BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON- CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103.	DOCKET NO. E-01933A-05-0650
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-01933A-07-0402

TUCSON ELECTRIC POWER COMPANY

APPLICATION

TESTIMONY AND EXHIBITS

VOLUME 1 OF 4

July 2, 2007

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THIS IS PART
1 OF 4

OTHER
BARCODES FOR
THIS FILING ARE:
0000074435
0000074436
0000074437

Application

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Tucson Electric Power Company ("TEP" or "Company"), through undersigned counsel, and pursuant to A.R.S. §§ 40-250, 40-251, 40-301, A.A.C. R14-2-103, and Decision No. 69568 (May 21, 2007), hereby respectfully submits its Application for (i) an increase in the Company's retail rates effective no later than January 1, 2009; and (ii) other related relief. The Company's request is fully supported by the testimony, exhibits, and schedules submitted concurrently with this Application in these consolidated dockets. In support hereof, the Company states as follows:

I. SUMMARY OF TEP'S REQUEST FOR RATE INCREASE AND OTHER RELATED RELIEF.

Pursuant to the 1999 Settlement Agreement,[1] on January 1, 2009, the TEP rate moratorium ends and the Company is authorized to charge market-based rates for its electric generation service. In these consolidated dockets, TEP is asking the Commission to (i) set new rates for the Company's distribution and must-run generation, (ii) confirm that TEP's transmission and ancillary rates will continue to reflect the existing FERC-approved tariff rates, and (iii) affirm TEP's authority to charge market-based rates for generation service using the Company's "Market Methodology," all in time for the new rates to be in place on January 1, 2009. The Market Methodology will produce a rate increase of approximately 21.9% over TEP's current retail rates based on current projections for wholesale market power prices.

However, in the event that the Commission does not affirm that TEP is authorized to charge market-based rates for generation service, the Company is offering two alternate ratemaking methodologies: the "Cost-of-Service Methodology" and the "Hybrid Methodology." Each of these alternatives is designed to provide TEP with adequate rate relief and will necessitate an amendment to Decision No. 62103, which approved the 1999 Settlement Agreement.

The "Cost-of-Service Methodology" sets TEP's retail rates based upon cost-of-service principles for distribution, transmission <u>and</u> generation services. This methodology (i) utilizes regulatory assets to make the Company whole for the transition of generation service from a regulated monopoly regime to a non-regulated competitive scheme and then back to the regulated monopoly regime; (ii) implements a purchased power and fuel adjustment clause ("PPFAC") to ensure timely recovery of TEP's power supply costs; and (iii) restores the exclusivity of the Company's certificate of convenience and necessity ("CC&N") in recognition of the return to the

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[1] The Amended Settlement Agreement entered into by TEP, Arizona Residential Utility Consumers Office ("RUCO"), Arizonans For Electric Choice and Competition ("AECC") and Arizona Community Action Association ("ACAA") and approved by the Arizona Corporation Commission in Decision No. 62103 (November 30, 1999).

regulated monopoly regime. The Cost-of-Service Methodology will produce a rate increase of approximately 23.0% over TEP's current retail rates based on current expectations for future power supply costs.

The "Hybrid Methodology" also sets TEP's retail rates based upon cost-of-service principles for distribution, transmission, and generation. However, some of TEP's generation assets are excluded from the Company's rate base and are designated as wholesale assets. The Hybrid Methodology incorporates only one regulatory asset and includes a PPFAC. The Hybrid Methodology will produce a rate increase of approximately 14.9% over TEP's current retail rates based on current expectations for future power supply costs.

The Company is seeking approval of its requested rate design (which includes progressive Time-of-Use rates and a Lifeline Rate Block) as well as modifications to its Rules and Regulations and its Tariffs.

In Decision No. 69568, the Company was ordered to present information regarding a Demand-Side Management ("DSM") Portfolio and a Renewable Energy Action Plan ("REAP") in two separate proceedings, to be filed with the Commission on or before July 2, 2007. TEP is filing DSM Portfolio information in a separate proceeding but is requesting that the Commission adopt a cost recovery mechanism in this rate case prior to the implementation of any new DSM Portfolio programs. TEP incorporates by this reference any of the information in the DSM Portfolio proceeding that the Commission may deem necessary in order to approve the cost recovery mechanism.

Also, since Decision No. 69568 was issued, the Arizona Attorney General certified the Commission's Renewable Energy Standard Tariff ("REST") rules, which will become effective shortly. The REST Rules moot the REAP. Accordingly, in response to the requirement to file REAP information, TEP will file in a separate proceeding a statement of its intent to (i) comply with the procedures and provisions of the REST rules; (ii) file its REST compliance plan with the Commission within the schedule set forth in those rules; and (iii) seek approval of a REST recovery mechanism in the compliance plan proceeding as provided for in the REST rules.

TEP's requested relief is just, reasonable and fair to all affected constituencies. It is in the public interest for the Commission to authorize a rate increase for TEP consistent with the data and information presented and to resolve any outstanding issues relative to the 1999 Settlement Agreement as soon as possible, and in no event later than December 31, 2008.

II. REASONS FOR TEP'S RATE INCREASE AND OTHER RELATED RELIEF.

TEP's rate increase request is based on several factors. The first is that TEP's rates are too low to be able to continue to provide safe and reliable electric service at the levels the Company has worked so hard to achieve. Under the 1999 Settlement Agreement, TEP agreed to reduce and then freeze its rates until January 1, 2009. TEP's rates are now below the rates that were in place in 1994 and the Company's earnings are well below its authorized rate of return when analyzed on a cost-of-service basis.

Secondly, over the same time that rates have been reduced, the cost of providing service has increased dramatically. Since 1999, the prices of steel and copper have increased 71% and 323% respectively, driving up the cost of facilities required for electric generation, transmission and distribution. Meanwhile, wages have increased 26%, employee benefits have increased 43%, and fuel costs have increased 34%. The impact of these rising costs is exacerbated by TEP's significant customer growth. TEP's customer base has been expanding by 2.3% per year, while its load is growing by 4% per year.

In short, TEP needs higher rates so it can maintain its current system and level of service, build new facilities and acquire additional generating capacity in order to safely and reliably serve its customers' growing needs.

III. THE RATE METHODOLOGIES.

By this Application, TEP is seeking a rate increase based upon the Market Methodology. At the same time, however, TEP has provided the Commission with two alternative methods – the Cost-of-Service Methodology and the Hybrid Methodology – for establishing new rates and resolving the current dispute over the 1999 Settlement Agreement. Under the Cost-of-Service Methodology and the Hybrid Methodology, rates are set by traditional cost-of-service principles, which includes rates for transmission and ancillary services reflecting the rates established by the TEP Open Access Transmission Tariff ("OATT") approved by the Federal Energy Regulatory Commission ("FERC"). Base generation rates are set at different levels under each alternate methodology, and there are differences in the amounts TEP seeks to recover as regulatory assets under each methodology. A chart depicting the elements of the three methodologies is attached hereto as Exhibit 1 and by this reference incorporated herein.

A. Market Methodology.

Under the Market Methodology, all rates are set under cost-of-service principles except that the unbundled generation service rate is set by the Market Generation Credit ("MGC") under Section 2.1(d) of the 1999 Settlement Agreement, as subsequently amended by Decision No. 65751 (March 20, 2003). Under the Market Methodology, TEP is requesting a regulatory asset to recover only approximately $14.2 million in direct costs incurred to implement competition in compliance with the 1999 Settlement Agreement. The Company is not seeking recovery of any of the other costs it incurred in the transition to retail electric competition in this methodology.

B. Cost-of-Service Methodology.

Under the Cost-of-Service Methodology, distribution, transmission, and generation rates are established using cost-of-service principles. This methodology also seeks (i) recovery of costs and losses associated with the transition to retail competition under two (2) regulatory assets, (ii) approval of a PPFAC, and (iii) restoration of the exclusivity of TEP's CC&N.

In this methodology, TEP is utilizing a test year comprised of the twelve (12) months ending December 31, 2006, and has employed the calculations traditionally used by the Commission for determining fair value rate base ("FVRB"), fair value rate of return ("FVRR") and operating income. TEP is aware, however, that the Court of Appeals' recent ruling in *Chaparral City Water Company v. Arizona Corporation Commission*, 1 CA-CC 05-002 (February 13, 2007) ("*Chaparral City*"), may result in some modification of the Commission's traditional approach. TEP's use of the Commission's traditional definitions and calculations are therefore presented as a baseline for establishing new cost-of-service rates for TEP.[2] TEP believes that any new approach adopted by the Commission for establishing cost-of-service rates will be at or above the baseline cost-of-service rates established by the Cost-of-Service Methodology. Accordingly, TEP is providing the Commission with additional fair market value information and testimony that the Commission may find useful in determining FVRB, FVRR and operating income in this case.

The Cost-of-Service Methodology also implements a PPFAC. TEP presently does not have a PPFAC in place. Given the recent volatility in fuel and purchase power costs, TEP would require a PPFAC to allow timely recovery of its fuel and purchased power costs and to provide meaningful price signals to customers if it is to be returned to cost-of-service rates. There are two (2) primary components of TEP's PPFAC rate:

(i) <u>Forward Component</u>: This component would be based on the forecasted fuel and purchased power costs for the following year. For example, forecasts for fuel and purchased power in 2010 would be used to establish the PPFAC Forward Component for 2010. Forward prices also would be used to establish the PPFAC Forward Component annually.

(ii) <u>True-Up Component</u>: This component would compare actual fuel and purchase power costs with the amount TEP collected through base rates as well as the PPFAC rate for the prior year. If actual costs were above what was collected, the True-Up Component would become an additional amount to be collected from customers in the subsequent year. If actual costs were below what was collected, the True-Up Component would reflect a credit towards the PPFAC rate for the following year. For example, the difference between the forecasted 2009 fuel and purchased power costs and the costs

[2] TEP reserves all rights and claims in connection with any approach ultimately employed by the Commission as a result of the *Chaparral City* ruling. Additionally, the Company reserves its rights to incorporate the fair market value information (presented in this case for informational purposes) into its request in the event that the Commission adopts an approach to rate base or revenue requirement determination that includes fair market values of assets devoted to public service.

actually incurred during that year would be incorporated into the 2010 PPFAC rate via the True-Up Component.

The Cost-of-Service Methodology further includes recovery of two (2) regulatory assets. First, TEP seeks recovery of approximately $47 million of costs incurred in the transition to retail competition under the 1999 Settlement Agreement. These costs include software changes made to the Company's billing systems and actions taken to renegotiate coal contracts. This regulatory asset (the "Implementation Costs Regulatory Asset" or "ICRA") is included in rate base and recovered through base rates. Second, TEP seeks recovery of $788 million reflecting the financial impact of meeting its obligations under the 1999 Settlement Agreement and transitioning back to cost-of-service ratemaking in 2009. This regulatory asset (the "Termination Costs Regulatory Asset" or "TCRA") is recovered through a separate charge (the "Termination Cost Regulatory Asset Charge" or "TCRAC") at an average rate of $0.0126 per kWh.

C. Hybrid Methodology.

Under the Hybrid Methodology, TEP's distribution, transmission, and generation rates would be established in the same manner as under TEP's Cost-of-Service Methodology except that certain generation assets would be excluded from the rate base. TEP also seeks approval of a PPFAC under this methodology, but the only regulatory asset requested under this methodology is the $47 million ICRA.

The assets excluded from rate base under the Hybrid Methodology are (i) the Company's interest in Navajo Generating Station Units 1, 2 and 3, and (ii) the Company's interest in Four Corners Generating Station Units 4 and 5 (the "excluded generation assets"). These excluded generation assets will be dedicated to wholesale market transactions, although the power could be used to supply TEP's retail customers at prices reflecting wholesale market conditions. In that circumstance, the cost to supply TEP's retail customers from those excluded generation assets would be recovered through the PPFAC and not base rates.

The Hybrid Methodology includes (i) the same PPFAC as utilized under the Cost-of-Service Methodology; (ii) recovery of only the $47 million ICRA (and not the TCRA); and (iii) a restoration of TEP's exclusivity under its CC&N except that direct access within TEP's service territory would be available for customers whose demand exceeds three (3) MW.

IV. RATE DESIGN.

In 2000, the Commission approved unbundled tariffs for TEP that opened the Company's territory to direct access. The Commission's Retail Electric Competition Rules still require unbundled rates. Therefore, as part of its Application, TEP is proposing unbundled tariffs for each of the three (3) methodologies. The generation rate will be determined by the methodology adopted. The transmission and ancillary services rates will be set to reflect the OATT rate approved by FERC. The rates for distribution and must-run generation will be set to recover the costs of providing those services.

Additionally, TEP is proposing progressive Time-of-Use rates and a Lifeline Rate Block. TEP's Time-of-Use proposal has been developed and is offered with the intent to make a meaningful impact on customer usage. The Lifeline programs are similarly offered to provide a significant mitigation of the cost of electric service for those who require it for their basic needs.

V. RULES AND REGULATIONS AND TARIFFS.

TEP is requesting modifications to its Rules and Regulations and to its Tariffs. These modifications are intended to modernize and standardize TEP's Rules and Regulations and Tariffs with the corresponding rules, regulations and tariffs of TEP's affiliates, UNS Gas, Inc. and UNS Electric, Inc., to add TOU offerings and to set forth separate Direct Access Rules and Regulations.

VI. DSM RECOVERY MECHANISM.

TEP is filing its DSM Portfolio and REAP information in separate dockets as ordered by the Commission in Decision No. 69568.[3] However, TEP is requesting that the Commission approve the appropriate DSM Portfolio cost recovery mechanism in this proceeding prior to the implementation of those programs so that the Company can recover its costs in a timely manner.

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[3] TEP, to the extent deemed necessary by the Commission in order to reach a determination on the requests, hereby incorporates by reference into these consolidated dockets the DSM Portfolio and REAP filings made by the Company.

APPLICATION

I.

The Company is a corporation duly organized, existing and in good standing under the laws of the State of Arizona. Its principal place of business is One South Church Avenue, Tucson, Arizona, 85701.

II.

The Company is a public service corporation principally engaged in the transmission and distribution of electricity for sale in Arizona pursuant to Certificates of Convenience and Necessity issued by the Commission.

III.

All communications and correspondence concerning this Application, as well as communications and pleadings with respect thereto filed by other parties, should be served upon the following:

Raymond S. Heyman, Esq.
Michelle Livengood, Esq.
UniSource Energy Corporation
One South Church, Suite 200
Tucson, Arizona 85701

and

Michael W. Patten, Esq.
J. Matthew Derstine, Esq.
Roshka, DeWulf & Patten, PLC
One Arizona Center
400 East Van Buren Street, Suite 800
Phoenix, Arizona 85004

IV.

This Commission has jurisdiction to conduct public hearings to determine the fair value of the property of a public service corporation, to fix a just and reasonable rate of return thereon, and thereafter, to approve rate schedules designed to develop such return. Further, the Commission has jurisdiction to establish the practices and procedures to govern the conduct of such hearing, including, but not limited to, such matters as notice, intervention, filing, service, exhibits, discovery and other pre-hearing and hearing matters.

V.

Accompanying this Application are the standard filing requirements and rate design schedules described in A.A.C. R14-2-103 and the direct testimony and related exhibits of the following witnesses:

- James S. Pignatelli
- Michael J. DeConcini
- David G. Hutchens
- Kentton C. Grant
- Kevin P. Larson
- Karen G. Kissinger
- Dallas J. Dukes
- Dawn Sabers
- D. Bentley Erdwurm
- Thomas N. Hansen
- Dr. Kimbugwe Kateregga
- Judah L. Rose
- Dr. Samuel Hadaway

VI.

TEP respectfully requests that this Commission set a date for a hearing on this Application such that new rates for the Company will become effective on or before January 1, 2009. At the hearing conducted pursuant to this rate request, TEP will establish, among other things, that:

(1) its current rates and charges do not permit the Company to earn a fair return on the fair value of its assets devoted to public service and are therefore no longer just and reasonable;

(2) pursuant to the 1999 Settlement Agreement, TEP is entitled to charge market-based rates for generation service commencing January 1, 2009;

(3) the requested increase, under any of the methodologies, is the minimum amount necessary to allow the Company an opportunity to earn a fair return on the fair value of its assets devoted to public service, for preservation of the Company's

financial integrity and for the attraction of new capital investment on reasonable terms;

(4) the proposed modifications to TEP's rate design should be approved;

(5) the proposed modifications to TEP's Rules and Regulations and Tariffs should be approved;

(6) the requested PPFAC for the Company should be adopted so that proper protections and price signals are provided to the customers and TEP timely recovers the cost of fuel and purchased power; and

(7) the requested DSM Portfolio cost recovery mechanism should be approved prior to the implementation of new DSM programs.

VII.

In addition to setting a hearing date, TEP asks that the Commission issue a procedural order setting forth the prescribed notice for the Application, establishing procedures for intervention, and providing for appropriate discovery. TEP further requests that the Company be authorized to serve all discovery requests, answers and objections electronically. Hard copy service would remain available to parties upon request or where the confidential nature of the information makes the use of electronic service impractical.

WHEREFORE, TEP respectfully requests that the Commission:

(1) issue a procedural order establishing a date for hearing evidence concerning the Application and prescribing the time and form of notice to TEP customers and establishing procedures for intervention and discovery as described above;

(2) issue a final order granting the Company the permanent rate increase sought herein as well as any amendments to Decision No. 62103, if necessary ;

(3) issue a final order approving the new or modified rate and service schedules included with the Company's Application with an effective date as soon as practicable, but in no event later than January 1, 2009;

(4) issue a final order approving TEP's revised Rules and Regulations and revised Tariffs, as set forth in the related testimony and exhibits;

(5) issue a final order authorizing TEP's depreciation rates and classifications;

(6) issue a final order approving the requested PPFAC;

(7) issue a final order approving TEP's proposed DSM cost recovery mechanism; and

(8) grant the Company such additional relief as is just and proper.

RESPECTFULLY SUBMITTED this 2nd day of July 2007.

TUCSON ELECTRIC POWER COMPANY

By ______________________

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Roshka, DeWulf & Patten, PLC
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Phoenix, Arizona 85004

and

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Michelle Livengood
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Attorneys for Tucson Electric Power Company

Original and 15 copies of the foregoing filed this 2nd day of July 2007 with:

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Phoenix, Arizona 85007

Copy of the foregoing hand-delivered/mailed
this 2nd day of July 2007 to:

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Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

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1200 West Washington Street
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Commissioner Jeff Hatch-Miller
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Phoenix, Arizona 85018

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Bisbee, Arizona 85603

By Mary Ippolito

EXHIBIT 1

Exhibit 1

TEP Rate Case Scenarios
June 2007

	Full COS	Hybrid	Full Market
Assets Subject to ACC Jursidiction:	Distribution & Generation	Distribution & Some Generation	Distribution & Local Generation
Fuel & PP Recovery:	PPFAC	PPFAC	MGC
Recovery of Non-Fuel Generation Costs			
Rate Base Treatment	All Generation Except Below	Local Generation, San Juan & SPVL 2	Local Generation
Market-Based Demand Charge	Luna & SPVL 1	Luna & SPVL 1	None
Designated as Wholesale Generation Assets	None	Navajo & 4 Corners	All Non-Local Gen
Regulatory Asset Recovery			
Termination Costs Regulatory Asset (1)	$788 mil.	none	none
Other Regulatory Assets (2)	$47 mil.	$47 mil.	$14.2 mil.

(1) Represents compensation for rate freeze based on revenue deficiency identified in 2004 rate review. Amortized over ten years using mortgage style amortization through separate rate.

(2) Represents coal contract termination/amendment fees, financing write-offs and $14.2 million of direct access costs. Amortized over four years using straight-line amortization.

Direct Testimony of James Pignatelli

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON - CHAIRMAN
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Direct Testimony of

James S. Pignatelli

on Behalf of

Tucson Electric Power Company

July 2, 2007

Executive Summary of the Direct Testimony of James S. Pignatelli

Mr. Pignatelli is the Chairman of the Board, President and Chief Executive Officer of Tucson Electric Power Company ("TEP" or the "Company"). Mr. Pignatelli's Direct Testimony addresses the following matters:

1. **Summary of Rate Increase Request.** TEP has operated under a rate increase moratorium since the 1999 Settlement Agreement and is currently under-earning on a cost-of-service basis. The rate moratorium ends on December 31, 2008. TEP has faced and continues to experience significant customer growth, increased energy demand and rapidly rising costs associated with providing service. TEP's rate increase request is necessary to maintain current service levels, build new transmission and distribution facilities and to acquire additional generation (such as the Springerville Generating Station Unit 1) to serve its customers' growing needs.

   For these reasons, TEP is compelled to request the first increase in its rates in more than a decade. The Company is proposing three methodologies that could be used to implement its rate increase request: (i) the Market Methodology; (ii) the Cost-of-Service Methodology; and (iii) the Hybrid Methodology. All three methodologies use cost-of-service principles to determine distribution ("ACC") and transmission ("FERC") rates. But each methodology uses a different approach for determining the rate for generation service.

   a. **Market Methodology.** This methodology would determine transmission and distribution rates using cost-of-service principles. Rates for generation service would be determined by using the market-based proxy, the Market Generation Credit ("MGC"), which was adopted in the 1999 Settlement Agreement and approved in Decision No. 62103. The rate base in this methodology would include an Implementation Cost Regulatory Asset ("ICRA") of $14.2 million amortized over four years to reflect a portion of the costs (i.e. software acquisition and modification) of TEP's transition to retail competition under the 1999 Settlement Agreement. Under this methodology, TEP's service area would remain open to direct access retail competition. The Market Methodology would result in an increase of 21.9% over current rates.

   b. **Cost-of-Service Methodology.** This methodology would determine transmission, distribution and generation rates using cost-of-service principles. The rate base in this methodology would include an ICRA of $47 million amortized over four (4) years to reflect the costs of TEP's transition to retail competition under the 1999 Settlement Agreement. This methodology also would include a Termination Cost Regulatory Asset ("TCRA") of $788 million to be recovered through a charge for the financial harm incurred by TEP for performing under the 1999 Settlement Agreement, but not being permitted to charge market rates for generation service beginning in 2009. This methodology would also implement a Purchased Power and Fuel Adjustment Clause ("PPFAC"). Additionally, the exclusivity of TEP's Certificate of Convenience and Necessity ("CC&N") would be restored. The Cost-of-Service Methodology would result in an overall increase of 23.0% over current rates.

c. **Hybrid Methodology.** This methodology would utilize a hybrid ratemaking approach whereby TEP's transmission, distribution and generation rates would be established by cost-of-service principles in the Cost-of-Service Methodology, including the $47 million ICRA, except that certain generation assets would not be included in TEP's cost-of-service rate base. The excluded generation assets are (i) the Company's interest in the Navajo Generating Station Units 1, 2 and 3; and (ii) the Company's interest in the Four Corners Generating Station Units 4 and 5 (the "excluded generation assets"). The excluded generation assets would be dedicated to wholesale market transactions. In addition, this hybrid methodology would include a PPFAC. Also, under this methodology, TEP's service area would be open to direct access retail competition for customers with at least 3 MW of load. The Hybrid Methodology would result in an overall increase of 14.9% over current rates.

TEP has presented the Market Methodology to the Commission because it believes that when the rate increase moratorium in the 1999 Settlement Agreement is lifted on January 1, 2009, it is entitled to (i) a rate increase for transmission and distribution service; and (ii) charge rates for generation service based upon the market-based methodology set forth in the 1999 Settlement Agreement.

TEP has submitted the Cost-of-Service Methodology and the Hybrid Methodology to the Commission to evaluate the Company's proposals for amending the 1999 Settlement Agreement and Decision No. 62103. If the Commission accepts either of these methodologies, TEP requests that the new rates become effective as soon as possible but in no event later than January 1, 2009.

2. **Purchased Power and Fuel Adjustment Clause.** TEP does not currently have an energy and/or fuel adjustment clause. TEP is proposing a PPFAC (and related Plan of Administration) that would reflect a forward-looking estimate of fuel and purchased power costs. A PPFAC would be used in connection with both the Cost-of-Service and Hybrid Methodologies.

3. **Regulatory Assets.** As part of all three methodologies, TEP is seeking to include the ICRA in rate base to be amortized over four (4) years. The ICRA is approximately $47 million in the Cost-of-Service and Hybrid Methodologies, and approximately $14.2 million in the Market Methodology. The Company also seeks to recover, through a charge, a TCRA in the amount of $788 million to be amortized over 10 years in the Cost-of-Service Methodology.

4. **Fair Market Value and Wholesale Market Information.** TEP has calculated its fair value rate base and fair value rate of return in accordance with the Commission's traditional practice. At the same time, TEP is presenting data regarding the fair market value of its rate base assets for informational purposes and in order to preserve its rights in the event that such data is relied upon by the Commission in response to the Arizona Court of Appeals' ruling in the *Chaparral City* decision. The Company also is presenting evidence demonstrating that the wholesale electric market in the Southwest is robust and competitive.

5. **DSM Cost Recovery Mechanism.** TEP is filing Demand-Side Management ("DSM") Portfolio and Renewable Energy Action Plan ("REAP") information in separate dockets as ordered in Decision No. 69568 (May 21, 2007). However, TEP is requesting that the Commission order that the appropriate DSM cost recovery mechanism be established in this proceeding so that the Company may recover its costs associated with the DSM Portfolio in a timely manner. In light of the imminent implementation of the REST rules, TEP is presenting for informational purposes its proposed procedure for adoption of a REAP/REST cost recovery mechanism. TEP is also requesting that the cost recovery mechanisms be in place prior to the implementation of any plans.

6. **Rate Design (Time-of-Use and Lifeline Rate Block).** TEP is presenting significant rate design proposals in this proceeding regarding Time-of-Use ("TOU") and Lifeline rates.

   TEP is proposing to control peak demand through TOU rates under each of the methodologies presented in this case. TOU rates should help defer new generation and provide customers the opportunity to achieve savings by managing their electric service usage patterns. Accordingly, TEP is proposing that all new customers be placed on TOU rates and that any existing customers who change meters also be placed on a TOU rate. Additionally, all commercial and industrial customers - new and existing - with loads of 200 kW or greater will be placed on a TOU rate.

   TEP is also proposing a progressive Lifeline Rate Block that will aid not only those in need of financial assistance, but all customers regarding their basic energy needs.

TEP's overall rate design objectives are the same under the three methodologies. The proposed rate design is responsive to customers' concerns, and promotes the long term financial integrity of TEP and the economic vitality of southern Arizona. Major stakeholders' interests coincide regarding peak load control, conservation during high cost periods, and providing basic energy needs at affordable prices. TEP proposes to ambitiously expand TOU programs and to introduce a Lifeline Rate Block. Lifeline Rates offer a monthly block of "basic-needs" energy at a reduced price per kWh. Under the Lifeline Rate Block, the price per unit increases as consumption increases, and conservation is promoted. TOU reinforces the conservation incentive by pricing on-peak period energy at higher prices. On-peak consumption may be avoided or shifted to less critical shoulder-peak or off-peak periods where prices are closer to or lower than typical, non-time differentiated levels. If sufficient customers shift load away from the on-peak period, additional capacity may be avoided or deferred and cost savings may result.

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I. INTRODUCTION AND BACKGROUND.

Q. Please state your name and business address.

A. My name is James S. Pignatelli. My business address is One South Church Avenue, Tucson, Arizona 85701.

Q. Mr. Pignatelli, please provide a brief review of your education and work experience.

A. I received an undergraduate degree in accounting with a minor in economics from Claremont Men's College. I received a Juris Doctor Degree from the University of San Diego School of Law. I am an inactive member of the California State Bar, and have passed the certified public accounting exam. I have worked in the utility industry since my college days, with the exception of two years when I was in the military during the Vietnam War. I served in various positions at San Diego Gas & Electric Company and Southern California Edison Company in accounting, economics, business planning and strategic planning.

Prior to joining UniSource Energy Corporation ("UniSource Energy"), I served as the Chief Executive Officer of Mission Energy, which, at the time, was the largest independent power producer in the world.

Q. What is your position with Tucson Electric Power Company ("TEP" or the "Company")?

A. I am Chief Executive Officer, President and Chairman of the Board of Directors of TEP. I hold the same positions with UniSource Energy Corporation, TEP's parent company.

In these positions, I am responsible for the overall operation of TEP. I take very seriously TEP's role as a provider of electric service. I believe TEP has an important obligation to our customers to provide safe and reliable electric service. I believe our performance demonstrates our commitment to fulfilling this obligation.

I also believe TEP has an obligation to be a prudent steward of its investors' assets. I take pride in knowing that during the TEP rate moratorium period (from 1999 through 2008), the Company has been able to meet its obligations to both customers and shareholders.

However, TEP will not be able to continue to operate at current service levels without a rate increase. During the TEP rate moratorium period, the cost of providing service has dramatically increased. For example, since 1999, materials such a steel and copper have increased 71% and 323%, respectively; wages have increased 26%; employee benefits have increased 43%, and fuel costs have increased 34%. A chart showing the increase in these costs is attached to my testimony as Exhibit JSP-1 and incorporated herein.

Over the same period that these vital and unavoidable costs have increased, TEP's rates actually decreased. Indeed, TEP's current rate levels are 2% below the rates that were in place in 1994. TEP agreed to a rate moratorium as a part of the 1999 Settlement Agreement. Clearly, this rate moratorium has been very fortuitous for our customers who, for at least eight (8) years, have not had to pay for the increase in the costs TEP has incurred in providing safe and reliable electric service. But, as the rate moratorium provision of the 1999 Settlement Agreement reaches an end, it is time for TEP's electric service rates to accurately reflect the Company's costs for providing service. A chart showing TEP's rates compared with the rate levels of selected other utilities (which have not been subject to the same rate moratorium as TEP) is attached to my testimony as Exhibit JSP-2 and incorporated herein.

Regardless of which methodology the Commission employs for determining new rates, it is entirely appropriate for TEP's rates to be increased now in recognition of the increase in customer growth, energy demand and the cost of providing service. We are experiencing new customers coming into our service territory and existing customers are using more electricity. TEP's ability to maintain safe and reliable service levels while meeting the needs of this growth also plays an important role in the economic development of the State of Arizona.

Higher rates are needed to ensure that TEP can afford not only to expand its transmission and distribution facilities to meet customer growth, but also to acquire needed electric generation. TEP expects to invest significant amounts to secure the additional power it will need to meet its future load. The Company will acquire additional generation by building, buying or leasing power plants, or by entering into contracts to purchase power in the wholesale market. To carry out any of these options, TEP will need to improve its financial stability and strength. Approval of the rates requested by TEP in this case would bolster the Company's financial condition and, in so doing, improve its ability to procure future generation for its customers.

The future of Unit 1 at TEP's coal-fired Springerville Generating Station offers an example of how improving the Company's financial condition would serve the long-term interests of our customers and the Company's ability to provide continued safe and reliable service. TEP currently receives the unit's full 380-MW output through a leveraged lease arrangement with the owner participants of the Springerville Unit No. 1 Lease (the "Springerville Unit No. 1 Lease.") The Springerville Unit No. 1 Lease expires in 2015, at which time TEP will have the option to purchase the assets at fair market value. We believe customers would be best served if TEP has the financial strength to purchase those equity interests at that time. By owning Springerville Unit No. 1, TEP could continue to provide this low-cost source of coal-fired generation to its customers rather than turning to the volatile wholesale power markets to replace its output. Without the requested rate relief, I believe that TEP's ability to acquire Springerville Unit No. 1 on reasonable terms will be significantly jeopardized.

Q. Mr. Pignatelli, what is the Company asking the Arizona Corporation Commission ("Commission") to do in this proceeding?

A. We are asking the Commission to issue an order prior to December 31, 2008, that increases TEP's rates from their current levels, effective no later than January 1, 2009.

Q. How does TEP propose that the Commission set rates in this proceeding?

A. TEP is proposing that the Commission adopt the "Market Methodology" for setting rates in this case. TEP believes this is the methodology that complies with terms and conditions of the 1999 Settlement Agreement.

The Market Methodology would determine distribution and transmission rates using cost-of-service principles. Specifically, the transmission rates are based upon FERC's cost-based open access transmission tariff ("OATT"). Rates for generation service would be determined by a market-based formula pursuant to the 1999 Settlement Agreement. The Market Methodology would include recovery of certain costs of implementing retail electric competition (the "Implementation Cost Regulatory Asset", or "ICRA").

However, in the event that the Commission does not affirm that TEP is authorized to charge market-based rates for generation service, the Company is offering two alternate ratemaking methodologies. Each of these alternatives is designed to provide the Company with adequate rate relief and will necessitate an amendment to Decision No. 62103, which approved the 1999 Settlement Agreement.

The "Cost-of-Service Methodology" would determine transmission, distribution and generation rates using cost-of-service principles. This methodology includes regulatory assets to address the financial impacts to TEP from (i) implementing retail electric competition (the ICRA); and (ii) complying with the 1999 Settlement Agreement without being permitted to charge market rates for generation service due to the modification or termination of the 1999 Settlement Agreement (the "Termination Cost Regulatory Asset", or "TCRA"). This methodology also would incorporate a Purchased Power and Fuel Adjustment Clause ("PPFAC") to ensure the timely recovery of future fuel and purchased power costs. TEP presently does not have a PPFAC in place. Additionally, the exclusivity of TEP's Certificate of Convenience and Necessity ("CC&N") would be restored.

The "Hybrid Methodology" would utilize a hybrid ratemaking approach whereby TEP's transmission, distribution and generation rates would be established by cost-of-service principles except that certain generation assets would not be included in TEP's cost-of-service rate base. The excluded generation assets would be (i) the Company's interest in the Navajo Generating Station Units 1, 2 and 3; and (ii) the Company's interest in the Four Corners Generating Station Units 4 and 5 (the "excluded generation assets"). The excluded generation assets would be dedicated to wholesale market transactions. This methodology also would incorporate a PPFAC as well as recovery of an ICRA.

A chart specifying and comparing the features of each methodology is attached to my testimony as Exhibit JSP-3 and incorporated herein. Regardless of which methodology the Commission employs for determining new rates, it is entirely appropriate for TEP's rates to be increased now in recognition of the increase in customer growth, energy demand and the cost of providing service and the need for TEP to be able to maintain safe and reliable service.

Q. So is TEP filing three separate rate cases in this proceeding?

A. No, not at all. TEP is presenting three alternative methodologies for determining one rate increase. The same core data will be used, with appropriate adjustments, for each methodology.

The Company's primary request in this case is that the Commission adopt the Market Methodology. TEP believes this is the methodology that was authorized by the 1999 Settlement Agreement. The Market Methodology will use the same data and information that will be presented in connection with the Cost-of-Service Methodology for determining transmission and distribution rates. The unbundled generation rate developed in the Cost-of-Service Methodology will be replaced in the Market Methodology with the Market Generation Credit ("MGC") rate pursuant to the 1999 Settlement Agreement.

The Cost-of-Service Methodology will calculate generation, transmission and distribution rates using cost-of-service ratemaking principles and a historic test year based on the twelve (12) months ending December 31, 2006.

The Hybrid Methodology will utilize the same test year, data and principles from the Cost-of-Service Methodology, adjusted to reflect removal of the excluded generation assets.

We are submitting, with our Application, a full set of rate schedules pursuant to A.A.C. R14-2-103 for the Market Methodology, the Cost-of-Service Methodology and the Hybrid Methodology. Although some information may be redundant, we believe that providing separate copies of the schedules for each methodology will make it easier for the Commission to analyze each approach on its own merits. We are also providing separate tariffs for each of the methodologies.

Q: **Mr. Pignatelli, why are you presenting the Commission with three methodologies for setting rates in this proceeding?**

A. TEP's position regarding its right to charge market-based rates is well documented. We are presenting the Market Methodology to the Commission because we believe that when the rate increase moratorium imposed by the 1999 Settlement Agreement expires on December 31, 2008, we are entitled to (i) a rate increase for transmission and distribution service; and (ii) charge rates for generation service based upon the market-based methodology set forth in the 1999 Settlement Agreement.

We have filed the Cost-of-Service Methodology and the Hybrid Methodology to help the Commission evaluate our proposals for amending the 1999 Settlement Agreement and Decision No. 62103 in furtherance of settlement discussions and negotiations among the parties to the 1999 Settlement Agreement. We originally proposed this approach during the hearing held in Docket No. E-01933A-05-0650, (the "1999 Settlement Agreement Amendment Case"). The Commission accepted TEP's proposal and ordered the Company to file our Application in this case with the different methodologies in Decision No. 69568 (May 21, 2007).

Q. **What do you anticipate the rate increase will be if the Market Methodology is used?**

A. Based on assumptions detailed in our schedules, testimony and exhibits, we believe that market-based rates for generation service, together with an increase for transmission and distribution service, effective January 1, 2009 will result in an increase over current rates of 21.9%.

Q. What do you anticipate the rate increase will be if the Cost-of-Service Methodology is used?

A. If TEP's rates for generation, transmission and distribution services are determined using cost-of-service principles, including the Company's recommended regulatory assets, the increase over current rates is expected to be 23.0%. As TEP is requesting a PPFAC as part of this rate setting methodology, this estimate is based on the Company's expectations for fuel and purchased power costs in 2009.

Q. What do you anticipate the rate increase will be if the Hybrid Methodology is used?

A. Pursuant to the Hybrid Methodology, the increase over current rates is expected to be 14.9%. A PPFAC would also be implemented in the same fashion as the Cost-of-Service Methodology that I described above.

Q. Do you believe these new rates are just, reasonable and in the public interest?

A. Yes, I do. Even if the Commission does not agree that TEP is entitled to charge market-based rates for generation service commencing January 1, 2009, dramatic increases in the cost of providing electric service justify an increase under any of the proposed methodologies.

As I analyze rates to determine if they are just, reasonable, and in the public interest, I refer to the fundamental ratemaking standards established by the U.S. Supreme Court in the seminal cases *Bluefield Water Works and Improvement Co. v. Pub. Serv. Comm'n of West Virginia*, 262 U.S. 679 (1923) (the "*Bluefield*" case) and *Federal Power Comm'n v. Hope Natural Gas*, 320 U.S. 591 (1944) (the "*Hope*" case). The *Bluefield* case established the standards by which rates and a reasonable return are to be evaluated by stating:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.[1]

In *Hope,* the U.S. Supreme Court expanded on the *Bluefield* principles by stating:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for capital costs of the business. These include service on the debt and dividends on the stock...By that standard the return to the equity owner should be commensurate with return on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital.[2]

In these two cases, the U.S. Supreme Court set forth the public interest balancing test that I believe the Commission should use when determining rates for TEP. For me, this balancing test defines the public interest because it considers the impact of rate relief on both the investors and the customers.

In this case, it is indisputable that TEP's rates are below those found to be just and reasonable by the Commission and charged to customers in 1994, resulting in a substantial benefit for our customers. The cost increases incurred over the past thirteen (13) years make it inevitable that any rate methodology proposed by the Company will result in higher costs for customers. Nonetheless, when those costs are balanced against the long-term benefits provided to both customers and the Company, it is clear that our methodologies are just, reasonable and in the public interest.

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[1] 262 U.S. at 692-93.

[2] 320 U.S. at 603.

Q. Are you asking the Commission to address any significant policy questions in this proceeding?

A. Yes. We are asking the Commission to determine whether TEP's generation service rates will be based on a market-based formula, cost-of-service principles or a hybrid of those two approaches. In addressing this issue, the Commission will necessarily resolve questions about TEP's rights under the 1999 Settlement Agreement, while making a clear statement about the future of electric competition in Arizona.

Also, TEP currently does not have a PPFAC. If generation assets are returned to cost-of-service ratemaking and regulation, it will be important to ensure that customers pay a fair cost for power during periods of volatility in the purchased power and fuel markets. By approving a PPFAC, the Commission will accomplish this goal while addressing a significant threat to the Company's financial stability.

We also are providing the Commission with information regarding the fair value of TEP's assets devoted to public service. In light of the Court of Appeals' ruling in *Chaparral City Water Company v, Arizona Corporation Commission*, 1 CA-CC 05-002 (February 13, 2007) ("*Chaparral City*") and the uncertainty as to how the Commission will determine fair value rate base and fair value rate of return in the future, we believe it is important for the Commission to have fair market value information when deliberating and deciding the Company's rate increase request.

Accordingly, although we have presented our rate request consistent with prior filings, we also are providing the Commission with a range of information regarding the value of TEP's assets, rate base and revenue requirements. The Company reserves its rights to incorporate this information into its request if the Commission adopts an approach to rate base or revenue requirement determination that includes fair market values of assets devoted to public service.

Q. Why is TEP requesting that the rate increase be effective no later than January 1, 2009?

A. The skyrocketing costs associated with providing electric service compel the Company to seek rate relief as soon as possible. Because the rate moratorium in the 1999 Settlement Agreement expires December 31, 2008, TEP could begin charging higher rates as soon as January 1, 2009. By filing our Application in this case on July 2, 2007, we have given the Commission approximately eighteen (18) months to reach a resolution that would take effect upon termination of the rate increase moratorium.

Our need for prompt rate relief is exacerbated by TEP's growing customer base, which is expected to continue expanding by 2.3% per year – compared to an industry average growth rate of 1.5%. (A map of TEP's service territory is attached to my testimony as Exhibit JSP-4.) To serve our customers' rising energy needs, we have significantly increased our spending to generate and acquire power and to expand and maintain the transmission and distribution facilities we use to deliver that power to customers.

Based on its 2004 rate review filing, TEP has been under-earning by $111 million dollars per year. While Staff and RUCO reached conclusions of differing amounts, both agreed that TEP has been under-earning. But for the moratorium on higher rates, TEP would have requested a rate increase in 2004 or sooner.

The expansion of Demand-Side Management ("DSM") and renewable energy programs also puts new pressure on the Company's costs. The sooner the Commission enacts appropriate and effective cost-recovery mechanisms, the sooner the Company can implement programs commensurate with the funding.

Since the 1999 Settlement Agreement, TEP has decreased its rates and then held them at that level. We need the additional revenues now that will come from the requested rate increase in order to continue to provide the same levels of safe and reliable electric service and meet our financial obligations.

II. THE HISTORICAL CONTEXT OF THIS RATE CASE FILING.

Q. Mr. Pignatelli, please provide some historical context for this rate case filing.

A. As I have previously stated, the two basic purposes for this rate case filing are to increase TEP's rates and, if possible, to resolve the questions that have been raised about the 1999 Settlement Agreement.

The testimony, exhibits and schedules sponsored by other witnesses in this case will establish the economic and financial need for TEP's rate request.

The detailed history of the 1999 Settlement Agreement and the events that lead to the filing of this rate case are sufficiently documented in the pleadings, testimony and orders in the record of the 1999 Settlement Agreement Amendment Case, which has been consolidated with this rate case proceeding.

However, I think it is worthwhile to review, in general terms, the history of the 1999 Settlement Agreement and the events that lead to the filing of this rate case. Doing so reveals that while TEP has held steadfast to the 1999 Settlement Agreement, the terms, conditions and status, of electric competition have changed several times. TEP has done its best to adapt its business and plans to this moving target.

Until 1996, TEP held the exclusive right to provide electric service to its customers. In the early 1990s, independent power producers, large industrial customers and consumer advocates around the country began lobbying for competition in the electric industry.

In Decision No. 59943 (December 26, 1996), the Commission enacted the Electric Competition Rules. The Electric Competition Rules required TEP and other utilities to implement electric competition no later than January 1, 1999.

From 1996 to 1999, the Electric Competition Rules were revised no less than three (3) times. Key provisions of the Rules were stayed. Eight (8) utilities and the Arizona Residential Utility Consumer Office ("RUCO") were forced to sue the Commission over various aspects of the Electric Competition Rules.

By January 1, 1999, electric competition was bogged down in litigation. The Commission formally waived the implementation of the Electric Competition Rules in Decision No. 61311 (January 11, 1999).

It was against this background that RUCO, Arizonans for Electric Choice and Competition ("AECC") and Arizona Community Action Association ("ACAA") negotiated the 1999 Settlement Agreement with TEP.

The primary purpose of the 1999 Settlement Agreement was to deregulate TEP's generation service and transition to a competitive marketplace. Among other things, the agreement requires TEP to charge the MGC rate for generation service. Until December 31, 2008, an adjustment mechanism referred to as the "Floating CTC" will operate to keep generation service rates at 1998 cost-of-service levels. This was implemented to provide a transition period from non-competitive (regulated) rates to competitive (market) rates for generation service. While the Floating CTC terminates on December 31, 2008, the agreement set no expiration date for the MGC rate.

In 2005, some parties to the 1999 Settlement Agreement began to express concern that TEP would be entitled to charge market-based rates for generation service after 2008. I believe the reason for their concern is that the retail electric competition market did not develop the way that they had hoped, i.e. market prices increased. So they began to argue that TEP is supposed to abandon the MGC rate in 2009 and revert back to charging a cost-of-service rate for generation service.

TEP filed a series of pleadings with the Commission seeking to clarify the status of the 1999 Settlement Agreement and to reaffirm the Company's right to begin charging market rates for generation service on January 1, 2009. Eventually, TEP filed a Motion to Amend Decision No. 62103. In Decision No. 68669 (April 20, 2006), the Commission ordered that a hearing was to be held on the motion.

On March 6, 2007, the hearing began in the 1999 Settlement Agreement Amendment Case. During the course of the hearing, I indicated that TEP had formulated a proposal for amending the 1999 Settlement Agreement and Decision No. 62103 that I called the "hybrid proposal." Under this proposal, I said TEP's rates would be established by cost-of-service principles, but certain generation assets would not be returned to TEP's rate base and dedicated to wholesale market transactions. In addition, the "hybrid proposal" would include a PPFAC and a greatly reduced regulatory asset.

At the hearing, we also offered to present a procedural framework that would (i) address the concerns expressed by Staff, AECC, RUCO, and the Department of Defense ("DOD") that the parties could not properly evaluate TEP's new "hybrid" or other alternative proposals for amending the 1999 Settlement Agreement and Decision No. 62103 without the information that would be provided in a general rate case filing; and (ii) reserve all parties' rights if a mutually acceptable amendment to the 1999 Settlement Agreement was not achieved through the process of analyzing TEP's various proposals through an informational rate case filing.

We also indicated that this rate case filing would be used to evaluate all our proposals for amending that 1999 Settlement Agreement and Decision No. 62103 as a means for furthering settlement discussions and negotiations.

After the hearing ended, we submitted a proposed recommended opinion and order laying out the process that we described at the March hearing. Other parties then commented on the proposed recommended opinion and order. The Administrative Law Judge issued a recommended opinion and order, the parties commented on it and, at an open meeting, the Commission, with slight modification, approved it in Decision No. 65698.

III. <u>THE THREE RATE SETTING METHODOLOGIES.</u>

Q. Mr. Pignatelli, please describe in more detail the Company's Market Methodology.

A. Under the Market Methodology, the Commission would determine TEP's transmission and distribution rates using cost-of-service principles. I describe those principles more fully below in my discussion of the Cost-of-Service Methodology. TEP's generation service rate would be unbundled and determined using the MGC formula set forth in Section 2.1(d) of the 1999 Settlement Agreement, as subsequently amended by the Commission in Decision No. 65751 (March 20, 2003). A copy of Schedule MGC-1, "Market Generation Credit ("MGC") Calculation" is attached to my testimony as Exhibit JSP-5.

The Market Methodology would not include a PPFAC but it would include a $14.2 million ICRA, to be included in rate base and amortized over a four (4) year period for TEP.

Finally, TEP's service area would remain fully open to direct access. TEP's unbundled rates would be the same as they would under the Cost-of-Service Methodology except that the MGC would be used for the generation rate.

Q. **Please describe the Cost-of-Service Methodology.**

A. The Cost-of-Service Methodology would determine transmission, distribution and generation rates using traditional cost-of-service principles. In particular, TEP is using a test year comprised of the twelve (12) months ending December 31, 2006.

TEP's rate base in this case (calculated on a 50-50 weighting of original cost depreciated and reconstruction cost new depreciated) is approximately $1.4 billion. We would not exclude any generation assets from rate base. Pursuant to Decision No. 56659 (October 24, 1989), Springerville Unit No. 1 is included at its market value of $25.67 per kW-month. TEP's recently-acquired Luna Energy Facility would be included in the PPFAC at its market value of $7.00 per kW-month for capacity plus the cost of fuel. Mr. David Hutchens discusses the Springerville Unit No. 1 and Luna Energy Facility valuations in greater detail in his Direct Testimony. I would note that the fair market value of TEP's properties included in rate base, as determined by Mr. Judah Rose and Mr. Kentton Grant, is substantially higher than the rate base value included in both the Cost-of-Service and Hybrid Methodologies.

Test year operating revenues are approximately $713 million, on a retail jurisdictional basis. TEP's requested return on equity is 10.75%, cost of debt is 6.39% and the revenue requirement is $871 million, exclusive of TCRA recovery.

The Cost-of-Service Methodology also includes recovery of: (i) the ICRA in the amount of $47 million, which is included in rate base and amortized over a four (4) year period; and (ii) the TRCA in the amount of $788 million, which will not be included in rate base but will be amortized over a ten (10) year period and recovered through a separate charge on customers' bills.

The Cost-of-Service Methodology would also incorporate a PPFAC to provide timely recovery of purchased power and fuel costs. Mr. Hutchens describes in detail the Company's proposed PPFAC.

Finally, the exclusivity of TEP's CC&N would be restored under the Cost-of-Service Methodology. It is only proper that if the Commission rejects the Market Methodology that TEP's exclusive CC&N be restored in full.

Q. Please describe the Hybrid Methodology in more detail.

A. Under the Hybrid Methodology TEP's rates would be established by cost-of-service principles, but some generating assets would be excluded from rate base. The excluded generation assets would be dedicated to wholesale market transactions. The Hybrid Methodology also would include both recovery of the ICRA and a PPFAC as discussed in the Cost-of-Service Methodology.

Q. Why has TEP chosen to exclude from rate base the Navajo and Four Corners generating units in the Hybrid Methodology?

A. TEP has chosen to exclude its interest in Navajo Units 1, 2 and 3 and Four Corners Units 4 and 5 because those units (i) are jointly owned with other utilities; and (ii) the Company is not the operating agent for any of those units. Thus, TEP does not have the same level of control over the operation and maintenance of the excluded generation assets as it does over those units that will be included in the Company's rate base under the Hybrid Methodology. TEP's share of the electricity generated at the Navajo and Four Corners units is approximately 278 MW, or roughly one-eighth ($1/8^{th}$) of TEP's total generation capacity of 2,194 MW.

Pursuant to the 1999 Settlement Agreement, none of TEP's generation assets would be included in a cost-of-service rate base, except for those assets providing must-run generation service. Under the Cost-of-Service Methodology, all owned generation assets would be included in a cost-of-service rate base except for the Luna Energy Facility which would be included in the PPFAC. The Hybrid Methodology offers a compromise that would include most generation assets in a cost-of-service rate base while excluding others.

Finally, TEP's CC&N would be partially restored under the Hybrid Methodology, and direct access would be provided to customers with a demand in excess of 3 MW. The demand of TEP's current customers with at least 3 MW of load is approximately the same as the capacity of the Navajo and Four Corners units that are being excluded. Rates would be unbundled in the same manner as they would be under the Cost-of-Service Methodology.

Q. Do you believe the Cost-of-Service Methodology or the Hybrid Methodology will require an amendment to Decision No. 62103?

A. Yes, I do.

IV. REGULATORY ASSETS.

Q. Mr. Pignatelli, please discuss TEP's inclusion of regulatory assets in its ratemaking approaches?

A. A regulatory asset is an accounting tool that is generally used to recognize costs incurred, or otherwise make a company whole as a result of requirements imposed by laws, orders, rules or statutes. A regulatory asset is commonly recovered through either a separate surcharge or as an addition to the Company's rate base. In this proceeding, TEP is requesting that regulatory assets (the ICRA, the TRCA, or both) be included in all three methodologies, as appropriate.

Q. Why has TEP requested that the ICRA be included in rates in the Cost-of-Service, Hybrid and Market Methodologies?

A. The ICRA represents costs incurred by TEP solely in connection with the implementation of electric competition as required by the Commission's Electric Competition Rules (A.A.C. R14-1601 et seq.). If the Commission adopts either the Cost-of-Service or Hybrid Methodologies, the costs incurred by TEP to transition to electric competition (approximately $47 million, related to software acquisition and modification as well as other actions such as coal contract buy-downs) will be unrecoverable without inclusion of the ICRA. It is only fair that the Commission allow TEP to recover those costs that were incurred in compliance with the Commission's rules.

Under the Market Methodology, the ICRA is limited to costs that were previously authorized for deferral by the Commission. These costs (approximately $14.2 million) are direct costs that TEP incurred for software acquisition and modification related to electric competition. TEP witness Ms. Karen Kissinger addresses these costs in greater detail in her Direct Testimony.

Q. Why is TEP proposing that the TCRA be recovered through a separate charge if the Cost-of-Service Methodology is adopted?

A. The TCRA represents economic harm that will have been suffered by TEP if the 1999 Settlement Agreement is not honored and generation service rates are based solely on cost-of-service principles. The TCRA will place TEP in the position it would have been but for the 1999 Settlement Agreement. The amount of the TCRA included in the Company's rate request under the Cost-of-Service Methodology is $788 million, which is based on the $111 million revenue deficiency proved in the 2004 Rate Review. Applying this revenue deficiency, the Company has determined that it will have foregone revenues in an amount that will reach $788 million by May 2008. The cumulative balance of the foregone revenues will grow to $921 million by December 2008. However, because TEP believes that the continuation of the collection of CTC revenues beyond May 2008 is a partial mitigation of the losses that TEP has suffered as a result of the 1999 Settlement Agreement not being honored in full, the Company is proposing the lower $788 million balance for the TCRA. TEP witness Mr. Kentton Grant discusses the TCRA in greater detail in his Direct Testimony.

V. <u>PURCHASED POWER AND FUEL ADJUSTOR CLAUSE.</u>

Q. Mr. Pignatelli, why is TEP requesting a PPFAC?

A. TEP does not currently employ a PPFAC. However, in light of the volatile fuel and purchased power costs experienced in recent years, TEP should have a PPFAC mechanism in place to provide for the timely recovery of fuel and purchased power costs incurred in serving its customers. A PPFAC would serve the best interests of TEP and its customers.

Q. Please provide an overview of how the PPFAC charge will be determined.

A. TEP witness Mr. David Hutchens discusses the mechanics and operation of the PPFAC in greater detail in his Direct Testimony. On a more general basis, I would point out that there are two primary components of TEP's PPFAC charge:

(i) **__Forward Component__**: This component would be based on the forecasted fuel and purchased power costs for the following year. For example, forecasts for fuel and purchased power in 2010 would be used to establish the PPFAC Forward Component for 2010. Forward prices also would be used to establish the PPFAC Forward Component annually.

(ii) **__True-Up Component__**: This component would compare actual fuel and purchase power costs with the amount TEP collected through base rates as well as the PPFAC rate for the prior year. If actual costs were above what was collected, the True-Up Component would become an additional amount to be collected from customers in the subsequent year. If actual costs were below what was collected, the True-Up Component would reflect a credit towards the PPFAC rate for the following year. For example, the difference between the forecasted 2009 fuel and purchased power costs and the costs actually incurred during that year would be incorporated into the 2010 PPFAC rate via the True-Up Component.

Q. Mr. Pignatelli, why is the implementation of a PPFAC in the public interest?

A. TEP relies on significant quantities of natural gas and purchased power to meet its retail load. Although TEP has served the majority of its load with company-owned generating resources, it relies on natural gas and purchased power to meet a growing percentage of its customer demand. This gas and power is purchased at market prices, so TEP should be allowed to recover these costs.

The PPFAC that TEP is proposing in this case will protect the Company and its customers by providing for the recovery or return of the difference between the actual cost of natural gas and purchased power versus the costs established in base rates.

In fact, TEP's proposed PPFAC is a forward-looking mechanism similar to the Power Supply Adjustor that Staff proposed in the recent rate case involving Arizona Public Service Company ("APS") (Docket No. E-01345A-05-0816). In the 1999 Settlement Agreement Amendment Case, I had proposed an energy cost adjustment clause (the "ECAC") that was designed to keep operating cost risk with the Company. But, there was so much skepticism and opposition to the concept of the ECAC, that we have not pursued that type of a mechanism in this filing. If the Commission would prefer to implement an ECAC rather than a PPFAC, TEP will present evidence in support of an ECAC during this proceeding.

VI. CERTIFICATE OF CONVENIENCE AND NECESSITY.

Q. Mr. Pignatelli, why is TEP requesting to have the exclusivity of its CC&N restored?

A. As I indicated earlier in my testimony, if the Commission adopts the Cost-of-Service Methodology, then it will have abandoned retail electric competition for TEP's customers. In that case, TEP should have the right to exclusively provide electric service within its certificated area. To ensure that TEP has the exclusive right to provide electric service, the Commission should order that its exclusive CC&N is restored. Additionally under the Hybrid Methodology, where a majority of TEP's generation would be returned to cost-of-service ratemaking, it is also appropriate to partially restore the exclusivity of TEP's CC&N.

VII. DEMAND-SIDE MANAGEMENT ("DSM") AND RENEWABLE ENERGY ACTION PLAN ("REAP") COST RECOVERY MECHANISMS.

Q. Mr. Pignatelli, please explain what the Company is requesting regarding DSM and REAP cost recovery mechanisms.

A. In Decision No. 69568, the Commission ordered that "Tucson Electric Power Company shall file a detailed DSM Portfolio based upon Tucson Electric Power Company's existing and proposed DSM programs and a Renewable Energy Action Plan with the Commission by July 2, 2007. The DSM Portfolio and REAP, together with information regarding cost recovery thereof, shall be filed in separate dockets."

At the time that Decision No. 69568 was issued, the Renewable Energy Standard Tariff ("REST") rules had not been certified by the Arizona Attorney General. That has now occurred. Consequently, the REST rules will become effective in short order. The REST rules provide a deadline and procedure by which TEP will file a compliance plan with the Commission. The REST rules also contemplate that cost recovery mechanisms will be approved in the compliance plan proceeding. Accordingly, TEP will file a statement of intent to comply with the procedures and provisions of the REST rules in the separate proceeding contemplated in Decision No. 69658. In this case, we are simply recommending that the Commission implement an appropriate cost recovery mechanism for the REST programs in connection with and as a part of its order approving the TEP REST compliance plan in that separate docket.

We are also filing DSM Portfolio information in a separate docket as ordered by the Commission. However, we are requesting that the appropriate DSM cost recovery mechanism be approved by the Commission in this rate case so that the Company may recover its costs associated with the DSM Portfolio in a timely manner. We also are requesting that the DSM cost recovery mechanism be in place prior to the implementation of any DSM programs. The details of TEP's proposed DSM cost recovery mechanism are addressed in the Direct Testimony of TEP witness Mr. Thomas Hansen.

VIII. RATE DESIGN (TIME-OF-USE AND LIFELINE RATE BLOCK).

Q. Mr. Pignatelli, is TEP proposing any significant rate design changes in this case?

A. Yes, we are. Our overall proposal for rate design in this case is presented in the Direct Testimony of TEP witness Mr. Bentley Erdwurm. However, there are two aspects of our rate design that I want to highlight. Those are our proposed Time-of-Use ("TOU") rates and Lifeline Rate Block.

TEP is proposing to control peak demand through TOU rates under each of the methodologies presented in this case. TOU rates should help defer new generation and provide customers the opportunity to achieve savings by managing their electric service usage patterns. Accordingly, TEP is proposing that all new customers be placed on TOU rates and that any existing customers who change meters also be placed on a TOU rate. Additionally, all commercial and industrial customers - new and existing - with loads of 200 kW or greater will be placed on a TOU rate.

TEP is also proposing a progressive Lifeline Rate Block that will aid not only those in need of financial assistance, but all customers regarding their basic energy needs.

TEP's overall rate design objectives are the same under the three methodologies that TEP is presenting in this case. The proposed rate design is responsive to customers' concerns, and promotes the long term financial integrity of TEP and the economic vitality of southern Arizona. Major stakeholders' interests coincide regarding peak load control, requesting that the DSM cost recovery mechanism be in place prior to the implementation of any DSM programs. The details of TEP's proposed DSM cost recovery mechanism are addressed in the Direct Testimony of TEP witness Mr. Thomas Hansen.

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TEP's overall rate design objectives are the same under the three methodologies that TEP is presenting in this case. The proposed rate design is responsive to customers' concerns, and promotes the long term financial integrity of TEP and the economic vitality of southern Arizona. Major stakeholders' interests coincide regarding peak load control, conservation during high cost on-peak periods, and providing basic energy needs at affordable prices. TEP proposes to ambitiously expand TOU programs and to introduce Lifeline rate structures that are designed to make a difference.

TOU rates reinforce the conservation incentive by establishing on-peak period energy prices at higher levels. On-peak consumption may be avoided or shifted to less critical shoulder-peak or off-peak periods where prices are closer to or even lower than non-time-differentiated levels. If sufficient customers shift load away from the on-peak period, additional capacity may be avoided or deferred and cost savings may result.

Lifeline Rates offer a monthly block of "basic-needs" energy at a reduced price per kWh. Under the Lifeline structure, the price per unit increases as consumption increases, and conservation is promoted.

Q. Does TEP plan to increase its emphasis on Time-of-Use programs?

A. Yes. TOU is a valuable tool and should be utilized to help control peak load growth. We live in an area with rapid growth. Moreover, extreme weather conditions in the summer result in high peak demand relative to average demand. TEP wants to significantly slow the growth of peak demand, because this will slow the need to expand generation, transmission and distribution facilities. TEP has listened to the Commissions' comments about TOU programs, particularly those focusing on "super-peak" rates. Under a super-peak rate, the on-peak period is narrowed to the most critical hours. TEP notes that it introduced "super-peak" rates approximately a decade ago, after studying the shortcomings of Residential TOU Rate 21, which was classified as an "experimental rate" when implemented in the early 1990's. TEP's new TOU rates are super-peak rates. We believe that meaningful demand reductions are most likely to occur when the focus is on a small increment of time (e.g., 4 consecutive peaks hours). Customers can more easily adjust their schedules around a 4-hour super-peak than around a 12-hour "traditional" peak period. TEP intends to educate consumers about the new TOU proposals, including ways they can significantly reduce bills with minimal inconvenience.

Q. Mr. Pignatelli, why is the Company proposing that TOU rates be mandatory for new customers?

A. All new customers joining the system should pay a price for service reflecting the costs they impose on the system. The system now faces constraints, and "price-signals" are a proven way to bring about load reductions in the on-peak period and load shifts to off-peak periods. I would like to see existing customers begin shifting to TOU; however, there are practical considerations in resetting tens of thousands of meters on short notice.

I am not supportive of keeping non-TOU rates as an option for new customers. I believe that to do so would only prolong the problem the Company experiences with excessive load in the critical on-peak period. Rates for non-TOU customers should reflect the reality that these customers' costs may be higher. While TEP could structure such rates, any modification made in the rate-setting process could destroy any effective price signals in a non-TOU rate. Without effective price signals that customers understand and pay attention to, fixing old subsidies and inequities is unnecessarily prolonged. I do not believe that it is good public policy to continue to allow some of our highest cost-to-serve customers to pass on their costs to other system customers.

Q. Mr. Pignatelli, why is TEP proposing a Lifeline Rate Block when the Company has other programs for low-income customers?

A. The Lifeline Rate Block is not just aimed at low-income customers. The Lifeline Rate offers all customers, regardless of income, a "basic needs" block of electricity at a reduced price. Certainly, lower-income customers who control usage may benefit significantly, but so can any other customer. Under the Lifeline Rate Block, usage in the "high-use" third block is priced at a higher unit price to make up for the lower basic-needs first block, and customers respond by using less energy. This offers increased chances that capacity may be deferred along with future rate increases if load reductions come during on-peak periods.

Q. Will there be any benefit to a customer who cannot limit consumption to the Lifeline Rate Block?

A. Yes, in some cases. TEP's proposed residential rates include a Lifeline block of 500 kWh. If a customer uses 750 kWh in a month, the customer still receives the first 500 block at a reduced price. In this case, on a "weighted average" basis, two-thirds of his month usage (i.e., 500 out of 750 kWh) is still at the reduced rate. Customers who can "hold the line" on consumption are rewarded with a lower average price for electricity.

Q. Can a Lifeline Rate Block and a TOU structure be incorporated into a single rate?

A. Yes. In fact, that is exactly what TEP is proposing in the Residential Pricing Plan R-70N and General Service Pricing Plan GS-76N. While the structure is a little more complex than the current design, customers will quickly realize that the best way to keep the average price of electricity down is to keep usage low and shift to the off-peak period when the price is lower. TOU and Lifeline are used together to maximize incentives to "do the right thing" and keep on-peak consumption under control.

IX. TEP'S WITNESSES.

Q. Mr. Pignatelli, in addition to you, who are the witnesses who are filing Direct Testimony for TEP in this case?

A. TEP is presenting the Direct Testimony of officers, managers and directors who have responsibility for the subject matter about which they will testify. In addition, TEP is presenting expert testimony from outside consultants regarding depreciation rates and methodology, cost of capital, fair market value and the state of the wholesale electric market. The following individuals are presenting testimony in this proceeding:

A. Company Employee Witnesses.

Mr. Michael J. DeConcini. Mr. DeConcini is the Senior Vice President of UniSource Energy and TEP. Mr. DeConcini will discuss TEP's: (i) operating areas, (ii) maintenance practices related to operations, (iii) customer service, (iv) continued growth, and its impact on the Company, (v) environmental compliance, (vi) capital spending, (vii) Springerville Unit 3 addition, and (viii) proposed changes to its Rules and Regulations.

Mr. David G. Hutchens. Mr. Hutchens is the Vice President of Wholesale Energy at TEP. Mr. Hutchens will discuss the following: (i) Pro Forma Fuel Adjustments in TEP's Cost-of-Service Methodology, (ii) fuel-related regulatory assets in TEP's Cost-of-Service Methodology, (iii) TEP's proposed PPFAC, (iv) TEP's Hybrid Methodology and related adjustments, and (v) TEP's Market Methodology.

Mr. Kentton C. Grant. Mr. Grant is the Vice President of Finance and Rates for TEP. Mr. Grant will testify about: (i) the need for a regulatory recovery asset if the Company is returned to full cost-of-service ratemaking, (ii) factors relevant to a determination of fair value rate base, (iii) the fair market value of TEP's transmission and distribution assets, and (iv) TEP's proposed treatment of true-up revenue.

Mr. Kevin P. Larson. Mr. Larson is the Senior Vice President, Chief Financial Officer and Treasurer of UniSource Energy and TEP. He will testify about TEP's: (i) financial condition; (ii) capital structure; (iii) cost of debt; and (iv) weighted average cost of capital and proposed rate of return on rate base.

Mr. Larson also will sponsor the following schedules:

A-3	Summary of Capital Structure
A-4	Construction Expenditures and Gross Plant in Service
D-1 though D-4	Cost of Capital
F-1 though F-4	Financial Projections

Ms. Karen G. Kissinger. Ms. Kissinger is the Vice President, Controller and Chief Compliance Officer for UniSource Energy and TEP. She will testify concerning the Company's financial statements and rate base. She will sponsor the following schedules:

B-1 through B-5	Rate Base
C-3	Computation of Gross Revenue Conversion Factor
E-1 through E-9	Financial Statements and Statistical Data

Mr. Thomas J. Hansen. Mr. Hansen is the Vice President of Environmental Services, Conservation and Renewable Energy at TEP. Mr. Hansen will present the Company's proposals for a DSM cost recovery mechanism.

Mr. Dallas J. Dukes. Mr. Dukes is the Director of Revenue Requirements for TEP and its affiliates. He will testify concerning the TEP income statement, and adjustments to the income statement for regulatory purposes, including various adjustments to expenses. He will also sponsor the following schedules:

A-1 Computation of Increase in Gross Revenue Requirements

A-2 Summary Results of Operations

A-5 Summary Changes in Financial Position

C-1 Adjusted Test Year Income Statement

C-2 Income Statement Pro Forma Adjustments

Ms. Dawn Sabers. Ms. Sabers is the General Manager, Shared Services at TEP. She will testify regarding compensation and pension-related issues.

Mr. D. Bentley Erdwurm. Mr. Erdwurm is the Lead Customer Pricing Analyst for TEP and its affiliates. Mr. Erdwurm will testify about: (i) weather normalization; (ii) year-end customer annualization; (iii) cost-of-service; and (iv) rate design and other pricing plan changes. Mr. Erdwurm will sponsor the proposed tariffs and the following schedules:

G-1 through G-7 Cost of Service

H-1 through H-5 Effect of Proposed Rate Schedules

B. Outside Expert Witnesses.

Dr. Kimbugwe A. Kateregga. Dr. Kateregga will testify about depreciation rates and methodology.

Mr. Judah Rose. Mr. Rose will testify regarding the fair market value of TEP's owned generating assets, and provide additional testimony on the state of the wholesale power market in the Southwest.

__**Dr. Samuel C. Hadaway.**__ Dr. Hadaway will testify concerning the cost of equity capital for TEP and the reasonableness of the Company's requested capital structure.

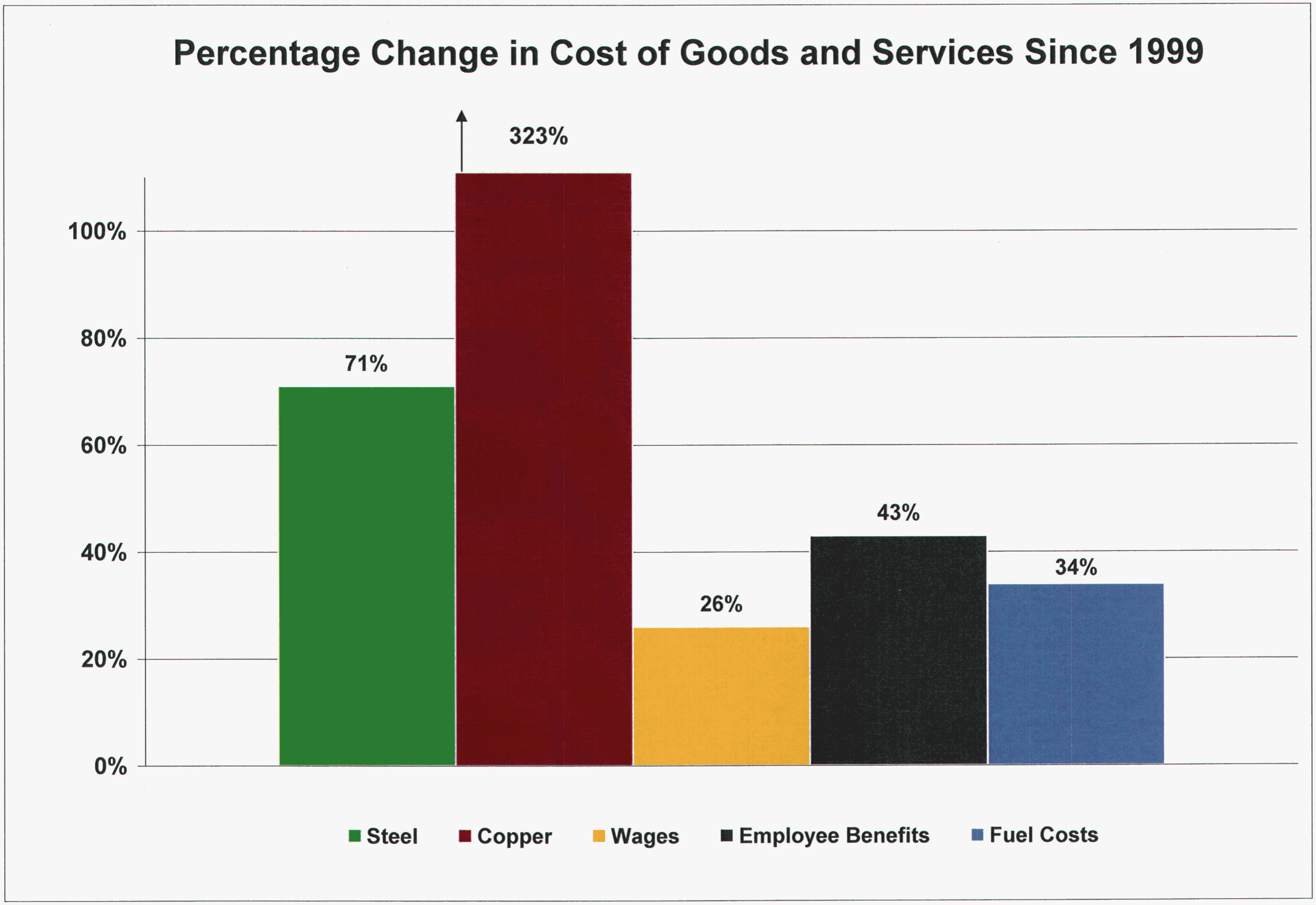
Q. Mr. Pignatelli, does this conclude your Direct Testimony?

A. Yes, it does.

EXHIBIT

JSP-1

Exhibit JSP-1



EXHIBIT

JSP-2

EXHIBIT

JSP-3

TEP Rate Case Scenarios
June 2007

	Full COS	Hybrid	Full Market
Assets Subject to ACC Jursidiction:	Distribution & Generation	Distribution & Some Generation	Distribution & Local Generation
Fuel & PP Recovery:	PPFAC	PPFAC	MGC
<u>Recovery of Non-Fuel Generation Costs</u>			
Rate Base Treatment	All Generation Except Below	Local Generation, San Juan & SPVL 2	Local Generation
Market-Based Demand Charge	Luna & SPVL 1	Luna & SPVL 1	None
Designated as Wholesale Generation Assets	None	Navajo & 4 Corners	All Non-Local Gen
<u>Regulatory Asset Recovery</u>			
Termination Costs Regulatory Asset (1)	$788 mil.	none	none
Other Regulatory Assets (2)	$47 mil.	$47 mil.	$14.2 mil.

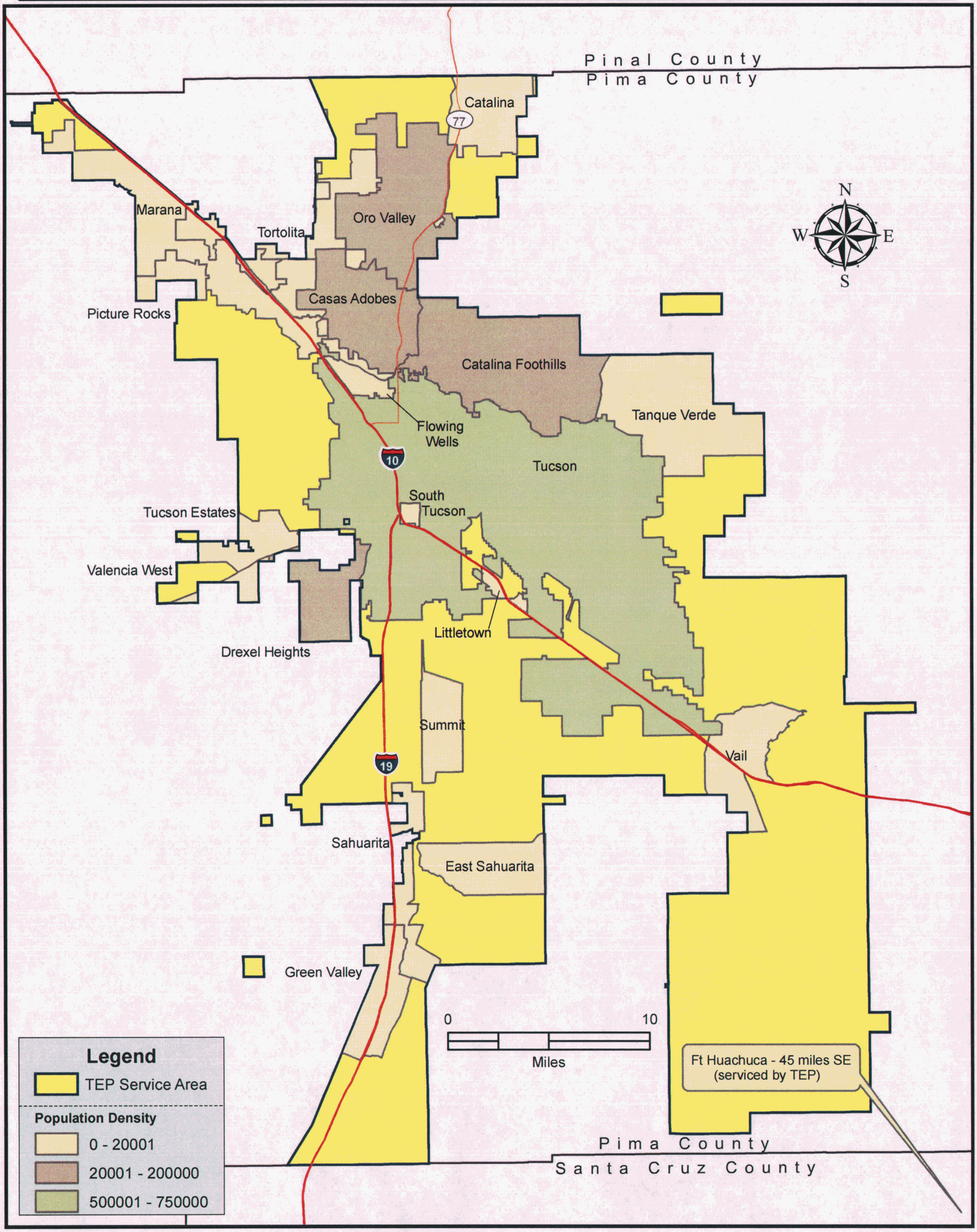
(1) Represents compensation for rate freeze based on revenue deficiency identified in 2004 rate review. Amortized over ten years using mortgage style amortization through separate rate.

(2) Represents coal contract termination/amendment fees, financing write-offs and $14.2 million of direct access costs. Amortized over four years using straight-line amortization.

EXHIBIT

JSP-4

Tucson Electric Power Service Area



EXHIBIT

JSP-5

Schedule MGC-1
Tucson Electric Power Company
Market Generation Credit (MGC) Calculation

A UniSource Energy Company

Introduction

There are two purposes of the Market Generation Credit (MGC). The first purpose is to establish a price to which TEP's energy customers can compare to the prices of competitors. The second purpose is to enable the calculation of the variable or "floating" component of TEP's stranded cost recovery. Shown below are the terms of the MGC methodology per TEP's Settlement Agreement, Section 2.1(d), as amended March 20, 2003:

> The monthly MGC amount shall be calculated in advance and stated as both an on-peak value and an off-peak value. The monthly on-peak MGC component shall be equal to the Market Price multiplied by one plus the appropriate line loss (including unaccounted for energy ("UFE")) amount. The Market Price shall be equal to the Platts Long-Term Forward Assessment for the Palo Verde Forward price, except when adjusted for the variable cost of TEP's must-run generation. The Market Price shall be determined thirty (30) days prior to each calendar month using the average of the most recent three (3) business days of Platts Long-Term Forward Assessment for Palo Verde settlement prices. The off-peak MGC component shall be determined in the same manner as the on-peak component, except that the Platts Long-Term Forward Assessment for the Palo Verde Forward price will be adjusted by the ratio of off-peak to on-peak prices from the Dow Jones Palo Verde Index of the same month from the preceding year. The MGC shall be equal to the hours-weighted average of the on-peak and off-peak pricing components and shall reflect the cost of serving a one hundred percent (100%) load factor customer.

To reflect the cost of serving a 100% load factor customer, the actual MGC used for billing calculations will be a loss adjusted average price that is weighted by the ratio of on-peak and off-peak hours. This process is illustrated in equations 4 and 5 below and will be posted to TEP's website http://partners.tucsonelectric.com thirty (30) days prior to each calendar month. This composite price will be credited to all energy consumption, regardless of the time period in which it is consumed.

Calculations

Five steps are outlined below for the calculation of the MGC. None of the steps are excludable for any customer type. Acronyms are defined in the Glossary at the end of this document.

1. Calculating the on-peak MGC

Thirty (30) days prior to each calendar estimation month, the Platts Long-Term Forward Assessment for Palo Verde Forward prices for the three (3) most recent business days are used. The simple average (or arithmetic mean) is calculated for these three (3) days for the estimation month.

$$MGC_{ON,i} = \frac{\sum (PLATTS)_i}{3} \qquad \text{(Equation 1)}$$

The calculation is illustrated in the table below.

Forward Prices per MWh	Apr-2002
3/1/2002	$25.50
2/28/2002	$25.50
2/27/2002	$24.75
Average	$25.25

2. Calculating the off-peak MGC

The off-peak MGC is determined by multiplying the on-peak MGC value by the off-peak price weighting factor (WEIGHT). The WEIGHT is equal to the simple average of all off-peak prices from the Dow Jones Palo Verde Index in the same month of the previous year, divided by the simple average of all on-peak prices from the Dow Jones Palo Verde Index in the same month of the previous year. Off-peak, on-peak and holiday hours are defined by NERC in the estimation month.

$$\mathrm{MGC}_{\mathrm{OFF},i} = \mathrm{MGC}_{\mathrm{ON},i} * \mathrm{WEIGHT}_i \qquad \text{(Equation 2)}$$

where

$$WEIGHT_i = \frac{DJPVI_{OFF,i}}{DJPVI_{ON,i}} \qquad \text{(Equation 3)}$$

3. Weighting the MGC for hours in the month

The on-peak and off-peak MGCs are combined to form an average MGC by computing a weighted average of the two time periods. This is done by multiplying the on-peak MGC by the percentage of on-peak hours in the same month of the previous year and then adding the product of the off-peak MGC and the percentage of off-peak hours in the same month of the previous year. Off-peak, on-peak and holiday hours are defined by NERC in the estimation month.

$$MGC_{WEIGHT,i} = MGC_{ON,i} * \left(\frac{ONHOURS}{ONHOURS + OFFHOURS} \right) + MGC_{OFF,i} * \left(\frac{OFFHOURS}{ONHOURS + OFFHOURS} \right)$$

(Equation 4)

4. Loss-adjusting the MGC

The average MGC must be adjusted for line losses. The appropriate line loss adjustment factor (LLAF) for a large industrial customer is 1.0515. For all other customers, the appropriate factor is 1.0919.

$$MGC_{LOSS,i} = MGC_{WEIGHT,i} * LLAF$$ (Equation 5)

5. Adjusting the MGC for variable must-run

The MGC will be adjusted for variable must-run as defined in TEP's Stranded Cost Settlement Agreement and AISA protocols. Fifteen (15) days prior to each month, TEP forecasts a ratio of its variable must-run generation to retail system demand for the following month. The MGC is determined by adding the product of MGC_{LOSS} and one minus the ratio of variable must-run generation to total retail system demand to the product of $15/MWh and the variable must-run ratio.

$$MGC_i = \left[MGC_{LOSS,i} * (1 - VMR_i)\right] + (\$15 * VMR_i)$$ (Equation 6)

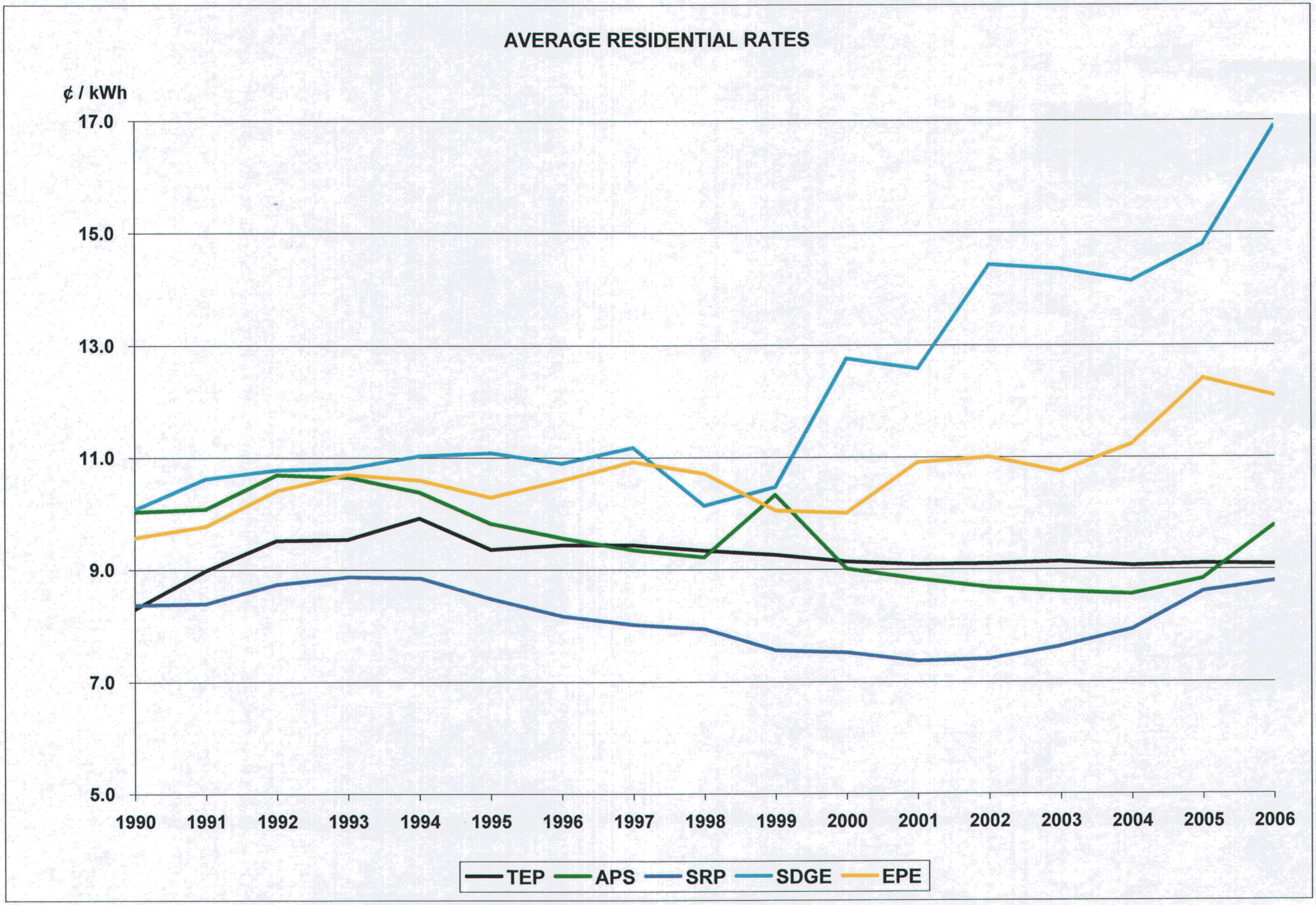
This calculation produces the final value for the Market Generation Credit.

Schedule MGC-1
Tucson Electric Power Company
Market Generation Credit (MGC) Calculation

GLOSSARY

$DJPVI_{OFF}$	Simple average of off-peak prices on the Dow Jones Palo Verde Index.
$DJPVI_{ON}$	Simple average of on-peak prices on the Dow Jones Palo Verde Index.
Dow Jones Palo Verde Index	Daily calculation of actual firm on-peak and firm off-peak weighted average prices for electricity traded at Palo Verde, Arizona switchyard.
AISA	Arizona Independent Scheduling Administrator, a temporary entity, independent of transmission-owning organizations, intended to facilitate nondiscriminatory retail direct access using the transmission system in Arizona. Required by the Arizona Corporation Commission Retail Electric Competition Rules.
LLAF	Line-loss adjustment factor.
MGC	Market Generation Credit.
MGC_{OFF}	MGC_{ON} weighted by the ratio of off-peak to on-peak prices on the Dow Jones Palo Verde Index.
MGC_{ON}	Average of the Platts prices on days appropriate for the calculation of the MGC.
MGC_{LOSS}	MGC_{WEIGHT} adjusted for line losses (including unaccounted for energy) on TEP's generation and energy delivery systems.
MGC_{WEIGHT}	A weighted average of MGC_{ON} and MGC_{OFF} by ONHOURS and OFFHOURS.
Must-run Generation	The cost associated with the running of local generating units needed to maintain distribution system reliability and to meet load requirements in times of congestion on certain portions of the interconnected grid.
NERC	North American Electric Reliability Council. A voluntary not-for-profit organization established to promote bulk electric system reliability and security. Membership includes: investor-owned utilities; federal power agencies; rural electric cooperatives; state, municipal and provincial utilities; independent power producers; power marketers; and end-use customers.

OFFHOURS	Number of total monthly off-peak hours as defined by NERC. Off-peak hours are hour ending 0100 – hour ending 0600 and hour ending 2300 – hour ending 2400, Monday through Saturday, Pacific Prevailing Time (PPT). All Sunday hours are considered off-peak. PPT is defined as the current clock time in the Pacific time zone.
ONHOURS	Number of total monthly on-peak hours as defined by NERC. On-peak hours are hour ending 0700 – hour ending 2200 Monday through Saturday, Pacific Prevailing Time (PPT). PPT is defined as the current clock time in the Pacific time zone.
PLATTS	A McGraw-Hill publication that provides an independent daily evaluation of on-peak Long Term Forward Assessment of market prices of electricity at the Palo Verde, Arizona switchyard. The forward product is "6 x 16," power is for 16 hours a day for six days a week (Monday through Saturday) for the delivery period, excluding NERC holidays.
Stranded Costs	The difference between revenues under competition and the costs of providing service, including the inherited fixed costs from the previous regulated market.
TEP	Tucson Electric Power Company, a subsidiary of UniSource Energy Corp.
TEP Settlement Agreement	An agreement between TEP, the Arizona Residential Utility Consumer Office, members of the Arizonans for Electric Choice and Competition, and Arizona Community Action Association regarding TEP's implementation of retail electric competition, implementation of unbundled tariffs, and recovery of stranded costs.
VMR	Ratio of variable must-run generation (MW) to total retail system demand (MW) in TEP's service territory.
WEIGHT	Ratio of off-peak to on-peak prices on the Dow Jones Palo Verde Index.


AVERAGE RESIDENTIAL RATES
¢ / kWh
17.0
15.0
13.0
11.0
9.0
7.0
5.0
1990
1991
1992
1993
1994
1995
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APS
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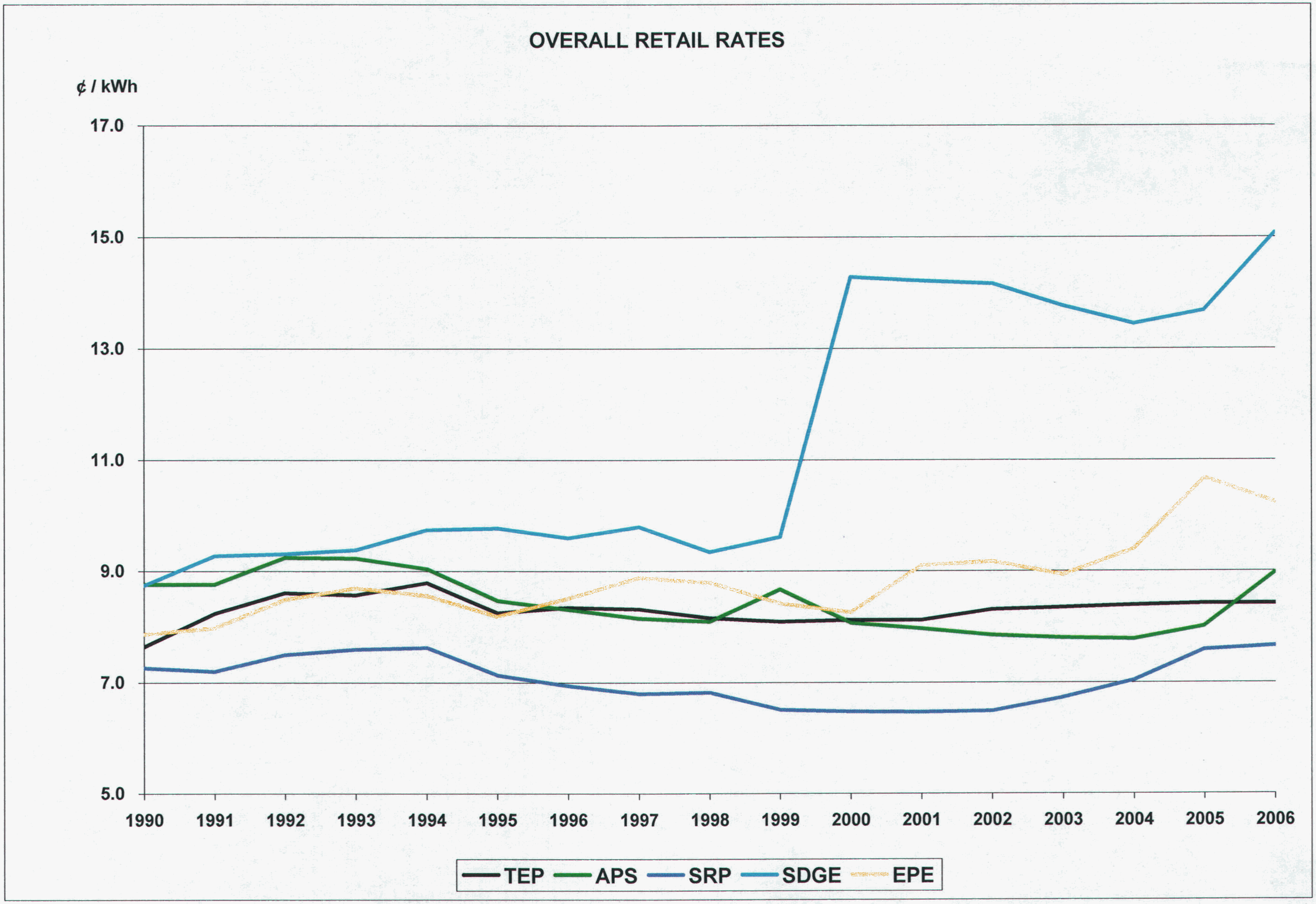
OVERALL RETAIL RATES
¢ / kWh
17.0
15.0
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1990
1991
1992
1993
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2006
TEP
APS
SRP
SDGE
EPE

Testimony of Michael J. DeConcini

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON- CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103.)	DOCKET NO. E-01933A-05-0650
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.)	DOCKET NO. E-01933A-07-____

Direct Testimony of

Michael J. DeConcini

on Behalf of

Tucson Electric Power Company

July 2, 2007

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Michael J. DeConcini. My business address is One South Church Avenue, Tucson, Arizona, 85701.

Q. What is your employment position?

A. I am employed by UniSource Energy Corporation ("UniSource") and Tucson Electric Power Company ("TEP" or the "Company") as Senior Vice President and Chief Operating Officer, Transmission and Distribution.

Q. Please describe your background, education and experience.

A. I have been employed by TEP since 1988, serving in various management capacities since 1994. Positions I have held at TEP include Manager, Wholesale Marketing; Manager, Business and Product Development; Vice President of Strategic Planning; and most recently as Senior Vice President and Chief Operating Officer, Energy Supply. I hold a Masters in Business Administration from Arizona State University, and a Bachelor of Science in Finance from Moorhead State University.

Q. Are you filing Direct Testimony on behalf of TEP?

A. Yes.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to describe TEP's (i) operating areas, (ii) maintenance practices related to operations, (iii) customer service, (iv) continued growth and its impact on the Company, (v) environmental compliance, (vi) capital and operations and maintenance spending, (vii) the Springerville Unit 3 addition, (viii) pro forma adjustments, and (ix) proposed rules and regulations.

Q. Please summarize your testimony.

A. In my testimony, I describe the business operations of TEP and our continuing commitment to provide safe and reliable service to our customers. Our operations include distribution of electricity within our service territory, transmission of power into our service territory, and the generation of that power by both remote and local facilities. I also describe TEP's dedication to customer service. Moreover, all parts of our operations are impacted with the customer and demand growth that we have experienced and the unique challenges upon us, as represented in future capital spending plans which include significant environmental spending. TEP continues to look for opportunities to leverage our assets, such as the build-out of additional units at Springerville Generating Station. My testimony concludes with proposed revisions of the Rules and Regulations designed to clarify existing provisions, add other provisions, and reorganize them to provide better alignment with current Commission regulations and UNS Electric, Inc.

II. <u>TEP'S OPERATIONS.</u>

Q. Mr. DeConcini, please describe TEP's customer delivery operations.

A. TEP serves approximately 392,000 customers in Pima County. The TEP service territory spans 1,155 square miles, with boundaries extending north to the Pinal County Line and south to the Santa Cruz County Line. TEP serves customers in the City of Tucson, the City of South Tucson, the Town of Oro Valley, the Town of Sahuarita, the Town of Marana, and unincorporated areas of Pima County. Additionally TEP serves the power requirements of Fort Huachuca, a military base, located in Cochise County. As of

December 31, 2006, TEP owned or participated in an overhead electrical transmission and distribution system consisting of:

- 512 circuit-miles of 500-kV lines;
- 1,098 circuit-miles of 345-kV lines;
- 365 circuit-miles of 138-kV lines;
- 437 circuit-miles of 46-kV lines; and
- 2,631 circuit-miles of lower voltage primary lines.,

The underground electric distribution system is comprised of 4,402 cable-miles. TEP owns approximately 60% of the poles on which the lower voltage lines are located. Electric substation capacity consisted of 101 substations with a total installed transformer capacity of approximately 6.7 million kilovolt amperes.

Q. Please describe TEP's generation assets.

A. As of December 31, 2006, TEP owned or leased 2,194 MW of net generating capability consisting of a total of twenty units, of which thirteen are steam type units, and seven are simple cycle internal combustion type units. The generating source, location, fuel type, size and ownership are set forth in the following table:

Generating Source	Unit No.	Location	Date In Service	Fuel Type	Net Capability MW	Operating Agent	TEP's Share	
							%	MW
Springerville Station(1)	1	Springerville, AZ	1985	Coal	380	TEP	100.0	380
Springerville Station	2	Springerville, AZ	1990	Coal	380	TEP	100.0	380
San Juan Station	1	Farmington, NM	1973	Coal	327	PNM	50.0	164
San Juan Station	2	Farmington, NM	1980	Coal	316	PNM	50.0	158
Navajo Station	1	Page, AZ	1974	Coal	750	SRP	7.5	56
Navajo Station	2	Page, AZ	1975	Coal	750	SRP	7.5	56
Navajo Station	3	Page, AZ	1976	Coal	750	SRP	7.5	56
Four Corners Station	4	Farmington, NM	1969	Coal	784	APS	7.0	55
Four Corners Station	5	Farmington, NM	1970	Coal	784	APS	7.0	55
Luna Energy Facility	1	Deming, NM	2006	Gas	570	PNM	33.0	190
Sundt Station	1	Tucson, AZ	1958	Gas/Oil	81	TEP	100.0	81
Sundt Station	2	Tucson, AZ	1960	Gas/Oil	81	TEP	100.0	81
Sundt Station	3	Tucson, AZ	1962	Gas/Oil	104	TEP	100.0	104
Sundt Station(1)	4	Tucson, AZ	1967	Coal/Gas	156	TEP	100.0	156
Internal Combustion Turbines		Tucson, AZ	1972	Gas/Oil	122	TEP	100.0	122
Internal Combustion Turbines		Tucson, AZ	2001	Gas	95	TEP	100.0	95
Solar Electric Generation		Springerville/ Tucson, AZ	2002-2005	Solar	5	TEP	100.0	5
Total TEP Capacity								2,194

(1) Leased assets.

Q. Mr. DeConcini, please comment on growth, both customer and consumption, that TEP has been experiencing.

A. TEP has experienced customer growth over the last five years of approximately 2.3%. Specifically, customer growth during the test year period (the calendar year 2006; the "Test Year") for the TEP service territory was 2% or 7,579 new customers. The residential class is made up of 358,000 customers (91%); the commercial class includes 34,000 customers (9%), and there are approximately 700 customers in the remaining classes (including industrial.)

While customer growth is increasing 2%, TEP is experiencing an annual growth rate in electrical consumption of approximately 4%. The discrepancy between the customer and consumption growth rates can be attributed to two factors: (1) existing customers are increasing consumption on a per capita basis, and (2) new customers on average have higher power requirements than those of our existing customer base.

Furthermore, specific areas within the TEP service territory have experienced much higher growth than the average. Much of the growth is occurring in areas with limited existing electrical infrastructure. In particular, we have seen the following average annual percentage kW demand growth in the areas listed below:

- Vail-- 14.7%;
- Oro Valley-- 8.2%;
- Green Valley Area-- 9.4%; and
- Marana/Northwest-- 7.0%.

Q. Do you expect similar growth in the future?

A. Yes, similar average growth is expected.

Q. Mr. DeConcini, can you compare the reliability of TEP's distribution assets to others in the industry?

A. TEP's distribution assets compare favorably on two common industry benchmarks: System Average Interruption Frequency Index ("SAIFI") and Customer Average Interruption Duration Index ("CAIDI"). The 2005 Edison Electric Institute ("EEI") Distribution Reliability Survey collected data from 67 utility companies who serve approximately 60 million electric utility customers. The survey data is formatted into 1st, 2nd, 3rd and 4th quartiles. The 2005 TEP SAIFI result was .95, earning TEP a 1st quartile spot compared to other participating companies; and the 2006 TEP SAIFI measure was 1.25, a 2nd quartile result. Another reliability index covered in the 2005 EEI Survey is CAIDI. CAIDI numbers for TEP of 83.5 in 2005 and 85.2 in 2006 would be grouped into the 1st quartile of the surveyed companies for both years. So, TEP's distribution assets are among the most reliable in the industry.

Q. How reliable are TEP's generation plants?

A. TEP measures coal-fired plant reliability using the industry measure of Equivalent Availability Factor ("EAF"). EAF is the ratio of the hours that a unit is available to provide power at its maximum continuous rating ("MCR") divided by the period hours. Therefore, EAF includes all unit scheduled and forced outage and all de-ratings.

TEP uses the NERC-GADS data for comparison of the reliability of our units to the industry. TEP has obtained an average annual EAF of 89% or above, which exceeds the industry average of 85% for the past five (5) years. So, TEP's generation plants are very reliable, based on industry data.

Q. Mr. DeConcini, what about measures of reliability regarding overall customer satisfaction?

A. Each year, nationally prominent research firm JD Power & Associates conducts a customer satisfaction study for electric utility companies in the United States. The overall customer satisfaction scores are based on six criteria: Power Quality & Reliability, Company Image, Price & Value, Communications, Billing & Payment and Customer Service.

According to its most recent study, which was published in July of 2006, TEP was ranked fifth in the nation among medium-size electric utility companies (between 160,000 and 400,000 residential customers) for overall customer satisfaction, and was the highest-rated investor-owned utility ("IOU") in that size category. TEP was also ranked fifth in the western region for utilities of any size, and was the number-one rated IOU in the West, beating out companies such as San Diego Gas & Electric, Arizona Public Service, Southern California Edison and Portland General Electric.

Customer satisfaction has been a principal focus of TEP for many years, and the Company has consistently fared well in the JD Power & Associates annual customer satisfaction study as a result. Over the past five years, TEP has scored well above the national and western region averages, and even achieved the top spot in the entire western region in the 2001 study.

Q. Do the favorable measures of reliability in transmission and distribution ("T&D") impact the safety performance of those working on T&D assets?

A. T&D has an excellent safety performance history. TEP has created and customized its own required annual Occupational Safety and Health Administration ("OSHA") training program to maximize its effectiveness. TEP also initiates annual visits from local inspectors. As a result, in 2004 and 2005, TEP was recognized by OSHA as an employer who "operates an exemplary safety and health management system" and is included in OSHA's Safety and Health Achievement Recognition Program ("SHARP"). It is expected that TEP will receive the same recognition for 2006. Additionally, TEP's goal for 2007 includes participating in OSHA's next and highest level, the Voluntary Protection Programs ("VPP"). If the Company is successful, it would be the only utility in the Southwest to achieve this rating.

One of the measures that TEP uses to compare its safety record to other utilities nationwide is the OSHA Incident Rate. This value is determined by taking the number of incidents and the number of hours worked and adjusting that number to reflect what the average would be for 100 employees working one year. In 2006, the national average for utilities in our class is 5.1. TEP's average for 2006 was 3.92, beating the national average for the third straight year.

To make sure TEP employees are involved in the safety programs, TEP has created an Outage and Incident Committee whose responsibilities are to record safety incidents, analyze such incidents for root cause, identify trends, and recommend changes that will help prevent future incidents. This group is made up of both classified (union) and management representatives. Additionally, in 2006 TEP implemented a Safety Observation Program where classified and management employees are teamed together to visit crews in the field to emphasize positive behavior, to identify areas that need improvement, and to listen to employees' safety concerns.

Q. What efforts does TEP undertake to maintain its safety record at its TEP's generation plants?

A. TEP has always been concerned about operational and public safety. The generation unit shares many of the same programs as mentioned in the T&D safety discussion.

Additionally, the generation unit has developed a core group of safety professionals who guide management teams in implementing occupational safety initiatives. The generation unit has developed specific accident prevention manuals, conducted pre-job briefing guides, has standardized safe work procedures, implemented joint labor/management safety committees, and created supervisor safety work teams. Plant managers actively participate in incident review as well as process/equipment improvement and regular safety inspections. Supervisors attend regular safety training which includes the prestigious National Safety Council's Supervisor Safety Training Course. The generation unit's safety professionals meet monthly to exchange information and ideas for improvement in all units.

Additionally, the generation unit's maintenance procedures include predictive, preventive and corrective maintenance activities managed by a computerized maintenance management system ("CMMS"). Corrective maintenance work orders are reviewed by management in the mornings to set priorities and identify safety related work priorities. The generation unit also uses the OSHA Incident Rate to compare to other utilities nationwide. For 2006, the generation unit experienced an Incident Rate which was above the national average; this was due to hearing threshold shifts being a significant contributor. For 2007, significant emphasis is being placed on reinforcement of the safety methods and policies to reduce the Incident Rate going forward.

III. TEP'S MAINTENANCE.

Q. How do you ensure reliability in TEP's T&D operating area?

A. Along with our favorable rating on overall reliability measures, TEP uses other measures to gauge reliability. For example, we prepare – on a monthly basis – an equipment outage report pertaining to the operation of substation equipment. This report looks at current month year-to-date failure rate(s) against the same time frame of the previous three years.

