docket No. 5568, 10 P.U.C. BULL. 961 (July 10, 1984), the parties adopted the methodology used by TNP in this docket to functionalize these dual-use substations. None of the parties in this docket have objected to TNP's method of functionalizing these dual-use substations. The examiners recommend that TNP's functionalizing of these accounts based on a detailed functionalization study and power flow analysis be adopted.

B. Classification

During the classification process, each investment and expense is classified as either demand, energy, or customer-specific. The parties reviewed the expense accounts to determine if any contain amounts which could be assigned to one or more classification.

1. Minimum Size for Distribution Plant and Expenses

TNP utilized a minimum-size study to classify distribution plant as demand or customer-related. The minimum-size methodology is based on the supposition that the distribution system is initially designed and built to meet the utility's obligation to serve. This minimum plant size is constructed regardless of the customers' energy usage and is classified as a customer-related component. The plant is enlarged beyond the minimum level to meet the demand within the distribution system. The additional plant is classified as a demand-related component. TNP Exhibit No. 65, pp. 8-9. Both TIEC and Staff utilized TNP's minimum-size study in preparing their recommendations. OPC argued that the minimum-size study did not accurately identify customer-specific costs. OPC's concerns are discussed below in the section relating to distribution plant and expenses.

2. General Plant and Expenses

This topic is discussed below in the section relating to administrative & general and plant expenses.

C. <u>Allocation</u>

Some costs are allocated to each class directly. However, those costs which are incurred to support the overall electrical system or benefit all customers are assigned to each class using an allocation factor. The allocators are based on the relative responsibility of each class for the expense incurred.

1. Purchased Power Demand Expenses

TNP is a summer-peaking utility. Its highest demand occurs during one of the four summer months (June, July, August, and September). Additionally, TNP relies entirely upon purchased power. Therefore, its production allocation is based on its purchased power demand expenses.

TNP is proposing to allocate its purchased power demand expense, which results from the application of a demand ratchet in a supplier's tariff, with the D-10 allocator, which is a 4-CP ("coincident peak") methodology. This allocates the demand cost of ratcheted months entirely on the basis of a class's peak demand during the summer months. A demand ratchet is used to stabilize the cash flow of the utility by leveling out peaks and filling in valleys. The ratchet is determined by a certain percentage of the maximum demand of TNP. During a non-summer month, the demand charge will be based either on actual usage or the demand ratchet, whichever is higher. TNP also proposed that a D-30 allocator (12-CP) be used in any month when the actual demand exceeds the ratcheted demand, such as in the summer months and the non-ratcheted non-summer months. TNP Exhibit No. 65, pp. 13-14.

Staff witness North recommended separating the demand in ratcheted months into two components and allocating them separately. The actual demand would be determined and then the costs associated with this demand would be allocated on the basis of each class's contribution to each of the twelve monthly coincident peaks ("12-CP") experienced during the test year. That part of purchased power demand cost that exceeds the actual cost would then be allocated on a class's contribution to the summer peak period demands, i.e., 4-CP. Ms. North also agreed with TNP in recommending that a 12-CP allocator be used whenever actual purchased power demand exceeds the ratcheted demand, such as in the summer months and the non-ratcheted non-summer months. Staff Exhibit No. 20, pp. 6-11.

TIEC's witness Brubaker recommended that the purchased power demand costs should be allocated entirely on a 4-CP basis. According to TIEC's witness

Carlson, 97 percent of TNP's demand-related purchased power costs are incurred as a result of summer period demands. Because of the overwhelming influence that the summer months have on TNP's purchased power demand costs, TIEC argued, all of these cost should be allocated on a 4-CP basis. As an alternative, TIEC proposed that the summer demands be allocated on a 4-CP basis, while non-summer non-ratcheted demands be allocated on a 12-CP basis. TIEC Exhibit No. 11, pp. 17-25.

OPC's witness Johnson recommended an Average & Peak/4-CP ("A&P/4-CP") allocator for TNP's Southeast division and a 4-CP allocator for the other divisions. Mr. Johnson concentrated his analysis on the Southeast division because he saw this division as the focal point of the forces driving the ongoing restructuring of TNP's production costs. His evaluation considered the following factors: the costs of supply in the division, the load characteristics which affect the demand within the division, and the prospective installation of TNP One generation. OPC Exhibit No. 14, p. 20. Mr. Johnson concluded that TNP's approach would be reasonable if the underlying tariffs of TNP's suppliers provide a reasonable basis for formulating expectations about future demand costs. As an alternative to the Average & Peak methodology, OPC recommended that the staff's proposal be approved.

The following chart summarizes the parties' proposed allocators:

Month	TNP	Staff	TIEC #1	TIEC #2	OPC #1	OPC #2
Summer	12-CP	12-CP	4-CP	4-CP	A&P/4-CP 4-CP	12-CP
Non-Ratchet	12-CP	12-CP	4-CP	12-CP	A&P/4-CP 4-CP	12-CP
Ratchet	4-CP	Actual 12-CP Ratchet 4-CP	4-CP	4-CP	A&P/4-CP	Actual 12-CP Ratchet 4-CP

Each of the parties believed that its proposal would be the most appropriate for TNP. However, cost allocation is not an exact science. The parties are forced to base their recommendations on incomplete information, because obtaining information that would perfectly track costs would be cost prohibitive. Therefore, after reviewing the evidence presented and considering the proposals submitted by the parties, the examiners find that the record evidence demonstrates that TNP's proposal best allocates TNP's purchased power demand costs.

The methodology proposed by OPC should not be adopted. This methodology is based upon expectations that the power supply for TNP's Southeast Division will be in a state of change, and that the load characteristics of this division are substantially different from TNP's other divisions. The record evidence shows that OPC's methodology does not properly track how TNP's purchased power demand costs are incurred. Furthermore, by concentrating on the Southeast Division OPC is ignoring the Commission's historical practise of setting uniform systemwide rates. Finally, Mr. Johnson's consideration of future generation from TNP One as a basis for allocating purchased power expenses goes against cost-matching principles. Because there are no direct costs of TNP One in this proceeding, there is no justification for using TNP One for allocating costs.

TNP is a summer-peaking utility. In fact, 97 percent of the demand-related purchased power costs are incurred as a result of summer period demands. TIEC Exhibit No. 11, p. 18. TIEC's proposal would allocate almost all of the purchased power demand costs on a 4-CP basis. Staff's proposal, on the other hand, would allocate approximately 12 percent of TNP's purchased power demand expense on a 4-CP allocator while allocating the remaining portion on a 12-CP basis. Staff Exhibit No. 20, Staff COS Study, p. 5 of 11. TNP's proposal allocates approximately 37 percent of the purchased power demand expense on a 4-CP allocator, allocating the remainder using a 12-CP allocator. TIEC Exhibit No. 11, p. 17.

The Staff's proposal is similar to its position in Docket No. 5568, and as in Docket No. 5568 these examiners also recognize that a given level of demand would have been incurred in spite of the existence of a demand ratchet. However, the ratchet would not have existed at all if demand remained constant instead of fluctuating over the year. Conversely, TIEC's proposal does not recognize that in non-ratcheted months, the summer peak has no effect upon that month's actual purchased power demand. The examiners find that the 4-CP method for allocating purchased power demand costs for ratcheted months most appropriately tracks TNP's costs and should be adopted by the Commission.

As for summer months and non-ratcheted non-summer months, the examiners find that a 12-CP allocator is the most appropriate methodology. The 4-CP allocator proposed by TIEC, as discussed above, fails to recognize that in months where actual demand exceeds the ratchet, the ratchet is of no consequence.

2. Transmission Plant and Expenses

TNP proposed the use of the D-10 allocator (4-CP) to allocate transmission plant and expenses. The D-10 allocator was chosen by TNP because its transmission system was designed to accommodate the system's peak demand which occurs in the four summer months. TNP Exhibit No. 65, p. 11. Staff and TIEC did not contest TNP's proposed use of the D-10 allocator. OPC proposed that a 12-CP allocator be used for transmission plant and expenses.

OPC placed strong emphasis on the concept of economies of scale in making its recommendation. According to OPC's witness Johnson, economies of scale exist if proportionate increases in investment capacity or the scale of operations lead to a less than proportionate increase in cost. Therefore, where economies of scale do exist, the peak demand allocator (D-10) overstates the cost responsibility of peak users. In Mr. Johnson's opinion, the 12-CP allocator would mitigate the overstatement of cost causation associated with usage at system peak by relying upon a greater number of hours to establish peak responsibility. OPC Exhibit No. 14, pp. 25-30.

As was pointed out by TNP's witness Johnston on rebuttal, transmission line costs are demand-related. TNP's objective is to assign the transmission costs in a reasonable manner that reflects the usage of the line. TNP did not dispute that economies of scale are present when planning a transmission system, but after these savings are considered, the cost of the line must still be assigned. TNP Exhibit No. 69, pp. 6-8.

OPC's Johnson's emphasis on economies of scale may be theoretically sound. As a practical matter, however, it cannot accurately and efficiently track costs. Furthermore, the record evidence does not support his suppostion that economies of scale are a major factor in determining cost causation for transmission plant and expenses. Therefore, the examiners recommend that the Commission adopt TNP's proposed 4-CP allocator for transmission plant and expenses. The 4-CP allocator properly allocates transmission plant and expense based on TNP's peak demand which occurs during the four summer months.

3. Distribution Plant and Expenses

TNP proposes to use the D-20 allocator (4-NCP ["non-coincident peak"]) for distribution plant and expenses above the minimum plant size. According to TNP's witness Gunderson, these non-coincident peaks are the peak demands established by each class and do not necessarily coincide with the system peak in the four summer months. Mr. Gunderson stated that this allocation method acknowledges peak responsibility for cost causation yet recognizes the diversity of demand among the various classes of service. The demand-related portion of the distribution system, that portion above the minimum plant size, is sized to meet peak demand placed on the distribution system during the system peak. TNP Exhibit No. 65, pp. 11-13.

To calculate 4-NCP from the non-coincident peak demands, TNP made two adjustments. First, all transmission level demands were removed. Customers receiving service at the transmission level do not cause any distribution costs to be incurred. Second, the demand portion within the minimum size component was removed to prevent a double allocation of these costs. Id. at p. 12. As was discussed earlier, the minimum plant size is constructed regardless of the customers' energy usage, and TNP classifies the minimum plant as a customer-related component.

TIEC argued that TNP's allocation of distribution costs fails to consider adequately the difference in costs between those customers who take service at the primary distribution voltage level and those served at the secondary voltage level for which additional transformation is required. TIEC speculated that the cost of additional transformers and cumulative line and transformation losses would demonstrate that a distinctive rate class may be ascertained. Therefore, TIEC requested that TNP be required to analyze this difference in its next rate case. TNP plans to file its next rate case in February 1990 and would be unable to perform such a study because of time constraints. The examiners do not recommend that TNP be required to perform TIEC's requested study in its next rate case. TIEC could itself prepare a study if it wanted the Commission to consider the cost differences between secondary and primary voltage. Neither TIEC nor staff challenged TNP's allocation of distribution plant and expense.

OPC's witness Johnson argued that the minimum size concept introduces a theoretical cost into the cost study without any clear evidence that the "hypothetical" amount is related to the number of customers. Therefore, he concluded, these "hypothetical" costs should be regarded as inherently unallocable. Because these costs are conceptually similar to overhead, Mr. Johnson recommended that they be allocated to all customers on the basis of all remaining revenue requirements. OPC Exhibit No. 14, pp. 31-35. Mr. Johnson agreed that the demand-related costs associated with distribution plants should be allocated on the basis of a 4-NCP allocator as proposed by TNP. Id. at pp. 35-36.

Mr. Johnson also proposed a cost study based upon his perception that because TNP's divisions do not operate from a system-wide power grid, interdivisional power cost differentials have become a source of significant inequities in a class cost-of-service study. OPC Exhibit No. 14, pp. 10-17. He thereupon made his recommendations concerning production demand costs, transmission costs, distribution costs, administrative and general expense, general plant expenses, and energy efficiency programs based on theoretical assumptions concerning demography, meteorology, topography, and electrical engineering as it related to TNP's system. TNP's service area may be quite diverse; as was pointed out on cross examination, however, Mr. Johnson is neither an economist nor an engineer. Additionally, there is nothing in the record identifying his expertise in demography, meteorology, or topography. Therefore, his cost-of-service study lacks credibility.

The record does not support adoption of Mr. Johnson's analysis. First, there is no credible evidence in the record that Mr. Johnson's proposal is based on actual cost-causation analysis. Second, by allocating the distribution plant expense on the basis of revenue, customers who take service at transmission level would be allocated costs that they did not incur. Additionally, the evidence supports TNP's analysis of Mr. Johnson's study in that the minimum plant methodology does not add "hypothetical" costs but only classifies existing costs as customer-related or demand-related. TNP's Reply Brief, pp. 18-23, (January 12, 1990).

The Commission practise is to allocate costs on a cost causation basis and not on the basis of speculative unsubstantiated theories. The examiners find that TNP's proposed allocation of distribution costs is reasonable and supported by the record evidence, and therefore recommend that it be approved by the Commission.

4. Administrative & General and Plant Expenses

a. Energy Efficiency Programs. TNP is in the process of implementing two demand-side management programs, and have included estimated costs for implementing these programs of $237,600 above its test year revenues. As was discussed above in Section IV.F.C. "Cost of Service Treatment for Demand Side Programs," the examiners recommended that the estimated portion of these expenses be denied. However, the approximately $80,000 of partial payments made by TNP should be allocated as discussed below.

Both of these energy efficiency programs are limited to residential customer participation. The savings from these programs will flow directly to residential customers through rebates, and indirectly to all of TNP's customers through potentially lower purchased power costs. TNP Exhibit No. 13, pp. 19-20. TNP's witness Gunderson testified that the costs associated with these programs be allocated using the C-10 allocator (4-CP) for customer-related costs and the D-10 allocator (4-CP) for demand-related costs. Both TIEC and staff used TNP's allocator for these expenses. TNP Exhibit No. 65, p. 19.

OPC's witness Johnson testified that classes of customers do not receive the long-term benefits of this program in proportion to the number of customers. In Mr. Johnson's opinion, a properly designed energy efficiency program provides benefits to the system by reducing "system average costs" to all ratepayers and the avoidance of future capacity costs. Therefore, Mr. Johnson developed an allocator weighted by the annual revenues required for distribution and transmission plant and purchase power costs. OPC Exhibit No. 14, pp. 40-42.

One of the principles of cost-causation is the application, whenever possible, of applying directly attributable costs to the class of customer causing the expense. The examiners find that TNP's method for allocating the energy efficiency programs' costs is appropriate, and therefore recommend that the Commission approve it.

b. <u>FERC Accounts</u>. TNP's witness Gunderson testified that TNP is proposing to classify Administrative & General expenses and Plant expenses ("A&G&P") based on the percentage of the sum of each classification component (customer, demand, or direct) to the total of the production, transmission, and distribution plant. Customer-related costs would then be allocated using the C-10 allocator (4-CP), while demand-related costs would be allocated using the D-10 allocator (4-CP). The direct component would be allocated on the ratio of each class's directly-assigned plant to the total directly-assigned plant. Administrative and General expenses would be allocated in the same manner. TNP Exhibit No. 65, p. 19.

Staff's witness North recommended that Account 920 "Salaries," Account 921 "Office Supplies," and Account 926 "Employee Pension and Benefits" use a payroll allocator. Additionally, she recommended that Account 923 "Outside Services," and Account 928 "Regulatory Commission Expense" use a total revenue allocator. Ms. North testified that when developing an allocation factor for a single account, one should examine the reasons why the expenditures were incurred. To that end she developed a revenue allocator and a payroll-related allocation factor. The use of a revenue allocator for these accounts recognizes that the levels of certain expenses are closely related to TNP's overall revenue. The revenue allocator has been used by the Commission in <u>Application of El Paso Electric Power Company for Authority to Change Rates</u>, Docket No. 5700, 10 P.U.C. BULL. 1071 (December 7, 1984) and in <u>Application of Houston Lighting and Power Company for Authority to Change Rates</u>, Docket No. 6765, 13 P.U.C. BULL. 365 (December 22, 1986). The use of a payroll allocator for these accounts recognizes that certain expenses are incurred as a result of providing support for TNP's entire system. The payroll allocator has been used by the Commission in <u>Application of El Paso Electric Power Company for Authority to Change Rates</u>, Docket No. 5700, 10 P.U.C. BULL. 1071 (December 7, 1984) and in <u>Application of West Texas Utilities Company for Authority to Change Rates</u>, Docket No. 7510, 14 P.U.C. BULL. 620 (November 30, 1987). Staff Exhibit No. 20, pp. 11-12.

OPC's witness Johnson recommended that A&G&P be allocated on the basis of total revenue requirement. According to Mr. Johnson, TNP's use of the plant allocator fails to recognize that overhead costs also support the production function as well as the transmission and distribution functions of the utility. Mr. Johnson points out that distribution plant makes up 83 percent of TNP's plant accounts. Therefore, the use of a plant allocator would be heavily influenced by the distribution plant. OPC's Exhibit No. 14, pp. 36-40. OPC also disputed Ms. North's use of the payroll allocator because it did not include production-related costs associated with A&G&P expenses. However, on cross-examination Ms. North stated that her allocation analysis for A&G&P included those employees working in production-related functions. Transcript at pp. 5465-5466.

On rebuttal, TNP's witness Johnston testified that OPC's allocator does not take into account that A&G&P expenses are not directly related to the revenue requirement for each rate group. As an example, Mr. Johnston hypothesized that if purchased power costs were to increase suddenly or decrease, A&G&P expenses would not be affected. However, A&G&P expenses are affected by growth in the number of customers and increased investment in the installed plant-in-service required to serve additional customers. Additionally, Mr. Johnston noted that only four TNP employees in the General Office are involved in regulatory proceedings involving TNP's wholesale producers who sell TNP its purchased power, but that 66 percent of TNP's total revenue requirement is composed of purchased power costs. OPC Exhibit No. 14, p. 38. However, there are approximately 150 people in the General Office. If there were a direct relationship between purchased power costs and A&G&P expenses, one would expect more than four employees to be involved in this area. TNP Exhibit No. 69, pp. 8-9; TNP's Reply Brief, p. 25, (January 12, 1990). TNP did not provide any testimony in rebuttal to Ms. North's recommendations.

The examiners find that TNP's proposed allocation of A&G&P expenses, as modified by Staff witness North, is the most reasonable methodology proposed by the parties. This proposal is amply supported by the record and the examiners recommend its approval by the Commission.

5. Allocation by Jurisdiction versus Division

TNP uses system-wide uniform rates for its four operating divisions in Texas. The rates are based on a system-wide cost allocation. This approach has been specifically approved by the Commission in past TNP rate cases: Application of Community Public Service Company for a Rate Increase, Docket No. 3370 (December 22, 1980); and Application of Texas-New Mexico Power Company for a Rate Increase, Docket No. 4240, 7 P.U.C. BULL. 955 (June 2, 1982). OPC's witness Johnson argued that by adopting an interdivisional averaging approach in the cost analysis, TNP's study implies very strong presumptions about the homogeneity of costs and customer usage characteristics. He then argues that this homogeneity does not exist in TNP's five diverse, geographically dispersed divisions. OPC Exhibit No. 14, pp. 11-12. As was noted in an earlier section of this report, Mr. Johnson has no expertise in demography, meteorology, or topography, nor does he have any advanced degrees in economics.

From a practical standpoint, the cost of maintaining sufficient data for five separate cost allocation studies would be substantial. OPC has not presented any credible evidence which would indicate that such an effort would yield any benefit. Additionally, OPC did not reurge Mr. Johnson's argument in its post-hearing briefs. The examiners find that there is no credible evidence to suggest that the use of system-wide uniform rates improperly allocates costs. Therefore, the examiners recommend that TNP's use of system-wide uniform rates for its divisions in Texas be continued.

6. Direct Assignments

TNP specifically assigned Accounts 371 and 587 to outdoor lighting; Accounts 373, 585 and 596 to street lighting; and Account 557 and portions of 555 to the industrial power service class. Accounts 555 and 557 represent the cost of providing industrial power service ("IPS") standby service. None of the other parties challenged TNP's assignments. The examiners find these direct assignments reasonable and recommend that the Commission approve them.

7. Other Allocators

TNP used additional allocators which are listed in Examiners' Attachment D. None of the other parties challenged TNP's use of these allocators. The examiners find these individual allocators reasonable and recommend that the Commission approve them.

VII. Revenue Allocation

Examiners' Attachment G is a schedule detailing the examiners' recommended revenue allocation.

TNP's witness Gunderson testified that once the cost allocation process is complete, it is then necessary to determine the revenue needed to collect the allocated costs plus a return on TNP's investment from each rate class. TNP's proposed revenue allocation is based on three criteria: 1) cost of service; 2) historical rates and rates of return for each class of service; and 3) revenue stability, which considers both individual class as well as total revenues. Class risk and value of service are two other criteria commonly considered in revenue allocation. However, TNP did not propose to allocate revenue based on these two criteria. TNP Exhibit No. 65, p. 20.