In this particular report, TEP defines an equipment failure as any substation equipment that fails to function as designed. Any equipment failure that results in non-scheduled customer service interruption, momentary or otherwise, is classified as an outage. All failure types are considered unscheduled maintenance. On a monthly basis, each equipment failure and outage is reviewed to ensure that follow up corrective maintenance is taking place or scheduled.

Q. What other measures does TEP take to ensure reliability in its T&D operating area?

A. In addition to the monthly equipment report, a transformer fleet assessment is updated and published quarterly. The assessment uses several factors to generate an index number used for ranking of transformer condition. Some of the factors include: oil condition, maintenance history, fault history, paper condition, bushings, lightning arrestors, age, maintenance bulletins, infrared scans, and loading history. All these factors are used for projecting equipment life cycles. The information obtained is helpful in building capital budgets for transformer replacements.

TEP also continues to invest in infrastructure to ensure reliability for our customers. For example, TEP operates a fleet of mobile transformers/substations. In late 2006, TEP added an additional mobile substation to its existing fleet, and an additional improvement was made to by modifying the oil cooling system to make it safer and easier to transport.

In order to respond to any 345 kV structure damage, TEP maintains an inventory of spare lattice and two emergency restoration structures. The use of the structures depends on the damage and/or location. If a structure is damaged, but the foundation is intact, the use of a spare structure may be appropriate. If there is damage to the structure and the foundations, TEP will use its emergency restoration structure. This structure is designed to be assembled and used without the need of a foundation. TEP can assemble this structure in 24 to 48 hours using prepared emergency hardware kits.

Q. What on-going maintenance programs are in place in T&D to ensure continued reliability?

A. The Company has several ongoing maintenance programs as described below:

<u>Substation Maintenance</u>

TEP plans to and executes substation maintenance using a computerized maintenance management system known as MP2. The maintenance philosophy for different equipment is determined by what is the most effective technique. Substation equipment that TEP maintains in this manner includes:

- **<u>Transformers</u>**: Substation transformers are the heart of a substation, and proper maintenance is critical to safe and reliable operation. A substation transformer's cost could easily exceed $1 million and the manufacturing lead time is approaching two years on certain transformers. In order to protect the investment and to provide safe and reliable service, TEP follows a well defined and disciplined scheduled maintenance program.
- **<u>Air & Vacuum Circuit Breaker Maintenance</u>**: TEP has switched some breaker maintenance from a time-based maintenance basis to a predictive-based maintenance philosophy. Rather than simply inspecting and dissembling breakers based on a set timeframe, TEP performs maintenance based on diagnostic tests. Additionally, certain breakers are on scheduled maintenance, which may also include overhauling certain breakers.
- **<u>Station Batteries:</u>** All substation equipment operates with station batteries, which are also the only source of energy in emergencies to operate protective devices.

For this reason, batteries are critical to reliable substation operation. The batteries are inspected and tested every two months. In addition, there is monitoring of some critical battery bank voltages on a real time basis and reviewing any daily alarms.

Transmission Line Maintenance

The transmission line maintenance department uses a database known as the Transmission Line Asset Management Program ("TLAMP") to manage inspections and maintenance on the 138 kV and 345 kV structures. TEP assigns a priority in TLAMP depending on the observation.

Transmission Line maintenance also includes an aggressive vegetation management plan. Growth cycles are set at five years and determined by U.S. Forest Service experts. In all cases, the vegetation is managed so that it stays within the five-year growth zone. The regular tree-trimming maintenance cycle is five years unless an inspection reveals faster than expected growth.

Maintenance is performed on transmission structures by inspecting towers on a time-based system which varies by the voltage class. A few examples are:

- **345 kV Tower Inspections**

  Towers are aerially inspected on a semiannual basis. Inspectors look for imminent dangers to the system, vegetation clearance, anchor condition, guy wire condition, or foreign objects caught in the lines and towers. Furthermore, towers are closely inspected from the ground for a variety of conditions on a five-year basis.
- **138 kV Structures**

  On an annual basis, a ground patrol of the 138 kV structures are performed. Inspectors look at the condition of insulators, guy wires, wood poles, cross arms, cross and knee braces, ground wire attachments, static wire, conductor and vegetation.

Q. What on-going maintenance programs are in place for generation to ensure continued reliability?

A. The maintenance programs for the generating units include ongoing maintenance performed during the year based on a preventative maintenance program, a predictive maintenance program and a corrective work request program. These programs and the resulting work orders are housed in the CMMS. Additionally, maintenance and improvements are performed during regularly scheduled maintenance outages. During these scheduled maintenance outages, the components that together make up the generating unit are inspected and repairs and/or improvements are made based on industry standards, good utility practice, findings of previous and current inspections, OEM recommendations, our predictive and preventative maintenance program, and our outage corrective work program.

IV. <u>CUSTOMER SERVICE.</u>

Q. Mr. DeConcini, you mentioned that TEP seeks to provide customers with safe and reliable service. What improvements have been made to customer service?

A. The Company has enhanced its call center operations since the General Rate Case Information filing in 2004. The number of Customer Service Representatives has increased from approximately 60 to approximately 75 today. Inbound trunk capacity has been increased from 120 lines to 230 lines. The primary driver of this expansion was consolidation of call center functions for TEP, UNS Gas, Inc. and UNS Electric, Inc. in Tucson. However, TEP customers have benefited from the increased capacity which allows the call center to handle more customers simultaneously. The expanded capacity is especially beneficial during outages.

Q. Are there additional improvements being made to assist the call center and the customer service functions?

A. Yes. The most significant has been the new customer information system, the Customer Care and Billing system ("CC&B"). Since August, 2004, UNS has been working towards the combining of all three utility companies' customer information system into one system rather than the three that are in current use. The advantages include:

- the elimination of the mainframe at TEP;
- the elimination of the third-party provider of customer billing at both UNS Gas, Inc. and UNS Electric, Inc.;
- the ability of the combined call center to streamline all processes into one system for all three utility companies;
- the ability to leverage off of one system for further future improvements such as an enhanced Interactive Voice Response ("IVR"); and
- the ability to utilize expanded inbound trunk capacity and resources.

Q. Please describe the Company's bill payment options.

A. TEP customers have a variety of bill payment options. Many customers use the traditional US Mail method of payment. Others elect to pay in person at drop boxes located in grocery stores throughout Tucson, or at America's Cash Express locations. Our Sure No Hassle Automatic Payment ("SNAP") option provides for a monthly payment from a customer's bank account. Customers also have the option to pay using credit or debit either through a TEP Customer Service Agent or the 24 hour automated teller. The electronic billing option has proven to be popular with customers since it was introduced in May of 2003. 19% of our residential customer base has migrated to electronic billing.

This compares to an industry average of electronic billing of approximately 4%. 34% of TEP's residential customers pay through electronic means.

Q. How does TEP measure its call center performance?

A. Universally, call centers use a variety of metrics to measure customer service levels. TEP is no exception. Examples of metrics used by TEP include average speed of answer, abandonment rate, handling time and agent productivity.

Q. Has TEP taken any other steps to improve customer programs or community programs?

A. Yes, TEP continuously looks for opportunities to improve its service delivery and TEP's commitment to customers goes far beyond providing safe and reliable electrical service. TEP is an active partner and corporate citizen in the communities it serves.

As an example of how TEP seeks ways to improve service delivery, TEP partnered with one of its affiliates to achieve significant improvements in line location services. This ultimately benefits our customers and the general public by reducing outage and safety incidents caused by inaccurately marked electric facilities. Furthermore, by reducing the overall response time by TEP to Arizona Blue Stake requests, efficiencies and cost savings are realized by TEP and Blue Stake requestors. In 2006, only three incidents were recorded due to line location service errors.

In another example, TEP has partnered with the Southern Arizona Homebuilders Association ("SAHBA") to establish builder focus groups that provide a means for gathering direct customer feedback and for communicating changes in TEP construction standards. In 2006, TEP met over 95% of its scheduling commitments to homebuilders and held six conduit installation training classes for contractors.

TEP also partners with the U.S. Forest Service during its controlled burn and other vegetation management projects. TEP's Raptor Protection Program was developed in partnership with the Arizona Game and Fish Department and the University of Arizona to reduce electrocution of raptors, with special emphasis on nest sites. In addition, the TEP Irvington campus is an Arizona Game and Fish site for 55 burrowing owl nests and associated habitat study.

Q. Please describe TEP's efforts to increase electric safety awareness.

A. TEP partners with many other Tucson area Public Service providers in conducting electrical safety training. In 2006, TEP employees taught the "Stay Away/Stay Alive-Electricity Awareness" classes to employees of local area public service providers, including the Tucson Fire Department, the Rural Metro Fire Department, the Golder Ranch Fire Department, the Tucson Police Department, and Comcast Communications. TEP has also provided safety classes to Davis Monthan Air Force Base personnel and participated in joint rescue classes with the Tucson Fire Department.

For many years, TEP has conducted electrical safety classes in Tucson area schools and the Company continues a multimedia public awareness campaign emphasizing electrical safety, especially during storm season. According to JD Power & Associates, TEP's safety campaign consistently ranks near the top nationally for customer impact.

Q. How has TEP taken advantage of the internet to improve customer and community service?

A. Customer service and community service are fundamental to the operation of TEP, and the Company's recently redesigned website emphasizes those two areas of focus. In terms of customer service, many routine transactions, in addition to viewing and paying a bill, can now be executed online, and TEP's customers have responded in ever-increasing numbers.

Since the new site launched in the third quarter of 2005, the number of "page views" jumped from approximately 500,000 per month to well over 2,000,000 per month, and the average number of "visits" per month has increased by more than 50 percent.

Q. Please describe TEP's service to the community.

A. TEP's focus on community service is well documented. The Company's roots in the community extend back to 1892, the year that "The Electric Light and Power Company" was formed by a group of Tucson investors. Over the years, TEP has demonstrated its commitment to customers and the community at large through a variety of programs and partnerships.

Working to improve the quality of life for everyone in the Tucson and White Mountains areas, TEP employees and their families and friends donate thousands of hours "off the clock" each year while volunteering for community organizations and projects – more than 32,000 hours in 2006 alone. By contrast, volunteer hours in 2001 totaled approximately 26,000. The Company supports volunteering by employees and their families by providing logistical and organizational support, as well as shareholder funding to the nonprofits to enable volunteer projects. In fact, senior management includes employee volunteerism among its annual corporate goals.

Q. Has TEP received recognition for its service to the community?

A. TEP is nationally renowned for its volunteer program, having won its second Points of Light Foundation "Award for Excellence in Workplace Volunteer Programs" in 2004. This is an unprecedented achievement. TEP also received the Points of Light Foundation "National Family Volunteer Award" in 2005. In addition, TEP's parent company, UniSource Energy Corporation ("UniSource Energy"), just last year was named the "National Corporate Advocate of the Year" by the Child Welfare League of America.

Shareholders of UniSource Energy fund contributions of cash and in-kind services to community organizations at levels in excess of $900,000 a year. As part of that effort, TEP's "Grants That Make a Difference" program provides technical training and grants to charitable organizations that assist at-risk youth and their families. Since the program's inception in 2001, the Company has awarded 61 grants for more than $451,000 to improve the safety and health of children up to 18 years of age.

V. GROWTH.

Q. How does TEP plan for generation and transmission growth over the long term?

A. To address the issue of future growth, TEP's Long-Term Integrated Resource Plan ("LTRP") identifies the "best" long-term expansion plan for generation and transmission additions to support our growing demand. The criteria for determining the "best" plan includes optimizing a number of conflicting objectives including:

- Continuing to provide reliable electric service to TEP's retail customers, and complying with all regional and national reliability standards;
- Providing reasonable cost of electricity to TEP's retail customers based on a consideration of both capital costs and operating costs; and
- Addressing the impacts of Demand-Side Management ("DSM"), the Environmental Portfolio and, now, the Renewable Energy Standard and Tariff ("REST") requirements as promulgated by the Arizona Corporation Commission ("Commission").

The LPRP considers the impact of alternatives in areas such as:

- Economic growth;
- Customer load growth;
- Natural gas prices;

- Wholesale electric market prices; and
- Air quality standard changes.

Q. Are the existing generation assets and transmission system assets able to accommodate the growth that the service territory has experienced, and the future growth of TEP's customer base?

A. Although existing generation assets provide the majority of TEP's base load requirements, TEP still has to purchase additional capacity from the market to take care of peak system shortages. These purchases include obtaining capacity on the available extra-high voltage ("EHV") transmission systems.

Based on the LTRP, TEP plans to invest in major EHV transmission projects to increase TEP's cumulative import capacity by approximately 600-800 MW during a 15-year period. These projects will ultimately interconnect the Palo Verde market hub with TEP's retail load center and will allow TEP to gain access to surplus generation assets in Arizona.

In addition to increasing its import capacity, TEP is pursuing the purchase of additional gas-fired simple-cycle and combined-cycle generation for intermediate and peaking needs.

Q. How will TEP continue to service the growth within the service territory as related to your distribution assets?

A. Up until the present, all of the increases in the previously mentioned high-growth areas have been accommodated through the construction of new distribution feeder circuits out of existing substations. However, we have now reached transformer and/or substation capacity limits at the existing stations in these areas. Going forward, additional load growth will require the construction of new substations. To accommodate this growth, TEP is proposing several new substations in these specific high growth areas:

- Cienega Substation in the Vail area (2009);
- Catalina Substation in the northern Oro Valley area (2009);
- Canoa Ranch Substation in the southern Green Valley area (2009); and
- Marana Substation in the northwest Marana area (2011).

In the near term, we are employing interim measures to alleviate problems in two of the above areas: (1) a mobile transformer was installed during the Spring of 2007 in the Vail area to reduce peak demand on overloaded Vail Substation and Los Reales Substation feeders, and (2) a new 25 MVA transformer to be installed at Lateral 7-1/2 Substation in Summer 2007 to accommodate the initial phases of new construction in several large master-planned subdivisions in northwest Marana.

Q. Please describe the configuration of TEP's transmission system.

A. TEP's primary transmission system in our service territory is a 138kV system. Based on the increased growth and subsequent demands on the system, TEP is continually evaluating the system's ability to support these increased loads. These evaluations reveal the potential for overloads and voltage issues to the system. As a result, there are operating procedures and controlled load shedding schemes to mitigate 138kV overloads in the short term to realistically schedule system reinforcement and expansion projects. Typical system reinforcement consists of reconductoring and the addition of new 138kV circuits.

Q. How does TEP address voltage constraints on its system?

A. Regarding the voltage issues, TEP has historically been voltage stability constrained because most power is imported into Tucson from remote generation stations. Many times, local generation is run to supply dynamic reactive power to keep the voltage from dropping. The recommendation of the LTRP calls for TEP to increase its import capability into Tucson; as import capability is increased, it is expected that the voltage issues will be further aggravated. To mitigate this problem, TEP is working to install a Static Var Compensator ("SVC") near the load center at a cost of approximately $18 million. The SVC is providing a dynamic source of reactive power required to control voltage under various system conditions. Our analysis indicates that the SVC may virtually eliminate voltage stability issues on the current 138kV system. Future major additions to the local 138kV system or new EHV transmission lines routed into Tucson will require additional evaluation of voltage stability.

Q. Are there other T&D assets TEP is planning due to growth?

A. Yes. In addition to the four substations previously mentioned, TEP presently has five other new distribution substations and one new transmission substation budgeted for construction within the next five (5) years.

Q. How long does it take to plan and construct new substations?

A. It now takes approximately three years to permit, engineer, procure, and construct a standard distribution substation. The extended development schedule is primarily due to land and permit related issues. Additionally, acquiring and installing substation transformers have increasingly become a long-term project, going from a 30-week lead-time in the late 1990's to almost two (2) years now.

Many challenges exist concerning the planning, siting, engineering, and construction of new distribution and transmission substations. The extended schedule to permit and construct substations makes it challenging for TEP to construct the infrastructure required to serve new large subdivisions. Unfortunately, the problems are compounded as much of the new construction is in the more rural parts of TEP's service territory. The Vail area is a good example of this recent trend.

Furthermore, these changes impact more than just scheduling and the ability to meet our load-serving obligations. The dramatic increase in permitting requirements, land purchase costs, and equipment costs have resulted in an approximate 67% increase in the total cost of developing a typical distribution substation since 2001. For example, the Los Reales Substation was completed in 2001 at a cost of $4.5 million. Today, TEP budgets $7.6 million – the average estimate – for a distribution substation of similar scope (initial 50 MVA substation and feeder getaway system).

TEP has also made modifications to the planning and substation standards in an attempt to optimize the overall economics of our infrastructure, ranging from the transmission lines, to the distribution substations, to the distribution feeders. The Company's evaluation showed that TEP received more value building smaller substations (new standard of 100 MVA ultimate capacity) rather than constructing larger substations (old standard of 200 MVA) and then building the distribution system necessary to transport that energy to our customers.

Q. You have discussed growth as it relates to physical assets. How is the growth affecting day-to-day operations in terms of human resource needs?

A. T&D construction and maintenance work is generally organized into three major areas: Distribution, Substations, and Transmission. Construction of new transmission lines is cyclical in nature. TEP is entering into a construction peak expected to last five to eight years, similar to the peak the Company experienced in the mid-1980's. TEP's most significant upcoming transmission project is the construction of the Pinal South Line in 2011. As a result, projections reflect that Transmission work will account for nearly 50% of TEP's total Construction Man Hours ("CMH") and capital labor dollars.

TEP engages the services of various line construction contractors to fill gaps during periods of peak demand for line construction and services. Additionally, other TEP contractors provide cost-effective, specialty services in areas such as civil construction, meter reading and line location, which allows TEP to remain focused on customer service, reliability and safety. TEP has recently developed a formal alliance agreement with Sturgeon Electric, a large national contractor, to further enhance productivity and cost efficiencies. Overall, TEP contractors fulfill approximately 30% of TEP's total T&D workload.

To deal with the increased work load, TEP has also focused on productivity gains. The volume of work in New Business Construction, part of Distribution, has increased over 62% since 2003. In order to complete this amount of work with a 90% on-time delivery, TEP focused on productivity gains through improved design, scheduling and construction practices. Construction personnel have been mentoring the design staff to improve designs and inspections which has resulted in fewer rejections at the construction phase and more timely completion of work. Having customer in-service dates has allowed the scheduling group to create a rolling three-month forecast of work and to assign resources accordingly. The construction crews are measured by how much work they complete and are held to the in-service dates for completion. These process improvements have resulted in a 39% gain in crew productivity in 2006.

In addition to the above challenges, the T&D area of the Company has many pending retirements of existing personnel. Out of 439 employees engaged in the various aspects of electric service delivery, 181 are eligible to retire in the next four years. The majority of the eligible employees are in craft positions. In response, the T&D area currently has 38 employees in apprenticeship programs and will continue to add to these numbers. To help with acquiring new employees, TEP has partnered with Pima Community College in developing and offering a course of study that is specific to the electric utility industry so that TEP can use this class as a hiring pool for future craft positions.

VI. ENVIRONMENTAL COMPLIANCE.

Q. What is the environmental compliance status for TEP's generating assets?

A. TEP generating assets are required to comply with environmental requirements of facility permits and applicable requirements of local, state, and federal environmental rules. TEP generating assets are currently in compliance with the requirements of facility permits and applicable local, state, and federal environmental requirements.

TEP is committed to being in compliance with environmental requirements. Specifically, environmental compliance is achieved by:

- installing, maintaining and operating equipment in accordance with good engineering practices;
- training personnel on how to achieve compliance with permit conditions;
- maintaining records of compliance;
- meeting compliance deadlines of local, state, and federal agencies; and
- following the general and specific conditions of facility permits.

Q. Please provide specific examples of environmental spending that has kept TEP in compliance with various environmental permits, requirements, rules, or programs in your generating facilities.

A. TEP requires annual spending of approximately $4.5 million to ensure compliance with all local, state and federal environmental regulations at its Tucson and Springerville generating stations. Additionally, TEP has made several upgrades of major pollution control equipment to its generating assets, since the 1980s.

Upgrades of pollution control equipment associated with Springerville Units 1 and 2 were part of the recent Springerville Expansion Project. In 2004 and 2005, approximately $60 million was spent on pollution control equipment upgrades on Units 1 and 2 including the addition of two spray dry absorber modules (one for each unit) for controlling sulfur dioxide ("SO_2") emissions and new low nitrogen oxide ("NO_x") burners. The upgrades have resulted in SO_2 emission reductions of approximately 75 percent and NO_x emission reductions of approximately 50 percent.

TEP is a partner in the ownership of the Navajo Generating Station. The Navajo Scrubber Project began in 1994 and finished in 1999. This project included the construction of three SO_2 scrubbers, one for each of the three Navajo units. The scrubber upgrades have resulted in an SO_2 emission reduction of approximately 95 percent. In addition, the installed wet scrubbers have a secondary benefit of removing fly ash. The Navajo Scrubber Project was completed at a cost of approximately $420 million; TEP's share was $31.5 million.

TEP is a partner in the ownership of the San Juan Generating Station. In 1999 the station started operation of a new $75 million pollution control system using a limestone-forced oxidation process which absorbs about 60 percent more SO_2 than the previous system. TEP's share of the limestone-forced oxidation process was approximately $15 million. Also, the pollution controls at the San Juan Generating Station will be upgraded over the next three years at a cost of approximately $65 million for TEP. The new technologies will provide mercury control, reduction of NO_x emissions by 35%, reduction of particulate matter emissions by 70% and additional SO_2 emission reductions from the increased scrubbing.

TEP is also a partner in the Four Corners Generating Station. In the mid to late 1980's, TEP spent approximately $31 million to install a fabric filter particulate removal system which removes approximately 99% of the fly ash from the exhaust gas stream exiting the stacks. A wet SO_2 scrubber system was also installed. Additionally, from 1989 to 1991, TEP spent approximately $3 million for the installation of low NOx burners to reduce the emissions of nitrogen oxides.

TEP has budgeted approximately $86 million for capital expenses related to environmental compliance in the next five years (2007-2011) at its Arizona and New Mexico generating stations. Included are costs for mercury monitoring beginning in 2008. Mercury controls are required at the generating units by 2013 and additional costs will be incurred in preparation of meeting these new requirements.

VII. CAPITAL AND OPERATIONS AND MAINTENANCE SPENDING.

A. Historical Capital Spending.

Q. Please provide historical capital spending for TEP.

A. During the test year, capital expenditures were approximately $146 million, excluding the Luna Energy Facility. Continued customer growth played a significant role in test year capital expenditures. During the test year, TEP spent over $31 million in capital dollars to provide infrastructure to new businesses and residences in its service area. In response to the demands placed on the system due to the increases in customer growth, TEP spent $54 million in capital on system reinforcement and reliability projects. Of that $54 million, $26 million was for transmission projects and $28 million for distribution-related projects. These projects will help to further guarantee the integrity of the system and ensure reliable delivery of services. Also helping to ensure the continuity of service is the capital work done to maintain and improve the operating levels of the generating stations. During the test year, $36 million in capital was spent on generation replacement and betterment projects for this purpose. An additional $1 million was spent on environmental projects at the generating stations.

The cumulative capital spending for the four years prior to, and including the test year, beginning January 2002 and ending December 2006, totaled $615 million, including $165 million related to generation replacements and betterments, $73 million for transmission initiatives, $107 million for distribution projects, $119 million to accommodate new business demands and $6 million for environmental projects. The following table outlines annual capital spending for the five-year period ending December 2006.

($ Millions)	2002	2003	2004	2005	2006	Total Capital Spending
Capital Expenditures*	$100	$118	$112	$139	$146	$615

* Excludes Luna Energy Facility.

B. Future Capital Spending.

Q. Mr. DeConcini, what are TEP's plans for capital expenditures in the future?

A. Overall, there is a significant amount of future capital investments planned at TEP. The key components of this include (i) expansion of the distribution and transmission systems, (ii) new business initiatives, (iii) continued work in replacement and betterment activities for generating facilities, (iv) environmental upgrades for generating facilities, and (v) investment in information technology. The planned cumulative capital expenditures for the calendar years 2007 through 2011 total $1.074 billion, not including dollars to buy-out the Sundt Unit 4 lease or for the operations of the Luna Energy Facility. The following table outlines planned capital expenditures on an annual basis for the five-year period ending December 2011.

($ Millions)	2007	2008	2009	2010	2011	Total Capital Spending
Capital Expenditures*	$198	$238	$193	$226	$219	$1,074

* Excludes Luna Energy Facility and Sundt Unit 4 lease buyout.

Total capital spending for the period beginning January 2002 and ending December 2006 totaled $615 million. When this is compared to the five-year capital plan for years 2007 through 2011, there is an increase of capital expenditures of $459 million. The main components of this increase include $205 million for transmission initiatives, $80 million for environmental initiatives, $76 million for distribution projects, $45 million for generation replacement and betterment projects and $36 million for capital associated with new business.

Q. Mr. DeConcini, you mentioned that in the future TEP is looking to make significant improvements primarily to its distribution and transmission system. What information can you provide on future capital spending for these systems?

A. One of the major capital drivers will revolve around work to continue on improving the continuity of service and system reliability. During the next five-year period, $460 million in capital is expected to be spent on system reinforcement projects, of which $182 million is estimated for distribution and $278 million for transmission initiatives. The distribution and transmission figures include plans to spend $58 million for the 138 kV reliability initiative and $166 million for the Palo Verde interconnect respectively. In addition, $156 million in capital is expected to be spent to provide infrastructure to new businesses and residences moving into the service area over the next five years.

Q. What about future TEP capital improvements in areas other than distribution and transmission?

A. In order to continue to provide a high level of service, $210 million in capital is planned to be spent for replacement and betterment projects at our generating stations. From 2007 through 2011, TEP is expected to spend $86 million on environmental initiatives as outlined in the Environmental Compliance section. In addition, an estimated $50 to $80 million to be spent for the buyout the Sundt Unit 4 lease.

In order to best meet the increased demands and complexities of the utility industry, TEP is planning to invest $71 million in Information Technology capital projects over the five-year period. This will enable TEP to leverage the most out of its current platforms as well as providing for the best technology solutions going forward.

Q. Mr. DeConcini, you have mentioned growth, transmission initiatives, and environmental projects all contributing to the increase in capital spending. Are there other factors driving up costs?

A. Yes, another factor that contributes to the increase in capital expenditures relates to material costs. There have been significant increases in material costs due to supply and demand issues. With the increased growth in emerging economies, there has been increased pricing pressure on construction commodities such as steel, copper, concrete petroleum based products and other related materials. In addition, domestic factors such as the housing boom and the reconstruction efforts due to the damage from Hurricane Katrina have also put pressures on commodity prices. The spot price of copper doubled in 2006, which created substantial increases in TEP's cost of cable and transformers. In New Business projects alone, TEP experienced an overall material cost increase of 48% in 2006. Likewise, operational support costs such as TEP's transportation costs have been significantly affected by increases in fuel and equipment.

As mentioned above, continued customer growth continues to drive increased capital expenditures. TEP, over the past few years, has experienced an average annual growth rate of 2.3%. Not only is the volume of growth telling, the location of the growth is important. Much of the growth is occurring in geographic areas with no existing services, as developers build new subdivisions, office complexes and shopping centers on the fringes of the city. This requires extensive and more costly infrastructure work in order to provide services. In order to keep pace with this type of growth in new services and subdivisions, and to meet TEP on-time delivery commitments, TEP at times must run crews at extended hours and hire additionally full-time construction contractors.

Of course, contractors are faced with the same economic factors as TEP. Contractor rates have increased over the past few years as a result of escalating fuel, equipment, asphalt and concrete costs. Concrete prices have doubled in the last five years as many national construction indices confirm. The type of infrastructure to build substations and to extend lines to outlying areas typically encompasses all these types of costs (heavier gauge cable, transformers, concrete, fuel, equipment and outside civil contractors.) Couple this with inflationary increases in labor rates and benefit costs over the past several years to fully understand the overall cost pressures on TEP capital spending.

C. <u>Operations and Maintenance Spending</u>.

Q. Are the operations and maintenance ("O&M") costs incurred by TEP in the Test Year reasonable?

A. Yes. TEP monitors its O&M costs very carefully. O&M costs can vary significantly from year to year for various reasons. A good example of the variability of TEP's costs are related to generation outages, which can fluctuate greatly year to year, depending on major or minor outages at any number of different generation plants. Customer growth is also significant for TEP, and growth affects our costs. As previously discussed, TEP's service territory continues to grow at a rate of over 2% per year. More customers require TEP to spend more O&M dollars. Additionally, a significant portion of O&M is made up of labor and labor-related costs. Labor and labor-related costs also continue to increase over time. In spite of these many challenges, TEP's O&M costs have tracked at an average of 3.5% per year since 1995. This has been accomplished by closely monitoring O&M costs throughout the Company, as management recognizes that there are many pressures as outlined above that increase O&M costs. Management believes strongly in making O&M cost containment everyone's job, as evidenced by the employee incentive program which includes a cost containment goal. Furthermore, our O&M spending is prudent given TEP's exemplary reliability indices for T&D and generation, its outstanding customer service and strong safety records, all of which were discussed previously in my Direct Testimony.

VIII. <u>SPRINGERVILLE UNIT NO. 3.</u>

Q. TEP recently completed the third of four units at the Springerville facility. Please describe how this unit came to be built.

A. In the late 1970's, TEP originally developed the Springerville generation site for four similar sized pulverized coal-fired units. The first two units went into commercial operation in 1985 and 1990 respectively. At the end of 2000, TEP decided to leverage the value of the site and develop the two additional units ("Springerville Expansion Project") and spread the cost of the infrastructure and operation and maintenance over four units instead of two. TEP, however, did not have the need for additional coal-fired generation, nor the capital investment required to construct the new units. TEP decided to develop the Springerville Expansion Project and then sell the development rights to Tri-State Generating and Transmission Association. ("Tri-State") for Unit 3 and to SRP for Unit 4.

The synergy savings to Units 1 and 2 from the operation of Unit 3 are approximately $12.7 million per year before taxes. These savings are evident, in shared operations and maintenance, property taxes, capital lease payments, and insurance, to name a few examples. The pre-tax transmission revenues associated with Unit 3 are approximately $5.4 million. These transmission revenues are realized because Tri-State is purchasing transmission rights on our system to move their power from Springerville Generating Station to the Four Corners' area.

The development of the Springerville Expansion Project was accomplished through the UniSource Energy Development Company ("UED"), a subsidiary of UniSource Energy. The development period lasted approximately three years and UED made expenditures of approximately $30 million. These development costs were risks that the UniSource Energy shareholders shouldered if the Project never closed. See Decision No. 65347 (November 1, 2002), Findings of Fact 62 and 65.

In October of 2003, Tri-State was able to obtain financing for Unit 3 and construction commenced. However, SRP decided to delay the construction of Unit 4 until it needed more power and UED provided an option to SRP for the development rights for Unit 4. Both new units were planned to be approximately the same size as Units 1 and 2. Unit 3 achieved commercial operation in July of 2006. SRP is currently starting construction of Unit 4 with a scheduled completion date of December 31, 2009.

Q. Mr. DeConcini, you mentioned that Units 1 and 2 were enhanced with environmental upgrades and common facilities improvements. Are there other benefits to be realized by TEP customers as a result of Unit 3 being built?

A. The upgrades to Units 1 and 2, as described above, included both the addition of pollution control equipment and common facilities improvements. The environmental upgrades on Units 1 and 2 allowed SO_2 and NOx emissions to be reduced by approximately 75% and 50% respectively. These reductions in emissions from Units 1 and 2 would most likely have been required in the future anyway, based on overall emissions reductions being legislated by our regulators. In addition, the approximate $3 million operating lime cost of the Spray Dry Absorbers (FGD Scrubbers) to meet the new emissions levels, is paid for by Units 3 and 4. Having Tri-State and SRP pay for the environmental upgrades and the lime costs benefits TEP and the customers.

Additional benefits to customers include less cost for O&M, property taxes and insurance since these costs are now shared between four units instead of two.

IX. PRO FORMA ADJUSTMENTS.

Q. What are the various Plant Overhaul and Outage Normalization adjustments?

A. These adjustments are made to test year non-labor expenses to achieve a normal annual level of generating unit maintenance overhaul activity. In the Cost-of-Service Methodology, the adjustment reflects historical and projected major and minor overhaul frequency and cost data for the TEP's share of the San Juan, Four Corners, and Navajo jointly-owned remote generation facilities, and the Company's Sundt, (formerly Irvington) and Springerville Generating Units except for Springerville Unit No. 1, the costs of which are established by the fixed cost recovery factor described in Mr. Hutchen's Direct Testimony. In the Hybrid Methodology, similar adjustments to the

Cost-of-Service Methodology are made, except outage dollars are not normalized at the Four Corners and Navajo generating facilities. The classification of overhaul work as being major or minor is based on the extent of work performed or scheduled.

Q. Please comment on the Springerville Unit 3 adjustment and the Gain on Sale of SO_2 Allowances adjustment.

A. Only a few adjustments are being made regarding the building of Unit 3 and its operation. Many synergies are already being shared with our customers, such as O&M savings, Administrative and General savings, and Property Tax savings. Other savings and revenue gains are related to the risk the shareholder incurred in the decision to build Unit 3, and therefore are not shared with the customer, as discussed previously in my Direct Testimony.

X. <u>PROPOSED RULES AND REGULATIONS.</u>

Q. Why has TEP proposed changes to its Rules and Regulations?

A. TEP proposes several changes to its Rules and Regulations to better clarify existing provisions and to insert additional provisions. We are also re-structuring these Rules and Regulations to better harmonize them with how the Commission's regulations in the Arizona Administrative Code ("Code") are organized. TEP believes these changes will better delineate what the Company's obligations are to the customer, as well as the customer's responsibilities.

Many additions are taken directly from either the Code or the UNS Electric Rules and Regulations. In other words, some of the insertions are made to better align TEP's Rules and Regulations with those of UNS Electric. We also propose provisions here that we proposed for UNS Electric's Rules and Regulations.

Another reason to reorganize the Rules and Regulations is to make them easier to read and understand. Thus, many of the changes and edits made to the language in the Rules and Regulations are stylistic changes and are not substantive. In addition, several provisions are relocated within the proposed Rules and Regulations so that they fit better. Exhibit MJD-1 to my testimony is a redlined version of the standard Rules and Regulation. Exhibit MJD-2 is the clean version of those Rules and Regulations. Not every formatting change is redlined within the proposed Rules and Regulations because we did not want to provide Staff with a document that was littered with redlined changes, for every tab, indentation, or other formatting changes. So, the only redlined changes in the redlined version are the more major changes TEP is proposing from its current Rules and Regulations.

Q. Did TEP remove terms and conditions related to retail electric competition?

A. Those provisions were moved to separate Direct Access Rules and Regulations. TEP's proposed Rules and Regulations remove references to Electric Service Providers and other definitions, terms and conditions related to retail electric competition and competitive services. Given the unsettled nature of the Electric Competition Rules that give rise to many of these terms and conditions, we felt it best to take those definitions and provisions out of these Rules and Regulations, and relocate those provisions into a separate document. That document, also attached to my testimony, is entitled "Direct Access Rules and Regulations." Definitions of terms related to competitive services – like Electric Service Providers, Interval Metering and Scheduling Coordinator – are relocated to Subsection A in the proposed Direct Access Rules and Regulations. Provisions located within TEP's existing Rules and Regulations that were related to competitive services, but not in the Direct Access section, are relocated to Subsection B in the proposed Direct Access Rules and Regulations. These Direct Access Rules and Regulations are attached as Exhibit MJD-3 to my testimony.

What remains in TEP's Rules and Regulations are provisions directly related to TEP and its existing and new customers, without references to competitive services that may confuse customers.

Q. What about references to charges for specific services currently spread throughout the Rules and Regulations?

A. Rather than keep specific charges littered throughout the Rules and Regulations, we add language referring to the "Statement of Additional Charges." TEP believes it is easier for customers to only have to refer to one portion of the tariff to find charges for all such services.

Q. Can you describe the additional major changes TEP made to its Rules and Regulations?

A. Certainly. I will describe what changes we are proposing be approved in this rate case by going through the Rules and Regulations section by section. My discussion will also include any major structural changes we have made, even if the actual provisions are not being altered substantively.

Q. Please describe the substantive changes to Section 1, entitled "Applicability of Rules and Regulations and Description of Service."

A. This Section is basically a new section to outline the applicability of the Rules and Regulations to customers. UNS Electric's proposed Rules and Regulations have this language and we believe it provides a good overview that these provisions will apply to both the customers and the Company.

Q. What changes were made to the "Definitions" section (Section 2)?

A. Several changes are made to this Section. As stated above, we took out any terms and conditions relating to retail electric competition. Consequently, we are removing definitions like "Electric Service Provider," "Scheduling Coordinator," and "Standard Offer Service." We also remove additional definitions for terms that are never used in the rest of the Rules and Regulations. For instance, "horsepower" is defined – but is never used – in TEP's existing Rules and Regulations. We remove that definition along with definitions for "energy diversion," "collection fee," and "local Arizona time." Finally, we added definitions for terms that are used in the existing Rules and Regulations, but are not defined when such definition helps clarify what is meant. This is why we add definitions for terms like "Pricing Plans" and "Rules and Regulations."

Q. Did TEP make significant changes to Section 3 – "Establishment of Service?"

A. Yes. We make several changes to this Section.

First, we replace the existing language regarding customer deposits with the language we are also proposing for UNS Electric. This language better clarifies and delineates the obligations regarding customer deposits. Most of these provisions, however, are not been altered substantively. We do propose that the interest rate on customer deposits held for over 12 months be at the established one-year Treasury Constant Maturities rates – effective on the first business day of that year – as published in the Federal Reserve website.

We also propose a new Subsection entitled "Conditions for Supplying Service." As its title suggests, this Subsection delineates what conditions must be met before TEP can provide electric service. TEP took this language from UNS Electric's existing Rules and Regulations.

In Subsection 3.E.2., regarding "Service Establishment or Reestablishment Charge," we insert language indicating that it may not be possible to establish or reestablish service after-hours, depending on the availability of TEP staff. We also relocate the provision addressing reconnection charges to Subsection 3.E.4. Finally, we add three new Subsections addressing the following topics: identification of load and premises, identification of responsible party and tampering with or damaging equipment. These provisions are currently in UNS Electric's Rules and Regulations and we believe they help clarify additional conditions for establishing service and consequences for tampering with TEP's equipment.

Q. What about Section 4 – "Minimum Customer Information Requirements?"

A. Basically, we combine two articles from the existing Rules and Regulations: the "Election of Rate Schedules" article; and the existing "Minimum Customer Information Requirements" are merged to form Section 4. We also add a sentence to TEP's proposed Rules and Regulations at Subsection 4.A.6. indicating that the Company is not obligated to provide a statement of actual consumption to a customer more than once in a calendar year.

Q. Is TEP proposing additions to Section 6 – "Service Lines and Establishments"?

A. Yes, we are proposing two additions for this section. First, we propose to add Subsection 6.B.1.d. to indicate that the customer will have to provide access to the main switch or breaker for the safe installation and removal of Company meters. Second, regarding overhead service connections for secondary service, we add Subsection 6.B.2.d. to make clear that customer-advanced funds in excess of that allowed at no charge will be Contributions-In-Aid-of-Construction ("CIAC").

Q. Have any changes been made to the "Line Extension" Section, which is Section 7 in the proposed Rules and Regulations?

A. The following changes were made to this Section:

- First, we replaced Subsection 7.C.4. in order to clarify the policy on replacing overhead lines with underground lines. It has not been a practice at TEP to do this for free (although it was previously stated that the Company may). The new language clarifies TEP's current practice. The new language also clarifies TEP's stance when it is mandated that we do in fact have to change overhead lines to underground lines.
- The cost of construction for a single-phase line went from $5.00 per foot to $20.53 per foot. The cost of construction for a three-phase line went from $8.00 per foot to $27.38 per foot. This change was made to cover the costs of construction.
- We also added definitions for Economic Feasibility Analysis, Single-Phase Service, and Three-Phase Service to Section 2, in light of the additions and modifications made in these proposed Rules and Regulations.

Q. What changes have been proposed for Section 8 entitled "Provision of Service?"

A. TEP proposes to add a new provision under Subsection 8.D.3. that mirrors A.A.C. R14-2-208.D.3. This Subsection merely states that the Company may interrupt service – should a national emergency or local disaster arise – so that the Company may provide emergency service necessary for civil defense or emergency service agencies until normal service can be restored to those agencies. Section 8 within TEP's proposed Rules and Regulations also incorporates what is currently Article Nos. 11 and 12 – "Interruption of Service" and "Force Majeure." Further, we add a "General Liability" Subsection to clarify what TEP will and will not be responsible for. This Subsection is also in UNS Electric's proposed Rules and Regulations.

Q. What about additions to Section 9 – "Voltage, Frequency and Phase?"

A. We inserted Subsections regarding customer-provided protection for motor installations and delineating customer responsibility for equipment used in receiving electric energy. Also, we moved section 17 "Highly Fluctuating Loads" under this section and modified the language to be consistent with UNS. It is important to address highly fluctuating loads to limit the disturbances on TEP's system.

Q. Are there any provisions proposed to be added to the "Meter Reading" section, which is now Section 10?

A. In this Section, we simply propose two changes that are also in UNS Electric's proposed Rules and Regulations:

1. Adding Subsection 10.C.2 that states "any reread may be charged to the Customer at a rate set forth in the Statement of Additional Charges, if the original reading was in error."
2. Rewriting Subsection 10.F. regarding customer requested meter tests provision. This change is not a substantive change from the current provision in TEP's existing Rules and Regulations.

Q. Please discuss the changes proposed for Section 11 – "Billing and Collection."

A. In TEP's existing Rules and Regulations, Subsection 11.C.3, we have changed the language to more clearly state our policy on delinquent bills. Delinquent bills will receive a late payment finance charge of 1.5%, as stated in the Statement of Additional Charges.

There is also a Subsection entitled "Returned Checks and Electronic Fund Transfers." In our proposed Rules and Regulations, we rewrite this Subsection and entitle it "Non-sufficient Funds (NSF) Checks." In addition to clarifying the provisions in this Subsection, it is expanded to include checks, electronic fund transfers or other financial instruments for electric service. We also add a provision stating that no personal checks will be accepted if TEP received two NSF checks from a customer within a 12-month period. This new language is codified in our proposed Rules and Regulations in Subsection 11.F.

We also insert, as Subsection 11.I.3., a provision indicating that an outgoing customer is responsible for providing access to the meter so TEP can get a final meter reading. This provision is adopted from A.A.C. R14-2-210.I.3.

Finally, we propose to add an electronic billing option for TEP customers. The provisions for electronic billing are the same as what was proposed for both UNS Electric and UNS Gas. The electronic billing provisions are contained in Subsection 11.J. of TEP's proposed Rules and Regulations.

Q. **What were the changes made to Section 12 – "Termination of Service?"**

A. First, we add two additional provisions to Subsection 12.A. that state that TEP will not disconnect service to a customer if that customer fails – as the guarantor – to pay the bill of the guarantee; and on disputed bills where the customer is following the Commission's rules on customer bill disputes. We add those Commission rules to our Rules and Regulations in Subsection 14.C. Next, we insert a provision allowing TEP to terminate service without notice if the customer has failed to make good on non-sufficient checks, electronic fund transfers or any other financial instrument, in accordance with the rewritten provisions located in Subsection 11.F. Finally, we add provisions to allow termination with notice on three additional conditions:

1. When a customer fails to meet agree-upon deferred payment arrangements.
2. When a non-imminent hazard exists that may cause property damage.

3. When customer facilities do not comply with Company requirements or specifications.

These additional provisions are located in Subsection 12.C. We also insert a provision requiring the Company to keep records of all terminations of service with notice for one year and make such available for Commission inspection.

Q. Finally, what did TEP add to the "Administrative and Hearing Requirements" in Section 14?

A. We insert a new Subsection – taken directly from A.A.C. R14-2-212.C. – outlining the process for resolving service and bill disputes. This Subsection gives Customers guidance as to how they may file a statement with the Commission against the Company and how the Commission Staff will seek to try and resolve the dispute.

Q. Do you have any final thoughts about TEP's proposed Rules and Regulations?

A. TEP believes this is an opportune time to make the Rules and Regulations clearer and better-structured. But we also insert important provisions that would put the customer on notice as to what will be the customer's responsibilities. Most importantly, we restate provisions to make them less confusing, and took out provisions that were either unnecessary or were related to direct access and competitive services. We believe all of these changes lessen customer confusion and disputes between TEP and customers. We ask the Commission to approve all of the changes as being in the public interest.

Q. Does this conclude your testimony?

A. Yes.

EXHIBIT

MJD-1

Tucson Electric Power Company

Rules & Regulations

TABLE OF CONTENTS

SECTION 1
APPLICABILITY OF RULES AND REGULATIONS AND DESCRIPTION OF SERVICE

A. Tucson Electric Power Company ("Company") is an electric utility operating within portions of the state of Arizona. The Company will provide service to any person, institution or business located within its service area in accordance with the provisions of its Pricing Plans and the terms and conditions of these Rules and Regulations.

B. All electricity delivered to any Customer is for the sole use of that Customer on that Customer's premises only. Electricity delivered by the Company will not be redelivered or resold, or the use thereof by others permitted unless otherwise expressly agreed to in writing by the Company. However, those Customers purchasing electricity for redistribution to the Customer's own tenants (only on the Customer's premises) may separately meter each tenant distribution point for the purpose of prorating the Customer's actual purchase price of electricity delivered among the various tenants on a per unit basis.

C. These Rules and Regulations will apply to all electric service furnished by the Company to its Customers.

D. These Rules and Regulations are part of the Company's Pricing Plans on file with, and duly approved by, the Arizona Corporation Commission. These Rules and Regulations will remain in effect until modified, amended, or deleted by order of the ACC. No employee, agent or representative of the Company is authorized to modify the Company Rules.

E. These Rules and Regulations will be applied uniformly to all similarly situated Customers.

F. In case of any conflict between these Rules and Regulations and the ACC's rules, these Rules and Regulations will apply.

G. Whenever the Company and an Applicant or a Customer are unable to agree on the terms and conditions under which the Applicant or Customer is to be served, or are unable to agree on the proper interpretation of these Rules and Regulations, either party may request assistance from the Consumer Services Section of the Utilities Division of the ACC. The Applicant or Customer also has the option to file an application with the ACC for a proper order, after notice and hearing.

H. The Company's supplying electric service to the Customer and the acceptance thereof by the Customer will be deemed to constitute an agreement by and between the Company and the Customer for delivery, acceptance of and payment for electric service under the Company's Rules and Regulations and applicable Pricing Plans.

~~RULES AND REGULATIONS~~
~~ELECTRIC~~

~~PREFACE~~

~~Upon the effective date of these Rules and Regulations, the Rules and Regulations, Electric, Tariff No. RR previously filed by the Company with the Arizona Corporation Commission and effective on March 31, 1996 and as revised September 13, 1996, shall become null and void and of no further legal effect.~~

~~**ARTICLE NO. 1 - GENERAL**~~

~~The Company shall furnish service under its rate schedules and these Rules and Regulations as approved from time to time by the Arizona Corporation Commission and in effect at the time. These Rules and Regulations shall govern all service except as specifically modified by the terms and conditions of the rate schedules or written contracts. Copies of currently effective Rules and Regulations are available for inspection at the office of the Company during normal business hours.~~

SECTION 2
DEFINITIONS

A. In these Rules and Regulations, the following definitions will apply unless the context requires otherwise:

~~**ARTICLE NO. 2 - DEFINITIONS**~~

~~When used in these Rules and Regulations, unless the context otherwise requires, the following definitions shall apply. In addition, the definition of principal terms used in these Rules and Regulations shall have the same meaning as ascribed to them in the approved ACC Competition Rules, unless otherwise expressly stated herein.~~

1. Advance in Aid of Construction: Funds provided to the Company by the Applicant under the terms of a line extension agreement, the value of which may be refundable.

2. Applicant: A person requesting the Company to supply electric service.

3. Application: A request to the Company for electric service, as distinguished from an inquiry as to the availability or charges for this~~such~~ service.

4. Arizona Corporation Commission ("ACC" or "Commission"): The regulatory authority of the State of Arizona having jurisdiction over public service corporations operating in Arizona, hereinafter referred to as the "Commission."

5. Billing Month: The period between any two regular readings of the Company's meters at approximately thirty (30) day intervals.

6. Billing Period: The time interval between two consecutive meter readings taken for billing purposes.

~~7.Collection Fee: The charge specified in the Company's tariffs which covers the cost of collecting utility charges at the customer's premises to avoid discontinuation of service.~~

7. Company: Tucson Electric Power Company acting through its duly authorized officers or employees within the scope of their respective duties.

8. Competitive Services: All aspects of retail service except those services specifically defined as "Non-competitive Services" pursuant to R14-2-1601(27) of the ACC-approved Competition Rules, or noncompetitive services as defined by the Federal Energy Regulatory Commission.

9. Connected Load: The sum of the power rating of the Customer's electrical apparatus connected to the Company's system.

10. Contributions in Aid of Construction ~~or~~ ("Contribution"): Funds provided to the Company by the Applicant under the terms of a line extension agreement and/or service connection ~~tariff~~Pricing Plan, the value of which is not refundable.

11. Customer: The person(s) or entity(ies) in whose name service is rendered, as evidenced by the request for electric service by the Applicant(s), or by the receipt and/or payment of bills regularly issued in his name regardless of the identity of the actual user of the service.

12. Customer Charge: The amount the Customer must pay the Company for the availability of electric service, excluding any electricity used, as specified in the Company's Pricing Plans.

13. Day: Calendar Day

14. Demand: The rate at which power is delivered during any specified period of time. Demand may be expressed in kilowatts, kilovolt-amperes, or other suitable units.

~~15.~~

~~17.Disputed Bill: Unless otherwise stated, "disputed bill "shall be as defined in Article 17 of TEP's rules and regulations.~~

~~18.Electric Service Provider (ESP): A company supplying marketing or brokering at retail any competitive services, as defined in the Rules pursuant to a Certificate of Convenience and Necessity.~~

~~19.Electric Service Provider (ESP) Service Acquisition Agreement: A contract between an ESP and TEP to deliver power to retail end users, or between an ESP and a Scheduling Coordinator to schedule transmission service.~~

SECTION 2
DEFINITIONS
(continued)

15. Disabled: A person with a physical or mental condition which substantially contributes to the person's inability to manage his or her own resources, carry out daily living activities, or protect oneself from neglect or hazardous situations without assistance from others.

~~15.~~16. Distribution Lines: The Company's lines operated at distribution voltage, which are constructed along public roadways or other bona fide rights-of-way, including easements on Customer's property.

17. Economic Feasibility Analysis: The calculation used to determine the deposit required for a line extension. Normally a unitized per foot cost, but could be a cost to revenue calculation for large customers.

~~17.~~18. Elderly: A person who is 65 years of age or older.

~~18.~~19. Energy: Electric energy, expressed in kilowatt-hours.
~~22.Energy Diversion: Any action which allows electrical energy to be consumed without proper metering and/or billing.~~

~~19.Handicapped: A person with a physical or mental condition which substantially contributes to the person's inability to manage his or her own resources, carry out daily living activities, or protect oneself from neglect or hazardous situations without assistance from others.~~
~~i.Horsepower: The nameplate rating of motors or its equivalent in other apparatus. For conversion purposes, one horsepower shall be considered as equivalent to 1.0 kilowatt.~~

20. Illness: A medical ailment or sickness for which a residential Customer obtains a verified document from a licensed medical physician stating the nature of the illness and that discontinuance of service would be especially dangerous to the Customer's health.

21. Inability to Pay: Circumstances in which residential Customer:

    a. Is not gainfully employed and unable to pay, or

    b. Qualifies for government welfare assistance, but has not begun to receive assistance on the date he receives his bill and can obtain verification of that fact from the government welfare assistance agency.

    c. Has an annual income below the published federal poverty level and can produce evidence of this, and

d. Signs a declaration verifying that the Customer meets one of the above criteria and is either elderly, handicapped, or suffers from illness.

22. Interruptible Electric Service: Electric service that is subject to interruption as specified in the Company's ~~tariff~~Pricing Plan.

~~ii.Interval Metering: The purchase, installation and maintenance of electricity metering equipment capable of measuring and recording minimum data requirements, including hourly interval data required for Direct Access settlement processes.~~

23. Kilowatt (kW): A unit of power equal to 1,000 watts.

24. Kilowatt-Hour (kWh): The amount of electric energy delivered in one hour at a constant rate of one kilowatt.

25. Law: Any statute, rule, order or requirement established and enforced by government authorities.

SECTION 2
DEFINITIONS
(continued)

~~25.~~26. Line Extension: The lines and equipment necessary to extend the electric distribution system of the Company to provide service to additional Customers.

~~E. Local Arizona Time: All time references in this Article are in local Arizona time, which is Mountain Standard Time. Arizona does not observe Daylight Savings Time.~~

27. Long-Term Rental Mobile Home Park: A park which is finish-graded and has permanently paved roadways, sewer and water connections, and which provides rental spaces to permanent and semi-permanent occupants of mobile homes which are owned either by the occupant or by other persons.

28. Master Meter: A meter for measuring or recording the flow of electricity at a single location before distribution to tenants or occupants for their individual usage.

29. Megawatt (MW): Unit of power equal to 1,000,000 watts.

30. Meter: The instrument and any associated equipment used for measuring, indicating or recording the flow of electricity that has passed through it.

~~iii.Meter-Reading Service Provider (MRSP): An entity providing all functions related to the collection and storage of consumption data, and that reads meters, performs validation, editing, and estimation on raw meter data to create bill-ready meter data; translates bill-ready data to an approved format; posts this data to a server for retrieval by billing agents; manages the server; exchanges data with market participants, and stores meter data for problem resolution.~~

~~iv.Meter Service Provider (MSP): An entity providing all functions related to measuring electricity consumption.~~

31. Meter Tampering: A situation in which a meter has been illegally altered, including, but not limited to: meter bypassing, use of magnets to slow the meter recording, and broken meter seals.

~~31.~~32. Minimum Charge: The amount the Customer must pay for the availability of electric service, including an amount of usage, as specified in the Company's ~~tariffs~~Pricing Plans.

33. Month: The period between any two (2) regular readings of the Company's meters at approximately thirty (30) day intervals.

~~33.~~34. On-site Generation: Any and all power production generated on or adjacent to a Customer's property that is controlled, utilized, sold, or consumed by said Customer or its agent.

~~34.~~35. Permanent Customer: A Customer who is a tenant or owner of a service location who applies for and receives permanent electric service.

36. Permanent Service: Service which, in the opinion of the Company, is of a permanent and established character. The use of electricity may be continuous, intermittent, or seasonal in nature.

~~36.~~37. Person: Any individual, partnership, firm, corporation, governmental agency, or other organization operating as a single entity.

SECTION 2
DEFINITIONS
(continued)

~~37.~~38. Point of Delivery: In all cases, unless otherwise specified, "point of delivery" is the location on the Customer's building, structure, or premises where all wires, conductors, or other current-carrying devices of the Customer join or connect with wires, conductors, or other current-carrying devices of the Company. Location of the point of delivery ~~shall~~will be determined by the Company in conformity with its standards and specifications, rate schedules and construction standards as they exist from time to time. Location of metering facilities ~~shall~~will be determined by the Company and may or may not be at the same location as the point of delivery.

39. Power: The rate of generating, transferring and/or using electric energy, usually expressed in kilowatts.

~~39.~~40. Power Factor: The ratio of real or active power (kW) to apparent or reactive power (KVA) ~~for any given load and time, generally expressed as a percentage ratio~~.

41. Premises: All of the real property and apparatus employed in a single enterprise on an integral parcel of land undivided by public streets, alleys or railways.

42. Pricing Plans: A part of the Company's Tariffs that sets forth the rates and charges related to specific categories of Customers and related terms and conditions.

43. Primary Service and Metering: Service supplied directly from the Company's high voltage distribution or transmission lines without prior transformation to a secondary level.

44. Residential Subdivision Development: Any tract of land which has been divided into six or more contiguous lots with an average size of one acre or less for use for the construction of residential buildings or permanent mobile homes for either single or multiple occupancy.

~~44.~~45. Residential Use: Service to Customers using electricity for domestic purposes such as space heating, air conditioning, water heating, cooking, clothes drying, and other residential uses, including use in apartment buildings, mobile home parks, and other multi-unit residential buildings.

~~45.~~46. Rules and Regulations or Company Rules: These Rules and Regulations that are part of the Company's Tariffs and Pricing Plans.~~Rules: Approved ACC Competition Rules.~~

~~48.Scheduling Coordinator (SC): An entity that provides schedules for power transactions over transmission or distribution systems to the party responsible for the operation and control of the transmission grid, such as a Control Area Operator, Arizona Independent Scheduling Administrator or Independent System Operator.~~

47. Secondary Service: Service supplied at secondary voltage levels from the load side of step-down transformers connected to the Company's high voltage distribution lines.

48. Service Area: The territory in which the Company has been granted a certificate of convenience and necessity and is authorized by the Commission to provide electric service.

~~48.~~49. Service Classifications: Service classifications ~~shall~~will be those provided by the filed rate schedules.

SECTION 2
DEFINITIONS
(continued)

~~49.~~50. Service Drop: The overhead service conductors from the last Company-owned pole or other aerial support to and including the splices, if any, connecting to the Customer's service entrance conductors at a building or other structure.

~~50.~~51. Service Establishment Charge: The charge as specified in the Company's ~~tariffs~~Pricing Plans which covers the cost of establishing a new account.

~~51.~~52. Service Lateral: The underground service conductors between the street main, including any risers at a pole or other structure or from transformers, and the first point of connection to the Customer's service entrance conductors in a terminal box or meter or other enclosure with adequate space, inside or outside the building wall.

~~52.~~53. Service Line: The last line extending from a distribution line or transformer to the Customer's premises or point of delivery.

~~53.~~54. Service Point: Unless otherwise stated, all references to "service point" in this agreement ~~shall~~will refer to an installed service, identified by a Universal Node Identifier ("UNI").

~~54.~~55. Service Reconnection Charge: The charge as specified in the Company's ~~tariffs~~Pricing Plans which must be paid by the Customer prior to reestablishment of electric service each time the electricity is disconnected for nonpayment or whenever service is otherwise discontinued for failure to comply with the Company's ~~tariffs~~Pricing Plans or Rules and Regulations.

~~55.~~56. Service Re~~-~~establishment Charge: A charge as specified in the Company's ~~tariffs~~Pricing Plans for service at the same location where the same Customer had ordered a service disconnection within the preceding twelve-month period.

~~56.~~57. Single Family Dwelling: A house, apartment, or a mobile home permanently affixed to a lot, or any other permanent residential unit which is used as a permanent home.

58. Single-Phase Service: Three (3) wire service (usually 120/240 volts).

~~60.customer~~~~Customers in TEP's service territory at regulated rates, including metering, meter reading, billing and collection services, demand-side management services including but not limited to time-of-use, and consumer information services. All components of Standard Offer Service shall be deemed noncompetitive as long as those components are provided in a bundled transaction pursuant to R14-2-1606(A) of the ACC-approved Competition Rules.~~

~~58.~~59. Tariffs: The documents filed with the Commission which list the services offered by the Company which set forth the terms and conditions and a schedule of the rates and charges for those services.

~~59.~~60. Temporary Service: Service to premises or enterprises which are temporary in character, or where it is known in advance that the service will be of limited duration. Service which, in the opinion of the Company, is for operations of a speculative character is also considered temporary service.

SECTION 2
DEFINITIONS
(continued)

~~59.~~61. Third-Party Notification: A notice of pending discontinuance of service to a Customer of record sent to an individual or a public entity in order to make satisfactory arrangements with the Company on behalf of said Customer.

62. Three-Phase Service: Four (4) wire service (usually 277/480 volts).

~~60.~~63. Universal Node Identifier ("UNI"): A unique, permanent identification number assigned to each service ~~delivery~~ point of delivery.

~~61.~~64. Weather Especially Dangerous to Health: That period of time commencing with the scheduled termination date when the local weather forecast, as predicted by the National Oceanic and Atmospheric Administration, indicates that the temperature will not exceed 32 degrees Fahrenheit for the next day's forecast.

SECTION 3
ESTABLISHMENT OF SERVICE

~~ARTICLE NO. 3 - ESTABLISHMENT OF SERVICE~~

A. Information from New Applicants

1. The Company may obtain the following minimum information from each new application for service:

   a. Name or names of Applicant(s);

   b. Service address or location and telephone number;

   c. Billing address and ~~/~~telephone number, if different than service address;

   d. Social security number ~~and/~~or Driver's License number and date of birth to be consistent with verifiable information on legal identification.

   ~~e.~~

   ~~d.~~e. Address where service was provided previously;

   ~~e.~~f. Date Applicant will be ready for service;

   ~~f.~~g. Whether premises ha~~ve~~d been supplied with electric service previously;

   ~~g.~~h. Purpose for which service is to be used;

   ~~h.~~i. Whether Applicant is owner or tenant of, or agent for the premises;

   ~~i.~~j. Information concerning the energy and demand requirements of the Customer; and

   ~~j.~~k. Type and kind of life-support equipment, if any, used by the Customer.

~~2.The Company may require a new Applicant for service to appear at the Company's designated place of business with proof of identity~~

~~3.~~2. The supplying of electric service by the Company and the acceptance of that electric service~~thereof~~ by the Customer ~~shall~~will be deemed to constitute an agreement by and between the Company and the Customer for delivery, acceptance of and payment for electric service under the Company's applicable ~~rates~~Pricing Plans and Rules and Regulations.

~~4.~~3. The term of any agreement not otherwise specified ~~shall~~will become operative on the day the Customer's installation is connected to the Company's facilities for the purpose of taking electric energy.

~~5.~~4. The Company may require a written contract with special guarantees from Applicants whose unusual characteristics of load or location would require excessive investment in facilities or whose requirements for service are of a special nature.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

~~6.~~5. Signed contracts may be required for service to commercial and industrial establishments. Neither these contracts, nor any modifications to these contracts, will be binding ~~No such contract or any modification thereof shall be binding~~ upon the Company until executed by a duly authorized representative of the Company.

~~7.~~6. Where service is rendered to two (2) or more Customers whose name appears on the bill, as evidenced on the bill, the Company will~~shall~~ have the right to collect the full amount owed it from any one of the Customers.

B. Deposits

1. The Company may require from any present or prospective Customer a deposit to guarantee payment of all bills. This deposit may be retained by the Company until service is discontinued and all bills have been paid, except as provided in Subsection 3.B.3 below. Upon proper application by the Customer, the Company will then return said deposit, together with any unpaid interest accrued thereon from the date of commencement of service or the date of making the deposit, whichever is later. The Company will be entitled to apply said deposit together with any unpaid interest accrued thereon, to any indebtedness for the same class of service owed to the Company for electric service furnished to the Customer making the deposit. When said deposit has been applied to any such indebtedness, the Customer's electric service may be discontinued until all such indebtedness of the Customer is paid and a like deposit is again made with the Company by the Customer. No interest will accrue on any deposit after discontinuance of the service to which the deposit relates.

   The Company will not require a deposit from a new Applicant for residential service if the Applicant is able to meet any of the following requirements:

   a. The Applicant has had service of a comparable nature with the Company at another service location within the past two (2) years and was not delinquent in payment during the last twelve (12) consecutive months of service or was not disconnected for nonpayment; or

   b. The Applicant can produce a letter regarding credit verification from an electric utility where service of a comparable nature was last received which states that the Applicant has had a timely payment history at time of service discontinuation; or

   c. Instead of a deposit, the Company receives deposit guarantee notification from a social or governmental agency acceptable to the Company. A surety bond may be provided as security for the Company in an amount equal to the required deposit.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

2. The Company may issue a non-assignable, non-negotiable receipt to the Applicant for the deposit. The inability of the Customer to produce his or her receipt will in no way impair the Customer's right to receive a refund of the deposit that is reflected on the Company records.

3. Cash deposits held by the Company twelve (12) months or longer will earn interest at the established one-year Treasury constant maturities rate, effective on the first business day of each year, as published in the Federal Reserve website.

   a. Residential Customers – Deposits or other instruments of credit will automatically expire or be refunded or credited to the Customer's account, after twelve (12) consecutive months of service during which time the Customer has not been delinquent more than two (2) times in a twelve (12) month period.

   b. All Customers – Upon final discontinuance of the use of the service and full settlement of all bills by the Customer, any deposit, not previously refunded, with accrued interest, if any, in accordance with the provisions of these Rules and Regulations will be returned to the Customer or, at the Company election, it may be applied to the payment of any unpaid accounts of the Customer and the balance, if any, returned to the Customer.

4. The Company may require a Customer to establish or reestablish a deposit if the Customer became delinquent in the payment of three (3) or more bills within a twelve (12) consecutive month period, or has been disconnected from service during the last twelve (12) months.

5. The Company may review the Customer's usage after service has been connected and adjust the deposit amount based upon the Customer's actual usage.

6. A separate deposit may be required for each meter installed.

7. Residential Customer deposits will not exceed two (2) times that Customer's estimated average monthly bill. Non-residential Customer deposits will not exceed two and one-half (2.5) times that Customer's maximum estimated monthly bill. If actual usage history is available, then that usage, adjusted for normal weather, will be the basis for the estimate.

8. The posting of a deposit will not preclude the Company from terminating service when the termination is due to the Customer's failure to perform any obligation under the agreement for service or any of these Rules and Regulations.

~~1)Establishment and Re-establishment of Credit/Deposits~~

~~i.Establishment of Credit~~

~~1.Residential~~

~~1)The Company shall not require a deposit from a new applicant for residential service if the applicant is able to meet any of the following requirements:~~

~~i.The applicant has had service of a comparable nature with the Company at another service location within the past two (2) years and was not delinquent in payment during the last twelve (12) consecutive months or disconnected for nonpayment.~~

~~ii.The applicant can produce a letter regarding credit verification from an electric utility where service of a comparable nature was last received which states that the applicant has had service of a comparable nature with the utility at another service location within the past two (2) years and was not delinquent in payment during the last twelve (12) consecutive months or discontinued for nonpayment.~~

~~iii.In lieu of a deposit, a new applicant may provide a surety bond as security for the Company in a sum equal to the required deposit.~~

~~a.When credit cannot be established to the satisfaction of the Company, the applicant will be required to:~~

~~B.Place a cash deposit to secure payment of bills for service as prescribed herein, or~~

~~C.Provide a surety bond acceptable to the Company in an amount equal to the required deposit.~~

~~SECTION 3~~
~~ESTABLISHMENT OF SERVICE~~
~~(continued)~~

~~B.Nonresidential~~

~~A.All nonresidential customers will be required to:~~

~~2)Place a cash deposit to secure payment of bills for service as prescribed herein, or~~

~~3)Provide a security acceptable to the Company for payment to the Company in an amount equal to the required deposit.~~

~~ii.Re-establishment of Credit~~

~~a.Former Customers with an Outstanding Balance~~
~~An applicant who has been a customer of the Company and who is indebted to the Company will be required to re-establish credit by paying all delinquent bills (unless collection of such debt is barred by law) and by depositing the amount prescribed herein.~~

~~F.Delinquent Customer~~
~~A customer whose electric service has been discontinued for nonpayment of bills for service may be required, before service is restored, to re-establish credit by paying all delinquent bills (unless collection of such debt is barred by law) and by depositing the amount prescribed herein.~~

~~b.The Company may require a residential customer to re-establish a deposit if the customer becomes delinquent in the payment of three (3) or more bills within a twelve (12) consecutive month period or has been disconnected from service during the last twelve (12) months.~~

~~1.Deposits~~

~~i.The amount of a deposit required by the Company to establish or re-establish credit shall be determined according to the following terms:~~

~~a.Residential customer deposits shall not exceed two times that customer's estimated average monthly bill.~~

~~b.Nonresidential customer deposits shall not exceed two and one-half times that customer's estimated maximum monthly bill.~~

~~ii.Applicability to Unpaid Accounts~~
~~Deposits and interest prescribed herein will be applied to unpaid bills owing to the Company when service is discontinued.~~

~~SECTION 3~~
~~ESTABLISHMENT OF SERVICE~~
~~(continued)~~

~~iii. Refunds of Deposits~~

~~A. Upon discontinuance of service, the Company will refund any balance of the deposit, plus applicable interest, in excess of unpaid bills. The Company will return any credit balance by check to the last known customer address.~~

~~B. After a residential customer has, for twelve (12) consecutive months, paid all bills prior to the next regular billing, the Company shall deem such customer to have satisfactorily established credit and shall refund the deposit with earned interest within thirty (30) days.~~

~~iv. Interest on Deposits~~

~~Deposits shall earn simple interest at the rate of six percent per annum payable upon refund of the deposit or upon discontinuance of service, or upon customer's request, but not more than once in any 12-month period, provided that such deposit has been held by the Company for a period of not less than 12 months. Deposit interest is not payable on accounts after an effort to refund the deposit has been made, and reasonable efforts to locate a customer for that purpose have been undertaken without success.~~

~~The posting of a deposit shall not preclude the Company from terminating the agreement for service, or suspending service, because of a customer's failure to make timely payment of any bill, customer's failure to perform any obligation under the agreement for service or a customer's violation of any of these Rules and Regulations.~~

~~v. The Company may review the customer's usage after service has been connected and adjust the deposit amount based upon the customer's actual usage.~~

~~vi. A separate deposit may be required for each meter installed.~~

~~vii. The Company shall issue a non-negotiable receipt to the applicant and/or customer for the deposit. The inability of the customer to produce such a receipt shall in no way impair his right to receive a refund of the deposit, which is reflected on the Company's records.~~

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

C. Conditions for Supplying Service

The Company reserves the right to determine the conditions under which service will be provided. Conditions for service and extending service to the Customer will be based upon the following:

1. Customer has wired his premises in accordance with the National Electric Code, City, County and/or State codes, whichever are applicable.

2. Customer has installed the meter loop in a suitable location approved by the Company.

3. In the case of a mobile home, the meter loop must be attached to a meter pole or to an approved support.

4. In case of temporary construction service, the meter loop must be attached to an approved support.

5. All meter loop installations must be in accordance with the Company's specifications and located at an outdoor location accessible to the Company.

6. Individual Customers may be required to have their property corner pins and/or markers installed to establish proper right-of-way locations.

7. Developers must have all property corner pins and/or markers installed necessary to establish proper locations to supply electric service to individual lots within subdivisions.

8. Where the installation requires more than one meter for service to the premises, each meter panel must be permanently marked (not painted) by the contractor or Customer to properly identify the portion of the premises being served.

9. The identification will be the same as the apartment, office, etc., served by that meter socket. The identifying marking placed on each meter panel will be impressed into or raised from a tab of aluminum, brass or other approved non-ferrous metal with minimum one-fourth (l/4) inch-high letters. This tag must be riveted to the meter panel. The impression must be deep enough to prevent the identification(s) from being obscured by subsequent painting of the building and attached service equipment.

10. The Company may require the assistance of the Customer and/or the Customer's contractor to open the apartments or offices at the time the meters are set, in order to verify that each meter socket actually serves the apartment or office indicated by the marking tag. In the case of multiple buildings the building or unit number and street address will be identified on the pull section in the manner described above.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

D. Grounds for Refusal of Service

The Company may refuse to establish service if any of the following conditions exist:

1. The Applicant has an outstanding amount due for the same class of service with the Company and the Applicant is unwilling to make satisfactory arrangements with the Company for payment.

2. A condition exists which in the Company's judgment is unsafe or hazardous to the Applicant, the general population, or the Company's personnel or facilities.

3. Refusal by the Applicant to provide the Company with a deposit when the Customer has failed to meet the credit criteria for waiver of deposit requirements.

4. Customer is known to be in violation of the Company's ~~tariffs~~Pricing Plans filed with and approved by the Commission.

5. Failure of the Customer to furnish such funds, service, equipment, and/or rights-of-way necessary to serve the Customer and which have been specified by the Company as a condition for providing service.

6. Customer fails to provide access to the meter that would be serving the Customer.

7. Applicant falsifies his or her identity for the purpose of obtaining service.

E. Service Establishment, Reestablishment and Reconnection Charge

1. The Company ~~shall~~will make a charge, as approved by the Commission, for ~~the~~ service establishment or re-establishment for service reads only ~~of electric services~~ as set forth in the Statement of Additional Charges. ~~A charge of thirteen dollars and fifty cents ($13.50) shall be assessed for the establishment or re-establishment of service.~~

2. The Company will make a charge, as approved by the Commission, for service establishment or reestablishment, other than service reads under usual operating procedures, for single-phase service only, during regular business hours as set forth in the Statement of Additional Charges.

~~2.~~3. Should single-phase service be established or re-established during a period other than regular working hours at the Customer's request, the Customer ~~shall~~will be required to pay an after-hours charge for the service connection as set forth in the Statement of Additional Charges~~of thirty-five dollars ($35.00)~~. Where Company scheduling will not permit service establishment on the same day as requested, the Customer may elect to pay the after-hours charge for establishment that day or his/her service will be established on the next available business day. Even so, a Customer's request to have the Company establish service after-hours is subject to the Company having Staff available; there is no guarantee that the Company will have the staffing available for service establishment , ~~or~~ reestablishment or reconnection outside of regular business hours. ~~Otherwise, service will be established on the next available normal working day.~~

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

4. The Company will make a charge, as approved by the Commission, for service establishment or reestablishment, other than service reads under usual operating procedures, for three-phase service only, during regular business hours as set forth in the Statement of Additional Charges.

5. Should three-phase service be established or reestablished during a period other than regular working hours at the Customer's request, the Customer will be required to pay an after-hours charge for the service connection as set forth in the Statement of Additional Charges. Where Company scheduling will not permit service establishment on the same day as requested, the Customer may elect to pay the after-hours charge for establishment that day or his/her service will be established on the next available business day. Even so, a Customer's request to have the Company establish service after-hours is subject to the Company having Staff available; there is no guarantee that the Company will have the staffing available for service establishment, reestablishment or reconnection outside of regular business hours.

~~3.~~6. For the purpose of this rule, the definition of service establishment is where the ~~Customer~~Applicant's facilities are ready and acceptable to the Company, the Applicant~~Customer~~ has obtained all required permits and/or inspections indicating that the Applicant~~Customer~~'s facilities comply with local construction safety and governmental standards and regulations, and the Company needs only to install a meter, read a meter, or turn the service on.

~~**SECTION 3**~~
~~**ESTABLISHMENT OF SERVICE**~~
~~(continued)~~

7. Reconnection Charge: Whenever the Company has discontinued service under its usual operating procedures because of any default by the Customer as provided herein, a reconnection charge not to exceed the charge for the reestablishment of service as set forth in the Statement of Additional Charges will be made and may be collected by the Company before service is restored. When, due to the behavior of the Customer, it has been necessary to discontinue service utilizing other than usual operating procedures, the Company will be entitled to charge and collect, through verifiable means, actual costs to restore service.

~~a. TEP will waive service establishment and re-establishment charges for customerCustomers switching from Direct Access to Standard Offer service.~~

F. Temporary Service

1. Applicants for temporary service may be required to pay the Company in advance of service establishment, the estimated cost of installing and removing the facilities necessary for furnishing the desired service.

2. Where duration of service is to be less than one month, the Applicant may also be required to advance a sum of money equal to the estimated bill for service.

3. Where the duration of service is to exceed one month, the Applicant may also be required to meet the deposit requirements of the Company.

4. If at any time during the term of the agreement for services the character of a temporary Customer's operations changes so that in the opinion of the Company the Customer is classified as permanent, the terms of the Company's line extension rules ~~shall~~will apply.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

G. Identification of Load and Premises: Upon request of the Company, the Applicant must identify the electric load and premises to be served by the Company at the time of application. If the service address is not recognized in terms of commonly-used identification system, the Applicant may be required to provide specific written directions and/or legal descriptions before the Company will be required to act upon a request for electric service.

H. Identification of Responsible Party: Any person applying on behalf of another Applicant for service to be connected in the name of or in care of another Applicant must furnish to the Company written approval from that Applicant guaranteeing payment of all bills under the account. The Customer is responsible in all cases for service supplied to the premises until the Company has received proper notice of the effective date of any change. The Customer will also promptly notify the Company of any change in billing address.

~~SECTION 3~~
~~ESTABLISHMENT OF SERVICE~~
~~(continued)~~

I. Tampering With or Damaging Company Equipment

1. The Customer agrees, when accepting service, that no one except authorized Company employees or agents of the Company will be allowed to remove or replace any Company owned equipment installed on Customer's property.

2. No person, except an employee or agent acting on behalf of the Company will alter, remove or make any connection to the Company's meter or service equipment.

3. No meter seal may be broken or removed by anyone other than an employee or agent acting on behalf of the Company; however the Company may give its prior consent to break the seal by an approved electrician employed by a Customer when deemed necessary by the Company.

4. The Customer will be held responsible for any broken seals, tampering, or interfering with the Company's meter(s) or any other Company owned equipment installed on the Customer's premises. In cases of tampering with meter installations, interfering with the proper working thereof, or any tampering, interfering, theft, or service diversion, including the falsification of Customer read-meter readings, Customer will be subject to immediate discontinuance of service. The Company will be entitled to collect from the Customer whose name the service is in, under the appropriate rate, for all power and energy not recorded on the meter as the result of such tampering, or other theft of service, and also additional security deposits as well as all expenses incurred by the Company for property damages, investigation of the illegal act, and all legal expenses and court costs incurred by the Company.

5. The Customer will be held liable for any loss or damage occasioned or caused by the Customer's negligence, want of proper care or wrongful act or omission on the part of any Customer's agents, employees, licensees or contractors.

SECTION 4
MINIMUM CUSTOMER INFORMATION REQUIREMENTS

~~ARTICLE NO. 4 - ELECTION OF RATE SCHEDULES~~

~~A. Upon application for service or upon request, the applicant or the customer shall elect the applicable rate schedule best suited to his requirements. The Company will assist in making such election, but shall not be held responsible for notifying the customer of the most favorable rate schedule and shall not be required to refund the difference in charges under different rate schedules.~~

~~B. Upon written notification of any material changes in the customer's installation or load conditions, the Company will assist in determining if a change in rate schedules is desirable, but not more than one (1) such change at the customer's request will be made within any twelve (12) month period.~~

~~C. The supply of electric service under a residential rate schedule to a dwelling involving some business or professional activity will be permitted only where such activity is of only occasional occurrence, or where the electricity used in connection with such activity is small in amount and used only by equipment which would normally be in use if the space were used as living quarters. Where the portion of a dwelling is used regularly for business, professional or other gainful purposes, and any considerable amount of electricity is used for other than domestic purposes, or electrical equipment not normally used in living quarters is installed in connection with such activities referred to above, the entire premises shall be classified as non-residential and the appropriate general service rate schedule shall be applied. The customer may, at his option, provide separate wiring so that the residential uses can be metered and billed separately under the appropriate residential service rate schedule, and the other uses under the appropriate general service rate schedule.~~

~~ARTICLE NO. 5 - MINIMUM CUSTOMER INFORMATION REQUIREMENTS~~

A. Information for Residential Customers

1. The Company ~~shall~~will make available upon Customer request not later than sixty (60) days from the date of the request, a concise summary of the rate schedule applied for by the~~such~~ Customer. The summary ~~shall~~will include the following:

   a. The monthly minimum or Customer charge, identifying the amount of the charge and the specific amount of usage included in the minimum charge, where applicable;

   b. Rate blocks, where applicable;

   c. Any adjustment factor(s) and method of calculation; and

   d. Demand charge, where applicable.

2. Upon application for service or upon request, the Applicant or the Customer will~~shall~~ elect the applicable Pricing Plan best suited to his requirements. The Company may~~will~~ assist in making this~~such~~ election, but will~~shall~~ not be held responsible for notifying the Customer of the most favorable Pricing Plan and will~~shall~~ not be required to refund the difference in charges under different Pricing Plans.

3. Upon written notification of any material changes in the Customer's installation or load conditions, the Company will assist in determining if a change in Pricing Plans is desirable, but not more than one (1) such change at the Customer's request will be made within any twelve (12) month period.

4. The supply of electric service under a residential rate schedule to a dwelling involving some business or professional activity will be permitted only where such activity is of only occasional occurrence, or where the

electricity used in connection with such activity is small in amount and used only by equipment which would normally be in use if the space were used as living quarters. Where the portion of a dwelling is used regularly for business, professional or other gainful purposes, and any considerable amount of electricity is used for other than domestic purposes, or electrical equipment not normally used in living quarters is installed in connection with such activities referred to above, the entire premises must~~shall~~ be classified as non-residential and the appropriate general service Pricing Plan~~rate schedule~~ will~~shall~~ be applied.

SECTION 4
MINIMUM CUSTOMER INFORMATION REQUIREMENTS
(continued)

5. Upon Customer request the Company ~~shall~~will make available within sixty (60) days from date of service commencement, a concise summary of the Company's ~~tariffs~~Pricing Plans or the Commission's Rules and Regulations concerning:

   a. Deposits;~~.~~

   b. Termination of service;~~.~~

   c. Billing and collection; and~~.~~

   d. Complaint handling.

6. Upon request of a Customer, the Company ~~shall~~will transmit a written statement of actual consumption for each billing period during the prior twelve (12) months unless this~~such~~ data is not reasonably ascertainable. But the Company will not be required to accept more than one such request from each Customer in a calendar year. Even so, t~~T~~he Company will charge a fee consistent with its ACC-approved ~~tariffs~~Pricing Plans and/or these Rules and Regulations for providing consumption, interval or other data to the~~a~~ Customer ~~or its agent, such as an ESP~~.

7. The Company ~~shall~~will inform all new Customers of their right to obtain the information specified above.

B. Information Required Due to Changes in ~~Tariffs~~Pricing Plans

1. The Company ~~shall~~will transmit to affected Customers a concise summary of any change in the Company's ~~tariffs~~Pricing Plans affecting those Customers.

2. This information ~~shall~~will be transmitted to the affected Customer within sixty (60) days of the effective date of the change.

SECTION 5
MASTER METERING

~~ARTICLE NO. 6 - MASTER METERING~~

A. Mobile Home Parks - New Construction/Expansion

1. The Company ~~shall~~will refuse service to all new construction and/or expansion of existing permanent residential mobile home parks unless the construction and/or expansion is individually metered by the Company. Line extensions and service connections to serve this new construction and/or~~such~~ expansion ~~shall~~will be governed by these Rules and Regulations. ~~the line extension and service connection tariff of the Company.~~

2. For the purpose of this rule, permanent residential mobile home parks ~~shall~~will mean mobile home parks where, in the opinion of the Company, the average length of stay for an occupant is a minimum of six months.

3. For the purpose of this rule, expansion means the acquisition of additional real property for permanent residential spaces in excess of that existing at the effective date of this rule.

B. Residential Apartment Complexes, Condominiums, and other Multi-unit Residential Buildings

1. Master metering ~~shall~~will not be allowed for new construction of apartment complexes and condominiums unless the building(s) will be served by a centralized heating, ventilation and/or air conditioning system and the contractor can provide to the Company an analysis demonstrating that the central unit will result in a favorable cost/benefit relationship.

2. At a minimum, the cost/benefit analysis ~~shall~~will consider the following elements for a central unit as compared to individual units:

   a. Equipment and labor costs;

   b. Financing costs;

   c. Maintenance costs;

   d. Estimated kWh usage;

   e. Estimated kW demand on a coincident demand and non-coincident demand basis (for individual units);

   f. Cost of meters and installation; and

   g. Customer accounting cost (one account vs. several accounts).

SECTION 6
SERVICE LINES AND ESTABLISHMENTS

~~ARTICLE NO. 7 - SERVICE LINES AND ESTABLISHMENTS~~

A. Priority and Timing of Service Establishments

1. After an Applicant has complied with the Company's application and deposit requirements and has been accepted for service by the Company and obtained all required easements, permits and/or inspections indicating that the Customer's facilities comply with local construction, safety and governmental standards or regulations, the Company ~~shall~~will schedule that Customer for service establishment.

2. Service establishments ~~shall~~will be scheduled for completion within five (5) ~~working day~~business days of the date the Customer has been accepted for service, except in those instances when the Customer requests service establishment beyond the five (5) ~~working day~~business day limitation.

3. When the Company has made arrangements to meet with a Customer for service establishment purposes and the Company or the Customer cannot make the appointment during the prearranged time, the Company ~~shall~~will reschedule the service establishment to the satisfaction of both parties.

4. The Company ~~shall~~will schedule service establishment appointments within a maximum range of four (4) hours during normal working hours, unless another time frame is mutually acceptable to the Company and the Customer.

5. Service establishments must~~shall~~ only be made ~~only~~ by the Company.

6. For the purposes of this rule, service establishments are where the Customer's facilities are ready and acceptable to the Company and the Company needs only to install or read a meter or turn the service on~~. Where the customer has opted for Direct Access service, the customer's ESP or its agent shall be responsible for installing the meter~~.

B. Service Lines

1. Customer-provided Facilities

   a. Each Applicant for service ~~shall~~will be responsible for all inside wiring, including the service entrance, ~~and~~ meter socket and conduit. For three-phase service, the Customer will provide, at his expense, all facilities, including conductors and conduit, beyond the Company-designated point of delivery.

SECTION 6
SERVICE LINES AND ESTABLISHMENTS
(continued)

b. Meters and service switches in conjunction with the meter must~~shall~~ be installed in a location where the meters will be readily and safely accessible for reading, testing and inspection and where such activities will cause the least interference and inconvenience to the Customer. Location of metering facilities ~~shall~~will be determined by the Company and may or may not be at the same location as the point of delivery. However, the meter locations ~~shall~~will not be on the front exterior wall of the home, or in the carport or garage, unless mutually agreed to between the home builder or Customer and the Company. Without cost to the Company, the Customer must~~shall~~ provide, at a suitable and easily accessible location, sufficient and proper space for installation of meters.

c. Where the meter or service line location on the Customer's premises is changed at the request of the Customer or due to alterations on the Customer's premises, the Customer, at his expense, must~~shall~~ provide and have installed all wiring and equipment necessary for relocating the meter and service line connection. The Company may assess a charge for moving the meter and/or service line.

d. Customer will provide access to the main switch or breaker for disconnecting load to enable safe installation and removal of company meters.

2. Overhead Service Connections - Secondary Service

a. ~~Service Drops:~~ Where the Company's distribution pole line is located on the Customer's premises, or on a street, highway, lane, alley, road or private easement immediately contiguous thereto, the Company will, at its own expense, furnish and install a single span of service drop from its pole to the Customer's point of attachment, provided such attachment is at the point of delivery and is of a type and so located that the service drop wires may be installed in a manner approved by the Company in accordance with good engineering practice, and in compliance with all applicable laws, ordinances, rules and regulations, including those governing clearances and points of attachments.

b. ~~Impaired Clearance:~~ Whenever any of the clearances required by the applicable laws, ordinances, rules or regulations of public authorities or standards of the Company from the service drops to the ground or any object become impaired by reason of any changes made by the owner or tenant of the premises, the Customer ~~shall~~will, at his own expense, provide a new and approved support, in a location approved by the Company, for the termination of the Company's service drop wires and ~~shall~~will also provide all service entrance conductors and equipment necessitated by the change of location.

c. ~~Service Entrance Conductors:~~ For each overhead service connection, the Customer ~~shall~~will furnish at his own expense a set of service entrance conductors that will~~which shall~~ extend from the point of ~~service~~ delivery at the point of termination of the Company's service drop on the Customer's support to the Customer's main disconnect switch. These~~Such~~ service entrance conductors ~~shall~~will be of a type and be in an enclosure which meets with the approval of the Company and any inspection authorities having jurisdiction.

d. The cost of any service line, in excess of that allowed at no charge, will be paid for by the Customer as a contribution in aid of construction.

SECTION 6
SERVICE LINES AND ESTABLISHMENTS
(continued)

3. Underground Service Connections - Secondary Service

~~a.General~~

a. In areas where the Company maintains an underground distribution system, individual services will be underground.

b. Whenever the Company's underground distribution system is not complete to the point designated by the Company where the service lateral is to be connected to the distribution system, the system may be extended in accordance with ~~ARTICLE NO.~~Section 7~~8~~.

c. ~~New Underground Service Connections~~For single-phase service, the Company will install a service lateral from its distribution line to the Customer's Company-approved termination facilities under the following conditions (unless otherwise agreed to by the Company and the Applicant):

i. The Customer, at his expense, ~~shall~~will perform the necessary trenching, conduit, conduit installation, backfill, landscape restoration and paving ~~or, in lieu thereof, pay the Company to do so;~~ and ~~shall~~will furnish, install, own and maintain termination facilities on or within the building to be served.

ii. The Company, at its expense, will furnish, install, own, and maintain the underground single-phase service cables to the Customer's Company-approved termination facilities.

iii. The Company will determine the minimum size and type of conduit and conductor for the single-phase service. ~~Where separately installed conduit or duct is required for single-phase service, t~~The Customer will furnish and install the conduit system, including pull ropes. The ownership of this~~such~~ conduit or duct ~~shall~~will be conveyed to the Company, and the Company will thereafter maintain this~~such~~ conduit or duct. ~~By mutual agreement and upon payment by the Customer of the estimated installed cost, the Company may furnish, install, own and maintain thissuch conduit or duct.~~ The maximum length of any ~~lateral~~service conductor ~~shall~~will be determined by the Company in accordance with accepted engineering practice in determining voltage drop, voltage flicker, and other relevant considerations.

d. For three-phase service, the Customer will provide at his expense all facilities, including conductors and conduit, beyond the Company-designated point of delivery.

C. Easements and Rights-of-Way

1. At no cost to the Company, each Customer must~~shall~~ grant adequate easements and rights-of-way satisfactory to the Company to ensure that Customer's proper service connection. Failure on the part of the Customer to grant adequate easements and rights-of-way ~~shall~~will be grounds for the Company to refuse service.

2. When the Company discovers that a Customer or his agent is performing work, has constructed facilities, or has allowed vegetation to grow adjacent to or within an easement or right-of-way and such work,

construction, vegetation or facility poses a hazard or is in violation of federal, state or local laws, ordinances, statutes, rules or regulations, or significantly interferes with the Company's access to equipment, the Company ~~shall~~will notify the Customer or his agent and ~~shall~~will take whatever actions are necessary to eliminate the hazard, obstruction or violation at the Customer's expense.

SECTION 6
SERVICE LINES AND ESTABLISHMENTS
(continued)

D. Number of Services to be Installed

The Company will not install more than one service, either overhead or underground, for any one building or group of buildings on a single premises, except as separate services may be installed for separate buildings or group of buildings where necessary for the operating convenience of the Company, where provided for in Pricing Plans~~tariff schedules~~, or where required by law or local ordinance.

E. Multiple Service Points

Unless otherwise expressly provided herein, or in a rate schedule or contract, any person, firm, corporation, agency or other organization or governmental body receiving service from the Company at more than one location or for more than one separately~~-~~operated business ~~shall~~will be considered as a separate Customer at each ~~such~~ location and for each ~~such~~ business. If several buildings are occupied and used by a Customer in the operation of a single business, then the Company, upon proper application, will furnish service for the entire group of buildings through one service connection at one point of delivery, provided all of these~~such~~ buildings are at one location on the same lot or tract, or on adjoining lots or tracts forming a contiguous plot (not separated by any public streets) wholly owned, or controlled, and occupied by the Customer in the operation of this~~such~~ single business. Dwelling units ~~shall~~will be served, metered and billed separately, except at the option of the Company.

SECTION 7
LINE EXTENSIONS

~~**ARTICLE NO. 8 - LINE EXTENSIONS**~~

Introduction

The Company will construct, own, operate and maintain lines along public streets, roads and highways which the Company has the legal right to occupy, and on public lands and private property across which rights-of-way and easements satisfactory to the Company may be obtained without cost to or condemnation by the Company.

A request for electric service often requires the construction of new distribution lines of varying distances. The distances and cost vary widely depending upon Customer's location and load size. With such a wide variation in extension requirements, it is necessary to establish conditions under which the Company will extend its electric facilities beyond this distance.

All extensions are subject to the availability of adequate capacity, voltage and Company facilities at the beginning point of an extension, as determined by the Company.

A standard policy has been adopted to provide service to Customers whose requirements are deemed by the Company to be economical and ordinary in nature.

In unusual circumstances, when the application of the provisions of this policy appear impractical, the Company will make a special study of the conditions to determine the basis on which service may be rendered.

A. General Requirements

1. Upon an Applicant's request for a line extension, the Company ~~shall~~will prepare, without charge, a preliminary ~~sketch~~electric design and ~~the~~ a rough estimate of the cost of installation ~~estimates~~ to be paid by said Applicant.

2. Any Applicant for a line extension requesting the Company to prepare detailed plans, specifications, or cost estimates may be required to deposit with the Company an amount equal to the estimated cost of preparation. The Company ~~shall~~will, upon request, make available within ninety (90) days after receipt of the deposit referred to above, these~~such~~ plans, specifications, or cost estimates of the proposed line extension. Where the Applicant authorizes the Company to proceed with construction of the extension, the deposit ~~shall~~will be credited to the cost of construction; otherwise the deposit ~~shall~~will be nonrefundable. If the extension is to include oversizing of facilities to be done at the Company's expense, appropriate details ~~shall~~will be set forth in the plans, specifications and cost estimates. Subdivision developers providing the Company with approved plats ~~shall~~will be provided with plans, specifications, or cost estimates within forty-five (45) days after receipt of the deposit referred to above.

SECTION 7
LINE EXTENSIONS
(continued)

3. Where the Company requires an Applicant to advance funds for a line extension, the Company ~~shall~~will provide a copy of the line extension Pricing Plan~~tariff~~ prior to the Applicant's acceptance of the utility's extension agreement.

4. All line extension agreements requiring payment by the Applicant ~~shall~~will be in writing and signed by each party.

5. The provisions of this rule apply only to those Applicants who, in the Company's judgment, will be permanent Customers of the Company. Applications for temporary service ~~shall~~will be governed by the Company's rules concerning temporary service applications. The Company reserves the right to delay the extension of facilities until the satisfactory completion of required site improvements, as determined by the Company, and an approved service entrance to accept electric service has been installed.

~~(continued)~~

B. Minimum Written Agreement Requirements

1. Each line extension agreement ~~shall~~will, at a minimum, include the following information:

   a. Name and address of Applicant(s);

   b. Proposed service address or location;

   c. Description of requested service;

   d. Description and sketch of the requested line extension;

   e. A cost estimate which includes materials, labor, and other costs as necessary;

   f. Payment terms;

   g. A concise explanation of any refunding provisions, if applicable;

   h. The Company's estimated commencement and completion dates for construction of the line extension; and

   i. A summary of the results of the economic feasibility analysis performed by the Company to determine the amount of advance required from the Applicant for the proposed line extension.

2. Each Applicant ~~shall~~will be provided with a copy of the written line extension agreement.

SECTION 7
LINE EXTENSIONS
(continued)

C. Line Extension Requirements

~~1.General~~

~~The Company will construct, own, operate and maintain lines along public streets, roads and highways which the Company has the legal right to occupy, and on public lands and private property across which rights-of-way and easements satisfactory to the Company may be obtained without cost to or condemnation by the Company.~~

~~SECTION 7~~
~~LINE EXTENSIONS~~
~~(continued)~~

~~2.~~1. Overhead Extensions to Individual ~~Residential and General Service (Rates 1, 2, 21, and 10)~~ Applicants and to the Perimeter of Duly-Recorded Real Estate Subdivisions

Except as otherwise provided herein, overhead extensions will be made as follows:

a. Free Extensions

Upon the Applicant's satisfactory completion of required site improvements, the Company will make extensions from its existing facilities of proper voltage and adequate capacity free of charge up to five hundred (500) feet. The distance of five hundred (500) feet is to be measured by the shortest feasible route along public streets, roads, highways, or suitable easements from the existing facilities to the Applicant's nearest point of delivery.

b. Extensions in Excess of Free Extension Distance

The Company ~~shall~~will make extensions in excess of five hundred (500) feet upon receipt of a non-interest bearing, refundable cash deposit with the Company to cover costs of construction computed at the rate of twenty ~~five~~ dollars and fifty-three cents ($20.53~~5.00~~) per foot for each foot of single-phase line extension or twenty-seven~~eight~~ dollars and thrty-eight cents ($~~8~~27.38~~00~~) per foot for each foot of three-phase line extension in excess of the free extension length (unless otherwise agreed to by the Company and the Applicant).

The foregoing charges of twenty~~five~~ dollars and fifty-three cents ($20.53~~5.00~~) and twenty-seven~~eight~~ dollars and thirty-eight cents ($~~8~~27.~~00~~38) per foot for line extensions are based on the company's current average cost of construction of distribution lines. The Company will review its costs periodically and ~~shall~~will file a ~~tariff~~Pricing Plan revision when such costs have changed by more than ten percent (10%) since the last revision of costs. Such revisions ~~shall~~will be subject to approval by the Commission before becoming effective.

SECTION 7
LINE EXTENSIONS
(continued)

c. Method of Refund

1) After a period of twelve (12) months from the date the Company is initially ready to render service from an extension, seventy-five percent (75%) of any revenue received from the Customer in excess of ten~~two~~ thousand two hundred and sixty-~~-~~five hundred dollars ($20~~5~~.~~00~~53 per ft. X 500 ft. = $~~2~~10,~~500~~265.00) for single-phase extensions or thirteen thousand six hundred and ninety~~four thousand~~ dollars ($27~~8~~.~~00~~38 per ft. X ~~2~~500 ft. = $13~~4~~,~~000~~690.00) for three-phase extensions during that period will be applied toward refunding the line extension deposit. The amount of refund may not exceed the amount of the deposit.

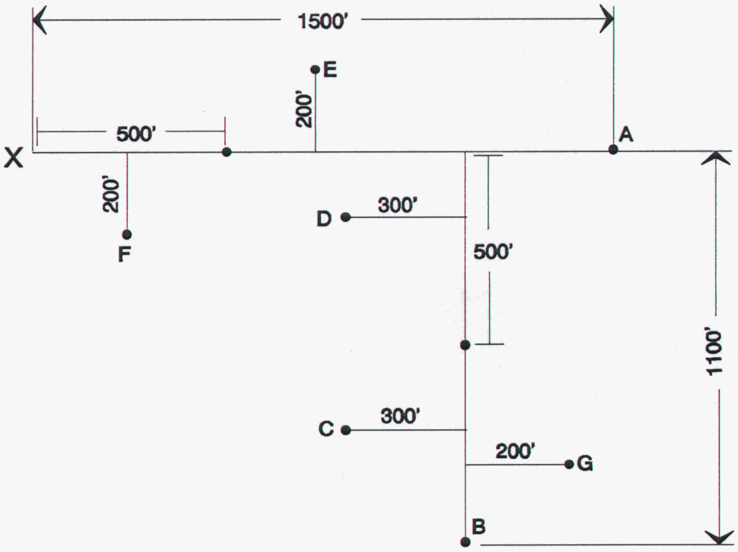
2) Deposit refunds will be made to a depositor when separately metered Customers are served directly from the line extension originally constructed to serve said depositor, providing the new line extension is less than five hundred (500) feet in distance, and the Customer to be served occupies a permanent structure designed for continued occupancy for either residential or business purposes, meeting established municipal, county or state codes as applicable.

The amount of the deposit refund will be equal to twenty~~five~~ dollars and fifty-three cents ($~~5~~20.~~00~~53) for single-phase or ~~eight~~twenty-seven dollars and thirty-eight cents ($27~~8~~.~~00~~38) for three-phase service multiplied by five hundred (500) feet less the actual footage of the new line extension required to serve the new Customer.

In no event ~~shall~~will the total of the refund payments made by the Company to a depositor be in excess of the deposit amount advanced.

A pictorial explanation of the method of refund for a single-phase line extension is as follows:

SECTION 7
LINE EXTENSIONS
(continued)



Applicant "A" – Customer makes refundable advance of $20,530 for footage over 500' at $20.53/foot.~~APPLICANT A) - Applicant puts up refundable deposit of $5,000.00 for footage over 500' at $5.00/foot.~~

Applicant "B" – Customer makes refundable advance of $12,318 for footage over 500' at $20.53/foot.~~APPLICANT B) - Applicant puts up refundable deposit of $3,000.00 for footage over 500' at $5.00/foot.~~ No refund to A for B's connection because B is over 500'.

Applicant "C" – Customer gets line at no cost. Refund goes to B at $20.53 x 200', or $4,106.00 because C ties directly into B's line and is less than 500'.~~APPLICANT C) - Applicant gets line at no cost. Refund goes to B at $5.00 x 200', or $1,000.00, because C ties directly into B's line and is less than 500'.~~

Applicant "D" – Customer gets line at no cost. Refund goes to B at $20.53 x 200', or $4,106.00, because it ties directly into B's line and is less than 500'.~~APPLICANT D) - Applicant gets line at no cost. Refund goes to B at $5.00 x 200', or $1,000.00, because D ties directly into B's line and is less than 500'.~~

Applicant "E" – Customer gets line at no cost. Refund goes to A at $20.53 x 300', or $6,159.00 because E ties directly into A's line and is less than 500'.~~APPLICANT E) - Applicant gets line at no cost. Refund goes to A at $5.00 x 300', or $1,500.00, because E ties directly into A's line and is less than 500'.~~

Applicant "F" – Customer gets line at no cost. Refund goes to A at $20.53 x 300', or $6,159.00 because F ties directly into A's line and is less than 500'.~~APPLICANT F) - Applicant gets line at no cost. Refund goes to A at $5.00 x 300', or $1,500.00, because F ties directly into A's line and is less than 500'.~~

Applicant "G" – Customer gets line at no cost. Refund goes to B at $20.53 x 300', or $6,159.00; B receives $4,106.00 since this is the remaining balance of the initial deposit.~~APPLICANT G) - Applicant gets line at no cost. Refund goes to B at $5.00 x 300', or $1,500.00; B receives $1,000.00 since this is the remaining balance of the initial deposit.~~

Note: This method requires that: i) The deposit advance made for an initial line extension cannot be refunded to the depositor unless a new line extension required to serve a new separately metered Customer is directly connected to the initial line extension; and ii) the new line extension is less than 5~~2~~00' in length.

SECTION 7
LINE EXTENSIONS
(continued)

~~2)~~3) Payment of eligible refunds will be made within ninety (90) days following receipt of notification to the Company that a qualifying permanent Customer has commenced receiving service from an extension.

~~3)~~4) The Customer may request an annual survey to determine if additional Customers have been connected to and are using service from the extension.

~~4)~~5) After a period of five~~ten~~ (~~10~~5) years from the date the Company is initially ready to render service from an extension, the Company ~~shall~~will review the deposit and make appropriate refunds then due, if any. Any unrefunded amount remaining thereafter will become the property of the Company and ~~shall~~will no longer be eligible for refund.

d. Extensions to Large Light and Power Customers (Rates~~-~~13, ~~and~~ 14, 85A, and 90A)

The Company will install, own and maintain, on an individual project basis, the distribution facilities necessary to provide permanent service to a large light and power Customer. Prior to the installation of facilities, the Customer ~~shall~~will be required to make a cash advance to the Company for any portion of the capital expenditures not justified by the estimated annual revenue derived from the unbundled charges associated with the facilities installed (e.g. revenue from the distribution secondary charge for 13.8 kV-facilities). Such advance, if any, will be in the amount determined by subtracting two (2) times the estimated annual revenue derived from the unbundled charges associated with the facilities installed from the total estimated installation costs.~~from the total estimated installation costs two (2) times the estimated annual revenue.~~ If the total of such charge is less than one hundred dollars ($100.00), the charge ~~shall~~will be waived by the Company.

Adjustments to the advance will be made after the initial twenty-four (24) month billing period, and the Company will refund to the amount by which the estimated advance exceeds the actual installation cost less the actual twenty-four (24) month billing.

~~3.~~2. Overhead or Underground Distribution Facilities Within a New Duly Recorded Residential Subdivision ~~for Permanent Service to Single and/or Multi-Family Residences~~

a. General

Required distribution facilities within a new duly recorded residential subdivision, including subdivision plats which are activated subsequent to their recordation, for permanent service to single and/or multi-family residences and/or unmetered area lighting, will be constructed, owned, operated and maintained by the Company in advance of applications for service by permanent Customers only after the Company and the Applicant have entered into a written contract which (unless otherwise agreed to by the Company and the Applicant) provides that:

SECTION 7
LINE EXTENSIONS
(continued)

1) The total estimated installed cost of such distribution facilities, exclusive of meters, services and exclusive of other costs as may be deemed as reasonable by the Company, is advanced to the Company as a refundable non-interest bearing cash deposit to cover the Company's cost of construction. In the event that the advance has not met the requirements for total refunding on or before the end of two (2) years from the date of installation of the Company's facilities, the advance ~~shall~~will further be utilized for reimbursement of the Company's cost of ownership as provided in Subs~~ARTICLE NO.~~ection 7~~8~~.C.~~3~~2.b. In lieu of the refundable cash deposit, the Applicant may elect to execute a Deferred Construction Deposit Agreement, secured by a bond or letter of credit in a form acceptable to the Company, equal to the deferred cash deposit, which guarantees the posting by the Applicant of the full cash deposit one (1) to four (4) years subsequent to the completion of construction of the Company's facilities. Letters of credit and bonds will not be acceptable where the original cash deposit would be less than one thousand dollars ($1,000.00).

2) Refundable advances will become non-refundable at such time and in such manner provided in ~~ARTICLE NO.8.~~Subsection 7.C.2~~3~~.b.

3) The Applicant will be responsible for ownership costs at such time and in such manner as provided in Subs~~ARTICLE NO.~~ection 7~~8~~.C.2~~3~~.b.

4) Where required line facilities within a subdivision exceed an average of five hundred (500) feet per lot, a nonrefundable cash amount equal to that portion of the total estimated installed cost represented by those required line facilities in excess of five hundred (500) feet per lot average ~~shall~~will be paid to the Company.

~~5)Where line facilities within a subdivision are provided for the operation of unmetered area lights, the Company may elect to retain ownership of said facilities for a maximum of two years unless otherwise agreed to in the written contract between the Company and the Applicant.~~

5) Underground Installations - Extensions of single-phase electric lines necessary to furnish permanent electric service to new residential buildings or mobile homes within a subdivision, in which facilities for electric service have not been constructed, for which applications are made by a developer ~~shall~~will be installed underground in accordance with the provisions set forth in this regulation except where it is not feasible from an engineering, operational, or economic standpoint. Extensions of single-phase underground distribution lines necessary to furnish permanent electric service within a new single family and/or multi-family residential subdivision will be made by the Company in advance of receipt of applications for service by permanent Customers in accordance with the following provisions (unless otherwise agreed to by the Company and the Applicant):

i. The subdivider or other Applicant ~~shall~~will provide at its expense the trenching, conduit, conduit installation, backfilling (including any imported backfill required), compaction, repaving, landscape restoration and any earthwork for pull boxes and transformer pad sites required to install the underground electric system, all in accordance with the specifications ~~and schedules~~ of the Company~~. Prior to the developer starting trenching on a project, the Company will advise the developer of the maximum amount of trench it will inspect each day on that project and select a mutually agreeable trench opening date. Within a 24-hour workday after the trench opening date, the Company will inspect up to the agreed upon footage of trench and if necessary similar footages on each subsequent workday. If the Company has not installed cable in an open trench within three working daybusiness days after the date the trench was inspected and approved for installation of cable, the Company will then provide any repairs of the trench necessary for proper installation of its cable. At its option, the Company may elect at the Applicant's expense to perform the activities necessary to fulfill the Applicant's responsibility hereunder, provided the expense to the Applicant is equal to or less than that which would otherwise be borne~~.

ii. Underground service will be installed, owned, operated and maintained as provided in ~~ARTICLE NO.~~Section 7 of these Rules and Regulations.

SECTION 7
LINE EXTENSIONS
(continued)

iii. Any underground electric distribution system requiring more than single-phase service is not governed by this Subs~~ARTICLE NO.~~ection ~~8~~7.C.~~3~~2, but rather ~~shall~~will be constructed pursuant to ~~this ARTICLE NO. 8.~~Subsection 7.C.4.

b. Method of Refund

1) On or after two (2) years subsequent to the installation of the Company's facilities, and thereafter every six (6) months, the Company will review the status of a subdivision to determine the percentage ratio that the number of lots or service locations occupied by permanent Customers bears to the total number of lots or service locations to be served by the extensions made within the subdivision. Refunds will be made prior to the actual occupancy by a permanent Customer if the lot or service location has been substantially completed so that in the judgment of the Company permanent occupancy will occur within a reasonable time. Such periodic review will continue until either: i) the calculated ratio equals a maximum of seventy-five percent (75%) at which time the total refund will be made to the Applicant; or ii) a five~~ten~~ (~~10~~5) year period subsequent to the completion of installation of the Company's facilities elapses. For purposes of computation of all charges and refundable deposit requirements under these Rules and Regulations, the installation of the Company's facilities ~~shall~~will be that date upon which the construction is determined to be completed and the facilities are entered into the Company records of Plant and Property~~ or, in case the developer has failed to complete backfill on underground installations, six (6) months after the installation of underground cable is completed, whichever comes first~~. The percentage ratio determined at the time of each review multiplied by the total refundable advance, less applicable cost of ownership charges previously deducted, if any, ~~shall~~will represent that portion of the advance qualified for refund. If the foregoing calculation indicates a refund is due, an appropriate refund of cash deposit, or reduction of the cash deposit requirement at the end of the deferral period in those cases where a Deferred Construction Deposit Agreement has been executed, will be made.

Refunds of cash deposits, less applicable cost of ownership charges, if any, will also be made by the Company within ninety (90) days following receipt of written notice from the developer requesting payment of earned refund, provided that the earned refund due represents a minimum of twenty percent (20%) of the total amount of the advance. Furthermore, if at any time a maximum of seventy-five percent (75%) or more of the total refundable advance qualifies for refund, any balance of the advance remaining, after applicable cost of ownership charges, if any, have been deducted, will be refunded. No payment will be made of the Company in excess of the total refundable advance less applicable cost of ownership charges, if any, nor after a period of five~~ten~~ (5~~10~~) years subsequent to the completion of construction of the Company's facilities. Any unrefunded amount remaining at the end of the five~~ten~~ (~~10~~5) year period will become nonrefundable and the property of the Company.

SECTION 7
LINE EXTENSIONS
(continued)

2) In the event that any portion of an advance has not qualified for refund at the time of each review, the developer will be responsible for the Company's cost of ownership charges based on the average (mean) of the electric facilities represented by:

~~1)~~i) that portion of the advance not qualified for refund at the time of current review, and
~~2)~~ii) that portion of the advance not qualified for refund at the time of the last periodic review.

When the advance is in the form of a cash deposit, the semi-annual cost of ownership charges ~~shall~~will be equal to the average of (i~~1~~) and (~~2~~ii) above multiplied by five and one-half percent (5-1/2%). When the advance is in the form of a Deferred Construction Deposit, the semi-annual cost of ownership charges ~~shall~~will be equal to (~~1~~i) and (ii~~2~~) above multiplied ~~-~~by the sum of five and one-half percent (5-1/2%) plus one-half of the original cost equivalent of the rate of return, expressed as a percent, last allowed to the Company by the Commission. Payment of such cost of ownership charges, which ~~shall~~will be computed and paid at the time of each review after the initial review, will be made in the following manner:

When the advance is in the form of a cash deposit, a deduction of cost of ownership charge will be made by the Company from the cash deposit.

When the advance is in the form of a Deferred Construction Deposit, the Company ~~shall~~will bill and developer ~~shall~~will pay to Company said cost of ownership charge. In the event that the Applicant fails to pay the cost of ownership charge when due, the Company will exercise its rights provided for in the Deferred Construction Deposit, and will call the bond or letter of credit.

The portion of the original advance on which cost of ownership charges are computed will not be reduced for purposes of that computation by amounts deducted previously for cost of ownership charges.

SECTION 7
LINE EXTENSIONS
(continued)

~~4.~~3. Underground Extensions to Individual Applicants and the Perimeter of Duly Recorded Real Estate Subdivisions

a. General

Underground line extensions will generally be made only where mutually agreed upon by the Company and the Applicant, or in areas where the Company does maintain underground distribution facilities for its operating convenience.

1) ~~Normally, U~~Underground extensions will be ~~installed,~~ owned, operated and maintained by the Company, provided the Applicant pays in advance a non-refundable sum equal to the estimated difference between the cost, exclusive of meters and services, of the underground extension and an equivalent overhead extension.

2) In addition to the non-refundable sum, the Applicant ~~shall~~will (unless otherwise agreed to by the Company and the Applicant) make such refundable deposit as otherwise would have been required under these Rules and Regulations if the extension had been made by overhead construction.

3) ~~Where mutually agreed upon by the Company and the Applicant, all or a portion of the Applicant's obligation for payment of the non-refundable sum provided in subsection a., above, may be met by the installation by t~~The Applicant will install~~of a portion or~~ all of the required underground duct system (including all or a portion of the necessary trenching, backfilling, conduits, ducts, transformer and equipment pads, manholes, and pull boxes) in accordance with the Company's specifications and subject to the Company's inspection and approval. Upon acceptance and approval by the Company, the Applicant will grant to the Company the exclusive right to use and occupy said duct system or, at the option of the Company, will transfer ownership thereof to the Company.

4) Refunds of cash deposits ~~shall~~will be made in the same manner as provided for overhead extensions to individual Applicants for service, in accordance with the applicable provisions of ~~ARTICLE NO.~~Subsection 7~~8., Section~~ C.

5) Underground services ~~shall~~will be installed, owned, operated and maintained as provided in ~~ARTICLE NO.~~Section 6~~7~~ of these Rules and Regulations.

SECTION 7
LINE EXTENSIONS
(continued)

4. Replacement of Overhead with Underground Distribution Facilities

   a. Where a Customer has requested that existing overhead distribution facilities be replaced with underground distribution facilities, the total cost of such replacement will be paid by the Customer.

   b. Mandated Undergrounding Cost Recovery

      When the Company is required to construct a new electric system underground, or place an existing overhead electric system underground during a maintenance or upgrading project due to a State, County, or Municipal regulation or requirement, the cost differential between an overhead system and an underground system shall be calculated by an established methodology.

      Any existing electric circuits within a one-mile radius of the new system that benefits from either N – 1 protocols or enjoys reduced ampacity loads as a result of the newly undergrounded system shall be identified and catalogued by the Company.

      When a new Customer requests electric service and the source of that service is either the undergrounded system or any one of the existing electric circuits within a one-mile radius of the underground system, and the new Customer's site has been previously catalogued as benefiting from the new underground system, that Customer shall pay an additional charge for connecting to the Company's system.

      The new Customer's charge shall be calculated on the following basis:

      i. For every 25 kVA of transformer capacity required to meet the customer's needs, then said customer shall be responsible for reimbursing the Company for one(1) percent of the calculated cost differential of the underground system that the Customer is benefited from.

      ii. The Company shall provide the customer a worksheet showing the cost differential expenses for the underground system and the calculations resulting in the assessment against the new service.

      iii. The Company shall accurately track the assessments made to cover the cost differential expenses for each electric system that was required to be constructed underground, and shall make those records available to any person who may request them.

SECTION 7
LINE EXTENSIONS
(continued)

Example:

The Company needs to install a three-phase feeder line within a road right-of-way that has been identified as a Scenic Corridor or Gateway Route by a local jurisdiction. The regulation or ordinance requires the system be placed underground. The Company performs a cost estimate and determines that the difference between constructing the system overhead and underground (differential costs) is $250,000.00.

A new Customer is requesting service from an existing electrical circuit that has benefited from either increased reliability or load-carrying capacity, and the new Customer is within a one mile radius of the underground system that was mandated to be placed underground. The Customer is building a 25-lot subdivision and the engineering design requires installing four, 50 kVA pad mount transformers.

The Customer would be assessed for 8% of the cost differential on the underground system or $20,000.00. (200 kVA / 25 kVA = 8. 1% x 8 = 8%. $250,000.00 x .08 = $20,000.00.)

~~In areas affected by public interest, the Company may, at its expense, replace its existing overhead distribution facilities with underground facilities along public streets, roads and alleys which the Company has the legal right to occupy and on public lands and private property across which rights-of-way satisfactory to the Company may be obtained without cost or condemnation by the Company, provided that:~~

~~The governing body of the city or town or of unincorporated areas of the county in which such distribution facilities are and will be located has:~~

~~b.Determined, after consultation with the Company and after holding public hearings on the subject, that such undergrounding is in the general public interest for one or more of the following reasons:~~

~~1)Such undergrounding will avoid or eliminate unusually heavy concentration of overhead distribution facilities;~~

~~2)Said street, road, alley or right-of-way is in an area extensively used by the general public and carries a heavy volume of pedestrian or vehicular traffic;~~

~~3)Said street, road, alley or right-of-way adjoins or passes through a civic area or public recreation area or an area of unusual scenic interest to the general public.~~

~~c.Adopted an ordinance creating an underground district in the area requiring, among other things:~~

~~2)That all existing overhead communication and electric distribution facilities in such district shall~~will ~~be removed;~~

~~3)That each property owner served from such electric overhead distribution facilities shall~~will ~~provide, in accordance with the Company's rules for underground service, all electrical facility changes on his premises necessary to receive service from the underground facilities of the Company as soon as such are available; and~~

~~4)That the Company is authorized to discontinue its overhead service.~~

~~(b) The Company's total annual expenditure for any calendar year for such undergrounding within any city or town or the unincorporated area of any county shall~~will ~~not exceed two percent (2%) of the preceding year's revenue of the Company derived from:~~

~~1. Customers therein who were served under the Company's electric rate schedules numbered 1, 2, 21 and 51; and~~

~~2. The sale of electric energy to the city or town within its corporate limits, or where applicable to the county within the unincorporated area of the county.~~

~~Any unexpended portion of the two percent (2%) of such revenue may be carried forward at the discretion of the Company for up to two additional years and for a reasonable and necessary additional period of time in furtherance of any active undergrounding program. No funds will be carried over except for ongoing projects where the findings and ordinances as provided by subsectionARTICLE 78.C.4.b(1)(a) have been made by the governing body. Where amounts are not expended or carried over for conversion within the community to which they are initially allocated, the Company may assign same where additional participation on a project is warranted or reallocate same to projects within communities with active undergrounding programs. Where there is a carryover, the Company has the right to set, as determined by its capability, reasonable limits on the rates of performance of the work to be financed by the funds carried over. Any costs for the conversion of overhead facilities to underground required by reason of the provisions of any franchise or ordinance shall~~will ~~be charged first against these budgeted funds. If, after installation, the underground distribution facilities constructed pursuant to this subsection are required to be moved, relocated or removed to avoid interference with public works or improvements and the Company is not reimbursed for the cost of such relocation or removal by the city, town, county or improvement district constructing such works, such cost shall~~will ~~be charged against these budgeted funds. All engineering and estimating costs arising by reason of the request by the governing body of the city, town or county for preliminary cost information for potential underground districts shall~~will ~~be charged against these budgeted funds. Except in those instances where the existing overhead facilities would in any event have to be relocated overhead at the cost of the Company by reason of street widening, change of grade, etc., the cost of conversion to be charged against these funds shall~~will ~~include the net cost of retirement of the overhead facilities; i.e., the original cost of the overhead plant less accrued depreciation plus or minus the net cost of removal.~~

~~(c) The undergrounding shall~~will ~~extend for a minimum distance of one (1) block or six hundred (600) feet, whichever is the lesser.~~

~~(2) In circumstances other than those covered by subsection a., above, the Company will replace its existing overhead distribution facilities with underground distribution facilities along public streets, roads and alleys which the Company has the legal right to occupy, and on public lands and private property across which rights-of-way satisfactory to the Company may be obtained without cost or condemnation by the Company, when requested by a Customer or Customers where all of the following conditions are met:~~

~~(a)~~ 1. ~~All property owners served from the overhead facilities to be removed first agree in writing to perform the wiring changes on their premises so that service may be furnished from the underground distribution system in accordance with the Company's Rules and Regulations and that the Company may discontinue its overhead service upon completion of the underground facilities; or,~~

2. ~~Suitable legislation is in effect requiring such property owners to make such necessary wiring changes and authorizing the Company to discontinue its overhead service.~~

~~(b) The Customer has:~~

1. ~~Paid a nonrefundable sum equal to the remaining undepreciated original cost of the existing overhead electric facilities to be removed plus the cost of removal of such overhead electric facilities less the salvage value of the facilities removed;~~

2. ~~Furnished and installed the pads and vaults for transformers and associated equipment, conduit, ducts, pull boxes, and performed other work related to structures and substructures, including breaking of pavement, trenching, backfilling and repaving required in connection with the installation of the underground system, all in accordance with the Company's specifications or, in lieu thereof, paid the Company to do so;~~

3. ~~Upon acceptance and approval of the facilities by the Company, granted to the Company the exclusive right to use and occupy same or, at the option of the Company, transferred ownership of such facilities in good condition to the Company; and,~~

4. ~~Paid a nonrefundable sum equal to the excess, if any, of the estimated costs exclusive of meters and services of completing the underground system and building a new equivalent overhead system.~~

~~(c) The area to be undergrounded shall~~will ~~include both sides of a street, road, alley or right-of-way for at least one (1) block or six hundred (600) feet, whichever is the lesser, and all existing overhead communication and electric distribution facilities within the area will be removed.~~

~~(d) Payment of these costs to the Company in advance of construction shall~~will ~~not be required where an improvement district has been formed pursuant to A.R.S. 1968, Chapter 160, Section 2, Article 6.1, 40-341 through 40-356, thereby securing payment of~~ Customer ~~costs.~~

~~(3) Unless otherwise agreed to by the Company and the Applicant, in circumstances other than those covered by subsections a. or b., above, where mutually agreed upon by the Company and a~~ Customer, ~~overhead distribution facilities may be replaced with underground distribution facilities provided the~~ Customer ~~requesting the change pays, in advance, a nonrefundable sum equal to the remaining undepreciated original cost of the existing overhead electric facilities to be removed plus the cost of removal of such overhead electric facilities less the salvage value of the facilities removed. In addition, the~~ Customer ~~must comply with the requirements set forth in ARTICLE NO. 8.~~subsection ~~7.C.4.b(2)(b) paragraphs~~ 2., 3. ~~and~~ 4.

~~(4) The term "underground distribution system " means an electric distribution system with pad-mounted or underground transformers, at the Company's option, with all wires installed underground except those wires in surface-mounted equipment enclosures. It~~

~~shall~~will ~~not include poles, overhead wires and associated overhead structures used for the transmission of electric energy at nominal voltage in excess of 14,000 volts.~~

~~(5) Underground services will be installed and maintained as provided in ARTICLE NO.~~Section ~~6~~7 ~~of these Rules and Regulations.~~

~~c.~~5. Conversion from Single-Phase to Three-Phase Service

Where it is necessary to convert all or any portion of an existing underground distribution system from single-phase to three-phase service to a Customer, the total cost of such conversion ~~shall~~will be paid by the Customer.

~~5.~~6. Long Term Rental Mobile Home Park, Townhouses, Condominiums and Apartment Complexes

Line extensions to long term rental mobile home parks, townhouses, condominiums and apartment complexes ~~shall~~will be made by the Company under terms and conditions provided in ~~ARTICLE NO. 8.~~Subsection 7.C.~~2~~1. The Company will, when requested by the Customer, install, own and maintain internal distribution facilities and individual metering for said development in accordance with the provisions pertaining to duly recorded real estate subdivisions as stated in ~~ARTICLE NO. 8~~ Subsection 7.C.~~3~~2 hereof.

7. ~~6.~~ Special Conditions

a. Contracts

Each subdivider or other Applicant for service requesting an extension over the free distance, or in advance of applications for service to permanent Customers, or in advance of completion of required site improvements ~~shall~~will (unless otherwise agreed to by the Company and the Applicant) be required to execute contracts covering the terms under which the Company will install lines at its own expense, or contracts covering line extensions for which advance deposits ~~shall~~will (unless otherwise agreed to by the Company and the Applicant be made in accordance with the provisions of these Rules and Regulations or of the applicable rate schedules.

SECTION 7
LINE EXTENSIONS
(continued)

b. Primary Service and Metering

The Company will provide primary service to a point of delivery, such point of delivery to be determined by the Company. The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load. The system will be treated as primary service for the purposes of billing. The Company reserves the right to approve or require modification to the Customer's distribution system prior to installation, and the Company will determine the voltage available for primary service. Instrument transformers, metering riser poles and associated equipment to be installed and maintained by the Company may be at the Customer's expense.

c. Advances under Previous Rules and Contracts

Amounts advanced under the conditions established by a rule previously in effect will be refunded in accordance with the requirements of such contract under which the advance was made.

~~c.~~d. Extensions for Temporary Service

Extensions for temporary service or for operations of a speculative character or questionable permanency will not be made under this Section 7~~ARTICLE NO. 8~~, but will be made in accordance with the provisions pertaining to temporary service.

~~d.~~e. Exceptional Cases

Where unusual terrain, location, soil conditions, or other unusual circumstances make the application of these line extension rules impractical or unjust to either party or in the case of extension of lines of other than standard distribution voltage, service under such circumstances will be negotiated under special agreements specifying terms and conditions covering such extensions.

~~e.~~f. Special or Excess Facilities

Under this rule, the Company ~~shall~~will install only those facilities which it deems are necessary to render service in accordance with the rate schedules. Where the Customer requests facilities which are in addition to, or in substitution for, the standard facilities which the Company normally would install, the extra cost thereof ~~shall~~will be paid by the Customer, unless otherwise agreed to by the Company and the Applicant.

~~f.~~g. Unusual Loads

Line extensions to unusually small loads not consisting of a residence or permanent building (e.g. individual lights, wells, signs, etc.) will not be granted the five hundred (500) foot free allowance but will instead be required to advance any costs of service in excess of their estimated two years annual revenue. Refunding will be according to ~~ARTICLE NO. 8.~~Subsections 7.C.1.c.2) and 7.C.1.d ~~78.c(2)~~.

SECTION 7
LINE EXTENSIONS
(continued)

D. Construction / Facilities Related Income Taxes

Any federal, state or local income taxes resulting from the receipt of a contribution or advance in aid of construction in compliance with this rule is the responsibility of the Company and will be recorded as a deferred tax asset and reflected in the Company's rate base for ratemaking purposes.

However, if the estimated cost of facilities for any service line or distribution main extension exceeds $500,000, the Company may require the Applicant to include in the contribution or advance an amount (the "gross up amount") equal to the estimated federal, state or local income tax liability of the Company resulting from the contribution or advance, computed as follows:

$$\text{Gross Up Amount} = \frac{\text{Estimated Construction Cost}}{(1 - \text{Combined Federal-State-Local Income Tax Rate})}$$

After the Company's tax returns are completed, and actual tax liability is known, to the extent that the computed gross up amount exceeds the actual tax liability resulting from the contribution or advance, the Company shall refund to the Applicant an amount equal to such excess. When a gross-up amount is to be obtained in connection with an extension agreement, the contract will state the tax rate used to compute the gross up amount, and will also disclose the gross-up amount separately from the estimated cost of facilities. In subsequent years, as tax depreciation deductions are taken by the Company on its tax returns for the constructed assets with tax bases that have been grossed-up, a refund will be made to the Applicant in an amount equal to the related tax benefit. Such refunds will be in addition to any required refunds of actual construction costs required by the extension agreement. In lieu of scheduling such refunds over the remaining tax life of the constructed assets, a reduced lump sum refund may be made at the time when actual construction costs are refunded in full. This lump sum payment shall reflect the net present value of remaining tax depreciation deductions discounted at the company's authorized rate of return.

SECTION 8
PROVISION OF SERVICE

~~ARTICLE NO. 9 - PROVISION OF SERVICE~~

A. Company Responsibility

1. The Company ~~shall~~will be responsible for the safe transmission and distribution of electricity~~, as set forth in the standards specified in ARTICLE NO. 9.E,~~ until it passes the point of delivery to the Customer.

2. The Company ~~shall~~will be responsible for maintaining in safe operating condition~~, as set forth in the standards specified in ARTICLE NO. 9.E,~~ all meters, equipment and fixtures installed on the Customer's premises by the Company for the purpose of delivering electric service to the Customer. The Company, however, will not be responsible for the condition of meters, equipment, and fixtures damaged or altered by the Customer.

3. The Company may, at its option, refuse service until the Customer has obtained all required permits and/or inspections indicating that the Customer's facilities comply with local construction and safety standards, including any applicable Company specifications.

B. Customer Responsibility

1. Each Customer ~~shall~~will be responsible for maintaining in safe operating condition all Customer facilities on the Customer's side of the point of delivery.

2. Each Customer ~~shall~~will be responsible for safeguarding all Company property installed in or on the Customer's premises for the purpose of supplying utility service to that Customer.

3. Each Customer ~~shall~~will exercise all reasonable care to prevent loss or damage to Company property, excluding ordinary wear and tear. The Customer ~~shall~~will be responsible for loss of, or damage to, Company property on the Customer's premises arising from neglect, carelessness, misuse, diversion or tampering and ~~shall~~will reimburse the Company for the cost of necessary repairs or replacements.

4. Each Customer, regardless of who owns the meter, ~~shall~~will be responsible for payment for any equipment damage and/or estimated unmetered usage and all reasonable costs of investigation resulting from unauthorized breaking of seals, interfering, tampering or bypassing the utility meter.

5. Each Customer ~~shall~~will be responsible for notifying the Company of any equipment failure identified in the Company's equipment.

SECTION 8
PROVISION OF SERVICE
(continued)

6. Each Customer ~~shall~~will be responsible for informing the Company of, and meeting the Company's requirements regarding, On-site Generation that the Customer or its agent intends to interconnect to the Company's transmission and distribution system.

7. The Customer, at his expense, may install, maintain and operate ~~at his expense such~~ check-measuring equipment as desired and of a type approved by the Company, provided that such equipment ~~shall~~will be installed so as not to interfere with operation of the Company's equipment, and provided that no electric energy ~~shall~~will be re-metered or sub-metered for resale to another or to others, except where such re-metering ~~shall~~will be done in accordance with the applicable orders of the Commission.

C. Continuity of Service

The Company ~~shall~~will make reasonable efforts to supply a satisfactory and continuous level of service. However, the Company ~~shall~~will not be responsible for any damage or claim of damage attributable to any interruption or discontinuation of service resulting from:

1. Any cause against which the Company could not have reasonably foreseen or made provision for (*i.e.*, force majeure);

2. Intentional service interruptions to make repairs or perform routine maintenance; or

3. Curtailment, including brownouts or blackouts.

~~2.Failure of equipment owned and/or installed by the ESP, its agent, or the .~~

D. Service Interruptions

1. The Company ~~shall~~will make reasonable efforts to re-establish service within the shortest possible time when service interruptions occur.

2. When the Company plans to interrupt service for more than four (4) hours to perform necessary repairs or maintenance, the Company ~~shall~~will attempt to inform affected Customers at least twenty-four (24) hours in advance of the scheduled date, and these~~such~~ repairs ~~shall~~will be completed in the shortest possible time to minimize the inconvenience to the Customers of the Company.

3. In the event of a national emergency or local disaster resulting in disruption of normal service, the Company may, in the public interest, interrupt service to other Customers to provide necessary service to civil defense or other emergency service agencies on a temporary basis until normal service to these agencies can be restored.

SECTION 8
PROVISION OF SERVICE
(continued)

4. The Commission ~~shall~~will be notified of interruption in service affecting the entire system or any major division thereof. The interruption of service and cause ~~shall~~will be reported by telephone to the Commission within four (4) hours after the responsible representative of the Company becomes aware of said interruption. A written report to the Commission ~~shall~~will follow.

E. Interruption of Service and Force Majeure

1. The Company ~~shall~~will make reasonable provision to supply a satisfactory and continuous electric service, but does not guarantee a constant or uninterrupted supply of electricity. The Company ~~shall~~will not be liable for any damage or claim of damage attributable to any temporary, partial or complete interruption or discontinuance of electric service attributable to a force majeure condition as set forth at Subs~~ARTICLE NO.~~ections 8.E.4. and 8.E.5.~~ 12,~~ or to any other cause which the Company could not have reasonably foreseen and made provision against, or which, in the Company's judgment, is necessary to permit repairs or changes to be made in the Company's electric generating, transmission or distribution equipment or to eliminate the possibility of damage to the Company's property or to the person or property of others.

2. Whenever the Company deems that a condition exists to warrant interruption or limitation in the service being rendered, this~~such~~ interruption or limitation ~~shall~~will not constitute a breach of contract and ~~shall~~will not render the Company liable for damages suffered thereby or excuse the Customer from further fulfillment of the contract.

3. The use of electric energy upon the premises of the Customer is at the risk of the Customer. The Company's liability ~~shall~~will cease at the point where its facilities are connected to the Customer's wiring.

4. Neither the Company nor the Customer ~~shall~~will be liable to the other for any act, omission or circumstances (including, with respect to the Company, but not limited to, inability to provide service) occasioned by or in consequence of the following:

   a. flood, rain, wind, storm, lightning, earthquake, fire, landslide, washout or other acts of the elements;

   b. accident or explosion;

   c. war, rebellion, civil disturbance, mobs, riot, blockade or other act of the public enemy;

   d. acts of God;

   e. interference of civil and/or military authorities;

   f. strikes, lockouts or other labor difficulties;

   g. vandalism, sabotage or malicious mischief;

SECTION 8
PROVISION OF SERVICE
(continued)

h. usurpation of power, or the laws, rules, regulations or orders made or adopted by any regulatory or other governmental agency or body (federal, state or local) having jurisdiction of any of the business or affairs of the Company or the Customer, direct or indirect;

i. breakage or accidents to equipment or facilities;

j. lack, limitation or loss of electrical or fuel supply; or

k. or any other casualty or cause beyond the reasonable control of the Company or the Customer, whether or not specifically provided herein and without limitation to the types enumerated, and which by the exercise of due diligence such party is unable to prevent or overcome; provided, however, that nothing contained herein ~~shall~~will excuse the Customer from the obligation of paying for electricity delivered or services rendered.

5. A failure to settle or prevent any strike or other controversy with employees or with anyone purporting or seeking to represent employees ~~shall~~will not be considered to be a matter within the control of the Company.

6. Nothing contained in this Section will excuse the Customer from the obligation of paying for electricity delivered or services rendered.

F. General Liability

1. Company will not be responsible for any third-party claims against Company that arise from Customer's use of Company's electricity.

2. Customer will indemnify, defend and hold harmless the Company (including the costs of reasonable attorney's fees) against all claims (including, without limitation, claims for damages to any business or property, or injury to, or death of, any person) arising out of any act or omission of the Customer, or the Customer's agents, in connection with the Company's service or facilities.

3. The liability of the Company for damages of any nature arising from errors, mistakes, omissions, interruptions, or delays of the Company, its agents, servants, or employees, in the course of establishing, furnishing, rearranging, moving, terminating, or changing the service or facilities or equipment will not exceed an amount equal to the charges applicable under the Company's Pricing Plans (calculated on a proportionate basis where appropriate) to the period during which the error, mistake, omission, interruption or delay occurs.

4. In no event will the Company be liable for any incidental, indirect, special, or consequential damages (including lost revenue or profits) of any kind whatsoever regardless of the cause or foreseeability thereof.

5. The Company will not be responsible for any loss or damage occasion or caused by the negligence or wrongful act of the Customer or any of his agents, employees or licensees in installing, maintaining, using, operating or interfering with any electric facilities.

SECTION 8
PROVISION OF SERVICE
(continued)

G. Construction Standards and Safety

The Company ~~shall~~will construct all facilities in accordance with the provision of the ANSI C2 Standards (National Electric Safety Code, 1997~~1990~~ edition, and other amended editions as are adopted by the Commission), the 1995~~1989~~ ANSI B.31.1 Standards, the ASME Boiler and Pressure Vessel Code, and other applicable American National Standards Institute Codes and Standards, except for such changes as may be made or permitted by the Commission from time to time. In the case of conflict between codes and standards, the more rigid code or standard will apply.

SECTION 9
CHARACTER OF SERVICE – VOLTAGE, FREQUENCY AND PHASE

~~ARTICLE NO. 10 - VOLTAGE, FREQUENCY AND PHASE~~

A. Electric energy furnished under these Rules and Regulations will be alternating current, sixty (60) hertz single or three-phase, at the standard, nominal voltages specified by the Company. The following nominal voltages are available on the Company's system:

1. Residential Customers: 120/240 volts single-phase

2. General Service or Light and Power Customers:

   a. Single-Phase: 120/240 volts (all areas)

   b. Three-Phase:

      1) 120/240 volts 4 wire delta (from overhead system only)*

      2) 240/480 volts 4 wire delta (from overhead system only)*

      3) 120/208 volts 4 wire wye

      4) 277/480 volts 4 wire wye

   * This may be available in some existing underground areas.

B. The primary voltage supplied will depend on the Customer's load and the system voltage available at that location; it will be specified by the Company. Normally, this will be one of the following nominal distribution or sub-transmission voltages: ~~2400/4160 volts 4 wire wye,~~ 7970/13800 volts 4 wire wye, or 46,000 volts 3 wire delta. The actual standard nominal voltages available to a specific Customer will depend on location, load, and type of system in the area and will be specified by the Company.

C. A Customer must meet certain minimum load requirements in order to qualify for three-phase service under ~~ARTICLE NO.~~ Section ~~7~~8.

D. The Company does not guarantee the constancy of its voltage or frequency, nor does it guarantee against its loss of one or more phases in a three-phase service. The Company will not be responsible for any damage to the Customer's equipment caused by any or all of these occurrences brought about by circumstances beyond its control.

SECTION 9
CHARACTER OF SERVICE – VOLTAGE, FREQUENCY AND PHASE
(continued)

E. Motor Protection

The following protective apparatus, to be provided by the Customer, is required on all motor installations:

1. No Voltage Protection: Motors that cannot be safely subjected to full voltage at starting must be provided with a device to insure that upon failure of voltage, the motors will be disconnected from the line. Said device should be provided with a suitable time delay relay.

2. Overload Protection: All motors whose voltage does not exceed 750 volts are to be provided with approved fuses of proper rating. Where the voltage exceeds 750 volts, protective devices are to be provided. In these cases it will be found desirable to install standard switch equipment. The installation of overload relays and no-voltage releases is recommended on all motors, not only as additional protection, but as a means of reducing the cost of refusing.

3. Phase Reversal: Reverse phase relays and circuit breakers or equivalent devices are recommended on all polyphase installations to protect the installation in case of phase reversal or loss of one phase

F. Load Fluctuation and Balance

1. Interference with Service: The Company reserves the right to refuse to supply loads of a character that may seriously impair service to any other Customers. In the case of hoist or elevator motors, welding machines, furnaces and other installations of like character where the use of electricity is intermittent or subject to violent fluctuations, the Company may require the Customer to provide at the Customer's own expense suitable equipment to reasonably limit those fluctuations.

2. The Company has the right to discontinue electric service to any Customer who continues to use appliances or other devices, equipment and apparati detrimental to the service after the Company notifies the Customer of his or her detriment to the service.

3. Allowable Instantaneous Starting Current Values: The instantaneous starting current (determined by tests or based on limits guaranteed by manufacturers) drawn from the line by any motor must not exceed a value (as determined by the Company) that may be deemed detrimental to the normal operation of the system. If the starting current of the motor exceeds that value, a starter must be used or other means employed to limit the current to the value specified. A reduced voltage starter may be required for polyphase motors.

4. When three-phase service supplied under a power rate includes incidental lighting, the Customer will supply any necessary lighting transformers and arrange its lighting to give a substantially balanced three-phase load.

SECTION 9
CHARACTER OF SERVICE – VOLTAGE, FREQUENCY AND PHASE
(continued)

G. Customer Responsibility for Equipment Used in Receiving Electric Energy

No statement or requirement in these Rules and Regulations can be construed as the assumption of any liability by the Company for any wiring of electrical equipment or the operation of same, installed in, upon, or about the Customer's premises, nor will the Company be responsible for any loss or damage occasioned or caused by the negligence, want of proper care or wrongful act of the Customer, or any of the Customer's agents or employees or licenses on the part of the Customer in installing, maintaining, using, operating, or interfering with any such wiring, machinery or apparatus.

~~ARTICLE NO. 11 - INTERRUPTION OF SERVICE~~

~~A. The Company shall make reasonable provision to supply a satisfactory and continuous electric service, but does not guarantee a constant or uninterrupted supply of electricity. The Company shall not be liable for any damage or claim of damage attributable to any temporary, partial or complete interruption or discontinuance of electric service attributable to a force majeure condition as set forth at ARTICLE NO. 12, or to any other cause which the Company could not have reasonably foreseen and made provision against, or which, in the Company's judgment, is necessary to permit repairs or changes to be made in the Company's electric generating, transmission or distribution equipment or to eliminate the possibility of damage to the Company's property or to the person or property of others.~~

~~B. Whenever the Company deems a condition exists which warrants interruption or limitation in the service being rendered, such interruption or limitation shall not constitute a breach of contract and shall not render the Company liable for damages suffered thereby or excuse the customer from further fulfillment of the contract.~~

~~B.The use of electric energy upon the premises of the customer is at the risk of the customer. The Company's liability shall cease at the point where its facilities are connected to the customer's wiring.~~

~~ARTICLE NO. 12 - FORCE MAJEURE~~

~~A. Neither the Company nor the customer shall be liable to the other for any act, omission or circumstances (including, with respect to the Company, but not limited to, inability to provide service) occasioned by or in consequence of flood, rain, wind, storm, lightning, earthquake, fire, landslide, washout or other acts of the elements, or accident or explosion, or war, rebellion, civil disturbance, mobs, riot, blockade or other act of the public enemy, or acts of God, or interference of civil and/or military authorities, or strikes, lockouts or other labor difficulties, or vandalism, sabotage or malicious mischief, or usurpation of power, or the laws, rules, regulations or orders made or adopted by any regulatory or other governmental agency or body (federal, state or local) having jurisdiction of any of the business or affairs of the Company or the customer, direct or indirect, or breakage or accidents to equipment or facilities, or lack, limitation or loss of electrical or fuel supply, or any other casualty or cause beyond the reasonable control of the Company or the customer, whether or not specifically provided herein and without limitation to the types enumerated, and which by the exercise of due diligence such party is unable to prevent or overcome; provided, however, that nothing contained herein shall excuse the customer from the obligation of paying for electricity delivered or services rendered.~~

~~B. A failure to settle or prevent any strike or other controversy with employees or with anyone purporting or seeking to represent employees shall not be considered to be a matter within the control of the Company.~~

SECTION 10
METER READING

~~ARTICLE NO. 13 - METER READING~~

A. Company or Customer Meter Reading

1. The Company may, at its discretion, allow for Customer reading of meters.

2. It ~~shall~~will be the responsibility of the Company to inform the Customer how to properly read his or her meter.

3. Where a Customer reads his or her own meter, the Company will read the Customer's meter at least once every six (6) months.

4. The Company ~~shall~~will provide the Customer with postage-paid cards or other methods to report the monthly reading to the Company.

5. The Company ~~shall~~will specify the timing requirements for the Customer to submit his or her monthly meter reading to conform with the Company's billing cycle.

6. In the event the Customer fails to submit the reading on time, the Company may issue the Customer an estimated bill.

7. Meters ~~shall~~will be read monthly on as close to the same day as practical.

B. Measuring of Service

1. All energy sold to Customers and all energy consumed by the Company, except that sold according to fixed charge schedules, ~~shall~~will be measured by commercially acceptable measuring devices owned and maintained by the Company. This ~~s~~Subsection will not apply~~, except~~ where it is impractical to install meters, such as street lighting or security lighting, or where otherwise authorized by the Commission.

2. When there is more than one meter at a location, the metering equipment ~~shall~~will be so tagged or plainly marked as to indicate the circuit metered or metering equipment in accordance with Subsection 3.C.8.

3. Meters which are not direct reading ~~shall~~will have the multiplier plainly marked on the meter.

4. All charts taken from recording meters ~~shall~~will be marked with the date of the record, the meter number, Customer, and chart multiplier.

5. Metering equipment ~~shall~~will not be set "fast" or "slow" to compensate for supply transformer or line losses.

SECTION 10
METER READING
(continued)

C. Customer Requested Rereads

1. The Company ~~shall~~will, at the request of a Customer, reread that Customer's meter within ten (10) ~~working day~~business days after the~~such~~ request by the Customer.

2. Any reread may be charged to the Customer at a rate set forth in the Statement of Additional Charges, if the original reading was not in error. ~~Any requested re-reads shall be authorized as a flat charge of $10.00 to the if the original reading is found to be correct.~~

3. When a reading is found to be in error, the Company will not charge the Customer for the reread~~the reread shall be at no charge to the~~.

D. Access to Customer Premises

At all times, the Company ~~shall~~will have the right of safe ingress to and egress from the Customer's premises at all reasonable hours for any purpose reasonably connected with the Company's property used in furnishing service and the exercise of any and all rights secured to it by law or these rules.

E. Meter Testing and Maintenance Program

1. The Company ~~shall~~will replace any meter found to be damaged or associated with an inquiry into its accuracy, whether initiated by the Customer or Company, and which has been in service for more than sixteen years. Replaced meters ~~shall~~will be tested for accuracy and ~~shall~~will be acceptable if found to have an error margin within plus or minus three percent (± 3%).

2. The Company ~~shall~~will file an annual report with the Commission summarizing the results of the meter maintenance and testing program for that year. At a minimum, the report should include the following data:

   a. Total number of meters tested at Company initiative or upon Customer request.

   b. Number of meters tested which were outside the acceptable error allowance of ± 3%.

F. Customer Requested Meter Tests

The Company will test a meter upon Customer request and the Company will be authorized to charge the Customer for the meter test. The charge for the meter test is set forth in the Statement of Additional Charges. However, if the meter is found to be in error by more than three percent (3%), then no meter testing fee will be charged to the Customer.

~~1. The Company shall test a meter upon request and may charge the a flat charge of $40.00 if the meter is found to be accurate within the specified percentages. However, if the meter is found to be in error by more than three percent (3%), no meter testing fee will be charged to the .~~

SECTION 10
METER READING
(continued)

G. Demands

1. The Customer's demand may be measured by a demand meter, under all rate schedules involving billings based on demand, unless appropriate investigation or tests indicate that the Customer's demand will not be such as to require a demand meter for correct application of the rate schedule. In cases where billings under a rate schedule requiring determination of the Customer's demand must be made before a demand meter can be installed, such billings may be made on an estimated demand basis pending installation of the demand meter; provided, however, that billings made on the basis of estimated demands will be appropriately adjusted, if indicated to be greater or less than the actual demands recorded after the demand meter is installed.

2. Demand meters may be installed at any metering location if the nature of the Customer's equipment and operation is such as to indicate that a demand meter is required for correct application of the rate schedule.

3. All demands used for billing purposes will be recorded, or computed to the nearest whole kW.

SECTION 11
BILLING AND COLLECTION

A. Frequency and Estimated Bills

1. The Company ~~shall~~will bill monthly for services rendered. Meter readings ~~shall~~will be scheduled for periods of not less than twenty-five (25) days or more than thirty-five (35) days.

2. If the Company is unable to read the meter on the scheduled meter read date, the Company will estimate the consumption for the billing period giving consideration to the following factors where applicable:

   a. The Customer's usage during the same month of the previous year.

   b. The amount of usage during the preceding month.

3. After the second consecutive month of estimating the Customer's bill for reasons other than severe weather, the Company will attempt to secure an accurate reading of the meter.

4. Failure on the part of the Customer to comply with a reasonable request by the Company for access to its meter may lead to the discontinuance of service.

5. Estimated bills will be issued only under the following conditions:

   a. Failure of a Customer who read his own meter to deliver his meter reading card to the Company, in accordance with the requirements of the Company billing cycle.

   b. Severe weather conditions, emergencies or work stoppages that prevent the Company from reading the meter.

   ~~c.~~Circumstances that make it dangerous or impossible to read the meter, including locked gates, blocked meters

   c. ~~meters~~, vicious or dangerous animals, or any force majeure condition as listed in Subsections 8.E.4 and 8.E.5.

6. Each bill based on estimated usage will indicate that it is an estimated bill~~will be identified as calculated~~.

B. Combining Meters, Minimum Bill Information

1. Each meter at a Customer's premises will be considered separately for billing purposes, and the readings of two (2) or more meters will not be combined unless otherwise provided for in the Company's Pricing Plans.

SECTION 11
BILLING AND COLLECTION
(continued)

2. Each bill for residential service will contain the following minimum information:

   a. Date and meter reading at the start of billing period or number of days in the billing period;

   b. Date and meter reading at the end of the billing period;

   c. Billed usage and demand (if applicable);

   d. Rate schedule number;

   e. Company telephone number;

   f. Customer's name;

   g. Service account number;

   h. Amount due and due date;

   i. Past due amount;

   j. Adjustment clause costs~~factor~~, where applicable;

   k. All applicable taxes~~Taxes~~; and

   l. The address for the Arizona Corporation Commission.

C. Billing Terms

1. All bills for the Company's services are due and payable no later than ten (10) days from the date the bill is rendered. Any payment not received within this time frame ~~shall~~will be considered past due.

2. For purposes of this rule, the date a bill is rendered may be evidenced by:

   a. The postmark date;

   b. The mailing date; or

   c. The billing date shown on the bill. However, the billing date ~~shall~~will not differ from the postmark or mailing date by more than two (2) days.

SECTION 11
BILLING AND COLLECTION
(continued)

3. All past due bills for the Company's services are due and payable within fifteen (15) days. Any payment not received within this time frame ~~shall~~will be considered delinquent and will~~could~~ incur a late payment finance charge.

4. All delinquent bills for which payment has not been received within five (5) days ~~shall~~will be subject to the provisions of the Company's termination procedures.

5. All payments of current amounts may be made at or mailed to the office of the Company or to the Company's duly authorized representative.

~~6.All payments of delinquent amounts mustshall be made in the office of the Company.~~

D. Applicable Pricing Plans, Time-of-Use Meters, Prepayment, Failure to Receive, Commencement Date, Taxes

1. Each Customer will~~shall~~ be billed under the applicable Pricing Plan~~tariff~~ indicated in the Customer's application for service.

2. For a Customer taking service under a TEP Time-of-Use ("TOU") rate schedule, TEP may charge a fee based on the incremental cost of a TOU meter versus a non-TOU meter.

3. Customers may pay for electrical service by making advance payments.

4. Failure to receive bills or notices which have been properly placed in the United States mail will~~shall~~ not prevent those~~such~~ bills from becoming delinquent nor relieve the Customer of his obligations therein.

5. Charges for service commence when the service is installed and connection made, whether used or not.

E. Billing and Meter Error Corrections

1. If, after testing, any meter is found to be more than three percent (3%) in error, either fast or slow, proper correction between three percent (3%) and the amount of the error ~~shall~~will be made to previous readings and adjusted bills ~~shall~~will be rendered according to the following terms:

   a. For the period of three (3) months immediately preceding the removal of such meter from service for test or from the time the meter was in service since last tested, but not exceeding three (3) months since the meter ~~shall~~will have been shown to be in error by such test.

   b. From the date the error occurred, if the date of the cause can be definitely fixed.

2. No adjustment ~~shall~~will be made by the Company except to the Customer last served by the meter tested.

SECTION 11
BILLING AND COLLECTION
(continued)

F. Non-sufficient Funds ("NSF") Checks~~Returned Checks and Denied Electronic Funds Transfers~~

1. The Company will be allowed to recover a fee, as set forth in the Statement of Additional Charges, for each instance where a Customer tenders payment for electric service with a~~n~~ non-~~in~~sufficient funds check. This fee will also apply when an electronic funds transfer ("EFT") is denied for any reason, including for lack of sufficient funds.

2. When the Company is notified by the Customer's bank or other financial institution that there are non-~~in~~sufficient funds to cover the check, EFT or other financial instrument for electric service has been denied for any reason, the Company may require the Customer to make payment in cash, by money order, certified check, or other means which guarantee the Customer's payment to the Company.

3. A Customer who tenders a~~n~~ non-~~in~~sufficient funds check, or for whom an EFT or other financial instrument has been denied will not be relieved of the obligation to render payment to the Company under the original terms of the bill nor defer the Company's provision for termination of service for nonpayment of bills.

4. No ~~personal~~ checks will be accepted if two (2) NSF checks have been received by the Company within a twelve-month period in payment of any billing.

~~a. The Company shall be allowed to recover a fee of ten dollars ($10.00) for each instance where a check from a customer or other entity used to pay a bill for utility or other service is returned to the utility as uncollectible for any reason, or an electronic funds transfer (EFT) is denied for any reason, including for lack of sufficient funds.~~

~~b. When the Company is notified by the customer's or other entity's bank that a check has been returned or an EFT has been denied for any reason, the utility may require the customer or other entity to make payment in cash, by money order, certified check, or other means which guarantees the customer's or other entity's payment to the Company.~~

~~c. A customer or other entity who tenders an insufficient funds check or for whom an EFT is denied shall in no way be relieved of the obligation to render payment to the Company under the original terms of the bill nor defer the Company's provision for termination of service or penalties, as applicable, for nonpayment of bills.~~

G. Levelized Billing Plan

1. The Company may, at its option, offer its Customers a levelized billing plan.

2. If the Company offers a levelized billing plan, the Company will then~~it shall~~ develop upon Customer request an estimate of the Customer's levelized billing for a twelve-month period based upon:

   a. Customer's actual consumption history, which may be adjusted for abnormal conditions such as weather variations.

b. For new Customers, the Company will estimate consumption based on the Customer's anticipated load requirements.

c. The Company's ~~tariff~~Pricing Plan ~~schedules~~ approved by the Commission applicable to that Customer's class of service.

3. The Company ~~shall~~will provide the Customer a concise explanation of how the levelized billing estimate was developed, the impact of levelized billing on a Customer's monthly electric bill, and the Company's right to adjust the Customer's billing for any variation between the Company's estimated billing and actual billing.

SECTION 11
BILLING AND COLLECTION
(continued)

4. For those Customers being billed under a levelized billing plan, the Company ~~shall~~will show, at a minimum, the following information on the Customer's monthly bill:

   a. Actual consumption;

   b. Amount due for actual consumption;

   c. Levelized billing amount due; and

   d. Accumulated variation in actual versus levelized billing amount.

5. The Company may adjust the Customer's levelized billing in the event the Company's estimate of the Customer's usage and/or cost should vary significantly from the Customer's actual usage and/or cost. This~~Such~~ review to adjust the amount of the levelized billing may be initiated by the Company or Customer.

H. Deferred Payment Plan

1. The Company may, prior to termination, offer to qualifying residential Customers a deferred payment plan for the Customer to retire unpaid bills for electric service.

2. Each deferred payment agreement entered into by the Company and the Customer, due to the Customer's inability to pay an outstanding bill in full, ~~shall~~will provide that service will not be discontinued if:

   a. Customer agrees to pay a reasonable amount of the outstanding bill at the time the parties enter into the deferred payment agreement.

   b. Customer agrees to pay all future bills for electric service in accordance with the Company's ~~billing and collection tariffs~~Pricing Plans ~~of the Company~~.

   c. Customer agrees to pay a reasonable portion of the remaining outstanding balance in installments over a period not to exceed six (6) months.

SECTION 11
BILLING AND COLLECTION
(continued)

3. For the purpose of determining a reasonable installment payment schedule under these rules, the Company and the Customer ~~shall~~will give consideration to the following conditions:

    a. Size of the delinquent account;

    b. Customer's ability to pay;

    c. Customer's payment history;

    d. Length of time the debt has been outstanding;

    e. Circumstances which resulted in the debt being outstanding; and

    f. Any other relevant factors related to the circumstances of the Customer.

4. Any Customer who desires to enter into a deferred payment agreement must do so before~~shall establish such agreement prior to~~ the Company's scheduled termination date for nonpayment of bills. The Customer's ~~-~~failure to execute a deferred payment agreement prior to the scheduled service termination date will~~shall~~ not prevent the Company from terminating~~discontinuing~~ service for nonpayment.

5. Deferred payment agreements may be in writing and may be signed by the Customer and an authorized Company representative.

6. A deferred payment agreement may include a finance charge in an amount equal to the Company's actual or average cost of providing such arrangements.

7. If a Customer has not fulfilled the terms of a deferred payment agreement, the Company has~~shall have~~ the right to disconnect service pursuant to the Company's T~~t~~ermination of S~~s~~ervice R~~r~~ules in ~~(~~Section 12~~)~~ and, under these~~such~~ circumstances, it will~~shall~~ not be required to offer subsequent negotiation of a deferred payment agreement prior to disconnection.

I. Change of Occupancy

1. ~~To order service to be discontinued or to change occupancy, The~~the Customer must give the Company at least three (3) business days advance notice in writing or by telephone, to discontinue service or to change occupancy.~~.Not less than three (3) working day~~business days ~~advance notice must be given in person, in writing, or by telephone at the Company's office to discontinue service or to change occupancy.~~

2. The outgoing Customer~~party~~ will ~~shall~~ be responsible for all electric services provided and/or consumed up to the scheduled turn-off date.

3. The outgoing Customer is responsible for providing access to the meter so that the Company may obtain a final meter reading.

SECTION 11
BILLING AND COLLECTION
(continued)

J. Electronic Billing

1. Electronic Billing is an optional billing service whereby Customers may elect to receive, view and pay their bills electronically. The Company may modify its Electronic Billing services from time to time. A Customer electing an electronic billing service may receive an electronic bill in lieu of a paper bill.

2. Customers electing an electronic billing service may be required to complete additional forms and agreements.

3. Electronic Billing may be discontinued at any time by Company or the Customer.

4. An Electronic Bill will be considered rendered at the time it is electronically sent to the Customer. Failure to receive bills or notices that have been properly sent by an Electronic Billing system does not prevent these bills from becoming delinquent and does not relieve the Customer of the Customer's obligations therein.

5. Any notices that the Company is required to send to the Customer who has elected an Electronic Billing service may be sent by electronic means at the option of the Company.

6. Except as otherwise provided in this subsection, all other provisions of the Company's Rules and Regulations and other applicable Pricing Plans are applicable to Electronic Billing.

7. The Customer must provide the Company with a current email address for electronic bill delivery. If the electronic bill is electronically sent to the Customer at the email address that the Customer provided to the Company, then the Electronic Bill will be considered properly sent. Further, the Customer will be responsible for updating the company with any changes to this email address. Failure to do so will not excuse the Customer from timely paying the Company for electric service.

SECTION 12
TERMINATION OF SERVICE

~~ARTICLE NO. 16 - TERMINATION OF SERVICE~~

A. Non-permissible Reasons to Disconnect Service

1. The Company ~~shall~~will not disconnect service for any of the reasons stated below:

   a. Delinquency in payment for services rendered to a prior Customer at the premises where service is being provided, except in the instance where the prior Customer continues to reside on the premises;

   b. Failure of the Customer to pay for services or equipment which are not regulated by the Commission;

   c. Nonpayment of a bill related to another class of service;

   d. Failure to pay for a bill to correct a previous underbilling due to an inaccurate meter or meter failure if the Customer agrees to pay over a reasonable period of time;

   e. Failure to pay the bill of another Customer as guarantor thereof; or

   f. Disputed bills where the Customer has complied with the ACC's rules on Customer bill disputes.

2. The Company ~~shall~~will not terminate residential service for any of the reasons stated below~~where the Customer has an inability to pay and~~:

   a. The Customer can establish through medical documentation that, in the opinion of a licensed medical physician, termination would be especially dangerous to the health of a Customer or permanent resident residing on the Customer's premises;

   b. Life supporting equipment used in the home that is dependent on electric service for operation of this equipment~~such apparatus~~; or

   c. Where weather will be especially dangerous to health as defined herein or as determined by the Commission.

3. Residential service to ill, elderly, or handicapped persons who have an inability to pay will not be terminated until all of the following have been attempted:

   a. The Customer has been informed of the availability of funds from various government and social assistance agencies of which the Company is aware; and~~.~~

   b. A third party previously designated by the Customer has been notified and has not made arrangements to pay the outstanding electric bill.

4. A Customer utilizing the provisions of Subsections 12.A.2~~e~~. or 12.A.3~~f~~. above may be required to enter into a deferred payment agreement with the Company within ten (10) days after the scheduled termination date.

~~i.Failure to pay the bill of another customerCustomer as guarantor thereof.~~

~~ii.Disputed bills where the customer~~Customer ~~has complied with the Commission's rules on customer~~Customer ~~bill disputes.~~

SECTION 12
TERMINATION OF SERVICE
(continued)

B. Termination of Service Without Notice

1. Electric service may be disconnected without advance written notice under the following conditions:

   a. The existence of an obvious safety or health hazard to the consumer, the general population or the Company's personnel or facilities;~~.~~

   b. The Company has evidence of meter tampering or fraud (e.g., NSF Checks, denied EFTs);~~.~~ or

   c. Failure of a Customer to comply with the curtailment procedures imposed by the Company during supply shortages.

2. The Company ~~shall~~will not be required to restore service until the conditions that led to~~which resulted in~~ the termination have been corrected to the satisfaction of the Company.

3. The Company ~~shall~~will maintain a record of all terminations of service without notice for a minimum of one (1) year and ~~shall~~will be available for inspection by the Commission.

C. Termination of Service With Notice

1. The Company may disconnect service to any Customer for any reason stated below provided that the Company has met the notice requirements described in Ssubsection 12.E. below~~established by the Commission~~:

   a. Customer violation of any of the Company's ~~tariffs~~Pricing Plans;

   b. Failure of the Customer to pay a delinquent bill for electric service;

   c. Failure of the Customer to meet agreed-upon deferred payment arrangements;

   d. Failure to meet or maintain the Company's deposit requirements;

   e. Failure of the Customer to provide the Company reasonable access to its equipment and property;

   f. Customer breach of a written contract for service between the Company and Customer;

   g. When necessary for the Company to comply with an order of any governmental agency having such jurisdiction;

~~a.Customer facilities which do not comply with Company requirements or specifications.~~

~~i.The Company shall maintain a record of all terminations of service with notice for one (1) year and be available for Commission inspection.~~

SECTION 12
TERMINATION OF SERVICE
(continued)

h. When a hazard exists that is not imminent, but in the Company's opinion, may cause property damage; or~~.~~

i. Customer facilities that do not comply with Company requirements or specifications.

2. The Company ~~shall~~will maintain a record of all terminations of service with notice for one (1) year and be available for Commission inspection.

D. The Company will not be obligated to renotify the Customer of the termination of service, even if the Customer – after receiving the required termination of service notification – has made payment, yet the payment is returned within three (3) to five (5) business days of receipt for any reason. The original notification will apply.

~~D.~~E. Termination Notice Requirements

1. The Company ~~shall~~will not terminate service to any of its Customers without providing advance written notice to the Customer of the Company's intent to disconnect service, except under those conditions specified in ~~S~~subsection 12.B. where advance written notice is not required.

2. This~~Such~~ advance written notice will~~shall~~ contain, at a minimum, the following information:

a. The name of the person whose service is to be terminated and the address where service is being rendered.

b. The Company's Pricing Plan ~~tariff~~ that was violated and explanation of the violation~~thereof~~ or the amount of the bill that~~which~~ the Customer has failed to pay in accordance with the payment policy of the Company, if applicable.

c. The date on or after which service may be terminated.

d. A statement advising the Customer to contact the Company at a specific address or phone number for information regarding any deferred payment or other procedures that the Company may offer or to work out some other mutually agreeable solution to avoid termination of the Customer's service.

e. A statement advising the Customer the Company's stated reason(s) for the termination of services may be disputed by contacting the Company at a specific address or phone number, advising the Company of the dispute and making arrangements to discuss the cause for termination~~e on~~ with a responsible employee of the Company in advance of the scheduled date of termination. The responsible employee ~~shall~~will be empowered to resolve the dispute and the Company ~~shall~~will retain the option to terminate service after affording this opportunity for a meeting and concluding that the reasons for termination is just and advising the Customer of his right to file a complaint with the Commission.

3. Where applicable, a copy of the termination notice will be simultaneously forwarded to designated third parties.

SECTION 12
TERMINATION OF SERVICE
(continued)

~~E.~~F. Timing of Terminations With Notice

1. The Company ~~shall~~will give at least a five (5) day advance written notice prior to the termination date.

2. This~~Such~~ notice ~~shall~~will be considered to be given to the Customer when a copy of the notice~~thereof~~ is left with the Customer or posted first class in the United States mail, addressed to the Customer's last known address.

3. If, after the period of time allowed by the notice has elapsed and the delinquent account has not been paid nor arrangements made with the Company for payment of the bill~~thereof,~~ — or in the case of~~-~~ a violation of the Company's rules the Customer has not satisfied the Company that this~~such~~ violation has ceased – then the Company may ~~then~~ terminate service on or after the day specified in the notice without giving further notice.

~~4.Service shall only be disconnected in conjunction with a personal visit to the premises by an authorized representative of the Company.~~

~~5.~~The Company will have the right (but not the obligation) to remove any or all of its property installed on the Customer's premises upon the termination of service. Upon the termination of service the Company may, without liability for injury or damage, dismantle and remove its line extension facilities within two (2) years after termination of service.~~, provided however~~ Tthe Company will~~shall~~ give the Customer thirty (30) days written notice before removing its facilities should the Company decide to do so, ~~,~~or else waive any re-establishment charge within the next one (1) year for the same service to the same Customer at the same location. ~~For purposes of this Section, notice to the Customer shall be deemed given at the time such notice to the Customer shall be deemed given at the time such notice is deposited in the U.S. Postal Service, first class mail, postage prepaid, to the Customer at his/her last known address.~~

~~5.~~4.

~~F.~~G. Landlord/Tenant Rule

1. In situations where service is rendered at an address different from the mailing address of the bill or where the Company knows that a landlord/tenant relationship exists and the landlord is the Customer of the Company, and where the landlord as a Customer would otherwise be subject to disconnection of service, the Company may not disconnect service until the following actions have been taken:

   a. Where it is feasible to so provide service, the Company, after providing notice as required in these rules, ~~shall~~will offer the occupant the opportunity to subscribe for service in his or her own name. If the occupant then declines to so subscribe, the Company may disconnect service pursuant to the rules.

   b. The Company ~~shall~~will not attempt to recover from a tenant, or condition service to a tenant, upon the prepayment of any outstanding bills or other charges due upon the outstanding account of the landlord.

SECTION 13
RECONNECTION OF SERVICE

~~ARTICLE NO. 18 - RECONNECTION OF SERVICE~~

When service has been discontinued for any of the reasons set forth in these Rules and Regulations, the Company ~~shall~~will not be required to restore service until the following conditions have been met by the Customer:

A. Where service was discontinued without notice:

1. The hazardous condition must~~shall~~ be removed and the installation ~~shall~~will conform to accepted standards.
2. All bills for service and/or applicable investigative costs due the Company by reason of fraudulent or unauthorized use, diversion or tampering must~~shall~~ be paid and a deposit to guarantee the payment of future bills may be required.
3. Required arrangements for service must~~shall~~ be made.

B. Where service was discontinued with notice:

1. The Customer must make arrangements for the payment of all bills and these arrangements must be satisfactory to the Company.~~Satisfactory arrangements for the payment of all bills for service then due shall be made.~~
2. The Customer must furnish a ~~A~~ satisfactory guarantee to pay all ~~of payment for all~~ future bills~~ shall be furnished~~.
3. The Customer must correct any and all violations ~~The violation~~ of these Rules and Regulations~~ shall be corrected~~.

~~a.Reconnection Charge~~

~~i.Whenever the Company has discontinued service under its usual operating procedures because of any default by the customer as provided herein, a reconnection charge not to exceed the charge for the re-establishment of service as set forth in the applicable rate schedule shall be made and may be collected by the Company before service is restored. When, due to the behavior of the customer, it has been necessary to discontinue service utilizing other than usual operating procedures, the Company shall be entitled to charge and collect actual costs to restore service.~~

SECTION 14
ADMINISTRATIVE AND HEARING REQUIREMENTS

~~ARTICLE NO. 17 - ADMINISTRATIVE AND HEARING REQUIREMENTS~~

A. Customer Service Complaints

1. The Company ~~shall~~will make a full and prompt investigation of all service complaints made by its Customers, either directly or through the Commission.

2. The Company ~~shall~~will respond to the complainant and/or the Commission representative within five (5) ~~working day~~business days as to the status of the Company's investigation.

3. The Company ~~shall~~will notify the complainant and/or the Commission representative of the final disposition of each complaint. Upon request of the complainant or the Commission representative, the Company ~~shall~~will report the findings of its investigation in writing.

4. The Company ~~shall~~will inform the Customer of his right of appeal to the Commission.

5. The Company ~~shall~~will keep a record of all written service complaints received that must~~which shall~~ contain, at a minimum, the following data:

   a. Name and address of complainant;

   b. Date and nature of the complaint;

   c. Disposition of the complaint; and

   d. A copy of any correspondence between the Company, the Customer, and/or the Commission.

6. This record ~~shall~~will be maintained for a minimum period of one (1) year and ~~shall~~will be available for inspection by the Commission

SECTION 14
ADMINISTRATIVE AND HEARING REQUIREMENTS
(continued)

B. Customer Bill Disputes

1. Any utility Customer who disputes a portion of a bill rendered for electric service must~~shall~~ pay the undisputed portion of the bill and notify the Company's designated representative that any~~such~~ unpaid amount is in dispute prior to the delinquent date of the bill.

2. Upon receipt of the Customer notice of dispute, the Company ~~shall~~will:

   a. Notify the Customer within five (5) ~~working day~~business days of the receipt of a written dispute notice.

   b. Initiate a prompt investigation as to the source of the dispute.

   c. Withhold disconnection of service until the investigation is completed and the Customer is informed of the results.

   d. Upon request of the Customer, the Company ~~shall~~will report the results of the investigation in writing.

   e. Inform the Customer of his right of appeal to the Commission.

3. Once the Customer has received the results of the Company's investigation, the Customer ~~shall~~will submit payment within five (5) ~~working day~~business days to the Company for any disputed amounts. Failure to make full payment may be grounds for termination of service.

4. The Company ~~shall~~will inform the Customer of his right of appeal to the Commission.

C. Commission resolution of service and bill disputes.

1. In the event the Customer and the Company cannot resolve a service or bill dispute the customer must file a written statement of dissatisfaction with the Commission; by submitting this statement to the Commission, the Customer will be deemed to have a filed an informal complaint against the Company.

2. Within 30 days of the receipt of a written statement of customer dissatisfaction related to a service or bill dispute, a designated representative of the Commission will endeavor to resolve the dispute by correspondence or telephone with the Company and the Customer. If resolution of the dispute is not achieved within 20 days of the Commission representative's initial effort, the Commission will hold an informal meeting to arbitrate the resolution of the dispute. This informal meeting will be governed by the following rules:

   a. Each party may be represented by legal counsel, if desired.

   b. All informal meetings may be recorded or held in the presence of a stenographer.

SECTION 14
ADMINISTRATIVE AND HEARING REQUIREMENTS
(continued)

c. All parties will have the opportunity to present written or oral evidentiary material to support the positions of the individual parties.

d. All parties and the Commission's representative will be given the opportunity to cross-examine the various parties.

e. The Commission's representative will render a written decision to all parties within five business days after the date of the informal meeting. This written decision of the arbitrator is not binding on any of the parties and the parties may still make a formal complaint to the Commission.

3. The Company may implement its termination procedures if the Customer fails to pay all bills rendered during the resolution of the dispute by the Commission.

4. The Company will maintain a record of written statements of dissatisfaction and their resolution for a minimum of one (1) year and make these records available for Commission inspection.

SECTION 15
TEMPORARY SERVICE OR CYCLICAL USAGE

~~ARTICLE NO. 19 - TEMPORARY SERVICE OR CYCLICAL USAGE~~

A. For electric service of a temporary nature [less than two (2) years], a service installation and removal charge will be made in addition to the regular charges for service which will be billed under the applicable rate schedule. Such installation and removal charge ~~shall~~will be the estimated average cost of labor, transportation and material required for installing and removing the temporary service facilities, less the estimated average net salvage value of the material. Emergency, supplementary, breakdown or other standby service is not considered temporary and is subject to the provisions of ~~ARTICLE NO.~~Section 16 ~~20~~. Permanent or semi-permanent businesses whose characteristics of operation result in infrequent cyclical usage of energy (e.g., asphalt batch plants, lettuce cooling plants) will require separate contracts with the Company to assure full recovery of the Company's annual ownership cost on the total facilities installed to provide service to the Applicant.

SECTION 16
STANDBY SERVICE

~~ARTICLE NO. 20 - STANDBY SERVICE~~

A. Emergency, breakdown, supplementary or other standby service will be supplied by the Company at its option only under special contracts specifying the rates, terms and conditions governing such service.

~~SECTION 17~~
~~HIGHLY FLUCUATING LOADS~~

~~ARTICLE NO. 21 - HIGHLY FLUCTUATING LOADS~~

~~B. Electric service shallwill not be used in such a manner so as to cause any unusual voltage fluctuations on or other disturbances to the Company's system. For installations having highly fluctuating or intermittent power demands which seriously affect voltage regulation, including, but not limited to, welding equipment, x-ray apparatus, elevator motors or other equipment, the Company shallwill notify the Customer in writing of the condition and failing adequate correction of the condition may adjust the billing basis or make such additional charges as may be necessary to take into account the special equipment, power capacity, and other costs to the Company required to serve thissuch equipment.~~

~~C. All equipment used by the Customer shallwill be so operated and have such starting and performance characteristics that its use will not cause unusual voltage fluctuations or other disturbances on the Company's system.~~

~~D. When three-phase service supplied under a power rate includes incidental lighting, the Customer shallwill supply any necessary lighting transformers and arrange its lighting to give a substantially balanced three-phase load.~~

SECTION 17
POWER FACTOR

~~ARTICLE NO. 22 - POWER FACTOR~~

A. The Company may require the Customer by written notice to either maintain a specified minimum lagging power factor or the Company may after thirty (30) days install power factor corrective equipment and bill the Customer for the total costs of this~~such~~ equipment and installation.

B. In the case of apparatus and devices having low power factor, now in service, which may hereafter be replaced, and all similar equipment hereafter installed or replaced, served under general commercial schedules, the Company may require the Customer to provide, at the Customer's own expense, power factor corrective equipment to increase the power factor of any such devices to not less than ninety (90) percent.

~~B.~~C. If the Customer installs and owns the capacitors needed to supply his reactive power requirements, then the Customer must~~shall~~ equip them with suitable disconnecting switches, so installed that the capacitors will be disconnected from the Company's lines whenever the Customer's load is disconnected f~~there~~from the Company's facilities.

~~C.~~D. Gaseous tube installations totaling more than one thousand (1,000) volt-amperes must~~shall~~ be equipped with capacitors of sufficient rating to maintain a minimum of ninety percent (90%) lagging power factor.

~~D.~~E. Company installation and removal of metering equipment to measure power factor will be at the discretion of the Company.

SECTION 18
STATEMENT OF ADDITIONAL CHARGES

A.	Service Establishment and Reestablishment During Regular Business Hours - service reads only	$13.50
B.	Service Establishment and Reestablishment under usual operating procedures During Regular Business Hours – Single-Phase Service	$~~13.50~~22.00
C.	Service Establishment and Reestablishment under usual operating procedures After Regular Business Hours (includes Saturday, Sundays and Holidays) – Single-Phase Service	$~~35.00~~51.00
D.	Service Establishment and Reestablishment under usual operating procedures During Regular Business Hours – Three-Phase Service	$~~13.50~~71.00
E.	Service Establishment and Reestablishment under usual operating procedures After Regular Business Hours (includes Saturdays, Sundays and Holidays) – Three-Phase Service	$~~35.00~~198.00
F.	Meter Reread	$~~10.00~~13.00
G.	Meter Field Test	$~~40.00~~144.00
H.	NSF Check	$10.00
I.	Late Payment Finance Charge	1.5%
J.	Interest on Customer Deposits	~~6.0%~~One-Year Treasury constant maturities rate

~~SECTION 19~~

~~COMPLIANCE~~

~~ARTICLE NO. 23 - COMPLIANCE~~

~~A.The Commission adopted "Regulation R14-2-103" effective March 2, 1982. The Company adopts and accepts by these Rules and Regulations the Commission's "Regulation R14-2-103." To the extent that any subject matter contained in the Commission's "Regulation R14-2-103" is not included in these Rules and Regulations, the Company intends that the language of "Regulation R14-2-103" is applicable and is incorporated by reference in these Rules and Regulations.~~

~~cceptable to both the ESP and~~

~~12. On-Site Inspections/Site Meets~~

~~a. TEP may perform on-site inspections of meter installations. The ESP shall be notified if the inspections uncover any material non-compliance by the MSP with the approved specifications and standards.~~

~~b. For new construction, TEP shall ensure that the owner/builder has met the construction standards outlined in the TEP Electric Service Requirements Manual, as well as local municipal agency requirements, and any updates, supplements, amendments and other changes that may be made to this manual and requirements. TEP shall perform a pre-installation inspection on all new construction. Local city/county clearances will also be required prior to energizing any new construction.~~

~~c. TEP may require a site meet to exchange or remove an IDR meter which requires an optical device to retrieve interval data; an existing totalized metering installation; a restricted access location for which TEP forbids key access; co-generation, bi-directional or detented metering; or on request of an ESP or MSP. The ESP and TEP's Meter Services Department shall coordinate the time of the site meet. If the ESP or MSP misses two (2) site meets, TEP may cancel the applicable DASR.~~

~~d. TEP may charge for a site meet requested by the ESP or MSP, or if the ESP or MSP fails to arrive within thirty (30) minutes of the appointment time, or if the ESP fails to cancel a site meet at least one (1) working day in advance of the appointment time. The ESP or MSP may charge for a site meet requested by TEP under the same conditions specified herein.~~

~~13. Meter Service Options and Obligations~~

~~a. Meter Ownership shall be limited to TEP, an ESP, or the customer. The customer must obtain the meter through TEP or an ESP. Although a customer may own the electric meter, maintenance and servicing of the metering equipment shall be limited to TEP, the ESP, or the ESP's agent.~~

~~b. If the ESP or customer owns the meter, the ESP may purchase the existing CTs and PTs and/or associated metering equipment from TEP. If the ESP chooses not to purchase the CTs and PTs and/or associated equipment, the ESP will still retain responsibility for maintaining and replacing CTs and PTs and/or associated equipment.~~

~~c. The following provisions apply to the ownership of CTs and PTs:~~

~~(1) For distribution voltages up to 25kv, the ESP or TEP shall own the CTs and PTs. For transmission primary voltages (over 25kv), the CTs and PTs shall be owned by TEP. ESP-owned CTs & PTs must meet TEP specifications. No CTs and PTs or associated metering equipment shall be set or allowed to remain in service if it is determined that the CTs and PTs or its associated equipment did not meet TEP's approved specifications, as set forth in TEP's Electric Service Requirements Manual, in place at the time of installation.~~

~~d. All CT-rated meter installations shall utilize safety test switches, and all self-contained commercial metering shall utilize safety test blocks as provided in the TEP Electric Service Requirements Manual. During meter exchanges, the ESP or its agent's employees who are certified to perform the related MSP activities may install, replace or operate TEP test switches and operate TEP-sealed customer-owned test blocks.~~

~~e. Direct Access premises with multiple service entrance sections will be considered separately for metering purposes. Existing totalizing installations will be discontinued upon a customer's entrance into Direct Access.~~

~~14. Installation Options~~

~~a. The ESP may choose from the following list of options for meter installation:~~

~~(1) ESP owned/ESP installed metering~~

~~(2) ESP owned/TEP installed metering~~

~~(3) Customer owned/ESP installed metering~~

~~(4) Customer owned/TEP installed metering~~

~~(5) TEP owned/TEP installed metering~~

~~b. ESP or their agents must be certified by the ACC in order to offer MSP services. The policies and procedures described in this Section assume that the MSP service provider and his meter installers have ACC certification. ESPs may elect to offer metering services by:~~

~~(1) Becoming a certified Metering Service Provider.~~

~~(2) Subcontracting with a third party that is a certified MSP.~~

~~(3)Subcontracting with TEP under the circumstances described in Section I.2 of this Article.~~

~~15. ESP's Obligations When Providing Metering Services~~

~~a. If lock rings are used, they shall meet TEP requirements and protocols.~~

~~b. Provide information to TEP on the specifications and other specifics on meters not purchased from or installed by TEP.~~

~~c. For customers transferring from Direct Access to Standard Offer service, the ESP shall either allow TEP to remove the customer's meter, or schedule a joint meet to remove the meter. If the ESP allows TEP to remove meters, the ESP shall coordinate with TEP's Meter Services Department~~

~~regarding the return of the ESP's meters, which shall be to a location within TEP's service territory. For customers transferring from Standard Offer to Direct Access Service, TEP shall either allow the ESP to remove the customer's meter, or schedule a joint meet to remove the meter. If TEP allows the ESP to remove meters, TEP shall coordinate with the ESP or its agent regarding the return of TEP's meters.~~

~~d. Be responsible for obtaining and providing reads from any meter that it installs from the time it is installed to the time it is removed or until meter reading responsibilities are assumed by another ESP or the customer returns to Standard Offer service.~~

~~e. Ensure that ESP and MSP employees working in TEP territory follow ACC and other applicable safety standards.~~

~~f. In the event that unauthorized energy use is suspected and a safety hazard exists, notify TEP immediately, or within twenty-four (24) hours for non-safety issues, and cooperate with TEP in response thereto.~~

~~g. ESPs and their agents shall take no action to impede TEP's safe and unrestricted access to a customer's service entrance.~~

~~h. Glass over any socket when a meter is removed and a new meter is not installed.~~

~~16. ESP's Obligations When Providing MRSP Services~~

~~a. MRSP functions shall be performed by certified MRSPs on the ESP's behalf in accordance with ACC regulations, and shall be the responsibility of the party specified in the DASR. MRSP obligations and responsibilities are as stated in the ACC's Rules and requirements and include:~~

~~(1) Meter data for Direct Access Customers shall be read, validated, edited, and transferred pursuant to ACC approved standards.~~

~~(2) Both TEP and ESP shall have 24-hour/7 days per week access to the MRSP server.~~

~~(3) Meter read data including reads as well as the validated usage shall be posted to the MRSP server using EDI "867" format. Estimated reads, along with reasons for the estimate, shall be included with the reads on the MRSP server. The EDI format specification includes the estimated read reason codes to be used.~~

~~(4) The MRSP shall provide TEP with access to meter data at the MRSP server as required to allow the proper performance of billing and settlement.~~

~~(5) MRSPs shall read the customer's meter on the TEP read cycle. MRSP shall provide TEP with meter reading data in a manner that conforms to TEP's billing cycles in accordance with A.A.C. R14-2-209.~~

~~(6) The MRSP shall provide re-reads or read verifies within ten (10) working days of a request by TEP or the customer. The requesting party may be charged per the applicable ACC tariff if the original read was not in error.~~

~~17. Meter Reading Data Obligations~~

~~a. Accuracy for All Meters~~

~~(1) Meter clocks shall be maintained according to Arizona time within +/- three (3) minutes of the National Time Standard.~~

~~(2) Meter read date and time shall be accurate.~~

~~(3) All meter reading data shall be validated with the applicable ACC approved requirements.~~

~~b. Timeliness for Validated Meter Reading Data~~

~~(1) Pursuant to guidelines established by the Utilities Division Director timeliness requirements for the delivery of data, one hundred percent (100%) of the validated meter reads shall be available by 3:00 p.m. local Arizona time on the third working day after the~~

~~scheduled read date. If the meter reads are not posted or available or are posted clearly in error by 3:00 p.m. on the third working day after the scheduled read date, the read may be estimated or read by TEP and the ESP shall be charged an ACC-approved fee for this service. For newly installed IDR meters, IDR reads shall include the meter read, the interval data and enough information to calculate the read and total consumption to the exact cut-over date and time.~~

~~c. Proof of Operational Ability~~

~~(1) Prior to performing MRSP services in TEP's distribution service territory, or prior to making any significant change in MRSP service methodology, each MRSP will perform compliance testing to demonstrate its ability to read meters, validate data, edit data, estimate missing data and post validated data in TEP-compatible EDI format to the MRSP server. In addition, upon installation of the initial meter on Direct Access accounts in TEP's distribution service territory, each MRSP shall prove its ability to read its meters and post validated data in TEP-compatible EDI format to the MRSP server. If the MRSP is unsuccessful in its attempts to meet these requirements, all subsequent requests for meter exchanges will be postponed until the MRSP successfully demonstrates its operational ability.~~

~~d. Retention and Format for Meter Reading Data~~

~~(1) All meter reading data for a customer shall remain posted on the MRSP server for five (5) working days and will be recoverable for at least three (3) years.~~

~~(2) Meter reading data posted to the MRSP server shall be stored in TEP-compatible EDI format.~~

~~18. TEP Performing MSP and MRSP Functions~~

~~a. If TEP is eligible to perform Direct Access-related MSP and MRSP functions as defined in Section I.2, the following~~

~~restriction applies:~~
~~(1) During the phase-in period of October 1, 1999 to December 31, 2000 for load profiled customers in which TEP is reading the meter, the validated meter read will be posted in EDI format no later than three (3) working days following the scheduled read date.~~
~~19. Non-Conforming Meters, Meter Errors and Meter Reading Errors~~
~~a. Whenever TEP, the ESP or its agents becomes aware of any non-conforming meters, erroneous meter services and/or meter reading services that impact billing, it shall promptly notify the other parties and the customer in question. Bills found to be in error due to non-conforming meters or errors in meter services or meter reading services will be corrected by the appropriate parties.~~
~~b. In cases of meter failure or non-compliance, the ESP or its agents shall have five (5) working days to correct the non-compliance. If the non-compliance is not remedied within five (5) working days, the following actions may apply:~~
~~(1) A site meeting may be required when services are being performed. The non-compliant party will be charged an ACC-approved tariff for the meeting.~~
~~(2) TEP may repair the defect, and the other party shall be responsible for all related expenses.~~
~~(3) Upon a demonstrated pattern of non-compliance (with ACC requirements and this Article) and failure to correct the problem in a timely manner, TEP may give written notice to the non-compliant party and to the ACC. After five (5) working days, TEP may suspend processing DASRs from an ESP that uses an MSP or MRSP that is non-compliant until such non-compliance is corrected to TEP's satisfaction.~~
~~(4) A pattern of non-compliance by an ESP is defined by the following conditions:~~
~~(a) If more than one percent (1%) of the service points served by an ESP, or five (5) service points, whichever is greater, are found to be non-conforming and are not corrected during the first six months of Direct Access participation by that ESP.~~
~~(b) More than one-half of one percent (0.5%), or three (3) service points, whichever is greater, are found to be non-conforming and are not corrected during any six consecutive months thereafter.~~
~~c. TEP may refuse to enter into a new ESP Service Acquisition Agreement, or cancel an existing ESP Service Acquisition Agreement pursuant to Section H.10.a.1.b, with any ESP that has a demonstrated pattern of uncorrected non-compliance as established above. This provision shall not apply if the alleged demonstrated pattern of non-compliance or correction thereof is disputed and is pending before any agency or entity with jurisdiction to resolve the dispute.~~

~~INDEX~~

EXHIBIT

MJD-2

TABLE OF CONTENTS

SECTION 1
APPLICABILITY OF RULES AND REGULATIONS AND DESCRIPTION OF SERVICE

A. Tucson Electric Power Company ("Company") is an electric utility operating within portions of the state of Arizona. The Company will provide service to any person, institution or business located within its service area in accordance with the provisions of its Pricing Plans and the terms and conditions of these Rules and Regulations.

B. All electricity delivered to any Customer is for the sole use of that Customer on that Customer's premises only. Electricity delivered by the Company will not be redelivered or resold, or the use thereof by others permitted unless otherwise expressly agreed to in writing by the Company. However, those Customers purchasing electricity for redistribution to the Customer's own tenants (only on the Customer's premises) may separately meter each tenant distribution point for the purpose of prorating the Customer's actual purchase price of electricity delivered among the various tenants on a per unit basis.

C. These Rules and Regulations will apply to all electric service furnished by the Company to its Customers.

D. These Rules and Regulations are part of the Company's Pricing Plans on file with, and duly approved by, the Arizona Corporation Commission ("ACC" or "Commission"). These Rules and Regulations will remain in effect until modified, amended, or deleted by order of the ACC. No employee, agent or representative of the Company is authorized to modify the Company Rules.

E. These Rules and Regulations will be applied uniformly to all similarly situated Customers.

F. In case of any conflict between these Rules and Regulations and the ACC's rules, these Rules and Regulations will apply.

G. Whenever the Company and an Applicant or a Customer are unable to agree on the terms and conditions under which the Applicant or Customer is to be served, or are unable to agree on the proper interpretation of these Rules and Regulations, either party may request assistance from the Consumer Services Section of the Utilities Division of the ACC. The Applicant or Customer also has the option to file an application with the ACC for a proper order, after notice and hearing.

H. The Company's supplying electric service to the Customer and the acceptance thereof by the Customer will be deemed to constitute an agreement by and between the Company and the Customer for delivery, acceptance of and payment for electric service under the Company's Rules and Regulations and applicable Pricing Plans.

SECTION 2
DEFINITIONS

A. In these Rules and Regulations, the following definitions will apply unless the context requires otherwise:

1. Advance in Aid of Construction: Funds provided to the Company by the Applicant under the terms of a line extension agreement, the value of which may be refundable.

2. Applicant: A person requesting the Company to supply electric service.

3. Application: A request to the Company for electric service, as distinguished from an inquiry as to the availability or charges for this service.

4. Arizona Corporation Commission ("ACC" or "Commission"): The regulatory authority of the State of Arizona having jurisdiction over public service corporations operating in Arizona, hereinafter referred to as the "Commission."

5. Billing Month: The period between any two regular readings of the Company's meters at approximately thirty (30) day intervals.

6. Billing Period: The time interval between two consecutive meter readings taken for billing purposes.

7. Company: Tucson Electric Power Company acting through its duly authorized officers or employees within the scope of their respective duties.

8. Competitive Services: All aspects of retail service except those services specifically defined as "Non-competitive Services" pursuant to R14-2-1601(27) of the ACC-approved Competition Rules, or noncompetitive services as defined by the Federal Energy Regulatory Commission.

9. Connected Load: The sum of the power rating of the Customer's electrical apparatus connected to the Company's system.

10. Contributions in Aid of Construction ("Contribution"): Funds provided to the Company by the Applicant under the terms of a line extension agreement and/or service connection Pricing Plan, the value of which is not refundable.

11. Customer: The person(s) or entity(ies) in whose name service is rendered, as evidenced by the request for electric service by the Applicant(s), or by the receipt and/or payment of bills regularly issued in his name regardless of the identity of the actual user of the service.

12. Customer Charge: The amount the Customer must pay the Company for the availability of electric service, excluding any electricity used, as specified in the Company's Pricing Plans.

13. Day: Calendar Day

14. Demand: The rate at which power is delivered during any specified period of time. Demand may be expressed in kilowatts, kilovolt-amperes, or other suitable units.

SECTION 2
DEFINITIONS
(continued)

15. Disabled: A person with a physical or mental condition which substantially contributes to the person's inability to manage his or her own resources, carry out daily living activities, or protect oneself from neglect or hazardous situations without assistance from others.

16. Distribution Lines: The Company's lines operated at distribution voltage, which are constructed along public roadways or other bona fide rights-of-way, including easements on Customer's property.

17. Economic Feasibility Analysis: The calculation used to determine the deposit required for a line extension. Normally a unitized per foot cost, but could be a cost to revenue calculation for large customers.

18. Elderly: A person who is 65 years of age or older.

19. Energy: Electric energy, expressed in kilowatt-hours.

20. Illness: A medical ailment or sickness for which a residential Customer obtains a verified document from a licensed medical physician stating the nature of the illness and that discontinuance of service would be especially dangerous to the Customer's health.

21. Inability to Pay: Circumstances in which residential Customer:

    a. Is not gainfully employed and unable to pay, or

    b. Qualifies for government welfare assistance, but has not begun to receive assistance on the date he receives his bill and can obtain verification of that fact from the government welfare assistance agency.

    c. Has an annual income below the published federal poverty level and can produce evidence of this, and

    d. Signs a declaration verifying that the Customer meets one of the above criteria and is either elderly, handicapped, or suffers from illness.

22. Interruptible Electric Service: Electric service that is subject to interruption as specified in the Company's Pricing Plan.

23. Kilowatt (kW): A unit of power equal to 1,000 watts.

24. Kilowatt-Hour (kWh): The amount of electric energy delivered in one hour at a constant rate of one kilowatt.

25. Law: Any statute, rule, order or requirement established and enforced by government authorities.

<u>SECTION 2</u>
DEFINITIONS
(continued)

26. Line Extension: The lines and equipment necessary to extend the electric distribution system of the Company to provide service to additional Customers.

27. Long-Term Rental Mobile Home Park: A park which is finish-graded and has permanently paved roadways, sewer and water connections, and which provides rental spaces to permanent and semi-permanent occupants of mobile homes which are owned either by the occupant or by other persons.

28. Master Meter: A meter for measuring or recording the flow of electricity at a single location before distribution to tenants or occupants for their individual usage.

29. Megawatt (MW): Unit of power equal to 1,000,000 watts.

30. Meter: The instrument and any associated equipment used for measuring, indicating or recording the flow of electricity that has passed through it.

31. Meter Tampering: A situation in which a meter has been illegally altered, including, but not limited to: meter bypassing, use of magnets to slow the meter recording, and broken meter seals.

32. Minimum Charge: The amount the Customer must pay for the availability of electric service, including an amount of usage, as specified in the Company's Pricing Plans.

33. Month: The period between any two (2) regular readings of the Company's meters at approximately thirty (30) day intervals.

34. On-site Generation: Any and all power production generated on or adjacent to a Customer's property that is controlled, utilized, sold, or consumed by said Customer or its agent.

35. Permanent Customer: A Customer who is a tenant or owner of a service location who applies for and receives permanent electric service.

36. Permanent Service: Service which, in the opinion of the Company, is of a permanent and established character. The use of electricity may be continuous, intermittent, or seasonal in nature.

37. Person: Any individual, partnership, firm, corporation, governmental agency, or other organization operating as a single entity.

SECTION 2
DEFINITIONS
(continued)

38. Point of Delivery: In all cases, unless otherwise specified, "point of delivery" is the location on the Customer's building, structure, or premises where all wires, conductors, or other current-carrying devices of the Customer join or connect with wires, conductors, or other current-carrying devices of the Company. Location of the point of delivery will be determined by the Company in conformity with its standards and specifications, rate schedules and construction standards as they exist from time to time. Location of metering facilities will be determined by the Company and may or may not be at the same location as the point of delivery.

39. Power: The rate of generating, transferring and/or using electric energy, usually expressed in kilowatts.

40. Power Factor: The ratio of real or active power (kW) to apparent or reactive power (KVA).

41. Premises: All of the real property and apparatus employed in a single enterprise on an integral parcel of land undivided by public streets, alleys or railways.

42. Pricing Plans: A part of the Company's Tariffs that sets forth the rates and charges related to specific categories of Customers and related terms and conditions.

43. Primary Service and Metering: Service supplied directly from the Company's high voltage distribution or transmission lines without prior transformation to a secondary level.

44. Residential Subdivision Development: Any tract of land which has been divided into six or more contiguous lots with an average size of one acre or less for use for the construction of residential buildings or permanent mobile homes for either single or multiple occupancy.

45. Residential Use: Service to Customers using electricity for domestic purposes such as space heating, air conditioning, water heating, cooking, clothes drying, and other residential uses, including use in apartment buildings, mobile home parks, and other multi-unit residential buildings.

46. Rules and Regulations or Company Rules: These Rules and Regulations that are part of the Company's Tariffs and Pricing Plans.

47. Secondary Service: Service supplied at secondary voltage levels from the load side of step-down transformers connected to the Company's high voltage distribution lines.

48. Service Area: The territory in which the Company has been granted a certificate of convenience and necessity and is authorized by the Commission to provide electric service.

49. Service Classifications: Service classifications will be those provided by the filed rate schedules.

SECTION 2
DEFINITIONS
(continued)

50. Service Drop: The overhead service conductors from the last Company-owned pole or other aerial support to and including the splices, if any, connecting to the Customer's service entrance conductors at a building or other structure.

51. Service Establishment Charge: The charge as specified in the Company's Pricing Plans which covers the cost of establishing a new account.

52. Service Lateral: The underground service conductors between the street main, including any risers at a pole or other structure or from transformers, and the first point of connection to the Customer's service entrance conductors in a terminal box or meter or other enclosure with adequate space, inside or outside the building wall.

53. Service Line: The last line extending from a distribution line or transformer to the Customer's premises or point of delivery.

54. Service Point: Unless otherwise stated, all references to "service point" in this agreement will refer to an installed service, identified by a Universal Node Identifier ("UNI").

55. Service Reconnection Charge: The charge as specified in the Company's Pricing Plans which must be paid by the Customer prior to reestablishment of electric service each time the electricity is disconnected for nonpayment or whenever service is otherwise discontinued for failure to comply with the Company's Pricing Plans or Rules and Regulations.

56. Service Reestablishment Charge: A charge as specified in the Company's Pricing Plans for service at the same location where the same Customer had ordered a service disconnection within the preceding twelve-month period.

57. Single Family Dwelling: A house, apartment, or a mobile home permanently affixed to a lot, or any other permanent residential unit which is used as a permanent home.

58. Single-Phase Service: Three (3) wire service (usually 120/240 volts).

59. Tariffs: The documents filed with the Commission which list the services offered by the Company which set forth the terms and conditions and a schedule of the rates and charges for those services.

60. Temporary Service: Service to premises or enterprises which are temporary in character, or where it is known in advance that the service will be of limited duration. Service which, in the opinion of the Company, is for operations of a speculative character is also considered temporary service.

SECTION 2
DEFINITIONS
(continued)

61. Third-Party Notification: A notice of pending discontinuance of service to a Customer of record sent to an individual or a public entity in order to make satisfactory arrangements with the Company on behalf of said Customer.

62. Three-Phase Service: Four (4) wire service (usually 277/480 volts).

63. Universal Node Identifier ("UNI"): A unique, permanent identification number assigned to each service point of delivery.

64. Weather Especially Dangerous to Health: That period of time commencing with the scheduled termination date when the local weather forecast, as predicted by the National Oceanic and Atmospheric Administration, indicates that the temperature will not exceed 32 degrees Fahrenheit for the next day's forecast.

SECTION 3
ESTABLISHMENT OF SERVICE

A. Information from New Applicants

1. The Company may obtain the following minimum information from each new application for service:

   a. Name or names of Applicant(s);

   b. Service address or location and telephone number;

   c. Billing address and telephone number, if different than service address;

   d. Social security number or Driver's License number and date of birth to be consistent with verifiable information on legal identification.

   e. Address where service was provided previously;

   f. Date Applicant will be ready for service;

   g. Whether premises had been supplied with electric service previously;

   h. Purpose for which service is to be used;

   i. Whether Applicant is owner or tenant of, or agent for the premises;

   j. Information concerning the energy and demand requirements of the Customer; and

   k. Type and kind of life-support equipment, if any, used by the Customer.

2. The supplying of electric service by the Company and the acceptance of that electric service by the Customer will be deemed to constitute an agreement by and between the Company and the Customer for delivery, acceptance of and payment for electric service under the Company's applicable Pricing Plans and Rules and Regulations.

3. The term of any agreement not otherwise specified will become operative on the day the Customer's installation is connected to the Company's facilities for the purpose of taking electric energy.

4. The Company may require a written contract with special guarantees from Applicants whose unusual characteristics of load or location would require excessive investment in facilities or whose requirements for service are of a special nature.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

5. Signed contracts may be required for service to commercial and industrial establishments. Neither these contracts, nor any modifications to these contracts, will be binding upon the Company until executed by a duly authorized representative of the Company.

6. Where service is rendered to two (2) or more Customers whose name appears on the bill, as evidenced on the bill, the Company will have the right to collect the full amount owed it from any one of the Customers.

B. Deposits

1. The Company may require from any present or prospective Customer a deposit to guarantee payment of all bills. This deposit may be retained by the Company until service is discontinued and all bills have been paid, except as provided in Subsection 3.B.3 below. Upon proper application by the Customer, the Company will then return said deposit, together with any unpaid interest accrued thereon from the date of commencement of service or the date of making the deposit, whichever is later. The Company will be entitled to apply said deposit together with any unpaid interest accrued thereon, to any indebtedness for the same class of service owed to the Company for electric service furnished to the Customer making the deposit. When said deposit has been applied to any such indebtedness, the Customer's electric service may be discontinued until all such indebtedness of the Customer is paid and a like deposit is again made with the Company by the Customer. No interest will accrue on any deposit after discontinuance of the service to which the deposit relates.

   The Company will not require a deposit from a new Applicant for residential service if the Applicant is able to meet any of the following requirements:

   a. The Applicant has had service of a comparable nature with the Company at another service location within the past two (2) years and was not delinquent in payment during the last twelve (12) consecutive months of service or was not disconnected for nonpayment; or

   b. The Applicant can produce a letter regarding credit verification from an electric utility where service of a comparable nature was last received which states that the Applicant has had a timely payment history at time of service discontinuation; or

   c. Instead of a deposit, the Company receives deposit guarantee notification from a social or governmental agency acceptable to the Company. A surety bond may be provided as security for the Company in an amount equal to the required deposit.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

2. The Company may issue a non-assignable, non-negotiable receipt to the Applicant for the deposit. The inability of the Customer to produce his or her receipt will in no way impair the Customer's right to receive a refund of the deposit that is reflected on the Company records.

3. Cash deposits held by the Company twelve (12) months or longer will earn interest at the established one-year Treasury constant maturities rate, effective on the first business day of each year, as published in the Federal Reserve website.

   a. Residential Customers – Deposits or other instruments of credit will automatically expire or be refunded or credited to the Customer's account, after twelve (12) consecutive months of service during which time the Customer has not been delinquent more than two (2) times in a twelve (12) month period.

   b. All Customers – Upon final discontinuance of the use of the service and full settlement of all bills by the Customer, any deposit, not previously refunded, with accrued interest, if any, in accordance with the provisions of these Rules and Regulations will be returned to the Customer or, at the Company election, it may be applied to the payment of any unpaid accounts of the Customer and the balance, if any, returned to the Customer.

4. The Company may require a Customer to establish or reestablish a deposit if the Customer became delinquent in the payment of three (3) or more bills within a twelve (12) consecutive month period, or has been disconnected from service during the last twelve (12) months.

5. The Company may review the Customer's usage after service has been connected and adjust the deposit amount based upon the Customer's actual usage.

6. A separate deposit may be required for each meter installed.

7. Residential Customer deposits will not exceed two (2) times that Customer's estimated average monthly bill. Non-residential Customer deposits will not exceed two and one-half (2.5) times that Customer's maximum estimated monthly bill. If actual usage history is available, then that usage, adjusted for normal weather, will be the basis for the estimate.

8. The posting of a deposit will not preclude the Company from terminating service when the termination is due to the Customer's failure to perform any obligation under the agreement for service or any of these Rules and Regulations.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

C. Conditions for Supplying Service

The Company reserves the right to determine the conditions under which service will be provided. Conditions for service and extending service to the Customer will be based upon the following:

1. Customer has wired his premises in accordance with the National Electric Code, City, County and/or State codes, whichever are applicable.

2. Customer has installed the meter loop in a suitable location approved by the Company.

3. In the case of a mobile home, the meter loop must be attached to a meter pole or to an approved support.

4. In case of temporary construction service, the meter loop must be attached to an approved support.

5. All meter loop installations must be in accordance with the Company's specifications and located at an outdoor location accessible to the Company.

6. Individual Customers may be required to have their property corner pins and/or markers installed to establish proper right-of-way locations.

7. Developers must have all property corner pins and/or markers installed necessary to establish proper locations to supply electric service to individual lots within subdivisions.

8. Where the installation requires more than one meter for service to the premises, each meter panel must be permanently marked (not painted) by the contractor or Customer to properly identify the portion of the premises being served.

9. The identification will be the same as the apartment, office, etc., served by that meter socket. The identifying marking placed on each meter panel will be impressed into or raised from a tab of aluminum, brass or other approved non-ferrous metal with minimum one-fourth (l/4) inch-high letters. This tag must be riveted to the meter panel. The impression must be deep enough to prevent the identification(s) from being obscured by subsequent painting of the building and attached service equipment.

10. The Company may require the assistance of the Customer and/or the Customer's contractor to open the apartments or offices at the time the meters are set, in order to verify that each meter socket actually serves the apartment or office indicated by the marking tag. In the case of multiple buildings the building or unit number and street address will be identified on the pull section in the manner described above.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

D. Grounds for Refusal of Service

The Company may refuse to establish service if any of the following conditions exist:

1. The Applicant has an outstanding amount due for the same class of service with the Company and the Applicant is unwilling to make satisfactory arrangements with the Company for payment.

2. A condition exists which in the Company's judgment is unsafe or hazardous to the Applicant, the general population, or the Company's personnel or facilities.

3. Refusal by the Applicant to provide the Company with a deposit when the Customer has failed to meet the credit criteria for waiver of deposit requirements.

4. Customer is known to be in violation of the Company's Pricing Plans filed with and approved by the Commission.

5. Failure of the Customer to furnish such funds, service, equipment, and/or rights-of-way necessary to serve the Customer and which have been specified by the Company as a condition for providing service.

6. Customer fails to provide access to the meter that would be serving the Customer.

7. Applicant falsifies his or her identity for the purpose of obtaining service.

E. Service Establishment, Reestablishment and Reconnection Charge

1. The Company will make a charge, as approved by the Commission, for service establishment or reestablishment for service reads only as set forth in the Statement of Additional Charges.

2. The Company will make a charge, as approved by the Commission, for service establishment or reestablishment, other than service reads under usual operating procedures, for single-phase service only, during regular business hours as set forth in the Statement of Additional Charges.

3. Should single-phase service be established or reestablished during a period other than regular working hours at the Customer's request, the Customer will be required to pay an after-hours charge for the service connection as set forth in the Statement of Additional Charges. Where Company scheduling will not permit service establishment on the same day as requested, the Customer may elect to pay the after-hours charge for establishment that day or his/her service will be established on the next available business day. Even so, a Customer's request to have the Company establish service after-hours is subject to the Company having Staff available; there is no guarantee that the Company will have the staffing available for service establishment, reestablishment or reconnection outside of regular business hours.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

4. The Company will make a charge, as approved by the Commission, for service establishment or reestablishment, other than service reads under usual operating procedures, for three-phase service only, during regular business hours as set forth in the Statement of Additional Charges.

5. Should three-phase service be established or reestablished during a period other than regular working hours at the Customer's request, the Customer will be required to pay an after-hours charge for the service connection as set forth in the Statement of Additional Charges. Where Company scheduling will not permit service establishment on the same day as requested, the Customer may elect to pay the after-hours charge for establishment that day or his/her service will be established on the next available business day. Even so, a Customer's request to have the Company establish service after-hours is subject to the Company having Staff available; there is no guarantee that the Company will have the staffing available for service establishment, reestablishment or reconnection outside of regular business hours.

6. For the purpose of this rule, the definition of service establishment is where the Applicant's facilities are ready and acceptable to the Company, the Applicant has obtained all required permits and/or inspections indicating that the Applicant's facilities comply with local construction safety and governmental standards and regulations, and the Company needs only to install a meter, read a meter, or turn the service on.

7. Reconnection Charge: Whenever the Company has discontinued service under its usual operating procedures because of any default by the Customer as provided herein, a reconnection charge not to exceed the charge for the reestablishment of service as set forth in the Statement of Additional Charges will be made and may be collected by the Company before service is restored. When, due to the behavior of the Customer, it has been necessary to discontinue service utilizing other than usual operating procedures, the Company will be entitled to charge and collect, through verifiable means, actual costs to restore service.

F. Temporary Service

1. Applicants for temporary service may be required to pay the Company in advance of service establishment, the estimated cost of installing and removing the facilities necessary for furnishing the desired service.

2. Where duration of service is to be less than one month, the Applicant may also be required to advance a sum of money equal to the estimated bill for service.

3. Where the duration of service is to exceed one month, the Applicant may also be required to meet the deposit requirements of the Company.

4. If at any time during the term of the agreement for services the character of a temporary Customer's operations changes so that in the opinion of the Company the Customer is classified as permanent, the terms of the Company's line extension rules will apply.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

G. Identification of Load and Premises: Upon request of the Company, the Applicant must identify the electric load and premises to be served by the Company at the time of application. If the service address is not recognized in terms of commonly-used identification system, the Applicant may be required to provide specific written directions and/or legal descriptions before the Company will be required to act upon a request for electric service.

H. Identification of Responsible Party: Any person applying on behalf of another Applicant for service to be connected in the name of or in care of another Applicant must furnish to the Company written approval from that Applicant guaranteeing payment of all bills under the account. The Customer is responsible in all cases for service supplied to the premises until the Company has received proper notice of the effective date of any change. The Customer will also promptly notify the Company of any change in billing address.

I. Tampering With or Damaging Company Equipment

1. The Customer agrees, when accepting service, that no one except authorized Company employees or agents of the Company will be allowed to remove or replace any Company owned equipment installed on Customer's property.

2. No person, except an employee or agent acting on behalf of the Company will alter, remove or make any connection to the Company's meter or service equipment.

3. No meter seal may be broken or removed by anyone other than an employee or agent acting on behalf of the Company; however the Company may give its prior consent to break the seal by an approved electrician employed by a Customer when deemed necessary by the Company.

4. The Customer will be held responsible for any broken seals, tampering, or interfering with the Company's meter(s) or any other Company owned equipment installed on the Customer's premises. In cases of tampering with meter installations, interfering with the proper working thereof, or any tampering, interfering, theft, or service diversion, including the falsification of Customer read-meter readings, Customer will be subject to immediate discontinuance of service. The Company will be entitled to collect from the Customer whose name the service is in, under the appropriate rate, for all power and energy not recorded on the meter as the result of such tampering, or other theft of service, and also additional security deposits as well as all expenses incurred by the Company for property damages, investigation of the illegal act, and all legal expenses and court costs incurred by the Company.

5. The Customer will be held liable for any loss or damage occasioned or caused by the Customer's negligence, want of proper care or wrongful act or omission on the part of any Customer's agents, employees, licensees or contractors.

SECTION 4
MINIMUM CUSTOMER INFORMATION REQUIREMENTS

A. Information for Residential Customers

1. The Company will make available upon Customer request not later than sixty (60) days from the date of the request, a concise summary of the rate schedule applied for by the Customer. The summary will include the following:

   a. The monthly minimum or Customer charge, identifying the amount of the charge and the specific amount of usage included in the minimum charge, where applicable;

   b. Rate blocks, where applicable;

   c. Any adjustment factor(s) and method of calculation; and

   d. Demand charge, where applicable.

2. Upon application for service or upon request, the Applicant or the Customer will elect the applicable Pricing Plan best suited to his requirements. The Company may assist in making this election, but will not be held responsible for notifying the Customer of the most favorable Pricing Plan and will not be required to refund the difference in charges under different Pricing Plans.

3. Upon written notification of any material changes in the Customer's installation or load conditions, the Company will assist in determining if a change in Pricing Plans is desirable, but not more than one (1) such change at the Customer's request will be made within any twelve (12) month period.

4. The supply of electric service under a residential rate schedule to a dwelling involving some business or professional activity will be permitted only where such activity is of only occasional occurrence, or where the electricity used in connection with such activity is small in amount and used only by equipment which would normally be in use if the space were used as living quarters. Where the portion of a dwelling is used regularly for business, professional or other gainful purposes, and any considerable amount of electricity is used for other than domestic purposes, or electrical equipment not normally used in living quarters is installed in connection with such activities referred to above, the entire premises must be classified as non-residential and the appropriate general service Pricing Plan will be applied.

SECTION 4
MINIMUM CUSTOMER INFORMATION REQUIREMENTS
(continued)

5. Upon Customer request the Company will make available within sixty (60) days from date of service commencement, a concise summary of the Company's Pricing Plans or the Commission's Rules and Regulations concerning:

   a. Deposits;

   b. Termination of service;

   c. Billing and collection; and

   d. Complaint handling.