Currently, according to Mr. Gunderson, TNP is earning only 7.80 percent on the original cost rate base. This compares to 11.11 percent which was approved by the Commission in Application of Texas-New Mexico Power Company for Authority to Change Rates, Docket No. 8095, 14 P.U.C. BULL. 618 (September 8, 1988). Mr. Gunderson testified that Residential Service, Resale Service, Municipal Power, Street Lighting Service, and Outdoor Lighting Service are all earning below the average system rate of return. Therefore, he proposed that these classes receive a rate increase larger than the system average. General Service and Large General Service are earning above the system average rate of return. Consequently, Mr. Gunderson proposed that these classes receive a rate increase less than the system average. Currently, the Industrial Power Service Class is earning 25.25 percent above the average system rate of return. Therefore, Mr. Gunderson recommended that this class not receive a rate increase. Id. at pp. 21-22.

The following table illustrates TNP's proposed allocations:

Class of Service (a)	Current ROR (b)	Current Relative ROR (c)	Proposed ROR (d)	Proposed Relative ROR (e)	Requested % Increase (f)
1. Residential	6.4%	0.82	11.40%	0.93	6.31%
2. General Service	10.38	1.33	13.86	1.13	4.85
3. Large General Service	8.03	1.03	12.20	1.00	4.23
4. Resale	2.58	0.33	13.27	1.09	13.85
5. Industrial Power Service	21.20	2.72	21.09	1.73	0.00
6. Municipal Power Service	2.79	0.36	8.99	0.74	7.98
7. Street Lighting	(6.80)	(0.87)	(0.18)	(0.01)	19.26
8. Outdoor Lighting	7.17	0.92	12.03	0.98	13.88
9. Other Revenue	7.80	1.00	12.22	1.00	5.32

Columns b & c from Schedule P.1.B. revised 9/89
Columns d & e from Schedule P.1.A. revised 9/89
Column f from Schedule Q.1.

Table from TNP Post-Hearing Brief, January 4, 1990, p. 29.

All classes have either moved closer to a unity rate of return or are at a unity rate of return. TNP Exhibit No. 65, p. 22.

The staff proposed a different revenue allocation. Staff's witness North first equalized the rate of return among the classes using TNP's allowed rate of return of 11.11 percent. This produced class revenue increases ranging from (4.26) percent for Industrial Power Service to 72.14 percent for Street Lighting. Staff Exhibit No. 21, Supplemental Schedule KN-IV. She testified that the revenue increase for the system as a whole would be 2.26 percent. To reduce the relative impact of the rate increase, she restricted the percentage change to a range of 0 to 1.75 times the system average increase. This produced revenue increases of 0 percent to 3.96 percent. Id. A copy of Supplemental Schedule KN-IV is attached to this report as Examiner's Attachment E.

TIEC's revenue allocation proposal is driven by the fact that the rates for General Service ("GS"), Large General Service ("LGS"), and Industrial Power Service ("IPS") classes are above cost. Therefore, these classes are subsidizing other classes' service. TIEC requested that the Commission order a substantial movement towards equal rates of return for all classes. As detailed in the table below TIEC's witness Brubaker proposed that the GS, LGS, and IPS classes receive increases less than the system average percentage increase. The IPS class would actually receive a 1.5 percent rate reduction from TNP's present rates. According to Mr. Brubaker, even with the rate reduction the IPS class would still remain above cost. TIEC Exhibit Nos. 11 and 11a. The examiners' cannot recommend a rate decrease to the IPS class while all other classes' must share a rate increase. However, the record does support a zero increase as recommended by TNP and staff. A zero increase would bring the IPS class closer to unity rate of return.

OPC's witness Johnson recommended that the Residential and GS class should receive a percentage increase that is 90 percent of the system average percentage, that the LGS, Resale, and Outdoor Lighting should receive a percentage increase that is 125 percent of the system average percentage, and that the IPS and all other classes should receive an equal percentage increase. These recommendations are based on Mr. Johnson's cost-of-service study which, unlike the study used by the other parties, indicated that the Residential class was subsidizing the IPS class. This is exactly the opposite of TNP's, Staff's, and TIEC's studies. Additionally, Mr. Johnson testified that, in his opinion, comparisons of class rates of return can be deceptive. Therefore, in making his recommendations, Mr. Johnson does not rely on any objective standard for support. OPC Exhibit No. 14, pp. 42-44. The examiners cannot support OPC's recommendations because they are not supported by any objective criteria in the evidentiary record.

The following table compares the revenue allocations proposed by the parties. The values represent the class percentage increase divided by the overall increase less "Other Revenue." This comparison measures a class's relative rate increase against the system average increase. Therefore, a relative increase of 1.4, using Ms. North's calculated system average increase of 2.26 percent, would equate to a 3.164 percent rate increase.

Class of Service	TNP (a)	Staff (b)	TIEC (c)	OPC (d)
1. Residential	1.3	1.70	1.6	0.90
2. General Service	1.0	0.00	0.7	0.90
3. Large General Service	0.9	1.10	0.9	1.25
4. Resale	2.9	1.75	2.9	1.25
5. Industrial Power Service	0.0	0.00	(0.3)	1.10
6. Municipal Power Service	1.7	1.75	1.7	1.10
7. Street Lighting	4.0	1.75	4.0	1.10
8. Outdoor Lighting	2.9	1.75	2.9	1.25

Column a from TNP Exhibit No. 4, Schedule Q.1.
Column b from Staff Exhibit No. 21, Schedule KN-IV.
Column c from TIEC Exhibit No. 11, Exhibit MEB-4, Schedule 3.
Column d from OPC Post-Hearing Brief, January 4, 1990, p. 20.

Table from TNP Reply Brief, January 12, 1990, p. 26.

The recommendations of TNP, Staff, and TIEC are very similar; they all move the class rate of returns closer to unity. The examiners carefully reviewed the evidence and find that TNP's proposal yields the most reasonable and fairest results. TNP's methodology gradually moves all classes closer to unity without placing an unduly discriminatory burden on any one class. The examiners recommend TNP's proposal for the following reasons:

1. Ms. North applied a self-imposed limit of 1.75 times the system average increase without objective justification;

2. The overall system rate increase is relatively small; therefore, allocations which bring the customer classes closer to unity are also relatively small;

3. Because Outdoor Lighting is an optional service and is currently being subsidized by other customer classes, an increase above the system average is justified;

4. Street Lighting and Resale service have relatively low rates of return and need to move closer to unity so as to more accurately reflect cost causation; and

5. TNP's proposal brings Resale service and Outdoor Lighting much closer to unity relative rate of return.

Once again the examiners find that TNP's proposed revenue allocation is the most equitable and recommend that it be adopted.

VIII. Rate Design

Examiners' Attachment H is a rate design schedule detailing the examiners' recommendations.

A. <u>Residential Rate</u>

1. Good Cents Rider

TNP has requested the inclusion of a special heating season rider for some of its residential customers. This rider is part of TNP's energy efficiency Good Cents Home Program. To qualify, a customer must:

1. own a new "Good Cents" home which has a heat pump;

2. own an existing "Energy Checked Efficiency" home which has a heat pump;

3. currently have a heat pump which meets specified thermal efficiency standards; or

4. add a heat pump under the "High Efficiency Air Conditioner and Heat Pump Program" which meets specified thermal efficiency standards.

The rider consists of a reduced kWh charge of 1.75 cents for all energy over 800 kWh used in the November through April billing months. Staff Exhibit No. 8, p. 26.

According to TNP's witness Landry, the typical savings per customer would be approximately $84 annually and is a vital part of TNP's "Good Cents" program. The added promotional value of the rider in conjunction with the rebate aspect of the "Good Cents" program is designed to encourage other TNP customers to use more efficient heat pumps. TNP Exhibit No. 13, pp. 23-24. On rebuttal, Mr. Landry testified that a customer's payback period would be shortened from eleven years to seven years if the rider is applied. TNP Exhibit No. 56, p. 7.

Staff witness Treadway opposed the rider because it would probably increase the saturation of residential heat pumps by fuel switching and would in turn increase TNP's revenue requirement. Mr. Treadway concluded that the lower winter block rate would encourage greater electricity use among existing customers with heat pumps and not greater energy efficiency of electricity use as claimed by TNP. Staff Exhibit No. 8, p. 27. Mr. Landry did not address this issue in his rebuttal testimony. However, in a post-hearing brief, TNP argued that the only evidence of fuel switching is Mr. Treadway's "unsubstantiated opinion." TNP Post-Hearing Revenue Requirement Reply Brief, p. 89. First, Mr. Treadway is undeniably an expert on energy efficency programs. Staff Exhibit No. 8, Exhibit No. NT-2. Second, Section 40 of PURA places the burden of proof on TNP to establish that its rider does provide the energy efficiency benefits that it claims.

The examiners find that TNP has not met its burden concerning the energy efficiency benefits of its Good Cents rider, and therefore recommend that the Commission not approve its adoption.

2. Customer Charge

A customer charge is designed to recover those customer-related costs that vary directly with the number of customers. Staff witness North testified that accounts considered customer-related vary from one utility to another. There is general agreement among rate analysts, however, that meter reading, billing, collections, and mailing expenses are customer-related. Staff Exhibit No. 20,

p. 16. Currently, TNP's residential customer charge is $6.50 per month. TNP is proposing to increase this charge to $7.25 per month, while the Staff and OPC are proposing to decrease the residential customer charge to $6.00 per month and $5.75 per month, respectively.

Ms. North calculated the customer charge by simply adding the above-mentioned customer-related costs, which came to $5.32 per month. She then compared this cost to other utilities' residential customer charges. According to Ms. North, the average charge is $6.20 per month. On cross-examination, Ms. North acknowledged that she did not incorporate other utilities' residential customer charges requested in pending rate cases. She testified that if she had included these amounts, her average would have increased. Transcript at pp. 5469-5470.

OPC's witness Johnson testified that his calculation of the residential customer-related costs amounted to $3.69 per month. However, he recommended a customer charge of $5.75 per month, and could not recommend a charge any higher than $6.25 per month. OPC Exhibit No. 14, pp. 45-46.

TNP's witness Johnston testified on rebuttal that both Mr. Johnson and Ms. North failed to include certain customer costs in their analyses, such as the costs associated with the customer-related component of distribution poles, lines, and transformers. According to Mr. Johnston, had these costs been included, Ms. North's calculated residential charge would have been closer to TNP's. TNP Exhibit No. 69, p. 11. Mr. Johnston also pointed out that OPC's Johnson did not include many costs which Mr. Johnston believed to be customer-related, such as the costs associated with owning the service drop on the residential customer's house and the costs associated with owning the meter on the residential customer's house. According to TNP's Johnston, both Ms. North and Mr. Johnson failed to include the customer-related costs associated with line transformers in their analyses. Id. pp. 12-13.

Ms. North recognized that there is a general disagreement as to what should be included in the customer charge. She also recognized that customer-related costs will vary depending upon the particular utility in question. Therefore, considering that TNP uses a minimum-size distribution methodology to determine customer-related distribution expenses, the examiners find that those expenses which were identified by TNP's witness Johnston should be included in the cost calculation of the residential customer charge. The examiners find that the residential customer charge proposed by TNP is the most reasonable and is supported by the record, and therefore recommend its approval.

3. Summer/Winter Differential

Presently, TNP has a flat charge per kilowatt hour for the summer months that is 5 mils higher than the flat charge per kilowatt hour for the winter months. This differential reflects the lower costs associated with supplying service in the winter months. TNP Exhibit No. 65, pp. 23-24. TNP proposed to continue this differential. None of the parties contested this issue. Finding that the differential is reasonable and supported by the record evidence, the examiners recommend that the 5 mils differential be approved.

B. <u>General Service</u>

TNP proposed to increase the customer charge for General Service Single Phase rate from $9.00 per month to $10.00 per month and the customer charge for General Service Three Phase rate from $16.00 per month to $17.00 per month. Staff witness North also recommended these rates. Ms. North calculated a cost-based customer charge of $10.96 per month which she used as a reference point. The average customer charge for General Service, according to Ms. North, is $14.24. Staff Exhibit No. 20, pp. 17-18. None of the parties contested this issue. The examiners find that the General Service rates are reasonable and supported by the record evidence, and recommend that they be approved.

TNP also proposed an increase in the energy charge while maintaining the existing structure and the summer/winter differential in the proposed rate design. None of the parties contested this issue. The examiners find this to be reasonable and supported by the record, and therefore recommend its approval.

C. Large General Service

1. LGS-A/LGS-B Interclass Subsidy

According to TNP's witness Gunderson, the Large General Service class is divided into two sub-classes, LGS-A and LGS-B. The LGS-A subclass includes those customers that have a demand between 100 kW and 500 kW, while the LGS-B subclass includes those customers that have a demand between 500 kW and 22 mW. TNP has 450 LGS customers that are served under the LGS-A tariff and 55 LGS customers that are served under the LGS-B tariff. The division of the rate class is designed to limit the cross-subsidy that exists between the distinct groups within the LGS rate class and to assign risk accurately. TNP Exhibit No. 65, pp. 24-25.

Mr. Gunderson testified that under TNP's current rates the LGS-B class is still subsidizing the LGS-A class. This subsidy still occurs because a large portion of the demand cost is being collected in the energy charge. Under TNP's proposed rates the cross-subsidy is reduced. Id. at pp. 25-26. None of the parties contested this issue. Finding that the Large General Service rates are reasonable and supported by the record evidence, the examiners recommend that they be approved.

2. LGS-B

a. Minimum Bill. TNP has requested that similar notice and minimum bill provisions be included in the LGS-B and IPS tariffs. Copies of the proposed LGS-B and IPS tariffs are attached to this report as Examiners' Attachment F. The three proposed tariff changes are reproduced here for the convenience of the parties and the Commission.

1. Customer shall pay a monthly bill each month calculated on the actual demand and energy usage using the above monthly rates for each KW determined pursuant to "Determination of Demand." In addition, each monthly bill shall include the fuel and purchased power cost adjustment applicable to the current month's use, if any, and the applicable tax adjustment and any other adjustment approved by the Public Utility Commission of Texas.

2. The monthly bill shall be payable each month as calculated under paragraph 1. This amount shall be payable for this length of time whether or not (a) Customer is in default, (b) Customer actually establishes any demand, or (c) Customer has given notice to Company to terminate the contract. If the contract or tariff (if there is no contract) is properly terminated in accordance with its terms, the obligation to pay a monthly bill shall cease upon termination.

3. A contract must be executed by Customer for an initial term of not less than one year (three years for an IPS customer). In absence of a contract, the Customer must provide Company with notice of termination one Calendar Year and two months before the actual termination of service. A Calendar Year is defined to be a twelve month period from January 1 to December 31 of any year ("Calendar Year").

According to TNP's witness Gunderson, the proposed tariff changes affect only those LGS-B and IPS customers which leave TNP's system without proper notice, and charges to them the minimum bill and ratcheted demands in the LGS-B or IPS tariff, respectively. TNP Exhibit No. 65, pp. 27-31. The language proposed for these tariffs applies only to customers who have not signed a contract with TNP. TNP Exhibit No. 70, p. 2-3. Mr. Gunderson testified that TNP's purpose for proposing the tariff change was to:

1. insure that the customer who caused the costs pays for those costs and to prevent subsidy to TNP's other customers; and

2. provide a vehicle which allows a customer to leave TNP's system without incurring minimum bill or ratchet payments.

<u>Id.</u> at p. 2.

TIEC strongly opposed these tariff changes. TIEC's witness Brubaker contested TNP's assumption that large customers, such as LGS-B and IPS customers, create a greater risk to the system which would require a lengthy notice period before they can terminate service without incurring a continuing liability to TNP.

The record evidence demonstrates that larger customers do create a greater risk to the system. Because of their larger demand, if an LGS-B or IPS customer were to leave the system, it would have a greater impact on the future purchased power costs of TNP than if a smaller customer left TNP's system. TNP noted that if an LGS-B or IPS customer were to leave the system without the minimum notice, then TNP's other customers would have to pay those additional costs through a higher PCRF factor. Because of the supplier's ratchet, the demand costs would still be incurred, and consequently would flow through the PCRF. TNP Exhibit No. 70, pp. 3-5.

TIEC also contended that under the proposed tariff changes, a customer would be required to pay a minimum bill for at least 14 months, and possibly as long as 25 months, after the customer has given notice of termination. According to TIEC, TNP failed to demonstrate that this lengthy notice period was necessary to enable TNP to schedule its purchased power.

In its reply brief (January 12, 1990), TNP pointed out that the 25-month liability period as calcualted by TIEC is not entirely correct. Under the "Determination of Demand" provision in TNP's tariff, which is specifically referred to in the proposed tariff change, the customer would be responsible for payments to TNP for only 11 months after termination notice because that customer's <u>billing demand</u> would be the "kW supplied during the 15-minute period of maximum use during . . . the 12 months ending with the current month." According to TNP, after the eleventh month the highest demand would be zero and thus the amount owed by the customer would be zero. However, TNP's own calculation is not entirely correct. The LGS-B tariff states that the minimum demand shall not be less than 500 kW and the "Demand Charge" provision states that a customer must pay $5,605 for the first 500KW of <u>billing demand</u>. Similarly, the IPS tariff has a minimum billing demand of "5,000 kVA," for which the customer must pay $56,750 to TNP. Therefore, even after the eleventh month, the customer would still be liable for payments to TNP.

Mr. Gunderson also testified that a calendar year plus two months is necessary because most purchased power contracts available to avoid supplier ratchets are for a minimum of a calendar year. In a two-month period, TNP will attempt to obtain a short-term supply of purchased power to serve the requirements of the customer leaving the system. TNP Exhibit No. 70, pp. 5-6.

Even with these explanations, the record evidence does not show that it is reasonable to hold a customer leaving the system responsible for payments that may extend to 25 months beyond the notice of termination. Therefore, the examiners find that the tariff changes proposed by TNP are not reasonable and recommend that the Commission not approve them.

b. <u>Monthly Bill</u>. This topic was discussed by the examiners in Section VIII.C.2.a. above.

c. <u>Changes to Special Terms and Conditions</u>. This topic was discussed by the examiners in Section VIII.C.2.a. above.

D. <u>Industrial Power Service</u>

1. Minimum Bill

TNP's proposed tariff change is similar to the change in the LGS-B tariff discussed above in Section VIII.C.2.a. The examiners' analysis and findings are equally supported by the record evidence for the IPS tariff. Consequently, the examiners find that TNP's proposed tariff change is not reasonable and should not be approved.

2. Monthly Bill

TNP's proposed tariff change is similar to the change in the LGS-B tariff discussed above in Section VIII.C.2.a. The examiners' analysis and findings are equally supported by the record evidence for the IPS tariff. Consequently, the examiners find that TNP's proposed tariff change is not reasonable and should not be approved.

3. Changes to Special Terms and Conditions

TNP's proposed tariff change is similar to the change in the LGS-B tariff discussed above in Section VIII.C.2.a. The examiners' analysis and findings are equally supported by the record evidence for the IPS tariff. Consequently, the examiners find that TNP's proposed tariff change is not reasonable and should not be approved.

E. Public Highway Lighting Service, Street Lighting Service, and Outdoor Lighting

TNP proposed to add two new services to its Public Highway Lighting Service and Street Lighting Service tariffs, 100 W and 200 W High Pressure Sodium low-cost lights. This service will eventually replace Mercury Vapor, Metal-Halide, and higher-cost High Pressure Sodium lights. The old services will not be offered at new installations, but will be retained at existing installations until they can be refitted. The new services provide the same lumens while using less energy and create less light pollution than the services they are replacing. TNP Exhibit No. 65, pp. 31-32. None of the parties contested this issue. Finding that the tariff addition is reasonable and supported by the record evidence, the examiners recommend that it be approved.

TNP also proposed to add the High Pressure Sodium low cost lights to its Outdoor Lighting Service tariff for the same reasons as discussed above. None of the parties contested this issue. The examiners recommend that the tariff addition be approved.

F. Standby Service

TNP proposed changing its tariff for Standby Service to reflect the proposed changes in Houston Lighting & Power Company's ("HLP") Standby Service tariff if approved by the Commission in Application of Houston Lighting & Power Company for Authority to Change Rates, Docket No. 8425. TNP purchases all of its standby service for its customers from HLP. The proposed revisions will pass these costs on to those customers seeking the service. TNP Exhibit No. 65, pp. 32-33. None of the parties contested this issue. Finding that the tariff addition is reasonable, and supported by the record evidence, the examiners recommend that it be approved.

G. PCRF Rider

TNP is proposing language in the PCRF factor to allow TNP to make an adjustment in its calculation. As discussed above in Section V.D.5. the examiners recommend that TNP's requested adjustment to its PCRF Rider be denied.

H. Fixed Fuel Rider

TNP has proposed to add a Rider FC ("Fuel Charge") tariff to its rate schedules. This proposed rider is being added to allow TNP to recover fuel costs that will be associated with Unit One of TNP One. The fixed fuel factor has been set at zero and was offered so that the mechanism for implementing the fixed fuel factor will already be in place. None of the parties contested this addition to TNP's rate schedules. Finding that the tariff addition is reasonable and supported by the record evidence, the examiners recommend that it be approved.

I. Miscellaneous Service Charges

TNP is proposing to add three new charges to its Miscellaneous Service Charge tariff: field collection charge; tampering charge; and account initiation charge.

1. Field Collection Charge

TNP's witness Ownby testified that the Field Collection charge will be assessed against any customer for which TNP is required to make a trip to the customer's premises for the purpose of collecting an overdue amount. The customer will not be charged more than once in any given month regardless of the number of trips made. This charge is set at $12.00 and is supported by Mr. Ownby's cost study which includes the direct and indirect labor costs associated with this service. TNP Exhibit No. 10, pp. 5-7, and Exhibit RO-1. None of the parties contested this addition to TNP's rate schedules. Finding that the tariff addition is reasonable and supported by the record evidence, the examiners recommend that it be approved.

2. Tampering Charge

According to Mr. Ownby, the Tampering Charge will be billed to any TNP customer for an unauthorized connection, or other tampering with TNP's meters or any evidence of theft of electric service by any person on the customer's premises. This charge will be a base fee as a minimum charge for the cost of repairs and/or replacement of damaged facilities, installing protective equipment, or relocation of the meter, and shall also include an estimated amount of electric service not recorded by the meter. The charge is set at $40.00 and is supported by Mr. Ownby's cost study which includes the direct and indirect labor costs associated with this service. TNP Exhibit No. 10, pp. 6-7, and Exhibit RO-1. None of the parties contested this addition to TNP's rate schedules. The examiners recommend that the tariff addition be approved.

3. Account Initiation Charge

Finally, Mr. Ownby testified that the Account Initiation Charge (also known as a Connection Charge) would be assessed for the processing of an application for new service or for any transfer of existing service. The charge will not be applied when a customer is reconnected after being disconnected for nonpayment of service or when a request for name change is made when the actual party responsible for payment has not changed.

The charge for service connection where meter installation is required is set at $40.00, while the charge for service connection where no meter installation is required is set at $15.00. These charges are supported by Mr. Ownby's cost study which includes the direct and indirect labor costs associated with this service. TNP Exhibit No. 10, pp. 6-7, and Exhibit RO-1. None of the parties contested these additions to TNP's rate schedules. The examiners recommend that the tariff additions be approved.

J. Wheeling Rates for Qualifying Facilities

TNP's wheeling rate for qualifying facilities will be calculated pursuant to P.U.C. SUBST. R. 23.66(d)(4)(E). These calculations were sponsored by TNP's witness Ellis. TNP Exhibit No. 62, Exhibit BKE-3. On cross-examination Ms. Ellis testified that the wheeling revenue TNP receives is for wheeling other power producers on a firm and "as available" basis. These revenues have nothing to do with wheeling of power from TNP One. Transcript at pp. 1655-1657. None of the parties contested these changes to TNP's rate for wheeling. The examiners recommend that the calculations be approved.

IX. Service Rules

A. Fees and Charges

TNP is not proposing to change its current fees and charges, but it has added three new service charges which are discussed above in Section VIII.I.a. through Section VIII.I.c.

B. Rendering and Payment of Bills

TNP proposed new language for Rule No. 8 contained within Section 4 of its Service Rules. The language is needed to comply with the recent revisions to

P.U.C. SUBST. R. 23.45 which sets forth the interest charges to be applied on billing overcharges and undercharges. The examiners recommend that the proposed language be approved.

C. Other

TNP proposed several revisions for Section 4. These changes were included for clarity and to track the Commission's substantive rules. TNP is also proposing to delete Rule No. 5, "Fees and Charges." This information will now be contained in TNP's proposed Miscellaneous Service Charge tariff. This change will create easier access to TNP's tariffed charges. The examiners recommend that the revisions be approved.

X. Miscellaneous Issues

A. TSA's Request for Cost-of-Service Study

In its post-hearing briefs Texas State Agencies ("TSA") raised, for the first time, its request that the Commission order TNP to perform a cost-of-service study for the State. TNP strongly opposed TSA's request arguing that TSA takes service for a very diverse usage that includes such activities as highway lighting and prison service. Therefore, the use of one rate would be inappropriate. TNP also argued that TSA's request would create a situation wherein ratemaking would become customer-specific instead of usage-specific. Finally, TNP pointed out that TSA is receiving service under tariffs that are cost-based. The examiners cannot find any support for TSA's request in the record and strongly recommend that the Commission deny TSA's request.

B. Surcharge Cities' Rate Case Expenses

TNP requested in its rate filing package that the Commission authorize a surcharge of the Cities' rate case expenses to ratepayers located within the municipal boundaries of the intervenor cities. TNP did not brief this issue.

The examiners conclude that the Cities' efforts in the consolidated dockets will benefit all of TNP's ratepayers. The examiners recommend that the Commission deny TNP's request to surcharge the Cities' rate case expenses.

C. Billing Determinants

In Phase One of this proceeding, OPC's witness Allen testified that he had concerns about TNP's proposed billing determinants. However, he did not make any recommendations in Phase One, as was discussed above, nor did he make any recommendations in Phase Two. Finding that TNP's proposed billing determinants are reasonable and supported by the record evidence, the examiners recommend that they be approved as proposed.

VI. Findings of Fact and Conclusions of Law

The examiners recommend that the Commission adopt the following Findings of Fact and Conclusions of Law:

A. Findings of Fact

1. On June 13, 1989, Texas-New Mexico Power Company (TNP or the company) filed an application seeking a Commission order which would permit TNP to defer the depreciation expense, operation and maintenance expense, tax expense, and carrying costs associated with Units 1 and 2 of the company's first generating plant located in Texas. The generating plant, located in Robertson County, is referred to as TNP One. The application was designated Docket No. 8880.

2. On July 18, 1989, TNP filed a statement of intent and application to increase its rates in all unincorporated areas, and in all municipalities that have surrendered their original ratemaking jurisdiction, which the company serves. The application was designated Docket No. 8928.

3. TNP's application in Docket No. 8928 requested an effective date of August 23, 1989. Implementation of the proposed rates in Docket No. 8928 was

suspended for 150 days, until January 20, 1990. Because there were 36 hearing days, the suspension period was extended by 42 days, until March 3, 1990.

4. The company filed applications for rate increases with municipalities retaining original jurisdiction over electric utility rates. The ratemaking ordinances of Dickinson, League City, Bailey's Prairie, Booker, Holiday Lakes, Rio Vista, Whitney, Covington, LaMarque, Bells, Angleton, Gatesville, Spearman, Sweeney, Darrouzett, West Columbia, Perryton, Lewisville, Brazoria, Pearland, Texas City, Farmersville, Olney, Nacona, Fort Stockton, Alvin, Toyah, Pecos City, Friendswood, and Kermit were timely appealed to the Commission and were consolidated with Docket No. 8928.

5. By Order dated September 8, 1989, the examiner consolidated Dockets No. 8880 and 8928.

6. TNP published notice of its deferred accounting application once each week for two consecutive weeks in newspapers of general circulation in TNP's service area. TNP also gave direct notice by mail to the parties in TNP's last rate case, Docket No. 8095.

7. TNP published notice of its requested rate increase once each week for four consecutive weeks in newspapers of general circulation in TNP's service area. TNP gave direct notice by mail to the affected municipalities and its customers. TNP gave direct notice by mail to the commissioners' court of each county which would be affected by the proposed rate changes.

8. Four protest statements were filed. None of the protestants appeared at the hearing.

9. The hearing on the merits in the consolidated dockets was convened on October 24, 1989. The hearing lasted 36 days.

10. Docket No. 8880 was reassigned to Examiner Richard O'Connell on August 1, 1989.

11. TNP is a distribution utility in Texas. TNP has four service areas in the State.

12. TNP's proposed rates in Docket No. 8928 would increase the company's gross revenues by $16,088,054, 9.60 percent above adjusted test year revenues of $290,751,592. The company seeks an overall revenue requirement of $318,690,386. The amount of the proposed rate increase for each customer class, however, would differ depending upon each class's existing contribution to the overall return and TNP's proposed changes for each class.

13. For purposes of calculating TNP's purchased power expense attributable to Southwestern Public Service Company (SPS), it is appropriate to use SPS's monthly fuel adjustment factor applicable at the end of the test year rather than the factor applicable one month prior.

14. For purposes of calculating TNP's purchased power expense attributable to Houston Lighting & Power Company (HL&P), it is appropriate to use HL&P's rates in effect at the end of TNP's test year. In June 1989 HL&P implemented bonded rates pursuant to its rate case in Docket No. 8425.

15. The appropriate amount of purchased power expense, as based upon the corrected testimony of staff witness McClellan, and the testimony of staff witness North, is reflected on Schedule I attached to the order.

16. The company's test year unadjusted outside services expense should be reduced by $23,605, because the test year service provided by the firms of Stone & Webster, and Isham, Lincoln & Beale is not of a recurring nature.

17. The company's test year unadjusted advertising expense should be reduced by $14,616, because the test year expense was used to promote the use of security lighting.

18. The company's test year unadjusted Texas Atomic Energy Research Foundation dues expense should be reduced by $16,660, because this expense is not a reasonable cost of service for a utility with no nuclear generating plant.

19. The appropriate amount of unadjusted operations and maintenance expense is reflected on Schedule II of the order.

20. The appropriate amount of standby power expense is reflected on Schedule II of the order.

21. The allocation factors used by TNP to predict the amount of labor cost that is expensed, and the allocation factor used to predict the amount of general office labor attributable to Texas operations, are reasonable and should be approved.

22. The labor expense estimate prepared by Cities witness Stowe accurately reflects TNP's known and measurable labor expense because the estimate is based on known expense and employee levels that occurred during the second quarter of 1989.

23. The appropriate amount of labor expense is reflected on Schedule II of the order.

24. The pension plan expense methodology used by staff witness Foreman most accurately determines pension plan expense because it is based upon the 1989 actual pension funding requirements incurred by TNP.

25. The methodology used by TNP to determine workers' compensation and public liability insurance expense, thrift plan expense, and group life insurance expense is reasonable.

26. The appropriate labor-related expense is reflected on Schedule II of the order.

27. The appropriate amount of general office rent expense is reflected on Schedule II of the order.

28. TNP sells its accounts receivable to the factoring firm of CSW Credit, Inc. Factoring benefits TNP's ratepayers and therefore the related expense should be a recoverable expense. The factoring expense rate recommended by staff witness Foreman and OPC witness Allen is the most accurate rate because it is based upon the most recent known and measurable information.

29. The appropriate factoring expense is reflected on Schedule II of the order.

30. TNP incurred reasonable rate case expenses of $905,240.

31. The Cities' reasonable rate case expenses attributable to witnesses Stowe and Hopper total $87,116.

32. The Cities' reasonable rate case expenses attributable to the firm of Butler & Casstevens total $22,267.

33. TNP requested a donations and contributions expense of $42,082. Contributions are not a reasonable cost of service, given TNP's position that it must receive a rate increase to maintain its financial integrity. This expense should be disallowed.

34. A portion of EEI dues are attributable to legislative advocacy (15.28 percent), club dues (.07 percent), publications which promote consumption of electricity (.08 percent), political activity contributions (.34 percent), and legislative policy research (5.22 percent). The appropriate EEI dues expense is reflected on Schedule II of the order.

35. EPRI has agreed to grant TNP a "special credit" on its annual dues to reflect indirect EPRI dues payments through purchased power costs. The special credit will continue until TNP no longer pays EPRI dues indirectly. The 1990

special credit will be larger than TNP's 1990 EPRI dues. Including an EPRI dues expense would therefore be inappropriate.

36. Chambers of commerce dues in the amount of $8,550 are reasonable because membership in chambers of commerce improves the professional skills of TNP employees.

37. Civic club dues in the amount of $11,425 are reasonable because membership in civic clubs improves the professional skills of TNP employees.

38. "Other dues" in the amount of $8,076 should be disallowed. There is insufficient credible evidence in the record to find that the dues are paid towards activities that contribute to the professionalism of TNP employees.

39. The appropriate amount of interest on customer deposits is reflected on Schedule I of the order.

40. Pursuant to Finding of Fact No. 53, the Commission excludes the company's 345 KV transmission line from plant in service. The Commission should therefore disallow the related annual depreciation expense of $290,571.

41. Pursuant to Finding of Fact No. 55, the Commission rejects the company's proposed reclassification of CWIP to plant in service. The Commission should therefore disallow the related annual depreciation expense of $12,089.

42. The company's purchased rights-of-way are related to the company's transmission lines. The rights-of-way will not, however, lose their value upon the end of the service life of the related transmission line. The company's land rights should therefore not be depreciated, and the Commission should disallow the company's proposed depreciation of land rights in the amount of $122,437.

43. The appropriate amount of depreciation expense is shown on Schedule I attached to the order.

44. The Commission has adopted Cities witness Stowe's calculation of labor expense. It is therefore reasonable to adopt Mr. Stowe's calculation of payroll taxes, because it is based upon his recommended labor expense.

45. OPC witness Allen's calculation of state franchise tax expense is reasonable because it accurately weighs the effect of the reduction in the tax rate that will take effect May 1, 1990.

46. TNP's methodology to estimate ad valorem tax expense is reasonable because it is based upon an effective rate applied to the company's gross plant at the end of the test year. The ad valorem tax expense should, however, be reduced by taxes associated with CWIP. All costs, including ad valorem taxes, associated with CWIP should be capitalized, not expensed.

47. The Commission should rely upon the methodology used by staff witness Foreman to calculate Texas gross receipts tax expense. Ms. Foreman's methodology is reasonable because it is based upon the actual taxes paid during the test year.

48. The Commission should rely upon the methodology used by the company to calculate the street rental tax rate. The company's methodology relies upon an "effective rate" that is based upon test year taxes.

49. The Commission should rely upon the methodology used by the company to calculate the Texas PUC assessment. The company's methodology relies upon an "effective rate" that is based upon test year taxes.

50. The appropriate amount of taxes other than federal income taxes is shown on Schedule III attached to the order.

51. The appropriate federal income tax expense is shown on Schedule V attached to the order, as explained in section IV.A.5. of this report.

52. TIEC's proposed adjustment attributable to TNP's change from the meters-read method to the unbilled revenues method is not reasonable and should be rejected.

53. The proposed adjustments by staff witness Foreman and OPC witnesss Allen regarding the June 1989 refund of state franchise taxes should be rejected.

54. The company's 345 KV transmission line that runs from TNP One to the Twin Oak substation owned by TU Electric exists solely for the purpose of connecting TNP One with TNP's customers. The line does not at this time serve TNP's customers because TNP One is not in service The Commission should not include the line in the company's invested capital.

55. There is insufficient credible evidence in the record to conclude that the 345 KV line should be allowed in invested capital as plant held for future use.

56. TNP's proposed reclassification of test year end CWIP to plant in service should be rejected.

57. OPC witness Allen's recommended post-test year adjustment to accumulated depreciation should be rejected.

58. The appropriate amount of plant in service, accumulated depreciation, and net plant in service is shown on Schedule IV attached to the order.

59. Staff witness Taylor used a lead lag study to formulate her recommended working cash allowance. Ms. Taylor's lead lag study is the most reasonable such study in the record and should by adopted by the Commission. The appropriate amount of cash working capital is shown on Schedule VI attached to the order.

60. The appropriate amount of materials and supplies, deferred federal income taxes, and customer deposits and customer advances for construction that should be included in invested capital is shown on Schedule IV attached to the order.

61. The appropriate amount of invested capital is shown on Schedule IV attached to the order.

62. The company's cost of debt is 9.87 percent, as discussed in section IV.D.1. of this report.

63. The company's cost of preferred stock is 9.37 percent, as discussed in section IV.D.2. of this report.

64. Enron witness Kennedy's methodology used to determine the company's cost of equity is the most reasonable such study in the record. Mr. Kennedy's DCF analysis of comparable utilities should not, however, have been averaged with the DCF analysis of TNPE. None of the comparable utilities are facing the financing of a power plant that will triple the company's gross plant.

65. The market-to-book adjustments to the company's cost of equity proposed by TNP and by staff witness Hathhorn should be rejected by the Commission.

66. The company's cost of common equity is 12.86 percent.

67. The company's capital structure is 46.32 percent long-term debt, 5.03 percent preferred stock, and 48.65 percent common equity.

68. The appropriate rate of return for the company is 11.30 percent.

69. TNP's provides service that is safe, adequate, and reliable. TNP's quality of service does not justify an adjustment to return on invested capital fixed by the Commission.

70. The efficiency of the company's operations, and the quality of the company's management does not justify an adjustment to return on invested capital fixed by the Commission.

71. The company's continuing of service provided to the Lewisville plant of TI is 99.980 percent.

72. The Commission should order TNP to repair the design defect in the network of switches that serve the TI substation, as explained by staff witness Gordon. The design defect will be repaired upon TNP's installation of an oil circuit breaker at the West substation that connects to the TI substation.

73. TNP filed its energy efficiency plan with its rate application. TNP is in compliance with the statewide energy plan, but TNP's conservation efforts are not being considered favorably or unfavorably in fixing the company's rate of return.

74. The Commission should allow recovery of known and measurable post-test year expenses of $82,400 for the company's Good Cents Home Program and High Efficiency Air Conditioning and Heat Pump Plan.

75. The company's two adjustments to test year KW Hour sales are reasonable.

76. There is insufficient credible evidence in the record to determine the cost and usefulness of requiring TNP to implement a weather adjustment methodology. The Commission should not order TNP to implement a weather adjustment methodology.

77. The in-service date for commercial operation of Unit 2 of TNP One will be after June 1, 1991. The Commission evaluated TNP's application for deferred accounting treatment for Unit 2 at an open meeting in February 1990. The company therefore requests that the Commission approve the company's proposed deferral of expenses related to Unit 2 at least 15 months before the beginning of the proposed deferral period. The Commission cannot in February 1990 determine what the financial integrity of TNP will be in June 1991, given that the costs of financing vary over time, TNP may or may not take ownership of Unit 1 in the interim, and given that the Commission will most likely rule upon TNP's next rate case in the interim.

78. The Commission should reject TNP's application for deferred accounting treatment of Unit 2.

79. TNP will file its next rate case no later than March 30, 1990, seeking rate base treatment for Unit 1 of TNP One. The rate application will be based upon a test year ending September 30, 1989, and will rely upon the Commission's post-test year adjustment rule. The company will then have the right to implement bonded rates that reflect Unit 1 by October 1, 1990.

80. The company seeks deferred accounting treatment for Unit 1 until the unit is reflected in the company's rates. The company does not seek to defer costs after the date the company implements bonded rates that reflect the unit.

81. As shown on Examiners' Attachments B and C, the company's financial integrity during the period June 1990 through September 1990 will be so fragile that it will not have access to the capital markets on reasonable terms if the company implements the financing plan shown on the exhibits. This financial impairment will occur whether or not the Commission grants or denies TNP's application for deferred accounting treatment for Unit 1.

82. The Company did not establish that the proposed financing plan shown on Examiners' Attachments B and C must be fully implemented as scheduled. Upon the transfer of ownership of Unit 1 to TNP, the company's contractual obligation to retire or refinance the debt related to Unit 1 is as follows: the first one-third of the debt in September 1991, the second third in September 1992, and the final third in September 1993.

83. The credible evidence in the record does not show the company's financial integrity during the period June 1990 through September 1990, assuming that the company does not implement its proposed financing plan. The financial indicators listed on Examiners' Attachments B and C are all based upon company financial information that is the result of the previous proposed debt and stock issues.

84. The company will have the right to implement bonded rates that reflect Unit 1 no later than October 1, 1990. During the period June 1990 through September 1990 the company's financial integrity depends upon whether the company implements the proposed financing plan, not whether the Commission grants deferred accounting treatment for Unit 1. The Commission should therefore deny TNP's application for deferred accounting for Unit 1.

85. The company's proposed PCRF amendment would cause the company to collect from its ratepayers both purchased power costs and purchased power costs avoided due to power dispatched from TNP One. The Commission should deny the company's proposed PCRF amendment and permit the company to continue to use its current PCRF clause.

86. Staff witness McClellan's proposal that the company recover through a fixed fuel factor its purchased power capacity costs, purchased power energy costs, and purchased power costs avoided due to power dispatched from TNP One, should be rejected by the Commission.

87. The Commission should require the company to file a new application seeking approval of an interim fuel factor to recover fuel costs related to TNP One.

88. TNP's refunctionalization of 22 substations is reasonable, supported by the record, and should be adopted.

89. TNP's proposed allocation of purchased power demand expenses methodology of 4-CP in ratcheted months and 12-CP in summer months and non-ratcheted months is reasonable, supported by the record, and should be adopted.

90. TNP's proposed allocation of transmission plant and expenses methodology of 4-CP is reasonable, supported by the record, and should be adopted.

91. TNP's proposed use of the minimum plant size to allocate customer-related distribution plant and expenses is reasonable, supported by the record, and should be adopted. TNP's proposed use of the 4-NCP allocation factor to

allocate distribution plant and expenses which exceed the minimum plant size is also resonable, supported by the record, and should be adopted.

92. The record supports TNP's proposal to allocate its energy efficiency programs on a 4-CP basis and should be adopted.

93. TNP's proposed use of the 4-CP allocation factor to allocate its Administrative & General expenses and Plant expenses as modified by the Commission's staff is reasonable, supported by the record and should be adopted.

94. The record supports the reasonableness of TNP's use of system-wide averaging in its cost analysis and the use of system-wide uniform rates in its rate structure.