6. Upon request of a Customer, the Company will transmit a written statement of actual consumption for each billing period during the prior twelve (12) months unless this data is not reasonably ascertainable. But the Company will not be required to accept more than one such request from each Customer in a calendar year. Even so, the Company will charge a fee consistent with its ACC-approved Pricing Plans and/or these Rules and Regulations for providing consumption, interval or other data to the Customer.

7. The Company will inform all new Customers of their right to obtain the information specified above.

B. Information Required Due to Changes in Pricing Plans

1. The Company will transmit to affected Customers a concise summary of any change in the Company's Pricing Plans affecting those Customers.

2. This information will be transmitted to the affected Customer within sixty (60) days of the effective date of the change.

SECTION 5
MASTER METERING

A. Mobile Home Parks - New Construction/Expansion

1. The Company will refuse service to all new construction and/or expansion of existing permanent residential mobile home parks unless the construction and/or expansion is individually metered by the Company. Line extensions and service connections to serve this new construction and/or expansion will be governed by these Rules and Regulations.

2. For the purpose of this rule, permanent residential mobile home parks will mean mobile home parks where, in the opinion of the Company, the average length of stay for an occupant is a minimum of six months.

3. For the purpose of this rule, expansion means the acquisition of additional real property for permanent residential spaces in excess of that existing at the effective date of this rule.

B. Residential Apartment Complexes, Condominiums, and other Multi-unit Residential Buildings

1. Master metering will not be allowed for new construction of apartment complexes and condominiums unless the building(s) will be served by a centralized heating, ventilation and/or air conditioning system and the contractor can provide to the Company an analysis demonstrating that the central unit will result in a favorable cost/benefit relationship.

2. At a minimum, the cost/benefit analysis will consider the following elements for a central unit as compared to individual units:

   a. Equipment and labor costs;

   b. Financing costs;

   c. Maintenance costs;

   d. Estimated kWh usage;

   e. Estimated kW demand on a coincident demand and non-coincident demand basis (for individual units);

   f. Cost of meters and installation; and

   g. Customer accounting cost (one account vs. several accounts).

SECTION 6
SERVICE LINES AND ESTABLISHMENTS

A. Priority and Timing of Service Establishments

1. After an Applicant has complied with the Company's application and deposit requirements and has been accepted for service by the Company and obtained all required easements, permits and/or inspections indicating that the Customer's facilities comply with local construction, safety and governmental standards or regulations, the Company will schedule that Customer for service establishment.

2. Service establishments will be scheduled for completion within five (5) business days of the date the Customer has been accepted for service, except in those instances when the Customer requests service establishment beyond the five (5) business day limitation.

3. When the Company has made arrangements to meet with a Customer for service establishment purposes and the Company or the Customer cannot make the appointment during the prearranged time, the Company will reschedule the service establishment to the satisfaction of both parties.

4. The Company will schedule service establishment appointments within a maximum range of four (4) hours during normal working hours, unless another time frame is mutually acceptable to the Company and the Customer.

5. Service establishments must only be made by the Company.

6. For the purposes of this rule, service establishments are where the Customer's facilities are ready and acceptable to the Company and the Company needs only to install or read a meter or turn the service on.

B. Service Lines

1. Customer-provided Facilities

   a. Each Applicant for service will be responsible for all inside wiring, including the service entrance, meter socket and conduit. For three-phase service, the Customer will provide, at his expense, all facilities, including conductors and conduit, beyond the Company-designated point of delivery.

SECTION 6
SERVICE LINES AND ESTABLISHMENTS
(continued)

b. Meters and service switches in conjunction with the meter must be installed in a location where the meters will be readily and safely accessible for reading, testing and inspection and where such activities will cause the least interference and inconvenience to the Customer. Location of metering facilities will be determined by the Company and may or may not be at the same location as the point of delivery. However, the meter locations will not be on the front exterior wall of the home, or in the carport or garage, unless mutually agreed to between the home builder or Customer and the Company. Without cost to the Company, the Customer must provide, at a suitable and easily accessible location, sufficient and proper space for installation of meters.

c. Where the meter or service line location on the Customer's premises is changed at the request of the Customer or due to alterations on the Customer's premises, the Customer, at his expense, must provide and have installed all wiring and equipment necessary for relocating the meter and service line connection. The Company may assess a charge for moving the meter and/or service line.

d. Customer will provide access to the main switch or breaker for disconnecting load to enable safe installation and removal of company meters.

2. Overhead Service Connections - Secondary Service

a. Where the Company's distribution pole line is located on the Customer's premises, or on a street, highway, lane, alley, road or private easement immediately contiguous thereto, the Company will, at its own expense, furnish and install a single span of service drop from its pole to the Customer's point of attachment, provided such attachment is at the point of delivery and is of a type and so located that the service drop wires may be installed in a manner approved by the Company in accordance with good engineering practice, and in compliance with all applicable laws, ordinances, rules and regulations, including those governing clearances and points of attachments.

b. Whenever any of the clearances required by the applicable laws, ordinances, rules or regulations of public authorities or standards of the Company from the service drops to the ground or any object become impaired by reason of any changes made by the owner or tenant of the premises, the Customer will, at his own expense, provide a new and approved support, in a location approved by the Company, for the termination of the Company's service drop wires and will also provide all service entrance conductors and equipment necessitated by the change of location.

c. For each overhead service connection, the Customer will furnish at his own expense a set of service entrance conductors that will extend from the point of delivery at the point of termination of the Company's service drop on the Customer's support to the Customer's main disconnect switch. These service entrance conductors will be of a type and be in an enclosure which meets with the approval of the Company and any inspection authorities having jurisdiction.

d. The cost of any service line, in excess of that allowed at no charge, will be paid for by the Customer as a contribution in aid of construction.

SECTION 6
SERVICE LINES AND ESTABLISHMENTS
(continued)

3. Underground Service Connections - Secondary Service

   a. In areas where the Company maintains an underground distribution system, individual services will be underground.

   b. Whenever the Company's underground distribution system is not complete to the point designated by the Company where the service lateral is to be connected to the distribution system, the system may be extended in accordance with Section 7.

   c. For single-phase service, the Company will install a service lateral from its distribution line to the Customer's Company-approved termination facilities under the following conditions (unless otherwise agreed to by the Company and the Applicant):

      i. The Customer, at his expense, will perform the necessary trenching, conduit, conduit installation, backfill, landscape restoration and paving and will furnish, install, own and maintain termination facilities on or within the building to be served.

      ii. The Company, at its expense, will furnish, install, own, and maintain the underground single-phase service cables to the Customer's Company-approved termination facilities.

      iii. The Company will determine the minimum size and type of conduit and conductor for the single-phase service. The Customer will furnish and install the conduit system, including pull ropes. The ownership of this conduit or duct will be conveyed to the Company, and the Company will thereafter maintain this conduit or duct. The maximum length of any service conductor will be determined by the Company in accordance with accepted engineering practice in determining voltage drop, voltage flicker, and other relevant considerations.

   d. For three-phase service, the Customer will provide at his expense all facilities, including conductors and conduit, beyond the Company-designated point of delivery.

C. Easements and Rights-of-Way

1. At no cost to the Company, each Customer must grant adequate easements and rights-of-way satisfactory to the Company to ensure that Customer's proper service connection. Failure on the part of the Customer to grant adequate easements and rights-of-way will be grounds for the Company to refuse service.

2. When the Company discovers that a Customer or his agent is performing work, has constructed facilities, or has allowed vegetation to grow adjacent to or within an easement or right-of-way and such work, construction, vegetation or facility poses a hazard or is in violation of federal, state or local laws, ordinances, statutes, rules or regulations, or significantly interferes with the Company's access to equipment, the Company will notify the Customer or his agent and will take whatever actions are necessary to eliminate the hazard, obstruction or violation at the Customer's expense.

SECTION 6
SERVICE LINES AND ESTABLISHMENTS
(continued)

D. Number of Services to be Installed

The Company will not install more than one service, either overhead or underground, for any one building or group of buildings on a single premises, except as separate services may be installed for separate buildings or group of buildings where necessary for the operating convenience of the Company, where provided for in Pricing Plans, or where required by law or local ordinance.

E. Multiple Service Points

Unless otherwise expressly provided herein, or in a rate schedule or contract, any person, firm, corporation, agency or other organization or governmental body receiving service from the Company at more than one location or for more than one separately-operated business will be considered as a separate Customer at each location and for each business. If several buildings are occupied and used by a Customer in the operation of a single business, then the Company, upon proper application, will furnish service for the entire group of buildings through one service connection at one point of delivery, provided all of these buildings are at one location on the same lot or tract, or on adjoining lots or tracts forming a contiguous plot (not separated by any public streets) wholly owned, or controlled, and occupied by the Customer in the operation of this single business. Dwelling units will be served, metered and billed separately, except at the option of the Company.

SECTION 7
LINE EXTENSIONS

Introduction

The Company will construct, own, operate and maintain lines along public streets, roads and highways which the Company has the legal right to occupy, and on public lands and private property across which rights-of-way and easements satisfactory to the Company may be obtained without cost to or condemnation by the Company.

A request for electric service often requires the construction of new distribution lines of varying distances. The distances and cost vary widely depending upon Customer's location and load size. With such a wide variation in extension requirements, it is necessary to establish conditions under which the Company will extend its electric facilities beyond this distance.

All extensions are subject to the availability of adequate capacity, voltage and Company facilities at the beginning point of an extension, as determined by the Company.

A standard policy has been adopted to provide service to Customers whose requirements are deemed by the Company to be economical and ordinary in nature.

In unusual circumstances, when the application of the provisions of this policy appear impractical, the Company will make a special study of the conditions to determine the basis on which service may be rendered.

A. General Requirements

1. Upon an Applicant's request for a line extension, the Company will prepare, without charge, a preliminary electric design and a rough estimate of the cost of installation to be paid by said Applicant.

2. Any Applicant for a line extension requesting the Company to prepare detailed plans, specifications, or cost estimates may be required to deposit with the Company an amount equal to the estimated cost of preparation. The Company will, upon request, make available within ninety (90) days after receipt of the deposit referred to above, these plans, specifications, or cost estimates of the proposed line extension. Where the Applicant authorizes the Company to proceed with construction of the extension, the deposit will be credited to the cost of construction; otherwise the deposit will be nonrefundable. If the extension is to include oversizing of facilities to be done at the Company's expense, appropriate details will be set forth in the plans, specifications and cost estimates. Subdivision developers providing the Company with approved plats will be provided with plans, specifications, or cost estimates within forty-five (45) days after receipt of the deposit referred to above.

SECTION 7
LINE EXTENSIONS
(continued)

3. Where the Company requires an Applicant to advance funds for a line extension, the Company will provide a copy of the line extension Pricing Plan prior to the Applicant's acceptance of the utility's extension agreement.

4. All line extension agreements requiring payment by the Applicant will be in writing and signed by each party.

5. The provisions of this rule apply only to those Applicants who, in the Company's judgment, will be permanent Customers of the Company. Applications for temporary service will be governed by the Company's rules concerning temporary service applications. The Company reserves the right to delay the extension of facilities until the satisfactory completion of required site improvements, as determined by the Company, and an approved service entrance to accept electric service has been installed.

B. Minimum Written Agreement Requirements

1. Each line extension agreement will, at a minimum, include the following information:

   a. Name and address of Applicant(s);

   b. Proposed service address or location;

   c. Description of requested service;

   d. Description and sketch of the requested line extension;

   e. A cost estimate which includes materials, labor, and other costs as necessary;

   f. Payment terms;

   g. A concise explanation of any refunding provisions, if applicable;

   h. The Company's estimated commencement and completion dates for construction of the line extension; and

   i. A summary of the results of the economic feasibility analysis performed by the Company to determine the amount of advance required from the Applicant for the proposed line extension.

2. Each Applicant will be provided with a copy of the written line extension agreement.

SECTION 7
LINE EXTENSIONS
(continued)

C. Line Extension Requirements

1. Overhead Extensions to Individual Applicants and to the Perimeter of Duly-Recorded Real Estate Subdivisions

   Except as otherwise provided herein, overhead extensions will be made as follows:

   a. Free Extensions

      Upon the Applicant's satisfactory completion of required site improvements, the Company will make extensions from its existing facilities of proper voltage and adequate capacity free of charge up to five hundred (500) feet. The distance of five hundred (500) feet is to be measured by the shortest feasible route along public streets, roads, highways, or suitable easements from the existing facilities to the Applicant's nearest point of delivery.

   b. Extensions in Excess of Free Extension Distance

      The Company will make extensions in excess of five hundred (500) feet upon receipt of a non-interest bearing, refundable cash deposit with the Company to cover costs of construction computed at the rate of twenty dollars and fifty-three cents ($20.53) per foot for each foot of single-phase line extension or twenty-seven dollars and thrty-eight cents ($27.38) per foot for each foot of three-phase line extension in excess of the free extension length (unless otherwise agreed to by the Company and the Applicant).

      The foregoing charges of twenty dollars and fifty-three cents ($20.53) and twenty-seven dollars and thirty-eight cents ($27.38) per foot for line extensions are based on the company's current average cost of construction of distribution lines. The Company will review its costs periodically and will file a Pricing Plan revision when such costs have changed by more than ten percent (10%) since the last revision of costs. Such revisions will be subject to approval by the Commission before becoming effective.

SECTION 7
LINE EXTENSIONS
(continued)

c. Method of Refund

1) After a period of twelve (12) months from the date the Company is initially ready to render service from an extension, seventy-five percent (75%) of any revenue received from the Customer in excess of ten thousand two hundred and sixty-five hundred dollars ($20.53 per ft. X 500 ft. = $10,265.00) for single-phase extensions or thirteen thousand six hundred and ninety dollars ($27.38 per ft. X 500 ft. = $13,690.00) for three-phase extensions during that period will be applied toward refunding the line extension deposit. The amount of refund may not exceed the amount of the deposit.

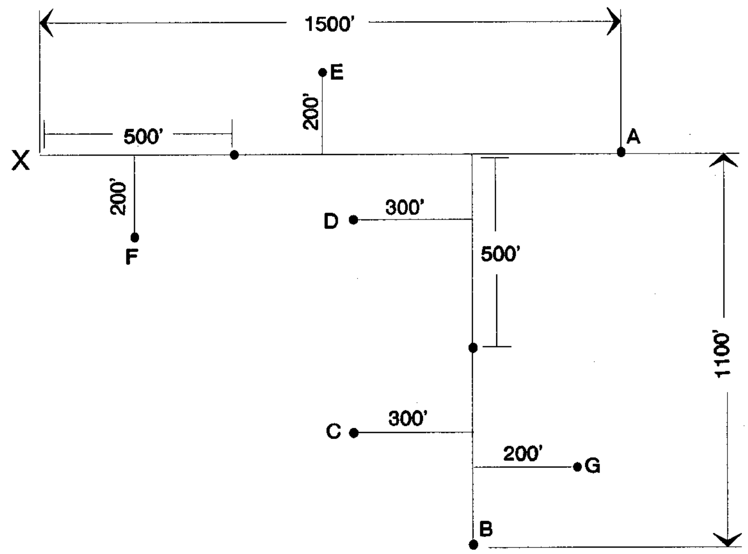
2) Deposit refunds will be made to a depositor when separately metered Customers are served directly from the line extension originally constructed to serve said depositor, providing the new line extension is less than five hundred (500) feet in distance, and the Customer to be served occupies a permanent structure designed for continued occupancy for either residential or business purposes, meeting established municipal, county or state codes as applicable.

The amount of the deposit refund will be equal to twenty dollars and fifty-three cents ($20.53) for single-phase or twenty-seven dollars and thirty-eight cents ($27.38) for three-phase service multiplied by five hundred (500) feet less the actual footage of the new line extension required to serve the new Customer.

In no event will the total of the refund payments made by the Company to a depositor be in excess of the deposit amount advanced.

A pictorial explanation of the method of refund for a single-phase line extension is as follows:

SECTION 7
LINE EXTENSIONS
(continued)



Applicant "A" – Customer makes refundable advance of $20,530 for footage over 500' at $20.53/foot.

Applicant "B" – Customer makes refundable advance of $12,318 for footage over 500' at $20.53/foot. No refund to A for B's connection because B is over 500'.

Applicant "C" – Customer gets line at no cost. Refund goes to B at $20.53 x 200', or $4,106.00 because C ties directly into B's line and is less than 500'.

Applicant "D" – Customer gets line at no cost. Refund goes to B at $20.53 x 200', or $4,106.00, because it ties directly into B's line and is less than 500'.

Applicant "E" – Customer gets line at no cost. Refund goes to A at $20.53 x 300', or $6,159.00 because E ties directly into A's line and is less than 500'.

Applicant "F" – Customer gets line at no cost. Refund goes to A at $20.53 x 300', or $6,159.00 because F ties directly into A's line and is less than 500'.

Applicant "G" – Customer gets line at no cost. Refund goes to B at $20.53 x 300', or $6,159.00; B receives $4,106.00 since this is the remaining balance of the initial deposit.

Note: This method requires that: i) The deposit advance made for an initial line extension cannot be refunded to the depositor unless a new line extension required to serve a new separately metered Customer is directly connected to the initial line extension; and ii) the new line extension is less than 500' in length.

SECTION 7
LINE EXTENSIONS

(continued)

3) Payment of eligible refunds will be made within ninety (90) days following receipt of notification to the Company that a qualifying permanent Customer has commenced receiving service from an extension.

4) The Customer may request an annual survey to determine if additional Customers have been connected to and are using service from the extension.

5) After a period of five (5) years from the date the Company is initially ready to render service from an extension, the Company will review the deposit and make appropriate refunds then due, if any. Any unrefunded amount remaining thereafter will become the property of the Company and will no longer be eligible for refund.

d. Extensions to Large Light and Power Customers (Rates 13, 14, 85A, and 90A)

The Company will install, own and maintain, on an individual project basis, the distribution facilities necessary to provide permanent service to a large light and power Customer. Prior to the installation of facilities, the Customer will be required to make a cash advance to the Company for any portion of the capital expenditures not justified by the estimated annual revenue derived from the unbundled charges associated with the facilities installed (e.g. revenue from the distribution secondary charge for 13.8 kV-facilities). Such advance, if any, will be in the amount determined by subtracting two (2) times the estimated annual revenue derived from the unbundled charges associated with the facilities installed from the total estimated installation costs. If the total of such charge is less than one hundred dollars ($100.00), the charge will be waived by the Company.
Adjustments to the advance will be made after the initial twenty-four (24) month billing period, and the Company will refund to the amount by which the estimated advance exceeds the actual installation cost less the actual twenty-four (24) month billing.

2. Overhead or Underground Distribution Facilities Within a New Duly Recorded Residential Subdivision

a. General

Required distribution facilities within a new duly recorded residential subdivision, including subdivision plats which are activated subsequent to their recordation, for permanent service to single and/or multi-family residences and/or unmetered area lighting, will be constructed, owned, operated and maintained by the Company in advance of applications for service by permanent Customers only after the Company and the Applicant have entered into a written contract which (unless otherwise agreed to by the Company and the Applicant) provides that:

SECTION 7
LINE EXTENSIONS
(continued)

1) The total estimated installed cost of such distribution facilities, exclusive of meters, services and exclusive of other costs as may be deemed as reasonable by the Company, is advanced to the Company as a refundable non-interest bearing cash deposit to cover the Company's cost of construction. In the event that the advance has not met the requirements for total refunding on or before the end of two (2) years from the date of installation of the Company's facilities, the advance will further be utilized for reimbursement of the Company's cost of ownership as provided in Subsection 7.C.2.b. In lieu of the refundable cash deposit, the Applicant may elect to execute a Deferred Construction Deposit Agreement, secured by a bond or letter of credit in a form acceptable to the Company, equal to the deferred cash deposit, which guarantees the posting by the Applicant of the full cash deposit one (1) to four (4) years subsequent to the completion of construction of the Company's facilities. Letters of credit and bonds will not be acceptable where the original cash deposit would be less than one thousand dollars ($1,000.00).

2) Refundable advances will become non-refundable at such time and in such manner provided in Subsection 7.C.2.b.

3) The Applicant will be responsible for ownership costs at such time and in such manner as provided in Subsection 7.C.2.b.

4) Where required line facilities within a subdivision exceed an average of five hundred (500) feet per lot, a nonrefundable cash amount equal to that portion of the total estimated installed cost represented by those required line facilities in excess of five hundred (500) feet per lot average will be paid to the Company.

5) Underground Installations - Extensions of single-phase electric lines necessary to furnish permanent electric service to new residential buildings or mobile homes within a subdivision, in which facilities for electric service have not been constructed, for which applications are made by a developer will be installed underground in accordance with the provisions set forth in this regulation except where it is not feasible from an engineering, operational, or economic standpoint. Extensions of single-phase underground distribution lines necessary to furnish permanent electric service within a new single family and/or multi-family residential subdivision will be made by the Company in advance of receipt of applications for service by permanent Customers in accordance with the following provisions (unless otherwise agreed to by the Company and the Applicant):

   i. The subdivider or other Applicant will provide at its expense the trenching, conduit, conduit installation, backfilling (including any imported backfill required), compaction, repaving, landscape restoration and any earthwork for pull boxes and transformer pad sites required to install the underground electric system, all in accordance with the specifications of the Company.

   ii. Underground service will be installed, owned, operated and maintained as provided in Section 7 of these Rules and Regulations.

SECTION 7
LINE EXTENSIONS
(continued)

iii. Any underground electric distribution system requiring more than single-phase service is not governed by this Subsection 7.C.2, but rather will be constructed pursuant to Subsection 7.C.4.

b. Method of Refund

1) On or after two (2) years subsequent to the installation of the Company's facilities, and thereafter every six (6) months, the Company will review the status of a subdivision to determine the percentage ratio that the number of lots or service locations occupied by permanent Customers bears to the total number of lots or service locations to be served by the extensions made within the subdivision. Refunds will be made prior to the actual occupancy by a permanent Customer if the lot or service location has been substantially completed so that in the judgment of the Company permanent occupancy will occur within a reasonable time. Such periodic review will continue until either: i) the calculated ratio equals a maximum of seventy-five percent (75%) at which time the total refund will be made to the Applicant; or ii) a five (5) year period subsequent to the completion of installation of the Company's facilities elapses. For purposes of computation of all charges and refundable deposit requirements under these Rules and Regulations, the installation of the Company's facilities will be that date upon which the construction is determined to be completed and the facilities are entered into the Company records of Plant and Property. The percentage ratio determined at the time of each review multiplied by the total refundable advance, less applicable cost of ownership charges previously deducted, if any, will represent that portion of the advance qualified for refund. If the foregoing calculation indicates a refund is due, an appropriate refund of cash deposit, or reduction of the cash deposit requirement at the end of the deferral period in those cases where a Deferred Construction Deposit Agreement has been executed, will be made.

Refunds of cash deposits, less applicable cost of ownership charges, if any, will also be made by the Company within ninety (90) days following receipt of written notice from the developer requesting payment of earned refund, provided that the earned refund due represents a minimum of twenty percent (20%) of the total amount of the advance. Furthermore, if at any time a maximum of seventy-five percent (75%) or more of the total refundable advance qualifies for refund, any balance of the advance remaining, after applicable cost of ownership charges, if any, have been deducted, will be refunded. No payment will be made of the Company in excess of the total refundable advance less applicable cost of ownership charges, if any, nor after a period of five (5) years subsequent to the completion of construction of the Company's facilities. Any unrefunded amount remaining at the end of the five (5) year period will become nonrefundable and the property of the Company.

SECTION 7
LINE EXTENSIONS
(continued)

2) In the event that any portion of an advance has not qualified for refund at the time of each review, the developer will be responsible for the Company's cost of ownership charges based on the average (mean) of the electric facilities represented by:

i) that portion of the advance not qualified for refund at the time of current review, and
ii) that portion of the advance not qualified for refund at the time of the last periodic review.

When the advance is in the form of a cash deposit, the semi-annual cost of ownership charges will be equal to the average of (i) and (ii) above multiplied by five and one-half percent (5-1/2%). When the advance is in the form of a Deferred Construction Deposit, the semi-annual cost of ownership charges will be equal to (i) and (ii) above multiplied by the sum of five and one-half percent (5-1/2%) plus one-half of the original cost equivalent of the rate of return, expressed as a percent, last allowed to the Company by the Commission. Payment of such cost of ownership charges, which will be computed and paid at the time of each review after the initial review, will be made in the following manner:

When the advance is in the form of a cash deposit, a deduction of cost of ownership charge will be made by the Company from the cash deposit.

When the advance is in the form of a Deferred Construction Deposit, the Company will bill and developer will pay to Company said cost of ownership charge. In the event that the Applicant fails to pay the cost of ownership charge when due, the Company will exercise its rights provided for in the Deferred Construction Deposit, and will call the bond or letter of credit.

The portion of the original advance on which cost of ownership charges are computed will not be reduced for purposes of that computation by amounts deducted previously for cost of ownership charges.

SECTION 7
LINE EXTENSIONS
(continued)

3. Underground Extensions to Individual Applicants and the Perimeter of Duly Recorded Real Estate Subdivisions

a. General

Underground line extensions will generally be made only where mutually agreed upon by the Company and the Applicant, or in areas where the Company does maintain underground distribution facilities for its operating convenience.

1) Underground extensions will be owned, operated and maintained by the Company, provided the Applicant pays in advance a non-refundable sum equal to the estimated difference between the cost, exclusive of meters and services, of the underground extension and an equivalent overhead extension.

2) In addition to the non-refundable sum, the Applicant will (unless otherwise agreed to by the Company and the Applicant) make such refundable deposit as otherwise would have been required under these Rules and Regulations if the extension had been made by overhead construction.

3) The Applicant will install all of the required underground duct system (including all or a portion of the necessary trenching, backfilling, conduits, ducts, transformer and equipment pads, manholes, and pull boxes) in accordance with the Company's specifications and subject to the Company's inspection and approval. Upon acceptance and approval by the Company, the Applicant will grant to the Company the exclusive right to use and occupy said duct system or, at the option of the Company, will transfer ownership thereof to the Company.

4) Refunds of cash deposits will be made in the same manner as provided for overhead extensions to individual Applicants for service, in accordance with the applicable provisions of Subsection 7.C.

5) Underground services will be installed, owned, operated and maintained as provided in Section 6 of these Rules and Regulations.

SECTION 7
LINE EXTENSIONS
(continued)

4. Replacement of Overhead with Underground Distribution Facilities

   a. Where a Customer has requested that existing overhead distribution facilities be replaced with underground distribution facilities, the total cost of such replacement will be paid by the Customer.

   b. Mandated Undergrounding Cost Recovery

   When the Company is required to construct a new electric system underground, or place an existing overhead electric system underground during a maintenance or upgrading project due to a State, County, or Municipal regulation or requirement, the cost differential between an overhead system and an underground system shall be calculated by an established methodology.

   Any existing electric circuits within a one-mile radius of the new system that benefits from either N – 1 protocols or enjoys reduced ampacity loads as a result of the newly undergrounded system shall be identified and catalogued by the Company.

   When a new Customer requests electric service and the source of that service is either the undergrounded system or any one of the existing electric circuits within a one-mile radius of the underground system, and the new Customer's site has been previously catalogued as benefiting from the new underground system, that Customer shall pay an additional charge for connecting to the Company's system.

   The new Customer's charge shall be calculated on the following basis:

   i. For every 25 kVA of transformer capacity required to meet the customer's needs, then said customer shall be responsible for reimbursing the Company for one(1) percent of the calculated cost differential of the underground system that the Customer is benefited from.

   ii. The Company shall provide the customer a worksheet showing the cost differential expenses for the underground system and the calculations resulting in the assessment against the new service.

   iii. The Company shall accurately track the assessments made to cover the cost differential expenses for each electric system that was required to be constructed underground, and shall make those records available to any person who may request them.

SECTION 7
LINE EXTENSIONS
(continued)

Example:

The Company needs to install a three-phase feeder line within a road right-of-way that has been identified as a Scenic Corridor or Gateway Route by a local jurisdiction. The regulation or ordinance requires the system be placed underground. The Company performs a cost estimate and determines that the difference between constructing the system overhead and underground (differential costs) is $250,000.00.

A new Customer is requesting service from an existing electrical circuit that has benefited from either increased reliability or load-carrying capacity, and the new Customer is within a one mile radius of the underground system that was mandated to be placed underground. The Customer is building a 25-lot subdivision and the engineering design requires installing four, 50 kVA pad mount transformers.

The Customer would be assessed for 8% of the cost differential on the underground system or $20,000.00. (200 kVA / 25 kVA = 8. 1% x 8 = 8%. $250,000.00 x .08 = $20,000.00.)

5. Conversion from Single-Phase to Three-Phase Service

   Where it is necessary to convert all or any portion of an existing underground distribution system from single-phase to three-phase service to a Customer, the total cost of such conversion will be paid by the Customer.

6. Long Term Rental Mobile Home Park, Townhouses, Condominiums and Apartment Complexes

   Line extensions to long term rental mobile home parks, townhouses, condominiums and apartment complexes will be made by the Company under terms and conditions provided in Subsection 7.C.1. The Company will, when requested by the Customer, install, own and maintain internal distribution facilities and individual metering for said development in accordance with the provisions pertaining to duly recorded real estate subdivisions as stated in Subsection 7.C.2 hereof.

7. Special Conditions

   a. Contracts

      Each subdivider or other Applicant for service requesting an extension over the free distance, or in advance of applications for service to permanent Customers, or in advance of completion of required site improvements will (unless otherwise agreed to by the Company and the Applicant) be required to execute contracts covering the terms under which the Company will install lines at its own expense, or contracts covering line extensions for which advance deposits will (unless otherwise agreed to by the Company and the Applicant be made in accordance with the provisions of these Rules and Regulations or of the applicable rate schedules.

SECTION 7
LINE EXTENSIONS
(continued)

b. Primary Service and Metering

The Company will provide primary service to a point of delivery, such point of delivery to be determined by the Company. The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load. The system will be treated as primary service for the purposes of billing. The Company reserves the right to approve or require modification to the Customer's distribution system prior to installation, and the Company will determine the voltage available for primary service. Instrument transformers, metering riser poles and associated equipment to be installed and maintained by the Company may be at the Customer's expense.

c. Advances under Previous Rules and Contracts

Amounts advanced under the conditions established by a rule previously in effect will be refunded in accordance with the requirements of such contract under which the advance was made.

d. Extensions for Temporary Service

Extensions for temporary service or for operations of a speculative character or questionable permanency will not be made under this Section 7, but will be made in accordance with the provisions pertaining to temporary service.

e. Exceptional Cases

Where unusual terrain, location, soil conditions, or other unusual circumstances make the application of these line extension rules impractical or unjust to either party or in the case of extension of lines of other than standard distribution voltage, service under such circumstances will be negotiated under special agreements specifying terms and conditions covering such extensions.

f. Special or Excess Facilities

Under this rule, the Company will install only those facilities which it deems are necessary to render service in accordance with the rate schedules. Where the Customer requests facilities which are in addition to, or in substitution for, the standard facilities which the Company normally would install, the extra cost thereof will be paid by the Customer, unless otherwise agreed to by the Company and the Applicant.

g. Unusual Loads

Line extensions to unusually small loads not consisting of a residence or permanent building (e.g. individual lights, wells, signs, etc.) will not be granted the five hundred (500) foot free allowance but will instead be required to advance any costs of service in excess of their estimated two years annual revenue. Refunding will be according to Subsections 7.C.1.c.2) and 7.C.1.d.

SECTION 7
LINE EXTENSIONS
(continued)

D. Construction / Facilities Related Income Taxes

Any federal, state or local income taxes resulting from the receipt of a contribution or advance in aid of construction in compliance with this rule is the responsibility of the Company and will be recorded as a deferred tax asset and reflected in the Company's rate base for ratemaking purposes.

However, if the estimated cost of facilities for any service line or distribution main extension exceeds $500,000, the Company may require the Applicant to include in the contribution or advance an amount (the "gross up amount") equal to the estimated federal, state or local income tax liability of the Company resulting from the contribution or advance, computed as follows:

$$\text{Gross Up Amount} = \frac{\text{Estimated Construction Cost}}{(1 - \text{Combined Federal-State-Local Income Tax Rate})}$$

After the Company's tax returns are completed, and actual tax liability is known, to the extent that the computed gross up amount exceeds the actual tax liability resulting from the contribution or advance, the Company shall refund to the Applicant an amount equal to such excess. When a gross-up amount is to be obtained in connection with an extension agreement, the contract will state the tax rate used to compute the gross up amount, and will also disclose the gross-up amount separately from the estimated cost of facilities. In subsequent years, as tax depreciation deductions are taken by the Company on its tax returns for the constructed assets with tax bases that have been grossed-up, a refund will be made to the Applicant in an amount equal to the related tax benefit. Such refunds will be in addition to any required refunds of actual construction costs required by the extension agreement. In lieu of scheduling such refunds over the remaining tax life of the constructed assets, a reduced lump sum refund may be made at the time when actual construction costs are refunded in full. This lump sum payment shall reflect the net present value of remaining tax depreciation deductions discounted at the company's authorized rate of return.

SECTION 8
PROVISION OF SERVICE

A. Company Responsibility

1. The Company will be responsible for the safe transmission and distribution of electricity until it passes the point of delivery to the Customer.

2. The Company will be responsible for maintaining in safe operating condition all meters, equipment and fixtures installed on the Customer's premises by the Company for the purpose of delivering electric service to the Customer. The Company, however, will not be responsible for the condition of meters, equipment, and fixtures damaged or altered by the Customer.

3. The Company may, at its option, refuse service until the Customer has obtained all required permits and/or inspections indicating that the Customer's facilities comply with local construction and safety standards, including any applicable Company specifications.

B. Customer Responsibility

1. Each Customer will be responsible for maintaining in safe operating condition all Customer facilities on the Customer's side of the point of delivery.

2. Each Customer will be responsible for safeguarding all Company property installed in or on the Customer's premises for the purpose of supplying utility service to that Customer.

3. Each Customer will exercise all reasonable care to prevent loss or damage to Company property, excluding ordinary wear and tear. The Customer will be responsible for loss of, or damage to, Company property on the Customer's premises arising from neglect, carelessness, misuse, diversion or tampering and will reimburse the Company for the cost of necessary repairs or replacements.

4. Each Customer, regardless of who owns the meter, will be responsible for payment for any equipment damage and/or estimated unmetered usage and all reasonable costs of investigation resulting from unauthorized breaking of seals, interfering, tampering or bypassing the utility meter.

5. Each Customer will be responsible for notifying the Company of any equipment failure identified in the Company's equipment.

SECTION 8
PROVISION OF SERVICE
(continued)

6. Each Customer will be responsible for informing the Company of, and meeting the Company's requirements regarding, On-site Generation that the Customer or its agent intends to interconnect to the Company's transmission and distribution system.

7. The Customer, at his expense, may install, maintain and operate check-measuring equipment as desired and of a type approved by the Company, provided that such equipment will be installed so as not to interfere with operation of the Company's equipment, and provided that no electric energy will be re-metered or sub-metered for resale to another or to others, except where such re-metering will be done in accordance with the applicable orders of the Commission.

C. Continuity of Service

The Company will make reasonable efforts to supply a satisfactory and continuous level of service. However, the Company will not be responsible for any damage or claim of damage attributable to any interruption or discontinuation of service resulting from:

1. Any cause against which the Company could not have reasonably foreseen or made provision for (*i.e.*, force majeure);

2. Intentional service interruptions to make repairs or perform routine maintenance; or

3. Curtailment, including brownouts or blackouts.

D. Service Interruptions

1. The Company will make reasonable efforts to reestablish service within the shortest possible time when service interruptions occur.

2. When the Company plans to interrupt service for more than four (4) hours to perform necessary repairs or maintenance, the Company will attempt to inform affected Customers at least twenty-four (24) hours in advance of the scheduled date, and these repairs will be completed in the shortest possible time to minimize the inconvenience to the Customers of the Company.

3. In the event of a national emergency or local disaster resulting in disruption of normal service, the Company may, in the public interest, interrupt service to other Customers to provide necessary service to civil defense or other emergency service agencies on a temporary basis until normal service to these agencies can be restored.

SECTION 8
PROVISION OF SERVICE
(continued)

4. The Commission will be notified of interruption in service affecting the entire system or any major division thereof. The interruption of service and cause will be reported by telephone to the Commission within four (4) hours after the responsible representative of the Company becomes aware of said interruption. A written report to the Commission will follow.

E. Interruption of Service and Force Majeure

1. The Company will make reasonable provision to supply a satisfactory and continuous electric service, but does not guarantee a constant or uninterrupted supply of electricity. The Company will not be liable for any damage or claim of damage attributable to any temporary, partial or complete interruption or discontinuance of electric service attributable to a force majeure condition as set forth at Subsections 8.E.4. and 8.E.5. or to any other cause which the Company could not have reasonably foreseen and made provision against, or which, in the Company's judgment, is necessary to permit repairs or changes to be made in the Company's electric generating, transmission or distribution equipment or to eliminate the possibility of damage to the Company's property or to the person or property of others.

2. Whenever the Company deems that a condition exists to warrant interruption or limitation in the service being rendered, this interruption or limitation will not constitute a breach of contract and will not render the Company liable for damages suffered thereby or excuse the Customer from further fulfillment of the contract.

3. The use of electric energy upon the premises of the Customer is at the risk of the Customer. The Company's liability will cease at the point where its facilities are connected to the Customer's wiring.

4. Neither the Company nor the Customer will be liable to the other for any act, omission or circumstances (including, with respect to the Company, but not limited to, inability to provide service) occasioned by or in consequence of the following:

   a. flood, rain, wind, storm, lightning, earthquake, fire, landslide, washout or other acts of the elements;

   b. accident or explosion;

   c. war, rebellion, civil disturbance, mobs, riot, blockade or other act of the public enemy;

   d. acts of God;

   e. interference of civil and/or military authorities;

   f. strikes, lockouts or other labor difficulties;

   g. vandalism, sabotage or malicious mischief;

SECTION 8
PROVISION OF SERVICE
(continued)

h. usurpation of power, or the laws, rules, regulations or orders made or adopted by any regulatory or other governmental agency or body (federal, state or local) having jurisdiction of any of the business or affairs of the Company or the Customer, direct or indirect;

i. breakage or accidents to equipment or facilities;

j. lack, limitation or loss of electrical or fuel supply; or

k. or any other casualty or cause beyond the reasonable control of the Company or the Customer, whether or not specifically provided herein and without limitation to the types enumerated, and which by the exercise of due diligence such party is unable to prevent or overcome; provided, however, that nothing contained herein will excuse the Customer from the obligation of paying for electricity delivered or services rendered.

5. A failure to settle or prevent any strike or other controversy with employees or with anyone purporting or seeking to represent employees will not be considered to be a matter within the control of the Company.

6. Nothing contained in this Section will excuse the Customer from the obligation of paying for electricity delivered or services rendered.

F. General Liability

1. Company will not be responsible for any third-party claims against Company that arise from Customer's use of Company's electricity.

2. Customer will indemnify, defend and hold harmless the Company (including the costs of reasonable attorney's fees) against all claims (including, without limitation, claims for damages to any business or property, or injury to, or death of, any person) arising out of any act or omission of the Customer, or the Customer's agents, in connection with the Company's service or facilities.

3. The liability of the Company for damages of any nature arising from errors, mistakes, omissions, interruptions, or delays of the Company, its agents, servants, or employees, in the course of establishing, furnishing, rearranging, moving, terminating, or changing the service or facilities or equipment will not exceed an amount equal to the charges applicable under the Company's Pricing Plans (calculated on a proportionate basis where appropriate) to the period during which the error, mistake, omission, interruption or delay occurs.

4. In no event will the Company be liable for any incidental, indirect, special, or consequential damages (including lost revenue or profits) of any kind whatsoever regardless of the cause or foreseeability thereof.

5. The Company will not be responsible for any loss or damage occasion or caused by the negligence or wrongful act of the Customer or any of his agents, employees or licensees in installing, maintaining, using, operating or interfering with any electric facilities.

SECTION 8
PROVISION OF SERVICE
(continued)

G. Construction Standards and Safety

The Company will construct all facilities in accordance with the provision of the ANSI C2 Standards (National Electric Safety Code, 1997 edition, and other amended editions as are adopted by the Commission), the 1995 ANSI B.31.1 Standards, the ASME Boiler and Pressure Vessel Code, and other applicable American National Standards Institute Codes and Standards, except for such changes as may be made or permitted by the Commission from time to time. In the case of conflict between codes and standards, the more rigid code or standard will apply.

SECTION 9
CHARACTER OF SERVICE – VOLTAGE, FREQUENCY AND PHASE

A. Electric energy furnished under these Rules and Regulations will be alternating current, sixty (60) hertz single or three-phase, at the standard, nominal voltages specified by the Company. The following nominal voltages are available on the Company's system:

1. Residential Customers: 120/240 volts single-phase

2. General Service or Light and Power Customers:

   a. Single-Phase: 120/240 volts (all areas)

   b. Three-Phase:

      1) 120/240 volts 4 wire delta (from overhead system only)*

      2) 240/480 volts 4 wire delta (from overhead system only)*

      3) 120/208 volts 4 wire wye

      4) 277/480 volts 4 wire wye

   * This may be available in some existing underground areas.

B. The primary voltage supplied will depend on the Customer's load and the system voltage available at that location; it will be specified by the Company. Normally, this will be one of the following nominal distribution or sub-transmission voltages: 7970/13800 volts 4 wire wye, or 46,000 volts 3 wire delta. The actual standard nominal voltages available to a specific Customer will depend on location, load, and type of system in the area and will be specified by the Company.

C. A Customer must meet certain minimum load requirements in order to qualify for three-phase service under Section 7.

D. The Company does not guarantee the constancy of its voltage or frequency, nor does it guarantee against its loss of one or more phases in a three-phase service. The Company will not be responsible for any damage to the Customer's equipment caused by any or all of these occurrences brought about by circumstances beyond its control.

SECTION 9
CHARACTER OF SERVICE – VOLTAGE, FREQUENCY AND PHASE
(continued)

E. Motor Protection

The following protective apparatus, to be provided by the Customer, is required on all motor installations:

1. No Voltage Protection: Motors that cannot be safely subjected to full voltage at starting must be provided with a device to insure that upon failure of voltage, the motors will be disconnected from the line. Said device should be provided with a suitable time delay relay.

2. Overload Protection: All motors whose voltage does not exceed 750 volts are to be provided with approved fuses of proper rating. Where the voltage exceeds 750 volts, protective devices are to be provided. In these cases it will be found desirable to install standard switch equipment. The installation of overload relays and no-voltage releases is recommended on all motors, not only as additional protection, but as a means of reducing the cost of refusing.

3. Phase Reversal: Reverse phase relays and circuit breakers or equivalent devices are recommended on all polyphase installations to protect the installation in case of phase reversal or loss of one phase

F. Load Fluctuation and Balance

1. Interference with Service: The Company reserves the right to refuse to supply loads of a character that may seriously impair service to any other Customers. In the case of hoist or elevator motors, welding machines, furnaces and other installations of like character where the use of electricity is intermittent or subject to violent fluctuations, the Company may require the Customer to provide at the Customer's own expense suitable equipment to reasonably limit those fluctuations.

2. The Company has the right to discontinue electric service to any Customer who continues to use appliances or other devices, equipment and apparati detrimental to the service after the Company notifies the Customer of his or her detriment to the service.

3. Allowable Instantaneous Starting Current Values: The instantaneous starting current (determined by tests or based on limits guaranteed by manufacturers) drawn from the line by any motor must not exceed a value (as determined by the Company) that may be deemed detrimental to the normal operation of the system. If the starting current of the motor exceeds that value, a starter must be used or other means employed to limit the current to the value specified. A reduced voltage starter may be required for polyphase motors.

4. When three-phase service supplied under a power rate includes incidental lighting, the Customer will supply any necessary lighting transformers and arrange its lighting to give a substantially balanced three-phase load.

SECTION 9
CHARACTER OF SERVICE – VOLTAGE, FREQUENCY AND PHASE
(continued)

G. Customer Responsibility for Equipment Used in Receiving Electric Energy

No statement or requirement in these Rules and Regulations can be construed as the assumption of any liability by the Company for any wiring of electrical equipment or the operation of same, installed in, upon, or about the Customer's premises, nor will the Company be responsible for any loss or damage occasioned or caused by the negligence, want of proper care or wrongful act of the Customer, or any of the Customer's agents or employees or licenses on the part of the Customer in installing, maintaining, using, operating, or interfering with any such wiring, machinery or apparatus.

SECTION 10
METER READING

A. Company or Customer Meter Reading

1. The Company may, at its discretion, allow for Customer reading of meters.

2. It will be the responsibility of the Company to inform the Customer how to properly read his or her meter.

3. Where a Customer reads his or her own meter, the Company will read the Customer's meter at least once every six (6) months.

4. The Company will provide the Customer with postage-paid cards or other methods to report the monthly reading to the Company.

5. The Company will specify the timing requirements for the Customer to submit his or her monthly meter reading to conform with the Company's billing cycle.

6. In the event the Customer fails to submit the reading on time, the Company may issue the Customer an estimated bill.

7. Meters will be read monthly on as close to the same day as practical.

B. Measuring of Service

1. All energy sold to Customers and all energy consumed by the Company, except that sold according to fixed charge schedules, will be measured by commercially acceptable measuring devices owned and maintained by the Company. This Subsection will not apply where it is impractical to install meters, such as street lighting or security lighting, or where otherwise authorized by the Commission.

2. When there is more than one meter at a location, the metering equipment will be so tagged or plainly marked as to indicate the circuit metered or metering equipment in accordance with Subsection 3.C.8.

3. Meters which are not direct reading will have the multiplier plainly marked on the meter.

4. All charts taken from recording meters will be marked with the date of the record, the meter number, Customer, and chart multiplier.

5. Metering equipment will not be set "fast" or "slow" to compensate for supply transformer or line losses.

SECTION 10
METER READING
(continued)

C. Customer Requested Rereads

1. The Company will, at the request of a Customer, reread that Customer's meter within ten (10) business days after the request by the Customer.
2. Any reread may be charged to the Customer at a rate set forth in the Statement of Additional Charges, if the original reading was not in error.
3. When a reading is found to be in error, the Company will not charge the Customer for the reread.

D. Access to Customer Premises

At all times, the Company will have the right of safe ingress to and egress from the Customer's premises at all reasonable hours for any purpose reasonably connected with the Company's property used in furnishing service and the exercise of any and all rights secured to it by law or these rules.

E. Meter Testing and Maintenance Program

1. The Company will replace any meter found to be damaged or associated with an inquiry into its accuracy, whether initiated by the Customer or Company, and which has been in service for more than sixteen years. Replaced meters will be tested for accuracy and will be acceptable if found to have an error margin within plus or minus three percent (± 3%).
2. The Company will file an annual report with the Commission summarizing the results of the meter maintenance and testing program for that year. At a minimum, the report should include the following data:
   a. Total number of meters tested at Company initiative or upon Customer request.
   b. Number of meters tested which were outside the acceptable error allowance of ± 3%.

F. Customer Requested Meter Tests

The Company will test a meter upon Customer request and the Company will be authorized to charge the Customer for the meter test. The charge for the meter test is set forth in the Statement of Additional Charges. However, if the meter is found to be in error by more than three percent (3%), then no meter testing fee will be charged to the Customer.

SECTION 10
METER READING
(continued)

G. Demands

1. The Customer's demand may be measured by a demand meter, under all rate schedules involving billings based on demand, unless appropriate investigation or tests indicate that the Customer's demand will not be such as to require a demand meter for correct application of the rate schedule. In cases where billings under a rate schedule requiring determination of the Customer's demand must be made before a demand meter can be installed, such billings may be made on an estimated demand basis pending installation of the demand meter; provided, however, that billings made on the basis of estimated demands will be appropriately adjusted, if indicated to be greater or less than the actual demands recorded after the demand meter is installed.

2. Demand meters may be installed at any metering location if the nature of the Customer's equipment and operation is such as to indicate that a demand meter is required for correct application of the rate schedule.

3. All demands used for billing purposes will be recorded, or computed to the nearest whole kW.

SECTION 11
BILLING AND COLLECTION

A. Frequency and Estimated Bills

1. The Company will bill monthly for services rendered. Meter readings will be scheduled for periods of not less than twenty-five (25) days or more than thirty-five (35) days.

2. If the Company is unable to read the meter on the scheduled meter read date, the Company will estimate the consumption for the billing period giving consideration to the following factors where applicable:

   a. The Customer's usage during the same month of the previous year.

   b. The amount of usage during the preceding month.

3. After the second consecutive month of estimating the Customer's bill for reasons other than severe weather, the Company will attempt to secure an accurate reading of the meter.

4. Failure on the part of the Customer to comply with a reasonable request by the Company for access to its meter may lead to the discontinuance of service.

5. Estimated bills will be issued only under the following conditions:

   a. Failure of a Customer who read his own meter to deliver his meter reading card to the Company, in accordance with the requirements of the Company billing cycle.

   b. Severe weather conditions, emergencies or work stoppages that prevent the Company from reading the meter.

   c. Circumstances that make it dangerous or impossible to read the meter, including locked gates, blocked meters, vicious or dangerous animals, or any force majeure condition as listed in Subsections 8.E.4 and 8.E.5.

6. Each bill based on estimated usage will indicate that it is an estimated bill.

B. Combining Meters, Minimum Bill Information

1. Each meter at a Customer's premises will be considered separately for billing purposes, and the readings of two (2) or more meters will not be combined unless otherwise provided for in the Company's Pricing Plans.

SECTION 11
BILLING AND COLLECTION
(continued)

2. Each bill for residential service will contain the following minimum information:

   a. Date and meter reading at the start of billing period or number of days in the billing period;

   b. Date and meter reading at the end of the billing period;

   c. Billed usage and demand (if applicable);

   d. Rate schedule number;

   e. Company telephone number;

   f. Customer's name;

   g. Service account number;

   h. Amount due and due date;

   i. Past due amount;

   j. Adjustment clause costs, where applicable;

   k. All applicable taxes; and

   l. The address for the Arizona Corporation Commission.

C. Billing Terms

1. All bills for the Company's services are due and payable no later than ten (10) days from the date the bill is rendered. Any payment not received within this time frame will be considered past due.

2. For purposes of this rule, the date a bill is rendered may be evidenced by:

   a. The postmark date;

   b. The mailing date; or

   c. The billing date shown on the bill. However, the billing date will not differ from the postmark or mailing date by more than two (2) days.

SECTION 11
BILLING AND COLLECTION
(continued)

3. All past due bills for the Company's services are due and payable within fifteen (15) days. Any payment not received within this time frame will be considered delinquent and will incur a late payment finance charge.

4. All delinquent bills for which payment has not been received within five (5) days will be subject to the provisions of the Company's termination procedures.

5. All payments of current amounts may be made at or mailed to the office of the Company or to the Company's duly authorized representative.

D. Applicable Pricing Plans, Time-of-Use Meters, Prepayment, Failure to Receive, Commencement Date, Taxes

1. Each Customer will be billed under the applicable Pricing Plan indicated in the Customer's application for service.

2. For a Customer taking service under a TEP Time-of-Use ("TOU") rate schedule, TEP may charge a fee based on the incremental cost of a TOU meter versus a non-TOU meter.

3. Customers may pay for electrical service by making advance payments.

4. Failure to receive bills or notices which have been properly placed in the United States mail will not prevent those bills from becoming delinquent nor relieve the Customer of his obligations therein.

5. Charges for service commence when the service is installed and connection made, whether used or not.

E. Billing and Meter Error Corrections

1. If, after testing, any meter is found to be more than three percent (3%) in error, either fast or slow, proper correction between three percent (3%) and the amount of the error will be made to previous readings and adjusted bills will be rendered according to the following terms:

   a. For the period of three (3) months immediately preceding the removal of such meter from service for test or from the time the meter was in service since last tested, but not exceeding three (3) months since the meter will have been shown to be in error by such test.

   b. From the date the error occurred, if the date of the cause can be definitely fixed.

2. No adjustment will be made by the Company except to the Customer last served by the meter tested.

SECTION 11
BILLING AND COLLECTION
(continued)

F. Non-sufficient Funds ("NSF") Checks

1. The Company will be allowed to recover a fee, as set forth in the Statement of Additional Charges, for each instance where a Customer tenders payment for electric service with a non-sufficient funds check. This fee will also apply when an electronic funds transfer ("EFT") is denied for any reason, including for lack of sufficient funds.

2. When the Company is notified by the Customer's bank or other financial institution that there are non-sufficient funds to cover the check, EFT or other financial instrument for electric service has been denied for any reason, the Company may require the Customer to make payment in cash, by money order, certified check, or other means which guarantee the Customer's payment to the Company.

3. A Customer who tenders a non-sufficient funds check, or for whom an EFT or other financial instrument has been denied will not be relieved of the obligation to render payment to the Company under the original terms of the bill nor defer the Company's provision for termination of service for nonpayment of bills.

4. No checks will be accepted if two (2) NSF checks have been received by the Company within a twelve-month period in payment of any billing.

G. Levelized Billing Plan

1. The Company may, at its option, offer its Customers a levelized billing plan.

2. If the Company offers a levelized billing plan, the Company will then develop upon Customer request an estimate of the Customer's levelized billing for a twelve-month period based upon:

    a. Customer's actual consumption history, which may be adjusted for abnormal conditions such as weather variations.

    b. For new Customers, the Company will estimate consumption based on the Customer's anticipated load requirements.

    c. The Company's Pricing Plan approved by the Commission applicable to that Customer's class of service.

3. The Company will provide the Customer a concise explanation of how the levelized billing estimate was developed, the impact of levelized billing on a Customer's monthly electric bill, and the Company's right to adjust the Customer's billing for any variation between the Company's estimated billing and actual billing.

SECTION 11
BILLING AND COLLECTION
(continued)

4. For those Customers being billed under a levelized billing plan, the Company will show, at a minimum, the following information on the Customer's monthly bill:

   a. Actual consumption;

   b. Amount due for actual consumption;

   c. Levelized billing amount due; and

   d. Accumulated variation in actual versus levelized billing amount.

5. The Company may adjust the Customer's levelized billing in the event the Company's estimate of the Customer's usage and/or cost should vary significantly from the Customer's actual usage and/or cost. This review to adjust the amount of the levelized billing may be initiated by the Company or Customer.

H. Deferred Payment Plan

1. The Company may, prior to termination, offer to qualifying residential Customers a deferred payment plan for the Customer to retire unpaid bills for electric service.

2. Each deferred payment agreement entered into by the Company and the Customer, due to the Customer's inability to pay an outstanding bill in full, will provide that service will not be discontinued if:

   a. Customer agrees to pay a reasonable amount of the outstanding bill at the time the parties enter into the deferred payment agreement.

   b. Customer agrees to pay all future bills for electric service in accordance with the Company's Pricing Plans.

   c. Customer agrees to pay a reasonable portion of the remaining outstanding balance in installments over a period not to exceed six (6) months.

SECTION 11
BILLING AND COLLECTION
(continued)

3. For the purpose of determining a reasonable installment payment schedule under these rules, the Company and the Customer will give consideration to the following conditions:

   a. Size of the delinquent account;

   b. Customer's ability to pay;

   c. Customer's payment history;

   d. Length of time the debt has been outstanding;

   e. Circumstances which resulted in the debt being outstanding; and

   f. Any other relevant factors related to the circumstances of the Customer.

4. Any Customer who desires to enter into a deferred payment agreement must do so before the Company's scheduled termination date for nonpayment of bills. The Customer's failure to execute a deferred payment agreement prior to the scheduled service termination date will not prevent the Company from terminating service for nonpayment.

5. Deferred payment agreements may be in writing and may be signed by the Customer and an authorized Company representative.

6. A deferred payment agreement may include a finance charge in an amount equal to the Company's actual or average cost of providing such arrangements.

7. If a Customer has not fulfilled the terms of a deferred payment agreement, the Company has the right to disconnect service pursuant to the Company's Termination of Service Rules in Section 12 and, under these circumstances, it will not be required to offer subsequent negotiation of a deferred payment agreement prior to disconnection.

I. Change of Occupancy

1. The Customer must give the Company at least three (3) business days advance notice in writing or by telephone, to discontinue service or to change occupancy.

2. The outgoing Customer will be responsible for all electric services provided and/or consumed up to the scheduled turn-off date.

3. The outgoing Customer is responsible for providing access to the meter so that the Company may obtain a final meter reading.

SECTION 11
BILLING AND COLLECTION

(continued)

J. Electronic Billing

1. Electronic Billing is an optional billing service whereby Customers may elect to receive, view and pay their bills electronically. The Company may modify its Electronic Billing services from time to time. A Customer electing an electronic billing service may receive an electronic bill in lieu of a paper bill.

2. Customers electing an electronic billing service may be required to complete additional forms and agreements.

3. Electronic Billing may be discontinued at any time by Company or the Customer.

4. An Electronic Bill will be considered rendered at the time it is electronically sent to the Customer. Failure to receive bills or notices that have been properly sent by an Electronic Billing system does not prevent these bills from becoming delinquent and does not relieve the Customer of the Customer's obligations therein.

5. Any notices that the Company is required to send to the Customer who has elected an Electronic Billing service may be sent by electronic means at the option of the Company.

6. Except as otherwise provided in this subsection, all other provisions of the Company's Rules and Regulations and other applicable Pricing Plans are applicable to Electronic Billing.

7. The Customer must provide the Company with a current email address for electronic bill delivery. If the electronic bill is electronically sent to the Customer at the email address that the Customer provided to the Company, then the Electronic Bill will be considered properly sent. Further, the Customer will be responsible for updating the company with any changes to this email address. Failure to do so will not excuse the Customer from timely paying the Company for electric service.

SECTION 12
TERMINATION OF SERVICE

A. Non-permissible Reasons to Disconnect Service

1. The Company will not disconnect service for any of the reasons stated below:

   a. Delinquency in payment for services rendered to a prior Customer at the premises where service is being provided, except in the instance where the prior Customer continues to reside on the premises;

   b. Failure of the Customer to pay for services or equipment which are not regulated by the Commission;

   c. Nonpayment of a bill related to another class of service;

   d. Failure to pay for a bill to correct a previous underbilling due to an inaccurate meter or meter failure if the Customer agrees to pay over a reasonable period of time;

   e. Failure to pay the bill of another Customer as guarantor thereof; or

   f. Disputed bills where the Customer has complied with the ACC's rules on Customer bill disputes.

2. The Company will not terminate residential service for any of the reasons stated below:

   a. The Customer can establish through medical documentation that, in the opinion of a licensed medical physician, termination would be especially dangerous to the health of a Customer or permanent resident residing on the Customer's premises;

   b. Life supporting equipment used in the home that is dependent on electric service for operation of this equipment; or

   c. Where weather will be especially dangerous to health as defined herein or as determined by the Commission.

3. Residential service to ill, elderly, or handicapped persons who have an inability to pay will not be terminated until all of the following have been attempted:

   a. The Customer has been informed of the availability of funds from various government and social assistance agencies of which the Company is aware; and

   b. A third party previously designated by the Customer has been notified and has not made arrangements to pay the outstanding electric bill.

4. A Customer utilizing the provisions of Subsections 12.A.2. or 12.A.3. above may be required to enter into a deferred payment agreement with the Company within ten (10) days after the scheduled termination date.

SECTION 12
TERMINATION OF SERVICE
(continued)

B. Termination of Service Without Notice

1. Electric service may be disconnected without advance written notice under the following conditions:

    a. The existence of an obvious safety or health hazard to the consumer, the general population or the Company's personnel or facilities;

    b. The Company has evidence of meter tampering or fraud (e.g., NSF Checks, denied EFTs);or

    c. Failure of a Customer to comply with the curtailment procedures imposed by the Company during supply shortages.

2. The Company will not be required to restore service until the conditions that led to the termination have been corrected to the satisfaction of the Company.

3. The Company will maintain a record of all terminations of service without notice for a minimum of one (1) year and will be available for inspection by the Commission.

C. Termination of Service With Notice

1. The Company may disconnect service to any Customer for any reason stated below provided that the Company has met the notice requirements described in Subsection 12.E. below:

    a. Customer violation of any of the Company's Pricing Plans;

    b. Failure of the Customer to pay a delinquent bill for electric service;

    c. Failure of the Customer to meet agreed-upon deferred payment arrangements;

    d. Failure to meet or maintain the Company's deposit requirements;

    e. Failure of the Customer to provide the Company reasonable access to its equipment and property;

    f. Customer breach of a written contract for service between the Company and Customer;

    g. When necessary for the Company to comply with an order of any governmental agency having such jurisdiction;

SECTION 12
TERMINATION OF SERVICE
(continued)

h. When a hazard exists that is not imminent, but in the Company's opinion, may cause property damage; or

i. Customer facilities that do not comply with Company requirements or specifications.

2. The Company will maintain a record of all terminations of service with notice for one (1) year and be available for Commission inspection.

D. The Company will not be obligated to renotify the Customer of the termination of service, even if the Customer – after receiving the required termination of service notification – has made payment, yet the payment is returned within three (3) to five (5) business days of receipt for any reason. The original notification will apply.

E. Termination Notice Requirements

1. The Company will not terminate service to any of its Customers without providing advance written notice to the Customer of the Company's intent to disconnect service, except under those conditions specified in Subsection 12.B. where advance written notice is not required.

2. This advance written notice will contain, at a minimum, the following information:

a. The name of the person whose service is to be terminated and the address where service is being rendered.

b. The Company's Pricing Plan that was violated and explanation of the violation or the amount of the bill that the Customer has failed to pay in accordance with the payment policy of the Company, if applicable.

c. The date on or after which service may be terminated.

d. A statement advising the Customer to contact the Company at a specific address or phone number for information regarding any deferred payment or other procedures that the Company may offer or to work out some other mutually agreeable solution to avoid termination of the Customer's service.

e. A statement advising the Customer the Company's stated reason(s) for the termination of services may be disputed by contacting the Company at a specific address or phone number, advising the Company of the dispute and making arrangements to discuss the cause for termination with a responsible employee of the Company in advance of the scheduled date of termination. The responsible employee will be empowered to resolve the dispute and the Company will retain the option to terminate service after affording this opportunity for a meeting and concluding that the reasons for termination is just and advising the Customer of his right to file a complaint with the Commission.

3. Where applicable, a copy of the termination notice will be simultaneously forwarded to designated third parties.

SECTION 12
TERMINATION OF SERVICE
(continued)

F. Timing of Terminations With Notice

1. The Company will give at least a five (5) day advance written notice prior to the termination date.

2. This notice will be considered to be given to the Customer when a copy of the notice is left with the Customer or posted first class in the United States mail, addressed to the Customer's last known address.

3. If, after the period of time allowed by the notice has elapsed and the delinquent account has not been paid nor arrangements made with the Company for payment of the bill – or in the case of a violation of the Company's rules the Customer has not satisfied the Company that this violation has ceased – then the Company may terminate service on or after the day specified in the notice without giving further notice.

4. The Company will have the right (but not the obligation) to remove any or all of its property installed on the Customer's premises upon the termination of service. Upon the termination of service the Company may, without liability for injury or damage, dismantle and remove its line extension facilities within two (2) years after termination of service. The Company will give the Customer thirty (30) days written notice before removing its facilities should the Company decide to do so, or else waive any re-establishment charge within the next one (1) year for the same service to the same Customer at the same location.

G. Landlord/Tenant Rule

1. In situations where service is rendered at an address different from the mailing address of the bill or where the Company knows that a landlord/tenant relationship exists and the landlord is the Customer of the Company, and where the landlord as a Customer would otherwise be subject to disconnection of service, the Company may not disconnect service until the following actions have been taken:

   a. Where it is feasible to so provide service, the Company, after providing notice as required in these rules, will offer the occupant the opportunity to subscribe for service in his or her own name. If the occupant then declines to so subscribe, the Company may disconnect service pursuant to the rules.

   b. The Company will not attempt to recover from a tenant or condition service to a tenant, upon the prepayment of any outstanding bills or other charges due upon the outstanding account of the landlord.

SECTION 13
RECONNECTION OF SERVICE

When service has been discontinued for any of the reasons set forth in these Rules and Regulations, the Company will not be required to restore service until the following conditions have been met by the Customer:

A. Where service was discontinued without notice:

1. The hazardous condition must be removed and the installation will conform to accepted standards.

2. All bills for service and/or applicable investigative costs due the Company by reason of fraudulent or unauthorized use, diversion or tampering must be paid and a deposit to guarantee the payment of future bills may be required.

3. Required arrangements for service must be made.

B. Where service was discontinued with notice:

1. The Customer must make arrangements for the payment of all bills and these arrangements must be satisfactory to the Company.

2. The Customer must furnish a satisfactory guarantee to pay all future bills.

3. The Customer must correct any and all violations of these Rules and Regulations.

SECTION 14
ADMINISTRATIVE AND HEARING REQUIREMENTS

A. Customer Service Complaints

1. The Company will make a full and prompt investigation of all service complaints made by its Customers, either directly or through the Commission.

2. The Company will respond to the complainant and/or the Commission representative within five (5) business days as to the status of the Company's investigation.

3. The Company will notify the complainant and/or the Commission representative of the final disposition of each complaint. Upon request of the complainant or the Commission representative, the Company will report the findings of its investigation in writing.

4. The Company will inform the Customer of his right of appeal to the Commission.

5. The Company will keep a record of all written service complaints received that must contain, at a minimum, the following data:

   a. Name and address of complainant;

   b. Date and nature of the complaint;

   c. Disposition of the complaint; and

   d. A copy of any correspondence between the Company, the Customer, and/or the Commission.

6. This record will be maintained for a minimum period of one (1) year and will be available for inspection by the Commission

SECTION 14
ADMINISTRATIVE AND HEARING REQUIREMENTS
(continued)

B. Customer Bill Disputes

1. Any utility Customer who disputes a portion of a bill rendered for electric service must pay the undisputed portion of the bill and notify the Company's designated representative that any unpaid amount is in dispute prior to the delinquent date of the bill.

2. Upon receipt of the Customer notice of dispute, the Company will:

   a. Notify the Customer within five (5) business days of the receipt of a written dispute notice.

   b. Initiate a prompt investigation as to the source of the dispute.

   c. Withhold disconnection of service until the investigation is completed and the Customer is informed of the results.

   d. Upon request of the Customer, the Company will report the results of the investigation in writing.

   e. Inform the Customer of his right of appeal to the Commission.

3. Once the Customer has received the results of the Company's investigation, the Customer will submit payment within five (5) business days to the Company for any disputed amounts. Failure to make full payment may be grounds for termination of service.

4. The Company will inform the Customer of his right of appeal to the Commission.

C. Commission resolution of service and bill disputes.

1. In the event the Customer and the Company cannot resolve a service or bill dispute the customer must file a written statement of dissatisfaction with the Commission; by submitting this statement to the Commission, the Customer will be deemed to have a filed an informal complaint against the Company.

2. Within 30 days of the receipt of a written statement of customer dissatisfaction related to a service or bill dispute, a designated representative of the Commission will endeavor to resolve the dispute by correspondence or telephone with the Company and the Customer. If resolution of the dispute is not achieved within 20 days of the Commission representative's initial effort, the Commission will hold an informal meeting to arbitrate the resolution of the dispute. This informal meeting will be governed by the following rules:

   a. Each party may be represented by legal counsel, if desired.

   b. All informal meetings may be recorded or held in the presence of a stenographer.

SECTION 14
ADMINISTRATIVE AND HEARING REQUIREMENTS
(continued)

c. All parties will have the opportunity to present written or oral evidentiary material to support the positions of the individual parties.

d. All parties and the Commission's representative will be given the opportunity to cross-examine the various parties.

e. The Commission's representative will render a written decision to all parties within five business days after the date of the informal meeting. This written decision of the arbitrator is not binding on any of the parties and the parties may still make a formal complaint to the Commission.

3. The Company may implement its termination procedures if the Customer fails to pay all bills rendered during the resolution of the dispute by the Commission.

4. The Company will maintain a record of written statements of dissatisfaction and their resolution for a minimum of one (1) year and make these records available for Commission inspection.

SECTION 15
TEMPORARY SERVICE OR CYCLICAL USAGE

A. For electric service of a temporary nature [less than two (2) years], a service installation and removal charge will be made in addition to the regular charges for service which will be billed under the applicable rate schedule. Such installation and removal charge will be the estimated average cost of labor, transportation and material required for installing and removing the temporary service facilities, less the estimated average net salvage value of the material. Emergency, supplementary, breakdown or other standby service is not considered temporary and is subject to the provisions of Section 16. Permanent or semi-permanent businesses whose characteristics of operation result in infrequent cyclical usage of energy (e.g., asphalt batch plants, lettuce cooling plants) will require separate contracts with the Company to assure full recovery of the Company's annual ownership cost on the total facilities installed to provide service to the Applicant.

SECTION 16
STANDBY SERVICE

A. Emergency, breakdown, supplementary or other standby service will be supplied by the Company at its option only under special contracts specifying the rates, terms and conditions governing such service.

SECTION 17
POWER FACTOR

A. The Company may require the Customer by written notice to either maintain a specified minimum lagging power factor or the Company may after thirty (30) days install power factor corrective equipment and bill the Customer for the total costs of this equipment and installation.

B. In the case of apparatus and devices having low power factor, now in service, which may hereafter be replaced, and all similar equipment hereafter installed or replaced, served under general commercial schedules, the Company may require the Customer to provide, at the Customer's own expense, power factor corrective equipment to increase the power factor of any such devices to not less than ninety (90) percent.

C. If the Customer installs and owns the capacitors needed to supply his reactive power requirements, then the Customer must equip them with suitable disconnecting switches, so installed that the capacitors will be disconnected from the Company's lines whenever the Customer's load is disconnected from the Company's facilities.

D. Gaseous tube installations totaling more than one thousand (1,000) volt-amperes must be equipped with capacitors of sufficient rating to maintain a minimum of ninety percent (90%) lagging power factor.

E. Company installation and removal of metering equipment to measure power factor will be at the discretion of the Company.

SECTION 18
STATEMENT OF ADDITIONAL CHARGES

A.	Service Establishment and Reestablishment During Regular Business Hours - service reads only	$13.50
B.	Service Establishment and Reestablishment under usual operating procedures During Regular Business Hours – Single-Phase Service	$22.00
C.	Service Establishment and Reestablishment under usual operating procedures After Regular Business Hours (includes Saturday, Sundays and Holidays) – Single-Phase Service	$51.00
D.	Service Establishment and Reestablishment under usual operating procedures During Regular Business Hours – Three-Phase Service	$71.00
E.	Service Establishment and Reestablishment under usual operating procedures After Regular Business Hours (includes Saturdays, Sundays and Holidays) – Three-Phase Service	$198.00
F.	Meter Reread	$13.00
G.	Meter Field Test	$144.00
H.	NSF Check	$10.00
I.	Late Payment Finance Charge	1.5%
J.	Interest on Customer Deposits	One-Year Treasury constant maturities rate

EXHIBIT

MJD-3

DIRECT ACCESS SERVICE

TERMS AND CONDITIONS FOR DIRECT ACCESS SERVICE

The following terms and conditions apply to Tucson Electric Power Company ("TEP"), Electric Service Providers ("ESPs") and their agents that participate in Direct Access under the Arizona Corporation Commission's ("ACC") rules for retail electric competition (A.A.C. R14-2-1601, *et seq.*, referred to herein as the "Rules"). "Direct Access Customer" refers to any qualified TEP retail Customer electing to procure its electricity and any other ACC-authorized Competitive Services directly from ESPs as defined in the Rules. ESPs who serve Direct Access Customer accounts shall possess a Certificate of Convenience and Necessity, issued by the ACC pursuant to A.A.C. R14-2-1604; enter into an ESP Service Acquisition Agreement with TEP; and an agreement with a TEP-approved and/or Arizona Independent Scheduling Administrator Association ("AISA") approved Scheduling Coordinator; be registered to do business in the State of Arizona; and meet any other applicable certification requirements established by State law and by the appropriate regulatory agencies.

A. Definitions:

All definitions in TEP's Rules and Regulations apply to these Rules and Regulations for Direct Access Service. The following additional definitions apply to TEP's Rules and Regulations for Direct Access Service.

1. Electric Service Provider ("ESP"): A company supplying marketing or brokering at retail any competitive services, as defined in the Rules pursuant to a Certificate of Convenience and Necessity.

2. Electric Service Provider ("ESP") Service Acquisition Agreement: A contract between an ESP and TEP to deliver power to retail end users or between an ESP and a Scheduling Coordinator to schedule transmission service.

3. Interval Metering: The purchase, installation and maintenance of electricity metering equipment capable of measuring and recording minimum data requirements, including hourly interval data required for Direct Access settlement processes.

4. Meter-Reading Service Provider ("MRSP"): An entity providing all functions related to the collection and storage of consumption data, and that reads meters, performs validation, editing, and estimation on raw meter data to create bill-ready meter data; translates bill-ready data to an approved format; posts this data to a server for retrieval by billing agents; manages the server; exchanges data with market participants, and stores meter data for problem resolution.

5. Meter Service Provider ("MSP"): An entity providing all functions related to measuring electricity consumption.

6. Rules: Approved ACC Competition Rules.

7. Scheduling Coordinator ("SC"): An entity that provides schedules for power transactions over transmission or distribution systems to the party responsible for the operation and control of the transmission grid, such as a Control Area Operator, Arizona Independent Scheduling Administrator or Independent System Operator.

8. Standard Offer Service: Bundled service offered by TEP to all Customers in TEP's service territory at regulated rates, including metering, meter reading, billing and collection services, demand-side management services

including but not limited to time-of-use, and consumer information services. All components of Standard Offer Service shall be deemed noncompetitive as long as those components are provided in a bundled transaction pursuant to R14-2-1606(A) of the ACC-approved Competition Rules.

B. General Service Provisions

1. Regarding Service Establishments and Reestablishment Charges: TEP will waive service establishment and reestablishment charges for Customers switching from Direct Access to Standard Offer Service.

2. Regarding the Company providing written statements of actual consumption: The Company will charge a fee consistent with its ACC-approved Pricing Plans and/or these Rules and Regulations for providing consumption, interval or other data to the Customer or its agent, such as an ESP. All other provisions regarding written statements of actual consumption in TEP's Rules and Regulations still apply to Direct Access Service.

3. Where the Customer has opted for Direct Access service, the Customer's ESP or its agent shall be responsible for installing the meter.

4. Where the Customer has opted for Direct Access service, the Customer's ESP or its agent will be responsible for installing the meter.

5. The Company shall not be responsible for any damage or claim of damage attributable to any interruption or discontinuation of service resulting from Failure of equipment owned and/or installed by the ESP, its agent, or the Customer.

C. Customer Selections

All TEP retail electric Customers shall obtain electric generation and ACC authorized energy services under one of two options:

1. Standard Offer Service ("Bundled Service"): With this election, retail Customers will receive all services, including metering, meter reading, billing, collection and other consumer information services, on a bundled basis at regulated rates authorized by the ACC. Any Customer that has not chosen Direct Access, and who is eligible for Direct Access, shall remain on Standard Offer Service. Direct Access Customers may also choose to return to Standard Offer Service after having elected Direct Access.

2. Competitive Service ("Direct Access"): This service election allows Customers eligible for Direct Access to purchase electric generation and other Competitive Services. Direct Access Customers with single premise demands greater than 20 kW will be required to have in place Interval Metering, as defined below, at no expense to TEP. Pursuant to the Rules, and any restrictions herein, the ESP serving these Customers will have options available for choosing to offer Meter Services, Meter Reading Services and/ or Billing Services on their own behalf (or through a qualified third party) or to have TEP provide those services, as specified within. Meter service options are described in the Sections on Metering Services and Meter Service Options and Obligations in this Article. Billing options are described in the Sections on Billing Service Options and Obligations in this Article and the ESP Service Acquisition Agreement.

D. General Obligations of TEP

1. Non-Discrimination

   TEP shall discharge its responsibilities under the Rules in a non-discriminatory manner as to Customers and providers of all Competitive Services. Unless otherwise authorized by the ACC, the Federal Energy Regulatory Commission ("FERC") or applicable affiliate transactions rules, TEP shall not:

   a. Represent that its affiliates or Customers of its affiliates will receive any different treatment with regard to the provision of TEP services than other, non-affiliated service providers as a result of affiliation with TEP; or

   b. Provide its affiliates, or Customers of its affiliates, any preference based on the affiliation including but not limited to terms and conditions of service, information, pricing or timing over non-affiliated suppliers or their Customers in the provision of TEP services.

2. Transmission and Distribution Service

   a. Subject to State law and the terms of the ACC's Rules and Regulations, this Article, the ESP Service Acquisition Agreement, applicable Pricing Plans and applicable ACC and FERC rules, and provided the ESP and Customer likewise comply therewith, TEP will offer transmission and distribution services on a non-discriminatory basis under applicable Pricing Plans, schedules and contracts for delivery of electric generation to Direct Access Customers.

   b. TEP shall grant distribution line extension allowances of 500 feet.

3. Competition Transition Charge ("CTC")

   As a condition for receiving Direct Access Service, direct access Customers will be responsible to TEP for all CTC charges (or any other means of recovering stranded costs) as authorized by the Rules and as may be subsequently approved by the ACC.

4. System Benefits Charge ("SBC")

   a. System Benefits Charges are those charges approved by the Commission for recovery of low-income, demand-side management, environmental, renewable, and other approved costs from Customers that elect Direct Access Service.

   b. As a condition for receiving Direct Access Service, these Customers will be responsible to pay their portion of System Benefits Charges authorized by the Rules in A.A.C. R14-2-1608 and as may be subsequently approved by the ACC.

E. General Obligations of ESPs

1. Timeliness, Due Diligence and Security Requirements

   a. ESPs shall exercise due diligence in meeting their obligations and deadlines under the Rules to facilitate Customer choice. ESPs shall make all payments owed to TEP in a timely manner (pursuant to the ACC's requirements, the Rules, the ESP Service Acquisition Agreement the ESP enters into with TEP, and TEP's Pricing Plans and schedules) and subject to applicable payment dispute provisions described below.

b. TEP shall exercise due diligence in meeting its obligations and deadlines under the Rules to facilitate Customer choice. TEP shall make all payments owed to the ESP in a timely manner (pursuant to the ACC's requirements, Rules, the ESP Service Acquisition Agreement the ESP enters into with TEP, and TEP's Pricing Plans and schedules) and subject to applicable payment dispute provisions described below.

c. ESPs shall adhere to all credit, deposit and security requirements specified in the ESP Service Acquisition Agreement and TEP's Pricing Plans and schedules.

2. Arrangements with ESP Customers

ESPs shall be solely responsible for having appropriate contractual or other arrangements with their Customers necessary to implement Direct Access consistent with all applicable laws, ACC requirements, the Rules and this Article. TEP shall not be responsible for monitoring, reviewing or enforcing such contracts or arrangements.

3. Responsibility for Electric Purchases

ESPs will be responsible for the purchase of their Direct Access Customers' electric generation needs and the delivery of such purchases to designated receipt points as set forth on schedules given to the Scheduling Coordinators ("SCs").

4. TEP Not Liable for ESP Services

To the extent the Customer elects to take other services from an ESP, TEP has no obligation to the Customer with respect to the services provided by the ESP.

5. Load Aggregation for Procuring Electric Generation/Split Loads

a. ESPs may aggregate individually metered electric loads for procuring competitive electric generation only. Load aggregation shall not be used to compute TEP charges or for Pricing Plan applicability.

b. Customers requesting Direct Access Services may not partition the electric loads of a service point among electric service options or providers. The entire load of a service point must be provided by only one (1) ESP. This provision shall not restrict the use of separate parties for metering and billing services.

6. Interval Metering

a. Interval Metering is required for all Customers that elect Direct Access and have maximum single premise demands in excess of 20 kW or 100,000 kWh annually. Interval Metering is optional for those Customers with demands of 20 kW or 100,000 kWh annually or less.

b. For new Customers without prior demand data, TEP shall estimate the demand at the time the Customer establishes a distribution service account with TEP. TEP shall determine, based on its estimates of the

Customer's demand, whether the Customer meets the requirements for Interval Metering. With the Customer's written consent, TEP shall provide the Customer's ESP with the data upon which the demand estimate was made.

7. Metering Requirements

Minimum meter data requirements consist of data required to bill TEP distribution Pricing Plans, including 15-minute interval data required for billing demands. TEP shall have access to meter data necessary for regulatory or rate-setting purposes as specified in TEP's protocol regarding meter-data requirements.

8. Statistical Load Profiles

a. Pursuant to R14-2-1604 (B)(3), TEP will offer statistical load profiles in place of Interval Metering, for qualifying Customers, to estimate hourly consumption for settlement and scheduling purposes.

9. Pursuant to R14-2-1612(K)(6), TEP will offer statistical load profiles in place of Interval Metering for predictable loads, as defined by TEP's Pricing Plans for unmetered loads, to estimate hourly consumption for settlement and scheduling purposes.

9. Fees and Other Charges

a. Direct Access Customers shall pay all applicable fees, surcharges, impositions, assessments and taxes on the sale of energy or the provisions of other services as authorized by law, ACC rules, rulings or decisions.

b. The ESP and TEP will each be respectively responsible for paying such fees to the taxing or regulatory agency to the extent it is their obligation to do so.

c. Both the ESP and TEP will be responsible for providing the authorized billing agent the information necessary to bill these charges to the Customer.

10. Liability In Connection With ESP Services

a. In this section, "damages" shall include all losses, harm, costs and detriment, both direct, indirect and consequential, suffered by the Customer or third parties.

b. Except as otherwise required by law, TEP shall not be liable for any damages caused by TEP's conduct in compliance with, or as permitted by, TEP's Rules and Regulations, the ESP Service Acquisition Agreement, the Rules, and associated legal and regulatory requirements related to Direct Access service, or as otherwise set forth in TEP's Rules and Regulations.

c. TEP shall not be liable for any damages caused to the Customer by any ESP, including failure to comply with TEP's Rules and Regulations and Pricing Plans, the ESP Service Acquisition Agreement, the Rules and associated legal and regulatory requirements related to Direct Access service.

d. TEP shall not be liable for any damages caused by the ESP's failure to perform any commitment to the Customer.

e. An ESP is not a TEP agent for any purpose. TEP shall not be liable for any damages resulting from acts, omissions, or representations made by an ESP in connection with soliciting Customers for Direct Access or rendering Competitive Services.

f. Under no circumstances shall TEP be liable to the Customer, ESP (including any entity retained by it to provide competitive services to the Customer) or third parties for lost revenues or profits, indirect or consequential damages or punitive or exemplary damages in connection with Direct Access Services. Under no circumstances shall the ESP (including any entity retained by it to provide competitive services to the Customer) be liable to TEP for lost revenues or profits, indirect or consequential damages or punitive exemplary damages in connection with Direct Access Services. This provision shall not limit remedies otherwise available to Customers under TEP's Pricing Plans, Rules and Regulations.

F. Customer Inquiries and Data Accessibility

1. <u>Customer Inquiries</u>

For Customers requesting information on Direct Access, TEP shall make available the following information:

a. Notification and informational materials to consumers about competition and consumer choices.

b. A list of ESPs that have been issued a Certificate of Convenience and Necessity to offer Competitive Services within TEP's service territory. TEP will provide the list maintained by the ACC, but TEP is under no obligation to assure the accuracy of this list. Reference to any particular ESP or group of ESPs on the list shall not be considered an endorsement or other form of recommendation by TEP.

2. <u>Access to Customer Usage Data</u>

For TEP Customers on Standard Offer Service, TEP shall provide Customer specific usage data to ESPs that have an ESP Service Acquisition Agreement in place with TEP, or to the Customer, subject to the following provisions:

a. ESPs may request Customer usage data prior to submission of a Direct Access Service Request ("DASR") by obtaining and submitting to TEP the Customer's written authorization. TEP may charge fees for Customer usage data at rates approved by the ACC.

b. Upon receipt of a Request DASR, if TEP has been the most recent provider of energy for the Customer, TEP will provide the most recent twelve (12) months of Customer usage data or the amount of data available for that Customer if there is less than twelve (12) months of usage.

3. <u>Customer Inquiries Concerning Billing-Related Issues</u>

a. Customer inquiries concerning TEP charges or services shall be directed to TEP.

b. Customer inquiries concerning ESP charges or services shall be directed to the ESP.

4. <u>Customer Inquiries Related to Emergency Situations and Outages</u>

a. TEP shall be responsible for responding to all Standard Offer Service or, in the case of Direct Access Customers, distribution service emergency system conditions, outages and safety situation inquiries related to TEP's distribution system. Customers contacting an ESP with such inquiries are to be referred directly to TEP for resolution. ESPs performing consolidated billing must show TEP's telephone number on their bills for use in emergencies.

b. TEP may shed or curtail Customer load as provided by its ACC-approved Pricing Plans, Rules and Regulations.

G. ESP Service Establishment

An ESP providing competitive generation shall satisfy the following requirements before the ESP can offer Direct Access services in TEP's distribution service territory:

1. Obtain a Certificate of Convenience and Necessity from the ACC which authorizes the ESP to offer Competitive Services to Direct Access Customers within TEP's distribution service territory.

2. Enter into an ESP Service Acquisition Agreement with TEP.

3. Provide proof of a service agreement with a certified Scheduling Coordinator.

4. Register to do business in the State of Arizona and obtain all other licenses and registrations needed as a legal predicate to the ESP's ability to offer Competitive Services to Direct Access Customers in TEP's distribution service territory.

5. Satisfy TEP's creditworthiness requirements as specified in the ESP Service Acquisition Agreement, TEP Billing and Credit Protocol, and TEP's Rules and Regulations if the ESP will offer ESP Consolidated Billing.

6. Satisfy any applicable ACC electronic data exchange requirements including:

   a. The ESP and/or its designated agents must successfully complete all necessary electronic interfaces between the ESP and TEP to exchange DASRs and general communications.
   b. The ESP or its agent must successfully complete all electronic interfaces between the ESP and TEP to exchange meter reading and usage data. This will include communication to and from MRSP servers for sharing of meter reading and usage data.

   c. The ESP must have the capability to exchange data with TEP electronically. Alternative arrangements may be acceptable if mutual agreement is reached between TEP and the ESP.

   d. TEP will require the ESP and its agents to exchange data with TEP using Electronic Data Interchange ("EDI") formats as established by the ACC.

   e. For the TEP Consolidated Billing or ESP Consolidated Billing options, compliance testing for EDI transactions will be required. Both the ESP and its agent must demonstrate the ability to perform the EDI data exchange functions required by the ACC and the ESP Service Acquisition Agreement. Any change of the billing agent will require a revalidation of the applicable compliance testing. Provided the ESP is acting diligently and in good faith, its failure to complete such compliance testing shall not affect its ability to offer electric generation to Direct Access Customers. Dual TEP/ESP Billing will be performed until the compliance testing is completed.

7. Have its Meter Reading Service Providers ("MRSPs") satisfy compliance testing to ensure that billing can be completed successfully. Any change of the MRSP will require a revalidation of the applicable compliance testing, which means that, as long as TEP's records show that the MRSP has successfully completed compliance testing for all services they propose to provide to the ESP, TEP will approve the MRSP. TEP reserves the right to charge the ESP for obtaining or estimating reads at ACC-approved rates until such time as the MRSP has completed successful compliance testing as outlined in Section I.17.c of this Article.

H. Direct Access Service Request

1. A Direct Access Service Request ("DASR") is submitted pursuant to the terms and conditions of the ESP Service Acquisition Agreement and this section, and shall also be used to define the Competitive Services that the ESP will provide the Customer.

2. ESPs shall have a CC&N from the ACC; have entered into an ESP Service Acquisition Agreement with TEP, if required; established creditworthiness with TEP; and have successfully completed EDI compliance testing before submitting DASRs.

3. The Customer's authorized ESP must submit a completed DASR to TEP before the Customer can be switched from Standard Offer Service or Competitive Service provided by another ESP. The DASR process described herein shall be used for Customer Direct Access elections, updates, cancellations, Customer-initiated returns to TEP Standard Offer Service, or requests for physical disconnection of service and ESP or Customer-initiated termination of an ESP/Customer service agreement.

4. A separate DASR must be submitted for each service delivery point. Each of the five (5) DASR operation types [Request ("RQ"), Termination of Service Agreement ("TS"), Physical Disconnect ("PD"), Cancel ("CL") and Update/Change ("UC")] has specific field requirements that must be fully completed before the DASR is submitted to TEP. A DASR that does not contain the required field information or is otherwise incomplete may be rejected. In accordance with the provisions of the applicable Service Acquisition Agreement, TEP may deny the ESP or Customer request for service if the information provided in the DASR is false, incomplete, or inaccurate in any material respect. ESPs filing RQ DASRs are thereby representing that they have their Customer's written authorization for such transaction. ESPs filing all other DASRs are thereby representing that they have their Customer's authorization for such transaction.

5. TEP requires that DASRs be submitted electronically using Comma Separated Value ("CSV") form through the ExoTran™ product of Exolink Corporation.

6. DASRs will be handled on a first-come, first-served basis. Each request shall be time and date-stamped when received by TEP.

7. Once the DASR is submitted, TEP will provide an acknowledgment of its receipt to the ESP or Customer within the following timeframes:

   a. TEP will acknowledge receiving Request ("RQ"), Termination of Service Agreement ("TS"), Cancel ("CL") and Update/Change ("UC") DASRs within two (2) working days of the time and date stamp. TEP will exercise best efforts, within three (3) working days to provide the ESP with a DASR status notification informing them whether the DASR has been accepted, rejected or placed in a pending status awaiting further information. If accepted, the effective switch date determined in accordance with Sections G.8, G.9, and G.12 of this Article, will be confirmed in the response to the ESP and the former ESP, if applicable. If a DASR is rejected, TEP shall provide the reasons for the rejection. If a DASR is held pending further information, it shall be rejected if the DASR is not completed with the required information within thirty (30) working days, or by a mutually agreed upon date, following the status notification.

b. When a Customer requests its electric services to be disconnected, the ESP is responsible for submitting a Physical Disconnect ("PD") DASR to TEP, regardless of who controls the meter, on behalf of the Customer.

(1) When the control of the meter resides with TEP, TEP shall perform the physical disconnect of the service. The "PD" DASR must be received by TEP at least three (3) working days prior to the requested disconnect date. TEP will acknowledge the "PD" DASR within the two (2) working days of the time and date stamp.

(2) When the control of the meter resides with the ESP, the ESP is responsible for performing the physical disconnect. The ESP shall notify TEP by DASR of the date of the physical disconnect. Disconnect reads must be posted to the MRSP or ESP server within five (5) working days following the disconnection.

8. Pursuant to A.A.C. R14-2-203(D)(4), DASRs for Customers that do not require a meter change must be received by TEP at least fifteen (15) calendar days prior to the next scheduled meter read date. The actual meter read date will be the effective switch date. DASRs received less than fifteen (15) calendar days prior to the next scheduled meter read date will be scheduled for switch to Direct Access on the following month's read date.

9. Accepted DASRs that require a meter exchange will have an effective change date to Direct Access with the meter exchange date. Notification of meter install dates shall be coordinated between the ESPs, MSPs and TEP's Meter Services Department.

10. If more than one (1) RQ DASR is received for a service delivery point within a billing cycle, only the first valid DASR received shall be processed in that period. All subsequent DASRs shall be rejected.

11. Upon acceptance of an RQ DASR, a maximum of twelve (12) months of Customer usage data, or the available usage for that Customer switching from Standard Offer, shall be provided to the ESP. If there is an existing ESP currently serving that Customer, that ESP shall be responsible for submitting the Customer usage data to the new ESP. In both cases, the Customer usage data will be submitted to the appropriate ESP no later than five (5) working days before the scheduled switch date. ESPs filing DASRs will thereby be representing that they have written authorization from the Customer to receive the Customer usage information.

12. Customers returning to TEP Standard Offer Service shall follow the same process timing as is used to establish Direct Access Service.

13. ESPs requesting to return a Direct Access Customer to TEP Standard Offer shall submit a Termination of Service DASR and shall be responsible for the continued provision of the Customer's electric supply service, metering, and billing services until the effective change date.

14. Customers requesting to return to TEP Standard Offer Service must contact their ESP. The ESP shall be responsible for submitting the appropriate DASR on behalf of the Customer.

15. TEP may assess the direct access Customer a charge for processing DASRs at a fee approved by the ACC. All ACC-approved charges are payable to TEP within fifteen (15) business days after the invoice date. All charges received after this date may be assessed applicable late fees pursuant to Article 15.

16. A Customer moving to new premises may retain or start Direct Access immediately. The Customer must first contact TEP to establish a service account. The Customer will be provided the necessary information that will enable its ESP to submit a DASR. The same timing requirements apply as set forth in Section G.8 and G.9 of this Article. Customer eligibility requirements set forth in the ACC Rules will apply during the phase-in period.

17. Billing option and metering option changes are requested through a "UC" DASR and cannot be changed more than once per billing cycle.

18. TEP shall not hold the ESP responsible for any Customer unpaid billing charges prior to the Customer's switch to Direct Access. Unpaid billing charges shall not delay the processing of DASRs and shall remain the Customer's responsibility to pay TEP. TEP Article 16 applies in the event of Customer non-payment, which includes the possible disconnection of distribution services. TEP shall not accept any DASRs submitted for Customers who have been terminated for nonpayment and have not yet been reinstated. Disconnection by TEP of a delinquent Customer shall not make TEP liable to the ESP or third parties for the Customer's disconnection.

19. TEP will not offer a levelized billing plan to Direct Access Customers. Customers who have a levelized billing plan at the time of their switch to Direct Access will be removed from such plan, and must pay any accumulated charges in full. TEP will refund any accumulated credit to the Customer after generation of the final Standard Offer bill.

20. During the phase-in period (October 1, 1999 through December 31, 2000), residential Customers will be eligible for Direct Access on a first-come, first-served basis. The percentage of eligible residential Customers will begin to increment on January 1, 1999. TEP will accept DASRs for the appropriate accumulated percentage reached, as specified in the Rules, when the TEP service area is opened to competition. Each quarter shall be closed once TEP has accepted DASRs for the total number of Customers eligible in that quarter. TEP shall reject DASRs received over the allowable quarterly limit, and notify the ESP and the Customer of quarter of eligibility. ESPs are responsible for resubmitting these rejected DASRs in the appropriate quarter.

21. During the phase-in period (October 1, 1999 through December 31, 2000), ESPs are required to complete a Direct Access Load Aggregation Submittal form ("DALAS") for those Customers they choose to aggregate. DALAS forms will be accepted for Customers aggregated into a combined load of 1 MW or greater. The DALAS form shall be submitted to TEP, at which point TEP will review and approve the form, if it is complete and accurate in all material respects and satisfies the requirements for load aggregation. TEP will notify the ESP if the DALAS form is valid within three (3) working days. Upon approval by TEP, ESPs must submit the DASRs for the service delivery points indicated on the DALAS form within three (3) working days. DASRs received prior to DALAS form approval shall be rejected. The ESP may submit additional DASRs to add new service points to their aggregate load pool consistent with TEP's DASR protocol and these Rules and Regulations. DASRs received by TEP for loads up to 999 kW will be rejected if not participating in a TEP-approved load aggregation pool (i.e., complied with the DALAS process set forth in this Section).

22. During the phase-in period (October 1, 1999 through December 31, 2000), the number of commercial and industrial Customers eligible to participate in Direct Access will be based on the amount of megawatts available for competition under the Rules. Available MWs will be distributed on a first-come, first-served basis to eligible

commercial and industrial Customers. TEP will begin accepting DASRs for eligible Customers (Customers with a non-coincident demand of 1MW and greater and those approved through the DALAS process) on the effective date of this Article until such time that the available load is fulfilled. Eligibility for Direct Access service for commercial and industrial Customers during the phase-in period is both Customer- and site-specific. During the phase-in period only, TEP shall not accept DASRs that specify a Direct Access switch date of more than sixty (60) calendar days from the date the DASR is submitted to TEP.

I. Billing Service Options and Obligations

1. Billing Options

Subject to availability, and pursuant to the terms in the ESP Service Acquisition Agreement and TEP's Billing and Credit Protocol, this Article, and applicable Pricing Plans and the restrictions therein, ESPs may select among the following billing options:

a. TEP Consolidated Billing

b. ESP Consolidated Billing

c. Dual TEP/ESP Billing

2. TEP Consolidated Billing

a. The Customer's authorized ESP sends its bill-ready data to TEP, or TEP calculates ESP charges, and TEP sends a consolidated bill containing both TEP and ESP charges to the Customer.

b. TEP's Obligations

(1) If the ESP elects to send bill-ready data, TEP shall include ESP charges and send the bill either by mail or electronic means to the Customer. TEP is not responsible for computing or determining the accuracy of the ESP charges on the bill. TEP is not required to estimate ESP charges if the expected bill-ready data is not received, nor is TEP required to delay TEP billing. Billing rendered on behalf of the ESP by TEP shall comply with A.A.C. R14-2-1613.

(2) TEP may elect to calculate ESP charges. If TEP elects to do so, and if the ESP elects to have TEP calculate the ESP charges, TEP shall update the Customer's records to reflect ESP charges to the Customer based upon the pre-defined ESP Pricing Plan or charges agreed upon between the ESP and the Customer for the ESP's services. TEP will calculate both TEP and ESP charges, include all charges on the bill, and send the bill either by mail or electronic means to the Customer.

(3) TEP bills shall include a total of ESP charges and applicable taxes, assessments and fees billed, the ESP's telephone number, and the Customer's rate schedule number or service offer. Any billing-related details of ESP charges may be provided as specified in the applicable Pricing Plan approved by the ACC. These items shall be printed with the TEP bill or electronically transmitted to the Customer.

(4) TEP shall process Customer payments. The ESP shall receive payment for its charges as specified in this Article at Section H.7, Payment and Collection Terms.

c. ESP's Obligations

(1) Once a billing election is in place as specified in the ESP Service Acquisition Agreement, the ESP may offer TEP Consolidated Billing services to Direct Access Customers.

(2) The ESP shall submit the necessary billing information to facilitate billing services under this billing option by service point, according to TEP's meter reading schedule, and pursuant to the applicable Pricing Plan. Timing of billing submittals is provided for in Section H.2.d below.

d. Timing Requirements

(1) Bills under this option will be rendered once a month. Nothing contained in this Article shall limit TEP's ability to render bills more frequently consistent with TEP's existing practices. However, if TEP renders bills more frequently than once a month, ESP charges need only to be calculated based on monthly billing periods.

(2) Except as provided in Section H.2.d.1, TEP shall require that all ESP and TEP charges be based on the same billing period data.

(3) ESP charges for normal monthly Customer billing and any adjustments for prior months' metering or billing errors must be received by TEP in EDI "810" (bill-ready data) format no later than 3:00 p.m. on the last working day of TEP's bill processing window. If billing charges have not been received from the ESP by this date, the last day of the TEP bill-processing window, TEP will render the bill for TEP charges only, without ESP charges. The ESP must wait until the next billing cycle, unless there is a mutual agreement for TEP to send an interim bill. If TEP renders the bill for TEP charges only, TEP will include a note on the bill stating that ESP charges will be forthcoming. An interim bill issued pursuant to this Section may also include a message that TEP charges were previously billed.

(4) ESP charges for a Physical Disconnect Final Bill must be received by 3:00 p.m. on the fifth working day following the actual disconnect date. If final billing charges have not been received from the ESP by this date, TEP will render the Customer's final bill for TEP charges only, without the ESP's final charges. If TEP renders the bill for TEP charges only, TEP will include a note on the bill stating that ESP charges will be forthcoming. The ESP must then produce a separate final bill for their charges, unless otherwise agreed upon by TEP and the ESP.

3. <u>ESP Consolidated Billing</u>

a. TEP calculates and sends its bill-ready data to the ESP. The ESP in turn sends a consolidated bill to its Customer. The ESP shall be obligated to provide the Customer detailed TEP charges to the extent that the ESP receives such detail from TEP. The ESP is not responsible for the accuracy of TEP charges.

b. TEP's Obligations

(1) TEP shall calculate all TEP charges once per month and provide these to the ESP to be included on the ESP consolidated bill or as otherwise specified.

(2) TEP shall provide the ESP sufficient detail of TEP charges, including any adjustments for prior months' metering and billing error, by EDI 810 format. TEP charges that are not transmitted to the ESP by 3:00 p.m. on the last working day of TEP's bill processing window need not be included in the ESP's bill. If TEP's billing charges have not been received by such date, the ESP may render the bill without TEP charges unless there is a mutual agreement to have the ESP send an interim bill to the Customer including TEP charges. If the ESP does not include such late-received charges, the ESP shall bill the charges in the next available billing cycle after receipt of the billing data from TEP. The ESP will include a message on the bill stating that TEP charges are forthcoming.

(3) For a Physical Disconnect Final Bill, TEP will provide the ESP with TEP's final bill charges by 3:00 p.m. on the fifth working day following the actual disconnect date. If TEP's billing charges have not been received by such date, the ESP may render the bill without TEP charges. TEP will then render a separate bill for the UDC charges, unless a mutual agreement is made between TEP and the ESP to have a final bill produced and sent to the Customer for the TEP final charges. The ESP shall include a message on the bill stating that TEP charges are forthcoming.

(4) TEP charges shall be calculated based on existing TEP billing cycles regardless of which party provides the meter reading. TEP charges shall be conveyed to the ESP electronically or by other means acceptable to both the ESP and TEP.

c. ESP Obligations

(1) Once an ESP Service Acquisition Agreement is entered into, including an appropriate billing election, creditworthiness has been established, and all other applicable prerequisites are met, the ESP may offer consolidated billing services to Direct Access Customers they serve.

(2) The ESP bill shall include any billing-related details of TEP charges. The TEP charges may be printed with the ESP bill or electronically transmitted. Billing rendered on behalf of TEP by the ESP shall comply with A.A.C. R14-2-1612.

(3) Other than including the billing data provided by TEP on the Customer's bill, the ESP has no obligations regarding the accuracy of TEP charges calculated by TEP or for disputes related to these charges. Disputed charges shall be handled according to ACC procedures.

(4) The ESP shall process Customer payments and handle collection responsibilities. Under this billing option, the ESP must pay all TEP charges due to TEP and not disputed by the Customer pursuant to Section H.7.b.1 of this Article.

(5) Subject to the limitations of this Section and with the written consent of the Customer, the ESP may offer Customers customized billing cycles or payment plans which permit the Customer to pay the ESP for TEP charges in different amounts than TEP charges to the ESP for any given billing period. Such plans shall not, however, affect in any manner the obligation of the ESP to pay TEP charges as billed by TEP. Should the Customer select an optional payment plan, all TEP charges must be billed in accordance with A.A.C. R14-210(G).

d. Timing Requirements

ESPs may render bills more or less frequently than once a month. However, TEP shall continue to bill the ESP each billing cycle period for the amounts due by the Customer for that billing month.

4. Dual TEP/ESP Billing

   a. TEP and the ESP each separately bill the Customer directly for services provided by them. The billing method is the sole responsibility of TEP and ESP.

   b. TEP and the ESP shall process only the Customer payments relating to their respective charges.

5. Billing Information and Inserts

   a. All TEP Customers, including Direct Access Customers, shall receive mandated legal, safety and other notices equally in accordance with A.A.C. R14-2-204 (B). If the ESP is providing consolidated billing, TEP shall make available one (1) copy of these notices per Customer to the ESP for distribution to Customers or, at the ESP's request, in electronic format to the ESP for production and communication to electronically billed Customers. If TEP is providing consolidated billing services, TEP shall continue to mail these notices in the billing envelope and may use the billing envelope as it does in current practices for providing such information.

   b. Under TEP Consolidated Billing, ESP bill inserts may be included pursuant to the applicable TEP Pricing Plan.

6. Billing Adjustments for Meter and Billing Error

   a. Meter and Billing Error

      (1) The MSP or MRSP (including the ESP or TEP if providing such services), whichever discovers it first, shall resolve any meter errors and must notify the ESP and TEP, as applicable, so any billing adjustments can be made. Additionally, the MSP or MRSP, whichever discovers the error or errors first, must notify all other affected parties, including the appropriate Scheduling Coordinator.

      (2) A billing error is the incorrect billing of the Customer's electrical usage. If the MSP, MRSP, ESP or TEP becomes aware of a potential billing error, the party discovering the billing error shall contact the ESP and TEP, as applicable, to investigate the error. If it is determined that there is in fact a billing error, the ESP and TEP will make any necessary adjustments, and the ESP will notify all other affected parties in a timely manner.

      (3) TEP Consolidated Billing

         (a) TEP shall be responsible for notifying the Customer and adjusting the bill for TEP charges to the extent those charges were affected by the meter or billing error.

         (b) The ESP shall be responsible for any recalculation of the ESP charges if the ESP is providing bill-ready data. Following the receipt of the recalculated charges from the ESP, the charges or credits will be applied to the Customer's next normal monthly bill, unless there is mutual agreement to have TEP send an interim bill to the Customer including the ESP's charges.

(c) TEP shall be responsible for any recalculation related to the ESP charges if TEP is calculating the ESP charges.

(4) ESP Consolidated Billing

(a) The ESP shall be responsible for notifying the Customer and adjusting the bill for ESP charges to the extent those charges were affected by the meter or billing error. The Customer shall be solely responsible for obtaining refunds of ESP electric generation overcharges attributable to a fast meter from its current and prior ESPs, as appropriate.

(b) TEP shall transmit adjusted TEP charges and any refunds for overcharges to the ESP with the Customer's next normal monthly bill. The ESP shall apply the charges to the Customer's next normal monthly bill, unless there is a mutual agreement to have the ESP send an interim bill to the Customer including TEP's charges.

(5) Dual TEP/ESP Billing

TEP and ESP shall be separately responsible for notifying the Customer and adjusting its respective bill for their charges.

7. Payment and Collection Terms

a. TEP Consolidated Billing

(1) TEP shall remit payments to the ESP for the total ESP charges collected from the Customer within three (3) working days after the Customer's payment is received. TEP is not required to pay amounts owed to the ESP for ESP charges billed but not received by TEP.

(2) The Customer is obligated to pay TEP for all undisputed TEP and ESP charges consistent with existing Pricing Plans and other contractual arrangements for service between the ESP and the Customer.

(3) The ESP is responsible for all collections related to the ESP services on the Customer's bill, including, but not limited to, security deposits and late charges unless otherwise agreed upon in the customized billing service agreement between ESP and TEP.

b. ESP Consolidated Billing

(1) The ESP shall pay amounts owed to TEP for undisputed TEP charges whether or not the Customer has paid the ESP. Payment is due in full from the ESP within fifteen (15) business days after the date TEP's charges are rendered to the ESP. The ESP shall pay all undisputed TEP charges due TEP regardless of whether the Customer has paid the ESP. All charges received after fifteen (15) business days may be assessed applicable late fees pursuant to Article 15. If an ESP fails to pay these charges prior to the next billing cycle, TEP may revert the billing option for that ESP's Customers to Dual Billing pursuant to Section H.10.d. If an ESP is late in paying charges a deposit or additional deposit as provided for in Section H.11 of this Article may be required.

(2) TEP shall be responsible for any follow-up inquiries with the ESP if there is question concerning the payment amount.

(3) TEP has no payment obligations to the ESP for Customer payments under ESP Consolidated Billing services.

c. Dual TEP/ESP Billing

TEP and ESP are separately responsible for collection of Customer payment for their respective charges.

8. Late or Partial Payments and Unpaid Bills

a. TEP Consolidated Billing

(1) TEP shall not be responsible for ESP's Customer collections, collecting the unpaid balance of ESP charges from Customers, sending notices informing Customers of unpaid ESP balances, or taking any action to recover the unpaid amounts owed the ESP. The ESP shall assume any collection obligations and/or late charge assessments for late or unpaid balances related to ESP charges under this billing option.

(2) All Customer payments shall be applied first to unpaid balances identified as TEP charges until such balances are paid in full, then applied to ESP charges. A Customer may dispute charges as provided by A.A.C. R14-2-212 and this Article, but a Customer will not otherwise have the right to direct partial payments between TEP and the ESP.

(3) ACC rules shall apply to late or non-payment of all TEP Customer charges. Undisputed TEP delinquent balances owed on a Customer account shall be considered late and subject to TEP late payment procedures by TEP.

b. Dual TEP/ESP Billing

TEP and the ESP are responsible for collecting their respective unpaid balances, sending notices to Customers informing them of the unpaid balance, and taking appropriate actions to recover their respective unpaid balances. Customer disputes with ESP charges must be directed to the ESP and Customer disputes with TEP charges must be directed to TEP.

9. Service Disconnects and Reconnects

a. In accordance with ACC rules, TEP has the right to disconnect electric service to the Customer for a variety of reasons, including, but not limited to, the non-payment of TEP final bills or any past due charges by the Customer, or evidence of safety violations, energy theft, or fraud, by the Customer. TEP will perform the disconnect for non-payment regardless of the ESP. The following provides for service disconnects and reconnects.

(1) TEP shall notify the Customer and the Customer's ESP of TEP's intent to disconnect electric service for the non-payment of TEP charges prior to disconnecting electric service to the Customer. TEP shall further notify the ESP at the time the Customer has been disconnected. To the extent authorized by the

ACC, a service charge may be imposed on the Customer if a field call is performed to disconnect electric service.

(2) TEP shall reconnect electric service for an ACC-authorized service fee when the criteria for reconnection have been met to TEP's satisfaction. TEP shall notify the ESP of a Customer's reconnection.

(3) TEP shall not disconnect electric service to the Customer for the non-payment of ESP charges by the Customer. In the event of non-payment of ESP charges by the Customer, the ESP may submit a DASR requesting termination of the service agreement and request return to TEP Standard Offer Service. TEP will then advise the Customer that they will be placed on TEP Standard Offer Service unless a DASR is received from another ESP on their behalf.

10. Involuntary Service Changes

a. Service Changes

(1) A Customer may have its service of electricity, billing, or metering from an ESP changed to another provider, including TEP, involuntarily in the following circumstances:

(a) The ACC has decertified the ESP or the ESP otherwise receives an ACC order that prohibits the ESP from serving the Customer.

(b) The ESP, including its agents, has materially failed to meet its obligations under the terms of the ESP's ESP Service Acquisition Agreement with TEP (including applicable Pricing Plans and schedules) so as to constitute an Event of Default under the terms of the ESP Service Acquisition Agreement, and TEP exercises its contractual right to terminate the ESP Service Acquisition Agreement.

(c) The ESP has materially failed to meet its obligations under the terms of the ESP Service Acquisition Agreement (including applicable Pricing Plans and schedules) so as to constitute an Event of Default and TEP exercises a contractual right to change billing options.

(d) The ESP ceases to perform by failing to provide schedules through a Scheduling Coordinator wherever such schedules are required, or the ESP fails to have a Service Acquisition Agreement in place with a Scheduling Coordinator.

(e) The Customer fails to meet its Direct Access requirements and obligations under the ACC rules and TEP's Pricing Plans and schedules.

b. Change of Service Election in Exigent Circumstances

In the event TEP finds that an ESP or the Customer has materially failed to meet its obligations under this Article or the ESP Service Acquisition Agreement such that TEP elects to invoke its remedies under this Section H.10 (other than termination of ESP Consolidated Billing under Section H.10.a.1.c) and the failure constitutes an emergency (defined as posing a substantial threat to the reliability of the electric system or to public health and safety), or the failure relates to ESP's sale of unscheduled energy, TEP may initiate a change in the Customer's service election, or terminate an ESP's ability to offer certain services under Direct Access. In such case, TEP shall initiate the change or termination by preparing a DASR, but the change or termination may be made immediately notwithstanding the applicable DASR processing times set forth in this Article. TEP shall provide such notice and opportunity to cure the problem as is reasonable under the circumstances, if any is reasonable. Additionally, TEP shall notify the ACC of the circumstances that required the change or the termination and the resulting action taken by TEP. The ESP and/or Customer shall have the right to seek an order from the ACC restoring the Customer's service election and/or the ESP's ability to offer services. Unless expressly ordered by the ACC, the provisions of this section shall not disconnect electric service provided to the Customer other than as provided in Section G.7.b.2 of this Article.

c. Change in Service Election Absent Exigent Circumstances

(1) In the event TEP finds that an ESP has materially failed to meet its obligations under this Article or the ESP Service Acquisition Agreement such that TEP seeks to invoke its remedies under this Section H.10 (other than termination of ESP Consolidated Billing under Section H.10.a.1.c), and the failure does not constitute an emergency (as defined in Section 7.10.2.1) or involve an ESP's unauthorized energy use, TEP shall notify the ESP and the ACC of such finding in writing stating the following:

(a) The nature of the alleged failure;

(b) The actions necessary to cure the failure; and

(c) The name, address and telephone number of a contact person at TEP authorized to discuss resolution of the failure.

(2) The ESP shall have thirty (30) calendar days from receipt of such notice to cure the alleged failure or reach an agreement with TEP regarding the alleged failure. If the failure is not cured and no agreement is reached between TEP and the ESP following this thirty (30) day period, TEP may initiate the DASR process set forth in this Article to accomplish its remedy and shall notify the Customers of such remedy. Unless expressly ordered by the ACC, the provisions of this section shall not disconnect electric service provided to the Customer other than as provided in Section G.7.b.2 of this Article.

d. Termination of ESP Consolidated Billing

(1) ESP Consolidated Billing may be terminated under the circumstances set forth in this Section H.10.d. This Section H.10.d sets forth the notice and opportunity to cure provisions applicable to defaults that permit a remedy of terminating ESP Consolidated Billing under this Article (which is incorporated by reference in the ESP Service Acquisition Agreement)

(2) TEP may terminate ESP Consolidated Billing under the following circumstances:

(a) If TEP finds that the information provided by the ESP in the ESP Service Acquisition Agreement is materially false, incomplete or inaccurate; the ESP attempts to avoid payment of ACC-authorized TEP charges; or the ESP files for bankruptcy, fails to have an involuntary bankruptcy proceeding filed against the ESP dismissed within sixty (60) calendar days, admits insolvency, makes a general assignment for the benefit of creditors, is unable to pay its debts as they mature, or has a trustee or receiver appointed over all or a substantial portion of its assets, TEP shall notify affected

Customers that ESP Consolidated Billing services will be terminated, and TEP may switch affected Customers to Dual Billing as promptly as possible.

(b) If the ESP fails to pay TEP (or dispute payment pursuant to the procedures set forth in this Article) the full amount of all TEP charges and fees by the applicable due date, TEP shall notify the ESP of the past due amount within two (2) working days of the applicable past due date. If the ESP incurs late charges on more than three (3) occasions or fails to pay overdue amounts including late charges within five (5) working days of the receipt of notice by TEP, TEP may notify the ESP's Customers and the ESP that ESP Consolidated Billing services will be terminated, and that Customers shall be switched to Dual Billing.

(c) If the ESP fails to comply within thirty (30) calendar days of the receipt of notice from TEP of any additional credit, security or deposit requirements set forth in Sections F.6 and H.11 of this Article, TEP may notify the ESP that ESP Consolidated Billing services will be terminated, and that Customers shall be switched to Dual Billing.

(3) Upon termination of ESP Consolidated Billing pursuant to this Section H.10.d, TEP may deliver a separate bill for all TEP charges that were not previously billed by the ESP.

(4) TEP may reinstate the ESP's eligibility to engage in ESP Consolidated Billing upon a reasonable showing by the ESP that the problems causing the revocation of ESP Consolidated Billing have been cured, including payment of any late charges, reestablishing credit requirements in compliance with Sections F.6 and H.11, and payment to TEP of all costs associated with changing ESP Customers' billing elections to and from dual billing.

(5) In the event TEP terminates ESP Consolidated Billing, TEP will return any security posted by the ESP pursuant to the ESP Service Acquisition Agreement.

e. Upon termination of ESP Direct Access services pursuant to this Section H.10, the provision of the affected service(s) shall be assumed by another eligible ESP from which the Customer elects to obtain the affected service(s). Absent an election by the Customer, TEP shall provide such services, until such time that the Customer makes an election.

f. TEP shall not use involuntary service changes in an anticompetitive or discriminatory manner.

11. <u>ESP Security Deposits</u>

a. TEP may, at its discretion, require cash security deposits from any ESP that has on more than one occasion failed to timely pay TEP charges or ACC-approved Direct Access charges, such as DASR fees, meter or billing error or service fees, and other fees applicable to an ESP through this Article and TEP's other Pricing Plans and schedules.

b. The amount of the security deposit required shall not exceed two and one-half (2.5) times the estimated maximum monthly bill to the ESP for such charges, and a separate security deposit may be required for separate categories of ESP or Direct Access charges.

c. Security deposits required pursuant to this Section H.11 shall be in the form of a cash deposit or other acceptable means of security accruing interest as specified in TEP's Article 3. TEP shall issue the ESP a nonnegotiable receipt for the amount of the deposit.

d. TEP may refuse to accept DASRs from, or provide other TEP services to, an ESP that fails to comply with ten (10) business days to a demand that the ESP establish a security deposit pursuant to this Section H.11.

J. Meter Services

1. Under Direct Access, ESPs may offer certain metering services for Direct Access implementation, including meter ownership, (MSP) and (MRSP) services.

2. TEP has the right to offer the following meter services:

   a. Metering and Meter Reading for Residential Load-Profiled Customers.

   b. All competitive Metering or Meter Reading services as authorized pursuant to Rule R14-2-1615.

   c. Other services as authorized by the ACC.

3. TEP reserves the right to perform meter disconnects, regardless of meter ownership, in cases of non-payment for TEP charges.

4. An ESP may sub-contract Metering or Meter Reading Services to a qualified third party. If the ESP sub-contracts any of the components of these services to a third party, the ESP shall, for the purposes of this Article, remain responsible for the services.

5. ESPs providing Metering or Meter Reading Services to Direct Access Customers either on their own or through a third party assume full responsibility for meeting the applicable meter and communication standards, as well as assuming responsibility for the safe installation and operation of the meter and any personal injuries and damage caused to Customer or TEP property by the meter or its installation. This liability will lie with the ESP regardless of whether the ESP or its subcontractors perform the work.

6. <u>Meter Specifications</u>

   a. The Director of Utilities Division of the ACC has determined the following specifications and standards shall apply to competitive metering where applicable:

   b. Metering standards (American National Standards Institute):

ANSI C12.1	Code for Electricity Metering
ANSI C12.6	Marketing & Arrangement of Terminals for Phase Shifting Devices used in Metering
ANSI C12.7	Watt-hour Meter Socket

ANSI C12.10	Electromechanical Watt-hour Meters
ANSI C12.13	Electronic TOU Registers for Electricity Meters
ANSI C12.18	Type 2 Optical Port
ANSI C12.20	0.2% & 0.5% Accuracy Class Meters
ANSI C37.90	Surge Withstand Test
ANSI 57.13	Instrument Transformers (All CTs & PTs)
ANSI Z1.4	Sampling Procedures and Tables for Inspection
ANSI Z1.9	Sampling Procedures and Tables for Inspection

c. EEI Electricity Metering Handbook

d. Electric Utilities Service Equipment Requirements Committee ("EUSERC")

e. National Electric Code ("NEC") & Local Requirements

f. TEP Electric Service Requirements Handbook

g. National Electrical Safety Code

h. ESPs or their contractors providing competitive metering services shall also comply with such other specifications or standards determined to be applicable or appropriate by the ACC's Director of Utilities Division.

7. Meter Conformity

a. All Direct Access meters shall have a visual kWh display and must have a physical interface to enable on-site interrogation of all stored meter data. All meters installed must support the Customer's TEP Pricing Plan.

b. If TEP is providing MRSP functions for the ESP, meters must be compatible with TEP's meter reading system.

c. No meter or associated metering equipment shall be set or allowed to remain in service if it is determined that the meter or its associated equipment did not meet TEP's existing approved specifications, as set forth in TEP's Electric Service Requirements Manual in place at the time of installation.

8. Meter Testing

a. If a manufacturer's sealed meter has not previously been set and the meter was tested within the last twelve (12) months, the meter shall be deemed in compliance with ACC standards without additional testing.

b. Any meter removed from service shall receive a calibration test prior to reinstallation.

c. Records on calibration shall be maintained by the MSP and provided to the requesting parties within three (3) working days of such a request for such records. The latest calibration record shall be kept as long as the meter is in service.

9. Meter Test Requests

a. Pursuant to A.A.C. R14-209 (F), either party may request that the other party perform a meter test, in which instance the requesting party is entitled to witness the test if it so chooses.

b. The requesting party shall be notified of the test date and written test results from the testing party. If the meter is found to be within ACC-approved standards, the requesting party shall reimburse the other party for all costs incurred in the process of testing the meter (per ACC-approved Pricing Plans).

c. The MSP shall take reasonable measures to detect meter error. The MSP shall notify TEP as soon as it becomes aware of any meter that is not operating in compliance with ACC performance specifications. The MSP shall make any repairs or changes required to correct the error and notify TEP's Meter Services Department.

10. Meter Identification

a. The ESP or its agent shall install a Universal Meter Identifier ("UMI") as prescribed in the ACC Competition Rules. This UMI sticker must be readily visible from the front of the meter.

b. When an ESP installs either its own meter or a Customer owned meter, the ring or lock ring must be secured with an orange seal that is imprinted with the name of the load serving ESP's name or logo or their agent.

11. Installation of Metering Equipment

a. All metering equipment shall be installed according to all applicable ACC requirements and TEP's Electric Service Requirements Manual, Rules and Regulations.

b. An ESP or its agent must be authorized by TEP to remove a TEP-owned meter or PTs and CTs. Once authorized, when the ESP or its agent intends to remove a TEP meter with or without CTs and PTs and install a new meter with or without CTs and PTs in its place, the ESP or its agent must first notify TEP's Meter Services Department.

c. During the phase-in period (October 1, 1999 through December 31, 2000) the meter exchange must be completed within 60 days of the date that the RQ DSAR is submitted.

d. The ESP or its agent shall inform TEP's Meter Services Department of all meter activity, such as meter installations, exchanges, CT and PT exchanges within the time frames specified above. Additionally, the ESP must provide TEP with the most recent meter calibration test data. If final meter reads are not provided to TEP, are inaccurate, or otherwise result in TEP not being able to render accurate final bills to Customers pursuant to ACC Rules and Regulations, the ESP shall be responsible for any unbilled, disputed, or unrecoverable amounts and applicable late charges. If TEP is acting as the MRSP for an ESP, and final meter reads are not provided to the ESP, are inaccurate, or otherwise result in the ESP not being able to render accurate final bills to Customers pursuant to ACC Rules and Regulations, TEP shall be responsible for any unbilled, disputed, or unrecoverable amounts and applicable late charges.

e. The ESP or its agent shall return the existing meter with any removed PTs and CTs to TEP at one of TEP's designated locations throughout TEP's service territory within fifteen (15) working days after its removal, or be charged the cost of the meter and metering equipment and/or any other charges per the applicable ACC-approved Pricing Plan. The ESP or its agent shall be responsible for damage to the meter and/or metering equipment occurring during shipment. TEP shall return the existing ESP meter with any removed PTs and CTs owned by the ESP or its agent to the ESP at one of the ESP's designated locations throughout TEP's service territory within fifteen (15) working days after its removal, or be charged the cost of the meter and metering equipment and/or any other charges per the applicable ACC-approved Pricing Plan. TEP shall be responsible for damage to the meter and/or metering equipment occurring during shipment.

12. On-Site Inspections/Site Meets

a. TEP may perform on-site inspections of meter installations. The ESP shall be notified if the inspections uncover any material non-compliance by the MSP with the approved specifications and standards.

b. For new construction, TEP shall ensure that the owner/builder has met the construction standards outlined in the TEP Electric Service Requirements Manual, as well as local municipal agency requirements, and any updates, supplements, amendments and other changes that may be made to this manual and requirements. TEP shall perform a pre-installation inspection on all new construction. Local city/county clearances will also be required prior to energizing any new construction.

c. TEP may require a site meet to exchange or remove an IDR meter which requires an optical device to retrieve interval data; an existing totalized metering installation; a restricted access location for which TEP forbids key access; co-generation, bi-directional or detented metering; or on request of an ESP or MSP. The ESP and TEP's Meter Services Department shall coordinate the time of the site meet. If the ESP or MSP misses two (2) site meets, TEP may cancel the applicable DASR.

d. TEP may charge for a site meet requested by the ESP or MSP, or if the ESP or MSP fails to arrive within thirty (30) minutes of the appointment time, or if the ESP fails to cancel a site meet at least one (1) working day in advance of the appointment time. The ESP or MSP may charge for a site meet requested by TEP under the same conditions specified herein.

13. Meter Service Options and Obligations

a. Meter Ownership shall be limited to TEP, an ESP, or the Customer. The Customer must obtain the meter through TEP or an ESP. Although a Customer may own the electric meter, maintenance and servicing of the metering equipment shall be limited to TEP, the ESP, or the ESP's agent.

b. If the ESP or Customer owns the meter, the ESP may purchase the existing CTs and PTs and/or associated metering equipment from TEP. If the ESP chooses not to purchase the CTs and PTs and/or associated equipment, the ESP will still retain responsibility for maintaining and replacing CTs and PTs and/or associated equipment.

c. The following provisions apply to the ownership of CTs and PTs:

(1) For distribution voltages up to 25kv, the ESP or TEP shall own the CTs and PTs. For transmission primary voltages (over 25kv), the CTs and PTs shall be owned by TEP. ESP-owned CTs & PTs must meet TEP specifications. No CTs and PTs or associated metering equipment shall be set or allowed to remain in service if it is determined that the CTs and PTs or its associated equipment did not meet TEP's approved specifications, as set forth in TEP's Electric Service Requirements Manual, in place at the time of installation.

d. All CT-rated meter installations shall utilize safety test switches, and all self-contained commercial metering shall utilize safety-test blocks as provided in the TEP Electric Service Requirements Manual. During meter exchanges, the ESP or its agent's employees who are certified to perform the related MSP activities may install, replace or operate TEP test switches and operate TEP-sealed Customer-owned test blocks.

e. Direct Access premises with multiple service entrance sections will be considered separately for metering purposes. Existing totalizing installations will be discontinued upon a Customer's entrance into Direct Access.

14. Installation Options

a. The ESP may choose from the following list of options for meter installation:

(1) ESP owned/ESP installed metering

(2) ESP owned/TEP installed metering

(3) Customer owned/ESP installed metering

(4) Customer owned/TEP installed metering

(5) TEP owned/TEP installed metering

b. ESP or their agents must be certified by the ACC in order to offer MSP services. The policies and procedures described in this Section assume that the MSP service provider and his meter installers have ACC certification. ESPs may elect to offer metering services by:

(1) Becoming a certified Metering Service Provider.

(2) Subcontracting with a third party that is a certified MSP.

(3) Subcontracting with TEP under the circumstances described in Section I.2 of this Article.

15. ESP's Obligations When Providing Metering Services

a. If lock rings are used, they shall meet TEP requirements and protocols.

b. Provide information to TEP on the specifications and other specifics on meters not purchased from or installed by TEP.

c. For Customers transferring from Direct Access to Standard Offer service, the ESP shall either allow TEP to remove the Customer's meter, or schedule a joint meet to remove the meter. If the ESP allows TEP to remove meters, the ESP shall coordinate with TEP's Meter Services Department regarding the return of the ESP's meters, which shall be to a location within TEP's service territory. For Customers transferring from Standard Offer to Direct Access Service, TEP shall either allow the ESP to remove the Customer's meter, or schedule a joint meet to remove the meter. If TEP allows the ESP to remove meters, TEP shall coordinate with the ESP or its agent regarding the return of TEP's meters.

d. Be responsible for obtaining and providing reads from any meter that it installs from the time it is installed to the time it is removed or until meter reading responsibilities are assumed by another ESP or the Customer returns to Standard Offer service.

e. Ensure that ESP and MSP employees working in TEP territory follow ACC and other applicable safety standards.

f. In the event that unauthorized energy use is suspected and a safety hazard exists, notify TEP immediately, or within twenty-four (24) hours for non-safety issues, and cooperate with TEP in response thereto.

g. ESPs and their agents shall take no action to impede TEP's safe and unrestricted access to a Customer's service entrance.

h. Glass over any socket when a meter is removed and a new meter is not installed.

16. <u>ESP's Obligations When Providing MRSP Services</u>

a. MRSP functions shall be performed by certified MRSPs on the ESP's behalf in accordance with ACC regulations, and shall be the responsibility of the party specified in the DASR. MRSP obligations and responsibilities are as stated in the ACC's Rules and requirements and include:

(1) Meter data for Direct Access Customers shall be read, validated, edited, and transferred pursuant to ACC-approved standards.

(2) Both TEP and ESP shall have 24-hour/7 days per week access to the MRSP server.

(3) Meter read data including reads as well as the validated usage shall be posted to the MRSP server using EDI "867" format. Estimated reads, along with reasons for the estimate, shall be included with the reads on the MRSP server. The EDI format specification includes the estimated read reason codes to be used.

(4) The MRSP shall provide TEP with access to meter data at the MRSP server as required, to allow the proper performance of billing and settlement.

(5) MRSPs shall read the Customer's meter on the TEP read cycle. MRSP shall provide TEP with meter reading data in a manner that conforms to TEP's billing cycles in accordance with A.A.C. R14-2-209.

(6) The MRSP shall provide re-reads or read verifies within ten (10) working days of a request by TEP or the Customer. The requesting party may be charged per the applicable ACC-approved Pricing Plan if the original read was not in error.

17. Meter Reading Data Obligations

a. Accuracy for All Meters

(1) Meter clocks shall be maintained according to Arizona time within +/- three (3) minutes of the National Time Standard.

(2) Meter read date and time shall be accurate.

(3) All meter reading data shall be validated with the applicable ACC-approved requirements.

b. Timeliness for Validated Meter Reading Data

(1) Pursuant to guidelines established by the Utilities Division Director timeliness requirements for the delivery of data, one hundred percent (100%) of the validated meter reads shall be available by 3:00 p.m. local Arizona time on the third working day after the scheduled read date. If the meter reads are not posted or available or are posted clearly in error by 3:00 p.m. on the third working day after the scheduled read date, the read may be estimated or read by TEP and the ESP shall be charged an ACC-approved fee for this service. For newly installed IDR meters, IDR reads shall include the meter read, the interval data and enough information to calculate the read and total consumption to the exact cut-over date and time.

c. Proof of Operational Ability

(1) Prior to performing MRSP services in TEP's distribution service territory, or prior to making any significant change in MRSP service methodology, each MRSP will perform compliance testing to demonstrate its ability to read meters, validate data, edit data, estimate missing data and post validated data in TEP-compatible EDI format to the MRSP server. In addition, upon installation of the initial meter on Direct Access accounts in TEP's distribution service territory, each MRSP shall prove its ability to read its meters and post validated data in TEP-compatible EDI format to the MRSP server. If the MRSP is unsuccessful in its attempts to meet these requirements, all subsequent requests for meter exchanges will be postponed until the MRSP successfully demonstrates its operational ability.

d. Retention and Format for Meter Reading Data

(1) All meter reading data for a Customer shall remain posted on the MRSP server for five (5) working days and will be recoverable for at least three (3) years.

(2) Meter reading data posted to the MRSP server shall be stored in TEP-compatible EDI format.

18. TEP Performing MSP and MRSP Functions

a. If TEP is eligible to perform Direct Access-related MSP and MRSP functions as defined in Section I.2, the following restriction applies:

(1) During the phase-in period of October 1, 1999 to December 31, 2000 for load profiled Customers in which TEP is reading the meter, the validated meter read will be posted in EDI format no later than three (3) working days following the scheduled read date.

19. Non-Conforming Meters, Meter Errors and Meter Reading Errors

a. Whenever TEP, the ESP or its agents becomes aware of any non-conforming meters, erroneous meter services and/or meter reading services that impact billing, it shall promptly notify the other parties and the Customer in question. Bills found to be in error due to non-conforming meters or errors in meter services or meter reading services will be corrected by the appropriate parties.

b. In cases of meter failure or non-compliance, the ESP or its agents shall have five (5) working days to correct the non-compliance. If the non-compliance is not remedied within five (5) working days, the following actions may apply:

(1) A site meeting may be required when services are being performed. The non-compliant party will be charged an ACC-approved Pricing Plan for the meeting.

(2) TEP may repair the defect, and the other party shall be responsible for all related expenses.

(3) Upon a demonstrated pattern of non-compliance (with ACC requirements and this Article) and failure to correct the problem in a timely manner, TEP may give written notice to the non-compliant party and to the ACC. After five (5) working days, TEP may suspend processing DASRs from an ESP that uses an MSP or MRSP that is non-compliant until such non-compliance is corrected to TEP's satisfaction.

(4) A pattern of non-compliance by an ESP is defined by the following conditions:

(a) If more than one percent (1%) of the service points served by an ESP, or five (5) service points, whichever is greater, are found to be non-conforming and are not corrected during the first six (6) months of Direct Access participation by that ESP.

(b) More than one-half of one percent (0.5%), or three (3) service points, whichever is greater, are found to be non-conforming and are not corrected during any six (6) consecutive months thereafter.

c. TEP may refuse to enter into a new ESP Service Acquisition Agreement, or cancel an existing ESP Service Acquisition Agreement pursuant to Section H.10.a.1.b, with any ESP that has a demonstrated pattern of uncorrected non-compliance as established above. This provision shall not apply if the alleged demonstrated pattern of non-compliance or correction thereof is disputed and is pending before any agency or entity with jurisdiction to resolve the dispute.

Direct Testimony of David G. Hutchens

BEFORE THE ARIZONA CORPORATION COMMISSION

<u>**COMMISSIONERS**</u>
MIKE GLEASON - CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103.	DOCKET NO. E-01933A-05-0650
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-01933A-07-____

Direct Testimony of

David G. Hutchens

on Behalf of

Tucson Electric Power Company

July 2, 2007

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I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is David G. Hutchens. My business address is One South Church Avenue, Tucson, Arizona 85701.

Q. By whom are you employed and in what capacity?

A. I am employed by both Tucson Electric Power Company ("TEP" or the "Company") and UNS Gas, Inc. ("UNS Gas"). My position at TEP is Vice President, Wholesale Energy. I oversee the fuel and wholesale power procurement, trading, marketing and risk management functions for TEP and its affiliates, UNS Gas and UNS Electric, Inc ("UNS Electric"). Additionally, I have operational responsibility for UNS Gas as its Vice President of Operations.

Q. Please describe your education and experience.

A. I received a Bachelor of Science degree in Aerospace Engineering from the University of Arizona in 1988 and a Master of Business Administration degree from the University of Arizona's Eller Graduate School of Management in 1999.

I was commissioned into the United States Navy in 1988 and served as a Nuclear-Trained Submarine Line Officer until 1993. From 1993 to 1994, I worked as a Process Engineer for Alcatel Telecommunications Cable in Roanoke, Virginia. From 1994 to 1995, I worked as the Instrumentation and Control Team Leader for Magma Copper Company in San Manuel, Arizona.

I was hired by TEP in 1995 as an Analyst in Product Planning and Development. In 1996, I moved into TEP's Wholesale Marketing Department as an Energy Marketer/Trader. I was promoted to Supervisor of the area in 1999, Manager in 2001 and General Manager in 2003. I was promoted to my current position of Vice President of Wholesale Energy in 2007.

Q. What is the purpose of your Direct Testimony?

A. In my Direct Testimony, I discuss various pro forma fuel adjustments and their impact on test year fuel costs in the Cost-of-Service Methodology. These pro forma fuel adjustments are shown in Schedule C of this rate case filing. I also discuss the pro forma adjustment that replaces test year operations and maintenance expenses related to Springerville Unit 1 capacity and a pro forma adjustment for bringing the Luna Energy Facility into rate base. Additionally, I describe TEP's proposed Purchased Power and Fuel Adjustment Clause ("PPFAC") as it applies in the Cost-of-Service and Hybrid Methodologies. I also discuss TEP's Hybrid Methodology and the necessary adjustments under this Methodology. Finally, I explain how the rates for generation service would be determined under the Market Methodology.

Q. Please summarize your testimony.

A. In my testimony I will describe: (i) Pro Forma Fuel Adjustments in TEP's Cost-of-Service Methodology, (ii) fuel related regulatory assets in TEP's Cost-of-Service Methodology, (iii) TEP's proposed PPFAC, (iv) TEP's Hybrid Methodology and related adjustments, and (v) TEP's Market Methodology.

II. COST-OF-SERVICE METHODOLOGY AND PRO FORMA FUEL COST ADJUSTMENTS.

Q. Mr. Hutchens, please explain why the Company has made pro forma adjustments in the Cost-of-Service Methodology.

A. The Company has made pro forma adjustments in order to normalize the test year and remove the revenue and expense impact of certain wholesale transactions. We have also adjusted test year fuel and purchased power expenses for changes which are known and measurable. The results of these adjustments will provide a base cost of generation service to be used with the PPFAC discussed later in my testimony.

Q. How were the pro forma fuel cost adjustments determined?

A. TEP utilized the NewEnergy Associates' PROMOD IV production costing model to determine the variable pro forma fuel cost adjustments that result from changes in fuel consumption. The variable fuel cost adjustments are dependent on the amount of fuel actually consumed. Other fuel cost adjustments are independent of the amount of fuel consumed and can be calculated outside of PROMOD. These can be characterized as fixed fuel cost adjustments. Variable cost adjustments, on the other hand, cannot be calculated as accurately without using PROMOD. Because of the dynamic nature of PROMOD, a change in fuel price at one station may change the dispatch of the system and result in a different distribution of energy. For example, an increase in fuel price at one station could lead to a decrease in fuel costs for that station because the dispatch order may have changed. PROMOD captures these dispatch differences. PROMOD will take these price changes into account, as well as the redistribution of energy to the available generation sources, to minimize the total fuel and purchased power costs.

Q. Please provide an overview of the PROMOD model.

A. PROMOD is a computer model TEP uses to simulate production requirements, fuel usage, energy costs and related factors in system operations. PROMOD employs probabilistic algorithms when considering the impact of forced outage rates on fuel requirements and costs. Generating unit fuel costs, forced outage rates, maintenance schedules and fuel conversion efficiency data are modeled in the program. PROMOD then solves to economically dispatch generation – or alternatively make purchases – to meet all retail load and sales for resale (*i.e.,* wholesale sales). The total fuel cost that results from this system simulation is reported as the sum of each generating unit's fuel cost. Generation reports are provided monthly and are summarized on an annual basis.

Q. Briefly, please explain how the PROMOD model simulates the various pro forma adjustments.

A. The PROMOD model represents resources with probabilistic forced outages, scheduled maintenance, fuels, heat rates and purchases. Monthly load duration curves depict sales and demands. The model also computes the least cost related to each pro forma adjustment. If the adjustment increases load, the PROMOD model calculates the least cost of supplying that load. If the adjustment decreases load, the model determines the highest costs that can be avoided commensurate with the decreased load. By comparing fuel costs before and after making the pro forma adjustments, TEP can determine the impact on fuel costs.

Q. What was the first step in the fuel cost impact analysis?

A. The first step in the analysis was to benchmark the PROMOD model. A "benchmark" verifies the adequacy of a model. In this case, the purpose of the "benchmark" is to verify that PROMOD is capable of simulating the actual operation of TEP's generating resources during the test year ending December 31, 2006.

Q. Please provide evidence that the PROMOD model has been benchmarked in order to simulate the test-year ending December 31, 2006.

A. The PROMOD model has been run in an attempt to simulate the operation of the Company's energy sources during the test period. The PROMOD model's "benchmark" computer run shows energy sources of 13,078 gigawatt-hour ("GWh"). After adjusting for classification differences, as shown in Exhibit DGH-1, this compares closely to the energy shown for the test year inputs to TEP's Federal Energy Regulatory Commission ("FERC") Form No. 1. Additionally, as also shown in Exhibit DGH-1, the PROMOD model's benchmark computer run shows fuel costs of $248.5 million, which is within $600,000 of that derived from TEP's income statement inputs for the FERC Form No. 1 report.

A. <u>Variable Fuel Pro Forma Adjustments</u>.

Q. Please list the variable pro forma adjustments which affect fuel costs.

A. The variable pro forma adjustments which affect fuel costs are:

1. Customer Annualization;
2. Weather Normalization;
3. Short-term Sales Exclusion;
4. Unit Availability Normalization; and
5. Tri-State Purchases.

Q. Has the Company prepared an exhibit which shows the impacts for those adjustments?

A. Yes. Exhibit DGH-2 shows the net energy and fuel and purchased power cost impacts for each adjustment as well as the combination of all adjustments.

1. Customer Annualization adjustment.

Q. Please explain the Customer Annualization adjustment.

A. The Customer Annualization adjustment is performed to correct for known and measurable changes in the customer base during the test year. A detailed description of the Customer Annualization adjustment is included in TEP witness Mr. D. Bentley Erdwurm's Direct Testimony. This adjustment more closely reflects the conditions during the period in which rates will be in effect. Annual sales were adjusted to reflect the energy usage based upon the number of customers on TEP's system at the end of the test-year. The effect of the annualization is to increase or decrease the monthly number of customers in each rate class to match the end of the test year customer count. The adjusted customer counts are used to estimate the impact of changes in the customer base on kWh sales, revenues and fuel expense. The energy adjustment for Customer Annualization is an increase to the test year of 68.7 GWh. Exhibit DGH-2 shows TEP's Customer Annualization adjustment and associated fuel and purchased power costs during the test year.

2. Weather Normalization adjustment.

Q. Please explain the Weather Normalization adjustment.

A. The purpose of weather normalization is to adjust for the year-to-year impact of weather on kWh sales by rate class. A detailed description of the Weather Normalization adjustment is also included in Mr. Erdwurm's Direct Testimony. The Weather Adjustment normalizes sales during the test year to levels that would be expected based on average monthly weather conditions over the most recent 10-year period. In other words, normalizing for weather adjusts kWh sales by rate class so that the impacts of extreme weather are removed. This adjustment for the test year is necessary to prevent rates from being formulated based on abnormal weather conditions that may have occurred during that particular year, and may not be representative of the conditions typically encountered over a longer period of time. The difference between actual monthly kWh sales during the test year and normalized sales is used to calculate the effect of normal weather on kWh sales, revenues and fuel expense. This adjustment results in an increase of 58.4 GWh. Exhibit DGH-2 shows TEP's Weather Normalization adjustment and associated fuel and purchased power costs during the test year.

3. Short-term Sales Exclusion adjustment.

Q. Please explain the adjustment made for short-term sales for resale.

A. This pro forma adjustment is to eliminate the costs and revenues associated with all of TEP's short-term sales for resale. Short-term sales for resale are identified as sales that were generated from Company system resources other than long-term sales for resale (*e.g.*, multi-year sales to Salt River Project and the Navajo Tribal Utility Authority that will continue well beyond the test-year period) and are accounted for through TEP's jurisdictional allocation of costs between the Arizona Corporation Commission ("Commission") and FERC. The energy associated with this adjustment was 1,621 GWh. The fuel costs associated with these sales were determined by comparing a PROMOD model (absent the sales) to the benchmark case. Exhibit DGH-2 shows TEP's short-term sales for resale (and associated fuel costs) during the test period.

Q. Why is this adjustment being made?

A. Both the revenues and the costs associated with these sales are being removed to provide a more accurate base cost of generation for TEP's retail customers. As described more fully later in my testimony, the PPFAC includes a forecast of these revenues and expenses and then also provides a true-up for the actual revenues and expenses. Since these revenues and expenses are captured in the PPFAC, they need to be removed from the test year information.

Q. How were the short-term sales volumes determined?

A. The short-term sales are comprised of forward sales and 'system' real-time sales. Forward sales are transactions committed to in advance, prior to generating for the sale. These sales are typically negotiated one month to one year prior to delivery. Forward sales are entered into based on anticipated generation surplus and the forward market price index. Real-time sales are sales that are typically negotiated in the day-ahead and hourly markets. Real-time purchases are negotiated in a similar manner. To determine the system transactions (sales from generating resources and purchases for retail and firm load obligations), a netting process is used. Each individual hour of the test year is likely to have multiple sales and purchase transactions. A complete hourly data set of real-time sales is netted against an hourly real-time purchase data set. For each hour, if the sum of the sales is greater than the sum of the purchases the resultant energy and revenue is by default a 'system' delivery or system real-time sale. Conversely for each hour, when inbound energy and costs are greater than outbound energy and revenue, the net is determined to be a system real-time purchase. The energy that is netted out is determined to be the wholesale trading activity.

4. Unit Availability Normalization adjustment.

Q. Please explain the pro forma adjustment made to normalize TEP's generating unit availability.

A. During the test year period, the net capacity factor ("NCF") of TEP's coal fleet was higher than the NCF of the four-year sample period just prior to the test-year. As a result of lighter than normal planned maintenance, the actual test-year generation from coal resources was 10,962 GWh as compared to the four-year sample period where energy from coal-fired generation averaged 10,822 GWh. This pro forma adjustment normalizes the test year by removing approximately 139 GWh of coal generation to account for a more reasonable expectation of unit availability. Exhibit DGH-3 illustrates the NCF comparison between the test year and four-year sample period. This results in a decrease to coal generation fuel costs. But we see a net increase in total fuel costs due to the replacement of this energy with gas-fired generation and purchases. Exhibit DGH-2 demonstrates the fuel cost differential. The 139 GWh volume is not shown on DGH-2, because the system volume did not change, however, this is the quantity of energy served from other resources as a result of the capacity factor adjustment.

5. Tri-State Purchases adjustment.

Q. Explain the pro forma adjustment made to remove the power received from Tri-State Generation and Transmission Association ("Tri-State").

A. Springerville Generation Station Unit No. 3 ("SGS3") began commercial operation in late July of 2006. As a result, in 2006, TEP obtained 439 GWh of generation from Tri-State, the owner of SGS3. This power was removed from the test year due to the one-time, non-recurring nature of these purchases. As illustrated in Exhibit DGH-2, the exclusion of Tri-State power results in reduced replacement fuel and purchased power costs of $1.53 million. There is no volume associated with this adjustment, as the power was replaced with other resources.

Q. Please explain why this pro forma adjustment, which removes TEP's 5-year Tri-State purchase, is being made?

A. The Tri-State Power Purchase Agreement ("PPA") has a provision that gives Tri-State an option to call back energy and capacity from this PPA with a 90-day written notice. In April, 2007 Tri-State served notice of their option to recall 100% of the energy and capacity effective August 1, 2007 thereby terminating the PPA.

Q. Please discuss the combined results of the variable adjustments.

A. As shown in Exhibit DGH-2, individually, the Short-term Sales Exclusion and SGS3 Adjustment pro forma adjustments decrease fuel costs while the other adjustments increase fuel costs. The composite effect of all five variable pro forma fuel adjustments is to decrease fuel and purchased power costs by $39.8 million.

B. <u>Fixed Pro Forma Fuel Adjustments.</u>

Q. Please list the fixed pro forma adjustments which affect fuel costs.

A. The fixed pro forma adjustments which affect fuel costs are:

1. Sundt Unit No. 4 ("Sundt 4") Coal Costs
2. San Juan Coal Costs
3. Navajo Coal Costs
4. Wholesale Trading Activity

1. Sundt 4 Coal Cost adjustment.

Q. Please explain the Sundt 4 Coal Cost adjustment.

A. The last year of a three-year contract for both coal and transportation from the Twenty-Mile Mine to supply Sundt 4 was 2006. In December of 2006, TEP entered into a two year coal contract to supply Sundt 4 from the Colowyo Mine. Market conditions for coal had changed considerably in the intervening three years and the coal price is now higher than the test year. Exhibit DGH-4 illustrates the increase in fuel costs as a result of this adjustment.

Q. How is the adjustment calculated?

A. The delivered coal price for the new coal supply was compared to the delivered pricing for the coal contract in place during the test year. The adjustment is the difference in pricing between an equivalent amount of coal delivered in 2007 as was burned in the test year.

Q. The market price for the coal increased; did the transportation cost increase as well?

A. Yes. Although TEP shipped coal in the test year pursuant to a transportation contract with Union Pacific ("UP"), UP declined to negotiate a discounted rate for 2007 or beyond and instead quoted its common carrier rate. This rate is approximately twice what the rate had been during the test year.

2. San Juan Coal Cost adjustment.

Q. Please explain the final San Juan Coal Cost adjustment.

A. The cost of coal from the underground mine is forecasted to increase from the test year. The adjustment reflects this increase in costs.

Q. How was the amount of the adjustment calculated?

A. The actual costs of the coal in the test year on a per ton basis were compared to the miner's forecast of costs in 2007. The difference in these costs was multiplied by the number of tons burned in the test year.

Q. What are the factors driving these higher coal costs?

A. The increase in costs is largely due to the poor roof conditions encountered in the underground mine. The price for materials to support the roof, roof bolts, meshing, support structures are steel, and steel prices have increased. Because the mine is getting progressively deeper, more pressure is applied to the roof and more support is needed. Therefore, more materials are also needed to provide support. Other factors include changes in safety requirements enacted last year in response to underground mine tragedies, and two long-wall moves in one year.

3. Navajo Coal Cost adjustment.

Q. Please explain the final Navajo Coal Cost adjustment.

A. The cost of coal from the Kayenta mine is forecasted to increase from the test year. The adjustment reflects this increase in costs.

Q. **How was the amount of the adjustment calculated?**

A. The actual costs of the coal in the test year on a per ton basis were compared to the Operating Agent's (Salt River Project) forecast of costs in 2007. The difference in these costs was multiplied by the number of tons burned in the test year.

Q. What are the factors driving these higher coal costs?

A. The increase in costs is largely due to a provision in the coal sales contract, the Five Year Price Review. The Five Year Price Review allows for a review of the specific costs associated with several factors in order to determine if the Base Mine Price of coal accurately reflects the miner's expended costs. If the costs are higher than the factors currently in use, then the factors are increased to allow the miner to recover any costs not received in the next five year period (2007 – 2011). If the costs are lower than the factors currently in use, then the factors are decreased to allow the Navajo

Participants to recover any overpayment of costs in the next five year period (2007-2011). This adjustment will be retroactive to January 1, 2007.

Q. What are the factors that are adjusted every five years?

A. Labor, materials and supplies, administrative and general, and inflation/deflation are adjusted every five years.

4. Wholesale Trading Activity adjustment.

Q. Please explain the adjustment for Wholesale Trading Activity.

A. Wholesale sales from trading are those for which the Company does not use its system resources to produce power. Wholesale trading activity volumes, cost and revenues were isolated through a netting process in order to arrive at the remaining short-term sales that occurred from system resources (see 'Short-term Sales Exclusion adjustment for details on the wholesale trading activity derivation). This adjustment removes the revenue and purchased power expense associated with these transactions. In netting transactions, the quantities of energy bought and sold are the same so no energy adjustment is required. Exhibit DGH-5 provides additional detail on this adjustment.

C. Springerville Unit No. 1 and Luna Energy Facility Pro Forma Adjustments.

1. Springerville Unit No. 1.

Q. Please explain the Springerville Unit No. 1 adjustments.

A. Decision No. 56659 (October 24, 1989), required TEP to adjust the revenue requirement effect of Springerville Unit No. 1 to reflect a stated dollar per kilowatt-month fixed cost recovery rate that reflected the market cost of long-term capacity for ratemaking purposes. A rate of $15 per kW per month was established in that rate case based on the cost of long-term generation capacity reasonably available at that time. The Company has since used this approach in its subsequent rate cases before the Commission.

The adoption of a fixed cost recovery rate for Springerville Unit No. 1 requires pro forma adjustments to both rate base and operating expenses. Rate base is adjusted to remove leasehold improvements less accumulated depreciation, as explained in TEP witness Ms. Kissinger's Direct Testimony. This adjustment removes the net plant in service associated with Springerville Unit No. 1 as of the end of the test year (December 31, 2006). The removal of the related accumulated deferred income taxes ("ADIT") is implicit in the deferred tax rate base adjustment also addressed in Ms. Kissinger's Direct Testimony.

Concurrent with the removal of all Springerville Unit No. 1 plant costs is the removal of all non-fuel operating expenses and substitution with an annual allowance computed on the basis of the fixed-cost recovery rate. The companion adjustment is explained below.

Q. What is the Springerville Unit No. 1 Expense adjustment?

A. This adjustment removes from test-year operating expenses all non-fuel amounts relating to Springerville Unit No. 1, as explained in TEP witness Mr. Dallas J. Dukes' Direct Testimony, and replaces them with an annual allowance based on the rated capacity of the generating facility and a fixed-cost dollar per kW-month cost recovery rate that reflects the current cost of long-term coal plant capacity reasonably available in this area. The pro forma adjustment allocates the total fixed cost allowance to the various affected accounts in the same proportion as the amounts that were removed.

Q. How was the allowance amount used in the adjustment calculated?

A. The allowance was computed by multiplying the 380 megawatt rated capacity of Springerville Unit No. 1 by a $25.67 per kW monthly fixed cost factor, then multiplying by 12 months to determine the annualized amount.

Q. You earlier testified that a $15 per kW fixed rate was used in the previous TEP rate application approved in Decision No. 56659. Why is $25.67 per kW used in this filing?

A. I discussed earlier in my Direct Testimony that Decision No. 56659 was the genesis for using a fixed cost recovery rate for Springerville Unit No. 1 for ratemaking purposes. At the time, the generating facility was owned by another entity and TEP obtained power pursuant to a wholesale power supply agreement. While there was no finding of imprudence relating to the installed costs of Springerville Unit No. 1, the Commission disagreed with certain portions of the methodology used in establishing the price for power supplied under the power supply agreement and the amount of capacity for which the Company had contracted. In lieu of reflecting actual contract demand costs in revenue requirements, the Commission required TEP to substitute an annual allowance based on a fixed rate. In that case, the fixed rate was $15 per kW-hour per month. This rate reflected the market cost of long-term capacity supplies at that time.

There is no requirement in Decision No. 56659 mandating the continued use of a fixed cost recovery rate for Springerville Unit No. 1 in all future rate cases. Nor is there any indication that a $15 per kW per month rate should apply in all future periods. To the contrary, the record in that rate case indicates that an increase in the cost of long-term power capacity supplies over time could be expected.

If the use of a fixed cost recovery rate instead of actual Springerville Unit No. 1 costs for ratemaking purposes continues, it is appropriate to use a more current surrogate for the cost of available capacity. This is because most of the factors underlying Decision No. 56659 no longer exist. For instance, the entity that owned Springerville Unit No. 1 no longer exists. Also, the related power supply agreement no longer exists. Perhaps most importantly, the market for wholesale electric power and the industry structure has dramatically changed since the Commission issued that decision.

Therefore, the Company strikes a proper balance by continuing to use a fixed-cost recovery rate substitution methodology, but with a rate that more appropriately recognizes current realities in the wholesale market for long-term power capacity supplies.

Q. Did TEP use this same logic and update the Springerville Unit No. 1 recovery rate in the 2004 rate review?

A. Yes. TEP updated the $15 per kW per month rate based on existing coal capacity levels at the time of that filing.

Q Can TEP provide any updated estimates on the market value of coal capacity?

A. Yes. TEP performed several market-based analyses to assess the capacity value of Springerville Unit No. 1 using 2009 forecasted market conditions.

Q. How did TEP derive these market-based comparisons?

A. The annual capacity value was derived by taking the potential wholesale market revenues that Springerville Unit No. 1 would have received selling its output into the wholesale market and subtracting the variable production costs. This production cost margin was then divided by the Unit 1 capacity of 380 MW. The resulting capacity margin was then divided by 12 to derive the cost per kW-month.

Q. How did TEP derive its 2009 forward wholesale market price assumptions?

A. The 2009 market forecasts were based on third-party price curves for the Palo Verde on and off peak energy markets. The third-party data sources were Tullett-Liberty, ICF International and Wood Mackenzie. These market assumptions are shown in Exhibit DGH-6.

Q. Can you provide some background information on the Tullett-Liberty, ICF International ("ICF") and Wood-MacKenzie forecast services?

A. Tullett-Liberty is the leading provider of real-time price information for the wholesale inter-dealer brokered financial and commodity markets. TEP subscribes to Tullett-Liberty's Power West Market forecast service. This service provides a rolling four-year forecast (current year plus subsequent three years) for Palo Verde on and off-peak market prices.

ICF has over 25 years of experience in generation sector work, much of which has involved the provision of due diligence services. ICF is a leader in integrated market analysis and modeling, regulatory support and strategy in the areas of North American electric power, natural gas, and air emissions markets. ICF's wholesale power practice routinely provides financial models for asset valuation in support of due diligence assessments for development and acquisition.

Wood Mackenzie is a leading research and advisory firm providing detailed bottom-up analysis on all aspects of the North America gas and power markets. TEP subscribes to Wood-Mackenzie's North America Power and Gas Service. This service provides monthly price forecasts (current year plus the next 19 years) for power and gas for the California and Arizona markets.

Q. What were the results of the 2009 market-based coal capacity estimates?

A. The first estimate was based on a Tullett-Liberty price forecast which resulted in a market based capacity value of $31.82 per kW-month. The second estimate was based on a 2009 market forecast by ICF. This estimate resulted in a capacity value of $30.94

per kW-month. Lastly, a capacity value of $26.40 per kW-month was derived from a Wood-Mackenzie forecast. The average capacity value of these three market based comparisons for Springerville Unit No. 1 was $29.72 per kW-month. These estimates are summarized in Exhibit DGH-7 at page 1.

Q. Are there available market proxies for long-term power sale agreements supplied from other fossil fueled generators?

A. Yes. Many agreements with power generated from gas-fired units have been signed recently. However, capacity charges in such contracts are not valid for this adjustment because of the difference in construction costs between gas-fired combined-cycle generators and coal-fired generators. The construction cost for a 600 MW gas-fired generation is in the range of $600 to $800 per kW, while the estimated cost for Springerville Unit No. 3 (rated at 400 MW) is approximately $2,000 per kW. Since capacity payments are designed to provide an owner recovery of its investment in the generator, capacity payments related to coal fired generation are typically higher than capacity payments for gas fired generation. Although the capacity cost for coal-fired generation is higher than for gas-fired generation, the all-in cost of coal is less expensive. This is because the variable operations and maintenance costs (including fuel) are typically lower with coal-fired generators as compared to gas-fired generators. In the current wholesale power market, the variable component under a long-term gas-fired generator contract may be five cents per kWh or more, whereas, the energy charge in the Tri-State agreement is a fixed rate of 1.67 cents per kWh.

Q. Can TEP provide any long-term market evaluations for coal capacity value?

A. Yes. TEP requested that ICF complete a long-term valuation on TEP's generation assets. This valuation was based on discounted cash flows available to these assets under a merchant ownership scenario. The results of these valuations ranged from $1808 to $3607 per kW (in 2007 dollars). The results of this valuation are presented in Exhibit DGH-7 on page 2.

Q. Are there additional sources for market-based valuations on coal capacity?

A. Yes, TEP also has access to other market forecast experts such as Wood- Mackenzie and Global Energy Decisions. Based on recent reports compiled in the Spring 2007, both Wood- Mackenzie and Global Energy Decisions, estimate the value of pulverized coal generation assets located in the WECC region to range between $1824-$2139 per kW (in 2007 dollars). These estimates are summarized in Exhibit DGH-7 at pages 3-4.

Q. How do these market based valuations compare to the 2009 market based coal capacity estimates?

A. In comparison, these market based valuations are in the same range as the 2009 market based coal capacity estimates. Using assumptions shown in Exhibit DGH-7, page 5, the present value equivalent for a $2,150/kW coal plant would be approximately $25.84/kW-mo on a levelized cost basis.

Q. Do you have any knowledge of recent coal-fired purchased power contracts and their related capacity charges?

A. Yes. TEP entered into a five-year power purchase agreement with Tri-State that started September 1, 2006. The capacity payment TEP made under this agreement was $25.67

per kW-Month.

Q. How does the capacity charge for the Tri-State purchased power agreement compare to the other market capacity estimates?

A. As you can see from Exhibit DGH-7, it is lower than the other three forward market capacity estimates.

Q. How does the Tri-State purchased power agreement differ from these market-based estimates?

A. While the Tri-State purchased power agreement is consistent with the timeframe of the market-based estimates (*i.e.*, 2008 through 2011), it has a call feature whereby Tri-State can recall the contract capacity, or a portion thereof, with sufficient notification. This call feature reduces the value of the contract. Therefore, it should be expected to be discounted to the other capacity estimates.

Q. What is the basis for the $25.67 per kW month capacity cost in your pro forma adjustment?

A. The $25.67 per kW-month for Springerville Unit No. 1 is based the Tri-State purchased power agreement.

Q. Why was the Tri-State purchased power agreement amount chosen versus the higher market based estimates?

A. While it is a significant discount to the market based estimates and has characteristics which would be tend to discount it vis-à-vis power supply from Springerville Unit No. 1 as previously discussed, the Tri-State purchased power agreement is a known and measurable coal capacity value. The agreement also reflects capacity values for a timeframe relevant in this case, 2006-2011.

2. Luna Energy Facility.

Q. Please explain the Luna Energy Facility market based capacity adjustment?

A. TEP is adjusting the 2006 test year with a market based capacity charge for the Luna Energy Facility. This adjustment reflects the market value of the Luna Energy Facility capacity.

Similar to the Springerville Unit No. 1 adjustment, the adoption of a market based fixed cost recovery rate for the Luna Energy Facility requires pro forma adjustments to both utility plant in service and operating expenses. Utility plant in service is adjusted to remove all plant in service, accumulated depreciation and accumulated deferred income taxes related to the Luna Energy Facility. This adjustment removes the net plant in service associated with the Luna Energy Facility as of the end of the test year (December 31, 2006). The removal of the related accumulated deferred income taxes ("ADIT") is implicit in the deferred tax rate base adjustment addressed in Ms. Kissinger's Direct Testimony.

Concurrent with the removal of all Luna Energy Facility plant costs is the removal of all non-fuel operating expenses, as explained in Mr. Dukes' Direct Testimony, and substitution with an annual allowance computed on the basis of the fixed-cost recovery rate. The companion adjustment is explained below.

Q. What is the Luna Energy Facility capacity adjustment?

A. This adjustment removes from test-year operating expenses all non-fuel amounts relating to the Luna Energy Facility and replaces them with an annual allowance based on the rated capacity of the generating facility and a fixed-cost dollar per kW-month cost recovery rate that reflects the current cost of long-term natural gas combined cycle plant capacity reasonably available in this area.

Q. How would this market-based annual allowance be recovered?

A. The market-based annual allowance would be recovered through TEP's proposed PPFAC.

Q. Can TEP provide any long-term market evaluations for combined-cycle plants in the Southwest region?

A. Yes. As mentioned earlier in my testimony, ICF completed a long-term valuation on all of TEP's generation assets. The results of the long-term valuation for the Luna Energy were estimated at $626 per kW (in 2007 dollars). The results of this valuation are presented in Exhibit DGH-7 on page 6.

Q. Can TEP site additional sources for market based valuations on combined-cycle capacity ?

A. Yes, as mentioned earlier in my testimony, Wood-Mackenzie and Global Energy Decisions recently reported the estimated value of combined-cycle gas generation assets located in the WECC region to range between $714 to $755 per kW (in 2007 dollars). These estimates are summarized in Exhibit DGH-7 at pages 3, 4 and 6.

Q. How do these market based valuations compare to the market based combined-cycle capacity estimates?

A. In comparison, these market based valuations are in the same range as the current market based capacity estimates. Using assumptions shown in Exhibit DGH-7, page 7, the present value equivalent for a \$730/kW coal plant would be approximately \$10.66/kW-mo on a levelized cost basis.

Q. What is the capacity adjustment for the Luna Energy Facility?

A. The firm capacity estimate of \$7.00/kw-mo is based on the lowest cost bid received through a request for proposal ("RFP") solicitation conducted in 2006 for TEP and UNS Electric, Inc. This confidential offer was based a 15-year firm, day-ahead, unit contingent, tolling agreement. Under this type of agreement, TEP would make capacity payments for the right to pre-schedule the unit on a day-ahead basis. TEP would be responsible for natural gas transportation and supply arrangements. The seller would be responsible for the operations and maintenance of the facility.

Q. In terms of system dispatch, how would this type of agreement differ from that of the Luna Energy Facility?

A. The day-ahead, unit contingent, tolling agreement referenced above would require TEP to schedule the resource on a day-ahead basis. This pre-scheduling requirement would not give TEP the full system dispatch benefit associated with the dynamic dispatch of the Luna Energy Facility. Therefore, it should be expected that a purchase power agreement of this type should be discounted relative to the value of the Luna Energy Facility.

Q. What is the annual amount of the capacity adjustment shown for the Luna Energy Facility?

A. The annual adjustment is $15,960,000. The allowance was computed by multiplying the 190 megawatt rated capacity of Luna Energy Facility by a $7.00 per kW monthly fixed cost factor, then multiplying by 12 months to determine the annualized amount.

D. <u>Regulatory Asset Fuel Adjustments.</u>

Q. Is the Company proposing any other fuel adjustments in the Cost-of-Service Methodology?

A. Yes. The costs of two coal contract buy-outs totaling $26.6 million are being included as regulatory assets to be amortized and recovered through rates as described in Ms. Kissinger's Direct Testimony as part of the Implementation Costs Regulatory Asset ("ICRA") valued at about $47 million.

Q. What are the two coal contract buyouts?

A. They are (i) the Sundt Coal Contract Buyout, and (ii) the San Juan Stranded Cost Buyout, as described fully below.

1. Sundt Coal Contract Buyout Regulatory Asset.

Q. Please explain the adjustment for the Sundt Coal Contract Buyout.

A. In 2002, the Company and Pittsburg and Midway Coal Mining Company terminated the long term contract that had an expiration date of December 2015 for coal to the

Sundt Station. The Company paid a lump-sum of $11.25 million to buy out of the agreement.

Q. How was the buyout valued for inclusion in the regulatory asset?

A. The $11.25 million buyout fee was used. This amount is included in the ICRA and will be amortized over 4 years at an average amount of $2.8 million per year as set forth in Ms. Kissinger's Direct Testimony. This regulatory asset is amortized over 4 years and would thus be amortized at a rate of $2.8 million per year.

Q. Why should the customers be responsible for this payment?

A. The termination of that agreement results in avoiding approximately $3.5 million per year in take-or-pay payments for 15 years. In other words, by terminating the agreement, the Company saves customers $3.5 million per year for 15 years, or $52.5 million in exchange for the customers being responsible for only $11.25 million of cost at a rate of $2.8 million per year for four years. This is a total net savings for customers of about $41 million.

2. San Juan Stranded Cost Buy-Out Regulatory Asset.

Q. Please explain the San Juan Stranded Cost Buyout Regulatory Asset.

A. In 2000, the Company and Public Service Company of New Mexico ("PNM") negotiated a new Underground Coal Supply Agreement ("UGCSA") with San Juan Coal Company ("SJCC"). This Agreement replaced two existing surface mining operations with an underground mine as the source of coal for the San Juan Station. As part of the transaction, the utilities paid SJCC a lump-sum amount of approximately

$77.8 million to compensate for the value in stranded surface operation assets that were no longer needed for an underground operation. This payment was made in December, 2002.

Q. How was the amount of the regulatory asset derived?

A. The amount of the regulatory asset that was TEP's share of the buy-out was $15.4 million, reflecting TEP's 19.8% ownership in the San Juan Station.

Q. Is this regulatory asset treated the same as the Sundt Coal Contract Buyout for ratemaking purposes?

A. Yes. This regulatory asset is also amortized over 4 years as explained in Ms. Kissinger's Direct Testimony. This particular asset would thus be amortized at a rate of $3.85 million per year.

Q. Was the lump-sum the only option considered?

A. No. There were three options considered to compensate SJCC for the cost of surface assets. The first option was to continue to pay for the stranded assets as an on-going cost of coal, at an annual cost to TEP in excess of $4 million for 15 years. The second option was to pay SJCC an annuity separate and independent of the cost of coal at an annual cost to TEP in excess of $3 million for 15 years. The third, and lowest cost option, was to pay the lump-sum which results in an annual amortized cost of only $3.85 million for only four years.

Q. Why should the customers be responsible for this payment?

A. The net savings of replacing the two surface mining operations with one underground operation is expected to save TEP millions of dollars per year over the life of the contract. The surface mines had been getting progressively deeper and more expensive to mine and the trend of more expensive coal was to continue. This cost savings is reflected in test year fuel expense.

Q. If there is net savings, then why is there no corresponding decrease in the cost of fuel at San Juan reflecting these savings?

A. There is no corresponding decrease because the savings arise primarily by avoiding the expected higher future costs of operating the two surface mines. While there is no known and measurable decrease in year over year fuel costs at San Juan at this time, and although the coal cost is increasing from year to year, the costs of the surface mining option would have been significantly higher than the cost of the underground coal operation.

III. <u>PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE ("PPFAC")</u>.

Q. Is TEP proposing a forward-looking PPFAC in this case?

A. Yes.

Q. Why is TEP proposing the PPFAC in this case?

A. TEP does not currently use a purchased power and fuel adjustment clause. But given the recent volatility in fuel and purchase power costs, TEP should have an adjustor to timely recover costs for fuel and purchased power to serve its customers. TEP's proposed PPFAC is very similar to the forward-looking Power Supply Adjustor that

Staff proposed in the recent rate case involving Arizona Public Service Company ("APS") (Docket No. E-01345A-05-0816). To protect TEP from excessive energy cost volatility that can affect its financial integrity and to provide meaningful price signals to TEP's customers, TEP requests that its proposed PPFAC be adopted.

Q. Is TEP proposing the PPFAC in all three proposed methodologies?

A. No. TEP is proposing the PPFAC only in the Cost-of-Service and Hybrid Methodologies. There is no PPFAC in the Market Methodology.

Q. Is the proposed PPFAC the same in the Cost-of-Service and Hybrid Methodologies?

A. The PPFAC principles and mechanics are the same for both cases. However, there are some slight calculation differences in the Hybrid Methodology to remove the costs associated with the assets that are removed from rate base. This is discussed later in my testimony.

Q. Can you explain further why TEP believes it needs the PPFAC?

A. TEP relies on significant quantities of natural gas and purchased power to meet its retail load. Although TEP has served the majority of its load with company-owned generating resources, it relies on natural gas and purchased power to meet a growing percentage of its customer demand. This gas and power is purchased at market prices, so TEP should be allowed to recover these costs. The PPFAC is designed to recover or return the difference between the actual cost of natural gas and purchased power versus the cost of natural gas and purchased power established in base rates.

TEP is concerned about the volatile fuel and energy markets causing large deferrals of uncollected costs. Without an adjustor mechanism to timely address these costs in a way that sends accurate price signals to customers, the Company could incur substantial deferrals that could affect its ability to secure financing on favorable terms. It also could affect the Company's ability to secure natural gas and purchase power in the future on terms as favorable to the Company and its customers. In fact, the Company could face credit terms that could hurt its ability to secure reasonably priced fuel and purchase power in the future by requiring credit enhancements such as prepayment or letters of credit. This could lead to the inability to hedge future prices or enter into long term resource or contract commitments and being forced to rely heavily on the volatile short-term and spot markets.

TEP believes that its proposed PPFAC would avoid the need to request a large surcharge being passed through to customers. It would rather have a situation where adjustments to the fuel and purchased power costs are more immediate and moderate. Staff has demonstrated concern about the volatility of fuel and purchased power costs and how that might affect the financial integrity of Arizona Utilities and the impact to its customers in APS' current rate case. We further believe our proposal balances the respective interests of both the Company and its customers.

Q. Is TEP proposing a Base Cost of Fuel and Purchased Power?

A. Yes. We are proposing to set the Base Cost of Fuel and Purchased Power in the Cost-of-Service Methodology based on 2009 forecasted Base Cost of Fuel and Purchased Power.

Q. Are you proposing that the Base Cost of Fuel and Purchased Power be provided later in this case?

A. Yes. We are proposing updating the Base Cost of Fuel and Purchased Power based on projected 2009 fuel prices and conditions. This is because we understand that this rate filing will not be fully decided until sometime in 2008. It seems logical to set the Base Cost of Fuel and Purchased Power as close as possible to the date that TEP's rate filing will likely be approved as this will prevent having a separate PPFAC rate when rates initially go into effect. We are also therefore proposing that the initial PPFAC rate be set at zero in this case and the first new PPFAC rate be established for the 2010-2011 PPFAC year as described hereafter.

Q. What is your current estimate of the forecasted Base Cost of Fuel and Purchased Power for 2009?

A. Based on current forward market conditions for 2009, the Company estimates the 2009 Base Cost of Fuel and Purchased Power to be $0.033 cents per kWh (ACC Jurisdiction Adjusted) as detailed in DGH-8. As previously mentioned, this calculation will be updated during this rate proceeding such that we are using the most reasonably current information as possible.

Q. Is TEP also requesting that a PPFAC Rate for 2009 be established in this case?

A. No. As previously mentioned the PPFAC rate for 2009 will be set at zero if the Base Cost of Fuel and Purchased Power will be set using a 2009 forecast, supplanting the need for a PPFAC rate. TEP is proposing the mechanism for setting the PPFAC rate for 2010 and subsequent years.

Q. When will 2010 PPFAC rate go into effect?

A. We would propose having the 2010 PPFAC rate in effect April 1, 2010. The process of determining the PPFAC rate for each year is discussed later in my testimony.

Q. How would TEP propose to establish the PPFAC rate for 2010?

A. I will explain this in more detail later, but TEP would propose a filing by October 31, 2009 to establish the PPFAC rate for 2010. We would propose that Staff review our filing and prepare its initial report within 45 days. Finally, we would propose that Staff issue its final report approving and/or modifying the Company's proposal for the 2010 PPFAC rate by February 15, so that the 2010 PPFAC rate would be effective on April 1, 2010. That 2010 PPFAC Rate would be in effect until March 31, 2011. Then the 2011 PPFAC Rate would be effective starting April 1, 2011 through March 31, 2012. Essentially, we propose that each year's PPFAC rate would be effective from April 1 of that year until March 31 of the following year.

Q. Could you explain how the PPFAC is structured?

A. TEP proposes that there be two primary components to the PPFAC rate. For the 2010 PPFAC rate, these two components would be:

1. Forward Component: This component would be based on the forecasted fuel and purchase power costs for the following year. For example, forecasts for fuel and purchase power in 2010 would be used to establish the PPFAC

Forward Component for 2010. Forward prices would also be used to establish the PPFAC Forward Component annually.

2. True-Up Component: This component would compare actual fuel and purchase power costs with the amount TEP collected through base rates as well as the PPFAC rate for the prior year. If actual costs were above what was collected, the True-Up Component would be an additional amount to be collected from customers in the subsequent year. But should actual costs be below what was collected, the True-Up Component would reflect a credit towards the PPFAC rate for the following year. For instance, reconciling actual versus forecasted 2009 fuel and purchase power rates would be incorporated into the 2010 PPFAC rate via the True-Up Component.

Q. Do you have a simple hypothetical to demonstrate how the PPFAC would work?

A. Yes. Suppose the Base Cost of Fuel and Purchased Power is five cents per kWh, but actual fuel and energy costs were forecasted to be six cents per kWh for 2010. The PPFAC rate for 2010 was set at one cent per kWh. So, the total fuel and energy cost collected was six cents per kWh, but the actual total amount of fuel and energy costs for 2010 turned out to be only 5.5 cents per kWh. For 2011, the fuel and energy cost forecasts anticipate 6.5 cents per kWh cost. Under this hypothetical:

Base Fuel and Energy Cost:	5 cents per kWh.
2011 Forward Component:	1.5 cents per kWh[1]
2011 True-Up Component:	-0.5 cents per kWh[2]
2011 PPFAC Rate (Forward + True-up):	1 cent per kWh

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[1] 2011 Forecast of 6.5 cents less Base Cost of Fuel and Purchased Power of 5 cents.

[2] 2011 True-up is based on 2010 actual cost versus recovery. 2010 recovery was based on forecast of 6 cents but actual cost was only 5.5 cents. Therefore, True-up = Actual – Recovery = 5.5 – 6.0 = -0.5 cents.

2011 Fuel and Energy Cost Collected: 6 cents per kWh

The above example, while simplified to ignore year over year sales volume differences, gives an accurate portrayal of the actual interplay between the Forward and True-Up Components to establish the annual PPFAC rate.

Q. How do you propose to establish the Forward Component for the PPFAC?

A. Earlier in my testimony, I indicated that TEP proposes to file information and calculations for establishing the Forward Component for the 2010 PPFAC rate by October 31, 2009. TEP would file this information annually every October 31 to start the process for determining the following year's PPFAC rate.

Q. What information would TEP file to establish the Forward Component?

A. TEP would provide the most current forecasts, including any known and measurable changes expected to take place, for the following year. These fuel and energy price forecasts would be the basis for establishing the Forward Component for the PPFAC rate for the following year.

Q. Should the Forward Component be established so that TEP recovers 100 percent of anticipated fuel and energy costs within a 12-month period?

A. Yes. First, the costs are based on forecasts that accurately reflect what fuel and energy costs are anticipated to be. These are costs of providing electric service to customers the Company will actually incur the following year. A 12-month period ensures that the Company is timely compensated for costs it has incurred. Second, to the extent the actual fuel and energy costs are more or less than what was collected, the True-Up

Component I describe below will be a charge or credit against the PPFAC rate for the following year. Third, deferring recovery beyond 12 months complicates the PPFAC rate process. A 12-month recovery period avoids having multiple PPFAC rates imposed in one year, or having multiple years incorporated into one PPFAC rate.

Q. How do you propose to establish the True-Up Component for the PPFAC?

A. At the same time that TEP proposes its Forward Component (October 31 of each year), TEP also provides information and calculation of the True-Up Component. Then, by February 1 of the following year, TEP will provide updated information and calculations to supplement its True-Up Component. The purpose of this supplement is to replace estimated balances with actual balances for that year ending.

Q. Would the True-Up Component also be established to ensure 100 percent recovery or refund within 12 months?

A. Yes. For the same reasons the Forward Component should be designed to recover 100 percent of the fuel and purchase power costs (no more and no less); the True-Up Component for each PPFAC rate should be designed to recover or refund 100 percent of the over-recovery or under-recovery that exists from the prior year.

Q. Once TEP makes its PPFAC filing, how would you envision the procedure occurring to approve the new PPFAC rate for the following year?

A. We propose Staff having 45 days (*i.e.*, by December 15 of that year) to issue any initial comments regarding TEP's filing or recommending any adjustments to the Company's calculations. TEP would file updated information and calculations concerning the True-Up Component by February 1 of the following year. We further propose Staff having an additional two weeks (*i.e.,* until February 15) to file any additional comments or recommendations about the True-Up Component. This would allow ample time to implement the new PPFAC rate with or without modification before March 31 so that the new PPFAC rate would be in effect by April 1. We would further propose that PPFAC rate being in effect for the subsequent 12 months (from April 1 through March 31 the following year.) Exhibit DGH-9 outlines the timeline TEP proposes for implementing the PPFAC rate for each PPFAC Year (*i.e.,* from April 1 to the following March 31.)

We further propose that unless the Commission acts to suspend the PPFAC or takes some other action by March 31, the PPFAC rate – as proposed on October 31 and as modified on February 1 – will go into effect on April 1 (*i.e.,* the start of the PPFAC Year.)

Q. So, TEP proposes annual filings to change the PPFAC rate every twelve months?

A. Yes. We believe this will provide enough frequency to allow the Company to promptly recover fuel and energy costs from customers without burdening the Commission with multiple dockets in a 12-month period. Under normal circumstances, there would only be one proceeding every 12 months to adjust the PPFAC rate.

Q. Does the PPFAC allow TEP to address calamities such as a hurricane that radically alters fuel and purchase power prices?

A. If there was an extraordinary event that led to a drastic change in fuel and energy prices for the remaining months in the current PPFAC Year, then TEP would have the option to seek modification of the Forward Component. Staff approval would be required to do so and notice would be provided to the Commission. That modification would only last until March 31, when the new PPFAC rate would be approved.

Q. Would the modification to the Forward Component be reconciled the following year through the True-Up Component?

A. Yes. The True-Up Component would address the modified Forward Component.

Q. Does TEP envision applying for a modification to the Forward Component regularly?

A. No. TEP would only apply for this modification if there were circumstances that led to a drastic difference in fuel and purchased power costs being collected from what was the actual costs due to some calamity or extreme event. The best example would be the Hurricanes that hit the Gulf Coast in August and September of 2005 that caused substantial increases in fuel and purchased power costs in the latter third of 2005. In that case, the variance between what was collected through base rates and the existing PPFAC rate and the actual costs incurred becomes so significant as to warrant a further adjustment to the current PPFAC rate, whether that be positive or negative. But the effect of the modified Forward Component would be to smooth out the PPFAC rate somewhat by ensuring that the True-Up Component does not result in a larger increase than necessary.

Q. Does the Company believe that there should be any caps or restrictions in the size or magnitude of the PPFAC rate?

A. No. The Company does not believe that any limits or caps should be put in place. We believe that the Commission will have ample control of the PPFAC through the proposals described above. Setting artificial restrictions in this proceeding hampers the goal of ensuring timely recovery for the Company, and may have a negative impact on the Company's ability to secure financing on attractive terms and conditions, as well as its overall creditworthiness. If costs are prudent and reasonable, TEP should receive prompt recovery of those costs.

Q. Is TEP proposing to recover broker's fees through the base cost of fuel and purchase power and the PPFAC?

A. Yes. These fees are an inevitable and necessary part of procuring fuel and purchase power. These costs are reasonable for TEP to incur in order to continue to be a reliable electric service provider. They must be incurred whenever securing future fuel and energy to provide to customers. Consequently, they should be recovered.

Q. Is the Company proposing a sharing mechanism as part of the PPFAC?

A. No. TEP has ample incentive to procure reliable sources of fuel and energy at reasonable prices, to hedge an appropriate amount of fuel and purchased power to provide stability in price, and to seek to procure a stable, reliable, and affordable supply of fuel and purchase power. The Company does not receive any return for these costs, and does not have anything to gain by not seeking out the most economical sources of fuel and purchase power. We have been diligent in our efforts to secure reliable sources at reasonable costs. In short, our procurement processes are prudent. Therefore, we do not believe a sharing mechanism is needed in the PPFAC and would not recommend such a feature.

Q. How are short-term off-system wholesale revenues treated?

A. TEP will credit 90% of short-term sales revenues to the PPFAC bank.

Q. Why is TEP crediting 90% rather than 100% of the short-term sales revenues?

A. By allowing TEP to keep a portion of the short-term sales revenue TEP will be adequately incentivized to optimize its excess resources in the wholesale market. This allows TEP to share a small portion of the wholesale revenue in order to appropriately align TEP and its customers' risks and rewards associated with optimizing these sales for mutual benefit.

Q. Does the Company have a Plan of Administration to show how exactly all of the PPFAC Components would be calculated?

A. Yes. Attached to my Direct Testimony is Exhibit DGH-10. This is TEP's proposed Plan of Administration ("POA") for its proposed PPFAC. The POA provides all the details as to how the PPFAC operates, what specific fuel and energy costs would be included from specific FERC accounts, applicable interest rates to apply and other specifics. We hope that this is helpful in allowing Staff, RUCO and the Commission, as well as other parties, to better understand what exactly we are proposing in this filing.

Q. In general, what costs does the Company propose be included in the PPFAC?

A. As described more completely in the attached POA, the PPFAC includes costs associated with FERC accounts 501, 547, 555 and 565. As previously mentioned, 90% of off-system wholesale revenue is credited to the PPFAC. TEP is also proposing to include any Coal and/or Carbon taxes and to include broker fees, credit costs and legal fees associated with its power supply and procurement. TEP is also proposing to recover amortized natural gas and electric interconnection costs through the PPFAC.

The POA also describes the ongoing treatment of the previously mentioned Luna Energy Facility market capacity adjustment as a pro forma adjustment to FERC Account 555.

IV. TEP'S HYBRID METHODOLOGY.

Q. Please provide an overview of TEP's Hybrid Methodology.

A. As introduced in Mr. Pignatelli's Direct Testimony, TEP is proposing a "Hybrid" between cost of service and market-based rates by removing certain generation assets from TEP's rate base and treating them as competitive wholesale assets.

Q. Under the Hybrid Methodology, which power plants will be removed from rate base?

A. TEP proposes removing the Four Corners Generating Station Units 4 and 5 ("Four Corners") and Navajo Generating Station Units 1, 2 and 3 ("Navajo") from TEP's rate base and deeming them to be competitive wholesale assets, ("Competitive Assets") for the duration of their operating lives.

Q. If the Commission adopts the Hybrid Methodology, should it order the divestiture of the Competitive Assets?

A. The Hybrid Methodology does not require the divestiture of the Competitive Assets, but the Commission could order divestiture under the Hybrid Methodology.

Q. Why were these Competitive Assets chosen?

A. These assets were chosen primarily due to their location to competitive markets. This allows TEP to replace these assets' output with purchases from competitive points that have transmission access to TEP's load. The Four Corners bus is a liquid, actively traded point with over 4,100 generation at the bus or within the Four Corners-San Juan-Shiprock common receipt node and access to the Arizona, New Mexico, Colorado, and California markets. Navajo is also a liquid hub with 2,200 MW of generation and access to Arizona, Nevada, and California markets. TEP's 110 MW of Four Corners and 168 MW of Navajo generation is a mere 4.4% of these totals. Having these Competitive Assets located at liquid hubs with market access means TEP's customers will receive more competitive prices at these hubs. This includes either power from the Competitive Assets or power that TEP purchases to replace these units.

Q. What else about the Navajo and Four Corners plants makes them appropriate to classify as Competitive Assets under the Hybrid Methodology?

A. For one thing, TEP does not operate Navajo and Four Corners. Salt River Project operates Navajo, while Arizona Public Service Company operates Four Corners. Further, TEP only has a 7.5 percent ownership interest in Navajo and only a 7 percent interest in Four Corners. TEP witness Mr. Michael DeConcini provides more details about TEP's generation assets in his Direct Testimony. But these factors further justify why it is appropriate – under TEP's Hybrid Methodology – that Navajo and Four Corners be classified as Competitive Assets.

Q. How are the Competitive Assets "excluded from rate base"?

A. This requires pro forma adjustments to both rate base and operating expenses. Rate base is adjusted to exclude all plant in service, accumulated depreciation and accumulated deferred income taxes. This adjustment removes the net plant in service associated with the Competitive Assets as of the end of the test year (December 31, 2006). The exclusion of the related accumulated deferred income taxes ("ADIT") is implicit in the deferred tax rate base adjustment addressed in Ms. Kissinger's Direct Testimony. Concurrent with the exclusion of all Competitive Asset costs is the exclusion of all non-fuel operating expenses.

In addition, an adjustment is made to completely exclude the fuel costs associated from Navajo and Four Corners from the Test Year. This adjustment is addressed in the Direct Testimony of Mr. Dukes.

Q. What other adjustments have to be made after excluding the Competitive Assets from rate base?

A. PROMOD was re-run without the Competitive Assets to determine the fuel and purchase power adjustment necessary to serve TEP's load without these assets for the Test Year. This adjustment was $87,239,000 (ACC Jurisdiction Adjusted) as shown in Exhibit DGH-8.

Q. Are the other pro forma fuel adjustments made in the Cost-of-Service Methodology also applicable to the Hybrid Methodology?

A. Yes. The other adjustments are the same as previously described.

Q. How are Competitive Assets revenues treated?

A. Wholesale revenues from the Competitive Assets are separated from TEP's other wholesale revenues. These revenues are treated as non-jurisdictional for the remaining lives of the Competitive Assets.

Q. How is TEP planning on marketing/selling the energy from its Competitive Assets?

A. TEP will market its Competitive Assets into the Southwest wholesale markets through its Wholesale Energy group. TEP could sell this power through direct bilateral negotiations with third parties, through existing forward and spot energy markets, or a combination of these methods. TEP could also use this power to serve its retail load if the Competitive Assets are the winning bid in a competitive solicitation.

Q. Please describe the competitive solicitation process if TEP were to use the Competitive Assets to serve its retail load.

A. TEP believes there are two distinct types of competitive solicitations that could be used if TEP desired to supply its retail load with the Competitive Assets. First, a full competitive solicitation process, similar to that used in Track B could be used so that TEP could bid the Competitive Assets freely into the solicitation without limitation. This type of solicitation would require an Independent Monitor and a Code of Conduct to ensure separation of those Employees bidding the Competitive Assets and those evaluating the Bids.

The second type of solicitation would allow TEP to set a "Price to Beat" at which it would supply the output of the Competitive Assets to its retail customers. A competitive solicitation would then be held, under the purview of an Independent

Monitor, to determine if others suppliers would be willing to supply TEP at a price lower than the "Price to Beat". If a supplier submitted a bid lower than the Price to Beat, TEP would purchase that energy; if not, TEP would supply the power from its Competitive Assets to its retail customers at the Price to Beat.

Q. Is TEP proposing the same PPFAC in the Hybrid Methodology as it did in the Cost-of-Service Methodology?

A. Yes, the mechanism itself would be the same but the costs running through the PPFAC would be different. As previously described, the Competitive Assets revenues and costs would not be included in the PPFAC in the Hybrid Methodology. Also, given that TEP will be actively marketing and optimizing the Competitive Assets in the wholesale market, it would not need any additional incentives or incur any additional costs in selling excess power from TEP's remaining jurisdictional assets. As such, TEP would credit 100% (rather than the 90% proposed in the Cost-of-Service Methodology) of its wholesale revenues from its jurisdictional assets to the PPFAC. Finally, provision must be made to ensure that any customers leaving TEP through direct access or returning to TEP from direct access pay the appropriate portion of the PPFAC.

Q. Is TEP proposing the same Base Cost of Fuel and Purchased Power in the Hybrid Methodology as it did in the Cost-of-Service Methodology?

A. No. While the methodology and timing is the same, i.e., the 2009 Base Cost of Fuel and Purchased Power will be determined prior to the outcome of this case and the initial PPFAC will take effect in 2010, the results will be different as they will be calculated without the Competitive Assets in rates.

Q. Are there any differences in the PPFAC in TEP's Hybrid Methodology as compared to the Cost-of-Service Methodology?

A. Only in the accounting details. Since the Hybrid Methodology excludes the Four Corners and Navajo generation from the retail rate base, the fuel costs associated with these Competitive Assets, which will continue to be reported in TEP's FERC Account 501, will be excluded from the calculation since they will no longer be ACC jurisdictional.

Q. If TEP were to supply a portion of its retail load from the Competitive Assets, how would the costs be captured in the PPFAC?

A. If, and only if, TEP were the successful winning bid of a solicitation described previously, the cost charged to the PPFAC would be either the winning "bid price" or "price to beat" depending on the solicitation type used.

V. <u>TEP'S MARKET METHODOLOGY.</u>

Q. Please describe TEP's Market Methodology.

A. In the Market Methodology, rates for generation service would be determined by a market-based formula pursuant to the 1999 Settlement Agreement.

Q. Are there any necessary fuel and purchased power adjustments in the Market Methodology?

A. No. Because rates are based solely on the wholesale market prices, no adjustments are needed. Also, there is no need for the PPFAC under the Market Methodology.

Q. How are retail generation rates determined under the Market Methodology?

A. Market prices for generation service would be calculated using the existing Market Generation Credit ("MGC") rate schedule (Rate Schedule MGC-1) from TEP's 1999 Settlement Agreement as modified by Decision No. 65754 (March 20, 2003). This Schedule is attached to my testimony as Exhibit DGH-11, and incorporated herein. This MGC value is derived from a Palo Verde market index published by Platts, a McGraw-Hill publication.

Q. Is this the same schedule that determines the generation rate in TEP's current rates?

A. Yes. This schedule has been unchanged since TEP began operating under the 1999 Settlement Agreement, except for a modification of the market indexes used to calculate the market generation credit ("MGC"), approved in Decision No. 65754. This was necessary because the previous indices were no longer available.

Q. How often are the current MGC rates calculated?

A. The current market rate (*i.e.*, the MGC) calculation is performed monthly, based on the Rate Schedule MGC-1.

Q. Is the Platts Long Term Forward Assessment for Palo Verde still being published?

A. Yes, Platts continues to be a widely accepted and utilized market data reference. It still remains the best available index for the Palo Verde market hub and Palo Verde is still the most representative market for TEP.

Q. Under TEP's Market Methodology, would customers be at risk, or be entitled to benefit, if TEP were to acquire power at a price above or below the MGC?

A. No. Under TEP's Market Methodology, TEP assumes all the risk, and commensurately receives any benefit, for acquiring power at a price above or below the MGC. TEP would competitively procure its additional needs in the market and customers would continue to pay the MGC for generation service, irrespective of the actual price paid by TEP.

Q. What are the historical and projected generation rates using the MGC calculation?

A. Exhibit DGH-12 provides the entire history of MGC rates to date. This exhibit also shows the projected 2009 annual average MGC based on current projections of market prices in 2009.

VI. TEP'S RATE METHODOLOGIES AND THE SOUTHWEST WHOLESALE MARKET.

Q. Do TEP's Market and Hybrid Methodologies increase TEP's exposure to the wholesale market prices compared to the Cost-of-Service Methodology?

A. Yes. TEP's Hybrid Methodology increases the amount of power in TEP's supply portfolio that is priced at market prices. TEP's Market Methodology prices all generation service at a market proxy price.

Q. Are there ways to mitigate this exposure?

A. Yes. In both the Cost-of-Service and Hybrid Methodologies, TEP would continue to hedge its fuel and purchased power price risk as it currently does under its Fuel and Wholesale Power Hedging Policy. Under the Market Methodology, the MGC, as currently defined, sets the generation service price based solely on market prices. Any hedging TEP undertook would not affect the ultimate price paid by its customers.

Q. Is TEP willing to address this potential price volatility in the Market Methodology through changes in the MGC mechanism and/or calculation?

A. Yes. TEP has demonstrated this willingness throughout its negotiations and filings under its motion to amend Decision No. 62103.

Q. Do the Hybrid or Market Methodologies increase the amount of energy that TEP must procure in the wholesale market?

A. No. Under these methodologies, TEP still retains control of all of its generation. It is not subject to any more wholesale purchases than it would be under the Cost-of-Service Methodology. TEP is not prohibited from using any and/or all of its assets to continue to physically supply its load as it currently does today. In other words, TEP still only needs to purchase its incremental supply, that above that which its resources can produce, from the wholesale market. The only difference is how the price of that supply is determined and passed on to our customers.

Q. Is the wholesale market competitive enough to support the Market and Hybrid Methodologies?

A. Yes, more than enough. In order to provide the Commission with a thorough overview of the wholesale markets in Arizona and the Southwest, TEP has retained Mr. Judah

Rose, an expert in this area. Mr. Rose's Direct Testimony addresses this question in detail.

Q. Does this conclude your testimony?

A. Yes.

EXHIBIT

DGH-1

Tucson Electric Power

Exhibit DGH-1

Benchmark Energy Comparison

Energy Source	FERC Form 1 GWh	PROMOD
Sources of Energy	14,857	
Wholesale Activity (1)	(1,775)	
Total Energy Sources	**13,082**	**13,078**

(1) Wholesale Activity was determined through a netting process in order to arrive at short-term sales from system resources.

Fuel Cost Item	FERC Form 1 Cost	PROMOD
(501 & 547) Fuel	$278,775,935	
TRA Amortization (2)	($15,341,552)	
Capital Lease (2)	($5,822,440)	
SGS3 - Fuel Oil & Handling (2)	($8,519,074)	
Steam Generation	$249,092,868	
Total Fuel Costs	**$249,092,868**	**$248,542,800**

* FERC From 1 Year-Ending December 31, 2006

(2) GL- General Ledger

EXHIBIT

DGH-2

Tucson Electric Power

Exhibit DGH-2

Variable Pro Forma Fuel Adjustments

	Energy Source	Volume (GWh)	Cost ($000)
(1)	Year-End Customer Annualization	68.7	4,036
(2)	Weather Normalization	58.4	2,328
(3)	Short-term Sales Adjustment	(1621.1)	(52,427)
(4)	Unit Availability Normalization	N/A	7,786
(5)	Tri-State Purchases	N/A	(1,530)
	Total Energy Sources	**(1,494)**	**(39,807)**

Source: PROMOD runs adjusted for the combined effects.

EXHIBIT

DGH-3

Tucson Electric Power

Exhibit DGH - 3

Coal Normalization Calculation

Based on 2002-2005 Plant and Performance Data

Coal Unit Normalization	2006 Test-Year	Capacity	TY NCF 2006	NCF 2002-2005	NCF Delta	Annual Normalization	GWh Delta
Four Corners	812	110	84.3%	77.0%	-7.2%	742	(69)
Navajo	1,215	168	82.6%	81.4%	-1.1%	1,199	(17)
San Juan	2,485	322	88.1%	84.6%	-3.5%	2,387	(99)
Springerville	5,826	760	87.5%	86.8%	-0.7%	5,782	(45)
Sundt 4	623	110	64.6%	74.0%	9.4%	713	90
Coal Total	10,962	1,470	85.1%	84.0%	-1.1%	10,822	(139)

Annual Unit Normalization = Unit Capacity x Annual Hours x Net Capacity Factor

EXHIBIT

DGH-4

Tucson Electric Power

Exhibit DGH - 4

Fixed Pro Forma Fuel Adjustments

	Description	Cost ($000)
(1)	Sundt Coal Costs	9,884
(2)	San Juan Coal Costs	7,384
(3)	Navajo Coal Costs	2,780
(4)	Wholesale Trading Activity	(104,381)
	Total Fixed Adjustments	**(84,333)**

EXHIBIT

DGH-5

Tucson Electric Power

Exhibit DGH - 5

Wholesale Trading Activity

Test Year Whole Sale Activity	**GWh**	**$000**
Purchased Power	3,026	$ 177,347
Less System Purchases	1,251	$72,966
Wholesale Trading Activity	1,775	$104,381
Total Wholesale Revenues	4,556	241,124
Less Firm Wholesale	1,161	57,339
Less Short-Term Wholesale Revenues	1,621	77,685
Wholesale Trading Activity	1,775	106,100

EXHIBIT

DGH-6

CONFIDENTIAL

EXHIBIT

DGH-7

CONFIDENTIAL

EXHIBIT

DGH-8

Tucson Electric Power Company
Test Year Ended December 31, 2006

FERC Accounts	Expense	Cost of Service ACC Jurisdiction Adjusted, $000	HYBRID ACC Jurisdiction Adjusted, $000
501	Fuel - PPFAC Eligible	$ 214,138	$ 267,033
547	Fuel - PPFAC Eligible	$ 24,061	$ 24,061
555	Purchase Power, Demand - PPFAC Eligible	$ 28,959	$ 33,020
555	Purchase Power, Energy - PPFAC Eligible	$ 35,857	$ 66,140
565	Transmission - PPFAC Eligible	$ 4,510	$ 4,510
	Base Cost	$ 307,525	$ 394,764
	Adjusted Retail Sales, GWh	9,319	9,319
	Base Cost per kWh	$ 0.033	$ 0.042
	Hybrid Adjustment		$ 87,239

EXHIBIT

DGH-9

PURCHASED POWER & FUEL ADJUSTMENT CLAUSE TIMELINE

October 31 – TEP files component calculations and supporting data for the PSAM rate for the upcoming PSAM Year (April 1 through March 31).

December 15 – Staff and Interested Parties file any comments or recommendations to TEP's October 31 filing for the upcoming PSAM Year.

February 1 – TEP files updates to its October 31 filing, including its tracking account balances and calculations for components.

February 15 – Staff and interested parties file any comments or recommendations to TEP's February 1st update.

April 1 – Start of the PSAM Year. New PSAM rate goes into effect and remains in effect until March 31 the following year.

EXHIBIT

DGH-10

Tucson Electric Power Company
Purchased Power and Fuel Adjustment Clause
Plan of Administration

Table of Contents

1. GENERAL DESCRIPTION

This document describes the plan for administering the Purchased Power and Fuel Adjustment Clause ("PPFAC") the Arizona Corporation Commission ("Commission") approved for Tucson Electric Power Company ("TEP") in Decision No. XXXXX [DATE]. The PPFAC provides for the recovery of fuel and purchased power costs from the date of that decision forward.

The PPFAC described in this Plan of Administration ("POA") uses a forward-looking estimate of fuel and purchased power costs to set a rate that is then reconciled to actual costs experienced. This POA describes the application of the PPFAC.

2. DEFINITIONS

Applicable Interest - Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release H-15.

Base Cost of Fuel and Purchased Power - An amount generally expressed as a rate per kWh, which reflects the fuel and purchased power cost embedded in the base rates as approved by the Commission in TEP' most recent rate case. The Base Cost of Fuel and Purchased Power revenue is the approved rate per kWh times the applicable sales volumes. Decision No. XXXXX set the base cost at $X.XXXX per kWh effective on [DATE].

Forward Component - An amount expressed as a rate per kWh charge that is updated annually on April 1 of each year and effective with the first billing cycle in April. The Forward Component for the PPFAC Year will adjust for the difference between the forecasted fuel and purchased power costs expressed as a rate per kWh less the Base Cost of Fuel and Purchase Power generally expressed as a rate per kWh embedded in TEP's base rates. The result of this calculation will equal the Forward Component, expressed as a rate per kWh.

Forward Component Tracking Account - An account that records on a monthly basis TEP's over/under-recovery of its actual costs of fuel and purchased power as compared to the actual Base Cost of Fuel and Purchased Power revenue and Forward Component revenue; plus Applicable Interest. The balance of this account as of the end of each PPFAC Year is, subject to periodic audit, reflected in the next True-Up Component calculation. TEP files the balances and supporting details underlying this Account with the Commission on a monthly basis via a monthly reporting requirement.

Mark-to-Market Accounting - Recording the value of qualifying commodity contracts to reflect their current market value relative to their actual cost.

Native Load - Native load includes customer load in the TEP control area for which TEP has a generation service obligation.

PPFAC - The Purchased Power and Fuel Adjustment Clause approved by the Commission in Decision No. XXXXX, which is a combination of two rate components that track changes in the cost of obtaining power supplies based upon forward-looking estimates of fuel and purchased power costs that are eventually reconciled to actual costs experienced. This PPFAC also provides for a reconciliation between actual and estimated costs of the last three months of estimated costs used in True-Up Component calculations.

PPFAC Year - A consecutive 12-month period beginning each April 1 and lasting through March 31 the following year. The PPFAC will begin on the date the Commission issues a decision in this proceeding (Decision No. XXXXX) and ending on March 31, 2009. The first full year of the PPFAC will begin on April 1, 2009 and end on March 31, 2010.

Preference Power - Power allocated to TEP wholesale customers by federal power agencies such as the Western Area Power Administration.

System Book Fuel and Purchased Power Costs - The costs recorded for the fuel and purchased power used by TEP to serve both Native Load and off-system sales, less the costs associated with applicable special contracts and Mark-to-Market Accounting adjustments. Wheeling costs and broker's fee are included.

Off-System Wholesale Sales Revenue - The revenue recorded from sales made to non-Native Load customers, for the purpose of optimizing the TEP system, using TEP-owned or contracted generation and purchased power, less Mark-to-Market Accounting adjustments.

Traditional Sales-for-Resale - The portion of load from Native Load wholesale customers (SRP, TOUA and NTUA) that is served by TEP, excluding the load served with Preference Power.

True-Up Component - An amount expressed as a rate per kWh charge that is updated annually on April 1 of each year and effective with the first billing cycle in April. The purpose of this charge is to provide for a true-up mechanism to reconcile any over or under-recovered amounts from the preceding PPFAC Year tracking account balances to be refunded/collected from customers in the coming year's PPFAC rate.

True-Up Component Tracking Account - An account that records on a monthly basis the account balance to be collected or refunded via the True-Up Component rate as compared to the actual True-Up Component revenues, plus Applicable Interest; the balance of which at the close of the preceding PPFAC Year is, subject to periodic audit, then reflected in the next True-Up Component calculation. TEP files the balances and supporting details underlying this Account with the Commission on a monthly basis.

Wheeling Costs (FERC Account 565, Transmission of Electricity by Others) - Amounts payable to others for the transmission of TEP's electricity over transmission facilities owned by others.

3. PPFAC COMPONENTS

The PPFAC Rate will consist of two components designed to provide for the recovery of actual, prudently incurred fuel and purchased power costs. Those components are:

1. The Forward Component, which recovers or refunds differences between expected PPFAC Year (each April 1 through March 31 period shall constitute a PPFAC Year) fuel and purchased power costs and those embedded in base rates.

2. The True-Up Component, which tracks the differences between the PPFAC Year's actual fuel and purchased power costs and those costs recovered through the combination of base rates and the Forward Component, and which provides for their recovery during the next PPFAC Year.

The PPFAC Year begins on April 1 and ends the following March 31. The first full PPFAC Year in which the PPFAC rate shall apply will begin on April 1, 2010 and end on March 31, 2011. Succeeding PPFAC Years will begin on each April 1 thereafter.

For the period from when the Commission issued Decision No. XXXXX in this case – until April 1, 2010 – the Base Cost of Fuel and Purchased Power rate established in that decision will be in effect.

On or before October 31 of each year, TEP will submit a PPFAC Rate filing, which shall include a proposed calculation of the components for the PPFAC Rate. This filing shall be accompanied by supporting information as Staff determines to be required. TEP will supplement this filing with True-Up Component filing on or before February 1 in order to replace estimated balances with actual balances, as explained below.

A. Forward Component Description

The Forward Component is intended to refund or recover the difference between: (1) the fuel and purchased power costs embedded in base rates and (2) the forecasted fuel and purchased power costs over a PPFAC Year that begins on April 1 and ends the following March 31. TEP will submit, on or before October 31 of each year, a forecast for the upcoming PPFAC year (April 1 through March 31) of its fuel and purchase power costs. It will also submit a forecast of kWh sales for the same PPFAC year, and divide the forecasted costs by the forecasted sales to produce the cents per kWh unit rate required to collect those costs over those sales. The result of subtracting the Base Cost of Fuel and Purchased Power from this unit rate shall be the Forward Component.

TEP shall maintain and report monthly the balances in a Forward Component Tracking Account, which will record TEP's over/under-recovery of its actual costs of fuel and purchased power as compared to the actual Base Cost of Fuel and Purchased Power revenue and Forward Component revenue. This Account will operate on a PPFAC Year basis (i.e. April 1 to the following March

31), and its balances will be used to administer this PPFAC's True-Up Component, which is described immediately below.

Should an unusual event occur causing a drastic change in forecasted fuel and energy prices – such as a hurricane or other calamity – TEP has the discretion to apply for an adjustment to the forward component. Such an adjustment would only last until March 31 and would not be implemented unless approved by Staff and upon notice to the Commission.

B. True-Up Component Description

The True-Up Component in any current PPFAC Year is intended to refund or recover the balance accumulated in the Forward Component Tracking Account (described above) during the previous PPFAC year. Also, any remaining balance from the True-Up Component Tracking Account as of March 31 would roll over into the True-Up Component for the coming PPFAC year starting April 1.The sum of projected Forward Component Tracking Account and True-Up Component Tracking Account balances on March 31 is divided by the forecasted PPFAC year kWh sales to determine the True-Up Component for the coming PPFAC year.

TEP shall maintain and report monthly the balances in a True-Up Component Tracking Account, which will reflect monthly collections or refunds under the True-Up Component and the amounts approved for use in calculating the True-Up Component.

Each annual TEP filing on October 31 will include an accumulation of Forward Component Tracking Account balances and True-Up Component Tracking Account balances for the preceding April through September and an estimate of the balances for October through March (the remaining six months of the current PPFAC Year). The TEP filing shall use these balances to calculate a preliminary True-Up Component for the coming PPFAC Year. On or before February 1, TEP will submit a supplemental filing that recalculates the True-Up Component. This recalculation shall replace estimated monthly balances with those actual monthly balances that have become available since the October 31 filing.

The October 31 filing's use of estimated balances for October through March (with supporting workpapers) is required to allow the PPFAC review process to begin in a way that will support its completion and before April 1. The February 1 updating will allow for the use of the most current balance information available before the PPFAC would go into effect. In addition to the February 1 update filing, TEP monthly filings (for the months of September through December) of Forward Component Tracking Account balance information and True-Up Component Tracking Account balance information will include a recalculation (replacing estimated balances with actual balances as they become known) of the projected True-Up Component unit rate required for the next PPFAC Year.

The True-Up Component Tracking Account will measure the changes each month in the True-Up Component balance used to establish the current True-Up Component as a result of collections under the True-Up Component in effect. It will subtract each month's True-Up Component collections from the True-Up Component balance. The True-Up Component

Account will also include Applicable Interest on any balances. TEP shall file the amounts and supporting calculations and workpapers for this account each month.

4. CALCULATION OF THE PPFAC RATE

The PPFAC rate is the sum of the two components; i.e., Forward Component and True-Up Component. The PPFAC rate shall be applied to customer bills. Unless the Commission has otherwise acted on a new PPFAC rate by March 31, the proposed PPFAC rate (as amended by the updated February 1 filing) shall go into effect on April 1. The PPFAC rate shall be applicable to TEP's retail electric rate schedules (except those specifically exempted) and is adjusted annually. The PPFAC Rate shall be applied to the customer's bill as a monthly kilowatt-hour ("kWh") charge that is the same for all customer classes.

The PPFAC rate shall be reset on April 1 of each year, and shall be effective with the first April billing cycle unless suspended by the Commission. It is not prorated.

5. FILING AND PROCEDURAL DEADLINES

A. October 31 Filing

TEP shall file the PPFAC rate with all Component calculations for the PPFAC year beginning on the next April 1, including all supporting data, with the Commission on or before October 31 of each year. That calculation shall use a forecast of kWh sales and of fuel and purchased power costs for the coming calendar year, with all inputs and assumptions being the most current available for the Forward Component. The filing will also include the True-Up Component calculation for the year beginning on the next April 1, with all supporting data. That calculation will use the same forecast of sales used for the Forward Component calculation.

B. February 1 Filing

TEP will update the October 31 filing by February 1. This update will replace estimated Forward Component Tracking Account balances, the True-Up Component Tracking Account balances with actual balances and with more current estimates for those months (January, February and March) for which actual data are not available. Unless the Commission has otherwise acted on the TEP calculation by April 1, the PPFAC rate that TEP proposed will go into effect on April 1.

C. Additional Filings

TEP will also file with the Commission any additional information that the Staff determines it requires to verify the component calculations, account balances, and any other matter pertinent to the PPFAC.

D. Review Process

The Commission Staff and interested parties will have an opportunity to review the October 31 and February 1 forecast, balances, and supporting data on which the calculations of the three PPFAC components have been based. Any objections to the October 31 calculations must be filed within 45 days of the TEP filing. Any objections to the February 1 calculations must be filed within 15 days of the TEP filing (i.e. by February 15.)

E. Extraordinary Circumstances

Should an unusual event occur that causes a drastic change in forecasted fuel and energy prices – such as a hurricane or other calamity – TEP will have the authority to request an adjustment to the forward component reflecting such a change. Staff must review and either approve, modify or deny TEP's request within 30 days. This adjustment will only last until March 31, or the end of the current PPFAC Year.

6. *VERIFICATION AND AUDIT*

The amounts charged through the PPFAC will be subject to periodic audit to assure their completeness and accuracy and to assure that all fuel and purchased power costs were incurred reasonably and prudently. The Commission may, after notice and opportunity for hearing, make such adjustments to existing balances or to already recovered amounts as it finds necessary to correct any accounting or calculation errors or to address any costs found to be unreasonable or imprudent. Such adjustments, with appropriate interest, shall be recovered or refunded in the True-Up Component for the following year (i.e. starting the next April 1.)

7. *CALCULATIONS*

A. Schedule 1: PPFAC Rate Calculation

Enter the appropriate effective periods for the Current and Proposed PPFAC columns and then complete the following in each respective column:

1. On Line 1, enter the Forward Component from Schedule 2, Line 8.
2. On Line 2, enter the True-Up Component from Schedule 4, Line 5.
3. On Line 3, enter the sum of Lines 1 and 2 to calculate the total PPFAC Rate.
4. Calculate the Increase/(Decrease) in rates and % Change by respective lines: Proposed Rates Less Current Rates equals Increase/(Decrease) with result divided by Current Rate to determine % of Increase/(Decrease).

Reflect notes as appropriate.