95. TNP's direct assignment of Accounts 371, 587, 373, 585, 596, 557, and a portion of 555 is reasonable, uncontroverted by the parties in this proceeding, supported by the record, and should be adopted.

96. TNP's use of the allocators listed in Examiners' Attachment D are reasonable, supported by the record, uncontested by the parties, and should be adopted.

97. The record supports the use of TNP's revenue allocation methodology as detailed in Examiners' Attachment G, because it moves all classes closer to unity without placing an undue burden upon any class. Further, TNP's allocation is not unreasonably discriminatory in favor of or against any customer class.

98. TNP's proposed Good Cents Rider is not reasonable because its promotes the use of electricity and not energy effiiency, and should not be adopted.

99. The record supports a customer charge of $7.25 per month for residential customers, $10.00 per month for general service single phase customers, and $17.00 per month for general service three phase customers.

100. The summer/winter differential for residential and general service rates proposed by TNP is reasonable, supported by the record, uncontroverted by the parties, and should be adopted.

101. TNP's proposed rates to limit the cross subsidy of the LGS classes is reasonable, supported by the record, uncontroverted by the parties, and should be adopted.

102. The minimum bill, monthly bill, and changes to the special terms and conditions of TNP's LGS-B and IPS tariffs are unreasonable because they require that a customer leaving TNP's system be charged for up to 25 months after it leaves. The examiners recommend that the tariff changes not be adopted.

103. TNP's proposed addition of two new services to its Public Highway Lighting Service, Street Lighting Service, and Outdoor Service tariffs is reasonable, supported by the record, and should be adopted.

104. TNP's proposed change to its Standby Service tariff is reasonable, supported by the record, and should be adopted.

105. TNP's proposed change to the language of its PCRF is unsupported by the record and should be denied.

106. The Fixed Fuel rider proposed by TNP is reasonable and should be adopted.

107. TNP's proposed additions to its Miscellaneous Service Charges tariff: field collection charge; tampering charge; and account initiation charge, are reasonable, supported by the record, and should be adopted.

108. The calculations of TNP's proposed wheeling rate for qualifying facilities is uncontroverted by the parties, supported by the record, in compliance with P.U.C. SUBST. R. 23.66(d)(4)(E), and should be adopted.

109. TNP's proposed new service rules and miscellaneous fee changes are reasonable, supported by the preponderance of the evidence in the record, and should be adopted.

110. TSA's request for a cost-of-service study for the state is not supported by the preponderance of the evidence in the record and should be denied.

111. TNP's request that the Cities' rate case expenses be surcharged to the ratepayers located within the municipal boundaries of the intervenor cities is not supported by the preponderance of the evidence in the record, is unreasonable, and should be denied.

112. TNP's proposed billing determinants are reasonable and should be adopted.

B. Conclusions of Law

1. TNP is a public utility as defined in section 3(c)(1) of the PURA and is therefore subject to the Commission's jurisdiction and authority.

2. The Commission has jurisdiction over the consolidated dockets pursuant to sections 16(a), 17(d), 17(e), 27, 37, and 43 of the PURA.

3. The rate filing package filed in Docket No. 8928 by TNP meets the requirements of section 43(a) of the PURA regarding the contents of a statement of intent.

4. The operation of the proposed rate schedule in Docket No. 8928 was suspended in accord with Section 43(d) of the PURA.

5. TNP complied with the notice requirements in Docket No. 8880 set by the Administrative Law Judge then presiding over the docket. P.U.C. PROC. R. 21.25.

6. TNP complied with the notice requirements in Docket No. 8928 regarding notice of the proposed rate changes. PURA §43(a) P.U.C. PROC. R. 21.22.

7. The reassignment of Docket No. 8880 to Examiner Richard O'Connell was made pursuant to section 15 of the APTRA and P.U.C. PROC. R. 21.102(b).

8. The purchased power expense adopted by the Commission is based upon the corrected calculations of staff witness McClellan. Ms. McClellan's calculation reflected only purchased power costs and rates in effect during the test year because there are no post-test year changes to purchased power expense that are known and measurable. P.U.C. SUBST. R. 23.21(a).

9. The promotion of the use of security lighting promotes the increased consumption of electricity. The related advertising expense should therefore be disallowed. P.U.C. SUBST. R. 23.21(b)(2)(F).

10. The portion of EEI dues that the Commission has disallowed that are attributable to legislative policy research and political activity contributions are directly or indirectly related to legislative advocacy. P.U.C. SUBST. 23.21(b)(1)(E)(iv).

11. TNP's 345 KV transmission line that connects TNP One to the ERCOT grid is not used and useful in rendering service to the public, and therefore cannot be included in invested capital. PURA section 39(a).

12. The Company provides adequate electric service to the Lewisville plant of TI. PURA section 58(a).

13. TNP has complied with the requirements for energy efficiency plans set forth in P.U.C. SUBST. R. 23.22.

14. As required by section 41(a) of the PURA, the net plant component of TNP's invested capital set forth in Schedule V of the order is based upon the original cost of property used by and useful to TNP in providing electric utility service.

15. The methods and rates of depreciation implicit in Schedules I and IV of the order are proper and adequate and have been uniformly and consistently applied, in accord with section 27(b) of the PURA.

16. To the extent included in invested capital, TNP's transmission and distribution facilities are safe, adequate, efficient, and reasonable, as required by section 35(a) of the PURA.

17. The overall rate of return and component rates of return recommended in section VI.D. of this report comply with P.U.C. SUBST. R. 23.21(c)(1).

18. Taking into consideration TNP's quality of management, quality of service, effort to conserve energy and resources, and efficiency of operations, the return set forth in Schedule I of the order constitutes a reasonable return on TNP's invested capital used and useful in rendering service to the public, in accord with section 39(b).

19. The return set forth in Schedule I of the order will permit TNP a reasonable opportunity to earn a reasonable return over and above its reasonable and necessary operating expenses, as required by section 39(a) of the PURA.

20. The expenses set forth in Schedule I of the order comply with P.U.C. SUBST. R. 23.21(b).

21. TNP has met the burden of proof imposed by section 40 of the PURA to show that rates producing the total Texas base revenue set forth in Schedule VII of the order are just and reasonable.

22. The rates approved by the Commission in this case are to effective only for customers in areas within the Commission's original jurisdiction and in the municipalities from which appeals were consolidated with this proceeding.

23. TNP's proposal that deferred accounting treatment be authorized for TNP One, Unit 2, is premature, and should be denied.

24. TNP's proposal that deferred accounting treatment be authorized for TNP One, Unit 1, does not meet the standards set forth for approval of such proposals, as found in prior Commission dockets. Docket No. 8230, Application of Houston Lighting and Power Company for Approval of Deferred Accounting Treatment for Limestone Unit 2 and the South Texas Project Unit 1, 14 P.U.C. BULL. 2752 (April 19, 1989); Docket No. 7560, Application of Central Power and Light Company for Approval of Deferred Accounting Treatment of Certain Costs Related to the South Texas Nuclear Project Unit 1, 14 P.U.C. BULL. 2669 (April 19, 1989).

25. TNP's proposed deferred accounting treatment for TNP One, Unit 1, should be denied under sections 16(a) and 27 of the Act.

26. The rates prescribed herein and detailed in Examiners' Attachment H will not be unreasonably preferential, prejudicial, or discriminatory, but will be sufficient, equitable, and consistent in application to each class of customers, and they should be approved.

Respectfully submitted,

Richard S. O'Connell

RICHARD S. O'CONNELL
HEARINGS EXAMINER

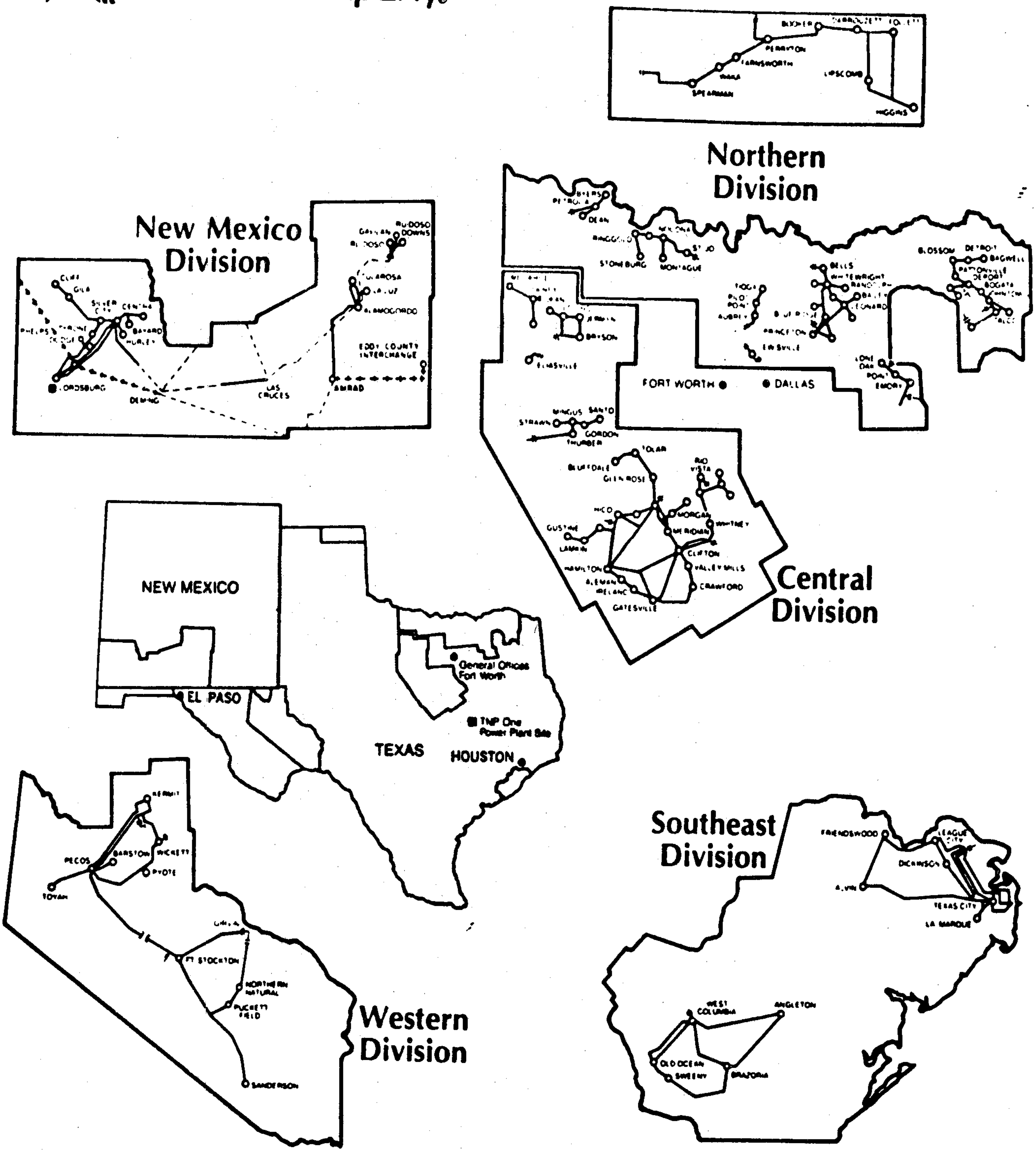
JEFFREY A. FRIEDMAN
HEARINGS EXAMINER

APPROVED on this the 1st **day of** February **1990.**

Mary Ross McDonald

MARY ROSS MCDONALD
DIRECTOR OF HEARINGS

Texas-New Mexico Power Company



Legend

- o Electric property
- ■ Generating station
- —+|— Inter-connection
- —— Transmission line
- - - - Transmission line (other ownership)
- + + + Transmission line (joint ownership with other companies in New Mexico)

POST TEST YEAR ADJUSTMENT

TEXAS-NEW MEXICO POWER COMPANY
WITHOUT DEFERRED ACCOUNTING TREATMENT
AND NO PCRF ADJUSTMENT

16-Oct-89
01:16 PM

12 MONTHS ENDING	NET INCOME	RETURN ON EQUITY	POST ISSUANCE INDENTURE COVERAGE	POST ISSUANCE PREFERRED STOCK COVERAGE	LONG TERM DEBT ISSUED	PREFERRED STOCK ISSUED	COMMON STOCK ISSUED	SHORT TERM DEBT	BANK LOANS REPAID	BALANCE BANK LOANS
TOTAL 1989	14,706,491	10.76%	2.959	1.947	20,000,000	0	15,000,000	24,500,000	(36,000,000)	20,000,000
MARCH 1990	14,760,198	10.86%	2.983	1.639	0	30,000,000	0	6,000,000	0	26,000,000
JUNE 1990	12,828,609	7.50%	3.023	0.689	0	0	35,000,000	317,000,000	(64,550,000)	278,450,000
SEPTEMBER 1990	5,995,708	3.35%	2.837	0.748	0	0	0	4,000,000	0	282,450,000
DECEMBER 1990	(1,328,390)	-0.60%	1.804	0.812	50,000,000	0	40,000,000	1,000,000	(89,250,000)	194,200,000
MARCH 1991	1,671,998	0.74%	2.431	0.966	0	40,000,000	0	0	(39,400,000)	154,800,000
JUNE 1991	5,099,193	1.88%	3.022	0.813	0	0	40,000,000	270,000,000	(40,000,000)	384,800,000
SEPTEMBER 1991	12,777,714	4.51%	2.690	1.002	80,000,000	0	0	0	(86,800,000)	298,000,000
DECEMBER 1991	17,481,774	5.53%	3.154	1.166	0	30,000,000	30,000,000	4,000,000	(59,550,000)	242,450,000
MARCH 1992	20,344,179	6.31%	2.590	1.334	90,000,000	0	0	0	(91,650,000)	150,800,000
JUNE 1992	25,660,794	7.84%	2.913	1.482	0	0	0	0	(5,000,000)	145,800,000
					240,000,000	100,000,000	160,000,000	626,500,000	(512,200,000)	

Examiners' Attachment B

Supplemental
General Counsel's First
Docket No. 8880
Attachment: DL-6b (PTY)
Page 2 of 32

POST TEST YEAR ADJUSTMENT

TEXAS-NEW MEXICO POWER COMPANY
WITH DEFERRED ACCOUNTING TREATMENT
AND NO PCRF ADJUSTMENT

16-Oct-89
12:01 PM

12 MONTHS ENDING	NET INCOME	RETURN ON EQUITY	POST ISSUANCE INDENTURE COVERAGE	POST ISSUANCE PREFERRED STOCK COVERAGE	LONG TERM DEBT ISSUED	PREFERRED STOCK ISSUED	COMMON STOCK ISSUED	SHORT TERM DEBT	BANK LOANS REPAID	BALANCE BANK LOANS
TOTAL 1989	14,706,491	10.76%	2.959	1.947	20,000,000	0	15,000,000	24,500,000	(36,000,000)	20,000,000
MARCH 1990	14,760,198	10.86%	2.983	1.639	0	30,000,000	0	6,000,000	0	26,000,000
JUNE 1990	16,196,696	9.47%	3.191	0.761	0	0	35,000,000	317,000,000	(64,550,000)	278,450,000
SEPTEMBER 1990	19,643,456	10.98%	3.520	1.053	0	0	0	4,000,000	0	282,450,000
DECEMBER 1990	22,793,730	10.39%	2.652	1.397	50,000,000	0	40,000,000	1,000,000	(89,250,000)	194,200,000
MARCH 1991	26,376,731	11.95%	3.327	1.520	0	40,000,000	0	0	(39,400,000)	154,800,000
JUNE 1991	29,792,963	11.36%	3.947	1.204	0	0	40,000,000	269,000,000	(40,000,000)	383,800,000
SEPTEMBER 1991	36,519,025	13.30%	3.323	1.374	80,000,000	0	0	0	(86,800,000)	297,000,000
DECEMBER 1991	40,064,027	13.08%	3.782	1.529	0	30,000,000	30,000,000	2,000,000	(59,550,000)	239,450,000
MARCH 1992	43,570,970	14.13%	3.080	1.720	90,000,000	0	0	0	(93,650,000)	145,800,000
JUNE 1992	46,818,736	15.08%	3.380	1.840	0	0	0	0	(7,000,000)	138,800,000
					240,000,000	100,000,000	160,000,000	623,500,000	(516,200,000)	

2168

Examiners' Attachment C

Supplemental
General Counsel's First
Docket No. 8880
Attachment: DL-3 (PTY
Page 2 of 32

Allocator ID	Allocator	Expense
GPLT	Total Gross Plant	Accumulated Deferred Income Tax
		Pre-1971 Unamortized ITC
		Ad Valorem
		Franchise Tax
		Admin. Service Tax
		Cash Working Capital
		Prepayments
		Material and Supplies
A454	Demand-Related Distribution Lines	Rent from Electric Property (Account 454)
OMXPP	Operation and Maintenance Expense Less Purchased Power Expense	Payroll Taxes
		Business Expense Disallowed
NOR	Net Operating Revenue	Tax Credits
NPLT	Net Plant	Interest on Debt Additional Depreciation

TNP Exhibit No. 65, page 18

PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 8928
TEXAS-NEW MEXICO POWER COMPANY
STAFF PROPOSED REVENUE REQUIREMENTS

SUPPLEMENTAL

SCHEDULE KN-IV
PAGE 1 OF 1

(1) CUSTOMER CLASS	(2) PRESENT REVENUE	(3) STAFF COST-OF-SERVICE @ UNIFORM RATE OF RETURN	(4)	(5) REVENUE CHANGE	(6) PERCENT CHANGE	(7) STAFF PROPOSED REVENUE ADJUSTMENT	(8)	(9) STAFF PROPOSED REVENUE REQ'MT	(10) ADJUSTED ROR	(11) RELATIVE ROR INDEX
	($)	($)	(%)	($)	(%)	($)	(%)	($)	(%)	(%)
RESIDENTIAL	120,042,262	124,798,278	11.11	4,756,016	3.96	4,651,362	3.87	124,693,624	11.05%	0.99
GENERAL SERVICE	50,365,983	50,350,241	11.11	(15,742)	(0.03)	0	0.00	50,365,983	11.13%	1.00
LG. GENERAL SERVICE	52,618,584	54,219,201	11.11	1,600,617	3.04	1,316,702	2.50	53,935,286	10.63%	0.96
RESALE	1,163,958	1,244,820	11.11	80,862	6.95	46,035	3.96	1,209,993	9.05%	0.81
INDUSTRIAL POWER	47,402,308	45,383,775	11.11	(2,018,533)	(4.26)	0	0.00	47,402,308	26.68%	2.40
MUNICIPAL POWER	3,542,066	3,909,953	11.11	367,887	10.39	140,089	3.96	3,682,155	6.73%	0.61
STREET LIGHTING	1,538,938	2,649,197	11.11	1,110,259	72.14	60,865	3.96	1,599,803	-8.29%	-0.75
OUTDOOR LIGHTS	2,665,938	3,105,062	11.11	439,124	16.47	105,438	3.96	2,771,376	6.82%	0.61
TOTAL	279,340,037	285,660,526	11.11	6,320,489	2.26	6,320,489	2.26	285,660,526	11.11%	1.00

Notes:

(1) Customer Classes
(2) From Workpaper 3
(3) From Attachment 1
(4) Recommended Rate of Return
(5) Column (3) - (2)
(6) Column (5) as a Percentage
(7) Column (8) x (2)
(8) Recommended Percentage Increase
(9) Column (2) + (7)
(10) From Workpaper 4
(11) Column (10) Divided by Total in Column (10)

Examiners' Attachment E

TEXAS-NEW MEXICO POWER COMPANY
TOTAL TEXAS

SECTION NO. 3 B
PUCOT SHEET NO. 3
EFFECTIVE August 1989
REVISION NO. 1
PAGE NO. 1 of 3

LARGE GENERAL SERVICE - B

Available for All alternating current electric service greater than 500 KW when all service is taken through one meter at a single point of delivery.

Not available for resale, temporary, breakdown or stand-by service.

Type of Service Single or three phase, 60 hertz, 120/240 volt or any available primary voltage. Service may also be furnished at 208, 480, or 2,400 volts when special arrangements are made in advance with Company. Where entire service cannot be measured at one utilization voltage with one standard type meter, it will be measured at primary voltage.

Monthly Rate

Demand Charge

$5,605.00 for first 500 KW of billing demand. (I)
$10.75 per KW for additional KW of billing demand.

Energy Charge

2.95¢ per KWH for all KWH. (I)

Monthly Bill

1. Customer shall pay a monthly bill each month calculated on the actual demand and energy usage using the above monthly rates for each KW determined pursuant to "Determination of Demand". In addition, each monthly bill shall include the fuel and purchased power cost adjustment applicable to the current month's use, if any, and the applicable tax adjustment and any other adjustment approved by the Public Utility Commission of Texas. (T) (N)

2. The monthly bill shall be payable each month as calculated under paragraph 1. This amount shall be payable for this length of time whether or not (a) Customer is in default, (b) Customer actually establishes any demand, or (c) Customer has given notice to Company to terminate the contract. If the contract or tariff (if there is no contract) is properly terminated in accordance with its terms, the obligation to pay a monthly bill shall cease upon termination.

Transmission Service Credit If customer receives service at any available standard voltage of 69.0 KV or higher, a transmission credit of $.45 per KW of demand and .12¢ per KWH will be applied to customer's bill. (D)

LARGE GENERAL SERVICE - B

Minimum Bill

1. \$8.063 per KW of the highest billing demand established in the 12 months ending with the current month, but not less than \$5,605.00. (I)

2. The minimum bill shall be payable each month as calculated under paragraph 1. This amount shall be payable for this length of time whether or not (a) Customer is in default, (b) Customer actually establishes any demand, or (c) Customer has given notice to Company to terminate the contract. If the contract or tariff (if there is no contract) is properly terminated in accordance with its terms, the obligation to pay a monthly bill shall cease upon termination. (T) (N)

Purchased Power Cost Plus purchased power cost in accordance with Rider PCRF.

Fuel Cost Plus fuel cost in accordance with Rider FC. (N)

Franchise Fees For service within the incorporated limits of a municipality which imposes a municipal franchise fee in excess of 2% of the revenue, subject to the fee imposition, received by Company within that municipality, such excess municipal franchise fee will be added to and separately stated on each customer's bill.

Determination of Demand The customer's billing demand will be the KW supplied during the 15 minute period of maximum use during the month, but not less than 75% of the maximum KW similarly determined during the billing months of May, June, July, August, September or October in the 12 months ending with the current month, nor less than 500 KW.

Power Factor For average lagging power factors of less than 80% the measured demand will be increased according to the following formula: $\frac{KW \times .80}{PF}$

Special Terms and Conditions

1. A contract must be executed by Customer for an initial term of not less than one year. In absence of a contract, the Customer must provide Company with notice of termination one Calendar Year and two months before the actual termination of service. A Calendar Year is defined to be a twelve month period from January 1 to December 31 of any year ("Calendar Year"). (T) (N)

LARGE GENERAL SERVICE - B

2. Any service provided under this Schedule is further subject to the Company's rules and regulations on file with the Commission. Company will not contract for additional power from suppliers until Customer has contracted with Company for the additional power. All terms and provisions between of the existing contracts and agreements between the Company and its Customers, not specifically addressed by this Schedule, shall remain in full force and effect. Any disagreement concerning this schedule, or any prior schedule under which service to this class of customer has been rendered, shall be submitted to the Commission for decision, subject to appeal as provided by law. (T) (N)

INDUSTRIAL POWER SERVICE

Available for All alternating current electric service when all service is taken through meters at points of delivery established by contract between Customer and Company.

Not available for resale, temporary, breakdown or stand-by service.

Type of Service Three phase, 60 hertz service delivered at 69.0 KV or above, where customer furnishes, installs and maintains all transformers and distribution facilities. Company may, at its option, meter service on the secondary side of the Customer's transformers and adjust for transformer losses.

Monthly Rate

Demand Charge

$56,750.00 for any amount of KVA from 0 KVA to 5,000 KVA (I)
$11.05 per KVA for all KVA above 5,000 KVA

Energy Charge

2.48¢ per KWH for all KWH. (I)

Monthly Bill

1. Customer shall pay a monthly bill each month calculated on the actual demand and energy usage using the above monthly rates for each KVA determined pursuant to "Determination of Demand". In addition, each monthly bill shall include the fuel and purchased power cost adjustment applicable to the current month's use, if any, and the applicable tax adjustment and any other adjustment approved by the Public Utility Commission of Texas. (T) (N)

2. The monthly bill shall be payable each month as calculated under paragraph 1. This amount shall be payable for this length of time whether or not (a) Customer is in default, (b) Customer actually establishes any demand, or (c) Customer has given notice to Company to terminate the contract. If the contract or tariff (if there is no contract) is properly terminated in accordance with its terms, the obligation to pay a monthly bill shall cease upon termination.

Minimum Bill

1. $8.288 per KVA of the highest billing demand established in the 12 months ending with the current month, but not less than $56,750. (I)

INDUSTRIAL POWER SERVICE

2. The minimum bill shall be payable each month as calculated under paragraph 1. This amount shall be payable for this length of time whether or not (a) Customer is in default, (b) Customer actually establishes any demand, or (c) Customer has given notice to Company to terminate the contract. If the contract or tariff (if there is no contract) is properly terminated in accordance with its terms, the obligation to pay a monthly bill shall cease upon termination. (T) (N)

Purchased Power Cost Plus purchased power cost in accordance with Rider PCRF.

Fuel Cost Plus fuel cost in accordance with Rider FC. (N)

Franchise Fees For service within the incorporated limits of a municipality which imposes a municipal franchise fee in excess of 2% of the revenues received by Company within that municipality and subject to the fee imposition, such excess municipal franchise fee will be added to and separately stated on each Customer's bill.

Determination of Demand The customer's billing demand will be the highest of the following:

(1) If the monthly off-peak KVA is less than 130% of the monthly on-peak KVA, the billing demand will be the average KVA supplied during the 15 minute period of maximum use during the monthly on-peak period.

(2) If the monthly off-peak KVA is greater than 130% of the Monthly on-peak KVA, the billing demand will be the average KVA supplied during the 15 minute period of maximum use during the month.

(3) 75% of the highest Annual on-peak KVA established established during the twelve (12) months ending with the current month. (T)

(4) 75% of the highest monthly on-peak KVA established for any month for customers of less than twelve (12) months.

(5) 5,000 KVA.

Definition of Terms

Annual On-Peak Company's annual on-peak hours are designated as 8 a.m. to 10 p.m. each Monday through Friday starting on May 15 and continuing through October 15 each year. Labor Day and Independence Day (July 4) shall not be considered on-peak. If July 4

INDUSTRIAL POWER SERVICE

occurs on Sunday, then the following Monday shall not be considered on-peak. The Company's annual on-peak hours may be changed from time to time and Customer will be notified 12 months prior to such change becoming effective.

Monthly On-Peak Company's monthly on-peak hours are designated as 8 a.m. to 10 p.m. each Monday through Friday for each month of the year. New Year's Day,, Independence Day (July 4), Labor Day, Thanksgiving Day and Christmas Day shall not be considered on-peak. The Company's monthly on-peak hours may be changed from time to time and customer will be notified 12 months prior to such change becoming effective.

Off-Peak Company's off-peak hours are all hours of the year not designated as annual on-peak hours or monthly on-peak hours.

Special Terms and Conditions

1. A contract must be executed by Customer for an initial term of not less than three years. In absence of a contract, the Customer must provide Company with notice of termination one Calendar Year and two months before the actual termination of service. A Calendar Year is defined to be a twelve month period from January 1 to December 31 of any year ("Calendar Year"). (T) (N)

2. Any service provided under this Schedule is further subject to the Company's rules and regulations on file with the Commission. Company will not contract for additional power from suppliers until Customer has contracted with Company for the additional power. All terms and provisions between of the existing contracts and agreements between the Company and its Customers, not specifically addressed by this Schedule, shall remain in full force and effect. Any disagreement concerning this schedule, or any prior schedule under which service to this class of customer has been rendered, shall be submitted to the Commission for decision, subject to appeal as provided by law.

(1) CUSTOMER CLASS	(2) PRESENT REVENUE	(3) COS @ UNIFORM ROR	(4)	(5) REVENUE CHANGE	(6) PERCENT CHANGE	(7) PROPOSED REV. ADJUSTMENT	(8)	(9) EXAMINER PROP REVENUE REQ'M	(10) ADJUSTED ROR	(11) RELATIVE ROR INDEX
	($)	($)	(%)	($)	(%)	($)	(%)	($)	(%)	(%)
RESIDENTIAL	122,006,043	128,089,516	11.30	6,083,473	4.99	3,758,032	3.08	125,764,075	9.99%	0.88
GENERAL SERVICE	51,216,201	51,770,532	11.30	554,331	1.08	819,459	1.60	52,035,660	11.67%	1.03
LG. GENERAL SERVIC	53,839,081	55,138,503	11.30	1,299,422	2.41	1,267,857	2.35	55,106,938	11.24%	0.99
RESALE	1,188,147	1,291,269	11.30	103,122	8.68	55,843	4.70	1,243,990	8.32%	0.74
INDUSTRIAL POWER	48,599,353	45,410,657	11.30	(3,188,696)	-6.56	0	0.00	48,599,353	41.99%	3.72
MUNICIPAL POWER	3,610,320	3,986,790	11.30	376,470	10.43	212,106	5.88	3,822,426	7.96%	0.70
STREET LIGHTING	1,565,481	2,628,730	11.30	1,063,249	67.92	183,944	11.75	1,749,425	-5.09%	-0.45
OUTDOOR LIGHTS	2,700,358	3,106,015	11.30	405,657	15.02	399,788	14.81	3,100,146	11.22%	0.99
TOTAL	284,724,984	291,422,013	11.30	6,697,029	2.35	6,697,029	2.35	291,422,013	11.30%	1.00

Examiners' Attachment G

Customer Class	Billing Units	Proposed Rate ($)	Revenue ($)
RESIDENTIAL			
Customer Charge	1,632,564	7.25	11,836,089
Summer Energy Charge	973,117,474	0.0694	67,534,353
Winter Energy Charge	720,767,780	0.0644	46,417,445
Subtotal			125,787,887
	Rev. Mismatch	($)	(23,812)
		(%)	-0.02%
GENERAL SERVICE			
Customer Charge			
Single-Phase	192,084	10.00	1,920,840
Three-Phase	98,592	17.00	1,676,064
Summer Energy Charge			
0-1,000 kwh	278,185,019	0.0743	20,669,147
1,001 and above	129,080,139	0.0513	6,621,811
Winter Energy Charge			
0-1,000 kwh	218,015,395	0.0743	16,198,544
1,001 and above	106,457,838	0.0463	4,928,998
Subtotal			52,015,404
	Rev. Mismatch	($)	20,256
		(%)	0.04%

PUBLIC UTILITY COMMISSION OF TEXAS SCHEDULE I

TEXAS-NEW MEXICO POWER COMPANY -DOCKETS 8928/8880

REVENUE REQUIREMENT

DESCRIPTION		(COLUMN 1) TEST YEAR PER BOOKS		(COLUMN 2) COMPANY ADJUSTMENTS TO TEST YEAR		(COLUMN 3) COMPANY REQUESTED TEST YEAR		(COLUMN 4) EXAMINER ADJUSTMENTS TO REQUEST		(COLUMN 5) EXAMINER RECOMMENDED TEST YEAR
PURCHASED POWER	$	199,127,617	$	11,244,359	$	210,371,976	$	(11,851,331)	$	198,520,645
OPERATIONS AND MAINTENANCE		41,987,914		2,860,754		44,848,668		(1,419,300)		43,429,368
DEPRECIATION		12,353,250		647,628		13,000,878		(413,008)		12,587,870
INTEREST ON CUSTOMERS DEPOSITS		210,585		0		210,585		(0)		210,585
TAXES OTHER THAN INCOME TAXES		12,877,419		1,099,707		13,977,126		(511,180)		13,465,946
FEDERAL INCOME TAXES		4,009,329		3,927,423		7,936,752		(1,496,577)		6,440,175
RETURN		19,764,231		8,580,170		28,344,401		(3,486,595)		24,857,806
REVENUE REQUIREMENT	$	290,330,345	$	28,360,041	$	318,690,386	$	(19,177,991)	$	299,512,395

EXAMINER'S ADJUSTMENT TO TEST YEAR PER BOOKS IS DERIVED BY ADDING THE AMOUNT IN COLUMN 2 TO THE AMOUNT IN COLUMN 4

PUBLIC UTILITY COMMISSION OF TEXAS

SCHEDULE II

****

TEXAS-NEW MEXICO POWER COMPANY -DOCKETS 8928/8880

****

OPERATIONS AND MAINTENANCE (EXCLUDING FUEL AND PURCHASED POWER)

****

DESCRIPTION	(COLUMN 1) TEST YEAR PER BOOKS	(COLUMN 2) COMPANY ADJUSTMENTS TO TEST YEAR	(COLUMN 3) COMPANY REQUESTED TEST YEAR	(COLUMN 4) EXAMINER ADJUSTMENTS TO REQUEST	(COLUMN 5) EXAMINER RECOMMENDED TEST YEAR
O&M NOT ADJUSTED	$ 13,898,622	$ 0	$ 13,898,622	$ (57,770)	$ 13,840,852
STANDBY EXPENSE	1,784,216	215,013	1,999,229	0	1,999,229
LABOR COST	19,524,435	858,357	20,382,792	(321,804)	20,060,988
LABOR RELATED COST	2,744,443	106,981	2,851,424	(75,437)	2,775,987
FACTORING EXPENSE	2,991,403	292,207	3,283,610	(422,030)	2,861,580
EEI DUES	98,250	(13,863)	84,387	(7,749)	76,638
GENERAL OFFICE RENT	575,571	110,188	685,759	0	685,759
RATE CASE EXPENSE	326,500	652,879	979,379	35,244	1,014,623
DONATIONS	0	42,082	42,082	(42,082)	0
DUES AND SUBSCRIPTIONS	42,245	(2,857)	39,388	(8,076)	31,312
ENERGY EFFICIENCY PROGRAM	0	237,600	237,600	(155,200)	82,400
EPRI DUES	2,229	362,167	364,396	(364,396)	0
TOTAL OPERATIONS AND MAINTENANCE	$ 41,987,914	$ 2,860,754	$ 44,848,668	$ (1,419,300)	$ 43,429,368

EXAMINER'S ADJUSTMENT TO TEST YEAR PER BOOKS IS DERIVED BY ADDING THE AMOUNT IN COLUMN 2 TO THE AMOUNT IN COLUMN 4

PUBLIC UTILITY COMMISSION OF TEXAS

SCHEDULE III

TEXAS-NEW MEXICO POWER COMPANY -DOCKETS 8928/8880

SUMMARY OF TAXES OTHER THAN INCOME TAXES

DESCRIPTION	(COLUMN 1) TEST YEAR PER BOOKS	(COLUMN 2) COMPANY ADJUSTMENTS TO TEST YEAR	(COLUMN 3) COMPANY REQUESTED TEST YEAR	(COLUMN 4) EXAMINER ADJUSTMENTS TO REQUEST	(COLUMN 5) EXAMINER RECOMMENDED TEST YEAR
TEXAS AD VALOREM TAXES	$ 3,253,675	$ 200,707	$ 3,454,382	$ (3,885)	$ 3,450,497
PAYROLL TAXES	1,506,146	41,837	1,547,983	(23,260)	1,524,723
OTHER NON REVENUE RELATED TAXES	804,309	142,787	947,096	0	947,096
NON REVENUE RELATED TAXES	$ 5,564,130	$ 385,331	$ 5,949,461	$ (27,145)	$ 5,922,316
TEXAS PUC ASSESSMENT	$ 478,881	$ 46,778	$ 525,659	$ (31,633)	$ 494,026
TEXAS STATE GROSS RECEIPTS	3,448,620	336,868	3,785,488	(228,751)	3,556,737
TEXAS LOCAL GROSS RECEIPTS	3,385,788	330,730	3,716,518	(223,651)	3,492,867
REVENUE RELATED TAXES OTHER THAN INCOME TAXES	$ 7,313,289	$ 714,376	$ 8,027,665	$ (484,035)	$ 7,543,630

SUMMARY OF OTHER TAXES
OTHER THAN INCOME TAXES

DESCRIPTION	(COLUMN 1)	(COLUMN 2)	(COLUMN 3)	(COLUMN 4)	(COLUMN 5)
NON REVENUE RELATED TAXES	$ 5,564,130	$ 385,331	$ 5,949,461	$ (27,145)	$ 5,922,316
REVENUE RELATED TAXES	7,313,289	714,376	8,027,665	(484,035)	7,543,630
TOTAL TAXES OTHER THAN INCOME TAXES	$ 12,877,419	$ 1,099,707	$ 13,977,126	$ (511,180)	$ 13,465,946

EXAMINER'S ADJUSTMENT TO TEST YEAR PER BOOKS IS DERIVED BY ADDING
THE AMOUNT IN COLUMN 2 TO THE AMOUNT IN COLUMN 4

PUBLIC UTILITY COMMISSION OF TEXAS

SCHEDULE IV

TEXAS-NEW MEXICO POWER COMPANY -DOCKETS 8928/8880

INVESTED CAPITAL

DESCRIPTION	(COLUMN 1) TEST YEAR PER BOOKS	(COLUMN 2) COMPANY ADJUSTMENTS TO TEST YEAR	(COLUMN 3) COMPANY REQUESTED TEST YEAR	(COLUMN 4) EXAMINER ADJUSTMENTS TO REQUEST	(COLUMN 5) EXAMINER RECOMMENDED TEST YEAR
PLANT IN SERVICE	$ 361,615,540	$ 439,775	$ 362,055,315	$ (12,330,281)	$ 349,725,034
ACCUMULATED DEPRECIATION	(77,893,853)	0	(77,893,853)	0	(77,893,853)
NET PLANT IN SERVICE	283,721,687	439,775	284,161,462	(12,330,281)	271,831,181
WORKING CASH ALLOWANCE	(11,122,333)	(3,842,048)	(14,964,381)	359,956	(14,604,425)
MATERIALS AND SUPPLIES	4,165,591	0	4,165,591	0	4,165,591
PREPAYMENTS	816,141	0	816,141	0	816,141
DEFERRED FEDERAL INCOME TAXES	(37,844,306)	0	(37,844,306)	0	(37,844,306)
PRE 1971 INVESTMENT TAX CREDITS	(25,413)	0	(25,413)	0	(25,413)
CUSTOMERS DEPOSITS	(3,316,293)	0	(3,316,293)	0	(3,316,293)
OTHER COST FREE CAPITAL	(1,041,892)	0	(1,041,892)	0	(1,041,892)
TOTAL INVESTED CAPITAL	$ 235,353,182	$ (3,402,273)	$ 231,950,909	$ (11,970,325)	$ 219,980,584
RATE OF RETURN			0.122200	-0.009200	0.113000
RETURN			$ 28,344,401	$ (3,486,595)	$ 24,857,806

EXAMINER'S ADJUSTMENTS TO TEST YEAR PER BOOKS IS DERIVED BY ADDING THE AMOUNT IN COLUMN 2 TO THE AMOUNT IN COLUMN 4

SCHEDULE V

PUBLIC UTILITY COMMISSION OF TEXAS

****

TEXAS-NEW MEXICO POWER COMPANY -DOCKETS 8928/8880

****

FEDERAL INCOME TAXES

****

DESCRIPTION		EXAMINER RECOMMENDED TEST YEAR
RETURN	$	24,857,806
PLUS (MINUS)		
INTEREST EXPENSE		(10,053,113)
AMORTIZATION OF ITC		(736,519)
EXCESS DEFERRED TAX AMORTIZATION		(191,637)
ADDITIONAL DEPRECIATION		353,020
ENVIRONMENTAL TAX		15,262
DISALLOWED BUSINESS MEALS		28,785
TAXABLE COMPONENT OF RETURN		14,273,604
TAX FACTOR		0.515151515
TOTAL FEDERAL INCOME TAXES BEFORE ADJUSTMENTS		7,353,069
PLUS (MINUS):		
AMORTIZATION OF ITC		(736,519)
EXCESS DEFERRED TAX AMORTIZATION		(191,637)
ENVIRONMENTAL TAX		15,262
TOTAL FEDERAL INCOME TAXES	$	6,440,175

PUBLIC UTILITY COMMISSION OF TEXAS
TEXAS-NEW MEXICO POWER COMPANY -DOCKETS 8928/8880
WORKING CASH ALLOWANCE

DESCRIPTION		(COL. 1) EXAMINER RECOMMENDED REVENUE REQUIREMENT		(COL. 2) ADJUSTMENTS		(COL. 3) WORKING CASH CALCULATION AMOUNT	(COL. 4) (LEAD) LAG DAYS		(COL. 5) WORKING CASH AMOUNT ((COL. 3 * COL. 4)/365)
WORKING CAPITAL USES:									
REVENUE REQUIREMENT	$	299,512,395	$	(42,227,731)	$	257,284,664	18.59	$	13,103,896
WORKING CAPITAL SOURCES:									
PURCHASED POWER	$	198,520,645	$	0	$	198,520,645	-43.96		(23,909,500)
FUEL:									
O AND M EXCLUDING UNCOLLECTIBLES:									
STANDBY		1,999,229		0		1,999,229	-54.80		(300,158)
LABOR		20,060,988		0		20,060,988	-17.77		(976,668)
LABOR RELATED		2,775,987		0		2,775,987	-10.71		(81,454)
M&S CHARGED TO O&M		1,397,305		0		1,397,305	0.00		0
PREPAYMENTS CHARGED TO O&M		859,138		0		859,138	0.00		0
FACTORING		2,861,580		0		2,861,580	0.00		0
REMAINING O AND M		13,475,141		0		13,475,141	-15.69		(579,246)
DEPRECIATION		12,587,870		0		12,587,870	0.00		0
NON REVENUE RELATED TAXES:									
PAYROLL TAXES		1,524,723		0		1,524,723	-22.17		(92,611)
PROPERTY TAXES		3,450,497		0		3,450,497	-204.58		(1,933,980)
FRANCHISE TAXES - PREPAID		884,346		0		884,346	0.00		0
OTHER NON REVENUE RELATED TAXES		62,750		0		62,750	-123.56		(21,242)
REVENUE RELATED TAXES OTHER THAN INCOME TAXES:									
TEXAS PUC ASSESSMENT		494,026		0		494,026	-232.50		(314,688)
TEXAS STATE GROSS RECEIPTS		3,556,737		0		3,556,737	-78.59		(765,819)
TEXAS LOCAL GROSS RECEIPTS		3,492,867		0		3,492,867	-94.45		(903,839)
OTHER PEVENUE RELATED TAXES OTHER THAN INCOME TAXES		(0)		0		(0)	0.00		0
INTEREST ON CUSTOMER DEPOSITS		210,585		0		210,585	0.00		0
FEDERAL INCOME TAXES		6,440,175		(1,332,439)		5,107,736	-101.12		(1,415,053)
RETURN:									
INTEREST ON LT DEBT		10,053,113		0		10,053,113	0.00		0
PREFERRED DIVIDENDS		1,033,909		0		1,033,909	0.00		0
COMMON DIVIDENDS		13,770,785		0		13,770,785	0.00		0
TOTAL WORKING CAPITAL SOURCES	$	299,512,395	$	(1,332,439)	$	298,179,956			(31,294,259)
NET (LEAD) LAG IN RECOVERY OF COST OF SERVICE ITEMS									(18,190,364)
NON COST OF SERVICE ITEMS:									
CASH ALLOWANCE	$	3,585,939	$	0	$	3,585,939	365.00		3,585,939
TOTAL NON COST OF SERVICE ITEMS	$	3,585,939	$	0	$	3,585,939			3,585,939
WORKING CASH ALLOWANCE								$	(14,604,425)

TEXAS RETAIL	TNP ADJ. PRESENT REVENUE	TNP REQUESTED REVENUE	TNP INCREASE (DECREASE)	PERCENT	EXAMINER ADJ. PRESENT REVENUE	EXAMINER PROPOSED REVENUE	EXAMINER INCREASE (DECREASE)	PERCENT
Base Rate Revenue	296,575,724	310,708,442	14,132,718	4.77%	284,724,984	291,422,013	6,697,029	2.35%
Other Revenue	6,026,608	7,981,944	1,955,336	32.45%	6,026,608	7,981,944	1,955,336	32.45%
TOTAL	302,602,332	318,690,386	16,088,054	5.32%	290,751,592	299,403,957	8,652,365	2.98%

DOCKET NO. 8880

PETITION OF TEXAS-NEW MEXICO POWER COMPANY FOR APPROVAL OF DEFERRED ACCOUNTING TREATMENT FOR TNP ONE, UNITS 1 AND 2, AND ADJUSTMENT TO PCRF CALCULATION	§ § § § §	PUBLIC UTILITY COMMISSION OF TEXAS

DOCKET NO. 8928

APPLICATION OF TEXAS-NEW MEXICO POWER COMPANY FOR AUTHORITY TO CHANGE RATES	§ § §	

ORDER

In public meeting at its offices in Austin, Texas, the Public Utility Commission of Texas finds that the above styled applications were consolidated and processed in accordance with applicable statutes and Commission rules by examiners who prepared and filed a report containing findings of fact and conclusions of law. The Commission further finds that statutory notice of Docket No. 8928 was provided to the public and to interested persons, and that notice of Docket No. 8880 was provided to the public and to interested persons pursuant to the Commission's procedural rules.