B. Schedule 2: PPFAC Forward Component Rate Calculation

Enter the appropriate effective periods for the Current and Proposed PPFAC columns and then complete the following in each respective column:

1. On Line 1, enter the Projected Fuel and Purchased Power Costs for the coming year.
2. On Line 2, enter 90% of the Projected Off-System Sales Revenue (entered as a negative value) for the coming year.
3. On Line 3, enter the PPFAC Adjustments to Fuel and Purchased Power Costs for the coming year.
4. On Line 4, enter the sum of Lines 1 through 3 to arrive at the Net Fuel and Purchased Power Costs.
5. On Line 5, enter the Projected Native Load Sales (MWh), including Wholesale Native Load Customers (NTUA, SRP, TOUA) for the coming year.
6. On Line 6, enter the derivation of the Net Fuel and Purchased Power Costs divided by the Projected Native Load Sales to arrive at the Projected Average Net Fuel Cost per kWh.
7. On Line 7, enter the Authorized Base Cost of Fuel and Purchased Power Rate per kWh.
8. On Line 8, enter the sum of Line 6 less Line 7 to arrive at the Forward Component rate per kWh; and then carry forward resultant value to Schedule 1, Line 1.

Reflect notes as appropriate.

C. Schedule 3: Forward Component Tracking Account

Enter the appropriate: effective dates for the PPFAC Forward Component currently being tracked; year for the column headed "Cycle Billing Month"; and Base Rate and Forward Component in columns h and i. On lines 1 through 12 under the Cycle Billing Month, January through December for each respective column complete the following:

1. On Lines 1 to 12, enter the monthly PPFAC Retail Energy Sales (MWh) and the monthly Wholesale Native Load Energy Sales in columns a and b, respectively. The sum of columns a and b equals the Total Native Load Energy Sales in column c. Currently, Wholesale Native Load Energy Sales include Traditional Sales-for-Resale and any Supplemental Sales.
2. On Lines 1 to 12, enter the monthly System Book Fuel and Purchased Power Costs and 90% of the monthly System Book Off-System Sales Revenue in columns d and e, respectively:

   - The sum of column d minus e equals the monthly Net Native Load Power Supply Costs in column f.
   - The off-system sales margin is embedded in the Net Native Load Power Supply Cost. The costs associated with the off-system sales are included in the System Book Fuel and Purchased Power Costs.

- When the System Book Off-System Sales Revenue is subtracted from the System Book Fuel and Purchased Power Costs, the difference between the off-system sales costs and revenue ends up in the Net Native Load Power Supply Cost. That difference is the off-system sales margin.
- A list of the items included in the PPFAC sales and costs described above will be included in the PPFAC reporting schedules filed with the Commission each month.

3. On Lines 1 to 12, calculate the PPFAC Retail Power Supply Costs, column g by dividing the PPFAC Retail Energy Sales in column a by the Total Native Load Energy Sales in column c, then multiply the product by the Net Native Load Power Supply Costs in column f.
4. On Lines 1 to 12, calculate the amount recovered via the Commission approved embedded base fuel and purchased power rate by multiplying the Retail Energy Sales in column a by the Commission approved Base Cost of Fuel and Purchased Power rate entered in the above column heading the result which is entered in column h.
5. On Lines 1 to 12, calculate the amount recovered via the Forward Component rate by multiplying said rate by the Retail Energy Sales in column a, the result which is entered in column i.
6. On lines 1 to 12, calculate the respective level of (Over)/Under Collection in column j by subtracting the Base Rate Power Supply Recovery and the Forward Component Recovery from the PPFAC Retail Power Supply Costs, columns g and h, respectively.

An interest rate, based on the one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15, is applied each month to the previous month's Tracking Account Balance. The interest rate is adjusted annually on the first business day of the calendar year in the same manner as the TEP customer deposit rate.

The (Over)/Under Collection, the Interest and the prior month's Tracking Account Balance produce the current month's balance.

D. Schedule 4: PPFAC True-Up Component Rate Calculation

Enter the appropriate effective periods for the Current and Proposed PPFAC-2 columns and then complete the following in each respective column:

1. On Line 1, enter the Forward Component Tracking Account Balance from Schedule 3, Line13, column i.
2. On Line 2, enter the True-Up Component Tracking Account Balance from Schedule 5, Line 8.
3. On Line 3, enter the sum of Lines 1, and 2 to arrive at the Total (Refundable)/Collection Amount Balance.
4. On Line 4, enter the respective Projected Energy Sales (MWh).
5. On Line 5, enter the Applicable True-Up Component rate by dividing Line 3 by Line 4.

Reflect notes as appropriate.

E. Schedule 5: True-Up Component Tracking Account

Enter the appropriate: effective dates for the PPFAC Prior True-Up Component being tracked:

On Line 8, for March and Line 1 for April, enter the True-Up Component balance as of April 1, 20XX. On Line 2, (Prior period PPFAC True-Up Component Calculation From Schedule 4, Line 4) for April enter any true-up for the use of prior period estimates, (i.e. prior estimated January, February and March True-Up Component rate application revenues to subsequent actual data), the sum of Lines 1 and 2, to reflect the Adjusted True-Up Component Beginning Balance as of April 1, 20XX.

Each month, the Applicable True-Up Component rate is multiplied by the Retail Energy Sales to calculate the revenue received from the Applicable True-Up Component rate. The revenue is subtracted from the Adjusted Beginning Balance.

Interest is applied monthly based on the effective one-year Nominal Treasury Constant Maturities rate that is contained in the Federal Reserve Statistical Release, H-15, or its successor publication. The interest rate is adjusted annually on the first business day of the PPFAC Year.

Reflect notes as appropriate.

8. COMPLIANCE REPORTS

TEP shall provide monthly reports to Staff's Compliance Section and to the Residential Utility Consumer Office detailing all calculations related to the PPFAC. A TEP Officer shall certify under oath that all information provided in the reports itemized below is true and accurate to the best of his or her information and belief. These monthly reports shall be due within 30 days of the end of the reporting period.

The publicly available reports will include at a minimum:

1. The PPFAC Rate Calculation (Schedule 1); Forward Component and True-Up Component Calculations (Schedules 2 and 4); Annual Forward Component and, True-Up Component Tracking Account Balances (Schedules 3 and 5). Additional information will provide other relative inputs and outputs such as:
    a. Total power and fuel costs.
    b. Customer sales in both MWh and thousands of dollars by customer class.
    c. Number of customers by customer class.
    d. A detailed listing of all items excluded from the PPFAC calculations.
    e. A detailed listing of any adjustments to the adjustor reports.
    f. Total off-system sales revenues.
    g. System losses in MW and MWh.

h. Monthly maximum retail demand in MW.

2. Identification of a contact person and phone number from TEP for questions.

TEP shall also provide to Commission Staff monthly reports containing the information listed below. These reports shall be due within 30 days of the end of the reporting period. All of these additional reports must be provided confidentially.

A. Information for each generating unit will include the following items:
   1. Net generation, in MWh per month, and 12 months cumulatively.
   2. Average heat rate, both monthly and 12-month average.
   3. Equivalent forced-outage rate, both monthly and 12-month average.
   4. Outage information for each month including, but not limited to, event type, start date and time, end date and time, and a description.
   5. Total fuel costs per month.
   6. The fuel cost per kWh per month.

B. Information on power purchases will include the following items per seller (information on economy interchange purchases may be aggregated):
   1. The quantity purchased in MWh.
   2. The demand purchased in MW to the extent specified in the contract.
   3. The total cost for demand to the extent specified in the contract.
   4. The total cost of energy.

C. Information on off-system sales will include the following items:
   1. An itemization of off-system sales margins per buyer.
   2. Details on negative off-system sales margins.

D. Fuel purchase information shall include the following items:
   1. Natural gas interstate pipeline costs, itemized by pipeline and by individual cost components, such as reservation charge, usage, surcharges and fuel.
   2. Natural gas commodity costs, categorized by short-term purchases (one month or less) and longer term purchases, including price per therm, total cost, supply basin, and volume by contract.

E. TEP will also provide:
   1. Monthly projections for the next 12-month period showing estimated (Over)/undercollected amounts.
   2. A summary of unplanned outage costs by resource type.
   3. The data necessary to arrive at the System and Off-System Book Fuel and Purchased Power cost reflected in the non-confidential filing.
   4. The data necessary to arrive at the Native Load Energy Sales MWh reflected in the non-confidential filing.

Work papers and other documents that contain proprietary or confidential information will be provided to the Commission Staff under an appropriate protective agreement. TEP will keep fuel and purchased power invoices and contracts available for Commission review. The Commission has the right to review the prudence of fuel and power purchases and any calculations associated with the PPFAC within XX years of those costs being incurred. Any costs flowed through the PPFAC are subject to refund, if those costs are found to be imprudently incurred.

9. ALLOWABLE COSTS

A. Accounts

The allowable PPFAC costs include fuel and purchased power costs incurred to provide service to retail customers. Additionally, the prudent direct costs of contracts used for hedging system fuel and purchased power will be recovered under the PPFAC. The allowable cost components include the following Federal Energy Regulatory Commission ("FERC") accounts:

- 501 Fuel (Steam)
- 547 Fuel (Other Production)
- 555 Purchased Power
- 557 Broker Fees
- 565 Wheeling (Transmission of Electricity by Others)

These accounts are subject to change if the Federal Energy Regulatory Commission alters its accounting requirements or definitions.

B. Other Allowable Costs

In addition to the fuel and purchased power costs in the above mentioned FERC accounts, the following costs will also be recovered through the PPFAC:

- Credit costs necessary to support fuel and purchased power contracts
- Any and all federal and/or state coal and carbon taxes applied to TEP's generation or fuel and purchased power contracts
- Outside legal expenses incurred to litigate fuel and purchased power matters on behalf of TEP's customers, such as pipeline and transmission rate cases and contract disputes
- Amortized interstate pipeline and electric transmission interconnection costs

TUCSON ELECTRIC POWER COMPANY
Schedule 1
Purchased Power and Fuel Adjustment Clause (PPFAC) Rate Calculation Effective April 1, 20XX
($/kWh)

Line No.	PPFAC Rate Calculation		Current April 1, 20XX [1]	Proposed April 1, 20XX	Increase / (Decrease) $.000000/kWh	%
1	Forward Component Rate - FC (Sch. 2, L8)		$ -	$ -	$ -	0.00%
2	True Up Component Rate - HC (Sch. 4, L5)[2]		$ -	$ -	$ -	0.00%
3	PPFAC Rate April 1, 20XX and 20XX	(L1+L2+L8)	$ -	$ -	$ -	0.00%

Notes:

[1] See April 1, 20XX PPFAC Filing.

[2] A Historical Component is a true up related to respective prior period PPFAC activity.

TUCSON ELECTRIC POWER COMPANY

Schedule 2

PPFAC Forward Component Rate Calculation Effective April 1, 20XX

($ in thousands; Forward Component Rate in $/kWh)

Line No.	PPFAC Forward Component Rate - Calculation	Current April 1, 20XX [1]	Proposed April 1, 20XX	Increase / (Decrease) $ Values	Increase / (Decrease) %
1	Projected Fuel and Purchased Power Costs	$ -	$ -	$ -	0.00%
2	Projected Off-System sales Revenue Credit[2]	$ -	$ -	$ -	0.00%
3	PPFAC Ajustments to Fuel and Purchased Power Costs3	$ -	$ -	$ -	0.00%
4	Net Fuel and Purchased Power Cost (L1 through L3)	$ -	$ -	$ -	0.00%
5	Projected Native Load sales (MWhs)	0	0	-	0.00%
6	Projected Average Net Fuel Costs $/kWh (L4/L5)	$ -	$ -	$ -	0.00%
7	Authorized Base Cost of Fuel and Purchased Power Rate $/kWh	$ -	$ -	$ -	0.00%
8	Forward Component Rate April 1, 20XX and 20XX $/kWh (L6 - L7)	$ -	$ -	$ -	0.00%

Notes:

[1] See April 1, 20XX PPFAC Filing.

[2] Off-System Salesl revenues are credited at 90% as approved by the Commission in Decision No. xxxxx

[3] Includes mark-to-market accounting adjustments.

Schedule presentation will appear to roundup $'s and MWhs; however calculations are performed on an actual $ and MWh basis with resultant Rates/kWh roundup to $0.000000/kWh

TUCSON ELECTRIC POWER COMPANY
Schedule 3
Forward Component Tracking Account - (PPFAC Prior Forward Component Rate in effect from Jan 1, 20XX to DEC 31, 20XX
($ in thousands; Forward Component Rate and Base Rate in $/kWh)

Line No.	20XX Cycle Billing Month	(a) PPFAC Retail 1 Energy Sales (MWh)	(b) Wholesale [2] Native Load Energy Sales (MWh)	(c) Total Native Load Energy Sales (MWh)	(d) System [3] Book Fuel and Purchased Power Costs	(e) System Book[4] Off-System Sales Revenue	(f) Net Native Load Power Supply Costs	(g) PPFAC Retail Power Supply Costs	(h) Base Rate Power Supply Recovery	(i) Forward [6] Component Recovery	(j) (Over)/Under Collections	(k) Interest [5]	(l) Tracking [7] Account Balance
				(a + b)			(d - e)	(a/c*f)	(a*0.0XXXXX)	(a*0.00XXXX) (a*0.00XXXX)	(g - h - i)	(i * rate/12)	(j + k + l)
1	April	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	May	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	June	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	July	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	August	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	September	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	October	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	November	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	December	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	January	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	February	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	March	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	Total	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Interest rate [5]		0.00%										

Notes:

[1] PPFAC Retail Energy Sales are the calender month's MWh sales.

[2] Includes traditional sales-for-resale (NTUA, SRP and TOUA) and supplemental sales.

[3] Includes native load and off-system fuel and purchased power and mark-to-market accounting adjustments.

[4] Includes off-system revenueat 90% per Decision xxxx less mark-to-market accounting adjustments.

[5] Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15.

[6] Forward Component Rates $/kWh Effective Apr 1, 20XX to Mar 31, 20XX $ - Apr 1, 20XX to Mar 31, 20XX $ -

[7] Tracking Account Balance Line 13 carried to Schedule 4, Line 1.

Schedule presentation will appear to roundup $'s and MWhs; however calculations are performed on an actual $ and MWh basis with resultant Rates/kWh roundup to $0.000000/kWh

TUCSON ELECTRIC POWER COMPANY
Schedule 4
PPFAC True Up Component Rate Calculation Effective April 1, 20XX
($ in thousands; True Up Component Rate in $/kWh)

Line No.	PPFAC Historical Component Rate - Calculation	Current April 1, 20XX [1]	Proposed April 1, 20XX	Increase / (Decrease) $ Values	%
1	Forward Component Tracking Account Balance (From Schedule 3, L13, Cl L) [2,3]	$ -	$ -	$ -	0.00%
2	True Up Component Tracking Account Balance (From Schedule 5, L8) [4,5]	$ -	$ -	$ -	0.00%
3	Total True Up Amount to be (refunded)/Collected Balance (L1+L2) [6]	$ -	$ -	$ -	
4	Projected Native Load Sales (MWh)	0	0	-	0.00%
5	Applicable True Up Component Rate for Apr 1, 20XX & 20XX ($/kWh) (L3 / L4)	$ -	$ -	$ -	0.00%

Notes:

1 See April 1, 20XX PPFAC Filing.

2 Current Forward Component Tracking Account Balance as of December 31, 20XX.

3 Includes interest for October, November and December

4 Current Historical Component Tracking Account Balance as of March 31, 20XX.

5 Because the actual amount of revenue to be received in January, February, & March from application of the prior Applicable True Up Component is not available at the time of filing, Schedule 5 will reflect as necessary estimates for those periods as well as true-up calculations for the prior period estimates, See Schedule 5 for more detail.

6 Beginning Balance as of April 1, 2010 - to be carried forward to subsequent period PPFAC, True Up Component Tracking account Balance, Schedule 5, L1.

Schedule presentation will appear to roundup $'s and MWhs; however calculations are performed on an actual $ and MWh basis with resultant Rates/kWh roundup to $0.000000/kWh

TUCSON ELECTRIC POWER COMPANY
Schedule 5
True Up Component Tracking Account - Prior PPFAC True Up Component Rate in Effect April 1, 20XX through Mar 31, 20XX
($ in thousands; Historical Component Rate in $/kWh)

Line No.		20XX Data										20XX data		
		March	April	May	June	July	August	September	October	November	December	January	February	March
1a	TU Beginning Balance as of Apr. 1, 20XX [1] and thereafter.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1b	FC tracking Account Balance as of March 31, 20XX	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Revenue True-up from January-March Estimate [2]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	TU Adjusted Beginning Balance (L1 + L2)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Applicable True Up Component Rate ($/kWh) [3]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Retail Billed Sales (MWhs)[4]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Less Revenue from Application TU (L4 x L5)[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Monthly Interest (Line3 * Int Rate/12) [6]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	TU Ending Balance; (L3 - L6 + L7)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Notes:

[1] Beginning Balance as of April 1, 20XX - carried forward April 1, 20XX PPFAC Filing, Historical Component Calculation Schedule, Schedule 4, L2.

[2] True-up is the result of using estimated revenue for January through March since the actual amount was not available at the time of prior period PPFAC filing - No true-up since no rate applied in Prior April 20XX Filing.

[3] Historical Component, Prior Period PPFAC, Sch. 4, L5.

[4] Sales amounts are for energy billed beginning with the first billing cycle of April 20XX.

[5] Generally, Line 4 x Line 5 = Line 6; however, differences may occur due to billing adjustments.

[6] Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15. 0.00%

Schedule presentation will appear to roundup $'s and MWhs; however calculations are performed on an actual $ and MWh basis with resultant Rates/kWh roundup to $0.000000/kWh

EXHIBIT

DGH-11

Schedule MGC-1
Tucson Electric Power Company
Market Generation Credit (MGC) Calculation

A UniSource Energy Company

Introduction

There are two purposes of the Market Generation Credit (MGC). The first purpose is to establish a price to which TEP's energy customers can compare to the prices of competitors. The second purpose is to enable the calculation of the variable or "floating" component of TEP's stranded cost recovery. Shown below are the terms of the MGC methodology per TEP's Settlement Agreement, Section 2.1(d), as amended March 20, 2003:

> The monthly MGC amount shall be calculated in advance and stated as both an on-peak value and an off-peak value. The monthly on-peak MGC component shall be equal to the Market Price multiplied by one plus the appropriate line loss (including unaccounted for energy ("UFE")) amount. The Market Price shall be equal to the Platts Long-Term Forward Assessment for the Palo Verde Forward price, except when adjusted for the variable cost of TEP's must-run generation. The Market Price shall be determined thirty (30) days prior to each calendar month using the average of the most recent three (3) business days of Platts Long-Term Forward Assessment for Palo Verde settlement prices. The off-peak MGC component shall be determined in the same manner as the on-peak component, except that the Platts Long-Term Forward Assessment for the Palo Verde Forward price will be adjusted by the ratio of off-peak to on-peak prices from the Dow Jones Palo Verde Index of the same month from the preceding year. The MGC shall be equal to the hours-weighted average of the on-peak and off-peak pricing components and shall reflect the cost of serving a one hundred percent (100%) load factor customer.

To reflect the cost of serving a 100% load factor customer, the actual MGC used for billing calculations will be a loss adjusted average price that is weighted by the ratio of on-peak and off-peak hours. This process is illustrated in equations 4 and 5 below and will be posted to TEP's website http://partners.tucsonelectric.com thirty (30) days prior to each calendar month. This composite price will be credited to all energy consumption, regardless of the time period in which it is consumed.

Calculations

Five steps are outlined below for the calculation of the MGC. None of the steps are excludable for any customer type. Acronyms are defined in the Glossary at the end of this document.

Schedule MGC-1
Tucson Electric Power Company
Market Generation Credit (MGC) Calculation

1. Calculating the on-peak MGC

Thirty (30) days prior to each calendar estimation month, the Platts Long-Term Forward Assessment for Palo Verde Forward prices for the three (3) most recent business days are used. The simple average (or arithmetic mean) is calculated for these three (3) days for the estimation month.

$$MGC_{ON,i} = \frac{\sum (PLATTS)_i}{3} \qquad \text{(Equation 1)}$$

The calculation is illustrated in the table below.

Forward Prices per MWh	Apr-2002
3/1/2002	$25.50
2/28/2002	$25.50
2/27/2002	$24.75
Average	$25.25

2. Calculating the off-peak MGC

The off-peak MGC is determined by multiplying the on-peak MGC value by the off-peak price weighting factor (WEIGHT). The WEIGHT is equal to the simple average of all off-peak prices from the Dow Jones Palo Verde Index in the same month of the previous year, divided by the simple average of all on-peak prices from the Dow Jones Palo Verde Index in the same month of the previous year. Off-peak, on-peak and holiday hours are defined by NERC in the estimation month.

$$\text{MGC}_{\text{OFF},i} = \text{MGC}_{\text{ON},i} * \text{WEIGHT}_i \qquad \text{(Equation 2)}$$

where

$$WEIGHT_i = \frac{DJPVI_{OFF,i}}{DJPVI_{ON,i}} \qquad \text{(Equation 3)}$$

3. Weighting the MGC for hours in the month

The on-peak and off-peak MGCs are combined to form an average MGC by computing a weighted average of the two time periods. This is done by multiplying the on-peak MGC by the percentage of on-peak hours in the same month of the previous year and then adding the product of the off-peak MGC and the percentage of off-peak hours in the same month of the previous year. Off-peak, on-peak and holiday hours are defined by NERC in the estimation month.

$$MGC_{WEIGHT,i} = MGC_{ON,i} * \left(\frac{ONHOURS}{ONHOURS + OFFHOURS} \right) + MGC_{OFF,i} * \left(\frac{OFFHOURS}{ONHOURS + OFFHOURS} \right)$$

(Equation 4)

4. Loss-adjusting the MGC

The average MGC must be adjusted for line losses. The appropriate line loss adjustment factor (LLAF) for a large industrial customer is 1.0515. For all other customers, the appropriate factor is 1.0919.

$$MGC_{LOSS,i} = MGC_{WEIGHT,i} * LLAF$$ (Equation 5)

5. Adjusting the MGC for variable must-run

The MGC will be adjusted for variable must-run as defined in TEP's Stranded Cost Settlement Agreement and AISA protocols. Fifteen (15) days prior to each month, TEP forecasts a ratio of its variable must-run generation to retail system demand for the following month. The MGC is determined by adding the product of MGC_{LOSS} and one minus the ratio of variable must-run generation to total retail system demand to the product of $15/MWh and the variable must-run ratio.

$$MGC_i = \left[MGC_{LOSS,i} * (1 - VMR_i)\right] + (\$15 * VMR_i)$$ (Equation 6)

This calculation produces the final value for the Market Generation Credit.

Schedule MGC-1
Tucson Electric Power Company
Market Generation Credit (MGC) Calculation

GLOSSARY

$DJPVI_{OFF}$	Simple average of off-peak prices on the Dow Jones Palo Verde Index.
$DJPVI_{ON}$	Simple average of on-peak prices on the Dow Jones Palo Verde Index.
Dow Jones Palo Verde Index	Daily calculation of actual firm on-peak and firm off-peak weighted average prices for electricity traded at Palo Verde, Arizona switchyard.
AISA	Arizona Independent Scheduling Administrator, a temporary entity, independent of transmission-owning organizations, intended to facilitate nondiscriminatory retail direct access using the transmission system in Arizona. Required by the Arizona Corporation Commission Retail Electric Competition Rules.
LLAF	Line-loss adjustment factor.
MGC	Market Generation Credit.
MGC_{OFF}	MGC_{ON} weighted by the ratio of off-peak to on-peak prices on the Dow Jones Palo Verde Index.
MGC_{ON}	Average of the Platts prices on days appropriate for the calculation of the MGC.
MGC_{LOSS}	MGC_{WEIGHT} adjusted for line losses (including unaccounted for energy) on TEP's generation and energy delivery systems.
MGC_{WEIGHT}	A weighted average of MGC_{ON} and MGC_{OFF} by ONHOURS and OFFHOURS.
Must-run Generation	The cost associated with the running of local generating units needed to maintain distribution system reliability and to meet load requirements in times of congestion on certain portions of the interconnected grid.
NERC	North American Electric Reliability Council. A voluntary not-for-profit organization established to promote bulk electric system reliability and security. Membership includes: investor-owned utilities; federal power agencies; rural electric cooperatives; state, municipal and provincial utilities; independent power producers; power marketers; and end-use customers.

Schedule MGC-1
Tucson Electric Power Company
Market Generation Credit (MGC) Calculation

OFFHOURS	Number of total monthly off-peak hours as defined by NERC. Off-peak hours are hour ending 0100 – hour ending 0600 and hour ending 2300 – hour ending 2400, Monday through Saturday, Pacific Prevailing Time (PPT). All Sunday hours are considered off-peak. PPT is defined as the current clock time in the Pacific time zone.
ONHOURS	Number of total monthly on-peak hours as defined by NERC. On-peak hours are hour ending 0700 – hour ending 2200 Monday through Saturday, Pacific Prevailing Time (PPT). PPT is defined as the current clock time in the Pacific time zone.
PLATTS	A McGraw-Hill publication that provides an independent daily evaluation of on-peak Long Term Forward Assessment of market prices of electricity at the Palo Verde, Arizona switchyard. The forward product is "6 x 16," power is for 16 hours a day for six days a week (Monday through Saturday) for the delivery period, excluding NERC holidays.
Stranded Costs	The difference between revenues under competition and the costs of providing service, including the inherited fixed costs from the previous regulated market.
TEP	Tucson Electric Power Company, a subsidiary of UniSource Energy Corp.
TEP Settlement Agreement	An agreement between TEP, the Arizona Residential Utility Consumer Office, members of the Arizonans for Electric Choice and Competition, and Arizona Community Action Association regarding TEP's implementation of retail electric competition, implementation of unbundled tariffs, and recovery of stranded costs.
VMR	Ratio of variable must-run generation (MW) to total retail system demand (MW) in TEP's service territory.
WEIGHT	Ratio of off-peak to on-peak prices on the Dow Jones Palo Verde Index.

TUCSON ELECTRIC POWER COMPANY

Tucson, Arizona
Filed by: Steven J. Glaser
Title: Vice President, Rates & Regulatory Support
District: Entire Electric Service Area

Tariff No. RIDER NO. 1-ADDENDUM
Sheet No. 1 of 1
Revision No.
Effective: January 1, 2000

ADDER ASSOCIATED WITH MGC – RIDER NO. 1

(all prices in mills per kWh)

All customers up to 200 kW demand	Mills per kWh
Summer kWh up to 115% of winter kWh	3.84
Summer kWh greater than 115% but less than or equal to 145% of winter kWh	4.44
Summer kWh greater than 145% but less than or equal to 175% of winter kWh	5.04
Summer kWh greater than 175% but less than or equal to 205% of winter kWh	5.64
Summer kWh greater than 205% of winter kWh	6.24

All customers from 200 kW to 3000 kW demand	
Summer kWh up to 106% of of winter kWh	3.00
Summer kWh greater than 106% but less than or equal to 136% of winter kWh	3.48
Summer kWh greater than 136%	3.96

All customers 3000 kW demand and above	
Air Liquide	3.00
Fort Huachuca	3.00
Arizona Portland Cement	3.00
IBM	3.00
Asarco Mission 1	3.00
Asarco Mission 2	3.00
Asarco Silverbell	3.00
Cyprus	3.00
University of Arizona Main Campus	3.00
University of Arizona Health Sciences Center	3.00
University of Arizona Central Heating & Refrigeration Plant	3.00
Burr Brown	3.00
Davis Monthan Air Force Base	3.00
Raytheon	3.00
University Medical Center	3.00
Tucson Medical Center	3.00

TUCSON ELECTRIC POWER COMPANY

Tucson, Arizona
Filed by: Steven J. Glaser
Title: Vice President, Rates & Regulatory Support
District: Entire Electric Service Area

Tariff No. RIDER NO. 2
Sheet No. 1 of 1
Revision No.
Effective: January 1, 2000

MUST-RUN GENERATION – RIDER NO. 2

Must-Run Generation - Rider No.2

Variable Component	$ 0.015000 per kWh
Fixed Component	
Residential Service	$ 0.005017 per kWh
General Service - Rates No. 10 and 76	0.005493 per kWh
Mobile Home Parks - Rate No. 11	0.006549 per kWh
Interruptible Agricultural Pumping - Rate No. 31	0.003752 per kWh
Large General Service - Rates No. 13, 85 and 85A	0.003787 per kWh
Large Light & Power - Rates No. 14, 90, and 90A	0.002900 per kWh
Lighting - Rates No. 41, 50 and 51	0.004522 per kWh
Public Authority - Rates No. 40 and 43	0.004876 per kWh
(Weighted Average Fixed Component)	$ 0.004320 per kWh

Variable component is billed to scheduling coordinator based on actual must-run energy delivered.
Fixed component is billed directly to end-use customer.

During a month in which must-run generation is provided to meet retail load, the Market Price component used in calculating the on-peak MGC shall be a weighted average of the Palo Verde NYMEX futures price and the must-run variable cost charges that are levied on scheduling coordinators serving retail customers in the TEP load zone during that month, consistent with AISA protocols.

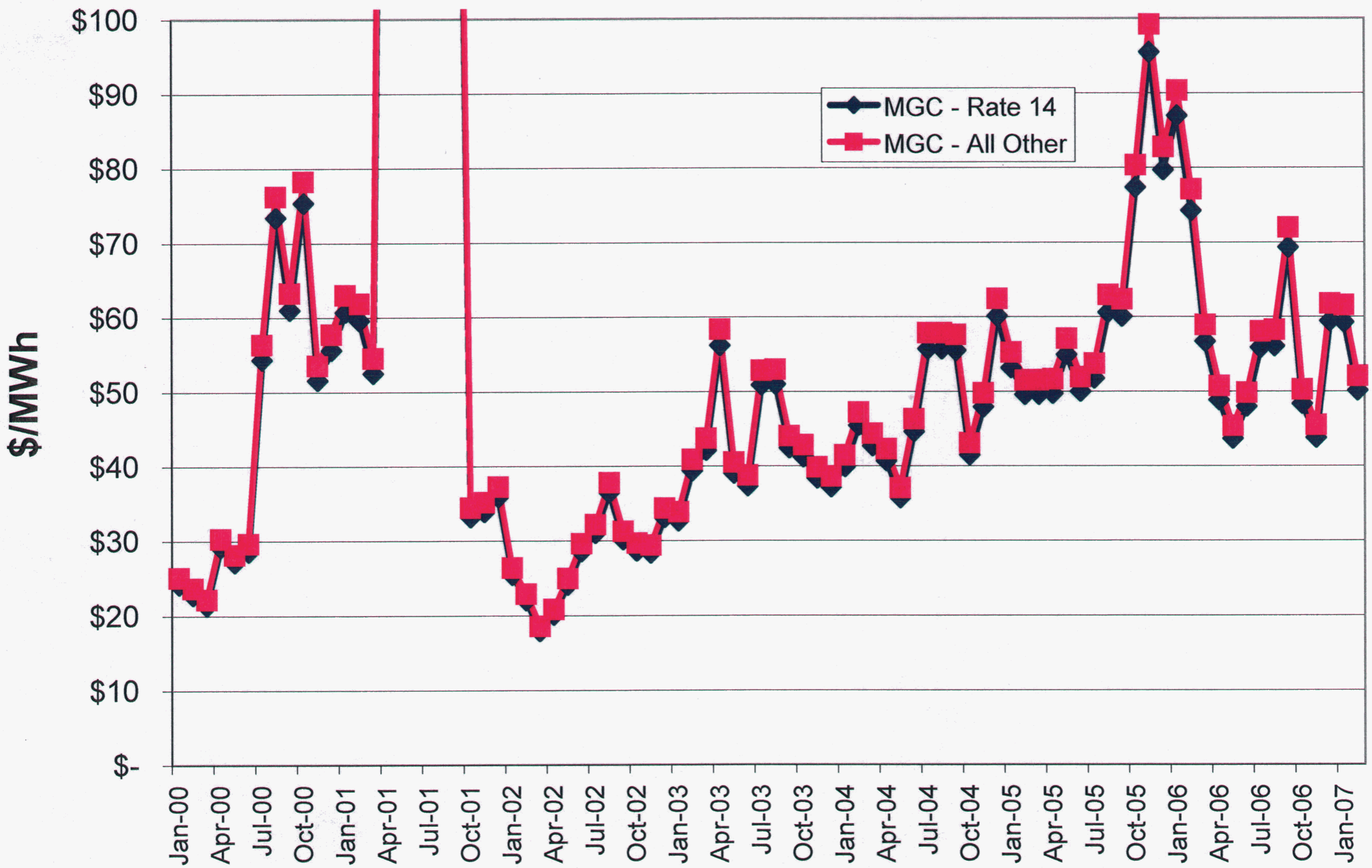
EXHIBIT

DGH-12

Date	MGC - Rate 14	MGC - All Other
1/1/2000	$ 24.17	$ 25.10
2/1/2000	$ 22.78	$ 23.65
3/1/2000	$ 21.37	$ 22.17
4/1/2000	$ 29.21	$ 30.30
5/1/2000	$ 27.14	$ 28.15
6/1/2000	$ 28.57	$ 29.62
7/1/2000	$ 54.37	$ 56.36
8/1/2000	$ 73.47	$ 76.22
9/1/2000	$ 60.99	$ 63.27
10/1/2000	$ 75.40	$ 78.24
11/1/2000	$ 51.61	$ 53.55
12/1/2000	$ 55.63	$ 57.71
1/1/2001	$ 60.67	$ 62.97
2/1/2001	$ 59.58	$ 61.84
3/1/2001	$ 52.51	$ 54.50
4/1/2001	$ 201.36	$ 209.07
5/1/2001	$ 170.89	$ 177.42
6/1/2001	$ 176.53	$ 183.25
7/1/2001	$ 272.88	$ 283.31
8/1/2001	$ 304.02	$ 315.63
9/1/2001	$ 193.18	$ 200.57
10/1/2001	$ 33.16	$ 34.41
11/1/2001	$ 33.87	$ 35.14
12/1/2001	$ 35.87	$ 37.23
1/1/2002	$ 25.44	$ 26.39
2/1/2002	$ 22.03	$ 22.85
3/1/2002	$ 17.90	$ 18.56
4/1/2002	$ 20.08	$ 20.83
5/1/2002	$ 24.08	$ 24.96
6/1/2002	$ 28.56	$ 29.60
7/1/2002	$ 31.02	$ 32.15
8/1/2002	$ 36.45	$ 37.78
9/1/2002	$ 30.16	$ 31.27
10/1/2002	$ 28.61	$ 29.68
11/1/2002	$ 28.34	$ 29.40
12/1/2002	$ 33.11	$ 34.35
1/1/2003	$ 32.65	$ 33.87
2/1/2003	$ 39.38	$ 40.87
3/1/2003	$ 42.12	$ 43.71
4/1/2003	$ 56.18	$ 58.31
5/1/2003	$ 39.03	$ 40.49
6/1/2003	$ 37.34	$ 38.75
7/1/2003	$ 50.89	$ 52.82
8/1/2003	$ 51.02	$ 52.96
9/1/2003	$ 42.43	$ 44.04
10/1/2003	$ 41.23	$ 42.81
11/1/2003	$ 38.37	$ 39.84
12/1/2003	$ 37.19	$ 38.62

Date	MGC - Rate 14	MGC - All Other
1/1/2004	$ 39.90	$ 41.43
2/1/2004	$ 45.46	$ 47.20
3/1/2004	$ 42.69	$ 44.33
4/1/2004	$ 40.71	$ 42.26
5/1/2004	$ 35.71	$ 37.06
6/1/2004	$ 44.61	$ 46.30
7/1/2004	$ 55.68	$ 57.79
8/1/2004	$ 55.68	$ 57.80
9/1/2004	$ 55.47	$ 57.58
10/1/2004	$ 41.46	$ 43.05
11/1/2004	$ 47.91	$ 49.75
12/1/2004	$ 60.08	$ 62.39
1/1/2005	$ 53.17	$ 55.20
2/1/2005	$ 49.60	$ 51.50
3/1/2005	$ 49.60	$ 51.50
4/1/2005	$ 49.74	$ 51.64
5/1/2005	$ 54.94	$ 57.04
6/1/2005	$ 50.01	$ 51.91
7/1/2005	$ 51.76	$ 53.73
8/1/2005	$ 60.60	$ 62.90
9/1/2005	$ 60.04	$ 62.33
10/1/2005	$ 77.38	$ 80.34
11/1/2005	$ 95.49	$ 99.15
12/1/2005	$ 79.70	$ 82.76
1/1/2006	$ 86.97	$ 90.31
2/1/2006	$ 74.26	$ 77.11
3/1/2006	$ 56.70	$ 58.88
4/1/2006	$ 48.86	$ 50.74
5/1/2006	$ 43.69	$ 45.37
6/1/2006	$ 47.99	$ 49.83
7/1/2006	$ 55.86	$ 58.01
8/1/2006	$ 56.08	$ 58.24
9/1/2006	$ 69.32	$ 71.98
10/1/2006	$ 48.37	$ 50.23
11/1/2006	$ 43.80	$ 45.48
12/1/2006	$ 59.44	$ 61.73
1/1/2007	$ 59.25	$ 61.51
2/1/2007	$ 50.14	$ 52.06

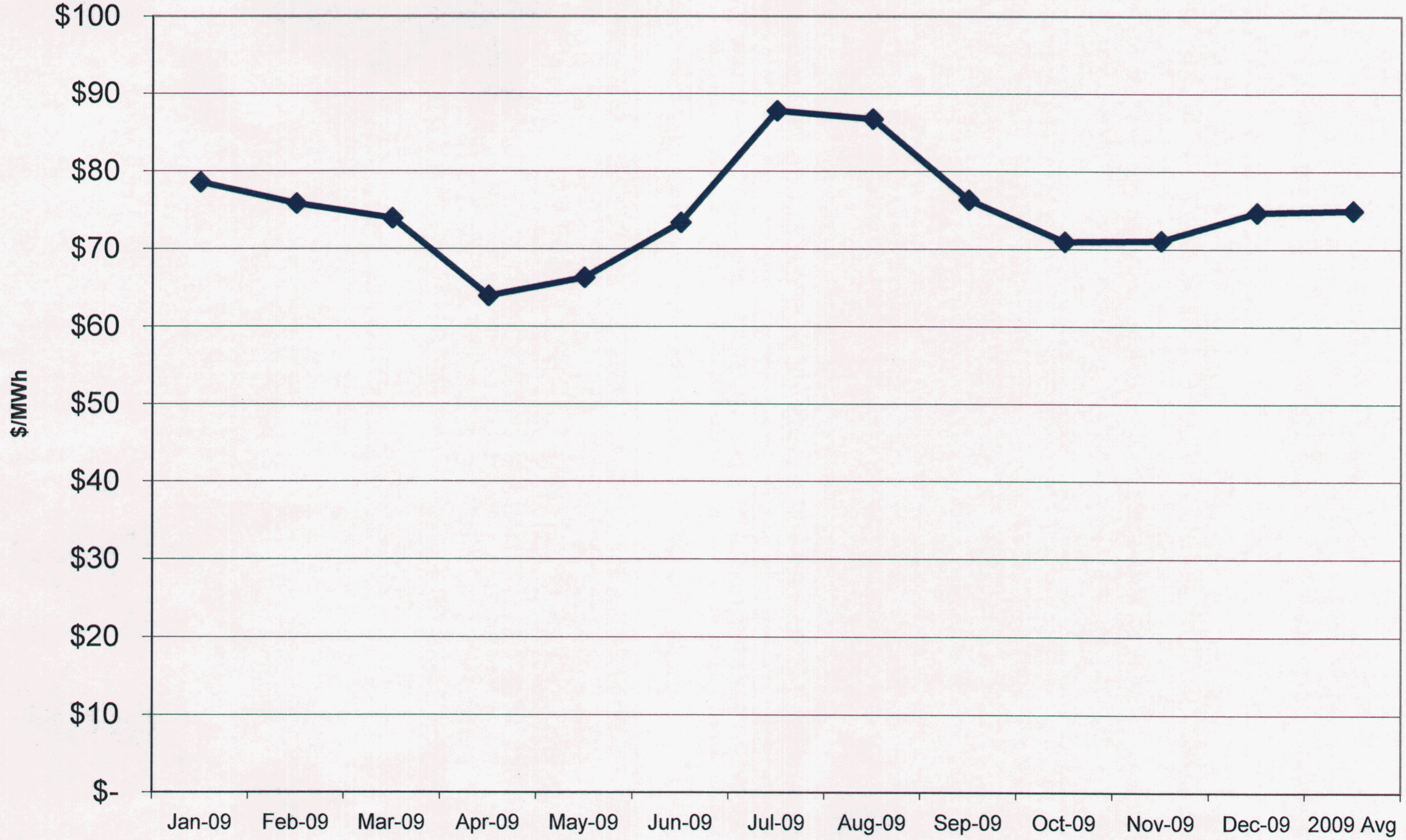
TEP Historical MGC



Estimated 2009 MGC

Jan-09	$	78.55
Feb-09	$	75.81
Mar-09	$	73.93
Apr-09	$	63.92
May-09	$	66.29
Jun-09	$	73.37
Jul-09	$	87.75
Aug-09	$	86.73
Sep-09	$	76.30
Oct-09	$	70.94
Nov-09	$	71.09
Dec-09	$	74.70
2009 Avg	**$**	**74.95**

Estimated 2009 MGC



BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON- CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103.	)	DOCKET NO. E-01933A-05-0650
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	)	DOCKET NO. E-01933A-07-____

TUCSON ELECTRIC POWER COMPANY

APPLICATION

TESTIMONY AND EXHIBITS

VOLUME 2 OF 4

July 2, 2007

Direct Testimony of Kentton C. Grant

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON - CHAIRMAN
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Direct Testimony of

Kentton C. Grant

on Behalf of

Tucson Electric Power Company

July 2, 2007

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Kentton C. Grant. My business address is One South Church Avenue, Tucson, Arizona, 85701.

Q. What is your employment position?

A. I am Vice President of Finance and Rates for UniSource Energy Corporation ("UniSource Energy") and Tucson Electric Power Company ("TEP" or the "Company").

Q. On whose behalf are you filing your direct testimony in this proceeding?

A. My testimony is filed on behalf of TEP.

Q. Please summarize your professional experience and education.

A. I received a Master of Business Administration degree with a concentration in finance from the University of Texas at Austin, as well as a Bachelor of Science degree in Civil Engineering from Purdue University. I am a member of the Chartered Financial Analyst ("CFA") Institute, and in 1995, I was awarded the professional designation of CFA. I am also a member of the Society of Utility and Regulatory Financial Analysts, and in 1992, I was awarded the designation of Certified Rate of Return Analyst ("CRRA").

From 1984 to 1995, I was employed by the Public Utility Commission of Texas. During this period I served in various staff positions, including Director of the Financial Review Division. In that role I directed a staff responsible for performing financial analyses, accounting reviews and management audits of electric and telecommunications utilities.

As a staff member I provided expert testimony on a variety of financial topics including the cost of capital, financial integrity, rate moderation and the valuation of utility properties.

I joined TEP in 1995 as a senior financial analyst. In 1997, I was promoted to Director of Capital Resources and elected Assistant Treasurer. I was subsequently promoted to Manager of Financial Planning and in 2003, became a General Manager in TEP's Shared Services Unit. In January 2007, I was elected Vice President of Finance and Rates for both TEP and UniSource Energy. In these roles I have gained extensive experience in financial forecasting, financial analysis, the structuring of new financings and other related activities.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to (i) quantify the Company's Termination Costs Regulatory Asset ("TCRA") and related TCRA Charge ("TCRAC") included in the Company's Cost-of-Service Methodology, (ii) discuss relevant factors affecting the determination of fair value rate base ("FVRB") for TEP, including the consideration of fair market value, and (iii) describe TEP's proposed treatment of true-up revenues related to the continuation of the Company's Fixed Competition Transition Charge ("Fixed CTC").

Q. Please summarize your testimony.

A. With respect to the TCRA, it is necessary to recognize a regulatory asset of $788 million in the Company's Cost-of-Service Methodology, in recognition of the economic burden imposed on TEP as a result of the extended rate freeze and the subsequent return to full cost-of-service regulation. In order to soften the initial rate impact on customers, the Company proposes to use a mortgage style amortization of this regulatory asset over ten years instead of a more traditional straight-line amortization method.

With respect to FVRB, the Company has proposed a calculation that is consistent with prior Commission practice. However, based on the results of a fair market value analysis conducted by TEP witness Mr. Judah Rose, as well as the analysis of transmission and distribution properties contained in my own testimony, it is apparent that the actual fair market value of TEP's electric utility properties greatly exceeds the values used in TEP's Cost-of-Service and Hybrid Methodologies.

With respect to the treatment of forecasted true-up revenues, TEP proposes to refund, with interest, the entire balance of true-up revenues collected through December 31, 2008 (or the date new rates are implemented, if earlier), under the Company's Market Methodology. For reasons explained later in my testimony, TEP is proposing that a credit be made under the Company's Cost-of-Service Methodology and an offset be made under the Hybrid Methodology.

II. TERMINATION COSTS REGULATORY ASSET.

Q. Mr. Grant, why is TEP requesting a TCRA as part of its Cost-of-Service Methodology?

A. In testimony filed in the 1999 Settlement Agreement Amendment Case, TEP witness Mr. James Pignatelli discussed at length the economic burden incurred by the Company under the extended rate freeze established in the 1999 Settlement Agreement. Had the Company not been subject to this rate freeze, which was agreed upon as part of a transition to market-based rates for generation services, the Company would have been entitled to significantly higher retail rates using traditional cost-of-service ratemaking principles. This economic burden, which may be quantified in terms of foregone revenues, represents a real cost to the Company and its shareholders. As such, it is only appropriate that it be recognized as a cost-of-service if TEP is transitioned back to full cost-of-service ratemaking.

Q. How does this estimate of economic harm compare with the forward-looking cost to the Company and its shareholders?

A. This cost, which is measured in terms of foregone revenues, is probably much smaller than the forward-looking cost to TEP.

Q. Please explain.

A. Certainly. One approach to estimating the forward-looking cost to TEP is to examine the future rate differential between the Market Methodology and the Cost-of-Service Methodology. Excluding the TCRAC, the Company's Cost-of-Service Methodology supports an average retail rate of approximately 9.1 cents per kWh in 2009. This rate is approximately 1.2 cents/kWh less than the average 10.3 cent rate forecasted to occur under market-based rates. With nearly 10,000 GWh of retail sales forecasted in 2009, the revenue loss to TEP associated with a return to cost-of-service ratemaking is approximately $120 million in the first year alone. However, if under the Cost-of-Service Methodology the Company's rates are ultimately set below 9.1 cents/kWh, or if the Company is not allowed to fully recover its fuel and purchased power costs through a rate adjustment mechanism, then the forward-looking economic cost to TEP would be even higher. Of course, estimating the future rate differential between the Market Methodology and the Cost-of-Service Methodology is complicated by changes that may occur to the wholesale price of power, the type of fuel and purchased power rate recovery mechanism that would be adopted under a cost-of-service approach, and the timing of future rate relief under cost-of-service regulation. However, barring a deep and prolonged slump in wholesale power prices, it is apparent that a return to cost-of-service regulation would cause TEP to incur substantial economic costs that are comparable to or higher than the $788 million TCRA on a present value basis.

Another approach to estimating the forward-looking cost to TEP is to compare the fair market value ("FMV") of the Company's owned generating assets to the original cost and replacement cost values used in cost-of-service ratemaking. Based on the valuation study described in the Direct Testimony of TEP witness Mr. Judah Rose, the estimated FMV of TEP's owned generating assets in the wholesale market is approximately $2.7 billion (excluding TEP's interest in the Luna Energy Facility). By contrast, as reflected in the Company's Cost-of-Service Methodology, the depreciated book value of TEP's generating assets is approximately $550 million on an original cost basis, while the replacement cost value of these assets is approximately $1.15 billion. Under the approach traditionally used by the Commission, the fair value of these assets is approximately $850 million, reflecting a 50% weighting of original cost and 50% weighting of replacement cost value. Therefore, regardless of whether original cost or fair value rate base is used for cost-of-service ratemaking, the FMV of these assets as determined by Mr. Rose is approximately $1.8 billion to $2.1 billion higher. Because a return to cost-of-service ratemaking would preclude the Company from realizing higher wholesale market prices for the bulk of its generating capacity, this difference in value is indicative of the economic cost to TEP associated with a return to cost-of-service ratemaking.

Q. Please explain how you quantified the beginning balance of the TCRA.

A. The TCRA consists of foregone revenues under the rate freeze, along with carrying costs on the accumulated balance. The foregone revenues are based on the annual retail revenue deficiency identified by TEP in the 2004 rate review docket. Testimony filed by the Company in that docket showed a retail revenue deficiency of $111 million for the test year ended December 31, 2003. This amount was adjusted downward to $109 million to reflect actual sales in 2003, and was then carried forward and adjusted for actual sales growth in each subsequent year through March 2007. For the period April 2007 through April 2008, forecasted sales levels were used to estimate total foregone revenues under the rate freeze. Assuming no refund of true-up revenues is ordered by the Commission, the foregone revenue calculation was terminated as of May 1, 2008, resulting in a total of $626 million of foregone revenues. This calculation is summarized in Exhibit KCG-1.

The Company's 8.78% weighted average cost of capital identified in the 2004 rate review was used to calculate carrying costs on the cumulative balance of foregone revenues. This cost of capital was applied to the average cumulative balance each year using the half-year convention. Using this approach, the total carrying costs through April 2008 were determined to be $162 million. As shown in Exhibit KCG-1, the sum of the foregone revenues and related carrying costs is $788 million.

Q. **What would the TCRA balance be if foregone revenues are calculated through December 31, 2008?**

A. Using the same approach described above, the total amount of foregone revenues with carrying costs would rise to $921 million, an increase of $133 million. By assuming no refund of true-up revenues, and using the lower TCRA balance in the Cost-of-Service Methodology, the Company is providing customers with a much larger benefit in present value terms relative to a one-time refund of true-up revenues.

Q. **How do you recommend recovering the TCRA through rates?**

A. I recommend the use of a separately identified rate called the TCRAC that is designed to recover the full balance of the TCRA over a ten-year period of time. In order to moderate the initial rate impact on customers, I further recommend using a mortgage style amortization instead of a traditional straight-line amortization method.

Q. Can you please explain how you calculated the TCRAC that is included in TEP's Cost-of-Service Methodology?

A. Yes. As shown in Exhibit KCG-2, the annual revenue requirement associated with recovery of the TCRA consists of amortization expense, a return on the unamortized balance and an allowance for income taxes on the return. Using a forecast of sales over the period 2009 through 2018, an iterative solution process was used to derive a levelized TCRAC that fully amortizes the $788 million TCRA over this ten-year period. The resulting TCRAC of 1.26 cents/kWh represents the average retail rate necessary to fully recover the TCRA over an estimated ten-year time period. To the extent that sales grow faster than anticipated, the TCRA would become fully amortized at an earlier date and the TCRAC would lapse sooner than forecasted. Likewise, if sales grow slower than anticipated, it would take longer for the TCRA to become fully amortized, and the TCRAC would remain in place longer than forecasted.

III. FAIR MARKET VALUE OF TEP'S RATE BASE.

Q. What definition of fair value has TEP incorporated in its various rate proposals?

A. For purposes of quantifying the requested level of rate relief, the Company adopted the approach traditionally used by the Commission. Specifically, TEP used the average of original cost rate base ("OCRB") and reconstructed cost new less depreciation ("RCND") rate base, as those terms are defined in the Commission's rules. The specific calculation of these values is described in the Direct Testimony of Ms. Karen Kissinger.

Q. Does fair value necessarily reflect the average of OCRB and RCND?

A. No. OCRB is an historical accounting concept that does not necessarily reflect the fair value of assets in today's dollars. Likewise, although RCND reflects the cost of replacing assets in today's dollars (net of any economic depreciation that has occurred), this value may not reflect the fair value of the assets from an economic perspective. In order to gain a better perspective of fair value, some consideration should also be given to the fair market value of assets included in rate base.

Q. How can fair market value ("FMV") be determined?

A. The FMV of an asset can be determined using a number of different techniques, some of which may be based on recent sales of comparable assets, the trading price of stocks or other securities, and the discounting of future expected cash flows associated with the asset in question.

Q. Has TEP attempted to quantify the FMV of its assets?

A. Yes. The Direct Testimony of TEP witness Judah Rose provides a quantification of the FMV of TEP's owned generating assets. Additionally, as described below, I also provide a quantification of FMV for TEP's transmission and distribution assets. A summary of the different valuation measures for TEP's plant in service may be found in Exhibit KCG-3.

Q. With regard to TEP's plant in service, how does the FMV of these assets compare with the measure of fair value traditionally employed by the Commission?

A. The FMV of TEP's plant in service is substantially higher. This is due primarily to the difference between the FMV of TEP's generating assets as identified by Mr. Rose and the ORCB and RCND values identified by Ms. Kissinger. As summarized on page 1 of Exhibit KCG-3, the FMV of TEP's owned generating assets included in the Cost-of-Service Methodology rate base is $2.7 billion on a total company basis, compared with a $550 million OCRB value and a $1.15 billion RCND value. By contrast, the difference between the FMV and the average of OCRB and RCND for the Company's transmission, distribution and general plant assets is fairly small. Since the RCND value for these assets is approximately two-times (2X) the OCRB value, and since the FMV of these assets is estimated at one-and-one-half times (1.5X) the OCRB value, the Commission's traditional approach to measuring fair value results in a valuation estimate that is very similar to FMV for these assets. For this reason, consideration of FMV has little impact on the determination of fair value in the Market Methodology where most generating assets are excluded from rate base. The same cannot be said for either the Cost-of-Service Methodology or the Company's Hybrid Methodology. Indeed, as may be seen on page 2 of Exhibit KCG-3, under the Cost-of-Service Methodology the fair value of TEP's net plant investment is $568 million higher than the traditional fair value figure if FMV is given equal weighting with OCRB and RCND. Likewise, an equal weighting of FMV under the Hybrid Methodology would result in a $348 million increase to fair value relative to the traditional valuation approach.

Q. Please describe the approach you used to estimate the FMV of TEP's transmission and distribution properties.

A. I applied a market-based approach that uses stock price information for a group of publicly traded electric utilities who are primarily engaged in the transmission and distribution of electricity for retail service.

Q. How did you select the companies used in your valuation analysis?

A. Using information contained in SEC and FERC filings, as compiled by SNL DataSource, we selected publicly traded companies that met the following screening criteria:

- More than 65% of total gross plant comprised of electric utility plant,
- More than 70% of net electric plant comprised of transmission and distribution plant,

- More than 80% of operating revenues derived from retail electric or gas operations, and
- Net utility plant represents more than 50% of total corporate assets.

Exhibit KCG-4 provides summary information on each of the six companies that were selected using this screening criteria.

Q. What results did you obtain from an analysis of these companies?

A. The ratio of market value to book value ("M/B ratio") applicable to the plant assets of these companies ranged from a low of 1.16X to a high of 1.86X, with a median value of 1.48X. Based on these results, I believe that a M/B ratio of 1.5X is appropriate for estimating the FMV of TEP's transmission, distribution and general plant assets.

Q. Please explain how you calculated the M/B ratios that are applicable to the plant assets of the companies you selected.

A. Exhibit KCG-5 provides the calculation of the M/B ratio for each company. As described previously, the market value of each company's common equity is used as a starting point in the analysis. The book value of all liabilities and mezzanine capital (such as preferred stock) is then added to the market value of common equity to arrive at an estimate of enterprise value (or market value of assets) for each company, as reflected in column D of Exhibit KCG-5. The market value of plant assets (column F in Exhibit KCG-5) is then derived by subtracting the book value of non-plant assets from total enterprise value. Finally, the M/B ratio for plant assets is obtained by dividing the market value of plant assets by the net book value of plant assets, as reflected in column H of Exhibit KCG-5.

Q. What is your estimate of the FMV for TEP's transmission and distribution properties?

A. As may be seen on page 1 of Exhibit KCG-3, the FMV of transmission, distribution and general plant for TEP was obtained by multiplying the OCRB values by 1.50, the median M/B ratio described above. On a total company basis, this results in a FMV of $779 million for distribution plant, $307 million for transmission plant, and $175 million for general and intangible plant.

Q. What is your estimate of the FMV for all of TEP's property dedicated to retail service?

A. Taking into account the valuation of generating assets prepared by Mr. Rose, as well as my own estimate of value for TEP's transmission, distribution and general plant, the FMV on a total company basis is approximately $4.0 billion under the Cost-of-Service Methodology and approximately $3.1 billion under the Hybrid Methodology. On a retail jurisdictional basis, the FMV is approximately $3.3 billion under the Cost-of-Service Methodology, $2.5 billion under the Hybrid Methodology and approximately $937 million under the Market Methodology, as shown at the bottom of page 1 of Exhibit KCG-3.

IV. <u>PROPOSED TREATMENT OF TRUE-UP REVENUES.</u>

Q. Mr. Grant, please provide your understanding of what the term "true-up revenues" means and the projected amount of "true-up revenues."

A. Certainly. As described in Decision No. 69568, true-up revenues represent Fixed CTC revenues collected by TEP after the $450 million Transition Recovery Asset ("TRA") is fully amortized. Based on the amortization expense recorded to date, as well as forecasted sales in 2007 and 2008, full recovery of the TRA is expected to occur in May 2008. As a result, a total of approximately $66 million of additional Fixed CTC revenues (or "true-up revenues") are anticipated between the full recovery date and December 31, 2008. Decision No. 69568 provides that true-up revenues "...shall accrue interest and shall be subject to refund, credit or other mechanism to protect customers as determined by the Commission in the forthcoming rate case docket."

Q. How does TEP propose to treat these true-up revenues under the Company's Market Methodology?

A. The Company proposes a full refund of all true-up revenues collected through December 31, 2008, or through an earlier date if market-based rates are established and effective prior to December 31, 2008. The balance of true-up revenues will accrue interest monthly using an annual interest rate equal to the Company's cost of short-term debt, the cost of which is currently equal to the London InterBank Offering Rate ("LIBOR") plus 0.55%. Using this interest rate, the true up revenue balance is projected to accrue approximately $1.1 million of interest through December 31, 2008, resulting in a total refund of approximately $67 million. In order to moderate the initial rate impact on customers associated with the move to market-based rates, the Company proposes to refund this amount over the first 12 months that new rates are in effect

Q. How does TEP propose to treat true-up revenues under the Company's Cost-of-Service Methodology?

A. Under the Cost-of-Service Methodology, TEP is proposing to credit the TCRA balance by an amount that exceeds the level of true-up revenues and related interest accruals. Specifically, TEP is proposing to reduce the balance of the TCRA to be recovered through rates by $133 million. This reduction to the TCRA, from $921 million to $788 million, greatly exceeds the amount of true-up revenues that would otherwise be refunded to customers. Over the long-run, customers would receive greater benefits under this approach relative to a one-time refund of true-up revenues.

Q. How does TEP proposed to treat true-up revenues under the Company's Hybrid Methodology?

A. Due to the unique features of the Hybrid Methodology, some of which provide benefits to the customer and some of which provide benefits to TEP, the Company believes that an approach other than a refund or credit of the true-up revenues is appropriate. The Company believes that the Hybrid Methodology represents a compromise between the Market and Cost-of-Service Methodologies, and as such, neither a refund (as is appropriate under the Market Methodology) nor a credit (proper under the Cost-of-Service Methodology) would accomplish the goal of properly protecting the interests of both the customer and the Company. In recognition of the fact that the Company is (i) foregoing recovery of the TCRA, (ii) only partially restoring the exclusivity of its Certificate of Convenience and Necessity ("CC&N") and (iii) seeking a lower rate increase request than it otherwise would if it were compensated for the TCRA and limited CC&N amendment, TEP believes that it is appropriate that it retain the true-up revenues as an offset. To quantify, in part, the customer benefits of the Hybrid Methodology, I would note that the average retail rate under the Hybrid Methodology is projected to be approximately 9.7 cents/kWh, which is 0.7 cents/kWh less than the Cost-of-Service Methodology (with the TCRAC) and 0.6 cents/kWh less than the Market Methodology. With retail sales of approximately 10,000 GWh forecast in 2009, this rate differential produces approximately $60 million to $70 million of customer benefits in the first year alone.

Q. Does this conclude your testimony?

A. Yes, it does.

EXHIBIT

KCG-1

Tucson Electric Power Company
Calculation of Foregone Revenues Under Rate Freeze

- $ in Thousands -	2003	2004	2005	2006	2007	Jan-Apr 2008
Total Retail Operating Revenues Under Rate Freeze (1)						
Revenue (Full Year)	$ 691,503	$ 719,341	$ 746,876	$ 781,728	$ 803,338	$ 211,643
% Increase		*4.0%*	*3.8%*	*4.7%*	*2.8%*	
Retail Revenues Supported by 2004 Rate Review (2)						
Revenue (Full Year)	$ 800,985	$ 833,231	$ 865,126	$ 905,495	$ 930,527	$ 245,152
% Increase		*4.0%*	*3.8%*	*4.7%*	*2.8%*	
Full-Year Revenue Deficiency (3)	$ 109,482	$ 113,890	$ 118,249	$ 123,767	$ 127,189	$ 33,508
Cumulative Balance of Foregone Revenues						
Target Revenues	$ 800,985	$ 833,231	$ 865,126	$ 905,495	$ 930,527	$ 245,152
Rate Freeze Revenues	$ 691,503	$ 719,341	$ 746,876	$ 781,728	$ 803,338	$ 211,643
Revenue Deficiency	$ 109,482	$ 113,890	$ 118,249	$ 123,767	$ 127,189	$ 33,508
Cumulative Balance of Foregone Revenues	$ 109,482	$ 223,372	$ 341,622	$ 465,389	$ 592,578	**$ 626,086**
Cumulative Balance with Carrying Costs						
Beginning Balance	$ -	$ 114,289	$ 243,213	$ 388,008	$ 551,275	$ 732,450
Current Year Revenue Deficiency	$ 109,482	$ 113,890	$ 118,249	$ 123,767	$ 127,189	$ 33,508
Carrying Costs (4)	$ 4,806	$ 15,034	$ 26,545	$ 39,500	$ 53,986	$ 21,927
Ending Balance	$ 114,289	$ 243,213	$ 388,008	$ 551,275	$ 732,450	**$ 787,885**

Notes
(1) 2003 - 2006 Actuals. 2007 - 2008 Projected.
(2) Escalated at same annual rate as actual / forecasted retail revenues under rate freeze.
(3) The filed revenue deficiency of $111.7M included customer and weather adjustments, and was equivalent to a $109.5M increase over 2003 actual revenues. (See table below.)
(4) Calculated using half-year convention and specified cost of capital.

Inputs for Cumulative Balance Calculation
Start Date of Revenue Deficiency
1/1/2003
End Date of Revenue Deficiency
4/30/2008
Cost of Capital
8.78%

Calculation of Test Year Deficiency	"Filed" Deficiency	"Actual" Deficiency
Retail Operating Revenues (Schedule C-1, 10K)	$ 691,503	$ 691,503
Customer Annualization (Schedule C-2)	2,999	
Weather Normalization (Schedule C-2)	(5,187)	
Normalized Operating Revenues (Schedule H-1)	$ 689,315	$ 691,503
Proposed Revenue (Schedule H-1)	$ 800,985	$ 800,985
Difference	**$ 111,670**	$ 109,482

EXHIBIT

KCG-2

Exhibit KCG-2

Tucson Electric Power Company
Calculation of Termination Cost Regulatory Asset Charge (TCRAC)

Year	Beginning Balance TCRA	Amortization	Return & Income Taxes	Revenue Requirement	Projected Retail MWh	TCRAC ($/MWh)
2009	$787,885,000	$35,590,433	$89,163,817	$124,754,251	9,883,970	$12.622
2010	$752,294,567	$42,546,192	$84,705,553	$127,251,746	10,081,840	$12.622
2011	$709,748,374	$50,238,945	$79,406,954	$129,645,898	10,271,523	$12.622
2012	$659,509,430	$58,909,060	$73,168,131	$132,077,192	10,464,148	$12.622
2013	$600,600,369	$68,442,212	$65,891,464	$134,333,676	10,642,924	$12.622
2014	$532,158,157	$79,249,353	$57,446,988	$136,696,341	10,830,112	$12.622
2015	$452,908,804	$91,331,680	$47,690,144	$139,021,823	11,014,354	$12.622
2016	$361,577,124	$104,959,628	$36,455,400	$141,415,028	11,203,962	$12.622
2017	$256,617,496	$119,933,083	$23,587,690	$143,520,774	11,370,795	$12.622
2018	$136,684,413	$136,684,413	$8,899,111	$145,583,524	11,534,221	$12.622

Cost of Capital Assumptions:

	% Capital	Cost	Wtd. Cost	Tax Factor	Pre-Tax Cost
L-T Debt	55.0%	6.39%	3.51%	1.0000	3.51%
Equity	45.0%	10.75%	4.84%	1.6564	8.01%
			8.35%		11.53%

EXHIBIT

KCG-3

Tucson Electric Power Company
Valuation Measures for Plant in Service

($ Thousands)

A. Original Cost Net of Accumulated Depreciation
(OCRB Calculation)

		Adjusted Total Company		Retail Jurisdictional		
	Total Company Per Books	Cost of Service Methodology	Hybrid Methodology	Cost of Service Methodology	Hybrid Methodology	Market Methodology
Distribution Plant	$ 519,618	$ 519,618	$ 519,618	$ 519,618	$ 519,618	$ 519,618
Transmission Plant	204,854	204,707	203,336	0	0	0
Generation Plant	662,546	550,348	475,043	487,350	416,161	57,229
General & Intangible Plant	116,871	111,904	110,349	81,845	80,376	43,976
Total Plant in Service	$ 1,503,890	$ 1,386,578	$ 1,308,346	$ 1,088,813	$ 1,016,155	$ 620,823

B. Reconstructed Cost New Less Depreciation
(RCND Calculation)

		Adjusted Total Company		Retail Jurisdictional		
	Total Company	Cost of Service Methodology	Hybrid Methodology	Cost of Service Methodology	Hybrid Methodology	Market Methodology
Distribution Plant	$ 1,011,011	$ 1,011,011	$ 1,011,011	$ 1,011,011	$ 1,011,011	$ 1,011,011
Transmission Plant	459,581	459,434	461,172	0	0	0
Generation Plant	1,274,403	1,147,359	966,079	1,012,583	840,169	119,311
General & Intangible Plant	139,559	134,098	134,459	97,960	97,803	52,634
Total Plant in Service	$ 2,884,553	$ 2,751,902	$ 2,572,721	$ 2,121,554	$ 1,948,983	$ 1,182,956

C. Fair Market Value
(FMV Calculation)

		Adjusted Total Company		Retail Jurisdictional (3)		
	Total Company	Cost of Service Methodology	Hybrid Methodology	Cost of Service Methodology	Hybrid Methodology	Market Methodology
Distribution Plant (1)	$ 779,428	$ 779,428	$ 779,428	$ 779,428	$ 779,428	$ 779,428
Transmission Plant (1)	307,281	307,061	305,003	0	0	0
Generation Plant (2)	2,830,000	2,716,000	1,856,100	2,405,101	1,626,035	82,000
General & Intangible Plant (1)	175,307	167,856	165,524	122,768	120,564	65,964
Total Plant in Service	$ 4,092,015	$ 3,970,344	$ 3,106,055	$ 3,307,296	$ 2,526,026	$ 927,392

Notes

(1) Total Company FMV = 1.50 x OCRB Value
(2) Total Company FMV based on testimony of TEP witness Judah Rose.
(3) Retail Jurisdictional Amounts for FMV are based on the same jurisdictional allocations used for OCRB (Cost-of-Service and Hybrid Methodologies). For Market Methodology, FMV of generation reflects FMV of must-run gas turbines and gas steam units.

Tucson Electric Power Company
Valuation Measures for Plant in Service

		Retail Jurisdictional Values		
	($ Thousands)	Cost of Service Methodology	Hybrid Methodology	Market Methodology
A.	Original Cost	$ 1,088,813	$ 1,016,155	$ 620,823
B.	RCND	$ 2,121,554	$ 1,948,983	$ 1,182,956
C.	Fair Market Value	$ 3,307,296	$ 2,526,026	$ 927,392
D.	FVRB - Traditional Weighting [= (A + B) / 2]	$ 1,605,183	$ 1,482,569	$ 901,889
E.	FVRB - With FMV Weighting [= (A + B + C) / 3]	$ 2,172,554	$ 1,830,388	$ 910,390

EXHIBIT

KCG-4

Tucson Electric Power Company
Electric Utilities Selected for Fair Market Value Analysis of T&D Assets

Company	Ticker	Gross Electric Plant as % of Total Gross Plant (1)	Net T&D Plant (Electric) as % of Net Total Plant (Electric) (2)	Net Plant Assets as % of Total Assets	Retail Revenues as % of Total Operating Revenues (3)
Allegheny Energy, Inc.	AYE	100.0%	72.8%	74.8%	81.1%
Duquesne Light Holdings, Inc.	DQE	97.9%	86.3%	58.9%	89.2%
NorthWestern Corporation	NWEC	66.9%	89.2%	62.3%	87.0%
NSTAR	NST	84.3%	95.3%	52.6%	95.9%
PG&E Corporation	PCG	72.5%	92.4%	62.6%	112.2%
Puget Energy, Inc.	PSD	69.0%	71.0%	73.3%	93.6%
Screening Criteria		> 65%	> 70%	> 50%	> 80%

Notes

All financial data as of 12/31/06 unless noted otherwise.

All data obtained from SNL DataSource unless noted otherwise.

(1) Data for this column for NorthWestern Corporation and Puget Energy obtained from the companies' respective 12/31/06 10-K reports.

(2) Data for this column for Puget Energy is from 2005.

(3) Data for this column for NorthWestern Corporation obtained from the company's 12/31/06 10-K report.

EXHIBIT

KCG-5

Tucson Electric Power Company
Derivation of Market-to-Book Ratios for T&D Assets

($ Millions)	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Company	Market Value of Common Equity	Book Value of Liabilities	Book Value of Mezzanine Capital	Market Value of Assets [= (A)+(B)+(C)]	Book Value of Non-Plant Assets	Market Value of Plant Assets [= (D) - (E)]	Book Value of Plant Assets	Market to Book Ratio for Plant Assets [= (F) ÷ (G)]
Allegheny Energy, Inc.	$ 7,592	$ 6,437	$ 35	$ 14,064	$ 2,156	$ 11,908	$ 6,397	1.86
Duquesne Light Holdings, Inc.	$ 1,740	$ 2,186	$ 177	$ 4,102	$ 1,294	$ 2,808	$ 1,854	1.51
NorthWestern Corporation	$ 1,261	$ 1,653	$ -	$ 2,914	$ 904	$ 2,010	$ 1,492	1.35
NSTAR	$ 3,670	$ 6,144	$ 43	$ 9,857	$ 3,683	$ 6,173	$ 4,086	1.51
PG&E Corporation	$ 17,710	$ 26,740	$ 252	$ 44,702	$ 13,018	$ 31,684	$ 21,785	1.45
Puget Energy, Inc.	$ 2,956	$ 4,950	$ -	$ 7,906	$ 1,885	$ 6,021	$ 5,181	1.16
							Median Value:	1.48

Notes
Market Value of Common Equity = Shares outstanding × closing stock price as of 12/31/06.
All financial data as of 12/31/06 unless noted otherwise.
All data obtained from SNL DataSource.

Direct Testimony of Kevin P. Larson

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON - CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103.	DOCKET NO. E-01933A-05-0650
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-01933A-07-____

Direct Testimony of

Kevin P. Larson

on Behalf of

Tucson Electric Power Company

July 2, 2007

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I. INTRODUCTION.

Q. Please state your name and address.

A. Kevin P. Larson. My business address is One South Church Avenue, Tucson, Arizona, 85701.

Q. What is your employment position?

A. I am employed by UniSource Energy Corporation ("UniSource Energy") as Senior Vice President, Chief Financial Officer and Treasurer. For Tucson Electric Power Company ("TEP" or the "Company"), I hold the same titles.

Q. Please summarize your professional experience and education.

A. I joined TEP in 1985 as a financial analyst and I have worked in the financial area since that time. In 1991, I became Assistant Treasurer. In 1994, I was elected Treasurer and, in 1997, I became a Vice President at TEP. I became Vice President, Chief Financial Officer and Treasurer of UniSource Energy and TEP in October 2000. I became Senior Vice President, Chief Financial Officer and Treasurer of UniSource Energy and TEP in September 2005. I became Vice President and Treasurer of UNS Electric, Inc. in April 2003.

My educational background includes a Bachelor of Science degree in Economics from the University of Minnesota, Minneapolis, and graduate work in finance at the University of Arizona. I am also a Chartered Financial Analyst ("CFA").

Q. On whose behalf are you filing your direct testimony in this proceeding?

A. My testimony is filed on behalf of TEP.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to describe (i) TEP's financial condition and (ii) TEP's financial outlook assuming its rate request is granted. My testimony also recommends (i) the proposed cost of debt capital for TEP and (ii) the proposed weighted average cost of capital for TEP. I also provide testimony on the Company's methodology on applying rate of return ("ROR") to fair value rate base ("FVRB").

Q. Please summarize your testimony.

A. Since 1994, the test year used in TEP's last general rate case, the Company has deployed cash flows to reduce total debt obligations by $1 billion. TEP believes that this is a significant achievement. TEP's balance sheet is still, however, leveraged higher than most utilities. At December 31, 2006, the Company's debt to total capitalization ratio (including capital lease obligations) was 71% compared with an average of 54% for all investor-owned electric utilities. TEP is entering a period when its financial condition will be very important, as it will rely on the capital markets to help fund, in part, its projected capital investments.

The Company's capital budget is projected to grow at an average rate of 8% per year, reaching $219 million by 2011. In addition, the Sundt Unit 4 lease expires in 2011. The estimated purchase price of Sundt Unit 4 in 2011 ranges from $50 to $80 million, an amount not included in the $219 million figured cited above. TEP's growing retail customer base and the need for environmental upgrades at some of its generating facilities are the primary factors putting upward pressure on TEP's capital needs.

The Company is also focused on maintaining and improving its credit ratings. Although TEP's credit ratings have improved since 1994, the Company's unsecured debt is rated speculative-grade by two rating agencies. One of TEP's objectives is to, over time, take steps that would raise those ratings to investment grade. TEP believes that its proposed rate request will (i) enable the Company to continue to improve its financial condition, (ii) be viewed positively by the rating agencies and (iii) position the Company so that it can favorably access the capital markets.

I recommend an overall rate of return (ROR or weighted average cost of capital) of 8.35%. This ROR is based on a 10.75% cost of common equity capital, a 6.39% cost of long-term debt and a pro forma capital structure consisting of 45.00% common equity and 55.00% long-term debt.

Following the historical Commission approach for each of its proposals, the Company applied its proposed ROR to original cost rate base ("OCRB"), which results in operating income of $82.1 million. Operating income was then divided by the Commission's definition of FVRB, which is the average of OCRB and RCND.

II. FINANCIAL CONDITION OF TEP.

Q. Has TEP's financial condition improved since it last filed a general rate case?

A. Yes. Since the end of 1994, TEP has reduced debt and capital lease obligations by $1 billion and, improved its common equity by $595 million. The Company has taken steady steps to improve its balance sheet, such as (i) using excess cash flow to make significant debt retirements and to purchase debt securities underlying its capital leases, (ii) amortizing capital lease obligations through scheduled payments, (iii) retaining earnings, (iv) managing and controlling its costs, and (v) receiving capital contributions from its parent company, UniSource Energy.

The following table illustrates the improvements made to TEP's consolidated balance sheet since the 1994 test year used in the Company's last general rate case.

($ Millions)	12/31/1994	12/31/2006	Improvement
Long-Term Debt	$1,399	$821	($578)
Net Capital Lease Obligations	936	514	(422)
Net Debt Outstanding	$2,335	$1,335	($1,000)
Common Equity	(42)	553	595
Total Capital	$2,293	$1,888	
Net Debt as % of Total Capital	100%	71%	

Q. **Please describe other steps the Company has taken to improve its financial condition.**

A. In 2001, TEP purchased a 13% equity ownership interest in the Springerville Coal Handling Facilities Leases for $13 million. And in 2006, TEP purchased a 14% equity ownership interest in the Springerville Unit No. 1 Lease for $48 million. These transactions reduced the ongoing capital lease payments made by TEP, and also reduced the total capital lease obligation on the Company's balance sheet, thus helping to reduce leverage. In addition, TEP has reduced its future capital requirements, as it will not have to purchase the equity ownership it already holds in these assets upon the expiration of the leases.

TEP has also taken steps to improve the Company's financial flexibility by refinancing its credit facility. In 2006, the Company amended and restated its credit agreement which resulted in lower fees, a reduced borrowing rate and an increase in the amount available under the revolving credit facility. The higher short-term borrowing capacity gives TEP much needed liquidity during periods when cash flows are inadequate to cover working capital requirements. This is especially critical during unplanned generating plant outages, as TEP currently absorbs all outage-related costs.

Q. What factors have contributed to TEP's gradual improvement in financial condition?

A. Several factors contributed to TEP's gradual improvement in financial condition including (i) customer growth, (ii) strong operating performance from its coal-fired generating facilities, (iii) a capital investment levels that were considerably lower than operating cash flows, which allowed the Company to use excess cash to reduce obligations, (iv) favorable capital market conditions that allowed TEP to reduce interest costs through refinancings, and (v) the repayment of an inter-company loan and a capital contribution from UniSource in 2005.

Q. Please summarize TEP's current financial condition and outlook.

A. TEP's current financial condition is stable when measured in terms of cash flow and liquidity. However, TEP's balance sheet has much higher leverage compared with other companies in the electric utility industry. Also, TEP expects to be more dependent on the capital markets given the Company's current projections for utility investments; for the period 2007-2011, TEP expects to invest nearly $1.1 billion on distribution, transmission and generating assets. Therefore, it is very important that TEP continues to improve cash flow metrics and strive for higher credit ratings, in order to obtain financing from the capital markets on favorable terms.

In 2011, the lease on Sundt Unit 4 expires, and in 2015, the leases on Springerville Unit No. 1 and the Springerville Fuel Handling Facilities expire. The Company intends to acquire these assets and will likely need to access the capital markets to do so. Purchasing these plants is important because Sundt Unit 4 and Springerville Unit No. 1 represent 536 MW of low-cost, coal-fired, base load generating resources. The Company's transmission system is linked to these facilities and TEP has an experienced work-force in place that operates these plants safely and reliably. If TEP's financial condition is such that it cannot acquire Sundt Unit 4 and Springerville Unit No. 1, the Company would then look to replace these resources with long-term purchased power agreements that would likely be subject to the volatility of gas prices, which would increase the commodity price risk to TEP and its customers through the proposed PPFAC. Further, if TEP becomes more reliant on purchased power to serve its retail demand, improving the Company's credit ratings will become imperative. Energy suppliers evaluate the credit ratings of their counterparties, seeking assurance that the counterparty will be able to fulfill its contractual obligation over a long period of time.

The uncertainty surrounding federal and state environmental regulations, and the related compliance costs, also requires the Company to be on solid financial footing. Nearly 70% of TEP's generating resources are coal-based, which means the Company is at risk if new regulations impose greater restrictions on SO_2, mercury and carbon emissions.

TEP's secured debt is rated investment grade by all three major credit rating agencies: Moody's Investors Service ("Moody's"), Standard & Poor's ("S&P"), and by Fitch Ratings ("Fitch"). However, TEP's unsecured debt carries a speculative-grade rating from S&P and Fitch. According to the rating agencies, factors that would support or possibly increase TEP's ratings include (i) sustainable cash flow metrics that compensate for a weak capital structure, (ii) continued balance sheet improvements, and (iii) regulatory outcomes that are supportive of credit quality, including, for example, a PPFAC.

Q. **How does TEP's debt leverage compare with the rest of the electric utility industry**?

A. Despite the improvement since 1994, TEP's debt leverage is much higher than the industry average. Since the rating agencies consider capital lease obligations to be debt equivalents, TEP's debt/capital ratio was 71% from a financial markets perspective at December 31, 2006. By contrast, the average debt/capital ratio for investor-owned electric utilities has ranged from 62% at the end of 2002 to 54% at December 31, 2006.

Q. Have the rating agencies responded to the improvement in TEP's balance sheet?

A. Yes. Since 1994, ratings on TEP's debt obligations have been upgraded by the three major credit rating agencies. For example, S&P upgraded TEP's unsecured credit rating by two notches between 1994 and 2006. Please refer to Exhibit KPL-1 for a summary of the different rating levels by each credit rating agency. The table below summarizes the improvement in TEP's credit ratings.

	Moody's	**S&P**	**Fitch**
Unsecured Credit Ratings			
12/31/94	B3	B-	Not Rated
Current	Baa3	B+	BB+
Notching level improvement	6	2	NA
Secured Credit Ratings			
12/31/94	B1	B+	BB-
Current	Baa2	BBB-	BBB-
Notching level improvement	5	4	3

	Moody's	S&P	Fitch
Unsecured Credit Ratings			
12/31/94	B3	B-	Not Rated
Current	Baa3	B+	BB+
Notching level improvement	6	2	NA
Secured Credit Ratings			
12/31/94	B1	B+	BB-
Current	Baa2	BBB-	BBB-
Notching level improvement	5	4	3

Q. Has TEP benefited from the higher credit ratings?

A. Yes. In general, TEP's higher ratings, as well as favorable conditions in the capital markets, have allowed the Company to acquire capital on better terms.

Q. How do TEP's credit ratings compare with other electric utilities?

A. Most electric utilities are rated much higher than TEP. As of March 31, 2007, the unsecured debt of approximately 83% of investor owned electric utilities was rated investment-grade by S&P. The minimum investment-grade ratings assigned by Moody's, S&P and Fitch are Baa3, BBB- and BBB-, respectively. Debt securities with ratings below this level are considered speculative-grade securities, and carry significantly higher interest rates relative to similar investment-grade debt securities.

As of March 31, 2007, the average unsecured rating assigned by S&P to the 70 investor owned utility companies tracked by the Edison Electric Institute ("EEI") was BBB (one notch above the minimum investment grade rating). According to the same EEI report, just

17% of the 70 investor owned utilities, including TEP, were rated below investment grade by S&P. Currently, TEP's unsecured debt is rated four notches below investment grade by S&P and one notch below investment grade by Fitch. Moody's assigns its minimum investment grade rating of Baa3 to TEP's unsecured debt.

Q. Why are TEP's credit ratings low compared to the industry average?

A. TEP experienced many financial problems in the late 1980s and early 1990s that eliminated a common equity balance that stood at $635 million at the end of 1989. As late as December 31, 1994, TEP reported negative common equity of $42 million and its capital structure was composed of 100% debt. While TEP's financial performance has steadily improved since 1994, the Company's current financial metrics do not warrant investment grade ratings by S&P or Fitch. The debt/capital range for S&P's investment grade criteria is 48%-58%; at December 31, 2006, TEP's debt/capital was 71%. See Exhibit KPL-2 for S&P's benchmark ratios for different rating levels.

Q. What factors concern the rating agencies?

A. From a financial perspective, the primary concern of all three rating agencies is TEP's highly leveraged balance sheet. This concern, however, is partially offset by TEP's cash flow metrics; the rating agencies base their ratings on TEP with the expectation that current cash flow metrics will remain sustainable or improve over time. Other factors noted in recent rating agency reports include the need for regulatory outcomes that support credit quality and concern about the occurrence of extended generation outages in the absence of the ability to recover, through rates, incremental fuel and purchased power costs.

Q. Can you describe the cash flow metrics mentioned above?

A. Yes. In addition to debt leverage, the rating agencies focus on funds from operations ("FFO") to total interest and FFO as a percentage of average total debt. FFO is generally defined by the rating agencies as cash flow from operations before changes in working capital. The table below provides a summary of TEP's key ratios as of December 31, 2006 compared with S&P's benchmark for its investment grade rating of BBB.

	TEP Ratio	S&P Investment Grade Range
Total Debt / Total Capitalization	71%	58% - 48%
FFO / Interest Coverage	3.0	3.0 – 4.2
FFO / Total Average Debt	18.5%	18.0% – 28%

Q. What are the most immediate actions that could improve TEP's credit rating?

A. If the Commission approves TEP's proposed rate request, the Company would expect the rating agencies to react positively. This could include (i) changing their rating outlook for TEP to "positive," (ii) placing TEP on "review for possible upgrade" or (iii) upgrading TEP's credit ratings.

Absent Commission approval of the Company's proposed rate request, we believe it is unlikely that that the rating agencies would take steps to upgrade TEP's ratings. Because the rates TEP charges to its retail customers are capped, and the Company bears all of the risk of power plant outages, and fluctuating natural gas and energy prices, there is a higher likelihood that the Company's ratings could be lowered. As previously noted, one of the primary concerns regarding TEP among the rating agencies is the occurrence of an extended generation outage in the absence of the ability to recover, through rates, incremental fuel and purchased power costs. One factor causing S&P to put TEP on "negative outlook" in September 2005 was a 26-day forced outage at Springerville Unit 2 in August 2005. That outage alone reduced TEP's gross margin (operating revenues less fuel and purchased power expense) by an estimated $14 million.

Q. What are TEP's longer-term objectives to improve its credit rating?

A. The Company's goal, over time, is to achieve an investment grade rating for its unsecured debt from all three rating agencies. TEP believes three things need to occur in order for the rating agencies to consider an upgrade of the Company's ratings: (i) clarification of TEP's long-term regulatory framework, (ii) sustainability of strong cash flows in the absence of the ability to recover, through rates, incremental fuel and purchased power costs and (iii) additional reductions in balance sheet leverage at TEP or UniSource Energy.

Q. Please provide a summary of TEP's historical capital investments and cash flow from operations.

A. The following table compares capital investments and operating cash flows for year-end 2006 versus the test year used in the Company's last general rate case.

($ Millions)	1994	2006	Increase (Decrease) 2004 vs 2006	Annual Growth Rate
Capital Investments	$63	$146	132%	7%
Operating Cash Flows	$144	$227	58%	4%
Adj. Operating Cash Flows[1]	$ 63	$ 42	(33%)	NM

Q. What caused TEP's capital investments to increase so dramatically?

A. Several factors contributed to the increase in capital investments from 1994 to 2006. TEP's retail customer base grew 33% between 1994 and 2006, which translates to nearly 100,000 new customers. This growth necessitated significant investments in transmission,

[1] Adjusted Operating Cash Flows is defined as Operating Cash Flows less Capital Investments and Net Capital Lease Obligation Payments.

distribution and generation assets. In addition, higher use per customer has required additional funding to maintain and reinforce existing assets used to serve existing customers. Other drivers of increasing capital investments include environmental upgrades to generating facilities, expansion of high-voltage transmission import capability into Tucson and information technology upgrades.

Q. What are your expectations for TEP's future capital investments?

A. The following table summarizes TEP's current projections of future capital investments, excluding the purchase of Sundt Unit 4 upon the expiration of the lease in 2011.

	Actual	**Estimated**					**Increase**	**Growth Rate**
($ Millions)	2006	2007	2008	2009	2010	2011	2006 vs. 2011	2006-2011
Capital Investments	$146	$198	$238	$193	$226	$219	50%	8%

Q. What is causing the significant increase in 2007-2011 capital investments compared with 2006?

A. TEP must begin making investment decisions now in order to meet the expanding energy needs of Tucson. The underlying drivers of projected capital investments include (i) customer growth - the Tucson Metropolitan area just surpassed the one million population mark and growth trends remain strong, (ii) higher material and construction costs, (iii) expansion of high-voltage transmission and distribution systems, (iv) environmental upgrades to generating facilities, and (v) continued investments in system reinforcement. Not only does TEP need to invest in utility infrastructure to serve new customers, the Company needs to keep pace with the increasing energy needs of its <u>existing</u> customer base by maintaining and reinforcing the <u>existing</u> utility system. The table below shows the increase in use per residential customer from 1994 to 2006.

	Average Use per Customer (kWh)		kWh	
Customer Class	1994	2006	Increase	% Increase
Residential	9,066	10,681	1,615	18%

The estimate for 2011 capital investments excludes the purchase of Sundt Unit 4 upon the expiration of the leases. The Direct Testimony of TEP witness Mr. Michael J. DeConcini provides additional discussion on the expansion and reinforcement of TEP's transmission and distribution system, as well as the need for environmental upgrades at TEP's generating facilities.

Q. Does TEP have any major capital commitments beyond 2011?

A. Yes. In 2015, TEP's leases on Springerville Unit No. 1 and the Springerville Fuel Handling Facilities expire. Springerville Unit No. 1 is a 380 MW coal-fired generating plant located in Springerville, Arizona. The renewal and purchase option for Springerville Unit No. 1 will be based on the market value of the plant in 2015 which is likely to be in excess of several hundred million dollars. The renewal and purchase option for the Springerville Fuel Handling Facilities is a fixed price. TEP's share of this cost is $73 million.

These are critical assets and it is vital that TEP continue to improve its financial condition so that it has the flexibility to purchase and finance, or renew the leases on these facilities. If TEP's future financial condition does not allow it to acquire Springerville Unit No. 1 upon the expiration of the lease, the Company would need to replace 380 MW of a coal-based resource with purchased power contracts, likely increasing the exposure of TEP and its customers to volatile natural gas prices. The Company's financial condition and credit ratings become equally important if TEP replaces coal-based generating resources with purchased power agreements, as energy suppliers will closely scrutinize the Company's financial condition before entering into long-term contracts.

Q. How are TEP's credit ratings and capital investments related?

A. If TEP's capital investments increase as expected, the Company will need to access the capital markets to help fund a portion of these investments. Improving TEP's credit ratings will allow the Company to achieve more favorable interest rates and negotiate better terms for debt financing. The Company will need to be very cautious in how it chooses to fund future capital investments, since issuing more debt would put pressure on its already highly leveraged balance sheet.

Q. Please summarize the importance of credit ratings.

A. TEP's credit ratings are viewed by lenders, as well as wholesale energy and gas providers, as a direct reflection of the Company's overall financial condition, including liquidity, credit worthiness and ability to service existing or new debt/contractual obligations. Although TEP's credit ratings have gradually improved since 1994, its ratings are still much lower than the industry average. A deterioration of TEP's credit ratings would limit its access to capital and significantly increase the cost of debt financing. Similarly, if conditions in the capital markets deteriorate, TEP's credit ratings become even more critical, as lenders will demand higher interest rates from companies with speculative-grade credit ratings.

On the other hand, if TEP's credit ratings rise and conditions in the capital markets remain the same, the cost of debt financing would decrease and the Company would be in a better position to negotiate for better terms and conditions. Higher credit ratings would also help TEP during periods when capital market conditions are unfavorable, as lenders tend to increase the cost of capital, and allocate less capital to companies with speculative-grade credit ratings.

Credit ratings also impact TEP's ability to procure energy and natural gas on a forward basis. Companies often use credit ratings to evaluate potential wholesale buyers and sellers of energy or natural gas. If TEP's credit ratings do not meet certain thresholds, companies often demand contractual protections, such as guarantees or collateral. In other cases, companies may exclude TEP from their approved list of counterparties because of the perceived risk associated with a speculative-grade rating. TEP's credit profile will become even more important as its reliance on purchased power and natural gas grows over time. The Direct Testimony of TEP witness Mr. David G. Hutchens provides additional discussion on TEP's purchased power and natural gas requirements.

III. <u>COST OF DEBT CAPITAL.</u>

Q. What was TEP's embedded cost of long-term debt for the test year?

A. As shown on Schedule D-2 of the Company's Application, the weighted average cost of long-term debt for TEP was 6.39% as of the end of the test year. This cost reflects the weighted average interest rate on all of the Company's fixed rate and variable rate long-term debt obligations as of December 31, 2006. It also reflects the cost of providing credit enhancement (letters of credit) in support of TEP's variable rate tax-exempt bonds, annual commitment fees on TEP's revolving credit facility, and the amortization of issuance expenses, debt discounts to par value and losses on reacquired debt.

Q. What cost of long-term debt do you recommend in this case?

A. I recommend a cost of long-term debt of 6.39%, which represents TEP's embedded cost of debt as of the end of the test year.

IV. WEIGHTED AVERAGE COST OF CAPITAL.

Q. Please summarize your findings regarding the weighted average cost of capital for TEP.

A. Based on (i) a pro forma capital structure, (ii) the cost of equity capital outlined in the Direct Testimony of TEP witness Dr. Samuel C. Hadaway, and (iii) the cost of debt I propose above, I recommend the Commission adopt an overall ROR of 8.35%. This value, reflecting TEP's weighted average cost of capital, is calculated as follows:

	% of Pro forma Capital Structure	Component Cost	Weighted Average Cost
Common Equity	45.00%	10.75%	4.84%
Long-Term Debt	55.00%	6.39%	3.51%
Total	100.00%		8.35%

Q. What is the difference between TEP's actual capital structure and the capital structure used for ratemaking purposes?

A. As described above, TEP's actual equity to total capitalization at December 31, 2006 was 29%, which is far below the investment grade comparable group referenced in Dr. Hadaway's Direct Testimony, and below S&P's minimum investment grade criteria of 42%. For ratemaking purposes, capital lease obligations are treated as operating leases, and therefore are not considered to be long-term debt when calculating total capitalization. Excluding capital lease obligations, TEP's total equity to total capitalization at December 31, 2006 was 40%. However, TEP's equity to total capitalization for ratemaking purposes is not comparable to the industry average or the S&P investment grade average, as those figures include capital lease obligations as part of total capitalization. The financial community, including the ratings agencies, includes TEP's capital lease obligations in their capital structure calculations.

Q. Why is TEP proposing the use of a pro forma capital structure?

A. The Company is focused on maintaining and improving its credit ratings. Although TEP's credit ratings have improved since 1994, the Company's unsecured debt is rated speculative-grade by two rating agencies. One of TEP's objectives is to, over time, improve its balance sheet and raise its unsecured ratings to investment grade. The key metric holding TEP's rating at the current level is total debt to total capitalization. By reinvesting a large portion of TEP's earnings in future capital investments, and relying less on external debt capital, TEP expects to increase its equity to total capitalization ratio gradually over time.

TEP is entering a period when its financial condition will be very important, as it will rely on the capital markets to help fund, in part, its projected capital investments. Excluding the purchase of Sundt Unit 4 in 2011, the Company's capital budget is projected to grow at an average rate of 8% per year, reaching $219 million by 2011. It is highly likely that TEP will use a mix of debt and equity financing to help fund future capital investments. Issuing more debt will put additional stress on TEP's already highly leveraged capital structure. Allowing TEP to set rates on a pro forma equity structure will help the Company to continue to make gradual improvements in its capital structure and position TEP to access the capital markets on favorable terms.

Q. What if the Commission does not allow TEP to use a pro forma capital structure?

A. If TEP uses its actual test year capital structure in this rate filing, which excludes capital lease obligations for ratemaking purposes, the cost of equity capital would need to be adjusted upward from 10.75% to 11.75%.

	% of Capital Structure Excluding Capital Leases	Component Cost	Weighted Average Cost
Common Equity	39.90%	11.75%	4.69%
Short-Term Debt	2.16%	5.92%	0.13%
Long-Term Debt	57.94%	6.40%	3.71%
Total	100.00%		8.53%

If the Commission does not allow TEP to use a pro forma capital structure, and does not allow a higher ROE, TEP's cash flows would be negatively impacted. Lower cash flows would make it very difficult for the Company to maintain its current credit ratings, as additional pressure would be placed on TEP's liquidity and already high debt leverage.

V. <u>RATE OF RETURN ON RATE BASE.</u>

Q. How did TEP calculate rate base for the purposes of this filing?

A. For purposes of quantifying the rate base, the Company is using the approach traditionally used by the Commission. Specifically, TEP used the average of original cost rate base ("OCRB") and reconstructed cost new less depreciation ("RCND") rate base, as those terms are defined in the Commission's rules, to calculate the Company's fair value rate base ("FVRB"). The specific calculation of these rate base values is described in the Direct Testimony of TEP witness Ms. Karen G. Kissinger.

Q. Please summarize how TEP used its proposed ROR to calculate operating income for purposes of cost-of-service rates.

A. TEP applied its proposed ROR to OCRB, which results in operating income of $82.1 million. Operating income was then divided by the FVRB – average of OCRB and RCND. The resulting ROR is 5.80% and lower than the Company's proposed ROR of 8.35%.

Q. Is this consistent with the Commissions historic practice of determining rate of return and operating income?

A. Yes. It has been the Commission's practice to use this methodology to determine ROR and operating income. The Commission lowers the overall ROR to achieve the same level of operating income calculated using OCRB.

VI. <u>SUMMARY OF SCHEDULES.</u>

A. <u>Schedules D-1 and D-2 .</u>

Q. Please describe Schedules D-1 and D-2 in the Company's Application.

A. Schedule D-1 contains the Company's actual and proposed capital structure and weighted average cost of capital for the test year ended December 31, 2006. This schedule also contains projected information pertaining to the Company's capital structure and weighted average cost of capital as of December 31, 2007.

Schedule D-2, page 1, provides a calculation of the weighted average cost of debt, both actual and proposed, for the test year ended December 31, 2006. Schedule D-2, page 2, contains a projection of the Company's cost of debt as of December 31, 2007. Schedule D-2 contains detailed information on TEP's cost of long-term debt.

B. <u>Schedules F1 through F-4.</u>

Q. Please describe Schedule F in the Company's Application.

A. The Company is a set of F Schedules for each of its Methodologies: (i) Market, (ii) Hybrid, and (iii) Cost-of-Service. Schedule F consists of four parts, Schedules F-1 through F-4.

Schedule F-1 contains a summary income statement and a return on common equity ("ROE") calculation for the test year ended December 31, 2006. This same information is presented on a projected basis for the year ending December 31, 2007. The projected year information is presented assuming that the requested rate increase for each proposal was implemented on January 1, 2007.

Schedule F-2 contains a summary cash flow statement for the test year ended December 31, 2006. This same information is presented on a projected basis for the year ending December 31, 2007. The projected year information is presented assuming that the requested rate increase for each proposal was implemented on January 1, 2007.

Schedule F-3 contains information on the Company's capital investments during the test year ended December 31, 2006. This same information is presented on a projected basis for calendar years 2007, 2008 and 2009.

Schedule F-4 contains a description of key forecast assumptions used in preparing the projected information appearing in Schedules F-1 through F-3

Q. Please comment on the projected information appearing in Schedules F-1 and F-2.

A. The financial projections that assume a continuation of current rates through December 2007 were taken from a base case financial forecast prepared for TEP. It should be noted that this forecast is based on numerous assumptions regarding sales growth, generating plant performance, wholesale energy prices, natural gas prices, operating and capital expenditure levels, and other factors that are subject to change over time.

Additional financial projections are provided in Schedules F-1 and F-2 that assume implementation of the Company's requested rates for each proposal beginning January 1,

2007. The Company did not actually implement new rates in 2007, and as the Company's proposed rates incorporate forecasts of fuel and purchased power costs in 2009, these projections are of limited value from a financial analysis perspective.

Q. The ROEs shown in Schedule F-1 for each Methodology are much higher than what you have requested in this rate case. Please explain.

A. The ROE calculations presented in schedule F-1 are based on TEP's GAAP financial statements, not on a regulatory accounting basis. TEP's GAAP financial statements reflect the entirety of TEP's retail and wholesale operations. In order to derive a fair picture of TEP's earnings on a retail jurisdictional basis, adjustments must be made to remove the financial impact of wholesale activities that are subject to regulation by the Federal Energy Regulatory Commission. Additionally, many differences between GAAP and regulatory accounting must be considered when assessing the Company's retail revenue requirement. For example, as a result of the 1999 Settlement Agreement, the application of GAAP required the Company to change the method of financial accounting for its generation segment. There are many reasons why the Company's GAAP financial reports cannot be used to measure financial performance on a regulatory basis, such as the recording of large non-recurring gains or losses under GAAP that would ordinarily be eliminated for ratemaking purposes. The point to be made is that a casual observation of reported returns should not be used to determine whether or not a Company has "over-earned" or "under-earned" on a retail jurisdictional basis.

VII. FINANCIAL OUTLOOK.

Q. What is the expected impact on TEP's financial condition if the proposed rate request is granted?

A. Each of TEP's proposed rate requests should provide for continued, gradual improvement of the Company's financial condition. Our proposals, if granted, will provide much needed financial flexibility to TEP by ensuring future liquidity remains adequate, maintaining ample cash flow to fund most of its capital investments, and addressing some of the concerns expressed by the rating agencies, some faster than others.

Q. How do you think the rating agencies would react if TEP's proposed rate request is granted?

A. While we cannot predict with certainty how the rating agencies would react if TEP's proposed rate request is adopted, we believe TEP's proposed rate request would support the Company's financial condition going forward.

While rating agency decisions are not based solely on ratios, analysts have stated in previous reports that their main concerns include (i) TEP's highly leveraged balance sheet, (ii) the sustainability of currently strong cash flow metrics, (iii) extended generation outages in the absence of the ability to recover, through rates, fuel and purchased power costs and (iv) regulatory outcomes that support credit quality. We believe that our proposals, when considered in its entirety, sufficiently address these concerns.

Q. Does this conclude your testimony?

A. Yes.

EXHIBIT

KPL-1

Exhibit KPL-1

Credit Rating Summary

Moody's Rating Definition	Credit Ratings Moody's	S&P	Fitch
Obligations rated Aaa are judged to be of the highest quality, with minimal credit risk.	Aaa1 Aaa2 Aaa3	AAA+ AAA AAA-	AAA+ AAA AAA-
Obligations rated Aa are judged to be of high quality and are subject to very low credit risk.	Aa1 Aa2 Aa3	AA+ AA AA-	AA+ AA AA-
Obligations rated A are considered upper-medium grade and are subject to low credit risk.	A1 A2 A3	A+ A A-	A+ A A-
Obligations rated Baa are subject to moderate credit risk. They are considered medium grade and as such may possess certain speculative characteristics.	Baa1 Baa2 Baa3	BBB+ BBB BBB-	BBB+ BBB BBB-
Obligations rated Ba are judged to have speculative elements and are subject to substantial credit risk.	Ba1 Ba2 Ba3	BB+ BB BB-	BB+ BB BB-
Obligations rated B are considered speculative and are subject to high credit risk.	B1 B2 B3	B+ B B-	B+ B B-
Obligations rated Caa are judged to be of poor standing and are subject to very high credit risk.	Caa1 Caa2 Caa3	CCC+ CCC- CCC	CCC+ CCC- CCC

Baa3/BBB- and above considered investment grade

EXHIBIT

KPL-2

Tucson Electric Power Company
S&P Benchmark Ratings

FFO / TOTAL AVERAGE DEBT

Note: TEP's current business profile is 6

Business Profile	Investment Grade BBB Category		Non-Investment Grade BB Category		TEP Ratio at 12/31/06
1	10.0	5.0			
2	12.0	8.0			
3	15.0	10.0	10.0	5.0	
4	20.0	12.0	12.0	8.0	
5	22.0	15.0	15.0	10.0	
6	28.0	18.0	18.0	12.0	18.5
7	30.0	20.0	20.0	15.0	
8	40.0	25.0	25.0	15.0	
9	45.0	30.0	30.0	20.0	
10	55.0	40.0	40.0	25.0	

FFO / INTEREST

Business Profile	Investment Grade BBB Category		Non-Investment Grade BB Category		TEP Ratio at 12/31/06
1	1.5	1.0			
2	2.0	1.0			
3	2.5	1.5	1.5	1.0	
4	3.5	2.5	2.5	1.5	
5	3.8	2.8	2.8	1.8	
6	4.2	3.0	3.0	2.0	3.0
7	4.5	3.2	3.2	2.2	
8	5.5	3.5	3.5	2.5	
9	7.0	4.0	4.0	2.8	
10	8.0	5.0	5.0	3.0	

TOTAL DEBT / TOTAL CAPITALIZATION

Business Profile	Investment Grade BBB Category		Non-Investment Grade BB Category		TEP Ratio at 12/31/06
1	60.0	70.0			
2	58.0	68.0			
3	55.0	65.0	65.0	70.0	
4	52.0	62.0	62.0	68.0	
5	50.0	60.0	60.0	65.0	
6	48.0	58.0	58.0	62.0	71.2
7	45.0	55.0	55.0	60.0	
8	42.0	52.0	52.0	58.0	
9	40.0	50.0	50.0	55.0	
10	35.0	48.0	48.0	52.0	

Direct Testimony of Karen G. Kissinger

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON - CHAIRMAN
WILLIAM A. MUNDELL
MIKE GLEASON
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103.	DOCKET NO. E-01933A-05-0650
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-01933A-07-____

Direct Testimony of

Karen G. Kissinger

on Behalf of

Tucson Electric Power Company

July 2, 2007

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I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Karen G. Kissinger and my business address is 4350 East Irvington Road, Tucson, Arizona, 85714.

Q. What is your employment position?

A. I am the Vice President, Controller and Chief Compliance Officer for UniSource Energy Corporation ("UniSource Energy"). I am also Vice President, Controller and Chief Compliance Officer of Tucson Electric Power Company ("TEP" or "Company").

Q. What are your duties and responsibilities?

A. My present functional areas of responsibility include internal and external financial reporting, plant and property accounting, payroll, customer and revenue accounting, accounts payable, tax planning and tax compliance reporting, and energy settlements for all UniSource Energy owned utilities. I am also responsible for the UniSource Energy Compliance Program, which focuses on corporate policies, practices, and procedures that are designed to assure that UniSource Energy is in compliance with all laws, regulations, and corporate policies.

Q. Would you please describe your education, background and experience?

A. I received a Bachelor of Arts Degree in Spanish from the University of Virginia in 1977. I received a Master of Business Administration with a Concentration in Accounting from the University of Arizona in 1982. I am a Certified Public Accountant licensed to practice in the State of Arizona. I am a member of the American Institute of Certified Public Accountants and the Arizona State Society of Certified Public Accountants. Before joining TEP in 1991, I was employed by Deloitte Haskins & Sells, and its successor by merger, Deloitte & Touche, in the audit department for approximately eight and one-half years. I was designated by Deloitte & Touche as a public utility specialist, and provided audit and consulting services to a client base comprised of both public and cooperative electric utilities. Since 1991, I have been employed by TEP as Vice President and Controller and as UniSource Energy's Vice President and Controller since the time of its formation. In 2003, I was assigned the additional responsibility of Chief Compliance Officer.