The Examiners' Report, as amended by the examiners on February 5, 1990, February 15, 1990, and February 16, 1990, is further AMENDED by the Commission as follows:

1. The portions of the Examiners' Report that concern the application of Texas-New Mexico Power Company (TNP) for deferred accounting for TNP One, Units 1 and 2, and adjustment to its PCRF calculation are DELETED. Specifically, Section V of the report, beginning on page 70 and ending on page 83 is DELETED. Findings of Fact Nos. 77 through 87 are DELETED. Conclusions of Law Nos. 23 through 25 are DELETED.

2. The last three sentences in the first paragraph on page 25 are DELETED. The following sentences are ADDED in their place: The

Cities' expenses of $17,267 attributable to the firm of Butler & Casstevens are therefore an appropriate rate case expense that the Company must reimburse to the Cities. It is also an allowable expense that TNP may recover in its cost of service. The Cities may recover their reasonable rate case expenses attributable to the firm of Butler & Casstevens in excess of $17,267, but no more than $55,053, pursuant to a reimbursement procedure as ordered by the Commission in Docket No. 8928.

3. The following sentence is ADDED to the end of the discussion concerning interest on customer deposits found on page 31: The appropriate interest on customer deposits is based upon the Commission's December 1, 1989, Order setting the 1990 rate for deposits held by utilities at 7.36 percent, and is shown on Schedule I.

4. The last sentence in the second complete paragraph on page 65 is DELETED.

5. The following findings of fact are ADDED immediately following Finding of Fact No. 74:

74a. Staff witness Mr. Nat Treadway recommended the following changes to each TNP energy efficiency program:

i. TNP should plan its program evaluations at the design stage of the program. Each evaluation should include at a minimum a process evaluation, a technical audit of program savings, and a cost-effectiveness evaluation; and

ii. TNP should conduct separate analyses for the northern and the south-eastern regions.

Mr. Treadway recommended the following changes to the Good Cents Home Program:

i. Concerning all portions of the program, require overhangs and solar screens or films to control solar gain;

ii. Concerning the dual-fuel conversion portion of the program, reduce the builder incentives and eliminate the rate discount;

iii. Concerning conservation, reduce the rebate offered to participants, eliminate the rate discount to reduce the rate impact, and prepare a new marketing strategy to increase participation above token levels;

iv. Concerning the dual-fuel heat pump portion of the program, increase the minimum efficiency requirements for heat pumps and prepare a new marketing strategy to increase participation; and

v. Concerning the dual-fuel air conditioner portion of the program, raise the efficiency standards and offer higher rebates for higher efficiency equipment.

Mr. Treadway recommended the following changes to the High Efficiency Air Conditioner and Heat Pump Program:

i. Implement a scale of rebates to encourage the adoption of highly efficient air conditioners; and

ii. Increase the minimum efficiency standards for the heat pumps in the dual-fuel heat pump portion of the program.

74b. The recommendations made by Mr. Treadway that are listed in Finding of Fact No. 74a are reasonable and TNP should address its efforts to comply with the recommendations in its next application for a major rate change.

6. The last two sentences of the discussion concerning weather adjustments found on page 70 are DELETED. Finding of Fact No. 76 is DELETED and in its place the following revised Finding of Fact No. 76 is ADDED: Extreme weather conditions occurring during the test year may cause a misrepresentation of the level of sales that will occur in the future, thus distorting the billing determinants used in the rate design process. The Commission should therefore require TNP to implement a weather adjustment methodology, and to incorporate a weather adjustment into its next rate case.

7. The first three complete sentences on page 92 are DELETED.

8. The first complete sentence on page 96 is DELETED.

9. The first complete sentence on page 107 is DELETED.

10. Finding of Fact No. 113 is ADDED:

113. Staff witness Ms. Ruth R. Runyon recommended that TNP be required to set forth accounts and procedures to reconcile the amortization of "protected" excess deferred taxes, as discussed in Section IV.A.5.b.iii. of the Examiners' Report. The procedure is reasonable because it ensures that TNP's ratepayers will receive the benefit of the amortization of the protected excess deferred taxes. The Commission should therefore require the Company to

establish the accounts and procedures to reconcile the amortization of protected excess deferred taxes described in the above-cited section of the Examiners' Report.

11. Revised Examiners' Attachment G is DELETED. The attached Commissioners' Revision of Revised Examiners' Attachment G is ADDED.

12. Revised Examiners' Attachment H is DELETED. The attached Commissioners' Revision of Revised Examiners' Attachment H is ADDED.

The Examiners' Report, as amended by the examiners on February 5, 1990, February 15, 1990, and February 16, 1990, and as further amended by the Commission above is ADOPTED and made a part of this Order. The Commission further issues the following Order:

1. The application of TNP for approval of deferred accounting treatment for TNP One, Units 1 and 2, and adjustment to its PCRF calculation, which was designated Docket No. 8880, is SEVERED from Docket No. 8928. Docket No. 8880 is REMANDED to the Commission's Hearings Division for purposes of reopening the evidentiary record to obtain additional evidence on the following: (1) the merits of TNP's application; (2) TNP's financing needs during TNP's proposed deferral period; and (3) other options available to TNP to finance TNP One, including a sale/leaseback of TNP One.

2. The application of TNP for authority to change rates, which was designated Docket No. 8928, is hereby GRANTED to the extent recommended in the Examiners' Report as adopted above.

3. TNP is ORDERED to address its efforts to comply with the recommendations of staff witness Treadway listed in Finding of Fact No. 74a in its next application for a major rate change.

4. TNP is ORDERED to implement a weather adjustment methodology, and to incorporate a weather adjustment into its next rate case.

5. TNP SHALL establish the accounts and procedures to reconcile the amortization of protected excess deferred taxes described in Section IV.A.5.b.iii. of the Examiners' Report.

[8] 6. For purposes of recovering rate case expenses attributable to the firm of Butler & Casstevens that are in excess of $17,267, but not more than $55,053, the Cities are directed to comply with the following procedures:

   a. Attorneys shall present legal bills to participating city councils on a pro rata share as determined by the steering committee;

   b. Cities shall pay their attorneys reasonable legal fees;

   c. Cities shall forward copies of paid invoices to Company and PUC staff;

   d. Company shall reimburse Cities for invoices that bring total Cities' legal fees to actual expenses or the cap of $55,053, whichever is the lesser amount; and

   e. Company will, upon Commission approval, surcharge the additional legal fees that are in excess of $17,267 but less than the lower of the Cities' actual legal fees or the cap of $55,053.

7. TNP shall file five copies of its tariff, revised in accordance with this Order, and sufficient to generate revenues no greater than those prescribed in this Order, with the Commission filing clerk and one copy with each of the intervenors within 20 days of the date of this Order. No later than 10 days after the date of the tariff filing by TNP, the parties shall file any objections to the tariff proposal and the general counsel shall file the staff's comments recommending approval or rejection of the individual sheets of the tariff proposal. Responses to objections shall be filed 15 days after the revised tariff. 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 procedure established herein. The tariff sheets shall be deemed approved and shall become effective upon expiration of 20 days after the date of filing, in absence of written notification of approval, modification or rejection by the Hearings Division. In the event that any sheets are modified or rejected, the company shall file proposed revisions of those sheets in accordance with the Hearings Division letter within 10 days after the date of that letter, with the review procedures set out above to again 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.

8. The revised and approved rates shall be charged only for service rendered in the areas over which this Commission is exercising its original jurisdiction, and said rates shall be charged only for service rendered after the tariff approval date. Should the tariff approval date fall within TNP's billing period, TNP shall be authorized to prorate each customer's bill to reflect that customer's customer charge, demand charge and daily energy consumption at the appropriate new rates.

9. Pursuant to Rule 201 of the Texas Rules of Civil Evidence, the Commission takes judicial notice of the Commission's Order of December 1, 1989, which set the calendar year 1990 interest rate for deposits held by utilities at 7.36 percent.

10. 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 the 24th day of February 1990.

PUBLIC UTILITY COMMISSION OF TEXAS

SIGNED: Marta Greytok
MARTA GREYTOK, COMMISSIONER

SIGNED: Paul D. Meek
PAUL D. MEEK, CHAIRMAN

I respectfully dissent from the majority's decision on the following matters:

TNP should be allowed to recover its EPRI dues that it will pay directly in its cost of service. These are reasonable and necessary expenses which the utility has a right to recover under PURA, §39. EPRI is the research consortium for the electric power industry. The results of EPRI's research directly benefits the utility's customers. I know of no other instance where recovery of such costs has ever been denied a utility. At a time when it is acknowledged that this country must invest more in research and development if we are to remain competitive in an international market, the majority's decision is contrary to the public interest as well as unlawful.

The majority's calculation of TNP's federal income tax allowance is contrary to the law of this state, which we have taken an oath of office to uphold. This Commission is bound by, and should follow, the decision of the Texas Supreme Court in Public Utility Commission v. Houston Lighting & Power Company, 748 S.W.2d 439 (Tex. 1987), and the decision of the Austin Court of Appeals in Southern Union Gas Co. V. Railroad Commission, 701 S.W.2d 277 (Tex. App. - Austin, 1985, writ ref'd n.r.e.). Those cases require the Commission to set rates based on a utility's actual federal income tax liability and preclude the Commission from including a hypothetical federal income tax liability in rates. I would therefore recognize disallowed expenses in calculating the federal income tax expense allowance.

I would further dissent from the majority's amortization of the unprotected excess deferred taxes over the useful life of the plant generating them. These are monies the utility will never pay to the federal government. They should be returned to those ratepayers who paid the excess taxes, not to future ratepayers. I would amortize them over a three year period, as urged by the intervenors.

I believe that the majority erred in not including the 345 KV transmission line as a part of TNP's invested capital. The line is necessary for the provision of testing and start-up power for TNP One and for delivering the output from TNP One to the ERCOT grid. At the time the line was built the company had every reason to believe it had a CCN for TNP One and in its wildest imagination could not have foreseen that the CCN for TNP One would become involved in the morass before the Commission that exists today. The Commission also granted the CCN for this transmission line. When the CCN was granted the Commission concluded that the "transmission line is necessary for the service, accommodation, convenience, or safety of the public within the meaning of Section 54(b) of the Act, taking into consideration the factors set out in Section 54(c) of the Act and discussed in Findings of Fact Nos 7 through 18." The majority in adopting the Examiner's Report has again concluded that "the credible evidence in the record shows that the 345 KV line was the most reasonable alternative."

The "term used and useful" as used in PURA is a term of art and includes both construction work in progress and plant held for future use. Yet construction of this line was completed and it was put into service by the end of the test year. The Court has held that the Commission must consider the nature and present usefulness of plant even where it is held for future use rather than arbitrarily disallow it. Southwestern Bell Telephone Co. v. Public Utility Commission. 571 S.W.2d 503, 516 (Tex. 1978). It is not disputed that the line is presently being used to provide the means for construction and start-up testing of TNP One, exporting energy during performance testing and trial operation, and satisfying the contractual commitments to the construction consortium that is constructing TNP One. These activities constitute property "used by and useful to the public utility in providing service." No utility would ever build a transmission line or a new generating plant if the majority uses such a restricted meaning as it does here for "used and useful to the public utility in providing service." Pursuant to PURA, §§39 & 41, TNP is entitled to include the asset in its invested capital and earn a reasonable return on such investment in this rate case. To do otherwise is to confiscate its property.

I would adopt the staff's recommended cost of debt of 9.74 percent. The credible evidence in the record shows that staff witness Hathhorn's corrected cost of debt recommendation employed the yield-to-maturity methodology required by the Commission's rules and regulations. The cost of debt adopted by the majority was not calculated in conformance with the Commission's rules and regulations. The Commissioner's rules have the force of law and are binding on the Commission. Texas Liquor Control Board v. Attic Club Inc., 457 S.W.2d 41 (Tex. 1980); Gulf Land Company v. Atlantic Refining Company, 134 Tex. 59, 131 S.W.2d 73 (1939).

I would adopt the staff's proposed allocation of purchased power demand expenses. The staff's proposal most appropriately tracks TNP's purchased power demand expenses.

Finally, I would adopt the staff's recommendation of a $6.00 residential customer service charge. The staff's computation of the residential customer service charge included all of the appropriate customer-realted costs that vary directly with the number of customers.

With the above exceptions, I concur with the Commissioners' Order.

SIGNED: Jo Campbell
JO CAMPBELL, COMMISSIONER

ATTEST:

Mary Ross McDonald
MARY ROSS McDONALD
SECRETARY OF THE COMMISSION

PUBLIC UTILITY COMMISSION OF TEXAS

SCHEDULE I

TEXAS-NEW MEXICO POWER COMPANY - DOCKET 8928

REVENUE REQUIREMENT

DESCRIPTION	(COLUMN 1) TEST YEAR PER BOOKS	(COLUMN 2) COMPANY ADJUSTMENTS TO TEST YEAR	(COLUMN 3) COMPANY REQUESTED TEST YEAR	(COLUMN 4) COMMISSION ADJUSTMENTS TO REQUEST	(COLUMN 5) COMMISSION ORDERED TEST YEAR
URCHASED POWER	$ 199,127,617	$ 11,244,359	$ 210,371,976	$ (11,959,091)	$ 198,412,885
PERATIONS AND MAINTENANCE	41,987,914	2,860,754	44,848,668	(1,423,424)	43,425,244
EPRECIATION	12,353,250	647,628	13,000,878	(413,008)	12,587,870
NTEREST ON CUSTOMERS DEPOSITS	210,585	0	210,585	33,494	244,079
AXES OTHER THAN INCOME TAXES	12,877,419	1,099,707	13,977,126	(644,080)	13,333,046
EDERAL INCOME TAXES	4,009,329	3,927,423	7,936,752	(1,496,449)	6,440,303
ETURN	19,764,231	8,580,170	28,344,401	(3,486,177)	24,858,224
EVENUE REQUIREMENT	$ 290,330,345	$ 28,360,041	$ 318,690,386	$ (19,388,735)	$ 299,301,651

OMMISSION'S ADJUSTMENT TO TEST YEAR PER BOOKS IS DERIVED BY ADDING
HE AMOUNT IN COLUMN 2 TO THE AMOUNT IN COLUMN 4

PUBLIC UTILITY COMMISSION OF TEXAS — SCHEDULE II

TEXAS-NEW MEXICO POWER COMPANY - DOCKET 8928

OPERATIONS AND MAINTENANCE (EXCLUDING FUEL AND PURCHASED POWER)

DESCRIPTION	(COLUMN 1) TEST YEAR PER BOOKS	(COLUMN 2) COMPANY ADJUSTMENTS TO TEST YEAR	(COLUMN 3) COMPANY REQUESTED TEST YEAR	(COLUMN 4) COMMISSION ADJUSTMENTS TO REQUEST	(COLUMN 5) COMMISSION ORDERED TEST YEAR
M NOT ADJUSTED	$ 13,898,622	$ 0	$ 13,898,622	$ (54,881)	$ 13,843,741
ANDBY EXPENSE	1,784,216	215,013	1,999,229	0	1,999,229
BOR COST	19,524,435	858,357	20,382,792	(321,804)	20,060,988
BOR RELATED COST	2,744,443	106,981	2,851,424	(75,437)	2,775,987
CTORING EXPENSE	2,991,403	292,207	3,283,610	(424,043)	2,859,567
I DUES	98,250	(13,863)	84,387	(7,749)	76,638
NERAL OFFICE RENT	575,571	110,188	685,759	0	685,759
TE CASE EXPENSE	326,500	652,879	979,379	30,244	1,009,623
NATIONS	0	42,082	42,082	(42,082)	0
ES AND SUBSCRIPTIONS	42,245	(2,857)	39,388	(8,076)	31,312
ERGY EFFICIENCY PROGRAM	0	237,600	237,600	(155,200)	82,400
RI DUES	2,229	362,167	364,396	(364,396)	0
TAL OPERATIONS AND MAINTENANCE	$ 41,987,914	$ 2,860,754	$ 44,848,668	$ (1,423,424)	$ 43,425,244

MMISSION'S ADJUSTMENT TO TEST YEAR PER BOOKS IS DERIVED BY ADDING
HE AMOUNT IN COLUMN 2 TO THE AMOUNT IN COLUMN 4

PUBLIC UTILITY COMMISSION OF TEXAS

SCHEDULE III

TEXAS-NEW MEXICO POWER COMPANY - DOCKET 8928

SUMMARY OF TAXES OTHER THAN INCOME TAXES

DESCRIPTION	(COLUMN 1) TEST YEAR PER BOOKS	(COLUMN 2) COMPANY ADJUSTMENTS TO TEST YEAR	(COLUMN 3) COMPANY REQUESTED TEST YEAR	(COLUMN 4) COMMISSION ADJUSTMENTS TO REQUEST	(COLUMN 5) COMMISSION ORDERED TEST YEAR
EXAS AD VALOREM TAXES	$ 3,253,675	$ 200,707	$ 3,454,382	$ (3,885)	$ 3,450,497
AYROLL TAXES	1,506,146	41,837	1,547,983	(23,260)	1,524,723
THER NON REVENUE RELATED TAXES	804,309	142,787	947,096	(127,592)	819,504
ON REVENUE RELATED TAXES	$ 5,564,130	$ 385,331	$ 5,949,461	$ (154,737)	$ 5,794,724
EXAS PUC ASSESSMENT	$ 478,881	$ 46,778	$ 525,659	$ (31,980)	$ 493,679
EXAS STATE GROSS RECEIPTS	3,448,620	336,868	3,785,488	(231,254)	3,554,234
EXAS LOCAL GROSS RECEIPTS	3,385,788	330,730	3,716,518	(226,108)	3,490,410
EVENUE RELATED TAXES OTHER THAN INCOME TAXES	$ 7,313,289	$ 714,376	$ 8,027,665	$ (489,343)	$ 7,538,322

SUMMARY OF OTHER TAXES
OTHER THAN INCOME TAXES

DESCRIPTION	(COLUMN 1)	(COLUMN 2)	(COLUMN 3)	(COLUMN 4)	(COLUMN 5)
ON REVENUE RELATED TAXES	$ 5,564,130	$ 385,331	$ 5,949,461	$ (154,737)	$ 5,794,724
EVENUE RELATED TAXES	7,313,289	714,376	8,027,665	(489,343)	7,538,322
OTAL TAXES OTHER THAN INCOME TAXES	$ 12,877,419	$ 1,099,707	$ 13,977,126	$ (644,080)	$ 13,333,046

COMMISSION'S ADJUSTMENT TO TEST YEAR PER BOOKS IS DERIVED BY ADDING THE AMOUNT IN COLUMN 2 TO THE AMOUNT IN COLUMN 4

PUBLIC UTILITY COMMISSION OF TEXAS

SCHEDULE IV

################################

TEXAS-NEW MEXICO POWER COMPANY - DOCKET 8928

##

INVESTED CAPITAL

################

DESCRIPTION		(COLUMN 1) TEST YEAR PER BOOKS		(COLUMN 2) COMPANY ADJUSTMENTS TO TEST YEAR		(COLUMN 3) COMPANY REQUESTED TEST YEAR		(COLUMN 4) COMMISSION ADJUSTMENTS TO REQUEST		(COLUMN 5) COMMISSION ORDERED TEST YEAR
LANT IN SERVICE	$	361,615,540	$	439,775	$	362,055,315	$	(12,330,281)	$	349,725,034
CCUMULATED DEPRECIATION		(77,893,853)		0		(77,893,853)		0		(77,893,853)
ET PLANT IN SERVICE		283,721,687		439,775		284,161,462		(12,330,281)		271,831,181
ORKING CASH ALLOWANCE		(11,122,333)		(3,842,048)		(14,964,381)		363,653		(14,600,728)
ATERIALS AND SUPPLIES		4,165,591		0		4,165,591		0		4,165,591
REPAYMENTS		816,141		0		816,141		0		816,141
EFERRED FEDERAL INCOME TAXES		(37,844,306)		0		(37,844,306)		0		(37,844,306)
RE 1971 INVESTMENT TAX CREDITS		(25,413)		0		(25,413)		0		(25,413)
USTOMERS DEPOSITS		(3,316,293)		0		(3,316,293)		0		(3,316,293)
THER COST FREE CAPITAL		(1,041,892)		0		(1,041,892)		0		(1,041,892)
TOTAL INVESTED CAPITAL	$	235,353,182	$	(3,402,273)	$	231,950,909	$	(11,966,628)	$	219,984,281
RATE OF RETURN						0.122200		-0.009200		0.113000
RETURN					$	28,344,401	$	(3,486,177)	$	24,858,224

COMMISSION'S ADJUSTMENT TO TEST YEAR PER BOOKS IS DERIVED BY ADDING THE AMOUNT IN COLUMN 2 TO THE AMOUNT IN COLUMN 4

SCHEDULE V

PUBLIC UTILITY COMMISSION OF TEXAS
################################
TEXAS-NEW MEXICO POWER COMPANY - DOCKET 8928
##
FEDERAL INCOME TAXES
###################

:SCRIPTION	COMMISSION RECOMMENDED TEST YEAR
:TURN	$ 24,858,224
.US (MINUS)	
ITEREST EXPENSE	(10,053,282)
1ORTIZATION OF ITC	(736,519)
(CESS DEFERRED TAX AMORTIZATION	(191,637)
)DITIONAL DEPRECIATION	353,020
4VIRONMENTAL TAX	15,262
ISALLOWED BUSINESS MEALS	28,785
4XABLE COMPONENT OF RETURN	14,273,853
4X FACTOR	0.515151515
)TAL FEDERAL INCOME TAXES BEFORE ADJUSTMENTS	7,353,197
.US (MINUS):	
1ORTIZATION OF ITC	(736,519)
(CESS DEFERRED TAX AMORTIZATION	(191,637)
4VIRONMENTAL TAX	15,262
)TAL FEDERAL INCOME TAXES	$ 6,440,303

PUBLIC UTILITY COMMISSION OF TEXAS
TEXAS-NEW MEXICO POWER COMPANY - DOCKET 8928
WORKING CASH ALLOWANCE

:SCRIPTION	(COL. 1) COMMISSION RECOMMENDED REVENUE REQUIREMENT	(COL. 2) ADJUSTMENTS	(COL. 3) WORKING CASH CALCULATION AMOUNT	(COL. 4) (LEAD) LAG DAYS	(COL. 5) WORKING CASH AMOUNT ((COL. 3 * COL. 4)/365)
;RKING CAPITAL USES:					
:VENUE REQUIREMENT	$ 299,301,651	$ (42,227,731)	$ 257,073,920	18.59	$ 13,093,162
;RKING CAPITAL SOURCES:					
JRCHASED POWER	$ 198,412,885	$ 0	$ 198,412,885	-43.96	(23,896,522)
JEL:					
AND M EXCLUDING UNCOLLECTIBLES:					
TANDBY	1,999,229	0	1,999,229	-54.80	(300,158)
ABOR	20,060,988	0	20,060,988	-17.77	(976,668)
ABOR RELATED	2,775,987	0	2,775,987	-10.71	(81,454)
:S CHARGED TO O&M	1,397,305	0	1,397,305	0.00	0
REPAYMENTS CHARGED TO O&M	859,138	0	859,138	0.00	0
ACTORING	2,859,567	0	2,859,567	0.00	0
EMAINING O AND M	13,473,030	0	13,473,030	-15.69	(579,156)
EPRECIATION	12,587,870	0	12,587,870	0.00	0
ON REVENUE RELATED TAXES:					
AYROLL TAXES	1,524,723	0	1,524,723	-22.17	(92,611)
ROPERTY TAXES	3,450,497	0	3,450,497	-204.58	(1,933,980)
RANCHISE TAXES - PREPAID	756,754	0	756,754	0.00	0
THER NON REVENUE RELATED TAXES	62,750	0	62,750	-123.56	(21,242)
EVENUE RELATED TAXES OTHER THAN INCOME TAXES:					
EXAS PUC ASSESSMENT	493,679	0	493,679	-232.50	(314,466)
EXAS STATE GROSS RECEIPTS	3,554,234	0	3,554,234	-78.59	(765,280)
EXAS LOCAL GROSS RECEIPTS	3,490,410	0	3,490,410	-94.45	(903,203)
THER REVENUE RELATED TAXES					
NTEREST ON CUSTOMER DEPOSITS	244,079	0	244,079	0.00	0
EDERAL INCOME TAXES	6,440,303	(1,332,439)	5,107,864	-101.12	(1,415,088)
ETURN:					
NTEREST ON LT DEBT	10,053,282	0	10,053,282	0.00	0
REFERRED DIVIDENDS	1,033,926	0	1,033,926	0.00	0
:OMMON DIVIDENDS	13,771,016	0	13,771,016	0.00	0
'OTAL WORKING CAPITAL SOURCES	$ 299,301,651	$ (1,332,439)	$ 297,969,212		(31,279,829)
ET (LEAD) LAG IN RECOVERY ;F COST OF SERVICE ITEMS					(18,186,667)
ION COST OF SERVICE ITEMS:					
:ASH ALLOWANCE	$ 3,585,939	$ 0	$ 3,585,939	365.00	3,585,939
'OTAL NON COST OF SERVICE ITEMS	$ 3,585,939	$ 0	$ 3,585,939		3,585,939
WORKING CASH ALLOWANCE					$ (14,600,728)

PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 8928
TEXAS-NEW MEXICO POWER COMPANY
COMMISSION REVENUE AND REVENUE DEFICIENCY

Schedule VII

TEXAS RETAIL	TNP ADJ. PRESENT REVENUE	TNP REQUESTED REVENUE	TNP INCREASE (DECREASE)	PERCENT	COMMISSION ADJ. PRESENT REVENUE	COMMISSION PROPOSED REVENUE	COMMISSION INCREASE (DECREASE)	PERCENT
Base Rate Revenue	296,575,724	310,708,442	14,132,718	4.77%	284,724,984	291,788,602	7,063,618	2.48%
Other Revenue	6,026,608	7,981,944	1,955,336	32.45%	6,026,608	7,513,043	1,486,435	24.66%
TOTAL	302,602,332	318,690,386	16,088,054	5.32%	290,751,592	299,301,645	8,550,053	2.94%

PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 8928
TEXAS–NEW MEXICO POWER COMPANY
COMMISSION PROPOSED REVENUE REQUIREMENTS

Commissioners' Revision of
Revised Examiners' Attachment G

(1) CUSTOMER CLASS	(2) PRESENT REVENUE	(3) COS @ UNIFORM ROR	(4)	(5) REVENUE CHANGE	(6) PERCENT CHANGE	(7) PROPOSED REVENUE ADJ	(8)	(9) REVENUE REQ'M	(10) ADJUSTED ROR	(11) RELATIVE ROR INDEX
	($)	($)	(%)	($)	(%)	($)	(%)	($)	(%)	(%)
RESIDENTIAL	122,006,043	128,258,735	11.30	6,252,692	5.12	3,935,585	3.23	125,941,628	9.99%	0.88
GENERAL SERVICE	51,216,201	51,830,654	11.30	614,453	1.20	807,776	1.58	52,023,977	11.57%	1.02
LG. GENERAL SERVICE	53,839,081	55,208,383	11.30	1,369,302	2.54	1,480,718	2.75	55,319,799	11.60%	1.02
RESALE	1,188,147	1,293,300	11.30	105,153	8.85	55,047	4.63	1,243,194	8.14%	0.72
INDUSTRIAL POWER	48,599,353	45,476,098	11.30	(3,123,255)	–6.43	0	0.00	48,599,353	41.36%	3.66
MUNICIPAL POWER	3,610,320	3,991,632	11.30	381,312	10.56	209,082	5.79	3,819,402	7.80%	0.69
STREET LIGHTING	1,565,481	2,626,738	11.30	1,061,257	67.79	181,322	11.58	1,746,803	–5.10%	–0.45
OUTDOOR LIGHTS	2,700,358	3,103,062	11.30	402,704	14.91	394,088	14.59	3,094,446	11.19%	0.99
TOTAL	284,724,984	291,788,602	11.30	7,063,618	2.48	7,063,618	2.48	291,788,602	11.30%	1.00

2204

PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 8928
TEXAS-NEW MEXICO POWER COMPANY
PROOF-OF-REVENUE STATEMENT

Commissioners' Revision of
Revised Examiners' Attachment H

Customer Class	Billing Units	Proposed Rate ($)	Revenue ($)
RESIDENTIAL			
Customer Charge	1,632,564	7.25	11,836,089
Summer Energy Charge	973,117,474	0.0695	67,631,664
Winter Energy Charge	720,767,780	0.0645	46,489,522
Subtotal			125,957,275
	Revenue Mismatch	($)	(15,647)
		(%)	-0.01%
GENERAL SERVICE			
Customer Charge			
Single-Phase	192,084	10.00	1,920,840
Three-Phase	98,592	17.00	1,676,064
Summer Energy Charge			
0-1,000 kwh	278,185,019	0.0743	20,669,147
1,001 and above	129,080,139	0.0513	6,621,811
Winter Energy Charge			
0-1,000 kwh	218,015,395	0.0743	16,198,544
1,001 and above	106,457,838	0.0463	4,928,998
Subtotal			52,015,404
	Revenue Mismatch	($)	8,573
		(%)	0.02%

PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 8928
TEXAS-NEW MEXICO POWER COMPANY
PROOF-OF-REVENUE STATEMENT

Commissioners' Revision of
Revised Examiners' Attachment H

Customer Class	Billing Units	Proposed Rate ($)	Revenue ($)
RESIDENTIAL			
Customer Charge	1,632,564	7.25	11,836,089
Summer Energy Charge	973,117,474	0.0695	67,631,664
Winter Energy Charge	720,767,780	0.0645	46,489,522
Subtotal			125,957,275
	Revenue Mismatch	($)	(15,647)
		(%)	-0.01%
GENERAL SERVICE			
Customer Charge			
Single-Phase	192,084	10.00	1,920,840
Three-Phase	98,592	17.00	1,676,064
Summer Energy Charge			
0-1,000 kwh	278,185,019	0.0743	20,669,147
1,001 and above	129,080,139	0.0513	6,621,811
Winter Energy Charge			
0-1,000 kwh	218,015,395	0.0743	16,198,544
1,001 and above	106,457,838	0.0463	4,928,998
Subtotal			52,015,404
	Revenue Mismatch	($)	8,573
		(%)	0.02%

DOCKET NO. 8928

APPLICATION OF TEXAS-NEW MEXICO POWER COMPANY FOR AUTHORITY TO CHANGE RATES	§ § §	PUBLIC UTILITY COMMISSION OF TEXAS

DOCKET NO. 8880

PETITION OF TEXAS-NEW MEXICO POWER COMPANY FOR APPROVAL OF DEFERRED ACCOUNTING TREATMENT FOR TNP ONE, UNITS 1 AND 2, AND ADJUSTMENT TO PCRF CALCULATION	§ § § § §	PUBLIC UTILITY COMMISSION OF TEXAS

ORDER ON REHEARING

On February 28, 1990, the Commission's February 24, 1990, signed final order in these consolidated dockets was mailed to all parties of record. Motions for rehearing were subsequently timely filed by Texas-New Mexico Power Company (TNP) and the Texas State Agencies. On April 4, 1990, in open meeting at its offices in Austin, Texas, the Public Utility Commission of Texas considered Texas-New Mexico Power Company's ("TNP's") motion for rehearing. After deliberation of the issues raised in TNP's motion for rehearing and the reply filed by Commission's General Counsel, the Commission hereby **GRANTS** rehearing on the following points and orders the following relief:

1. Finding of Fact No. 97 is amended to add the words, "as modified by TNP," so that the finding reads as follows:

    97. The record supports the use of TNP's revenue allocation methodology as detailed in Examiners' Attachment G as modified by TNP, because it moves all classes closer to unity without placing an undue burden upon any class. Further, TNP's allocation is not unreasonably discriminatory in favor of or against any customer class.

2. Conclusion of Law No. 26 is amended to add the words, "as modified by TNP," so that the conclusion reads as follows:

26. The rates prescribed herein and detailed in Examiners' Attachment H as modified by TNP will not be unreasonably preferential, prejudicial, or discriminatory, but will be sufficient, equitable, and consistent in application to each class of customers, and they should be approved.

3. TNP's revisions to Examiners' Exhibits G and H, and to Examiners' Schedule VII detailed in TNP's motion for rehearing are hereby **ADOPTED**.

4. On March 5, 1990, TNP filed its compliance tariff in conformance with the Commission's February 24, 1990, final order in these consolidated dockets. The compliance tariff was designated tariff control number 9415. The Commission by order dated March 21, 1990, postponed the date upon which TNP's compliance tariff would be deemed approved and become effective until April 15, 1990. The date upon which TNP's compliance tariff will be deemed approved and become effective is further **POSTPONED**. TNP is **ORDERED** to revise its compliance tariff in accordance with the Commission's order of February 24, 1990, in these consolidated dockets, as expressly amended by this Order. TNP is hereby **ORDERED** to file its revised compliance tariff in conformance with the procedures detailed in paragraph 7 of the Commission's February 24, 1990, final order in these consolidated dockets. Paragraph 7 provides that the compliance tariff will be deemed approved and become effective upon expiration of twenty days after the "date of filing," in absence of written notification of approval, modification or rejection by the Hearings Division. Paragraph 7 is **AMENDED** so that the

"date of filing," as set forth in paragraph 7, is designated as the date TNP files its revised compliance tariff in compliance with this Order.

5. In all other respects, the requests for relief contained in TNP's motion for rehearing and the reply to that motion are hereby **DENIED** for lack of merit.

6. This Order hereby incorporates by reference as if set out in full all aspects of the Order signed on February 24, 1990, in these consolidated dockets, including all findings of fact and conclusions of law made by the Commission in that Order, except as expressly amended by this Order.

SIGNED AT AUSTIN TEXAS on this the 12th **day of** April **1990.**

PUBLIC UTILITY COMMISSION OF TEXAS

SIGNED: Jo Campbell
JO CAMPBELL, COMMISSIONER

SIGNED: Marta Greytok
MARTA GREYTOK, COMMISSIONER

SIGNED: Paul D. Meek
PAUL D. MEEK, CHAIRMAN

ATTEST:

Mary Ross McDonald
MARY ROSS McDONALD
SECRETARY OF THE COMMISSION

APPLICATION OF CAP ROCK ELECTRIC COOPERATIVE, INC. FOR APPROVAL OF NEW RATE CLASSIFICATION § § § DOCKET NO. 9048

April 18, 1990

Commission approved a stipulation providing for a new industrial rate classification specifically designed for a single customer, a gas pipeline company. Commission did not order the electric cooperative to refund rates unlawfully charged and collected in violation of PURA §§31 and 46 for service provided to the pipeline company prior to Commission approval.

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

Customer-specific rates designed for a single industrial customer, a gas pipeline company, were not unreasonably discriminatory because the pipeline company is not "similarly situated" to other industrial customers for two reasons: (1) it is the only existing customer to receive power directly at transmission voltage, which avoids the incurrence of costs attributable to line losses which occur when providing service via a distribution line; and (2) the provision of service to such customer did not require the electric cooperative to make any additional major plant investment. A lower rate for the pipeline company is proper because the cooperative's costs in serving the pipeline company are lower than the costs of serving other industrial customers for the reasons stated above. (pp. 2220, 2222)

[2] RATEMAKING--RATE DESIGN--REFUNDS, CREDITS AND SURCHARGES

The institution of service and the collection of rates prior to Commission approval violates PURA §§31 and 46. Nothing in PURA, however, requires a utility to refund rates unlawfully charged and collected in violation of PURA §§31 and 46. In such instances, the Commission has the discretion to order the partial or complete refund of the unlawfully charged and collected rates. (p. 2221)

[3] It is appropriate for the Commission to conclude that an electric cooperative need not refund any rates unlawfully charged and collected in violation of PURA §§31 and 46 when (1) the cooperative did not wilfully violate PURA; (2) only one customer was affected directly by the institution of service and charging of rates prior to Commission approval; (3) the issues of the institution of service prior to Commission approval and the refund of unlawfully collected rates arose in response to matters raised by the administrative law judge, as opposed to a customer complaint; and (4) the joint stipulation in the docket did not provide for a refund. (p. 2221)

[4] It is appropriate for the Commission to conclude that a non-profit electric cooperative need not refund any rates unlawfully charged and collected in violation of PURA §§31 and 46 because such a cooperative does not retain any of the margins it realizes in the provision of

service, but rather annually allocates such margins to its members on a pro-rata basis in the form of capital credits. (p. 2222)

Public Utility Commission of Texas
7800 Shoal Creek Boulevard · Suite 400N
Austin, Texas 78757 · 512/458-0100

Jo Campbell
Commissioner

Marta Greytok
Commissioner

Paul D. Meek
Chairman

TO: Commissioner Jo Campbell
Commissioner Marta Greytok
Chairman Paul D. Meek
All Parties of Record

FROM: Stephen J. Davis SJD
Administrative Law Judge

DATE: April 3, 1990

RE: Docket No. 9048; Application of Cap Rock Electric Cooperative, Inc. for Approval of a New Rate Classification

This docket involves an application by Cap Rock Electric Cooperative, Inc. (Cap Rock) for the approval of a new rate classification (Industrial Service Rate - High Voltage) that is intended exclusively for a single customer, West Texas Chaparral Pipeline Company (Chaparral). Although Cap Rock has not obtained Commission approval of this new rate classification, either on an interim or permanent basis, it nevertheless instituted service to Chaparral pursuant to the proposed tariff on April 7, 1989, approximately five months before filing its original application with the Commission.

The administrative law judge (ALJ) recommends approval of the full stipulation jointly submitted by Cap Rock and the general counsel, the only parties in this docket. This stipulation recommends the approval of the proposed tariff, as modified, and resolves all issues in the docket, including the issue of whether Cap Rock should refund all or part of the revenues collected from Chaparral prior to Commission approval of the new rate classification. With respect to the latter, the ALJ adopts the general counsel's recommendation that Cap Rock not be required to refund any of the unlawfully collected revenues. If the Commission determines, however, that Cap Rock should render a full or partial refund of these revenues, the document appearing as Exhibit No. 3 in the evidentiary record index provides the information necessary for ordering a refund.

The ALJ has attached a proposed Final Order containing findings of fact and conclusions of law legally sufficient to support the adoption of the stipulation. These findings of fact and conclusions of law were based on the evidentiary record, which is comprised of (1) written testimony attached to the stipulation and (2) written testimony filed in response to the ALJ's requests for additional information. All of the record evidence is designated on the attached index. An indexed copy of the evidentiary record is available in the Office of Special Counsel for your review.

The jurisdictional deadline for this docket is April 18, 1990.

This docket will be considered at an open meeting scheduled for 9:00 a.m., April 18, 1990 at the Commission's offices, 7800 Shoal Creek Boulevard, Austin, Texas. Any corrections to the ALJ's recommendation must be filed and served on all parties by 3:00 p.m., Tuesday, April 10, 1990. An original and 15 copies must be filed with the Commission filing clerk, and a copy must be served upon the general counsel.

APPROVED this 3rd day of April, 1990.