Q. On whose behalf are you filing your direct testimony in this proceeding?

A. My testimony is filed on behalf of TEP.

Q. What is the purpose of your testimony in this proceeding?

A. My direct testimony supports TEP's rate request in this proceeding. I am the sponsoring witness for accounting and tax data reflected in TEP's rate case application, including the "B" Schedules (Rate Base), the "C" Schedules (Test Year Income Statements), and the "E" Schedules (Financial Statements and Statistical Schedules). I am also sponsoring the actual test period and prior years' data contained in Schedule A (Summary Schedules), Schedule B (Rate Base Schedules), Schedule C (Test-Year Income Statements), Schedule D (Cost of Capitol), and Schedule F (Projections and Forecasts), and certain pro forma adjustments in Schedules B and C.

Q. Please summarize your testimony.

A. In my testimony, I provide some background information regarding the base financial statements of TEP. I also provide support for the following rate base adjustments for the Cost-of-Service Methodology:

a. Implementation Costs Regulatory Asset;

b. Springerville Unit 1;

c. Renewable Resources;

d. Luna Plant;

e. Accumulated Deferred Income Tax ("ADIT"); and

f. Allowance for Working Capital.

In addition, I provide support for the following operating income adjustments in the Cost-of-Service Methodology:

a. Amortization of the Implementation Costs Regulatory Asset;

b. Depreciation Expense;

c. Property Tax Expense; and

d. Income Tax Expense.

With respect to the Hybrid Methodology, I provide support for the calculations required to remove the Navajo and Four Corners Generating Stations from rate base as well as the adjustments to remove the related amounts of ADIT and to recalculate Working Capital. I also support the depreciation, property tax and income tax operating income adjustments related to the removal of Navajo and Four Corners from rate base.

Finally, with respect to the Market Methodology, I provide support for a smaller Implementation Costs Regulatory Asset and its amortization.

II. <u>PRO FORMA ADJUSTMENTS.</u>

Q. Please explain the consideration of pro forma adjustments in the rate case process.

A. Public utility rates are based on the prudently-incurred costs of providing safe, reliable service. The revenue requirement underlying rates is developed on the basis of a test year that reflects a level of operating revenues and expenses and net plant investment that represents normal conditions that may be expected to exist during the time that resulting rates may be in effect. This affords the utility a reasonable opportunity to achieve a fair rate of return, as authorized by the respective regulatory authority.

Pro forma adjustments are made to recorded test year amounts that do not reflect the levels of expenses required for the provision of service, or that do not represent the levels expected to occur during the period when the new rates will be in effect. These adjustments may be made in the form of eliminations, annualizations, or normalizations.

Elimination adjustments are made to remove out-of-period or non-recurring transactions, or items that are not costs or revenues related to the provision of utility service. Thus, they are not eligible for reflection in revenue requirements.

Annualization adjustments are made to reflect the full, 12-month revenue or expense level of certain components of operating income. Annualization adjustments are typically computed using end-of-test-year quantities, and the most current known and measurable prices and rates. Examples in this case include restating test year operating revenues to reflect customer levels at the end of the test year, adjusting payroll expense to reflect current salary rates and changes in employee levels during the test year, and adjusting recorded depreciation expense to reflect the full effect of plant additions and retirements during the test year.

Normalization adjustments reflect that the recorded test year operating revenues and expenses may not represent a normal level for ratemaking purposes. Certain events may have affected recorded transactions in an atypical manner. Moreover, some transactions – while eligible for reflection in revenue requirements – are incurred at intervals less frequent than annually, provide benefits extending beyond a single year, or reoccur in significantly different amounts each year. As a result, the amounts recorded in the test year may not be viewed as "normal," thus requiring a restatement for ratemaking purposes. Normalization adjustments are made in these instances when a test-year level of revenues or expenses does not represent what would be expected on an on-going basis. Examples in this case include the adjustment for bad debt expense and the overtime factor implicit in the payroll adjustment.

Q. Are the pro forma adjustments that you are sponsoring in your testimony prepared by you or under your supervision?

A. Yes, they were.

Q. Have the pro forma adjustments for which you are responsible in this rate filing been computed in accordance with sound ratemaking principles and all applicable rules and policies of the Arizona Corporation Commission ("Commission")?

A. Yes. To the best of my knowledge, all of the adjustments that I am sponsoring have been so calculated.

III. RATE BASE ADJUSTMENTS.

A. Implementation Costs Regulatory Asset.

Q. Please describe the Implementation Costs Regulatory Asset ("ICRA") for which the Company is requesting recovery.

A. The ICRA is comprised of the following elements:

Direct Access Costs	$11,153,016
Deferred Divestiture Costs	1,193,003
Deferred GenCo Separation Costs	164, 026
Desert Star & West Connect Funding	1,702,798
Subtotal	14,212,843
San Juan Coal Stranded Cost Buyout Regulatory Asset	14,731,089
Sundt Coal Contract Buyout Regulatory Asset	11,259,934
Subtotal	25,991,023
Financing Costs - Generation	7,251,358
TOTAL	$47,455,224

I discuss these individual elements in more detail below. Later in my testimony there is an operating income adjustment to amortize this $47.5 million regulatory asset as an element of cost of service over a period of four years, the estimated period of time before we would have another rate proceeding become effective.

Q. Why is it appropriate for the Company to recover these costs at this time?

A. In the case of the Direct Access Costs, Deferred Divestiture Costs, Deferred GenCo Separation Costs and Desert Star & West Connect Funding, these were costs the Company incurred as a result of directives from the Arizona Corporation Commission, as described more fully below.

In the case of the San Juan Coal and Sundt Coal Contract payments, these costs were incurred to amend agreements to develop more cost-effective contractual terms. Had the Company not been under a rate freeze and expecting to go to a market-based rate for generation as a result of entering into the 1999 Settlement Agreement, the Company would have sought regulatory recovery of these costs at the time the underlying agreements were negotiated. Because of the 1999 Settlement Agreement, the Company believed it was precluded from requesting such relief. If the Company's generation rates are placed back under a cost-of-service paradigm, then recovery of these costs through rates through a traditional cost-of-service approach is appropriate. The Company's customers benefit from these buyouts through the receipt of lower fuel costs in their monthly electric bill.

In the case of the financing costs, these costs would have been amortized rather than written off at once, had generation continued to be considered "cost-based rate-regulated" for accounting purposes as described more fully below.

Direct Access Costs.

Q. Please explain the Deferred Direct Access Costs element of the ICRA.

A. Commission Decision No. 62103, issued in November 1999, approved the Settlement Agreement ("1999 Settlement Agreement") that provided for the introduction of competitive retail access in the Company's electric service territory. The Decision acknowledged that TEP was incurring costs in connection therewith, and was deferring them for future recovery. Section 4.6 of the 1999 Settlement Agreement, as approved by the Commission, states:

> TEP shall defer for future recovery its costs to implement Competitive Retail Access. The Commission shall authorize TEP to recover its reasonable and prudently incurred Competitive Retail Access implementation costs as a plant cost and/or deferred debit subject to review in the TEP June 1, 2004 filing.

Q. What types of costs are included in the Deferred Direct Access costs balance?

A. The largest component of the deferral is computer software costs. Other costs include outside consulting services and internal costs such as payroll and employee expenses.

__**Deferred Divesture Costs.**__

Q. Please explain the Deferred Divestiture Cost element of the ICRA.

A. In June 1998, the Commission issued Decision No. 60977, which addressed the issue of the stranded cost expected to be incurred by incumbent utilities in the transition to retail electric competition in the State of Arizona. That Decision limited incumbent utilities to two options for addressing potential stranded costs: a) mandatory divestiture/auction of all generation assets, and b) the provision of "sufficient revenues necessary to maintain the financial integrity, such as avoiding default under currently existing financial instruments for a period of ten years..." See Decision No. 60977 at 11-12. With the issuance of that Decision, TEP commenced planning for the divestiture of its generation assets, and began incurring costs in connection therewith.

As previously stated, the 1999 Settlement Agreement approved in Decision No. 62103 clearly acknowledges that the Commission will allow full recovery at reasonable and prudently incurred retail competition implementation costs. The Decision supported TEP's request to defer such costs for future recovery.

Q. What kinds of costs did TEP incur relative to the planned divestiture?

A. The deferral balance includes expenditures for outside consulting, accounting, and legal services, and internal costs such as payroll and employee expenses.

Deferred GenCo Separation Costs.

Q. Please explain the Deferred GenCo Separation Costs element of the ICRA.

A. Commission Decision No. 61677 issued in April 1999 addressed certain concerns raised by its previous Decision No. 60977. Decision No. 61677 states, at page 2:

> By limiting Affected Utilities to these two "options", the only viable option for stranded cost recovery was a forced divestiture/auction of all generation assets. Based on the record of this proceeding, we are not convinced that conditioning recovery of stranded costs upon forced divestiture is in the public interest.

As a result, Decision No. 61677 modified Decision No. 60977 to allow each Affected Utility to choose from a list of five options for addressing their potential stranded costs. Generation asset divestiture remained an option. Shortly after the issuance of Decision No. 61677, TEP filed an application with the Commission requesting approval of the 1999 Settlement Agreement. It was approved by Decision No. 62103 in November 1999.

Section 3.1 of the 1999 Settlement Agreement required TEP to transfer its generation and other competitive assets to a subsidiary ("GenCo") on or before December 31, 2002. The Commission characterized the asset transfer as a "business decision," and accordingly ordered that the costs incurred in connection therewith be deferred and allocated between the Company and its customers, with TEP being permitted to recover 67%. See Decision No. 62103, pages 15-16.

Q. Please distinguish between the Deferred Divestiture and Deferred GenCo separation costs.

A. They are quite similar in nature. The only real distinction is that the Deferred Divestiture costs were incurred during the period that the Company was planning to completely divest its generating assets as part of the transition to retail competition, while the

Deferred GenCo separation costs were those incurred after a change in strategic plans that moved the focus to creating an affiliated electric generation entity to which the assets would be transferred.

Q. What kind of separation costs did TEP incur?

A. The deferral balance is largely comprised of TEP payroll, payroll taxes, employee benefits, and administrative and general expenses.

Q. Were the competitive assets divested?

A. No they were not. In September 2002, the Commission issued its "Track A" Decision No. 65154 directing TEP to cancel plans to divest its generating assets.

Q. Since the generating assets were not divested, why is TEP requesting recovery of the Deferred Divestiture costs?

A. Decision No. 62103 recognized that TEP would incur costs in connection with the planned divestiture, and acknowledged their recoverability. Moreover, TEP incurred such costs prudently and in good faith. The Company should be allowed to reflect them in revenue requirements, as expressly contemplated by Decision No. 62103.

<u>Deferred Desert Star & WestConnect Fees.</u>

Q. Please explain the Deferred Desert Star & WestConnect Fees element of the ICRA.

A. The 1999 Settlement Agreement required TEP to fund and participate in the development of two entities, Desert Star and WestConnect, which is the successor to Desert Star. These entities were formed to provide more open access to the transmission grid in the state of Arizona. These costs are therefore part of the costs of implementing Competitive Retail Access. TEP should be afforded a reasonable opportunity to recover such costs, and this rate case is a proper venue. So, this element of the Regulatory Asset includes these unrecovered deferred costs in rate base, recognizing the Company's economic commitment.

San Juan Coal Stranded Cost Buyout Regulatory Asset.

Q. Please explain the San Juan Coal Stranded Cost Buyout Regulatory Asset element of the ICRA.

A. In 2000, the Company and Public Service Company of New Mexico ("PNM") negotiated a new Underground Coal Supply Agreement with San Juan Coal Company ("SJCC") that replaced two existing surface mining operations with an underground mine as the source of coal for the San Juan Station, as more fully explained by TEP witness Mr. David G. Hutchens in his Direct Testimony. As part of the transaction, in December 2002, participating utilities paid SJCC a lump-sum amount of approximately $78 million to compensate for the value in stranded assets no longer needed for the new underground operation. TEP's share of the buy out was $15.4 million, reflecting our 19.8% ownership in San Juan Station. This adjustment reflects the rate base treatment of the initial $15,413,887 paid, plus $155,309 of transaction costs, less $838,107 of sales taxes on the transaction which were subsequently refunded to the Company.

Sundt Coal Contract Buyout Regulatory Asset.

Q. Please explain the Sundt Coal Buyout Regulatory Asset.

A. As explained by Mr. Hutchens in his Direct Testimony, in 2002, the Company and Pittsburg and Midway Coal Mining Company terminated the long term contract for coal to the Sundt Station. This element of the ICRA reflects the addition to rate base of the amount spent to buy out the contract.

Financing Costs – Generation.

Q. Why would the Company request recognition of certain previously incurred refinancing costs related to its generation assets?

A. The Company wrote off approximately $7.3 million of financing costs, as a part of the transition to competition. Upon final execution of the approved 1999 Settlement Agreement, pursuant to *Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation* ("FAS 71"), the Company's generation operations no longer qualified as cost-based rate-regulated operations for financial reporting purposes. These financing costs were no longer able to be deferred and amortized when debt was reacquired or refinanced. Companies not following the FERC chart of accounts or qualifying for accounting under FAS 71 are not able to defer and amortize these costs, but rather recognize such costs as expense when incurred. Since these costs were not deferred and amortized, they are not included in the amortization of debt costs which form a part of the Company's on-going cost of debt used in determining its cost of capital for rate purposes. Had these amounts been deferred and amortized, they would have become part of such calculation for rate purposes. This element of the ICRA is intended to address that inequity. These financing costs are shown in the table below.

Credit Agreement – 2004 refinancing	$ 1,449,653
Credit Agreement – 2005 refinancing	2,635,576
First Mortgage Bonds 8.5% due 2009	38,487
Industrial Development Revenue Bonds Apache A	336,038
Industrial Development Revenue Bonds Pima B	1,853,687
Industrial Development Revenue Bonds Pima C	937,916
Total 2004 and 2005 write-off	$ 7,251,358

There were numerous accounting changes required as a result of TEP no longer being able to follow FAS 71 for financial statement purposes. They are described in more detail later in Section V. of this testimony.

B. Springerville Unit No. 1.

Q. How is the Springerville Unit No. 1 Lease recorded in the Company's financial statements for external public financial reporting purposes?

A. For GAAP financial reporting purposes, this lease is accounted for as a capital lease. This means the Company records a capital lease asset and a liability on its balance sheet. The asset is then reduced over time through depreciation, and the liability is reduced as principal on the debt is repaid. When we add leasehold improvements to these assets, we record them as utility plant and amortize the cost of such improvements over the remaining term of the lease. Interest expense accrues on the debt while such debt is outstanding. As we operate Springerville Unit No. 1, we also incur operating expenses related to this generating unit.

Q. Is this the manner in which the Commission recognizes expense for this generating unit for regulatory purposes?

A. No. As described more fully in Mr. Hutchens' Direct Testimony, the Commission has chosen in the past to provide recovery of the Springerville Unit 1 costs (lease payments, amortization of leasehold improvements, operating costs, and an allocable portion of the Springerville coal handling costs) through a levelized payment stream similar to a purchased power arrangement. Therefore, this adjustment removes Springerville Unit No. 1 leasehold improvements less accumulated amortization from rate base.

C. Renewable Resources.

Q. Please explain the Renewable Resources adjustment.

A. A.A.C. R14-2-1618 requires an Environmental Portfolio Standard ("EPS") for all electric load-serving entities in Arizona that requires them to provide to customers a designated percentage of energy produced from renewable resources. Under the EPS, TEP must seek a designated percentage of energy for renewable resources to supply to customers. The Commission approved a fixed surcharge, for all affected entities, to cover the costs of complying with the EPS. This surcharge is assessed to TEP's customers.

Since the implementation of the EPS, the costs of compliance and the operation and adequacy of the surcharge have been viewed separately from the normal provision of electric service and related service rates. Accordingly, adjustments are made in this filing to remove the effects of the EPS from test-year operations. This adjustment removes from rate base the Company's net plant investment in the photovoltaic generating equipment purchased for compliance with the EPS. There are companion adjustments removing the related revenues and expenses from test year operating results appearing in Mr. Dukes' Testimony.

D. Luna Plant.

Q. Please explain the Luna Plant Adjustment.

A. As described in Mr. Hutchens' Direct Testimony, the Company proposes recovering the capital cost of its investment in the Luna Energy Facility through a market-based capacity charge. Accordingly, the Company's net plant investment in the Luna Energy Facility, which began commercial operation in the spring of 2006, is removed from utility plant in service. There are related exclusions from ADIT and in the development of pro forma adjustments to property taxes and depreciation expense described later herein.

E. Accumulated Deferred Income Tax ("ADIT").

Q. Please explain the ADIT Adjustment.

A. The adjustment reduces rate base for the computed balance of ADIT, a source of non-investor capital, based on adjusted test year rate base and operating results and the Company's existing income tax ratemaking authority.

Q. What are deferred income taxes?

A. Deferred income taxes represent the tax effect of differences that arise between the time period when revenues and expenses are recognized for financial reporting purposes and when they are considered for income tax return purposes. For public utilities, the largest such difference is that which exists as a result of using accelerated methods and shorter lives in computing tax depreciation as compared with the manner in which book and regulatory depreciation is computed. The process of apportioning income taxes among accounting periods is referred to as "inter-period tax allocation."

For this purpose, it is useful to distinguish between "timing differences" and "permanent differences." Timing differences represent differences between book income before income taxes and taxable income which originate in one or more periods, and reverse or turn around, in one or more subsequent periods. Because of their capital intensity, the difference between book and tax depreciation is typically the largest timing difference affecting public utilities. Expenses that are deducted by utilities currently for tax purposes, but deferred on the books as regulatory assets for future recognition in rates is another example of a timing difference.

Permanent differences exist between book income and taxable income, and do not reverse in subsequent periods. Examples of permanent differences include non-taxable interest income from municipal bonds and non-deductible lobbying expenses.

Deferred income taxes are computed for timing differences, but not for permanent differences. The typical accounting for deferred taxes involves recognition of a deferred income tax provision (*i.e.* expense) on the income statement for the tax effect of the timing differences, with a corresponding entry made to a balance sheet ADIT reserve account. As the timing differences reverse over time, the deferred tax component of income tax expense becomes negative and the balance of the reserve account is extinguished.

Q. How do deferred income taxes affect public utility ratemaking?

A. The reflection of deferred income taxes in ratemaking is labeled "normalization." Some regulatory bodies permit utilities to recognize deferred income taxes associated with all book-tax timing differences in ratemaking ("full normalization"), while others only permit the recognition of certain timing differences required by the Internal Revenue Code to be recognized in utility ratemaking ("partial normalization"). To the extent that normalization is permitted in ratemaking, the resulting deferred income taxes are reflected as a component of income tax expense, with the corresponding balance sheet reserve for accumulated deferred taxes deducted from rate base as non-investor capital, reflecting the availability of such amounts for plant investment or operating purposes between the time they are collected from customers and ultimately remitted to taxing authorities.

Q. What income tax ratemaking authority has been granted to TEP?

A. Prior to 1979, TEP was a flow-through entity for ratemaking purposes, meaning that it was not permitted to reflect deferred income taxes in ratemaking. In Decision No. 50430 (1979), the Commission authorized the Company to begin rate recovery of deferred income taxes relating to the benefits (shorter lives and accelerated methods) of accelerated depreciation, starting with production plant placed in service during 1979, transmission plant installed in 1980, and distribution plant added in 1981. Then, the Commission issued Decision No. 56659 (October 24, 1989) expanding the Company's normalization authority prospectively to include all originating book-tax timing differences. The Commission ruled that "we will allow full tax normalization at this time". Decision No. 56659 at 38. This authority included the differences between the manner in which salvage and removal costs are recognized for book and tax purposes, as well as the effect of the debt component of the Allowance for Funds During Construction ("AFUDC") and taxable Contributions in Aid of Construction. In Decision No. 58497 (January 13, 1994) at 95, the Commission authorized TEP to implement *Statement of Financial Accounting Standards No. 109*, *Accounting for Income Taxes*, for regulatory accounting purposes.

However, FAS 109 is not directly compatible with ratemaking. FAS 109 requires the setting up of certain deferred tax assets that do not actually reflect the prepayment of tax and certain deferred tax liabilities that do not represent the collection of taxes prior to their remittance to taxing authorities. Accordingly, we exclude these amounts recorded on the Company's balance sheet in determining the correct amount of deferred tax assets and ADIT for ratemaking purposes.

F. Allowance for Working Capital.

Q. What is working capital?

A. Working capital is generally viewed as investor funding in excess of the balance of net utility plant reflected in rate base that is required for the provision of utility service.

Q. What are the items of working capital for which the Company requests a return?

A. The components of working capital that the Company is requesting be included in rate base are:

(i) Fuel Inventory;

(ii) Materials and Supplies;

(iii) Prepayments; and

(iv) Cash Working Capital.

As more fully explained later in my testimony, the amounts requested for rate base inclusion for the fuel inventory, materials and supplies and prepayments are based on test year recorded balances, adjusted to reflect normal levels. The cash working capital component was determined by the use of the Lead-Lag Study Methodology, covered in depth in the Direct Testimony of Mr. Dukes.

Q. Please explain the Working Capital adjustment.

A. The Working Capital adjustment was computed in two pieces. As indicated on page 2 of Schedule B-5, the first piece adjusts the recorded end-of-test year balances for Fuel Inventory, Materials and Supplies, and Prepayments to reflect the 13-month average monthly balances, in recognition of the variability in the monthly balances of the accounts. This is consistent with the treatment of such accounts in prior rate cases.

The second piece of the Working Capital Adjustment is the reflection in rate base of a measure of Cash Working Capital, developed through the preparation of a comprehensive lead-lag study.

Q. What is Cash Working Capital?

A. The receipt of customer revenues for the provision of service, and the disbursement of cash for the payment of the various costs of providing service rarely occur simultaneously. This is the fundamental consideration underlying the concept of Cash Working Capital. Cash Working Capital is generally viewed as the component of working capital that represents the amount of invested cash required to pay day-to-day operating expenses incurred in rendering service to customers. It may either increase or decrease rate base. If the computation of Cash Working Capital produces a positive result, then it indicates that there is an additional investment for which a return is warranted. Thus, that amount is added to rate base. If the computation produces a negative result, then it implies non-investor funding of Cash Working Capital, requiring a rate base deduction. Under the direction of Mr. Dukes, a comprehensive lead-lag study was prepared and is discussed in his Direct Testimony.

IV. OPERATING INCOME ADJUSTMENTS.

Q. Please explain the Amortization of the ICRA adjustment.

A. The Company proposes to amortize these costs over a period of four years, which is an estimate of the period of time before the Company would have another rate proceeding become effective. This yields an amortization expense of approximately $11.9 million per year. However, the FERC expense accounts we propose to charge for such amortization vary.

Q. Does the Company have a proposed amortization schedule with FERC expense account numbers that accompanies this adjustment?

A. Yes. The proposed adjustment would amortize by FERC account and year as follows:

FERC	FERC ACCOUNT DESCRIPTION	Amortization				
		Year One	Year Two	Year Three	Year Four	Total
407.3	Regulatory Debits	$11,863,806	$2,349,037			$14,212,843
501	Fuel Expense		$7,097,650	$9,446,687	$9,446,687	$25,991,024
428	Amortization of debt discount and expense		$2,417,119	$2,417,119	$2,417,119	$7,251,357
	Annual Amortization	$11,863,806	$11,863,806	$11,863,806	$11,863,806	$47,455,224

As you can see, due to the underlying nature of the costs, we propose using three different FERC accounts for the amortization. The costs arising directly out of signing the 1999 Settlement Agreement should be amortized to account 407.3, Regulatory Debits. The costs associated with the coal contract buyouts should be charged to account 501, Fuel Expense. The financing costs should be amortized to account 428, Amortization of debt discount and expense.

Q. Please explain why the expense allocation between FERC accounts would need to change by year.

A. The Deferred Direct Access Costs, Deferred Divestiture Costs, Deferred GenCo Separation Costs and Desert Start & West Connect Funding balances, totaling $14.2 million, are recorded as regulatory assets on the accounting records of the Company, based on the provisions contained in the 1999 Settlement Agreement. Under the terms of *Statement of Financial Accounting Standards No. 92, Regulated Enterprises – Accounting for Phase-in Plans* (FAS 92), the Company must recover a regulatory asset within a ten-year period or write off the asset for financial reporting purposes. By amortizing this $14.2 million portion of the ICRA first, we limit the period of time from initial deferral to final recovery of these costs to an approximately 10-year period and avoid writing off the asset prior to its recovery in rates. The remaining costs do not meet the requirements for establishing a regulatory asset absent specific action by this Commission, so they are not recorded as a regulatory asset for financial statement purposes. Therefore, we do not have a similar limit on recoverability of such costs. In other words, since these costs have already been written off, we are not at risk for a further write-off due to length of recovery period.

Q. Please explain the Depreciation Expense adjustment.

A. The Depreciation Expense adjustment is computed to reflect in pro forma operating expense an annual depreciation amount based on depreciable plant in service as of the end of the test year and book depreciation rates as presented in detail in the testimony of witness Dr. Kimbugwe A. Kateregga of Foster Associates, Inc. The calculation of the adjustment properly considers the effects of depreciation associated with assets (i.e. vehicles) that is charged to clearing accounts or expense categories other than depreciation.

Q. Please explain the Property Tax adjustment.

A. The Property Tax adjustment is intended to reflect in pro forma test year operating expenses an amount based on final, adjusted plant in service at the end of the test year, using the statutory assessment ratio of 23.5%, which is the rate scheduled to become effective January 1, 2008, and the most currently known average property tax rates. To the extent that more current average tax rate information becomes available during the conduct of this rate case, the Company is willing to update that part of the tax adjustment.

Q. Please explain the Income Tax Expense adjustment.

A. The Income Tax Expense adjustment is computed with the intent to reflect in pro forma test year operating expenses an amount of income taxes based on final adjusted operating revenues, operating expense, and rate base. It is computed in two parts. The first part is pro forma current income tax expense, the tax liability computed as though an actual income tax return was being prepared on final adjusted test year taxable operating income. For this purpose, it was necessary to identify all operating book-tax differences ("Schedule M items"), both timing and permanent, and then recompute based on adjusted test year operating revenues and expenses, if necessary. The tax deduction for interest was computed using a synchronization methodology reflecting final adjusted rate base and the weighted cost of debt in the capital structure.

The second part of the income tax calculation is deferred income tax expense. Deferred income taxes are computed on the Schedule M items representing timing differences for which the Company has obtained normalization ratemaking authority from the Commission as previously described in my testimony.

V. SUMMARY OF SCHEDULES.

A. Schedules B-1 through B-5.

Q. Please explain Section B of the Company's filing.

A. Section B, comprised of Schedule Nos. B-1 through B-5, presents the development of the rate base component of revenue requirements submitted for Commission consideration in this rate case filing. Some of the data in Section B, and in Schedules and exhibits referenced in my testimony, are taken from TEP's audited financial statements for the year ended December 31, 2006, as presented in UniSource Energy & Tucson Electric Power Company's Combined Form 10K for the year ended December 31, 2006 attached as Exhibit KGK-1.

Q. Please describe Schedule B-1.

A. This schedule summarizes the elements of TEP's rate base on both a net recorded original cost and depreciated reconstructed cost new ("RCND") basis at December 31, 2006, along with the pro forma adjustments to rate base. Original Cost Rate Base ("OCRB") is comprised of net utility plant, certain regulatory assets, and working capital, with deductions from rate base for ADIT, customer advances for construction and customer deposits recorded at the cost the Company incurred to acquire such assets and liabilities.

Q. Please explain briefly the basis for the determination of the RCND rate base.

A. Plant in service and customer advances for construction reported at reconstructed cost new ("RCN") are summarized from the results of a detailed plant cost trending study. The accumulated depreciation and ADIT reported on a RCN basis have been computed by multiplying the corresponding original cost balances by a ratio, the numerator of which is gross RCN of depreciable plant, and the denominator of which is gross original cost of depreciable plant. All other rate base elements are reflected at original cost.

Q. Please describe the plant cost trending study.

A. The trending study was prepared to establish a measure of the cost to reconstruct utility plant in service at current 2006 cost levels. The December 31, 2006 recorded balance in each plant account was analyzed by vintage component and adjusted to current cost levels by applying trending factors to each vintage total. For example, the RCN value for 1984 vintage assets in Account No. 362, Distribution Plant – Station Equipment was computed as follows:

Original Cost of 1984 vintage assets in Acct. 362 X <u>2006 Cost Index for Acct 362</u>
= 1984 Cost Index for Acct. 362

For most accounts, the <u>Handy-Whitman Index of Public Utility Construction Costs</u> for the Plateau Region has been employed. For plant accounts 303, 391, 393, 394, and 398, the "Marshall Valuation Service Cost Index" was used. For plant accounts 392, 395, 396, and 397, the Bureau of Labor Statistics producer price index was used. Where the Handy-Whitman Index was used for the trend factors, they are based on the index numbers released by Handy-Whitman for July 1, 2006. More current data has not yet been released.

Q. What is the Handy-Whitman Index?

A. It is an index of public utility construction costs that has been published continuously since 1924 by Whitman, Requardt and Associates of Baltimore, Maryland. The Handy-Whitman Index is a well-recognized, widely used and generally accepted method for measuring differences in property values for insurance and other purpose, including the valuation of public utility property for rate case purposes. It has been used by UniSource Energy's utilities and other companies in proceedings before the Commission for many years.

The Handy-Whitman Index is comprised of index numbers for various accounts prescribed by the Uniform System of Accounts and for six geographical divisions of the country, including the Plateau Division, in which Arizona and New Mexico are located. These index numbers result from a comparison of the current prices of materials, labor, and equipment to prices in a base year. Index numbers are determined for each year as of January 1 and July 1.

The index numbers are used to determine cost trend factors, which are then applied to known original costs of like plant and property to determine the fluctuation in cost between the date of original installation and the date of valuation.

Q. **What is the Marshall Index?**

A. The Marshall Index, prepared by the firm of Marshall & Swift, is an index of construction cost trend valuations. It was used in development of costs reported in the RCND Study for those plant accounts not reported by Handy-Whitman. The Bureau of Labor producer price index was then used when neither the Handy-Whitman nor the Marshall indices were available.

Q. **What is shown on Schedules B-2 and B-3?**

A. Schedule B-2 shows the pro forma adjustments to the original cost rate base. The information presented includes the actual per-books balances at the end of the test year, pro forma adjustments, and the adjusted balances. Schedule B-3 provides the same detail by functional account classifications as shown in Schedule B-2, except that it is shown on an RCND basis.

Q. Please identify the pro forma adjustments on Schedules B-2 and B-3 that you are sponsoring in this rate case filing.

A. I am sponsoring the pro forma rate base adjustments identified in the index to my testimony. Each adjustment was identified and the related computational methodology has been explained in detail above.

Q. Please explain Schedule B-4.

A. This schedule shows the balances of gross RCN and related accumulated depreciation by plant account at the end of the test year. It includes the applicable depreciation reserve ratio, based on original cost, for the depreciable plant balances.

Q. Please explain Schedule B-5.

A. This schedule summarizes the various elements of working capital that the Company is requesting for inclusion in rate base in this rate case.

Q. Why are the original costs and RCND costs of working capital the same in Schedule B-5?

A. They are the same because the original costs are at current prices or have been adjusted to current prices, meaning they have not been significantly affected by inflationary factors.

B. Schedules C-1 through C-3.

Q. Please describe Section C.

A. Section C, comprised of Schedule Nos. C-1 through C-3, presents the development of the net operating income component of revenue requirements submitted for Commission consideration in this rate case filing. Schedules C-1 and C-2 are sponsored by Mr. Dukes.

Q. What is the purpose of Schedule C-3?

A. Schedule C-3 contains the development of the Gross Revenue Conversion Factor. That factor is used to convert the computed test year return deficiency to an equivalent annual revenue increase amount. It effectively recognizes that there will be additional bad debt expense and income taxes associated with any adjustment to annual revenue levels.

C. Schedules E-1 through E-9.

Q. Please explain Section E of the Company's filing.

A. Section E, as is the same for all other sections of this rate case filing, was prepared in accordance with the filing requirements contained in AAC R14-2-103. It is comprised of Schedule Nos. E-1 through E-9, containing annual financial statements and key operating statistics and financial data extracted from the Company's regulatory books of account.

Q. On what basis are the regulatory books of account of TEP maintained?

A. The Company's regulatory books of account are maintained in accordance with the Uniform System of Accounts of the FERC, as required by AAC R14-2-212.G.2.

Q. Have there been any significant changes to the Company's accounting policies or principles since its last rate case?

A. Yes. Concurrent with the execution of the 1999 Settlement Agreement (approved by the Commission in Decision No. 62103), which opened the Company's service territory to retail competition, TEP ceased application of *Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation* ("FAS 71") to the generation segment of its business operations. Also, since 1999, numerous new accounting standards have been issued that the Company has adopted. The financial statement impact of some of the new standards has been different that it would have been had FAS 71 still applied to the generation operations. Three examples of these standards would be:

- *Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities ("FAS 133")*, which became effective at the beginning of 2001;
- *Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations* ("FAS 143"), which became effective at the beginning of 2003; and
- *Statement of Financial Accounting Standards No. 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans — an amendment of FASB Statements No. 87, 88, 106, and 132(R)*, which became effective in December 2006.

In addition, for FAS 133, hundred of interpretations in the form of Derivative Implementations Group releases, Emerging Issues Task Force releases and Financial Accounting Interpretations have been issued, each of which has slightly modified the manner that FAS 133 has impacted our financial statements over time.

Q. Please describe the current accounting treatment of TEP's generation assets as a result of the 1999 Settlement Agreement.

A. Those assets are no longer considered to be "cost-based rate regulated" from an accounting perspective. Concurrent with the execution of the 1999 Settlement Agreement – which opened the Company's service territory to retail competition – TEP ceased applying FAS 71 to the generation segment of its business operations. A regulated company must satisfy the following conditions to apply the accounting policies and practices of FAS 71:

- An independent regulator sets rates;
- The regulator sets the rates to cover specific costs of delivering service; and
- The service territory lacks competitive pressures to reduce rates below the rates set by the regulator.

In 1997, the FASB's Emerging Issues Task Force concluded in EITF 97-4 that applying FAS 71 should be discontinued once sufficiently detailed deregulation guidance is issued for a separable portion of a business. A company may continue to recognize regulatory assets formerly associated with the deregulated portion of the business, to the extent the transition plan provides for their recovery through the regulated transmission and distribution portion of the business. Effective November 1, 1999, we stopped applying FAS 71 to our generation operations because the 1999 Settlement Agreement provided sufficient details regarding the deregulation of TEP's generation operations, including but not limited to: (1) Consumer choice for energy supply was set to begin in January 2000 and (2) TEP was set to experience an extended energy rate freeze subsequent to three rate decreases of approximately 1% each.

As a result of no longer applying FAS 71, certain costs are recognized differently in TEP's income statements than they would have been if TEP were still applying FAS 71 to its generation costs. Some of the more significant differences are:

- We now recognize lease costs for generation capital lease assets and liabilities as depreciation and interest, similar to the accounting for all other capital assets. If these costs were still regulated, then they would be recognized as operating lease payments.
- We apply *Statement of Financial Accounting Standard No. 34, Capitalization of Interest Cost* ("FAS 34"). FAS 34 replaces the previous AFUDC calculation for generation-related construction projects and provides guidance on calculating the costs during construction of debt funds used to finance these projects. There is no equity return included in the FAS 34 calculation, as there is in AFUDC.
- Under the provisions of FAS 143 we may only accrue legally binding obligations to retire assets in the financial statements. Further, the methodology provided for in FAS 143 differs from the asset retirement obligation recognition methodology provided for in ACC regulation for TEP in previous rate cases.
- We recognize operating revenues and expenses at the time and in the amount they would be under GAAP for unregulated companies, whether or not the Commission approved TEP accounting for such costs differently for regulatory purposes. This includes the calculation of depreciation expense for generation assets, and expensing refinancing costs and recognizing interest expense.

Q. Have the financial statements been audited?

A. Yes. PriceWaterhouse Coopers LLP (Independent Certified Public Accountants) audited the Company's financial statements, for calendar years 2006, 2005 and 2004.

Q. Please describe Schedule E-1.

A. Schedule E-1 contains the comparative balance sheets of TEP for the test year ending December 31, 2006, and the two prior calendar years ending December 31, 2005, and December 31, 2004.

Q. Please describe Schedule E-2.

A. This Schedule sets forth comparative income statements for the test year ending December 31, 2006, and the two prior calendar years ending December 31, 2005 and 2004. The income statement for the test year supports the actual test period income statement shown on Schedules C-1 and C-2.

Q. Please describe Schedule E-3.

A. This Schedule presents the comparative statements of cash flows for the test year ending December 31, 2006 and the two prior calendar years ending December 31, 2005 and 2004.

Q. Please describe Schedule E-4.

A. This Schedule reports the changes that occurred in stockholders' equity (deficit) during the period beginning January 1, 2004 and ending December 31, 2006. Changes occurring each year in both the number of shares outstanding and in the amounts of the various elements of stockholders' equity are reflected.

Q. Please describe Schedule E-5.

A. Page 1 of Schedule E-5 presents a summary of the balances in the various electric utility plant account categories and accumulated depreciation at December 31, 2006 and December 31, 2005, and the net changes therein during 2006, with plant in service presented on a functional basis. Pages 2 and 3 of Schedule E-5 present the same information on a more detailed basis, by individual electric plant account.

Q. Please describe Schedule E-6.

A. Schedule E-6 contains Operating Income Statements for the test year and two previous calendar years. Retail revenues are reported by rate class. Operating Expenses are reported by major category.

Q. Please describe Schedule E-7.

A. This Schedule reports key electric operating statistics, in a comparative format, for the test year ending December 31, 2006 and the two prior calendar years ending December 31, 2004 and 2005.

Q. Please describe Schedule E-8.

A. This Schedule shows the taxes charged to operating expenses by tax type for the test year ending December 31, 2006 and the two prior calendar years ending December 31, 2005 and 2004.

Q. Please describe Schedule E-9.

A. This Schedule is intended to disclose important facts required for a proper understanding of the financial statements. We have included here the Company's FERC Form 1 for the year ending December 31, 2006. The footnotes and other statistical data contained therein provide additional information to facilitate understanding of the remaining information contained in Schedules E.

VI. ADJUSTMENTS RELATED TO THE HYBRID METHODOLOGY.

A. Navajo and Four Corners Generating Stations.

Q. Are there adjustments to Plant in Service proposed under the Hybrid Methodology?

A. Yes. As more fully described in the Direct Testimony of Mr. David Hutchens, the Company proposes to remove two generating stations from cost-of-service-based rate base under the Hybrid Methodology. The adjustments shown for the Navajo and Four Corners Generating Stations remove the book balance of Utility Plant in Service and the related balance of accumulated depreciation for each of these properties as of December 31, 2006, as another recovery mechanism is proposed for these assets.

B. ADIT.

Q. Are there related changes that must occur due to the removal of these items from rate base?

A. Yes. The ADIT associated with these two items of property must be removed from rate base as well. This adjustment removes only that ADIT related to the Navajo and Four Corners Generating Stations.

C. Working Capital.

Q. Would working capital also change?

A. Yes. Each element of working capital would change. First, a portion of the fuel, materials and supplies and prepayments contained in the working capital calculation are for Navajo and Four Corners. These items must be removed from working capital for consistency. In addition, the calculation of cash working capital must change to reflect that certain operating expenses related to these stations are no longer included in cost-based cost of service under the Hybrid Methodology.

D. Property Tax Expense.

Q. Why does property tax expense change in this scenario?

A. A portion of the property tax expense computed in the cost-based cost-of-service case is for property tax expense payable on Navajo and Four Corners. Therefore, the property taxes associated with such assets must be removed from cost of service under the Hybrid Methodology.

E. Depreciation Expense.

Q. Why does depreciation expense change under the Hybrid Methodology?

A. The amount of depreciation expense included in the Cost-of-Service methodology includes depreciation expense for Navajo and Four Corners. If another recovery mechanism is proposed for these assets, depreciation expense for these assets must be removed from the cost-of-service calculation.

F. Income Tax Expense.

Q. Why does income tax expense change under the Hybrid Methodology?

A. As noted in this testimony and the testimony of others, the elements of net income would change fairly significantly if assets and costs are recovered on another mechanism. As the amount of taxable income (both book and tax basis) would change as a result of this proposal, the amount of income taxes currently payable and deferrable would change.

This adjustment reflects income taxes that would be payable on the Company's net income, after all the other changes occur.

G. Schedules.

Q. Are there schedules that support the Hybrid Methodology?

A. Yes. There are schedules that support the Hybrid Methodology, just as there are for the Cost-of-Service Methodology. The description of the schedules for the Hybrid Methodology are the same as for the schedules that are discussed in Section V. of this testimony for the Cost-of-Service Methodology.

VII. ADJUSTMENTS AND SCHEDULES RELATED TO THE MARKET METHODOLOGY.

Q. Would any of the adjustments included in your testimony change if TEP's generation were market-based rather than cost-based?

A. Yes. The adjustment for ICRA would change. Under the Market Methodology, the Company proposes that this regulatory asset be limited to only those amounts specifically discussed in the 1999 Settlement, which amount to $14.2 million. To reiterate what I stated earlier in Section III of my testimony, this $14.2 million is comprised of the following elements:

Direct Access Costs	$11,153,016
Deferred Divestiture Costs	1,193,003
Deferred GenCo Separation Costs	164, 026
Desert Star & West Connect Funding	1,702,798
Total	$14,212,843

The reasons we believe we should be allowed to recover these costs are enumerated in Section III of my testimony. We propose to amortize this cost over a period of four years for regulatory purposes, amounting to approximately $3.55 million per year. These costs arising directly out of signing the 1999 Settlement Agreement should be amortized to account 407.3, Regulatory Debits.

Q. Ms. Kissinger, didn't you note earlier that the Company needs to recover these costs over a more limited period of time to avoid writing off these costs for financial statement purposes?

A. Yes, I did. Under the Market Methodology, we would accept the fact that a write-off would occur and accept a recovery period of four years. While the Company would prefer to avoid writing off an asset, given all the other elements of the Market Methodology case, the Company accepts recovering these costs over a four-year period to avoid introducing further complexities into the case.

Q. Would any of your other adjustments change under the Market Methodology?

A. No, none of the other adjustments would change; they would be jurisdictionally allocated under the Market Methodology.

Q. Do you support the schedules for the Market Methodology?

A. Yes. There are schedules that I support for the Market Methodology parallel the schedules for the Cost-of-Service Methodology. The description of the schedules for the Market Methodology is the same as the description of the schedules that are discussed in Section V of this testimony regarding the Cost-of-Service Methodology.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT

KGK-1

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

[X] **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2006

OR

[ ] **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from _________ to _________.

Commission File Number	Registrant; State of Incorporation; Address; and Telephone Number	IRS Employer Identification Number
1-13739	**UNISOURCE ENERGY CORPORATION** (An Arizona Corporation) One South Church Avenue, Suite 100 Tucson, AZ 85701 (520) 571-4000	86-0786732
1-5924	**TUCSON ELECTRIC POWER COMPANY** (An Arizona Corporation) One South Church Avenue, Suite 100 Tucson, AZ 85701 (520) 571-4000	86-0062700

Securities registered pursuant to Section 12(b) of the Act:

Registrant	**Title of Each Class**	**Name of Each Exchange on Which Registered**
UniSource Energy Corporation	**Common Stock, no par value, and Preferred Share Purchase Rights**	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well known seasoned issuer, as defined in Rule 405 of the Securities Act.
UniSource Energy Corporation Yes __X__ No____
Tucson Electric Power Company Yes _____ No__X__

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Act.
UniSource Energy Corporation Yes _____ No__X__
Tucson Electric Power Company Yes __X__ No____

Indicate by check mark whether each registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes __X__ No____

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of each registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [ ]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer or a non-accelerated filer. See definition of "accelerated filer" and "large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

UniSource Energy Corporation Large Accelerated Filer X Accelerated Filer__ Non-accelerated filer__
Tucson Electric Power Company Large Accelerated Filer__ Accelerated Filer__ Non-accelerated filer X

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).
UniSource Energy Corporation Yes ______ No X
Tucson Electric Power Company Yes ______ No X

The aggregate market value of UniSource Energy Corporation voting Common Stock held by non-affiliates of the registrant was $1,055,512,081 based on the last reported sale price thereof on the consolidated tape on June 30, 2006.

At February 23, 2007, 35,256,170 shares of UniSource Energy Corporation Common Stock, no par value (the only class of Common Stock), were outstanding.

At February 23, 2007, 32,139,434 shares of Tucson Electric Power Company's common stock, no par value, were outstanding, all of which were held by UniSource Energy Corporation.

Tucson Electric Power Company meets the conditions set forth in General Instructions (I)(1)(a) and (b) on Form 10-K and is therefore filing this report with the reduced disclosure format.

Documents incorporated by reference: Specified portions of UniSource Energy Corporation's Proxy Statement relating to the 2007 Annual Meeting of Shareholders are incorporated by reference into Part III.

Table of Contents

DEFINITIONS

The abbreviations and acronyms used in the 2006 Form 10-K are defined below:

1992 Mortgage	TEP's Indenture of Mortgage and Deed of Trust, dated as of December 1, 1992, to the Bank of New York, successor trustee, as supplemented.
1992 Mortgage Bonds	Bonds issued under the 1992 Mortgage.
ACC	Arizona Corporation Commission.
ACC Holding Company Order	The order approved by the ACC in November 1997 allowing TEP to form a holding company.
AMT	Alternative Minimum Tax.
APS	Arizona Public Service Company.
BMGS	Black Mountain Generating Station under development by UED.
Btu	British thermal unit(s).
Capacity	The ability to produce power; the most power a unit can produce or the maximum that can be taken under a contract; measured in MWs.
Citizens	Citizens Communications Company.
Collateral Trust Bonds	Bonds issued under the Indenture of Trust, dated as of August 1, 1998, of TEP to The Bank of New York, successor trustee.
Common Stock	UniSource Energy's common stock, without par value.
Company or UniSource Energy	UniSource Energy Corporation.
Cooling Degree Days	An index used to measure the impact of weather on energy usage calculated by subtracting 75 from the average of the high and low daily temperatures.
DSM	Demand side management.
Emission Allowance(s)	An allowance issued by the Environmental Protection Agency which permits emission of one ton of sulfur dioxide or one ton of nitrogen oxide. These allowances can be bought and sold.
Energy	The amount of power produced over a given period of time; measured in MWh.
EPA	The Environmental Protection Agency.
ESP	Energy Service Provider.
FAS 71	Statement of Financial Accounting Standards No. 71: Accounting for the Effects of Certain Types of Regulation.
FAS 133	Statement of Financial Accounting Standards No. 133: Accounting for Derivative Instruments and Hedging Activities, as amended.
FAS 143	Statement of Financial Accounting Standards No. 143: Accounting for Asset Retirement Obligations.
FERC	Federal Energy Regulatory Commission.
Fixed CTC	Competition Transition Charge of approximately $0.009 per kWh that is included in TEP's retail rate for the purpose of recovering TEP's $450 million TRA by December 31, 2008.
Four Corners	Four Corners Generating Station.
Global Solar	Global Solar Energy, Inc., a company that develops and manufactures thin-film photovoltaic cells. Millennium sold its interest in Global Solar in March 2006.
Haddington	Haddington Energy Partners II, LP, a limited partnership that funds energy-related investments.
Heating Degree Days	An index used to measure the impact of weather on energy usage calculated by subtracting the average of the high and low daily temperatures from 65.
IDBs	Industrial development revenue or pollution control revenue bonds.
IPS	Infinite Power Solutions, Inc., a company that develops thin-film batteries. Millennium owns 31.4% of IPS.
IRS	Internal Revenue Service.
ISO	Independent System Operator.
ITC	Investment Tax Credit.
kWh	Kilowatt-hour(s).

kV..................................	Kilovolt(s).
LIBOR..............................	London Interbank Offered Rate.
Luna................................	Luna Energy Facility.
Mark-to-Market Adjustments	Forward energy sales and purchase contracts that are considered to be derivatives are adjusted monthly by recording unrealized gains and losses to reflect the market prices at the end of each month.
MEG................................	Millennium Environment Group, Inc., a wholly-owned subsidiary of Millennium, which manages and trades emission allowances and related financial instruments.
MicroSat...........................	MicroSat Systems, Inc. is a company formed to develop and commercialize small-scale satellites. Millennium currently owns 35%.
Millennium..........................	Millennium Energy Holdings, Inc., a wholly-owned subsidiary of UniSource Energy.
MMBtu.............................	Million British Thermal Units.
MW..................................	Megawatt(s).
MWh................................	Megawatt-hour(s).
Navajo..............................	Navajo Generating Station.
NOL.................................	Net Operating Loss carryback or carryforward for income tax purposes.
PGA.................................	Purchased Gas Adjuster, a retail rate mechanism designed to recover the cost of gas purchased for retail gas customers.
Phelps Dodge Decision	An Arizona Court of Appeals decision issued in 2005 that invalidated portions of the ACC's Retail Electric Competition Rules.
PNM.................................	Public Service Company of New Mexico.
PNMR...............................	PNM Resources.
Powertrusion.......................	POWERTRUSION International, Inc., a company owned 77% by Millennium, which manufactures lightweight utility poles.
PPFAC..............................	Purchased Power and Fuel Adjustment Clause.
PWMT..............................	Pinnacle West Marketing and Trading.
REST rules............................	Renewable Energy Standard and Tariff rules approved by the ACC in October 2006.
Repurchased Bonds.............	$221 million of fixed-rate tax-exempt bonds that TEP purchased from bondholders on May 11, 2005.
RTO.................................	Regional Transmission Organization.
Rules................................	Retail Electric Competition Rules.
Sabinas.............................	Carboelectrica Sabinas, S. de R.L. de C.V., a Mexican limited liability company. Millennium owns 50% of Sabinas.
San Carlos..........................	San Carlos Resources Inc., a wholly-owned subsidiary of TEP.
San Juan............................	San Juan Generating Station.
SES.................................	Southwest Energy Solutions, Inc., a wholly-owned subsidiary of Millennium.
Settlement Agreement..........	TEP's Settlement Agreement approved by the ACC in November 1999 that provided for electric retail competition and transition asset recovery.
Springerville.......................	Springerville Generating Station.
Springerville Coal Handling Facilities Leases............	Leveraged lease arrangements relating to the coal handling facilities serving Springerville.
Springerville Common Facilities.......................	Facilities at Springerville used in common with Springerville Unit 1 and Springerville Unit 2.
Springerville Common Facilities Leases...........	Leveraged lease arrangements relating to an undivided one-half interest in certain Springerville Common Facilities.
Springerville Unit 1...............	Unit 1 of the Springerville Generating Station.
Springerville Unit 1 Leases......	Leveraged lease arrangement relating to Springerville Unit 1 and an undivided one-half interest in certain Springerville Common Facilities.
Springerville Unit 2..............	Unit 2 of the Springerville Generating Station.
Springerville Unit 3..............	Unit 3 of the Springerville Generating Station.
SRP.................................	Salt River Project Agricultural Improvement and Power District.
Sundt................................	H. Wilson Sundt Generating Station (formerly known as the Irvington Generating Station).
Sundt Lease........................	The leveraged lease arrangement relating to Sundt Unit 4.

SWG................................	Southwest Gas Corporation.
TEP.................................	Tucson Electric Power Company, the principal subsidiary of UniSource Energy.
TEP Credit Agreement..........	Amended and Restated Credit Agreement between TEP and a syndicate of Banks, dated as of August 11, 2006.
TEP Guarantee Home Program	The TEP Home Guarantee Program provides incentives to new home builders to construct homes that meet the highest construction and energy-efficient standards available.
TEP Revolving Credit Facility	Revolving credit facility under the TEP Credit Agreement.
Therm..............................	A unit of heating value equivalent to 100,000 British thermal units (Btu).
TOU.................................	Time of use.
Track A.............................	An order issued by the ACC in 2002 which granted a waiver from the requirement in TEP's Settlement Agreement that TEP transfer its generating assets to a subsidiary.
Track B.............................	An order issued by the ACC in 2003 which defined a competitive bidding process TEP must use to obtain capacity and energy requirements.
TRA.............................	Transition Recovery Asset, a $450 million regulatory asset established in TEP's 1999 Settlement Agreement to be fully recovered by December 31, 2008.
Tri-State............................	Tri-State Generation and Transmission Association.
UED.................................	UniSource Energy Development Company, a wholly-owned subsidiary of UniSource Energy, which engages in developing generation resources and other project development services and related activities.
UES.................................	UniSource Energy Services, Inc., an intermediate holding company established to own the operating companies (UNS Gas and UNS Electric) which acquired the Citizens Arizona gas and electric utility assets in 2003.
UES Settlement Agreement...	An agreement with the ACC Staff dated April 1, 2003, addressing rate case and financing issues in the acquisition by UniSource Energy of Citizens' Arizona gas and electric assets.
UniSource Credit Agreement..	Amended and Restated Credit Agreement between UniSource Energy and a syndicate of banks, dated as of August 11, 2006.
UniSource Energy................	UniSource Energy Corporation.
UNS Electric.......................	UNS Electric, Inc., a wholly-owned subsidiary of UES, which acquired the Citizens Arizona electric utility assets in 2003.
UNS Gas............................	UNS Gas, Inc., a wholly-owned subsidiary of UES, which acquired the Citizens Arizona gas utility assets in 2003.
UNS Gas/UNS Electric Revolver	Revolving credit facility under the Amended and Restated Credit Agreement among UNS Gas and UNS Electric as borrowers, and UES as guarantor, and a syndicate of banks, dated as of August 11, 2006.
Valencia............................	Valencia power plant owned by UNS Electric.

PART I

This Annual Report on Form 10-K contains forward-looking statements as defined by the Private Securities Litigation Reform Act of 1995. You should read forward-looking statements together with the cautionary statements and important factors included in this Form 10-K. (See *Item 7. – Management's Discussion and Analysis of Financial Condition and Results of Operations, Safe Harbor for Forward-Looking Statements*). Forward-looking statements include statements concerning plans, objectives, goals, strategies, future events or performance and underlying assumptions. Forward-looking statements are not statements of historical facts. Forward-looking statements may be identified by the use of words such as "anticipates," "estimates," "expects," "intends," "plans," "predicts," "projects," and similar expressions. We express our expectations, beliefs and projections in good faith and believe them to have a reasonable basis. However, we make no assurances that management's expectations, beliefs or projections will be achieved or accomplished. In addition, UniSource Energy and TEP disclaim any obligation to update any forward-looking statements to reflect events or circumstances after the date of this report.

ITEM 1. – BUSINESS

OVERVIEW OF CONSOLIDATED BUSINESS

UniSource Energy is a holding company that has no significant operations of its own. Operations are conducted by UniSource Energy's subsidiaries, each of which is a separate legal entity with its own assets and liabilities. UniSource Energy owns the outstanding common stock of TEP, UniSource Energy Services, Inc. (UES), Millennium Energy Holdings, Inc. (Millennium), and UniSource Energy Development Company (UED).

TEP, an electric utility, has provided electric service to the community of Tucson, Arizona, for over 100 years. UES was established in 2003 when it acquired the Arizona gas and electric properties from Citizens. UES, through its two operating subsidiaries, UNS Gas, Inc. (UNS Gas) and UNS Electric, Inc. (UNS Electric), provides gas and electric service to 30 communities in Northern and Southern Arizona. Millennium has existing investments in unregulated businesses; no new investments are planned in Millennium. On March 31, 2006, Millennium sold its interest in Global Solar Energy, Inc. (Global Solar), its largest holding. UED facilitated the expansion of the Springerville Generating Station and is currently developing the Black Mountain Generating Station (BMGS), a gas turbine project in Northern Arizona that, subject to ACC approval, is expected to provide energy to UNS Electric. We conduct our business in three primary business segments – TEP, UNS Gas and UNS Electric.

UniSource Energy was incorporated in the State of Arizona in 1995 and obtained regulatory approval to form a holding company in 1997. In 1998, TEP and UniSource Energy exchanged shares of stock resulting in TEP becoming a subsidiary of UniSource Energy. Following the share exchange, TEP transferred the stock of its subsidiary Millennium to UniSource Energy.

BUSINESS SEGMENT CONTRIBUTIONS

The table below shows the contributions to our consolidated after-tax earnings by our three business segments and Other net income (loss).

	2006	2005	2004
	-Millions of Dollars-		
TEP	$ 67	$ 49	$ 46
UNS Gas	4	5	6
UNS Electric	5	5	4
Other [1]	(7)	(7)	(5)
Income Before Discontinued Operations and Cumulative Effect of Accounting Change	69	52	51
Discontinued Operations – Net of Tax [2]	(2)	(5)	(5)
Cumulative Effect of Accounting Change – Net of Tax	-	(1)	-
Consolidated Net Income	$ 67	$ 46	$ 46

[(1)] Includes: UniSource Energy parent company expenses; interest expense on the note payable from UniSource Energy to TEP in 2004 and 2005; income and losses from Millennium investments and UED, interest expense (net of tax) on the UniSource Energy Convertible Senior Notes and on the UniSource Energy Credit Agreement in 2006 and 2005; and, 2004 includes costs associated with the proposed acquisition of UniSource Energy by an unrelated party.

[(2)] Relates to the discontinued operations of Global Solar.

See *Item 7. – Management's Discussion and Analysis of Financial Condition and Results of Operations, Outlook and Strategies, for a discussion of our plans and strategies and Rates and Regulation*, below, for the status of competition in Arizona.

References in this report to "we" and "our" are to UniSource Energy and its subsidiaries, collectively.

TEP ELECTRIC UTILITY OPERATIONS

TEP was incorporated in the State of Arizona in 1963. TEP is the principal operating subsidiary of UniSource Energy. In 2006, TEP's electric utility operations contributed 76% of UniSource Energy's operating revenues and comprised 82% of its assets.

SERVICE AREA AND CUSTOMERS

TEP is a vertically integrated utility that provides regulated electric service to more than 392,000 retail customers in Southeastern Arizona. TEP's service territory consists of a 1,155 square mile area and includes a population of approximately 1 million in the greater Tucson metropolitan area in Pima County, as well as parts of Cochise County. TEP holds a franchise to provide electric distribution service to customers in the Cities of Tucson and South Tucson. These franchises expire in 2026 and 2017, respectively. TEP also sells electricity to other utilities and power marketing entities in the Western U.S.

Retail Customers

TEP provides electric utility service to a diverse group of residential, commercial, industrial, and public sector customers. Major industries served include copper mining, cement manufacturing, defense, health care, education, military bases and other governmental entities. TEP's retail sales are influenced by several factors, including seasonal weather patterns and overall economic climate.

Local, regional, and national economic factors can impact the financial condition and operations of TEP's large industrial customers. Such economic conditions may directly impact energy consumption by large industrial customers and may indirectly impact residential and small commercial sales and revenues if employment levels and consumer spending change.

In 2006, TEP's number of retail customers increased by 2% and total retail energy consumption increased by approximately 4%. The table below shows the percentage distribution of TEP's energy sales by major customer class over the last three years.

	2006	2005	2004
Residential	41%	41%	40%
Commercial	21%	21%	21%
Non-mining Industrial	25%	26%	26%
Mining	10%	9%	10%
Public Authority	3%	3%	3%

TEP expects the number of its retail customers and retail energy consumption to increase 2 – 3% annually through 2010. The retail energy consumption by customer class through 2010 is expected to be similar to the 2006 distribution.

In 2001, all of TEP's retail customers became eligible to choose an alternative energy service provider (ESP), however by 2002, none of TEP's retail customers were served by an alternate ESP. Certain portions of the Arizona Corporation Commission's (ACC) rules that enabled ESPs to compete in the retail market were invalidated by an Arizona Court of Appeals decision in 2005. Unless and until the ACC clarifies the competition rules and ESPs offer to provide energy in TEP's service area, it is not possible for TEP's retail customers to use other energy providers. Even if some of TEP's retail customers are, in the future, able to choose other energy providers, the forecasted customer growth rates referred to above would continue to apply to its distribution business. See *Rates and Regulation, State*, below.

Wholesale Business

TEP's electric utility operations include the wholesale marketing of electricity to other utilities and power marketers. Wholesale sales transactions are made on both a firm and interruptible basis. A firm contract requires TEP to supply power on demand (except under limited emergency circumstances), while an interruptible contract allows TEP to stop supplying power under defined conditions. See *Purchases and Interconnections*, below.

TEP typically uses its own generation to serve the requirements of its retail and long-term wholesale customers. Generally, TEP commits to future sales based on expected excess generating capability, forward prices and generation costs, using a diversified portfolio approach to provide a balance between long-term, mid-term and spot energy sales. When TEP expects to have excess coal generating capacity and energy (usually in the first, second and fourth calendar quarters), its wholesale sales consist primarily of two types of sales:

(1) Sales under long-term contracts for periods of more than one year. TEP currently has long-term contracts with three entities to sell firm capacity and energy: Salt River Project Agricultural Improvement and Power District (SRP), which will expire in May 2016, the Navajo Tribal Utility Authority, which expires in December 2009, and the Tohono O'odham Utility Authority, which expires in August 2009.

(2) Short-term sales. Under forward contracts, TEP commits to sell a specified amount of capacity or energy at a specified price over a given period of time, typically for one-month, three-month or one-year periods. Under short-term sales, TEP sells energy in the daily or hourly markets at fluctuating spot market prices and makes other non-firm energy sales.

TEP participates in the wholesale energy markets, primarily by making sales and purchases in the short-term and forward markets. Over the past three years, both the natural gas and the Western U.S. wholesale electricity markets experienced some price spikes and volatility due to severe winter weather, gas production and storage concerns and, in 2005, hurricane activity in the Gulf of Mexico. TEP cannot predict, however, whether gas and wholesale electricity prices will remain volatile or how these prices will impact TEP's sales and revenues in the future.

TEP expects the market price in the Western U.S. and the demand for capacity and energy to continue to be influenced by the following factors, among others:

- availability and price of natural gas;
- weather;
- continued population growth in the Western U.S.;
- economic conditions in the Western U.S.;
- availability of generation capacity throughout the Western U.S.;
- the extent of electric utility restructuring in Arizona, California and other Western states;
- FERC regulation of wholesale energy markets;
- availability of hydropower;
- transmission constraints; and
- environmental regulations and the cost of compliance.

See *Item 7. – Management's Discussion and Analysis of Financial Condition and Results of Operations, Tucson Electric Power Company, Factors Affecting Results of Operations, Western Energy Markets,* for additional discussion of TEP's wholesale marketing activities.

GENERATING AND OTHER RESOURCES

At December 31, 2006, TEP owned or leased 2,194 MW of net generating capability, as set forth in the following table:

Generating Source	Unit No.	Location	Date In Service	Fuel Type	Net Capability MW	Operating Agent	TEP's Share %	TEP's Share MW
Springerville Station[1]	1	Springerville, AZ	1985	Coal	380	TEP	100.0	380
Springerville Station	2	Springerville, AZ	1990	Coal	380	TEP	100.0	380
San Juan Station	1	Farmington, NM	1973	Coal	327	PNM	50.0	164
San Juan Station	2	Farmington, NM	1980	Coal	316	PNM	50.0	158
Navajo Station	1	Page, AZ	1974	Coal	750	SRP	7.5	56
Navajo Station	2	Page, AZ	1975	Coal	750	SRP	7.5	56
Navajo Station	3	Page, AZ	1976	Coal	750	SRP	7.5	56
Four Corners Station	4	Farmington, NM	1969	Coal	784	APS	7.0	55
Four Corners Station	5	Farmington, NM	1970	Coal	784	APS	7.0	55
Luna Energy Facility	1	Deming, NM	2006	Gas	570	PNM	33.0	190
Sundt Station	1	Tucson, AZ	1958	Gas/Oil	81	TEP	100.0	81
Sundt Station	2	Tucson, AZ	1960	Gas/Oil	81	TEP	100.0	81
Sundt Station	3	Tucson, AZ	1962	Gas/Oil	104	TEP	100.0	104
Sundt Station[1]	4	Tucson, AZ	1967	Coal/Gas	156	TEP	100.0	156
Internal Combustion Turbines		Tucson, AZ	1972	Gas/Oil	122	TEP	100.0	122
Internal Combustion Turbines		Tucson, AZ	2001	Gas	95	TEP	100.0	95
Solar Electric Generation		Springerville/ Tucson, AZ	2002-2005	Solar	5	TEP	100.0	5
Total TEP Capacity [2]								2,194

[1] Leased assets.

[2] Excludes 719 MW of additional resources, which consist of certain capacity purchases and interruptible retail load. At December 31, 2006, total owned capacity was 1,658 MW and leased capacity was 536 MW.

Springerville Generating Station

Springerville Unit 1 is leased by TEP. The Springerville Generating Station also includes the Springerville Coal Handling Facilities and the Springerville Common Facilities.

The terms of the Springerville Unit 1 Leases, which include a 50% interest in the Springerville Common Facilities, expire in 2015, but have optional fair market value renewal and purchase provisions. In 1985, TEP sold and leased back its remaining 50% interest in the Springerville Common Facilities. The terms of the Springerville Common Facilities Leases expire in 2017 and 2021, but have a fixed price purchase provision. In 1984, TEP sold and leased back the Springerville Coal Handling Facilities. The terms of the Springerville Coal Handling Facilities Leases expire in 2015, but have a fixed price purchase provision.

Since entering into the Springerville leases, TEP has purchased a 14% equity ownership in the Springerville Unit 1 Leases and a 13% equity ownership in the Springerville Coal Handling Facilities Leases.

Sundt Generating Station

The Sundt Generating Station and the internal combustion turbines located in Tucson are designated as "must-run generation" facilities. Must-run generation units are required to run in certain circumstances to maintain distribution system reliability and to meet local load requirements.

Sundt Unit 4 is leased by TEP. The terms of the Sundt Lease expire in 2011, but have optional fair market value renewal and purchase provisions.

See *Note 8 of Notes to Consolidated Financial Statements, Debt, Credit Facilities, and Capital Lease Obligations*, and *Item 7. – Management's Discussion and Analysis of Financial Condition and Results of Operations, Tucson Electric Power Company, Liquidity and Capital Resources, Contractual Obligations*, for more information regarding the Springerville and Sundt leases.

Luna Energy Facility

The Luna Energy Facility (Luna), located in Southern New Mexico, is a 570 MW combined cycle plant and was completed in April 2006. TEP's one-third share of the plant's capacity is 190 MW. Luna allows TEP to displace some of its less efficient gas-fired generation and purchased power requirements and to make additional short-term energy sales in the wholesale market. TEP's total investment of $49 million was funded with internal cash.

Purchases and Interconnections

TEP purchases power from other utilities and power marketers. TEP may enter into contracts: (a) to purchase energy under long-term contracts to serve retail load and long-term wholesale contracts, (b) to purchase capacity or energy during periods of planned outages or for peak summer load conditions, and (c) to purchase energy for resale to certain wholesale customers under load and resource management agreements. Finally, TEP may purchase energy in the daily and hourly markets to meet higher than anticipated demands, to cover unplanned generation outages, or when it is more economical than generating its own energy.

TEP is a member of various regional reserve sharing, reliability and power sharing organizations. These relationships allow TEP to call upon other utilities during emergencies, such as plant outages and system disturbances, and reduce the amount of reserves TEP is required to carry.

Springerville Units 3 and 4

In conjunction with the expansion of the Springerville Generating Station, TEP entered into a contract to purchase up to 100 MW of capacity of system resources from Tri-State Generation and Transmission Association (Tri-State), which leases 100% of the 400 MW Springerville Unit 3 from a financial owner. In May 2006, SRP announced its intention to build Springerville Unit 4, a 400 MW coal-fired plant at the Springerville site. Under certain conditions, TEP would be required to purchase 100 MW of Unit 4 capacity from SRP. See *Item 7. – Management's Discussion and Analysis of Financial Condition. Tucson Electric Power Company, Factors Affecting Results of Operations, Springerville Units 3 and 4.*

Peak Demand and Resources

Peak Demand	2006	2005	2004	2003	2002
			-MW-		
Retail Customers – Net One Hour	2,365	2,225	2,088	2,060	1,899
Firm Sales to Other Utilities	331	342	187	171	228
Coincident Peak Demand (A)	2,696	2,567	2,275	2,231	2,127
Total Generating Resources	2,194	2,004	2,004	2,003	2,002
Other Resources [(1)]	719	788	454	486	308
Total TEP Resources (B)	2,913	2,792	2,458	2,489	2,310
Total Margin (B) – (A)	217	225	183	258	183
Reserve Margin (% of Coincident Peak Demand)	8%	9%	8%	12%	9%

[(1)] Other Resources include firm power purchases and interruptible retail and wholesale loads.

Peak demand occurs during the summer months due to the cooling requirements of TEP's retail customers. Retail peak demand has grown at an average annual rate of approximately 6% from 2002 to 2006.

The chart above shows the relationship over a five-year period between TEP's peak demand and its energy resources. TEP's margin is the difference between total energy resources and coincident peak demand, and the reserve margin is the ratio of margin to coincident peak demand. TEP maintains a minimum reserve margin in excess of 7% to comply with reliability criteria set forth by the Western Electricity Coordinating Council. TEP's actual reserve margin in 2006 was 8%.

Forecasted retail peak demand for 2007 is approximately 2,476 MW, compared with actual peak demand of 2,365 MW in 2006. Except for certain peak hours during the summer, TEP believes it will have sufficient resources to meet expected demand in 2007 with its existing generation capacity and power purchase agreements.

Future Generating Resources

TEP will continue to add peaking resources to serve the Tucson area as needed based upon our forecasts of retail and firm wholesale load, as well as statewide transmission infrastructure. TEP currently forecasts that it may need additional peaking resources of 150 MW in 2015.

FUEL SUPPLY

Fuel Summary

Fuel cost and usage information is provided below on a delivered to the boiler basis:

	Average Cost per MMBtu Consumed			Percentage of Total Btu Consumed		
	2006	2005	2004	2006	2005	2004
Coal	$1.69	$1.69	$1.57	94%	96%	96%
Gas	$7.03	$8.09	$6.75	6%	4%	4%
All Fuels	$2.03	$1.93	$1.79	100%	100%	100%

Coal

TEP's principal fuel for electric generation is low-sulfur, bituminous or sub-bituminous coal from mines in Arizona, New Mexico and Colorado. The majority of its coal supplies are purchased under long-term contracts, which result in more predictable prices. The average cost per ton of coal, including transportation for 2006, 2005, and 2004 was $32.36, $32.43, and $30.20, respectively.

Station	Coal Supplier	Contract Expiration	Average Sulfur Content	Coal Obtained From (A)
Springerville	Peabody Coalsales Company	2020	0.9%	Lee Ranch Coal Company
Four Corners	BHP Billiton	2016	0.8%	Navajo Indian Tribe
San Juan	San Juan Coal Company	2017	0.8%	Federal and State Agencies
Navajo	Peabody Coalsales Company	2011	0.4%	Navajo and Hopi Indian Tribes
Sundt	Rio Tinto Energy America	2008	0.4%	Colowyo Mine

(A) Substantially all of the suppliers' mining leases extend at least as long as coal is being mined in economic quantities.

<u>TEP Operated Generating Facilities</u>

TEP is the sole owner (or lessee) and operator of the Springerville Units 1 and 2 and Sundt Unit 4 Generating Stations. The coal supplies for the Springerville Units 1 and 2 are transported approximately 200 miles by railroad from Northwestern New Mexico. TEP expects coal reserves to be sufficient to supply the estimated requirements for Units 1 and 2 for their presently estimated remaining lives.

The coal supply agreement for Sundt Unit 4 expired on December 31, 2006. On December 28, 2006, TEP entered into agreements for the purchase and transportation of coal to Sundt Unit 4 through 2008. The coal supplies are transported approximately 1,300 miles by railroad from Colorado. The cost of coal and transportation under the new agreements will increase approximately 60%, primarily due to significantly higher rail costs. TEP expects to pay approximately $20 million annually, compared with approximately $14 million annually under the old agreement, however the total amount paid under these agreements depends on the number of tons of coal purchased and transported.

See *Item 7. – Management's Discussion and Analysis of Financial Condition and Results of Operations, UniSource Energy Consolidated, Contractual Obligations and Note 6 of Notes to Consolidated Financial Statements – Commitments and Contingencies, TEP Commitments, Purchase and Transportation Commitments.*

Generating Facilities Operated by Others

TEP also participates in jointly-owned generating facilities at Four Corners, Navajo and San Juan. These are mine mouth generating stations located adjacent to the coal reserves. The coal supplies are under long-term contracts administered by the operating agents. TEP expects coal reserves available to these three jointly-owned generating facilities to be sufficient for the remaining lives of the stations.

Natural Gas Supply

TEP typically uses generation from its facilities fueled by natural gas and purchased power, in addition to energy from its coal-fired facilities, to meet the summer peak demands of its retail customers and local reliability needs. Some of these purchased power contracts are price indexed to natural gas prices. Short-term and spot power purchase prices are also closely correlated to natural gas prices. Due to its increasing seasonal gas and purchased power usage, TEP hedges a portion of its total natural gas exposure from plant fuel, gas-indexed purchased power and spot market purchases with fixed price contracts for a maximum of three years. TEP purchases its remaining gas fuel needs from the Permian Basin, and purchased power in the spot and short-term markets.

TEP entered into a Gas Procurement Agreement with Southwest Gas Corporation (SWG) in 2001, with a primary term of five years. Starting January 1, 2006, interim supply terms were put into place on a month-to-month basis until terminated by either party with 30 days' notice and did not include a minimum volume obligation. SWG provided notice to TEP to terminate this agreement effective February 28, 2007. TEP is currently negotiating a new contract and tariff terms with SWG for supply to its Tucson gas plants starting March 1, 2007, as well as evaluating other supply options. TEP does not expect any gas supply disruptions to its plants.

TEP purchased gas transportation for Luna from El Paso Natural Gas (EPNG) from the Permian basin to the plant site. The initial term of this agreement is from February 2006 to January 2009, with rights of first refusal for continuation thereafter.

WATER SUPPLY

The Four Corners region of New Mexico, where the San Juan and Four Corners Generating Stations are located, experienced drought conditions in 2002 through 2004 that could have affected the water supply for these plants. TEP has a 50% ownership interest in each of San Juan Units 1 and 2 (322 MW capacity) and a 7% ownership interest in each of Four Corners Units 4 and 5 (110 MW capacity). In future years, drought conditions may affect the water supply of the plants if adequate moisture is not received in the watershed that supplies the area. The operating agents for San Juan and Four Corners have negotiated supplemental water contracts with BHP Billiton and the Jicarilla Apache Nation to assist the generating plants in meeting their water requirements in the event of a shortage.

Drought conditions within the Southwestern region, combined with increased water usage in Arizona, Nevada and Southern California, have caused water levels to recede at Lake Powell, which supplies operating water for the Navajo Generating Station. TEP has a 7.5% ownership interest in Navajo Units 1, 2 and 3 (168 MW capacity). The operating agent for Navajo, along with the other plant owners, are evaluating options to ensure adequate water supply is available in the event drought conditions adversely affect the water level at Lake Powell.

TRANSMISSION ACCESS

TEP has transmission access and power transaction arrangements with over 120 electric systems or suppliers. TEP is taking steps to increase the capacity and reliability of its transmission and distribution system. In 2004, TEP completed a 500 kV connection that increased its energy import capability from the region, allowing TEP to decrease the use of its less efficient gas generating units in favor of more economical purchases of energy in the wholesale market. TEP also has various ongoing projects that are designed to increase access to the regional wholesale energy market and improve the reliability and efficiency of its existing transmission and distribution systems.

Tucson to Nogales Transmission Line

TEP and UNS Electric are parties to a project development agreement for the joint construction of a 62-mile transmission line from Tucson to Nogales, Arizona. The project was initiated in response to an order by the ACC to improve reliability to UNS Electric's retail customers in Nogales, Arizona.

In 2002, the ACC approved the location and construction of the proposed 345-kV transmission line along the Western Corridor route subject to a number of conditions, including obtaining all required permits from state and federal agencies. TEP is currently seeking approvals for the project from the Department of Energy (DOE), the U.S. Forest Service, the Bureau of Land Management, and the International Boundary and Water Commission.

The DOE has completed a Final Environmental Impact Statement (EIS) for the project in which it would accept any of the routes in the EIS but the U.S. Forest Service has indicated the Central route as its preferred alternative, rather than the Western Corridor route.

Based on the alternative proposals and passage of time since it approved the location of the line, the ACC, in 2005, ordered TEP to review the status of electric service reliability in Nogales, Arizona and the need for the 345-kV transmission line. The ACC also indicated that it would review any new information regarding the location of the proposed transmission line.

In 2005, an Administrative Law Judge (ALJ) for the ACC issued a recommended opinion and order reaffirming the ACC's original position requiring the construction of the Tucson to Nogales transmission line. After a hearing on the issue in February 2006, the ACC directed the ALJ to amend the recommendation to direct the Line Siting Committee of the ACC to gather facts related to options for improving service reliability in Nogales, Arizona. TEP expects the ALJ to issue, and the ACC to address, an amended recommended opinion and order related to the Nogales transmission line in 2007.

RATES AND REGULATION

The FERC and the ACC regulate portions of TEP's utility accounting practices and electricity rates. The FERC regulates the terms and prices of TEP's transmission services and wholesale electricity sales. In 1996, TEP filed a tariff at FERC governing the rates, terms and conditions of open access transmission services. In 1997, TEP was granted a FERC tariff to sell power at market based rates. The ACC has authority over rates charged to retail customers, the issuance of securities, and transactions with affiliated parties.

State

Historically, the ACC determined TEP's rates for retail sales of electric energy on a "cost of service" basis, which was designed to provide, after recovery of allowable operating expenses, an opportunity to earn a reasonable rate of return on TEP's "fair value rate base." Fair value rate base was generally determined by reference to the original cost and the reconstruction cost (net of depreciation) of utility plant in service to the extent deemed used and useful, and to various adjustments for deferred taxes and other items, plus a working capital component. Over time, additions to utility plant in service increased rate base and depreciation and retirements of utility plant reduced rate base.

Settlement Agreement

In 1999, the ACC approved the Retail Electric Competition Rules (Rules) that provided a framework for the introduction of retail electric competition in Arizona, as well as the Settlement Agreement between TEP and certain customer groups related to the implementation of retail electric competition in Arizona. See *Item 7. – Management's Discussion and Analysis of Financial Condition and Results of Operations, Tucson Electric Power Company, Rates,* for more information.

Arizona Court of Appeals Decision Invalidating Certain Retail Electric Competition Rules

In 2004, an Arizona Court of Appeals decision held invalid certain portions of the ACC rules on retail competition and related market pricing. Based on this decision, we expect that the ACC will address the competition rules in an administrative proceeding. We cannot predict what changes, if any, the ACC will make to the competition rules. See *Item 7. – Management's Discussion and Analysis of Financial Condition and Results of Operations, Tucson Electric Power Company, Competition,* for more information.

TEP'S UTILITY OPERATING STATISTICS

	For Years Ended December 31,				
	2006	2005	2004	2003	2002
Generation and Purchased Power – kWh (000)					
Remote Generation (Coal)	**10,338,844**	10,059,315	10,159,729	10,182,706	10,067,069
Local Tucson Generation (Oil, Gas & Coal)	**1,482,342**	1,165,001	1,174,500	1,082,058	1,402,504
Purchased Power	**1,707,450**	1,638,737	1,322,084	1,153,305	1,329,574
Total Generation and Purchased Power	**13,528,636**	12,863,053	12,656,313	12,418,069	12,799,147
Less Losses and Company Use	**886,252**	806,168	821,008	778,285	791,852
Total Energy Sold	**12,642,384**	12,056,885	11,835,305	11,639,784	12,007,295
Sales – kWh (000)					
Residential	**3,778,369**	3,633,226	3,459,750	3,389,744	3,181,030
Commercial	**1,959,141**	1,855,432	1,787,472	1,689,014	1,605,148
Industrial	**2,278,244**	2,302,327	2,226,314	2,245,340	2,254,174
Mining	**924,898**	842,881	829,028	701,638	692,448
Public Authorities	**260,767**	241,119	240,426	250,038	256,867
Total – Electric Retail Sales	**9,201,419**	8,874,985	8,542,990	8,275,774	7,989,667
Electric Wholesale Sales	**3,440,965**	3,181,900	3,292,315	3,364,010	4,017,628
Total Electric Sales	**12,642,384**	12,056,885	11,835,305	11,639,784	12,007,295
Operating Revenues (000)					
Residential	**$ 343,459**	$ 330,614	$ 315,402	$ 309,807	$ 291,390
Commercial	**203,284**	192,966	186,625	175,559	168,838
Industrial	**165,068**	165,988	161,338	160,276	161,749
Mining	**43,724**	39,749	38,549	28,022	28,072
Public Authorities	**18,935**	17,559	17,427	17,839	18,672
Total – Electric Retail Sales	**774,470**	746,876	719,341	691,503	668,721
Electric Wholesale Sales	**187,750**	178,428	159,918	151,030	157,108
Other Revenues	**35,502**	12,166	10,039	9,018	8,618
Total Operating Revenues	**$ 997,722**	$ 937,470	$ 889,298	$ 851,551	$ 834,447
Customers (End of Period)					
Residential	**357,646**	350,628	341,870	334,131	326,847
Commercial	**34,104**	33,534	32,923	32,369	31,767
Industrial	**664**	673	676	676	695
Mining	**2**	2	2	2	2
Public Authorities	**61**	61	61	61	61
Total Retail Customers	**392,477**	384,898	375,532	367,239	359,372
Average Retail Revenue per kWh Sold (cents)					
Residential	**9.1**	9.1	9.1	9.1	9.2
Commercial	**10.4**	10.4	10.4	10.4	10.5
Industrial and Mining	**6.6**	6.5	6.5	6.4	6.4
Average Retail Revenue per kWh Sold	**8.4**	8.4	8.4	8.4	8.4
Average Revenue per Residential Customer	**$ 971**	$ 954	$ 933	$ 937	$ 902
Average kWh Sales per Residential Customer	**10,681**	10,484	10,231	10,249	9,842

ENVIRONMENTAL MATTERS

Air and water quality, resource extraction, waste disposal and land use are regulated by federal, state and local authorities. TEP believes that all existing facilities are in compliance and will be in compliance with expected environmental regulations.

Federal Clean Air Act Amendments

The 1990 Federal Clean Air Act Amendments (CAAA), through the Acid Rain Program, requires reductions of sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions; this affects all of TEP's generating facilities (except 142 MW of its internal combustion turbines).

TEP's generating units affected by CAAA Phase II have been allocated SO_2 Emission Allowances based on past operational history. Each allowance gives the owner the right to emit one ton of SO_2. Generating units subject to CAAA Phase II must hold Emission Allowances equal to the level of emissions in the compliance year or pay penalties and offset excess emissions in future years. TEP has Emission Allowances in excess of what is required to comply with the CAAA Phase II SO_2 regulations. The excess results primarily from a higher removal rate of SO_2 emissions at Springerville Units 1 and 2 following recent upgrades to environmental plant components and related changes to plant operations. Potential changes to the allocation of SO_2 allowances may impact these expectations in future years.

Title V of the CAAA requires that all of TEP's generating facilities obtain more stringent air quality permits. All TEP facilities (including those jointly owned and operated by others) have obtained these permits. TEP received a new Title V permit for the Springerville generating station in 2006. TEP expects that a new Title V permit will be issued for the Sundt generating station in 2007. Because TEP has submitted a permit renewal application for the Sundt facility, under its Title V permit, TEP can continue to operate the plant. TEP must pay an annual emission-based fee for each generating facility subject to a Title V permit. These emission-based fees are included in the CAAA compliance expenses discussed below. The CAAA also requires multi-year studies of visibility impairment in specified areas and studies of hazardous air pollutants. The results of these studies will impact the development of future regulation of electric utility generating units.

Mercury Emissions

In 2005, the EPA adopted regulations relating to mercury emissions requiring states to develop rules for implementing federal requirements. Arizona adopted its mercury emission limits in 2007 and TEP must meet these limits by 2013. TEP is analyzing the potential impact of the Arizona regulations on its operations but does not expect the capital costs to exceed $5 million.

TEP is also monitoring the New Mexico and Navajo Nation mercury emission regulations affecting plants for which TEP has an ownership share. Until these state procedures are adopted, TEP cannot determine if it will be significantly affected.

Greenhouse Gas Emissions

Federal, state and local legislative and regulatory bodies are considering the regulation of greenhouse gas emissions. At this time, we do not know whether any such regulations will be adopted, the scope of such regulations or how any such regulations could affect our operations.

Regional Haze

The EPA's Regional Haze Rule requires states to develop plans to restore visibility in Federal Class I Areas (such as parks, monuments and wilderness areas) to their natural conditions by 2064. State plans must be submitted to the EPA in December 2007, could require pollution control upgrades at some of TEP's power plants. The level of control required, if any, will not be known until the state plans are submitted and approved by EPA. If required, controls would need to be in place by 2013 or later.

TEP may incur additional costs to comply with recent and future changes in federal and state environmental laws, regulations and permit requirements at existing electric generating facilities. Compliance with these changes may reduce operating efficiency.

State Regulations

Arizona and New Mexico have adopted regulations restricting the emissions from existing and future coal, oil and gas-fired plants. TEP believes that all existing generating facilities are in compliance with all existing state regulations. These regulations are in some instances more stringent than those adopted by the EPA. The principal generating units of TEP are located relatively close to national parks, monuments, wilderness areas and Indian reservations. These areas have relatively high air quality and TEP could be subject to control standards that relate to the "prevention of significant deterioration" of visibility and tall stack limitation rules. See *Note 6 of Notes to Consolidated Financial Statements, Commitments and Contingencies, TEP Contingencies, Litigation and Claims Related to San Juan Generating Station.*

In October 2006, the ACC approved new Renewable Energy Standard and Tariff rules (REST rules) designed to require TEP, UNS Electric and other affected utilities to generate 15% of their total energy requirements from renewable energy technologies by 2025. To offset the increased costs of meeting the more aggressive standard, the REST rules allow a change in the existing Environmental Portfolio Surcharge. See *Item 7. – Management's Discussion and Analysis of Financial Condition and Results of Operations, TEP, Factors Affecting Results of Operations, Renewable Energy Standard and Tariff*, for more information.

Capital and Operating Costs

TEP capitalized $1 million in 2006, $1 million in 2005 and $9 million in 2004 in construction costs to comply with environmental requirements and expects to capitalize $18 million in 2007 and $42 million in 2008. The increase in environmental capital expenditures in 2007 and 2008 is due primarily to pollution control upgrades to be made at San Juan.

TEP recorded expenses of $10 million in 2006, $11 million in 2005 and $9 million in 2004 related to environmental compliance, including the cost of lime used to scrub the stack gas. TEP expects environmental expenses to be $11 million in 2007. TEP may incur additional costs to comply with recent and future changes in federal and state environmental laws, regulations and permit requirements at existing electric generating facilities. Compliance with these changes may result in a reduction in operating efficiency.

In order to meet Title V permit requirements in connection with the construction of Springerville Unit 3, the Unit 3 project paid approximately $90 million for upgrades to pollution control equipment on Springerville Units 1 and 2 and common facilities. See *Note 6 of Notes to Consolidated Financial Statements - Commitments and Contingencies, Resolution of Springerville Generating Station Complaint.*

UNS GAS

SERVICE TERRITORY AND CUSTOMERS

UNS Gas is a gas distribution company serving approximately 145,000 retail customers in Mohave, Yavapai, Coconino, and Navajo counties in Northern Arizona, as well as Santa Cruz County in Southeast Arizona. These counties comprise approximately 50% of the territory in the state of Arizona, with a population of approximately 773,000 in 2006.

UNS Gas' customer base is primarily residential. Total revenues derived from residential customers were approximately 61% in 2006, while sales to other retail customer classes accounted for approximately 30% of total revenues. Approximately 9% of total revenues in 2006 were derived from gas transportation services and a

Negotiated Sales Program (NSP). UNS Gas supplies natural gas transportation service to the 600 MW Griffith Power Plant located near Kingman, Arizona, under a 20-year contract which expires in 2021. UNS Gas also supplies natural gas to some of its large transportation customers through an NSP approved by the ACC. One half of the margin earned on these NSP sales is retained by UNS Gas, while the other half benefits retail customers through a credit to the purchased gas adjustor (PGA) mechanism which reduces the gas commodity price.

GAS SUPPLY AND TRANSMISSION

UNS Gas has a natural gas supply and management agreement with BP Energy Company (BP). Under the contract, BP manages UNS Gas' existing supply and transportation contracts and its incremental requirements. The initial term of the agreement expired in August 2005, but the agreement automatically extends for one year on an annual basis unless either party provides 180 days notice of its intent to terminate. No termination notice has been tendered by either party. The market price for gas supplied by BP will vary based upon the period during which the commodity is delivered. UNS Gas hedges its gas supply prices by entering into fixed price forward contracts at various times during the year to provide more stable prices to its customers. These purchases are made up to three years in advance with the goal of hedging at least 45% of the expected monthly gas consumption with fixed prices prior to entering into the month.

UNS Gas buys most of the gas it distributes from the San Juan Basin in the Four Corners region. The gas is delivered on the El Paso and Transwestern interstate pipeline systems. UNS Gas has firm transportation agreements with EPNG and Transwestern Pipeline Company (Transwestern) with combined capacity sufficient to meet its customers' demands.

With EPNG, the average daily capacity right of UNS Gas is approximately 655,000 therms per day, with an average of 1,095,000 therms per day in the winter season (November through March) to serve its Northern and Southern Arizona service territories. UNS Gas has capacity rights of 250,000 therms per day on the San Juan Lateral and Mainline of the Transwestern pipeline. The Transwestern pipeline principally delivers gas to the portion of UNS Gas' distribution system serving customers in Flagstaff and Kingman, Arizona, and also delivers gas to UNS Gas' facilities serving the Griffith Power Plant in Mohave County.

See *Item 7. – Management's Discussion and Analysis of Financial Condition and Results of Operations, UNS Gas, Liquidity and Capital Resources, Contractual Obligations, UNS Gas Supply Contracts*, for more information.

RATES AND REGULATION

The ACC regulates UNS Gas with respect to retail gas rates, the issuance of securities, and transactions with affiliated parties. UNS Gas' retail gas rates include a monthly customer charge, a base rate charge for delivery services and the cost of gas (expressed in cents per therm), and a PGA.

Purchased Gas Adjustor

The PGA mechanism is intended to address the volatility of natural gas prices and allow UNS Gas to recover its actual commodity costs, including transportation, through a price adjustor. The difference between UNS Gas' actual gas and transportation costs and the cost of gas and transportation recovered through base rates are deferred and recovered or returned to customers through the PGA mechanism. See *Item 7. – Management's Discussion and Analysis of Financial Condition and Results of Operations, UNS Gas, Factors Affecting Results of Operations, Rates and Regulation, Energy Cost Adjustment Mechanism*, for more information.

General Rate Case

In July 2006, UNS Gas filed a general rate case to recover the costs related to serving its growing customer base. UNS Gas also requested modifications to its PGA mechanism to help address problems posed by volatile gas prices. Under the terms of the UES Settlement Agreement, new rates cannot go into effect before August 1, 2007. See *Item 7. – Management's Discussion and Analysis of Financial Condition and Results of Operations, UNS Gas, Rates*, for more information.

ENVIRONMENTAL MATTERS

UNS Gas is subject to environmental regulation of air and water quality, resource extraction, waste disposal and land use by federal, state and local authorities. UNS Gas believes that all existing facilities are in compliance with all existing regulations and will be in compliance with expected environmental regulations.

UNS ELECTRIC

SERVICE TERRITORY AND CUSTOMERS

UNS Electric is an electric transmission and distribution company serving approximately 93,000 retail customers in Mohave and Santa Cruz counties. These counties had a population of approximately 240,000 in 2006.

UNS Electric's customer base is primarily residential, with some small commercial and both light and heavy industrial customers. Peak demand for 2006 was 417 MW.

POWER SUPPLY AND TRANSMISSION

Power Supply

UNS Electric has a full requirements power supply agreement with Pinnacle West Marketing and Trading (PWMT) which expires in May 2008. The agreement obligates PWMT to supply all of UNS Electric's power requirements at a fixed price. Payments under the contract are usage based, with no fixed customer or demand charges.

UNS Electric owns and operates the Valencia Power Plant (Valencia), located in Nogales, Arizona. Valencia consists of four gas and diesel-fueled combustion turbine units and provides approximately 68 MW of peaking resources. This includes a 20 MW unit installed in 2006. The facility is directly interconnected with the distribution system serving the city of Nogales and the surrounding areas. Under the PWMT agreement, Valencia will be dispatched by PWMT when needed for local reliability or when it is economic relative to other PWMT resources.

Transmission

UNS Electric imports the power it purchases from PWMT into its Mohave County and Santa Cruz County service territories over Western Area Power Administration's (WAPA) transmission lines. UNS Electric is currently negotiating a network transmission service agreement to replace its primary transmission capacity agreement with WAPA for the Parker-Davis system that expires in February 2008. The new agreement is expected to have no expiration date and be effective by the end of the first quarter of 2007. UNS Electric also has a long-term electric point to point transmission capacity agreement with WAPA for the Southwest Intertie system that expires in 2011.

UNS Electric plans to upgrade its existing 115 kV transmission line over time to improve the reliability of service in Santa Cruz County.

Future Power Supply

UNS Electric is in the process of evaluating and securing power supply resources to ensure adequate resources are in place when its PWMT agreement expires in May 2008. In 2006, UNS Electric entered into various power supply agreements for periods for one to five years beginning in June 2008. In addition, as part of its general rate case filing, UNS Electric included a proposal to purchase the 90 MW Black Mountain Generating Station (BMGS) in 2008, which is under development by UED. As of February 23, 2007, UNS Electric had 28% of its total expected resource needs for June 2008; this includes purchased power contracts as well as generating assets. See *Item 7. – Management's Discussion and Analysis of Financial Condition and Results of Operations, UNS Electric, Liquidity and Capital Resources, Contractual Obligations and Other, UED*, below for more information.

RATES AND REGULATION

UNS Electric is regulated by the ACC with respect to retail electric rates, quality of service, the issuance of securities, and transactions with affiliated parties, and by the FERC with respect to wholesale power contracts and interstate transmission service. UNS Electric's retail electric rates include a purchased power and fuel adjustment clause (PPFAC), which allows for UNS Electric to recover the actual costs of its power purchases.

General Rate Case

In December 2006, UNS Electric filed a general rate case to recover the costs related to serving its growing customer base. Under the terms of the UES Settlement Agreement, new rates cannot go into effect before August 1, 2007. See *Item 7. – Management's Discussion and Analysis of Financial Condition and Results of Operations, UNS Electric, Rates*, for more information.

ENVIRONMENTAL MATTERS

UNS Electric is subject to environmental regulation of air and water quality, resource extraction, waste disposal and land use by federal, state and local authorities. UNS Electric believes that all existing facilities are in compliance with all existing regulations and will be in compliance with expected environmental regulations.

Like TEP, UNS Electric is subject to the ACC's REST rules. See *TEP Electric Utility Operations, Environmental Matters, State Regulation,* above.

OTHER

UED

UED facilitated the expansion of the Springerville Generating Station and is currently developing the 90 MW gas-fired BMGS in Kingman, Arizona. In October 2006, UED purchased two electric generating gas turbines that will be part of the BMGS. Completion of the project is estimated to occur in May 2008. Pending ACC approval, BMGS is expected to be used as a resource for UNS Electric.

Millennium Investments

Through affiliates, Millennium holds investments in unregulated energy and emerging technology companies. At December 31, 2006, Millennium's assets represented 3% of UniSource Energy's total assets. UniSource Energy has ceased making loans or equity contributions to Millennium. We anticipate that the funding for Millennium's remaining commitments will be provided only out of existing Millennium cash or cash returns from Millennium investments. See *Item 7. – Management's Discussion and Analysis of Financial Condition and Results of Operations, Other, Liquidity and Capital Resources.*

Consolidated Millennium Investments

Southwest Energy Solutions, Inc. (SES), a wholly-owned Millennium subsidiary, provides electrical contracting services in Arizona to commercial, industrial and governmental customers in both high voltage and inside wiring capacities. SES also provides meter reading services to TEP and UNS Electric.

Millennium Environmental Group, Inc. (MEG), a wholly-owned Millennium subsidiary, manages and trades emission allowances and other environmental-related products, including derivative instruments. MEG is in the process of winding down its activities and does not anticipate engaging in any significant new activities.

Nations Energy Corporation (Nations Energy), a wholly-owned subsidiary of Millennium, has been inactive since 2001.

Equity Method Millennium Investments

Haddington Energy Partners II, LP (Haddington) is a limited partnership that funds energy-related investments. A member of the UniSource Energy Board of Directors has an investment in Haddington, has a non-management advisory role with respect to Haddington Ventures, LLP, a limited partnership that is the general partner of Haddington, and also is a voting member of the investment committee that makes decisions with respect to investments in Haddington. Millennium committed $15 million in capital, excluding fees, to Haddington in exchange for approximately 31% ownership. As of December 31, 2006, Millennium had invested $15 million in Haddington since its inception, and received distributions of $15 million. Millennium has no remaining commitment to Haddington. Millennium's total investment balance in Haddington at December 31, 2006 was $5 million.

Valley Ventures III, LP (Valley Ventures) is a venture capital fund that focuses on investments in information technology, microelectronics and biotechnology, primarily within the Southwestern U.S. Another member of the UniSource Energy Board of Directors was a general partner of the company that manages the fund until January 1, 2006, at which time the Board member terminated his role and interest as a general partner but maintained a non-voting financial interest in the company. Millennium committed $6 million, including fees, to the fund and owns approximately 15% of the fund. As of December 31, 2006, Millennium has not received any distributions from Valley Ventures and had $1 million remaining on this commitment, which is expected to be funded over the next two to three years. Millennium's total investment balance in Valley Ventures at December 31, 2006 was $4 million.

Carboelectrica Sabinas, S. de R.L. de C.V. (Sabinas) is a Mexican limited liability company created to develop up to 800 MW of coal-fired generation in the Sabinas region of Coahuila, Mexico. Sabinas also owns 19.5% of Minerales de Monclova, S.A. de C.V. (Mimosa). Mimosa is an owner of coal and associated gas reserves and a supplier of metallurgical coal to the Mexican steel industry and thermal coal to the major electric utility in Mexico. Millennium owns 50% of Sabinas. Altos Hornos de Mexico, S.A. de C.V. (AHMSA) and affiliates own the remaining 50%. UniSource Energy's Chairman, President and Chief Executive Officer is a member of the Board of Directors of AHMSA. Since 1999, both AHMSA and Mimosa are parties to a suspension of payments procedure, under applicable Mexican law, which is the equivalent of a U.S. Chapter 11 proceeding. Under certain circumstances, Millennium has the right to sell (a put option) its interest in Sabinas to an AHMSA affiliate for $20 million plus any accrued service fee. Millennium's remaining investment balance in Sabinas at December 31, 2006 was $14 million.

Discontinued Operations - Global Solar Energy

On March 31, 2006, Millennium completed the sale of its interest in Global Solar. The operating results of Global Solar are reported as discontinued operations.

EMPLOYEES (As of December 31, 2006)

TEP had 1,260 employees, of which approximately 54% are represented by the International Brotherhood of Electrical Workers (IBEW) Local No. 1116. A collective bargaining agreement between the IBEW and TEP was ratified in January 2006 and expires in January 2009.

UNS Gas had 214 employees, of which 126 employees were represented by IBEW Local No. 1116 and 6 employees were represented by IBEW Local No. 387. The agreements with the IBEW Local No. 1116 and No. 387 expire in June 2009 and February 2010, respectively.

UNS Electric had 164 employees, of which 28 employees were represented by the IBEW Local No. 387 and 109 employees were represented by the IBEW Local No. 769. The existing agreement with the IBEW Local No. 387 expires in February 2010 and the agreement with IBEW Local No. 769 expires in July 2007.

SES had 258 employees, of which approximately 96% are represented by unions. Of the employees represented by unions, 224 are represented by IBEW Local No. 1116, 11 by IBEW Local No. 769 and 13 by IBEW Local No. 570. The existing agreements expire as follows: IBEW Local No. 1116, January 2009; IBEW Local No. 769, July 2007; and IBEW Local No. 570, May 2009.

SEC REPORTS AVAILABLE ON UNISOURCE ENERGY'S WEBSITE

UniSource Energy and TEP make available their annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments to those reports as soon as reasonably practicable after they electronically file them with, or furnish them to, the Securities and Exchange Commission (SEC). These reports are available free of charge through UniSource Energy's website address: http://www.uns.com. A link from UniSource Energy's website to these SEC reports is accessible as follows: At the UniSource Energy main page, select Investor Relations from the menu shown at the top of the page; next select SEC filings from the menu shown on the Investor Relations page. UniSource Energy's code of ethics, and any amendments made to the code of ethics, is also available on UniSource Energy's website.

Information contained at UniSource Energy's website is not part of any report filed with the SEC by UniSource Energy or TEP.

ITEM 1A. – RISK FACTORS

The business and financial results of UniSource Energy and TEP are subject to a number of risks and uncertainties, including those set forth below and in other documents we file with the SEC.

Regulatory and other restrictions limit the ability of TEP, UNS Gas and UNS Electric to make distributions to UniSource Energy.

UniSource Energy is a holding company that is dependent on the earnings and distributions of funds from its subsidiaries to service its debt and pay dividends to shareholders.

Restrictions include:

- TEP, UNS Gas and UNS Electric are restricted from lending or transferring funds or issuing securities without ACC approval;
- The Federal Power Act restricts electric utilities' ability to pay dividends out of funds that are properly included in their capital account. TEP has an accumulated deficit rather than positive retained earnings. Although the terms of the Federal Power Act are unclear, we believe there is a reasonable basis for TEP to pay dividends from current year earnings. However, the FERC could attempt to stop TEP from paying further dividends or could seek to impose additional restrictions on the payment of dividends; and
- TEP, UNS Gas and UNS Electric must be in compliance with their respective debt agreements to make dividend payments to UniSource Energy.

UniSource Energy does not expect to receive distributions from UNS Gas or UNS Electric before 2008 due to the need to apply internally generated funds to the growth of these businesses.

TEP's retail rates are capped through 2008, which could negatively impact TEP's results of operations, net income and cash flows.

TEP's current retail rates were established under a Settlement Agreement approved by the ACC in 1999. Under the Settlement Agreement, TEP's rates are capped until December 31, 2008. Operational failures or unscheduled outages at TEP's generating stations, especially during peak seasons, could result in unanticipated power purchases which could significantly increase the cost of serving TEP's retail load. Operational failures or damage to TEP's facilities, from storms or other events, could result in increased operating and capital expenses.

In the event that any power purchase, natural gas or coal costs, operation and maintenance or other expenses increase, TEP could be adversely affected unless it were able to find ways of offsetting these increased costs with other cost reductions or increases in income and cash flow or otherwise seek rate recovery of such increased costs under emergency provisions of the Settlement Agreement. TEP may not be able to recover such costs.

Uncertainty exists as to what methodology the ACC will use to set TEP's retail rates after December 31, 2008, which could negatively impact TEP's results of operations, net income and cash flows.

There is disagreement between the participants in TEP's regulatory proceedings about what is to happen to the rates TEP charges for generation service after December 31, 2008. TEP believes the Settlement Agreement requires it to charge market-based generation service rates while other participants, including ACC staff, disagree.

The Settlement Agreement also requires TEP to record and amortize a $450 million transition recovery asset (TRA) and collect the balance from customers though a Fixed Competition Transition Charge (Fixed CTC). Based on current projections of retail sales, the TRA is expected to be fully amortized by mid-2008. The Fixed CTC currently produces revenues of slightly less than one cent per kWh sold, or approximately $90 million annually. If TEP is required to reduce its retail rates by the amount of the Fixed CTC, and is not allowed to charge market rates for its generation services or to adjust other rate components to reflect a higher cost of service, TEP's retail revenues will decrease approximately 12% relative to 2006 revenues from current retail rates.

Restrictions on rate increases and the ability to recover fuel costs at UNS Gas could negatively impact its liquidity, cash flows and net income.

UNS Gas filed a general rate case in July 2006. Under the terms of an ACC order, any resulting rate increase may not become effective until August 1, 2007.

UNS Gas is subject to operational risks, including operational failures or damage to facilities which could result in unplanned operation, maintenance and capital expenditures. UNS Gas could be adversely affected unless it was able to find ways of offsetting these increased costs.

UNS Gas has an automatic gas price adjustment mechanism, known as the Purchased Gas Adjustor (PGA), through which increases or decreases in the cost of gas can be passed on to customers. The PGA is subject to a cap on how much the factor can change in a 12-month period and anything above the cap must be approved by the ACC.

In 2006, the cost of gas represented more than 77% of UNS Gas' total operating costs. Natural gas prices may fluctuate substantially over relatively short periods of time and expose UNS Gas to commodity price risks to the extent they cannot be collected from customers in a timely manner.

If UNS Gas is unable to recover its fuel costs or other costs of providing service in a timely manner, its liquidity could be adversely affected and it may be more difficult for UNS Gas to satisfy its obligations, including purchasing and paying for gas. In addition, it may be more difficult for UNS Gas to comply with the obligations and restrictive covenants of its debt agreements, which limit its ability to borrow money, and could result in an event of default.

Restrictions on rate increases and the ability to recover purchased power and fuel costs at UNS Electric could negatively impact its liquidity, cash flows and net income.

UNS Electric filed a general rate case in December 2006. Under the terms of an ACC order, any resulting rate increase may not become effective until August 1, 2007.