Mary Ross McDonald
MARY ROSS McDONALD
DIRECTOR OF HEARINGS

DOCKET NO. 9048

INDEX OF RECORD

1. Joint Stipulation
2. Testimony of Mr. Nolan Simpson, Assistant to the Manager of Cap Rock Electric Cooperative
3. Testimony of Mr. Ulen North, Jr., Director of Administrative Services for Cap Rock Electric Cooperative
4. Testimony of Mr. R. Darrin Barker, Commission Rate Analyst
5. Proposed Industrial Service - High Voltage Tariff
6. Affidavits of Notice

DOCKET NO. 9048

APPLICATION OF CAP ROCK ELECTRIC COOPERATIVE, INC. FOR APPROVAL OF NEW RATE CLASSIFICATION	**§ § §**	**PUBLIC UTILITY COMMISSION OF TEXAS**

ORDER

In an open meeting at its offices in Austin, Texas, the Public Utility Commission of Texas finds that this docket was processed in accordance with applicable statutes and Commission rules by an administrative law judge, who prepared a recommendation based on an evidentiary record. All parties to the docket submitted a stipulation and submitted evidence in support of the stipulation. The stipulation is **APPROVED.**

The Commission **ADOPTS** the following findings of fact and conclusions of law:

A. Findings of Fact

1. Cap Rock Electric Cooperative, Inc. (Cap Rock) is a non-profit, member-owned cooperative organized and existing under the laws of the State of Texas. It serves approximately 17,000 members in a 13-county area in West Texas.

2. Cap Rock purchases all of its electric power wholesale from Texas Utilities Electric Company (TUEC); it does not generate any of the electric power which it provides to its members.

3. On September 15, 1989, Cap Rock filed an application seeking the approval of a new industrial rate classification exclusively intended for a single customer: West Texas Chaparral Pipeline Company (Chaparral). This application proposed the provision of service to Chaparral directly from Cap Rock's Vealmoore transmission line, *i.e.*, at transmission voltage rather than distribution voltage.

4. Cap Rock's application did not specify an effective date for its proposed tariff. Consequently, an effective date of October 20, 1989, the 35th day after the filing of the application, was imputed. The operation of the proposed tariff was also suspended until March 19, 1990.

5. An initial prehearing conference was convened on October 17, 1989; a second prehearing conference was convened by telephone on December 28, 1989. In both instances, Administrative Law Judge Stephen J. Davis (ALJ) presided. Mr. Tom W. Gregg, Jr. appeared on behalf of Cap Rock and Mr. Jack N. Fuerst appeared for the general counsel in both prehearing conferences.

6. Based upon a showing of good cause, Cap Rock was exempted from the full rate filing package requirements of P.U.C. PROC. R. 21.69.

7. In a motion filed on December 15, 1989, Cap Rock notified the ALJ that it had inadvertently failed to provide timely notice of its application, as directed by a prehearing order. In order to permit sufficient time in which to provide the notice ordered, Cap Rock agreed to extend its effective date for an additional thirty days to November 19, 1989. The operation of the proposed tariff was subsequently suspended until April 18, 1990.

8. Cap Rock provided three types of notice of its application: (1) two consecutive weeks of publication in the *San Angelo Standard Times*, *Big Spring Herald*, and *Midland Reporter-Telegram*; (2) direct notice by mail to each customer in its commercial and industrial rate classifications; and (3) direct notice by mail to five municipalities located in Cap Rock's service area.

9. No motions to intervene or protest letters were filed in this docket.

10. On February 15, 1990, Cap Rock and the general counsel filed a joint stipulation recommending the approval of the cooperative's application. In support of the joint stipulation, the parties attached (1) a copy of a revised Industrial Service - High Voltage tariff; (2) affidavits attesting to the provision of notice; (3) the testimony of Mr. Nolan Simpson, a Cap Rock employee; and (4) the affidavit of Commission rate analyst R. Darrin Barker.

11. After receipt of the joint stipulation, the hearing on the merits scheduled for March 1, 1990 was cancelled and the docket was processed administratively.

12. In response to the ALJ's written requests, Cap Rock and the Commission staff filed additional testimony about the matters addressed in the joint stipulation on March 12, 1990 and March 14, 1990, respectively.

13. Cap Rock instituted service to Chapparal pursuant to the new rate classification on April 7, 1989, approximately five months before filing its original application with the Commission.

14. Chaparral requested that Cap Rock institute service by April 1, 1989 in order to allow the pipeline company to operate an electric pumping station to be used for the transportation of natural gas liquid products to a location on the Gulf Coast.

15. Cap Rock has neither sought nor obtained interim approval of the proposed tariff.

16. Chaparral is the only customer directly affected by Cap Rock's institution of service prior to Commission approval.

17. As of February 1990, Cap Rock had collected $199,795.33 in revenues in its provision of service to Chaparral under the unapproved tariff.

18. As of February 1990, Cap Rock had realized a margin of $16,054.61 in its provision of service to Chaparral under the unapproved tariff.

19. The issue of Cap Rock's institution of service prior to Commission approval of the proposed tariff did not arise as the result of a customer complaint. The issue arose when the ALJ requested the cooperative to file an affidavit attesting to the status of Chaparral as either a new or existing customer.

20. The joint stipulation filed by Cap Rock and general counsel does not provide for a refund. The stipulation states that the general counsel weighed

the equities and determined that a refund would be inappropriate under the circumstances in this docket.

21. Because it is a non-profit cooperative, Cap Rock does not retain any of the margins it realizes in the provision of service. Rather, all such margins earned by Cap Rock are annually allocated to its members on a pro-rata basis in the form of capital credits.

22. In its negotiations with Cap Rock, Chaparral requested that any service obtained from the cooperative meet four criteria: (1) the delivery of service at 69,000 volts, *i.e.*, transmission level; (2) the use of a substation that would match the characteristics of the pumping station that Chaparral proposed to operate with the power obtained from Cap Rock; (3) the incorporation of an interruptible rate schedule similar to those schedules employed by other utilities serving Chaparral; and (4) the calculation of rates that resulted in a cost per kilowatt/hour falling within a targeted range of $0.0380-$0.0420. The proposed tariff substantially complies with these four criteria.

23. In operating its pipeline, Chaparral monitors the amount of power used by each of the pumping stations along the pipeline's route and determines which pumping station is the most economical to operate at any point in time. Given Chaparral's control of the operation of the pumping stations, Cap Rock agreed to design an energy charge and demand charge (1) which resulted in a cost per kwh falling within the targeted range requested by Chaparral ($0.0380-$0.0420 per kwh) and (2) which would be competitive with the rates charged by other utilities serving Chaparral.

24. The rates under the proposed tariff are based upon an estimated load factor for Chaparral between 70 and 100 percent. The typical load factor for a cooperative is between 45 to 50 percent. Therefore, the provision of service to Chaparral would most likely improve Cap Rock's load factor, which in turn would result in lower wholesale power costs from TUEC.

25. Chaparral will provide its own transmission line and substation in receiving service from Cap Rock. The only plant investment that Cap Rock must

make in order to serve Chaparral is that investment associated with tapping the cooperative's transmission line.

26. The cost of providing service to Chaparral includes (1) the cost of wholesale power purchased from TUEC; (2) the minor cost associated with line losses occurring at the point of delivery; and (3) the proportionate share of overhead associated with the provision of service to the pipeline company.

27. Cap Rock did not provide a complete cost-of-service study in support of the rates in the proposed tariff, but rather employed cost data from year-end 1988 to calculate such rates.

28. In 1988, the average cost of wholesale power from TUEC at the point of delivery at which Chaparral obtains service involved (1) an average energy cost of $0.027326 per kwh and (2) an average demand cost of $5.02 per kilowatt (kw).

29. The energy charge in the proposed tariff ($0.033333 per kwh) yields a 21.6 percent margin in excess of the 1988 average energy charge; the demand charge in the proposed tariff ($5.50 per kw) yields a 9.5 percent margin in excess of the 1988 average demand charge.

30. Other than the aforementioned energy and demand charges, the proposed tariff also incorporates two other items affecting the rates ultimately paid by Chaparral for service: (1) a 4 percent high-voltage discount given because because Cap Rock does not incur any line losses on Chaparral's privately owned transmission facilities and (2) a 25 percent discount on monthly billing demand given when Cap Rock's wholesale power peak does not coincide with Chaparral's demand.

31. The operating expense incurred in serving Chaparral is estimated as $0.000182 per kwh. The power expense incurred in serving Chaparral is estimated as $0.035183 per kwh. The total monthly cost associated with the provision of service to Chaparral is $0.035365 per kwh.

32. The rates in the proposed tariff result in the recovery of $0.042041 per kwh in revenues. This cost per kwh falls in the high end of the cost per kwh range initially proposed by Chaparral.

33. Based upon the calculations in Findings of Fact No. 31 and 32, the rates in the proposed tariff recover $0.006676 per kwh in excess of the costs incurred in serving Chaparral.

[1] 34. Chaparral is not similarly situated with any other Cap Rock customer for two reasons: (1) it is the only existing customer to receive power directly at transmission voltage, which avoids the costs attributable to line losses that occur when providing service via a distribution line, and (2) the provision of service to the pipeline company does not require Cap Rock to make any additional plant investment, with the exception of that minor investment associated with tapping the existing Vealmoore transmission line.

35. For the reasons stated in Finding of Fact No. 34, the cost per kwh that Cap Rock incurs in serving Chaparral is lower than the cost per kwh that the cooperative incurs in serving other industrial customers.

36. The proposed tariff should be restricted to Chaparral until Cap Rock has performed a complete cost-of-service study that determines the effects of permitting other industrial customers with similar load characteristics and investment requirements to take service under the proposed tariff.

B. Conclusions of Law

1. Cap Rock is a public utility, as defined by PURA §3(c)(1).

2. The Commission has jurisdiction over this docket under PURA §§16(a), 17(e), and 43(a).

3. Cap Rock provided proper notice to all affected persons in substantial compliance with the ALJ's directives.

4. Cap Rock's institution of service and collection of rates prior to [2] Commission approval violated PURA §§31 and 46, which require a utility to obtain Commission approval of proposed rates prior to the charging and collection of such rates.

5. PURA does not require a utility to refund unlawfully charged and collected rates in violation of PURA §§31 and 46. When a utility charges and collects unlawful rates in violation of those statutory provisions, the Commission has the discretion to order the partial or complete refund of the unlawfully charged and collected revenues.

6. The Commission has not exercised its discretion to order a utility to [3] refund unlawfully charged and collected revenues when: (1) the utility did not willfully violate PURA; (2) the number of customers affected by the unlawful act is minimal and the amount of money to be refunded is nominal; (3) the issue of unlawfully charged and collected rates has arisen incidentally and not as the result of a customer complaint; and (4) the stipulation entered into by the parties does not provide for a refund. *Application of Tri-County Telephone Company to Implement Mandatory Service Upgrade, Unbundle Service Connection Charges, and Detariff CPE and Inside Wire*, Docket No. 7598, 13 P.U.C. BULL. 858 (February 17, 1988).

7. Based on the application of the criteria in Conclusion of Law No. 6 to Finding of Fact Nos. 16-20, it is appropriate for the Commission to conclude that Cap Rock need not refund any of the unlawfully charged and collected rates.

8. In addition to the rationale stated in Conclusions of Law Nos. 6 and 7, [4] it is appropriate for the Commission to conclude that Cap Rock need not refund any of the unlawfully charged and collected rates for the reasons stated in Finding of Fact No. 21.

9 The rates in the proposed tariff meet the statutory requirement of just and reasonable rates in PURA §§38 and 40.

10. The rates in the proposed tariff are not unreasonably preferential, prejudicial, or discriminatory under PURA §38.

[1] 11. The proposed tariff does not grant an unreasonable preference or advantage to any customer or subject any customer to unreasonable prejudice or disadvantage, in compliance with PURA §45.

12. Adoption of the parties' stipulation in this case is in the public interest. PURA §16(a); Administrative Procedure and Texas Register Act (APTRA), Tex. Rev. Civ. Stat. Ann. art. 6252-13a, §13(e) (Vernon Supp. 1990).

As a result of these findings of fact and conclusions of law, the Commission issues the following order:

1. Cap Rock's application, as amended by the stipulation, is **APPROVED.**

2. Approval of the stipulation in this docket does not indicate the Commission's endorsement or approval of any principle or methodology that may underlie the stipulation.

3. The tariff sheets submitted with the stipulation and attached to this Order are **APPROVED** effective the date of this Order.

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

SIGNED AT AUSTIN, TEXAS the 18th day of April 1990.

PUBLIC UTILITY COMMISSION OF TEXAS

Jo Campbell
JO CAMPBELL, COMMISSIONER

Marta Greytok
MARTA GREYTOK, COMMISSIONER

Paul D. Meek
PAUL D. MEEK, CHAIRMAN

ATTEST:

Mary Ross McDonald
MARY ROSS MCDONALD
SECRETARY OF THE COMMISSION

APPLICATION OF TEXAS UTILITIES ELECTRIC COMPANY FOR AUTHORITY TO CHANGE RATES § § § DOCKET NO. 9300

Examiner's Order No. 15
April 26, 1990

Examiner's Order overruled utility's objection to request for information on the basis that information requested was relevant to post-test-year adjustments.

[1] PROCEDURE--PREHEARING PROCEEDINGS--DISCOVERY
RATEMAKING--INVESTED CAPITAL--POST-TEST-YEAR ADJUSTMENTS

If utility has information relevant to the issue of post-test-year adjustments, the utility may be required to provide the information, even if the material is not in a prepared format and requires the utility to make projections and calculations of the underlying data. (p. 2225)

DOCKET NO. 9300

APPLICATION OF TEXAS UTILITIES ELECTRIC COMPANY FOR AUTHORITY TO CHANGE RATES	§ § §	PUBLIC UTILITY COMMISSION OF TEXAS

EXAMINER'S ORDER NO. 15

ORDER OVERRULING TEXAS UTILITIES ELECTRIC COMPANY'S OBJECTION TO OFFICE OF PUBLIC UTILITY COUNSEL'S SIXTH REQUEST FOR INFORMATION

[1] On March 27, 1990, Texas Utilities Electric Company (TU Electric) filed objections to the Office of Public Utility Counsel's (OPC's) Sixth Request for Information (RFI). TU Electric objected to the five questions set out below, Questions 454-458.

Question 454

Please provide the class revenue and billing determinant adjustments to test year actuals necessary to reflect the anticipated number of customers at the commercial operation date for Comanche Peak Unit 1 (provide all supporting calculations).

Question 455

Please provide the anticipated total level of accumulated depreciation booked at the time of commercial operation of Comanche Peak Unit 1.

Question 456

Please provide the anticipated total plant in service booked at the time of commercial operation of Comanche Peak Unit 1.

Question No. 457

Please provide the anticipated total level of accumulated deferred federal income taxes booked at the time of commercial operation of Comanche Peak Unit 1.

Question 458

Please provide the payroll and related expense adjustment to test year actuals necessary to reflect the anticipated number of employees at the commercial operation date for Comanche Peak Unit 1.

TU Electric's objections to the questions were as follows: (1) the information does not exist; (2) production of the information would impose an undue burden and unnecessary expense; and (3) the information is irrelevant and not reasonably calculated to lead to discovery of admissible evidence.

On March 30, 1990, OPC filed a motion to compel TU Electric to provide answers to OPC's Sixth Request for Information. In its motion, OPC states that TU Electric has included post-test-year adjustments to both plant and O&M expenses, and states that pursuant to P.U.C. SUBST. R. 23.21(a), "post-test-year adjustments to historical test-year data will be considered only where the attendant impacts on all aspects of the utility's operations can be with reasonable certainty identified, quantified, and matched". In order to consider the attendant impacts on all aspects of Comanche Peak beyond the test-year to commercial operation date (COD), OPC has requested data from TU Electric regarding the number of customers, accumulated depreciation, total plant in service, deferred federal taxes, and payroll expenses at the time of COD.

On April 9, 1990, TU Electric filed its response to OPC's motion to compel. TU Electric disputes OPC's position and argues that the post-test-year adjustment rule does not require a complete revision of all the data in the utility's test-year. It contends that only the areas of TU Electric operations that are impacted by the post-test-year adjustments relative to Comanche Peak Unit I should be adjusted for attendant impacts, and that it has already made those requisite adjustments. Finally, it argues that OPC's questions call for the use of a projected test-year.

The post-test-year adjustment rule, P.U.C. SUBST. R. 23.21(a), was amended in June, 1989 to allow utilities to adjust historical test-year plant for "known and measurable changes" subsequent to the test-year. Pursuant to the rule, post-test-year adjustments will be considered only where the attendant impact on all aspects of the utility's operations can be identified, quantified, and matched with reasonable certainty. It is clear that OPC has requested this information in order to determine the impacts on other aspects of TU Electric's operations that are concomitant with the post-test-year adjustments made by TU Electric.

Therefore, TU Electric's objections as to relevancy are without merit. The questions are indeed relevant to the issue of attendant impacts, and they could possibly lead to the discovery of admissible evidence. The examiners agree with TU Electric that the questions, as presented, request information that may not yet exist in a prepared format because they require projections. However, given TU Electric's request for post-test-year adjustments and the relevancy of the information requested with respect to those adjustments, the examiners believe that TU Electric should provide the data requested, using the estimated COD used in the Rate Filing Package (RFP). If TU Electric did not specify a COD in its RFP, then it should use a good-faith estimate of a COD, based on current information, in calculating its responses to OPC's questions. The examiners acknowledge that any projections calculated in response to OPC's request will be good-faith estimates that may or may not accurately reflect circumstances at the time of actual COD.

Accordingly, TU Electric's objection to OPC's Sixth Request for Information is **OVERRULED.**

SIGNED AT AUSTIN, TEXAS on this the 26th day of April 1990.

PUBLIC UTILITY COMMISSION OF TEXAS

Stephen J. Davis

STEPHEN J. DAVIS
ADMINISTRATIVE LAW JUDGE

James Brazell

JAMES Z. BRAZELL
HEARINGS EXAMINER

Joyce M. Phoenix

JOYCE M. PHOENIX
HEARINGS EXAMINER

MEMORANDUM DECISIONS

TELEPHONE

Southwestern Bell Telephone Company, Docket No. 9015. Examiner's Report adopted May 2, 1990. Application to revise a base rate area boundary in Collin and Denton Counties approved.

Southwestern Bell Telephone Company, Docket No. 9025. Examiner's Report adopted May 2, 1990. Application to amend exchange area boundary in Jefferson County approved.

GTE Southwest, Docket No. 9036. Examiner's Report adopted May 2, 1990. Application to amend exchange area boundary in Wilson and Guadalupe Counties approved.

United Telephone, Docket No. 9077. Examiner's Report adopted June 7, 1990. Application for exchange area boundary amendment in Hamilton County approved.

Southwestern Bell Telephone Company, Docket No. 9101. Examiner's Report adopted May 2, 1990. Application to amend exchange area boundary in Duval County approved.

GTE Southwest, Docket No. 9115. Examiner's Report adopted June 7, 1990. Application to revise base rate area boundaries in Cooke and Grayson Counties approved.

Contel of Texas, Docket No. 9118. Examiner's Report adopted June 7, 1990. Application for exchange area boundary amendment in Newton and Sabine Counties approved.

Southwestern Bell Telephone Company, Docket No. 9122. Examiner's Report adopted June 7, 1990. Application to revise base rate area boundaries in Liberty, Montgomery and San Jacinto Counties approved.

Southwestern Bell Telephone Company, Docket No. 9123. Examiner's Report adopted June 7, 1990. Application to revise base rate area boundaries in Sabine , San Augustine and Shelby Counties approved.

Central Texas Telephone Cooperative, Docket No. 9128. Examiner's Report adopted May 2, 1990. Application to update and reformat local exchange tariff was approved.

GTE Southwest, Docket No. 9132. Examiner's Report adopted May 2, 1990. Application to revise base rate area boundaries in Dallas County approved.

GTE Southwest, Docket No. 9133. Examiner's Report adopted May 2, 1990. Application to revise base rate area maps approved.

Fort Bend Telephone Company, Docket No. 9185. Examiner's Report adopted June 7, 1990. Application for exchange area boundary amendment in Brazoria County approved.

Southwestern Bell Telephone Company, Docket No. 9303. Examiner's Report adopted June 7, 1990. Application for exchange area boundary amendment in Crockett County approved.

Southwestern Bell Telephone Company, Docket No. 9376. Examiner's Report adopted June 7, 1990. Application to revise base rate area boundaries in Dallas County approved.

GTE Southwest, Docket No. 9505. Examiner's Report adopted May 15, 1990. Application to amend exchange area boundaries in Val Verde County approved.

ELECTRIC

Houston Lighting & Power Company, Docket No. 8909. Examiner's Report adopted June 7, 1990. Application for a transmission line in Wharton, Matagorda, and Brazoria Counties approved.

West Texas Utilities, Docket No. 9061. Examiner's Report adopted May 2, 1990. Application for a transmission line in Coke County approved.

Southwestern Electric Power Company, Docket No. 9073. Examiner's Report adopted May 2, 1990. Application for a transmission line in Cass County approved.

Cap Rock Electric Cooperative, Docket No. 9221. Examiner's Report adopted May 2, 1990. Application for a transmission line in Martin County approved.

West Texas Utilities, Docket No. 9302. Examiner's Report adopted June 7, 1990. Application for a transmission line in Jones County approved.