Operational failures or damage to UNS Electric's facilities from storms or other events could result in increased operating and capital expenditures. UNS Electric could be adversely affected unless it was able to find ways of offsetting these increased costs.

The expiration of UNS Electric's power supply agreement will require UNS Electric to find alternate sources for its energy needs, which may not be recovered through rates.

UNS Electric has a full requirements power supply agreement for 100% of its customers' energy needs that expires May 2008. UNS Electric pays a fixed price per MWh for the power it purchases under the agreement. In 2006, UNS Electric sold approximately 1.6 million MWh to its retail customers. In 2008, UNS Electric will need a replacement source of energy for its customer base, which grew at 4% in 2006.

UNS Electric has a purchased power and fuel adjustment clause (PPFAC) through which increases or decreases in the cost of power and fuel can be passed on to customers. The cost of UNS Electric's existing power supply agreement is being fully recovered through the PPFAC. The ACC must approve any change to the PPFAC.

UNS Electric may be required to post margin under its power supply agreements which could negatively impact its liquidity.

UNS Electric is in the process of evaluating and securing power supply resourced to replace the full requirements power supply agreement which expires in May 2008. The agreements under which UNS Electric contracts for such resources include requirements to post credit enhancement in the form of cash or letters of credit under certain circumstances, including changes in market prices which affect contract values, or a change in the creditworthiness of UNS Electric.

In order to post such credit enhancement, UNS Electric would have to use available cash, draw under its revolving credit agreement, or issue letters of credit under its revolving credit agreement. As of February 23, 2007, the maximum amount that UNS Electric may use under its revolving credit facility is $30 million (to be increased to $45 million upon approval of a matter pending before the ACC).

TEP's, UNS Gas' and UNS Electric's revenues, results of operations and cash flows are seasonal, and are subject to weather conditions, economic conditions and customer usage patterns, which are beyond the Company's control.

TEP typically earns the majority of its operating revenue and net income in the third quarter because of higher air conditioning usage by its retail customers due to hot summer weather. Furthermore, TEP typically reports limited net income in the first quarter because of relatively mild winter weather in its retail service territory. UNS Gas' peak sales occur in the winter; UNS Electric's peak sales occur in the summer. Cool summers or warm winters may adversely affect the utility subsidiaries' operating revenues and net income by reducing sales.

Changes in federal energy regulation may affect TEP, UNS Gas and UNS Electric's results of operations, net income and cash flows.

TEP, UNS Gas and UNS Electric are subject to comprehensive and changing governmental regulation at the federal level that continues to change the structure of the electric and gas utility industries and the ways in which these industries are regulated. UniSource Energy's utility subsidiaries are subject to regulation by the Federal Energy Regulatory Commission (FERC). The FERC has jurisdiction over rates for electric transmission in interstate commerce and rates for wholesale sales of electric power, including terms and prices of transmission services and sales of electricity at wholesale prices.

Deregulation or restructuring of the electric utility industry may result in increased competition resulting in an erosion of TEP and UNS Electric's retail customer base and a reduction in TEP's wholesale revenues.

In 1999, the ACC approved rules providing a framework for the introduction of retail electric competition in Arizona. As a result of the energy crisis in California in 2000 and 2001 and the volatility of natural gas prices, the competitive retail market in Arizona that was anticipated in 1999 did not materialize. In addition, a 2005 Arizona Court of Appeals ruling held certain portions of the ACC's retail competition rules invalid.

Currently, none of TEP or UNS Electric's customers are receiving energy from other providers; however we cannot predict if retail competition will enter the Arizona market.

Competition in wholesale markets has greatly escalated due to increased participation by utilities, non-utility generators, independent power producers and other wholesale power marketers and brokers. Since 2001, electric generating capacity in Arizona has increased 61% to 25,600 MW, of which approximately 9,700 MW is from gas-fired generators.

Increased competition combined with increased supply and fewer creditworthy counterparties could reduce the prices at which TEP sells electricity in the wholesale market. In 2006, TEP's wholesale revenues were $188 million or 19% of TEP's total revenues.

UniSource Energy and its subsidiaries have a substantial amount of indebtedness which could adversely affect its business and results of operations.

UniSource Energy has no operations of its own and derives all of its revenues and cash flow from its subsidiaries. At December 31, 2006, total debt (including capital lease obligations) to total capitalization for UniSource Energy and its subsidiaries was 72%. The substantial amount of indebtedness of UniSource Energy and its subsidiaries could:

- require UniSource Energy and its subsidiaries to dedicate a substantial portion of their cash flow to pay principal and interest on its debt, which could reduce the funds available for working capital, capital expenditures, acquisitions and other general corporate purposes;
- make UniSource Energy and its subsidiaries more vulnerable to restrictions imposed by new governmental regulations as well as changes in general economic, industry and competitive conditions;
- limit UniSource Energy and its subsidiaries' ability to borrow additional amounts for working capital, capital expenditures, acquisitions, debt service requirements, execution of its business strategy or other purposes;
- limit the ability of the subsidiaries to pay dividends to UniSource Energy; and
- make it more difficult for UniSource Energy and its subsidiaries to comply with the obligations of its debt instruments, and any failure to comply with the obligations of any debt instruments, including financial and other restrictive covenants, could result in an event of default under the agreements.

The terms of UniSource Energy's and its subsidiaries' existing debt instruments and future debt instruments may restrict UniSource Energy's current and future operations, particularly the ability to respond to changes in its business or to take certain actions.

The UniSource Energy Credit Agreement, the TEP Credit Agreement and other existing debt instruments contain a number of restrictive covenants that impose significant operating and financial restrictions on UniSource Energy, including restrictions on the ability to engage in acts that may be in UniSource Energy's best long-term interests. The TEP Credit Agreement includes financial covenants, including requirements to maintain certain minimum cash coverage ratios and not to exceed certain maximum total leverage ratios. The UniSource Credit Agreement contains similar financial covenants.

The operating and financial restrictions and covenants in UniSource Energy's and its subsidiaries' existing debt agreements and any future financing agreements may adversely affect UniSource Energy's ability to finance future operations or capital needs or to engage in other business activities.

The cost of renewing or purchasing TEP's leased assets, or the cost of procuring alternate sources of generation or purchased power, could adversely affect TEP's results of operations, net income and cash flows.

TEP, under separate sale and leaseback arrangements, leases the following generation facilities:

- Springerville Unit 1;
- Sundt Unit 4;
- Springerville Coal Handling Facilities; and
- Springerville Common Facilities.

TEP may renew the leases or purchase the assets when the leases expire at various times between 2011 and 2021. The renewal and purchase options for Springerville Unit 1 and Sundt Unit 4 are generally for fair market value as determined at that time, whereas fixed purchase price options exist for the coal handling and common facilities leases. Upon expiration of the coal handling and common facilities leases (whether at the end of the initial term or any renewal term), TEP has the obligation under agreements with the Springerville Units 3 and 4 owners to purchase such facilities, and the owners of Springerville Units 3 and 4 have the obligation to purchase from TEP a 14% and 17% interest, respectively, in these facilities.

UniSource Energy's utility subsidiaries are subject to numerous environmental laws and regulations which may increase their cost of operations or expose them to environmentally-related litigation and liabilities.

UniSource Energy's utility subsidiaries are subject to numerous federal, state and local environmental regulations affecting present and future operations, including regulations regarding air emissions, water quality, wastewater discharges, solid waste and hazardous waste. Many of these regulations arise from TEP's use of coal as the primary fuel for energy generation.

Existing environmental regulations may be revised or new regulations may be adopted or become applicable to UniSource Energy's utility subsidiaries. Compliance with existing or new environmental laws and regulations can result in increased capital, operating and other costs. The U.S. Congress is considering the regulation of greenhouse gas emissions. At this time, we do not know whether any such regulations will be adopted, the scope of such regulations or how any such regulations could affect our operations.

TEP is also contractually obligated to pay a portion of its environmental reclamation costs at generating stations in which it has a minority interest and possibly at the mines that supply these generating stations. While TEP has recorded the portion of its costs that can be determined at this time, the total costs for final reclamation at these sites are unknown and could be substantial.

TEP may be required to redeem significant amounts of its outstanding tax-exempt bonds.

TEP has financed a portion of its utility plant assets with tax-exempt bonds for which the exemption from income taxes requires that the financed facilities be used for the local furnishing of electric energy. Approximately $359 million of these bonds were outstanding as of December 31, 2006. Various events, including, in certain circumstances, the formation of an RTO or an independent system operator, asset divestitures, changes in tax laws or changes in system operations, could require TEP to redeem or defease some or all of these bonds which would likely require the issuance and sale of higher cost taxable debt securities in the same or a greater principal amount.

TEP may not be permitted to construct a Tucson to Nogales transmission line and TEP or UNS Electric may be required to find alternate ways to improve reliability in UNS Electric's Santa Cruz service area.

In 2001, TEP entered into an agreement to build an approximately 60-mile transmission line from Tucson to Nogales, Arizona, in response to an order from the ACC to improve reliability to UNS Electric's retail customers in Nogales. Required regulatory approvals have delayed the construction of the transmission line, and in 2005, the ACC initiated proceedings to review the status of service in Nogales and need for the 345-kV line.

If TEP does not receive required approvals or if we abandon the project, it may be required to expense a portion of the $11 million it has incurred through December 31, 2006, in land acquisition, engineering and environmental expenses. In such an event, TEP or UNS Electric may be required to make additional expenditures to improve reliability. In the event TEP or UNS Electric are not able to recover such expenditures, their results of operations and net income could be adversely affected.

ITEM 2. – PROPERTIES

TEP PROPERTIES

TEP's transmission facilities, located in Arizona and New Mexico, transmit electricity from TEP's remote electric generating stations at Four Corners, Navajo, San Juan, Springerville and Luna to the Tucson area for use by TEP's retail customers (see *Item 1. – Business – Generating and Other Resources*). The transmission system is interconnected at various points in Arizona and New Mexico with a number of regional utilities. TEP has arrangements with approximately 120 companies to interchange generation capacity and transmission of energy.

As of December 31, 2006, TEP owned or participated in an overhead electric transmission and distribution system consisting of:

- 512 circuit-miles of 500-kV lines;
- 1,098 circuit-miles of 345-kV lines;
- 365 circuit-miles of 138-kV lines;
- 437 circuit-miles of 46-kV lines; and
- 2,631 circuit-miles of lower voltage primary lines.

The underground electric distribution system is comprised of 4,201 cable-miles. TEP owns approximately 60% of the poles on which the lower voltage lines are located. Electric substation capacity consisted of 101 substations with a total installed transformer capacity of 6,738,947 kilovolt amperes.

Substantially all of the utility assets owned by TEP are subject to the lien of the 1992 Mortgage. Springerville Unit 2, which is owned by San Carlos Resources Inc., a wholly-owned subsidiary of TEP (San Carlos), is not subject to the lien.

The electric generating stations (except as noted below), operating headquarters, warehouse and service center are located on land owned by TEP. The electric distribution and transmission facilities owned by TEP are located:

- on property owned by TEP;
- under or over streets, alleys, highways and other public places, the public domain and national forests and state lands under franchises, easements or other rights which are generally subject to termination;
- under or over private property as a result of easements obtained primarily from the record holder of title; or
- over American Indian reservations under grant of easement by the Secretary of Interior or lease by American Indian tribes.

It is possible that some of the easements, and the property over which the easements were granted, may have title defects or may be subject to mortgages or liens existing at the time the easements were acquired.

Springerville is located on land parcels held by TEP under a long-term surface ownership agreement with the State of Arizona.

Four Corners and Navajo are located on properties held under easements from the United States and under leases from the Navajo Nation, respectively. TEP, individually and in conjunction with PNM in connection with San Juan, has acquired easements and leases for transmission lines and a water diversion facility located on land owned by the Navajo Nation. TEP has also acquired easements for transmission facilities, related to San Juan, Four Corners, and Navajo, across the Zuni, Navajo and Tohono O'odham Indian Reservations. TEP, in conjunction with PNM and Phelps Dodge, holds an undivided ownership interest in the property on which Luna is located.

TEP's rights under these various easements and leases may be subject to defects such as:

- possible conflicting grants or encumbrances due to the absence of or inadequacies in the recording laws or record systems of the Bureau of Indian Affairs and the American Indian tribes;
- possible inability of TEP to legally enforce its rights against adverse claimants and the American Indian tribes without Congressional consent; or
- failure or inability of the American Indian tribes to protect TEP's interests in the easements and leases from disruption by the U.S. Congress, Secretary of the Interior, or other adverse claimants.

These possible defects have not interfered and are not expected to materially interfere with TEP's interest in and operation of its facilities.

TEP, under separate sale and leaseback arrangements, leases the following generation facilities (which do not include land):

- coal handling facilities at Springerville;
- a 50% undivided interest in the Springerville Common Facilities;
- Springerville Unit 1 and the remaining 50% undivided interest in the Springerville Common Facilities; and
- Sundt Unit 4 and related common facilities.

See *Note 8 of Notes to Consolidated Financial Statements, Debt, Credit Facilities, and Capital Lease Obligations and Item 7. – Management's Discussion and Analysis of Financial Condition and Results of Operations, Tucson Electric Power Company, Liquidity and Capital Resources, Contractual Obligations*, for additional information on TEP's capital lease obligations.

UES PROPERTIES

UNS Gas

As of December 31, 2006, UNS Gas' transmission and distribution system consisted of approximately 78 miles of steel transmission mains, 4,223 miles of steel and plastic distribution mains, and 148,432 customer service lines.

UNS Electric

As of December 31, 2006, UNS Electric's transmission and distribution system consisted of approximately 56 circuit-miles of 115-kV transmission lines, 236 circuit-miles of 69-kV transmission lines, and 3,432 circuit-miles of underground and overhead distribution lines. UNS Electric also owns 39 substations having a total installed capacity of 1,641,250 kilovolt amperes and the 65 MW Valencia plant.

The gas and electric distribution and transmission facilities owned by UNS Gas and UNS Electric are located:

- on property owned by UNS Gas or UNS Electric;
- under or over streets, alleys, highways and other public places, the public domain and national forests and state lands under franchises, easements or other rights which are generally subject to termination; or
- under or over private property as a result of easements obtained primarily from the record holder of title.

It is possible that some of the easements, and the property over which the easements were granted, may have title defects or may be subject to mortgages or liens existing at the time the easements were acquired.

ITEM 3 – LEGAL PROCEEDINGS

See *Item 7. – Management's Discussion and Analysis of Financial Condition and Results of Operations, Tucson Electric Power Company, Factors Affecting Operations*, for litigation related to ACC orders and retail competition.

We discuss other legal proceedings in Note 6 of *Notes to Consolidated Financial Statements, Commitments and Contingencies.*

City of Tacoma

In June 2004, the City of Tacoma, Washington filed a lawsuit (City of Tacoma v. American Electric Power Services Corporation, et al. (U.S. District Ct. W.D. Wash.)) against TEP and various other electricity generators and marketers alleging that the defendants violated antitrust laws by colluding to affect the price of electricity in the Pacific Northwest from May 2000 through 2001. In September 2004, the case was transferred to the United States District Court for the Southern District of California. TEP, along with other defendants, filed a joint motion to dismiss, which was granted on February 11, 2005. The City of Tacoma appealed the dismissal to the Ninth Circuit and the appeal is now pending.

TEP believes these claims are without merit and intends to vigorously contest them.

ITEM 4. – SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

Not applicable.

PART II

ITEM 5. – MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF COMMON EQUITY

Stock Trading

UniSource Energy's Common Stock is traded under the ticker symbol UNS and is listed on the New York Stock Exchange. On February 23, 2007, the closing price was $38.31, with 11,314 shareholders of record. UniSource Energy did not purchase any shares of its Common Stock during the fourth quarter of 2006.

Dividends

UniSource Energy's Board of Directors currently expects to continue to pay regular quarterly cash dividends on our Common Stock subject, however, to the Board's evaluation of our financial condition, earnings, cash flows and dividend policy. On February 9, 2007, UniSource Energy's Board of Directors indicated its desire to target, over the next several years, a dividend payout level of approximately 50% of net income.

TEP pays dividends on its common stock after its Board of Directors declares them. UniSource Energy is the sole shareholder of TEP's common stock and relies on dividends from its subsidiaries, primarily TEP, to declare and pay dividends.

See *Item 7. – Management's Discussion and Analysis of Financial Condition and Results of Operations, UniSource Energy Consolidated, Dividends on Common Stock.*

Common Stock Dividends and Price Ranges

Quarter:	2006 Market Price per Share of Common Stock [1]		2006 Dividends Declared	2005 Market Price per Share of Common Stock [1]		2005 Dividends Declared
	High	Low		High	Low	
First	$ 32.73	$ 29.90	$ 0.21	$ 34.80	$ 24.30	$ 0.19
Second	31.54	29.47	0.21	31.98	28.10	0.19
Third	35.17	31.04	0.21	33.92	30.50	0.19
Fourth	37.46	36.95	0.21	33.86	29.89	0.19
Total			$ 0.84			$ 0.76

[1] UniSource Energy's Common Stock price as reported in the consolidated reporting system.

On February 9, 2007, UniSource Energy declared a cash dividend of $0.225 per share on its Common Stock. The dividend will be paid March 14, 2007 to shareholders of record at the close of business February 20, 2007.

TEP declared and paid cash dividends to UniSource Energy of $62 million in 2006, $46 million in 2005 and $32 million in 2004.

Convertible Senior Notes

In March 2005, UniSource Energy issued $150 million of 4.50% Convertible Senior Notes due 2035. Each $1,000 of Convertible Senior Notes is convertible into 26.6667 shares of our Common Stock at any time, representing a conversion price of approximately $37.50 per share of our Common Stock, subject to adjustment in certain circumstances. See *Item 7. – Management's Discussion and Analysis of Financial Condition and Results of Operations, UniSource Energy Consolidated, Liquidity and Capital Resources, Financing Activities.*

ITEM 6. – SELECTED CONSOLIDATED FINANCIAL DATA

UniSource Energy	2006	2005	2004	2003	2002
			- In Thousands - (except per share data)		
Summary of Operations					
Operating Revenues [1]	**$ 1,316,869**	$ 1,224,056	$ 1,164,988	$ 970,651	$ 838,829
Income Before Discontinued Operations, Extraordinary Item and Accounting Change [1]	**$ 69,243**	$ 52,253	$ 50,982	$53,942	$ 47,847
Net Income [1] [2]	**$ 67,447**	$ 46,144	$ 45,919	$ 113,941	$ 34,928
Basic Earnings per Share:					
Before Discontinued Operations, Extraordinary Item & Accounting Change	**$ 1.96**	$ 1.51	$ 1.49	$ 1.60	$ 1.42
Net Income	**$ 1.91**	$ 1.33	$ 1.34	$ 3.37	$ 1.04
Diluted Earnings per Share:					
Before Discontinued Operations, Extraordinary Item & Accounting Change	**$ 1.85**	$ 1.44	$ 1.45	$ 1.57	$ 1.40
Net Income	**$ 1.80**	$ 1.28	$ 1.31	$ 3.32	$ 1.02
Shares of Common Stock Outstanding					
Average	**35,264**	34,798	34,380	33,828	33,665
End of Year	**35,190**	34,874	34,255	33,788	33,579
Year-end Book Value per Share	**$ 18.59**	$ 17.69	$ 16.95	$ 16.47	$ 13.60
Cash Dividends Declared per Share	**$ 0.84**	$ 0.76	$ 0.64	$ 0.60	$ 0.50
Financial Position					
Total Utility Plant – Net	**$ 2,259,620**	$ 2,171,461	$ 2,081,137	$ 2,069,215	$ 1,835,904
Investments in Lease Debt and Equity	**$ 181,222**	$ 156,301	$ 170,893	$ 178,789	$ 191,867
Other Investments and Other Property	**$ 66,194**	$ 58,468	$ 68,846	$ 90,137	$ 104,884
Total Assets	**$ 3,187,409**	$ 3,180,211	$ 3,186,936	$ 3,135,013	$ 2,897,932
Long-Term Debt	**$ 1,171,170**	$ 1,212,420	$ 1,257,595	$ 1,286,320	$ 1,128,963
Non-Current Capital Lease Obligations	**588,771**	665,737	701,931	762,968	801,611
Common Stock Equity	**654,149**	616,741	580,718	556,472	456,640
Total Capitalization	**$ 2,414,090**	$ 2,494,898	$ 2,540,244	$ 2,605,760	$ 2,387,214
Selected Cash Flow Data					
Net Cash Flows From Operating Activities	**$ 282,659**	$ 273,883	$ 306,979	$ 263,396	$ 176,437
Capital Expenditures	**$ (238,261)**	$ (203,362)	$ (166,861)	$ (135,731)	$ (105,359)
Other Investing Cash Flows	**(7,820)**	32,794	10,672	(215,001)	(165,531)
Net Cash Flows From Investing Activities	**$ (246,081)**	$ (170,568)	$ (156,189)	$ (350,732)	$ (270,890)
Net Cash Flows From Financing Activities	**$ (77,016)**	$ (112,664)	$ (98,028)	$ 97,674	$ (42,773)
Ratio of Earnings to Fixed Charges [3]	**1.73**	1.55	1.48	1.44	1.50

[1] In 2003, Operating Revenues, Income Before Extraordinary Item and Accounting Change and Net Income include results from UES for the period from August 11, 2003 to December 31, 2003.

(2) Net Income includes an after-tax loss for discontinued operations of $2 million in 2006, $5 million in 2005, $5 million in 2004, $7 million in 2003 and $13 million in 2002. Net income includes an after-tax loss of $0.6 million for the Cumulative Effect of Accounting Change from the implementation of FIN 47 in 2005 and an after-tax gain of $67 million for the Cumulative Effect of Accounting Change from the implementation of FAS 143 in 2003.

(3) For purposes of this computation, earnings are defined as pre-tax earnings from continuing operations before minority interest, or income/loss from equity method investments, plus interest expense, and amortization of debt discount and expense related to indebtedness. Fixed charges are interest expense, including amortization of debt discount and expense on indebtedness.

See *Item 7. – Management's Discussion and Analysis of Financial Condition and Results of Operations.*

ITEM 6. – SELECTED CONSOLIDATED FINANCIAL DATA

TEP	2006	2005	2004	2003	2002
	-Thousands of Dollars-				
Summary of Operations					
Operating Revenues	**$ 997,722**	$ 937,470	$ 889,298	$ 851,551	$ 834,447
Income Before Extraordinary Item and Accounting Change	**$ 66,745**	$ 48,893	$ 46,127	$ 61,442	$ 55,390
Net Income [1]	**$ 66,745**	$ 48,267	$ 46,127	$ 128,913	$ 55,390
Financial Position					
Total Utility Plant – Net	**$ 1,887,387**	$ 1,866,622	$ 1,816,782	$ 1,832,156	$ 1,835,904
Investments in Lease Debt and Equity	**$ 181,222**	$ 156,301	$ 170,893	$ 178,789	$ 191,867
Other Investments and Other Property	**$ 30,161**	$ 27,013	$ 23,393	$ 41,285	$ 21,358
Total Assets	**$ 2,623,063**	$ 2,617,219	$ 2,742,168	$ 2,767,047	$ 2,808,810
Long-Term Debt	**$ 821,170**	$ 821,170	$ 1,097,595	$ 1,126,320	$ 1,128,410
Non-Current Capital Lease Obligations	**588,424**	665,299	701,405	762,323	801,508
Common Stock Equity	**554,714**	558,646	414,510	406,054	353,832
Total Capitalization	**$ 1,964,308**	$ 2,045,115	$ 2,213,510	$ 2,294,697	$ 2,283,750
Selected Cash Flow Data					
Net Cash Flows From Operating Activities	**$ 227,228**	$ 243,013	$ 275,151	$ 260,989	$ 206,991
Capital Expenditures	**$ (156,180)**	$ (149,906)	$ (129,505)	$ (121,854)	$ (103,307)
Other Investing Cash Flows	**(25,786)**	21,001	3,743	11,408	(151,035)
Net Cash Flows From Investing Activities	**$ (181,966)**	$ (128,905)	$ (125,762)	$ (110,446)	$ (254,342)
Net Cash Flows From Financing Activities	**$ (78,984)**	$ (173,882)	$ (101,444)	$ (141,059)	$ (56,551)
Ratio of Earnings to Fixed Charges [2]	**1.84**	1.60	1.52	1.51	1.60

(1) Net Income includes an after-tax loss of $0.6 million for the Cumulative Effect of Accounting Change from the implementation of FIN 47 in 2005 and an after-tax gain of $67 million for the Cumulative Effect of Accounting Change from the implementation of FAS 143 in 2003.

(2) For purposes of this computation, earnings are defined as pre-tax earnings from continuing operations before minority interest, or income/loss from equity method investments, plus interest expense and amortization of debt discount and expense related to indebtedness. Fixed charges are interest expense, including amortization of debt discount and expense on indebtedness.

Note: Disclosure of earnings per share information for TEP is not presented as the common stock of TEP is not publicly traded.

See *Item 7. – Management's Discussion and Analysis of Financial Condition and Results of Operations.*

NON-GAAP MEASURES

Adjusted EBITDA

Adjusted EBITDA represents EBITDA excluding the cumulative effect of accounting change which is a non-cash item. EBITDA is earnings before interest, taxes, depreciation and amortization. Adjusted EBITDA is presented here as a measure of liquidity because it can be used as an indication of a company's ability to incur and service debt and is commonly used as an analytical indicator in our industry. Adjusted EBITDA measures presented may not be comparable to similarly titled measures used by other companies. Adjusted EBITDA is not a measurement presented in accordance with United States generally accepted accounting principles (GAAP), and we do not intend Adjusted EBITDA to represent cash flows from operations as defined by GAAP. Adjusted EBITDA should not be considered to be an alternative to cash flows from operations or any other items calculated in accordance with GAAP or an indicator of our operating performance.

UniSource Energy and TEP believe Adjusted EBITDA, which is a non-GAAP financial measure, provides useful information to investors as a measure of liquidity. The most directly comparable GAAP measure to Adjusted EBITDA is Net Cash Flows from Operating Activities.

Adjusted EBITDA and Net Cash Flows from Operating Activities

UniSource Energy	**2006**	**2005**	**2004**	**2003**
		- Millions of Dollars -		
Adjusted EBITDA (non-GAAP)	$ 470	$ 445	$ 444	$ 404
Net Cash Flows - Operating Activities (GAAP)	$ 283	$ 274	$ 307	$ 263
Net Cash Flows - Investing Activities (GAAP)	$ (246)	$ (170)	$ (156)	$ (351)
Net Cash Flows - Financing Activities (GAAP)	$ (77)	$ (113)	$ (98)	$ 98

TEP	**2006**	**2005**	**2004**	**2003**
		- Millions of Dollars -		
Adjusted EBITDA (non-GAAP)	$ 420	$ 400	$ 411	$ 403
Net Cash Flows - Operating Activities (GAAP)	$ 227	$ 243	$ 275	$ 261
Net Cash Flows - Investing Activities (GAAP)	$ (182)	$ (129)	$ (126)	$ (111)
Net Cash Flows - Financing Activities (GAAP)	$ (79)	$ (174)	$ (101)	$ (141)

Reconciliation of Adjusted EBITDA to Cash Flows from Operations

UniSource Energy	**2006**	**2005**	**2004**	**2003**
		- Millions of Dollars -		
Adjusted EBITDA (non-GAAP) [1]	$ 470	$ 445	$ 444	$ 404
Amounts from the Income Statements:				
Less: Income Taxes	44	38	37	17
Total Interest Expense	152	160	168	167
Changes in Assets and Liabilities and Other Non-Cash Items	9	27	68	43
Net Cash Flows - Operating Activities (GAAP)	**$ 283**	**$ 274**	**$ 307**	**$ 263**
Net Cash Flows - Investing Activities (GAAP)	**(246)**	**(170)**	**(156)**	**(351)**
Net Cash Flows - Financing Activities (GAAP)	**(77)**	**(113)**	**(98)**	**98**
Net Increase (Decrease) in Cash and Cash Equivalents (GAAP)	**$ (40)**	**$ (9)**	**$ 53**	**$ 10**

TEP	2006	2005	2004	2003
		- Millions of Dollars -		
Adjusted EBITDA (non-GAAP) [1]	$ 420	$ 400	$ 411	$ 403
Amounts from the Income Statements:				
Less: Income Taxes	42	34	35	21
Total Interest Expense	127	140	157	161
Changes in Assets and Liabilities and Other Non-Cash Items	(24)	17	56	40
Net Cash Flows - Operating Activities (GAAP)	**$ 227**	**$ 243**	**$ 275**	**$ 261**
Net Cash Flows - Investing Activities (GAAP)	**(182)**	**(129)**	**(126)**	**(111)**
Net Cash Flows - Financing Activities (GAAP)	**(79)**	**(174)**	**(101)**	**(141)**
Net Increase (Decrease) in Cash and Cash Equivalents (GAAP)	**$ (34)**	**$ (60)**	**$ 48**	**$ 9**

[1] Adjusted EBITDA was calculated as follows:

UniSource Energy	2006	2005	2004	2003
		- Millions of Dollars -		
Net Income (GAAP)	$ 67	$ 46	$ 46	$ 114
Amounts from the Income Statements:				
Less: Discontinued Operations	(2)	(5)	(5)	(7)
Cumulative Effect of Accounting Change	-	(1)	-	67
Plus: Income Taxes	44	38	37	17
Total Interest Expense	152	160	168	167
Depreciation and Amortization	131	133	132	128
Amortization of Transition Recovery Asset	66	56	50	32
Depreciation Included in Fuel and Other O&M Expense *(See Note 17 of Notes to Consolidated Financial Statements)*	8	6	6	6
Adjusted EBITDA (non-GAAP)	**$ 470**	**$ 445**	**$ 444**	**$ 404**

TEP	2006	2005	2004	2003
		- Millions of Dollars -		
Net Income (GAAP)	$ 67	$ 48	$ 46	$ 129
Amounts from the Income Statements:				
Less: Cumulative Effect of Accounting Change	-	(1)	-	67
Plus: Income Taxes	42	34	35	21
Total Interest Expense	127	140	157	161
Depreciation and Amortization	112	115	117	121
Amortization of Transition Recovery Asset	66	56	50	32
Depreciation Included in Fuel and Other O&M Expense (See *Note 17 of Notes to Consolidated Financial Statements*)	6	6	6	6
Adjusted EBITDA (non-GAAP)	**$ 420**	**$ 400**	**$ 411**	**$ 403**

Net Debt and Total Debt and Capital Lease Obligations - TEP

Net Debt represents the current and non-current portions of TEP's long-term debt and capital lease obligations less investment in lease debt. We have subtracted investment in lease debt because it represents TEP's ownership of the debt component of its own capital lease obligations. Net Debt measures may not be comparable to similarly titled measures used by other companies. Net Debt is not a measurement presented in accordance with GAAP and we do not intend Net Debt to represent debt as defined by GAAP. You should not consider Net Debt to be an alternative to debt or any other items calculated in accordance with GAAP. We believe Net Debt, which is a non-GAAP measure, provides useful information to investors as a measure of TEP's debt and capital lease obligations.

As of December 31,	2006	2005	2004	2003
		- Millions of Dollars -		
Net Debt (non-GAAP)	$ 1,335	$ 1,379	$ 1,684	$ 1,761
Total Debt and Capital Lease Obligations (GAAP)	$ 1,468	$ 1,535	$ 1,855	$ 1,940

Reconciliation of Total Debt and Capital Lease Obligations to Net Debt

As of December 31,	2006	2005	2004	2003
		- Millions of Dollars -		
Long-Term Debt	$ 821	$ 821	$ 1,098	$ 1,126
Current Portion – Long-Term Debt	-	-	2	2
Total Debt (GAAP)	821	821	1,100	1,128
Capital Lease Obligations	588	665	701	762
Current Portion – Capital Lease Obligations	59	49	54	50
Total Debt and Capital Lease Obligations (GAAP)	1,468	1,535	1,855	1,940
Investment in Lease Debt	(133)	(156)	(171)	(179)
Net Debt (non-GAAP)	$ 1,335	$ 1,379	$ 1,684	$ 1,761

ITEM 7. – MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Management's Discussion and Analysis explains the results of operations, the general financial condition, and the outlook for UniSource Energy and its three primary business segments and includes the following:

- outlook and strategies,
- operating results during 2006 compared with 2005, and 2005 compared with 2004,
- factors which affect our results and outlook,
- liquidity, capital needs, capital resources, and contractual obligations,
- dividends, and
- critical accounting estimates.

UniSource Energy is a holding company that has no significant operations of its own. Operations are conducted by UniSource Energy's subsidiaries, each of which is a separate legal entity with its own assets and liabilities. UniSource Energy owns the outstanding common stock of TEP, UniSource Energy Services, Inc. (UES), Millennium Energy Holdings, Inc. (Millennium), and UniSource Energy Development Company (UED).

TEP, an electric utility, has provided electric service to the community of Tucson, Arizona, for over 100 years. UES was established in 2003, when it acquired the Arizona gas and electric properties from Citizens. UES, through its two operating subsidiaries, UNS Gas, Inc. (UNS Gas) and UNS Electric, Inc. (UNS Electric), provides gas and electric service to 30 communities in Northern and Southern Arizona. Millennium has existing investments in unregulated businesses; however no new investments are planned at Millennium. UED facilitated the expansion of the Springerville Generating Station and is currently developing the Black Mountain Generating Station (BMGS), a gas turbine project in Northern Arizona that, subject to approval, is expected to provide energy to UNS Electric. We conduct our business in three primary business segments – TEP, UNS Gas and UNS Electric.

On March 31, 2006, Millennium sold its interest in Global Solar Energy, Inc. (Global Solar), its largest holding. At December 31, 2006, the investment in Millennium represented 3% of UniSource Energy's Total Assets.

UNISOURCE ENERGY CONSOLIDATED

OUTLOOK AND STRATEGIES

Our financial prospects and outlook for the next few years will be affected by many competitive, regulatory and economic factors. Our plans and strategies include the following:

- Efficiently manage our generation, transmission and distribution resources and seek ways to control our operating expenses while maintaining and enhancing reliability and profitability;

- Expand TEP's portfolio of generating and purchased power resources to meet growing retail energy demand and respond to wholesale market opportunities;

- Expand UNS Electric's portfolio of generating and purchased power resources to meet growing retail energy demand upon the expiration of the full requirements contract with PWMT;

- Resolve the uncertainty surrounding TEP's rates for generation service after 2008, while preserving TEP's benefits under the Settlement Agreement;

- Receive ACC approval of rate increases for UNS Gas and UNS Electric to provide adequate revenues to cover the rising cost of providing service to their customers;

- Enhance the value of existing generation assets by working with Salt River Project to support the construction of Springerville Unit 4;

- Enhance the value of TEP's transmission system while continuing to provide reliable access to generation for TEP and UNS Electric's retail customers and market access for all generating assets;

- Continue to develop synergies between UNS Gas,UNS Electric and TEP;
- Improve capital structure; and
- Promote economic development in our service territories.

To accomplish our goals, during 2007 we expect to spend the following on capital expenditures:

Segment	Estimated Capital Expenditures
	-Millions of Dollars-
TEP	$198
UNS Gas	38
UNS Electric	43
Other [1]	27
UniSource Energy Consolidated	$306

[1] Represents capital expenditures by UED related to the 90 MW BMGS to be constructed in Kingman, Arizona, in UNS Electric's service area. The project is expected to be completed in 2008.

While we believe that our plans and strategies will continue to have a positive impact on our financial prospects and position, we recognize that we continue to be highly leveraged, and as a result, our access to the capital markets may be limited or more expensive than for less leveraged companies.

RESULTS OF OPERATIONS

Executive Overview

UniSource Energy recorded Income Before Discontinued Operations and Cumulative Effect of Accounting Change of $69 million in 2006, $52 million in 2005 and $51 million in 2004. Net Income of $67 million in 2006 includes a $2 million loss from discontinued operations; net income of $46 million in 2005 includes a $5 million loss from discontinued operations and a $1 million loss from the cumulative effect of an accounting change; and net income of $46 million in 2004 includes a $5 million loss from discontinued operations.

2006 Compared With 2005

The improvement in UniSource Energy's results in 2006 is due primarily to: the higher availability of TEP's coal-fired generating plants; the start of commercial operations at Luna in April 2006; retail customer growth at TEP; interest savings related to various financing activities in 2005 and 2006; and the commencement of commercial operation of Springerville Unit 3 in August 2006. See *Tucson Electric Power Company, Results of Operations, below, and Tucson Electric Power Company, Liquidity and Capital Resources, Financing Activities*, below.

On March 31, 2006, Millennium sold Global Solar for $16 million in cash and an option to purchase, under certain conditions, 5% to 10% of Global Solar in the future. In 2006, UniSource Energy recorded an after-tax loss of approximately $2 million related to the discontinued operations and disposal of Global Solar. *See Other Non-Reportable Segments, Results of Operations, Discontinued Operations – Global Solar,* below.

2005 Compared With 2004

UniSource Energy's results in 2005 were negatively impacted by planned and unplanned outages at several of TEP's coal plants. One of TEP's largest coal plants suffered a nearly month-long outage in August 2005, during a period when customer demand was high and energy prices were boosted by the impact of hurricane activity in the Gulf of Mexico. Higher natural gas prices and the cost of purchasing replacement power during the outage contributed to an 82% increase in TEP's purchased power expense. See *Tucson Electric Power Company, Results of Operations, below.*

Also in 2005, UniSource Energy completed a financial restructuring, issuing $240 million of debt and using the proceeds to repay an inter-company note and infuse capital into its subsidiaries. TEP retired approximately $321 million of debt and capital lease obligations (net of proceeds received from TEP's investment in lease debt). See

Liquidity and Capital Resources, Financing Activities, below, and Tucson Electric Power Company, Liquidity and Capital Resources, Financing Activities, Bond Repurchases and Redemptions, below.

CONTRIBUTION BY BUSINESS SEGMENT

The table below shows the contributions to our consolidated after-tax earnings by our three business segments and Other net income (loss).

	2006	2005	2004
		-Millions of Dollars-	
TEP	$ 67	$ 49	$ 46
UNS Gas	4	5	6
UNS Electric	5	5	4
Other [1]	(7)	(7)	(5)
Income Before Discontinued Operations and Cumulative Effect of Accounting Change	69	52	51
Discontinued Operations – Net of Tax [2]	(2)	(5)	(5)
Cumulative Effect of Accounting Change – Net of Tax	-	(1)	-
Consolidated Net Income	$ 67	$ 46	$ 46

[1] Includes: UniSource Energy parent company expenses; in 2005 and 2006, UniSource Energy parent company interest expense (net of tax) on the UniSource Energy Convertible Senior Notes and on the UniSource Energy Credit Agreement; in 2004 and in the first nine months of 2005, interest expense (net of tax) on the note payable from UniSource Energy to TEP; income and losses from Millennium investments and UED; and in 2004 costs associated with the proposed acquisition of UniSource Energy.

[2] Relates to the discontinued operations of Global Solar.

LIQUIDITY AND CAPITAL RESOURCES

UniSource Energy Consolidated Cash Flows

	2006	2005	2004
		-Millions of Dollars-	
Cash provided by (used in):			
Operating Activities	$ 283	$ 274	$ 307
Investing Activities	(246)	(170)	(156)
Financing Activities	(77)	(113)	(98)

UniSource Energy's consolidated cash flows are provided primarily from retail and wholesale energy sales at TEP, UNS Gas and UNS Electric, net of the related payments for fuel and purchased power. Generally, cash from operations is lowest in the first quarter and highest in the third quarter due to TEP's summer peaking load.

We use our available cash primarily to:

- fund capital expenditures at TEP, UNS Gas and UNS Electric;
- pay dividends to shareholders; and
- reduce leverage.

The primary source of liquidity for UniSource Energy, the parent company, is dividends it receives from its subsidiaries, primarily TEP. Also, under our tax sharing agreement, our subsidiaries make income tax payments to UniSource Energy, which makes payments on behalf of the consolidated group. The table below provides a summary of the liquidity position of UniSource Energy on a stand-alone basis and each of its segments.

Balances As of February 23, 2007	Cash and Cash Equivalents	Borrowings under Revolving Credit Facility	Amount Available under Revolving Credit Facility
		-Millions of Dollars-	
UniSource Energy stand-alone	$ 13	$ -	$ 70
TEP	48	90	60
UNS Gas	16	-	30 (1)
UNS Electric	4	25	5 (1)
Other	31 (2)	NA	NA
Total	$ 112		

(1) Currently, either UNS Gas or UNS Electric may borrow up to a maximum of $30 million, but the total combined amount borrowed cannot exceed $40 million. Upon ACC approval of the increase in the UNS Gas/UNS Electric Revolver, either borrower may borrow up to a maximum of $45 million so long as the combined amount borrowed does not exceed $60 million. The matter is pending before the ACC.

(2) Includes cash and cash equivalents at Millennium.

Executive Overview

Operating Activities

In 2006, net cash flows from operating activities were $283 million or $9 million higher than 2005. The increase is due primarily to: an increase in TEP's cash receipts from electric retail and wholesale sales, net of fuel and purchased energy costs; higher UNS Gas retail revenues; and the wind down of activity at MEG; partially offset by a $32 million payment made to the IRS and state tax authorities related to a notice of a proposed adjustment to previously filed tax returns and an increase in federal and state extension and estimated tax payments.

Investing Activities

Net cash used for investing activities was $76 million higher in 2006 primarily due to: TEP's purchase of a 14% equity interest in Springerville Unit 1 Lease; growth and maintenance of TEP's electric system; utility system growth at UNS Gas and UNS Electric; the purchase of two gas turbines by UED; and TEP's share of the construction costs of Luna.

Forecasted Capital Expenditures

Business Segment	2007	2008	2009	2010	2011
	-Millions of Dollars-				
TEP	$198	$238	$195	$224	$293
UNS Gas	38	33	27	28	26
UNS Electric	43	39	42	28	34
Other	27	10	-	-	-
UniSource Energy Consolidated	$306	$320	$264	$280	$353

Capital expenditures of $1.2 billion for 2007 through 2010 are expected to be $331 million, or 39% higher than forecasted amounts reported in 2006. This increase is the result of several factors including: higher material and construction costs; the need to increase high-voltage transmission capacity into TEP's service territory; generation needs for UNS Electric; and continued strong customer growth in UniSource Energy's utility service territories.

Financing Activities

Net cash flows used for financing activities were $36 million lower in 2006 compared with 2005. Factors impacting cash used for financing activities in 2006 include: an increase in net revolving credit facility borrowings and lower debt issuance costs; partially offset by an increase in net repayments of long-term debt; higher payments on capital lease obligations by TEP; higher dividends paid by UniSource Energy to its shareholders. In 2005, UniSource Energy issued $240 million of debt, which it used to repay an inter-company note to TEP and infuse capital into its subsidiaries. TEP used the proceeds from the inter-company note repayment and capital infusion to retire $282 million of debt.

As a result of the activities described above, our consolidated cash and cash equivalents decreased to $104 million at December 31, 2006, from $145 million at December 31, 2005. We invest cash balances in high-grade money market securities with an emphasis on preserving the principal amounts invested.

Liquidity Outlook

As a result of growing capital expenditures at UniSource Energy's subsidiaries, the revolving credit facilities at UniSource Energy, TEP, UNS Gas and UNS Electric may be used on a more frequent basis. Other funding sources to meet the capital requirements of the strong utility customer growth could include the issuance of long-term debt, as well as capital contributions from UniSource Energy to its subsidiaries. The need for external funding sources is partially dependent on the outcome of rate-related proceedings at TEP, UNS Gas and UNS Electric.

For more information concerning liquidity and capital resources, see *Tucson Electric Power Company, Liquidity and Capital Resources, below, UNS Gas, Liquidity and Capital Resources, UNS Electric, Liquidity and Capital Resources, and Other Non-Reportable Segments, Liquidity and Capital Resources*, below.

Convertible Senior Notes

In March 2005, UniSource Energy issued $150 million of 4.50% Convertible Senior Notes due 2035, which are unsecured and are not guaranteed by TEP or any other UniSource Energy subsidiary.

Each $1,000 of Convertible Senior Notes is convertible into 26.6667 shares of our Common Stock at any time, representing a conversion price of approximately $37.50 per share of our Common Stock, subject to adjustment in certain circumstances.

Beginning in March 2010, UniSource Energy will have the option to redeem the notes, in whole or in part, for cash, at a price equal to 100% of the principal amount plus accrued and unpaid interest. Holders of the notes will have the right to require UniSource Energy to repurchase the notes, in whole or in part, for cash on March 1, 2015, 2020, 2025 and 2030, or if certain specified fundamental changes involving UniSource Energy occur. The repurchase price will be 100% of the principal amount of the notes plus accrued and unpaid interest.

In the event of a fundamental change that occurs prior to March 2010, UniSource Energy may be required to pay a make-whole premium on notes converted in connection with the fundamental change. The make-whole premium will be payable in shares of UniSource Energy Common Stock or the consideration into which UniSource Energy Common Stock has been converted or exchanged in connection with such fundamental change.

A fundamental change involving UniSource Energy will be deemed to have occurred if: (1) certain transactions occur as a result of which there is a change in control of UniSource Energy; or (2) UniSource Energy Common Stock ceases to be listed on a national securities exchange or quoted on The Nasdaq National Market or another established automated over-the-counter trading market in the United States.

The notes may be accelerated upon the occurrence and continuance of an event of default under the indenture governing the notes. The failure to make required payments on the notes or comply with the terms of the indenture may constitute an event of default. In addition, events of default may arise upon the acceleration of $50 million of indebtedness for borrowed money of UniSource Energy or TEP, or certain events of bankruptcy involving UniSource Energy or TEP.

UniSource Energy Credit Agreement

In August 2006, UniSource Energy amended and restated its existing credit agreement (UniSource Credit Agreement). The amendment extended the maturity from April 2010 to August 2011, reduced the interest rate payable on borrowings, and changed the amounts available under the term loan and the revolving credit facilities. As amended, the UniSource Credit Agreement consists of a $30 million term loan facility and a $70 million revolving credit facility. Prior to the amendment, the UniSource Credit Agreement included a $90 million term loan facility ($84 million outstanding) and a $15 million revolving credit facility (zero outstanding). On August 11, 2006, UniSource Energy repaid the $84 million outstanding term loan with $30 million of available cash, $30 million drawn under the new term loan and $24 million drawn under the revolving credit facility.

Quarterly principal payments of $1.5 million on the outstanding term loan are due beginning in September 2006, with the balance due at maturity. At December 31, 2006, there was $27 million outstanding under the term loan facility and $20 million outstanding under the UniSource Energy revolving credit facility at a weighted average interest rate of 6.67%. In January 2007, UniSource Energy repaid the $20 million outstanding on the revolving credit facility.

We have the option of paying interest on the term loan and on borrowings under the revolving credit facility at adjusted LIBOR plus 1.25% or the sum of the greater of the federal funds rate plus 0.5% or the agent bank's reference rate and 0.25%.

The UniSource Credit Agreement restricts additional indebtedness, liens, mergers, sales of assets, and certain investments and acquisitions. We must also meet: (1) a minimum cash flow to debt service coverage ratio for UniSource Energy on a standalone basis and (2) a maximum leverage ratio on a consolidated basis. We may pay dividends if, after giving effect to the dividend payment, we have more than $15 million of unrestricted cash and unused revolving credit. As of December 31, 2006, we were in compliance with the terms of the UniSource Credit Agreement.

If an event of default occurs, the UniSource Credit Agreement may become immediately due and payable. An event of default includes failure to make required payments under the UniSource Credit Agreement, failure of UniSource Energy or certain subsidiaries to make payments or default on debt greater than $20 million, or certain bankruptcy events at UniSource Energy or certain subsidiaries.

Guarantees and Indemnities

In the normal course of business, UniSource Energy and certain subsidiaries enter into various agreements providing financial or performance assurance to third parties on behalf of certain subsidiaries. We entered into these agreements primarily to support or enhance the creditworthiness of a subsidiary on a stand-alone basis. The most significant of these guarantees at December 31, 2006 were:

- UES' guarantee of $160 million of aggregate principal amount of senior unsecured notes issued by UNS Gas and UNS Electric to purchase the Citizens' Arizona gas and electric system assets;
- UES' guarantee of a $40 million revolving credit facility available to UNS Gas and UNS Electric; and
- UniSource Energy's guarantee of approximately $5 million in natural gas and supply payments and building lease payments for UNS Gas and UNS Electric.

To the extent liabilities exist under the contracts subject to these guarantees, such liabilities are included in the consolidated balance sheets.

In addition, UniSource Energy and its subsidiaries have indemnified the purchasers of interests in certain investments from additional taxes due for years prior to the sale. The terms of the indemnifications provide for no limitation on potential future payments; however, we believe that we have abided by all tax laws and paid all tax obligations. We have not made any payments under the terms of these indemnifications to date.

We believe that the likelihood that UniSource Energy would be required to perform or otherwise incur any significant losses associated with any of these guarantees is remote.

Contractual Obligations

The following charts display UniSource Energy's consolidated contractual obligations by maturity and by type of obligation as of December 31, 2006.

UniSource Energy's Contractual Obligations
- Millions of Dollars -

Payment Due in Years Ending December 31,	2007	2008	2009	2010	2011	2012 and after	Total
Long Term Debt							
Principal[1]	$ 6	$ 223	$ 6	$ 6	$ 382	$ 555	$1,178
Interest[2]	67	65	49	49	44	534	808
Capital Lease Obligations[3]:							
Springerville Unit 1[4]	83	82	30	57	83	401	736
Springerville Coal Handling	24	18	15	17	19	101	194
Sundt Unit 4	12	12	13	14	-	-	51
Springerville Common	6	6	6	6	6	148	178
Operating Leases	2	2	2	2	1	2	11
Purchase Obligations[5]:							
Coal and Rail Transportation[6]	89	89	80	80	42	242	622
Purchase Power[7]	3	27	36	24	15	16	121
Electric Generating Turbines	21	6	-	-	-	-	27
Transmission	7	2	1	1	1	-	12
Gas[8]	50	38	19	12	8	-	127
Other Long-Term Liabilities[9]:							
Pension & Other Post Retirement Obligations[10]	15	4	4	5	5	32	65
San Juan Pollution Control Equipment[11]	17	41	7	-	-	-	65
Acquisition of Springerville Coal Handling and Common Facilities[12]	-	-	-	-	-	226	226
Total Contractual Cash Obligations	$402	$615	$268	$273	$606	$2,257	$4,421

(1) Includes quarterly principal payments due on the term loan facility in UniSource Energy's Credit Agreement and amounts outstanding under the UNS Electric revolving credit facility. TEP's Variable Rate IDBs are backed by LOCs issued pursuant to TEP's Credit Agreement which expires in August 2011. Although the Variable Rate IDBs mature between 2018 and 2022, the above maturity reflects a redemption or repurchase of such bonds in 2011 as though the LOCs terminate without replacement upon expiration of the TEP Credit Agreement.

(2) Includes letter of credit and remarketing fees on variable rate debt. The interest rates for variable rate debt are estimated using Eurodollar futures rates for an approximation of LIBOR. For variable rate IDBs, a discount is applied to estimated LIBOR based on the historical discount the IDBs have had to LIBOR.

(3) Beginning with commercial operation of Springerville Unit 3 in September 2006, Tri-State is reimbursing TEP for various operating costs related to the common facilities on an ongoing basis, including 14% of the Springerville Common Lease payments and 17% of the Springerville Coal Handling Facilities Lease payments. Similar reimbursement obligations are required after Unit 4 is constructed. TEP remains the obligor under these capital leases. Capital Lease Obligations do not reflect any reduction associated with this reimbursement.

(4) Annual payments under the Springerville Unit 1 lease vary in accordance with the amortization schedules of the debt underlying the capital lease, with significantly larger principal payments occurring in 2007, 2008 and 2011.

(5) Purchase obligations reflect the minimum contractual obligation under legally enforceable contracts with contract terms that are both fixed and determinable. The total amount paid under these contracts depends on the quantity purchased and transported. TEP and UES' requirements are expected to be in excess of these minimums. UniSource Energy has excluded open purchase orders of approximately $13 million expected to be fulfilled in 2007.

(6) Based on prior years' expenditures, TEP expects to spend approximately $200 million annually for the purchase and transportation of coal through 2010. TEP is unable to estimate how much it will spend under these contracts beyond 2010 due to the impact of the amended Springerville coal contract.
(7) Includes TEP and UNS Electric's forward power purchases. TEP has not included capacity payments under TEP's purchased power agreement with Tri-State which may be reduced in increments of 25 MW with 90 days' notice. To date, TEP has received no such notice. If Tri-State does not give notice to reduce capacity, the minimum capacity payments will be $31 million annually in 2007 through 2010 and $21 million in 2011. UniSource Energy also has not included amounts payable to PWMT under UNS Electric's full requirements power supply agreement as payments under this contract are usage based with no fixed demand charges and are recovered through the purchased power and fuel adjustment clause (PPFAC) mechanism. We expect to spend approximately $100 million annually under this contract through May 2008.
(8) Amounts include UNS Gas' fixed price forward gas purchases and firm transportation agreements with EPNG and Transwestern. Incremental gas purchases are excluded as prices and volumes vary. Amounts also exclude swap agreements which are marked to market on a monthly basis and do not include any minimum payment obligation. UNS Gas entered into forward gas purchases for 2007 through 2010 totaling $9 million subsequent to December 31, 2006, which are excluded from the table above.
(9) Excludes TEP's liability for final environmental reclamation at the coal mines which supply the remote generating stations. TEP estimates its undiscounted final reclamation liability is $41 million with reclamation beginning in 2028. See Note 6. Also excludes asset retirement obligations expected to occur through 2066. See Note 3. Also, excludes Millennium's equity commitments totaling $1 million over two years to fund subsidiaries (Valley Ventures) as suitable investments are identified.
(10) These obligations represent TEP and UES' minimum required contributions to pension plans in 2007 and TEP's expected postretirement benefit costs to cover medical and life insurance claims as determined by the plans' actuaries. TEP and UES do not know and have not included pension contributions beyond 2007 due to the significant impact that returns on plan assets and changes in discount rates might have on such amounts. TEP funds the postretirement benefit plan on a pay-as-you-go basis.
(11) These obligations represent TEP's share of the cost of new pollution control equipment based on its ownership of San Juan. Under a settlement agreement signed in March 2005 with the New Mexico Environmental Department and environmental activist groups, the co-owners of San Juan will install new technology at the generating station to reduce mercury, particulate matter, NOx, and SO_2 emissions. In addition, TEP's share of increased operating and maintenance costs associated with the new technologies is expected to be approximately $12 million over the next 10 years.
(12) TEP has agreed with the owners of Springerville Units 3 and 4 that, upon expiration of the Springerville Coal Handling Facilities and Common Leases, TEP is obligated to acquire the facilities at fixed prices of $120 million in 2015, $38 million in 2017, and $68 million in 2021. Upon such acquisitions by TEP, each of the owners of Unit 3 and Unit 4 have the obligation to purchase from TEP a 17% and 14% interest, respectively, in such facilities.

We have reviewed our contractual obligations and provide the following additional information:

- We do not have any provisions in any of our debt or lease agreements that would cause an event of default or cause amounts to become due and payable in the event of a credit rating downgrade.
- None of our contracts or financing structures contains provisions or acceleration clauses due to changes in our stock price.

Dividends on Common Stock

On February 9, 2007, UniSource Energy declared a first quarter cash dividend of $0.225 per share on its Common Stock. The first quarter dividend, totaling approximately $8 million, will be paid March 14, 2007 to shareholders of record at the close of business February 20, 2007. During 2006, UniSource Energy paid quarterly dividends to its shareholders of $0.21 per share, totaling approximately $29 million. In 2005, UniSource Energy paid quarterly dividends to its shareholders of $0.19 per share, totaling approximately $26 million.

Income Tax Position

At December 31, 2006, UniSource Energy and TEP had, for federal and state income tax filing purposes, the following carryforward amounts:

	UniSource Energy Amount -Millions of Dollars-	Expiring Year	TEP Amount -Millions of Dollars-	Expiring Year
Capital Loss	$ 37	2010-2011	$ -	-
AMT Credit	48	-	34	-

Internal Revenue Service Matters

On its 2002 tax return, TEP filed for an automatic change in accounting method relating to the capitalization of indirect costs to the production of electricity and self-constructed assets. The new accounting method was also used on the 2003 and 2004 returns for TEP, UNS Gas and UNS Electric.

In August 2005, the IRS issued a ruling which draws into question the ability of electric and gas utilities to use the new accounting method. As a result, TEP, UNS Gas and UNS Electric have filed amended returns for 2002, 2003 and 2004 to remove the benefit previously claimed using the accounting method. In 2006, TEP and UNS Electric remitted tax and interest of $23 million and $1 million respectively to the IRS; and TEP, UNS Gas and UNS Electric remitted $8 million to state authorities. In December 2006, the IRS issued a final notice to the company disallowing the use of the accounting method. We are in the process of filing a protest and will proceed to appeals.

TUCSON ELECTRIC POWER COMPANY

RESULTS OF OPERATIONS

The financial condition and results of operations of TEP are currently the principal factors affecting the financial condition and results of operations of UniSource Energy on an annual basis. The following discussion relates to TEP's utility operations, unless otherwise noted.

2006 Compared With 2005

TEP recorded net income of $67 million in 2006 compared with $48 million in 2005. The following factors contributed to the improvement:

2006 included:

- a $53 million increase in total operating revenues less fuel and purchased power expense due to the following:
- a $28 million increase in retail revenues due to warm weather during the second quarter and retail customer growth;
- a $9 million increase in wholesale revenues due primarily to $3 million of transmission revenues related to Springerville Unit 3 and a $6 million increase in unrealized gains related to mark-to-market adjustments on forward sales. Margins on wholesale sales were lower than last year due to a decline in the average market price for power;
- a $23 million increase in other revenues due primarily to fees and reimbursements received from Tri-State for fuel and O&M costs related to Springerville Unit 3;
- a $24 million decrease in purchased power expense due to increased production at TEP's coal-fired generating plants and the availability of Luna to offset some of the wholesale purchases to meet retail customer demand during peak summer periods. Purchased power expense also reflects a $4 million increase in unrealized losses due to mark-to-market adjustments on forward purchases of energy; offset by
- a $31 million increase in fuel expense due to increased generation at TEP's coal-fired plants, gas-related fuel expense at Luna and $8 million of fuel costs associated with Springerville Unit 3;

- a $31 million increase in O&M expense. TEP's O&M includes $9 million of expenses related to Springerville Unit 3. In addition, pre-tax gains related to the sale of excess SO2 emission allowances were $7 million lower than 2005. Other factors contributing to higher O&M include operating expenses at Luna; generating plant maintenance; and higher payroll expenses;

- a $10 million increase in the amortization of TEP's TRA; and

- a $13 million decrease in total interest expense due primarily to lower interest on long-term debt and capital lease obligations, which was partially offset by interest paid to the IRS related to a notice of a proposed adjustment to previously filed tax returns and fees incurred in the third quarter of 2006 related to amending TEP's Credit Agreement.

In 2006, the net pre-tax benefit recognized by TEP related to Springerville Unit 3 for transmission revenues, operating fees and its share of the common costs was $8 million.

2005 Compared With 2004

TEP recorded income before cumulative effect of accounting change of $49 million in 2005 compared with $46 million in 2004. The following factors contributed to the improvement:

2005 Included:

- a $26 million decrease in TEP's total operating revenue less fuel and purchased power expense due to the following:

- a $60 million increase in TEP's purchased power expense resulting primarily from an extended unplanned outage of Springerville Unit 2 in August 2005, planned maintenance outages at San Juan Unit 2 and Four Corners Unit 5 during the second quarter and higher wholesale power prices;

- a $14 million increase in TEP's fuel expense due to a $3 million increase in natural gas costs primarily from higher gas prices and an $11 million increase in coal costs;

- a $28 million increase in retail revenues due to warm weather and a 3% increase in TEP's customer base; and

- a $19 million increase in TEP's wholesale revenues due to higher market prices for power compared to last year.

- a $22 million decrease in O&M. Higher maintenance costs at TEP's coal-fired plants were offset by an increase of $10 million in pre-tax gains on the sale of excess SO_2 Emission Allowances by TEP;

- a $6 million increase in the amortization of TEP's TRA; and

- a $17 million decrease in total interest expense related to the financial restructuring of TEP in May 2005.

2004 Included:

- expenses of $8 million related to a proposed but terminated acquisition of UniSource Energy.

Utility Sales and Revenues

Customer growth, weather and other consumption factors affect retail sales of electricity. Electric wholesale revenues are affected by market prices in the wholesale energy market, the availability of TEP generating resources, and the level of wholesale forward contract activity.

The table below provides trend information on retail sales by major customer class and electric wholesale sales made by TEP in the last three years as well as weather data for TEP's service territory.

	Sales			Operating Revenue		
	2006	2005	2004	2006	2005	2004
	-Millions of kWh-			-Millions of Dollars-		
Electric Retail Sales:						
Residential	3,778	3,633	3,460	$ 343	$ 331	$ 315
Commercial	1,959	1,856	1,788	203	193	187
Industrial	2,278	2,302	2,226	165	166	161
Mining	925	843	829	44	40	39
Public Authorities	261	241	240	19	17	17
Total Electric Retail Sales	9,201	8,875	8,543	774	747	719
Electric Wholesale Sales Delivered:						
Long-term Contracts	1,076	1,188	1,227	51	55	33
Other Sales	2,365	1,994	2,065	117	115	120
Transmission	-	-	-	13	7	5
Net Unrealized Gain (Loss) on Forward Sales of Energy	-	-	-	7	1	2
Total Electric Wholesale Sales	3,441	3,182	3,292	188	178	160
Total Electric Sales	12,642	12,057	11,835	$ 962	$ 925	$ 879
Weather Data:						
Cooling Degree Days	1,371	1,529	1,298			
10-Year Average	1,414	1,426	1,409			
Heating Degree Days	1,295	1,257	1,631			
10-Year Average	1,487	1,488	1,481			

2006 Compared with 2005

Total revenues from kWh sales to retail customers increased by $28 million, or 4%, in 2006 compared with 2005, due primarily to customer growth.

Wholesale revenues increased $9 million in 2006 compared with last year. In 2006, wholesale revenues included $3 million in transmission revenues related to Springerville Unit 3 and a $6 million increase in net unrealized gain due to mark-to-market adjustments on forward sales. Wholesale kWh sales increased 8% primarily due to the higher availability of TEP's coal plants; however, margins on wholesale sales were lower due to a 16% decrease in the average market price of wholesale energy. TEP's margins on wholesale sales were higher in 2005, as hurricane activity in the Gulf of Mexico boosted market prices for wholesale energy in the last six months of the year. See *Factors Affecting Results of Operations, Western Energy Markets, Market Prices*, below.

Mark-to-Market Adjustments on Trading Activity

The table below summarizes the net unrealized gains (losses) on TEP's forward sales and purchases of energy. Net unrealized gains (losses) on forward sales of energy are presented on the income statement in wholesale revenues. Net unrealized gains (losses) on forward purchases of energy are presented on the income statement in purchased power expense. Amounts for 2006 are based on the market price of energy as of December 31, 2006.

	2006	2005	2004
	-Millions of Dollars-		
Net Unrealized Gain (Loss) on Forward Sales of Energy	$7	$ 1	$2
Net Unrealized (Loss) Gain on Forward Purchases of Energy	(6)	(2)	-
Net Unrealized Gain (Loss)	$ 1	$ (1)	$2

2005 Compared with 2004

Total revenues from sales to retail customers increased by $28 million, or 4%, in 2005 compared with 2004, due primarily to customer growth and warm summer weather. Residential kWh sales increased 5% and commercial kWh sales increased 4% during 2005.

Despite lower coal plant availability and a 3% decrease in wholesale kWh sales, wholesale revenues increased $18 million, or 11%, in 2005 compared with 2004. The average wholesale market price of energy was $59 per MWh in 2005, compared with $44 per MWh in 2004. *See Factors Affecting Results of Operations, Western Energy Markets, Market Prices*, below.

Operating Expenses

2006 Compared with 2005

Fuel and Purchased Power

TEP's fuel and purchased power expense, and energy resources for 2006, 2005 and 2004 are detailed below:

	Generation			Expense		
	2006	2005	2004	2006	2005	2004
		-Millions of kWh-			-Millions of Dollars-	
Coal-Fired Generation						
Four Corners	812	783	749	$ 12	$ 11	$ 10
Navajo	1,215	1,221	1,244	17	16	15
San Juan	2,486	2,484	2,435	56	53	48
Springerville	5,826	5,572	5,731	96	94	92
Sundt 4	623	787	735	14	16	14
Total Coal-Fired Generation	10,962	10,847	10,894	$195	$190	$179
Gas-Fired Generation						
Luna	516	-	-	24	-	-
Other Units	334	368	432	31	36	34
Total Gas-Fired Generation	850	368	432	55	36	34
Solar and Other Generation	9	9	8	-	-	-
Total Generation (1)	11,821	11,224	11,334	250	226	213
Purchased Power	1,707	1,639	1,322	103	131	73
Net Unrealized (Gain) Loss on Forward Purchases of Energy	-	-	-	6	2	-
Total Purchased Power	1,707	1,639	1,322	109	133	73
Total Resources	13,528	12,863	12,656	$359	$359	$286
Less Line Losses and Company Use	886	806	821			
Total Energy Sold	12,642	12,057	11,835			

(1) Fuel expense in 2006 excludes $8 million related to Springerville Unit 3; the fuel costs incurred on behalf of Unit 3 are recorded in Fuel Expense and the reimbursement by Tri-State is recorded in Other Revenue.

The start of commercial operation of Luna and higher coal plant availability in the summer months led to a $24 million increase in fuel expense in 2006 (excluding fuel expenses at Springerville Unit 3); however, purchased power expense decreased $24 million as these same factors reduced TEP's need to purchase power during the summer months to meet retail demand. Gas-fired generation more than doubled in 2006, causing gas-related fuel expense to increase $19 million, or 53%. Coal-fired generation increased 1%, leading to a $5 million increase in coal-related fuel expense. Luna's generation output reported in the table above includes energy generated during its test phase, but does not include any associated fuel costs which were capitalized and reported as project costs.

Despite a 4% increase in purchased energy volumes, purchased power expense was $24 million, or 18%, lower due to a decrease in average wholesale energy prices in 2006 as well as fewer short-term purchases during the summer months when market prices for wholesale energy are typically higher. In September 2006, TEP began purchasing energy from Tri-State under a 100 MW purchased power agreement.

The table below shows TEP's average resource cost per kWh generated:

	2006	2005	2004
		-cents per kWh-	
Coal	1.78	1.75	1.64
Gas	6.69	9.78	7.87
All sources	2.61	2.01	1.88

*In 2006, the average cost of gas generation per kWh excludes test energy produced at Luna and its associated fuel costs.

TRA amortization increased $10 million in 2006. Amortization of the TRA is the result of the Settlement Agreement with the ACC, which changed the accounting method for TEP's generation operations. This item reflects the recovery, through 2008, of transition recovery assets which were previously regulatory assets of the generation business. The amount of amortization is a function of the TRA balance and total kWh consumption by TEP's distribution customers.

The table below shows estimated annual TRA amortization and unamortized TRA year-end balances for 2007 and 2008.

	Estimated TRA Amortization	**Unamortized TRA Balance**
	-Millions of Dollars-	
2007	76	26
2008	26	-

Other Income (Deductions)

In 2005, TEP's Income Statement included inter-company Interest Income of $2 million. This represented Interest Income on a promissory note TEP received from UniSource Energy in exchange for the transfer to UniSource Energy of its stock in Millennium in 1998. UniSource Energy repaid the inter-company promissory note on March 1, 2005. On UniSource Energy's Consolidated Statement of Income, this Interest Income, as well as UniSource Energy's related interest expense, was eliminated as an inter-company transaction. See *Liquidity and Capital Resources, TEP Cash Flows, Inter-Company Note from UniSource Energy*, below.

Operating Expenses

2005 Compared with 2004

Fuel and Purchased Power

During 2005, planned outages at Springerville Unit 2, San Juan Unit 2 and Four Corners Unit 5 and an extended unplanned outage at Springerville Unit 2 during the third quarter led to higher gas-related fuel costs and an 82% increase in purchased power expense. Purchased power expense increased $60 million compared with 2004, due to a 19% increase in MWhs purchased and an increase in wholesale market prices for power. The average market price for around-the-clock energy based on the Palo Verde Index increased 34% in 2005 compared with average prices in 2004. A combination of higher coal and natural gas costs contributed to a $13 million increase in total fuel expense at TEP's generating plants in 2005.

Cumulative Effect of Accounting Change

TEP adopted FIN 47 in December 2005 and recorded a one-time $1 million after-tax cost. See *Note 3 of Notes to Consolidated Financial Statements, Accounting Change: Accounting for Asset Retirement Obligations*, and *Critical Accounting Estimates, Accounting for Asset Retirement Obligations*, below.

FACTORS AFFECTING RESULTS OF OPERATIONS

Competition

In 2001, all of TEP's retail customers became eligible to choose an alternative energy service provider (ESP), however, only a small number of commercial and industrial customers initially chose an ESP. By 2002, none of TEP's retail customers were served by an alternative ESP.

In 2004, an Arizona Court of Appeals decision held invalid certain portions of the ACC rules on retail competition and related market pricing. In February 2006, the ACC Staff requested that a proceeding be opened to address the issue of retail electric competition. We cannot predict what changes, if any, the ACC will make to the competition rules. TEP has met all conditions required by the ACC to facilitate electric retail competition, including ACC approval of TEP's direct access tariffs. See *Rates, ACC Order to Review the Settlement Agreement*, below.

TEP competes against gas service suppliers and others that provide energy services. Other forms of energy technologies may provide competition to TEP's services in the future, but to date, are generally not financially viable alternatives for its retail customers. Self-generation by TEP's large industrial customers could also provide competition for TEP's services in the future, but has not had a significant impact to date.

In the wholesale market, TEP competes with other utilities, power marketers and independent power producers in the sale of electric capacity and energy.

ACC Order to Review the Settlement Agreement

Beginning in May 2005, TEP filed a series of pleadings requesting the ACC to resolve the uncertainty surrounding the methodology that will be applied to determine TEP's rates for generation service after 2008. TEP filed the pleadings in response to the Arizona Court of Appeals ruling related to retail competition and market pricing and a lack of agreement as to the interpretation of the Settlement Agreement by a number of participants in TEP's rate proceedings. TEP believes that the Settlement Agreement contemplated market based rates for generation service after 2008. See *Competition*, above for information regarding the recent court ruling.

In April 2006, the ACC ordered that a procedure be established to allow for an expeditious and complete review of, among other things, the Settlement Agreement and its effect on how TEP's rates for generation services will be determined after December 31, 2008.

The testimony filed by a number of participants in this proceeding, including the ACC Staff and Residential Utility Consumer Office (RUCO), reflect differing interpretations of the Settlement Agreement and a belief that TEP is required to charge cost-of-service rates for generation service in 2009.

According to testimony filed by TEP, its average retail rate would increase approximately 23% over current rates if 2009 generation service rates are market based. TEP also proposed two alternatives to charging market-based rates for generation in 2009: a market phase-in proposal with an initial rate increase capped at 12%; and a cost-of-service (including an $850 million regulatory asset and energy cost adjustment clause) proposal that would increase average retail rates in 2009 approximately 26% over current rates. See *TEP Testimony, The Market-Phase-in Proposal, and The Cost-of-Service (including Regulatory Asset and Energy Cost Adjustment Clause) Proposal*, below for more information.

In February 2007, parties in this proceeding participated in settlement discussions, however were unable to reach a settlement.

A public hearing before an ACC Administrative Law Judge (ALJ) is scheduled to begin on March 6, 2007. Following the public hearing, the ALJ will propose a recommended opinion and order for consideration by the ACC. We expect the ALJ to issue a recommendation in the second quarter of 2007.

If the ACC does not honor the Settlement Agreement allowing TEP to charge market-based rates for generation service in 2009 and orders TEP to return to cost-of-service generation rates without compensating TEP for financial impacts of the Settlement Agreement, TEP will file a lawsuit to preserve its right to declaratory relief and damages.

Rates

Settlement Agreement

In 1999, the ACC approved the Rules that provided a framework for the introduction of retail electric competition in Arizona, as well as the Settlement Agreement between TEP and certain customer groups related to the implementation of retail electric competition in Arizona.

The Rules and the Settlement Agreement established:

- a period from November 1999 through 2008 for TEP to transition its generation assets from a cost of service based rate structure to a market, or competitive, rate structure;
- the recovery through rates during the transition period of $450 million of stranded generation costs through a fixed competitive transition charge (Fixed CTC);
- capped rates for TEP retail customers through 2008;
- an ACC interim review of TEP retail rates in 2004;
- unbundling of electric services with separate rates or prices for generation, transmission, distribution, metering, meter reading, billing and collection, and ancillary services;
- a process for ESPs to become licensed by the ACC to sell generation services at market prices to TEP retail customers;
- access for TEP retail customers to buy market priced generation services from ESPs beginning in 2000 (currently, no TEP customers are purchasing generation services from ESPs);
- transmission and distribution services would remain subject to regulation on a cost of service basis; and
- beginning in 2009, TEP's generation would be market-based and its retail customers would pay the market rate for generation services.

Track A and Track B Proceedings

During 2002 and 2003, the ACC reexamined circumstances that had changed since it approved the Rules in 1999. The outstanding issues were divided into two groups. Track A related primarily to the divestiture of generation assets while Track B related primarily to the competitive energy bidding process.

Under the ACC's Rules, TEP and other utilities were required to divest their generation assets. TEP later requested a waiver of the divestiture requirement. The Track A order granted TEP's request and eliminated the divesture requirement. As a result, generation assets remain at TEP. At the same time, the ACC ordered the parties, including TEP, to develop a competitive bidding process and reduced the minimum amount of power to be acquired in the competitive bidding process to only that portion not supplied by TEP's existing resources.

The ACC Track B order defined the competitive bidding process TEP must use to obtain capacity and energy requirements. The Track B order did not address TEP's purchased power or asset acquisitions occurring subsequent to the 2003 competitive solicitation.

2004 General Rate Case Information

In June 2004, as required by the Settlement Agreement, TEP filed general rate case information with the ACC. TEP's filing did not propose any change in retail rates and, under the terms of the Settlement Agreement, no rate case filed by TEP through 2008 may result in a net rate increase. However, absent the restriction on raising rates, TEP believes that the data in its filing would have justified an increase in retail rates of 16%.

The general rate case information used a historical test year ended December 31, 2003 and established, based on TEP's standard offer service, that TEP was experiencing a revenue deficiency of $111 million. None of the intervenor testimony filed proposed any decrease to TEP's rates. Testimony filed by the ACC Staff, Residential Utility Consumer Office and Arizonans for Electric Choice and Competition indicated revenue deficiencies for TEP of $67 million, $32 million and $38 million, respectively. In 2005, the ALJ issued a procedural order suspending the remaining testimony filing deadlines and hearing in the 2004 rate review.

TEP Testimony

In August 2006, TEP filed testimony in the ACC proceedings to review the Settlement Agreement. TEP's testimony states its belief that it is entitled to charge market based generation service rates in 2009 and has complied with its obligations under the Settlement Agreement.

TEP testimony states that the Settlement Agreement provided the terms and conditions by which TEP is to transition into the competitive electric marketplace. The rate impact of charging market based generation service rates in 2009 would vary with market conditions which are influenced by the cost of natural gas. Assuming a natural gas cost of $7 per MMBtu, which equates to a wholesale power price of approximately $60 per MWh, TEP's average retail rate would be expected to increase approximately 23% over current rates if 2009 generation service rates are market based.

The Settlement Agreement required TEP to significantly change the way it conducted business. Under the terms of the Settlement Agreement, TEP agreed to: (i) rate reductions in 1999 and 2000; (ii) a rate freeze from July 1, 2000 through December 31, 2008, taking all the risk of inflation and cost increases; (iii) unbundled tariffed rates; (iv) accelerate depreciation of certain generation-related assets; (v) offset the standard offer generation rate (Market Generation Credit) by the amount of the Floating Competition Transition Charge; (vi) open its exclusive service territory to competition for generation service; (vii) assume the volatility and risk of market rates in 2009; and (viii) a rate check in 2004 when rates could not increase but could actually decrease.

In the testimony, TEP states that if the ACC or other parties to the Settlement Agreement seek to unilaterally change the contract and order TEP back to cost-of-service, which is a breach that will force TEP to protect its rights in court and seek an order, which may include an award for damages. TEP states that, if the ACC does not honor the Settlement Agreement, does not agree to one of TEP's alternative proposals, and orders that TEP's generation service rates will be based on traditional cost-of-service ratemaking without compensating TEP for the financial impacts of the Settlement Agreement, then TEP must: (1) file a rate case and (2) immediately file a lawsuit to preserve its right to declaratory relief and damages arising from the ACC's breach of the Settlement Agreement. TEP states that the financial impacts and costs directly attributable to the Settlement Agreement exceed $850 million.

In the testimony, TEP offered alternatives to charging market based generation service rates after December 31, 2008, as described below.

The Market Phase-In Proposal

TEP proposed a market rate phase-in plan in the event that the ACC desires to maintain a competitive wholesale generation market, but wants to mitigate the immediate impact of market rates. Elements of the market rate phase-in include:

- A cap would be set such that no customer class would realize an initial rate increase in excess of 12%. The phase-in period would begin in 2009, last approximately four years and then be fully market-based;
- TEP's current rates would remain frozen through the end of 2008; and
- Implementation of the new DSM, REST and TOU programs and tariffs.

The Cost-of-Service (including Regulatory Asset and Energy Cost Adjustment Clause) Proposal

TEP's cost-of-service proposal presents a framework for returning TEP to cost-of-service regulation for generation service if the ACC determines that it will abandon the concept of a competitive wholesale and retail generation market. Elements of the proposal include:

- A new regulatory asset of $850 million to be included in rate base will be created to compensate TEP for the financial impacts and costs incurred in performing under the Settlement Agreement;
- An energy cost adjustment clause (ECAC) to recover energy costs associated with serving the incremental retail load above that filed in its cost-of-service test year;
- Immediate filing of a cost-of-service rate case in 2007;

- Implementation of the new DSM, REST and TOU programs and tariffs; and

- Restore exclusivity of TEP's certificate of convenience and necessity.

The proposed ECAC would differ from some other purchase power and fuel clauses in that it would not include any fuel or purchased power price risks or plant operating risks associated with serving the test year portion of TEP's retail load. Also, the ECAC would not be a straight pass through of purchased power costs to serve the incremental load. In the event that TEP's actual fuel and purchased power costs related to the incremental load exceeds the ECAC rate, TEP would not be able to pass the "excess" costs through to customers. However, in the event that those costs are less than the ECAC rate, TEP would be entitled to retain those earnings.

If the ACC adopts TEP's cost-of-service proposal and approves a new regulatory asset of $850 million and implementation of the ECAC mechanism, TEP expects that its average retail rate in 2009 would increase by approximately 26% over current rates.

Renewable Energy Standard and Tariff

In October 2006, the ACC approved new Renewable Energy Standard and Tariff rules (REST rules) designed to require TEP, UNS Electric and other affected utilities to generate or purchase at least 15% of their total annual retail energy requirements from renewable energy technologies by 2025, with smaller amounts required in earlier years starting when the REST tariff submitted by an affected utility is approved by the ACC. To provide an opportunity for full recovery of the increased costs of meeting the more aggressive standard, the adopted REST rules allow for a new tariff to be implemented separate and apart from the existing Environmental Portfolio Surcharge. The rules require affected utilities to annually file with the ACC a REST tariff request with a REST implementation plan to recover the cost of purchasing or installing and operating the renewable resources. The tariff amount is annually subject to ACC approval.

The REST rules require utilities to file annual compliance reports outlining the results of the renewable programs implemented the prior year, highlighting steps they are taking to meet the REST annual renewable energy requirements. The REST rules adopted by the ACC must be certified by the Arizona Attorney General before taking effect. As of February 23, 2007, the Attorney General had not issued an opinion certifying the REST rules.

Western Energy Markets

As a participant in the Western U.S. wholesale power markets, TEP is directly and indirectly affected by changes in market conditions and market participants. TEP competes with other utilities, power marketers and independent power producers in the sale of electric capacity and energy at market-based rates in the wholesale market.

At the end of 2006, electric generating capacity in Arizona was approximately 25,600 MW, an increase of 61% since 2001. A majority of the growth is the result of 17 new or upgraded gas-fired generating units with a combined capacity of approximately 9,700 MW. The completion of Springerville Unit 3 in 2006 provided 400 MW of new coal-fired generation located in Arizona.

Market Prices

The average market price for around-the-clock energy based on the Dow Jones Palo Verde Index decreased in 2006, as did the average price for natural gas based on the Permian Index. We cannot predict whether changes in various factors that influence demand and supply will cause prices to change during 2007.

Average Market Price for Around-the-Clock Energy	$/MWh
Quarter ended December 31, 2006	$48
Quarter ended December 31, 2005	78
Year ended December 31, 2006	$50
Year ended December 31, 2005	59

Average Market Price for Natural Gas	$/MMBtu
Quarter ended December 31, 2006	$5.58
Quarter ended December 31, 2005	9.67
Year ended December 31, 2006	$6.05
Year ended December 31, 2005	7.17

In addition to energy from its coal-fired facilities, TEP typically uses purchased power, supplemented by generation from its gas-fired units, to meet the summer peak demands of its retail customers. Some of these purchased power contracts are price indexed to natural gas prices. Short-term and spot power purchase prices are also closely correlated to natural gas prices. Due to its increasing seasonal gas and purchased power usage, TEP hedges a portion of its total natural gas exposure from plant fuel and gas-indexed purchased power with fixed price contracts for a maximum of three years. TEP currently has approximately 35% of this exposure hedged for the summer peak period of 2007 (June – September) at a weighted average price of $7.18 per MMBtu. TEP purchases its remaining gas fuel needs and purchased power in the spot and short-term markets.

Market prices may also affect TEP's wholesale revenues. TEP commits to future sales of energy as part of its ongoing efforts to hedge its excess generation based on projected generation capability, forward prices and generation costs. For the first quarter of 2007, TEP has sold forward approximately 255,000 MWh at an average price of $70 per MWh, which excludes on-peak hours in April through September.

We expect the market price and demand for capacity and energy to continue to be influenced by factors including:

- availability and price of natural gas;
- weather;
- continued population growth in the Western U.S.;
- economic conditions in the Western U.S.;
- availability of generating capacity throughout the Western U.S.;
- the extent of electric utility industry restructuring in Arizona, California and other Western states;
- FERC regulation of wholesale energy markets;
- availability of hydropower;
- transmission constraints; and
- environmental regulations and the cost of compliance.

Coal Supply

On December 28, 2006, TEP entered into agreements for the purchase and transportation of coal to Sundt Unit 4 through 2008. The cost of coal and transportation under the agreements will increase approximately 60%, primarily due to significantly higher rail costs. Based on these agreements, and increases at other coal-fired plants, we expect TEP's total coal-related fuel expense across all of its plants to increase by approximately $17 million, or 9% in 2007.

Emission Allowances

TEP has SO_2 Emission Allowances in excess of what is required to operate its generating units. The excess results primarily from a higher removal rate of SO_2 emissions at Springerville Units 1 and 2 following recent upgrades to environmental plant components and related changes to plant operations. From time to time, TEP will sell a portion of its excess SO_2 Emission Allowances. The table below summarizes sales made in 2005 and 2006, and forward sales of SO_2 Emission Allowances, as of December 31, 2006.

Delivery	Allowances Sold	Pre-tax Gain (millions)
2005	15,000	$13
2006	10,000	7
2007	10,000	8

In addition to the allowances contracted to be sold in 2007, TEP expects to have approximately 20,000 excess SO_2 Emission Allowances through 2009.

Springerville Units 3 and 4

Springerville Unit 3, which commenced commercial operation in July 2006, is a 400 MW coal-fired generating facility located at the same site as Springerville Units 1 and 2. Tri-State is leasing 100% of Unit 3 from a financial owner. TEP allocates a portion of the fixed costs of the existing common facilities to the additional generating unit. TEP operates Unit 3 and will receive annual pre-tax benefits of approximately $15 million in the form of transmission revenues, rental payments and other fees and cost savings. As part of the project, Tri-State provided funding to improve sulfur dioxide scrubbers, low-nitrogen oxide burners and other emission control upgrades for Units 1 and 2, which were completed in 2005.

SRP is purchasing 100 MW of capacity from Tri-State under a 30-year power purchase agreement. In May 2006, SRP announced its intention to build Unit 4, a 400 MW coal-fired generating facility at the same Springerville site. Construction of Unit 4 has begun and, under the terms of existing regulatory permits, is required to be completed by December 31, 2009. Prior to Unit 4's completion, TEP may be required, along with Tri-State, to exercise best efforts to find a replacement purchaser for SRP to purchase 100 MW of capacity from Unit 3. If TEP and Tri-State are unable to find such a replacement purchaser, TEP would then purchase 100 MW of output from Unit 4, beginning with the commercial operation of Unit 4. Given the current level of wholesale power market prices, we believe it is unlikely that TEP would be required to find a replacement purchaser or to purchase SRP's 100 MW.

LIQUIDITY AND CAPITAL RESOURCES

TEP Cash Flows

During 2007, TEP expects to generate sufficient internal cash flows to fund most of its construction expenditures as well as its operating activities, required debt maturities and dividends to UniSource Energy. Cash flows may vary during the year, with cash flow from operations typically the lowest in the first quarter and highest in the third quarter due to TEP's summer peaking load. As a result of the varied seasonal cash flow, TEP will use, as needed, its revolving credit facility to fund its business activities.

The table below shows the cash available to TEP after capital expenditures, scheduled debt payments and payments on capital lease obligations:

	2006	2005	2004
		-Millions of Dollars-	
Net Cash Flows – Operating Activities (GAAP)	$ 227	$ 243	$ 275
Amounts from Statements of Cash Flows:			
Less: Capital Expenditures	(156)	(150)	(129)
Net Cash Flows after Capital Expenditures (non-GAAP)*	71	93	146
Amounts from Statements of Cash Flows:			
Less: Scheduled Repayments of Long-Term Debt	-	-	(2)
Less: Retirement of Capital Lease Obligations	(61)	(53)	(49)
Plus: Proceeds from Investment in Lease Debt	22	14	12
Net Cash Flows after Capital Expenditures and Required Payments on Debt and Capital Lease Obligations (non-GAAP)*	$ 32	$ 54	$ 107

	2006	2005	2004
Net Cash Flows – Operating Activities (GAAP)	$227	$243	$ 275
Net Cash Flows – Investing Activities (GAAP)	(182)	(129)	(126)
Net Cash Flows – Financing Activities (GAAP)	(79)	(174)	(101)
Net Cash Flows after Capital Expenditures (non-GAAP)*	71	93	146
Net Cash Flows after Capital Expenditures and Required Payments on Debt and Capital Lease Obligations (non-GAAP)*	32	54	107

* Net Cash Flows after Capital Expenditures and Net Cash Flows Available after Required Payments, both non-GAAP measures of liquidity, should not be considered as alternatives to Net Cash Flows - Operating Activities, which is determined in accordance with GAAP as a measure of liquidity. We believe that Net Cash Flows after Capital Expenditures and Net Cash Flows Available after Required Payments provide useful information to investors as measures of liquidity and our ability to fund our capital requirements, make required payments on debt and capital lease obligations, and pay dividends to UniSource Energy.

Liquidity Outlook

As a result of growing capital expenditures, TEP may use its revolving credit facility on a more frequent basis. Other funding sources to meet the capital requirements from TEP's strong customer growth could include the issuance of long-term debt as well as capital contributions from UniSource Energy. The need for external funding sources is partially dependent on the outcome of TEP's rate-related proceedings.

Operating Activities

In 2006, net cash flows from operating activities decreased by $16 million compared with the same period in 2005. Net cash flows were impacted by:

2006 included:

- a $28 million increase in cash receipts from electric retail and wholesale sales, net of fuel and purchased energy costs, due primarily to retail customer growth, higher availability of excess power to sell into the wholesale market; and the availability of Luna to offset some of TEP's purchased power requirements; and
- a $16 million decrease in total interest paid due to lower capital lease obligation balances, lower long-term debt balances and lower annual fees under the TEP credit agreement that was entered into in May 2005 and amended in August 2006;
- a $20 million increase in other cash receipts due primarily to payments from Tri-State for fees and the reimbursement of operating costs related to Springerville Unit 3; offset by
- a $42 million increase in income taxes paid due to a $31 million payment made to the IRS and state authorities related to a notice of a proposed adjustment to previously filed tax returns and an increase in federal and state extension and estimated tax payments;
- an $11 million increase in O&M costs due primarily to operating costs at Luna and higher generating plant maintenance costs;
- an $8 million decline in proceeds from the sale of excess emission allowances;
- a $4 million increase in taxes other than income taxes; and
- a $3 million increase in wages paid.

2005 included:

- $11 million of interest received from UniSource Energy related to an inter-company note repaid in the first quarter of 2005.

Investing Activities

Net cash used for investing activities was $53 million higher in 2006 compared with 2005 primarily due to:

- a $9 million increase in proceeds from investments in Springerville Lease Debt; offset by
- a $6 million increase in capital expenditures related to TEP's share of the construction costs of Luna and growth and maintenance of TEP's electric system; and
- TEP's purchase of a 14% equity interest in Springerville Unit 1 Lease, which represents approximately 53 MW of capacity.

Capital Expenditures

TEP's forecasted capital expenditures are summarized below:

Category	2007	2008	2009	2010	2011
			-Millions of Dollars-		
Transmission, Distribution and Other Facilities	$144	$149	$120	$183	$184
Generation Facilities	36	47	67	33	98
Environmental	18	42	8	8	10
Total	$198	$238	$195	$224	$292

Capital expenditures for TEP of $855 million for 2007 through 2010 are expected to be $216 million, or 34% higher than our 2005 forecast. This increase is the result of several factors including: strong customer growth; higher material and construction costs; the need to increase high-voltage transmission capacity into TEP's service territory; the reinforcement and expansion of distribution lines; and environmental upgrades to generating facilities.

These estimated expenditures include costs for TEP to comply with current federal and state environmental regulations. These estimates do not include the costs to construct the proposed Tucson to Nogales, Arizona transmission line. All of these estimates are subject to continuing review and adjustment. Actual construction expenditures may be different from these estimates due to changes in business conditions, construction schedules, environmental requirements, and changes to TEP's business arising from retail competition. TEP plans to fund these expenditures through internally generated cash flow.

Tucson to Nogales Transmission Line

If all regulatory approvals are received, the future costs to construct the transmission line from Tucson to Nogales, Arizona is expected to be approximately $95 million. Through December 31, 2006, approximately $11 million in land acquisition, engineering and environmental expenses have been incurred on this project. If the required approvals are not received, TEP may be required to expense a portion of the costs that have been capitalized related to the project, propose alternative methods to the ACC for improving reliability and spend additional amounts to implement such alternatives. See *Item 1. Business, Tucson Electric Utility Operations, Transmission Access, Tucson to Nogales Transmission Line.*

In addition to TEP's forecasted capital expenditures for construction, TEP's other capital requirements include its required debt maturities and capital lease obligations. See *Note 8 of Notes to Consolidated Financial Statements – Debt, Credit Facilities, and Capital Lease Obligations.*

Investments in Springerville Lease Debt and Equity

At December 31, 2006, TEP had $181 million of investments in lease debt and equity on its balance sheet. The yields on TEP's investments in Springerville Lease Debt, at the date of purchase, range from 8.9% to 12.7%. The table below provides a summary of the investment balances in lease debt.

Leased Asset	Lease Debt Investment Balance December 31, 2006	December 31, 2005
	- In Millions -	
Investments in Lease Debt:		
Springerville Unit 1	$ 81	$ 91
Springerville Coal Handling Facilities	52	65
Total Investment in Lease Debt	$133	$156

See *Note 8 of Notes to Consolidated Financial Statements – Debt, Credit Facilities and Capital Lease Obligations*

Financing Activities

Net cash used for financing activities was $95 million lower in 2006 compared with 2005. The following factors contributed to the decrease:

2006 included:

- a $30 million increase in net proceeds from borrowings under the TEP Revolving Credit Facility; offset by
- a $16 million increase in dividends paid to UniSource Energy; and
- an $8 million increase in scheduled payments made on capital lease obligations.

2005 included:

- a $110 million equity investment by UniSource Energy; and
- $95 million from UniSource Energy as a repayment for an inter-company loan; offset by
- $282 million to repay long-term debt;
- $5 million for debt issuance and retirement costs.

At December 31, 2006, there were $30 million in outstanding borrowings under the TEP Revolving Credit Facility.

TEP Credit Agreement

In August 2006, TEP amended and restated its existing credit agreement (TEP Credit Agreement). The amendment reduced the interest rate and fees payable on TEP's borrowings and letters of credit, increased the amount of its revolving credit facility to $150 million from $60 million, and extended the maturity to August 2011 from May 2010. In addition to the revolving credit facility, the TEP Credit Agreement includes a $341 million letter of credit facility which supports $329 million of tax-exempt variable rate bonds. The TEP Credit Agreement is secured by $491 million of 1992 Mortgage Bonds.

Interest rates and fees under the TEP Credit Agreement are based on a pricing grid tied to TEP's credit ratings. Letter of credit fees are 0.55% per annum and amounts drawn under a letter of credit would bear interest at LIBOR plus 0.55% per annum. TEP has the option of paying interest on borrowings under the revolving credit facility at LIBOR plus 0.55% or the greater of the federal funds rate plus 0.5% or the agent bank's reference rate.

The TEP Credit Agreement restricts additional indebtedness, liens, sale of assets and sale-leaseback agreements. The TEP Credit Agreement also requires TEP to meet a minimum cash coverage ratio and a maximum leverage ratio. If TEP complies with the terms of the TEP Credit Agreement, it may pay dividends to UniSource Energy. As of December 31, 2006, TEP was in compliance with the terms of the TEP Credit Agreement.

If an event of default occurs, the TEP Credit Agreement may become immediately due and payable. An event of default includes failure to make required payments under the TEP Credit Agreement; change in control, as defined; failure of TEP or certain subsidiaries to make payments or default on debt greater than $20 million; or certain bankruptcy events at TEP or certain subsidiaries.

Springerville Common Facilities Leases

In 1985, TEP sold and leased back its undivided one-half ownership interest in the common facilities at the Springerville Generating Station. TEP refinanced the lease debt totaling $68 million in June 2006. Interest is payable at LIBOR plus 1.5% for the next three years with the spread over LIBOR increasing every three years thereafter to 2% by June 2018. Prior to the refinancing, the interest rate was LIBOR plus 4%. The refinancing had no impact on the Springerville Common Facilities capital lease obligation or asset.

A portion of the rent payable by TEP pursuant to the Springerville Common Facilities Leases is determined by the amount of interest payable on the floating rate lease debt. On June 8, 2006, TEP entered into an interest rate swap to hedge a portion of the interest rate risk associated with the portion of rent determined by the interest rate on this debt. This swap has the effect of fixing the interest rate portion of rent at 7.27% on $37 million of the lease debt.

The LIBOR rate in effect on December 31, 2006 was 5.63%, and 3.68% on December 31, 2005, which resulted in a total interest rate on the lease debt of 7.13% at December 31, 2006, and 7.68% at December 31, 2005.

Inter-Company Note from UniSource Energy

In March 2005, UniSource Energy repaid to TEP a debt obligation in the principal amount of $95 million plus accrued interest of $11 million. TEP used the proceeds during May 2005 to redeem or repurchase certain of its existing debt through tender offers and redemptions. See *Bond Repurchases and Redemptions, below.*

Capital Contribution from UniSource Energy

In May 2005, UniSource Energy made a $110 million capital contribution to TEP. TEP used the proceeds during May 2005 to redeem or repurchase certain of its existing debt through tender offers and redemptions. See *Bond Repurchases and Redemptions*, below.

Bond Repurchases and Redemptions

TEP made a sinking fund payment of $1 million on its 6.1% 1941 Mortgage IDBs in January 2005. In March 2005, TEP redeemed at par the remaining $31 million of its 6.1% 1941 Mortgage IDBs due in 2008, as well as the remaining $21 million of its 7.5% 1941 Mortgage IDBs due in 2006.

In May 2005, TEP used the proceeds from the repayment of the note from UniSource Energy and the capital contribution from UniSource Energy to purchase $147 million of its 1997 Pima Series B and $74 million of its 1997 Pima Series C fixed-rate tax-exempt bonds (Repurchased Bonds) at a price of $101.50 per $100 principal amount. In May 2005, TEP redeemed at par the remaining $4 million of bonds outstanding under those series. TEP does not currently plan on canceling the Repurchased Bonds, which will remain outstanding under their respective indentures; however, the Repurchased Bonds will not be presented in our financial statements. TEP may choose to resell the Repurchased Bonds to third parties or cancel them in the future.

Mortgage Indentures

In June 2005, TEP terminated its 1941 Mortgage (formerly known as its First Mortgage). TEP's remaining mortgage is its 1992 Mortgage (formerly known as its Second Mortgage).

TEP's mortgage indenture creates a lien on and security interest in most of TEP's utility plant assets. Springerville Unit 2, which is owned by San Carlos, is not subject to this lien and security interest. TEP's mortgage indenture allows TEP to issue additional mortgage bonds on the basis of (1) a percentage of net utility property additions and/or (2) the principal amount of retired mortgage bonds. The amount of bonds that TEP may issue is also subject to a net earnings test under the indenture.

TEP's Credit Agreement, which totals $491 million and is secured by 1992 Mortgage Bonds, limits the amount of mortgage bonds that may be outstanding to no more than $840 million. At December 31, 2006, TEP had a total of $629 million in outstanding mortgage bonds, consisting of $491 million in bonds securing the TEP Credit Agreement, and $138 million in bonds securing the 7.50% Collateral Trust Bonds due in 2008. Although the 1992 Mortgage would allow TEP to issue additional bonds, the limit imposed by the TEP Credit Agreement is more restrictive and is currently the governing limitation.

Tax-Exempt Local Furnishing Bonds

TEP has financed a substantial portion of utility plant assets with industrial development revenue bonds issued by the Industrial Development Authorities of Pima County and Apache County. The interest on these bonds is excluded from gross income of the bondholder for federal tax purposes. This exclusion is allowed because the facilities qualify as "facilities for the local furnishing of electric energy" as defined by the Internal Revenue Code. These bonds are sometimes referred to as "tax-exempt local furnishing bonds." To qualify for this exclusion, the facilities must be part of a system providing electric service to customers within not more than two contiguous counties. TEP provides electric service to retail customers in the City of Tucson and certain other portions of Pima County, Arizona and to Fort Huachuca in contiguous Cochise County, Arizona.

TEP has financed the following facilities, in whole or in part, with the proceeds of tax-exempt local furnishing bonds: Springerville Unit 2, Sundt Unit 4, a dedicated 345-kV transmission line from Springerville Unit 2 to TEP's retail service area (the Express Line), and a portion of TEP's local transmission and distribution system in the Tucson metropolitan area. As of December 31, 2006, TEP had approximately $359 million of tax-exempt local furnishing bonds outstanding. Approximately $257 million in principal amount of such bonds financed Springerville Unit 2 and the Express Line. In addition, approximately $38 million of remaining lease debt related to the Sundt Unit 4 lease obligation was issued as tax-exempt local furnishing bonds.

Various events might cause TEP to have to redeem or defease some or all of these bonds:

- formation of an RTO or ISO;
- asset divestiture;
- changes in tax laws; or
- changes in system operations.

TEP believes that its qualification as a local furnishing system should not be lost so long as (1) the RTO or ISO would not change the operation of the Express Line or the transmission facilities within TEP's local service area, (2) the RTO or ISO allows pricing of transmission service such that the benefits of tax-exempt financing continue to accrue to retail customers, and (3) energy produced by Springerville Unit 2 and TEP's local generating units continues to be consumed in TEP's local service area. However, there is no assurance that such qualification can be maintained. Any redemption or defeasance of these bonds would likely require the issuance and sale of higher cost taxable debt securities in the same or a greater amount.

Capital Lease Obligations

At December 31, 2006, TEP had $647 million of total capital lease obligations on its balance sheet. The table below provides a summary of the outstanding lease amounts in each of the obligations.

Leased Asset	Capital Lease Obligation Balance at December 31, 2006	Expiration
	- In Millions -	
Springerville Unit 1	$381	2015
Springerville Coal Handling Facilities	112	2015
Springerville Common Facilities	107	2020
Sundt Unit 4	46	2011
Other Leases	1	2008
Total Capital Lease Obligations	$647	

Except for TEP's 14% equity ownership in the Springerville Unit 1 Leases and its 13% equity ownership in the Springerville Coal Handling Facilities, TEP will not own these assets at the expiration of the leases. TEP may renew the leases or purchase the leased assets at such time. The renewal and purchase options for Springerville Unit 1 and Sundt Unit 4 are generally for fair market value as determined at that time, while the purchase price option is fixed for the Springerville Coal Handling Facilities and Common Facilities. See *UniSource Energy, Contractual Obligations, footnote (3)*, for more information about the fixed purchase price amounts.

Contractual Obligations

The following charts display TEP's contractual obligations as of December 31, 2006 by maturity and by type of obligation.

TEP's Contractual Obligations
- Millions of Dollars -

Payment Due in Years Ending December 31,	2007	2008	2009	2010	2011	2012 and after	Total
Long-Term Debt:							
Principal	$ -	$ 138	$ -	$ -	$ 329	$ 355	$ 822
Interest	46	46	35	36	31	363	557
Capital Lease Obligations:							
Springerville Unit 1	83	82	30	57	83	401	736
Springerville Coal Handling	24	18	15	17	19	101	194
Sundt Unit 4	12	12	13	14	-	-	51
Springerville Common	6	6	6	6	6	148	178
Operating Leases	1	1	1	1	-	-	4
Purchase Obligations:							
Coal and Rail Transportation	89	89	80	80	42	242	622
Purchase Power	3	-	-	-	-	-	3
Gas	3	3	-	-	-	-	6
Other Long-Term Liabilities:							
Pension & Other Post -Retirement Obligations	13	4	4	5	5	30	61
San Juan Pollution Control Equipment	17	41	7	-	-	-	65
Acquisition of Springerville Coal Handling and Common Facilities(12)	-	-	-	-	-	226	226
Total Contractual Cash Obligations	$ 297	$ 440	$ 191	$ 216	$ 515	$1,866	$ 3,525

See *UniSource Energy Consolidated, Liquidity and Capital Resources, Contractual Obligations*, above, for a description of these obligations.

We have no other commercial commitments to report.

We have reviewed our contractual obligations and provide the following additional information:

- TEP's Credit Agreement contains pricing for its Revolving Credit Facility based on TEP's credit ratings. A change in TEP's credit ratings can cause an increase or decrease in the amount of interest TEP pays on its borrowings.

- TEP's Credit Agreement contains certain financial and other restrictive covenants, including interest coverage and leverage tests. Failure to comply with these covenants would entitle the lenders to accelerate the maturity of all amounts outstanding. At December 31, 2006, TEP was in compliance with these covenants. See *TEP Credit Agreement*, above.

- TEP conducts its wholesale marketing and risk management activities under certain master agreements whereby TEP may be required to post margin due to changes in contract values, a change in TEP's credit ratings or if there has been a material change in TEP's creditworthiness. As of December 31, 2006, TEP has not been required to post such credit enhancement.

Dividends on Common Stock

TEP declared and paid dividends to UniSource Energy of $62 million in 2006, $46 million in 2005 and $32 million in 2004.

TEP can pay dividends if it maintains compliance with the TEP Credit Agreement and certain financial covenants. As of December 31, 2006, TEP was in compliance with the terms of the TEP Credit Agreement.

The Federal Power Act states that dividends shall not be paid out of funds properly included in capital accounts. Although the terms of the Federal Power Act are unclear, we believe that there is a reasonable basis to pay dividends from current year earnings.

UNS GAS

RESULTS OF OPERATIONS

UniSource Energy formed two operating companies, UNS Gas and UNS Electric, to acquire the Arizona electric and gas assets from Citizens in 2003, as well as an intermediate holding company, UES, to hold the common stock of UNS Gas and UNS Electric.

UNS Gas reported net income of $4 million in 2006, $5 million in 2005 and $6 million in 2004. We expect operations at UNS Gas to vary with the seasons, with peak energy usage occurring in the winter months.

As of December 31, 2006, UNS Gas had approximately 145,000 retail customers, a 5% increase from last year. The table below shows UNS Gas' therm sales and revenues for 2006, 2005 and 2004.

	Sales			Revenues		
	2006	2005	2004	2006	2005	2004
	-Millions of Therms-			-Millions of Dollars-		
Retail Therm Sales:						
Residential	70	69	71	$ 96	$ 79	$ 76
Commercial	30	29	29	38	29	28
Industrial	3	3	3	3	2	2
Public Authorities	7	7	7	8	7	6
Total Retail Therm Sales	110	108	110	145	117	112
Transport	23	27	-	3	3	3
Negotiated Sales Program (NSP)	17	21	21	12	16	12
Total Therm Sales	150	156	131	$ 160	$ 136	$ 127

Through a Negotiated Sales Program (NSP) approved by the ACC, UNS Gas supplies natural gas to some of its large transportation customers. Approximately one half of the margin earned on these NSP sales is retained by UNS Gas while the remainder benefits retail customers through a credit to the Purchased Gas Adjustor (PGA) mechanism which reduces the gas commodity price. See *Factors Affecting Results of Operations, Rates and Regulation, Energy Cost Adjustment Mechanism*, below.

The table below provides summary financial information for UNS Gas.

	2006	2005	2004
	-Millions of Dollars-		
Gas Revenues	$ 160	$ 136	$ 127
Other Revenues	2	2	2
Total Operating Revenues	162	138	129
Purchased Energy Expense	114	91	82
Other Operations and Maintenance Expense	25	23	23
Depreciation and Amortization	7	7	5
Taxes other than Income Taxes	3	3	3
Total Other Operating Expenses	149	124	113
Operating Income	13	14	16
Total Other Income	1	-	-
Total Interest Expense	7	6	6
Income Tax Expense	3	3	4
Net Income	$ 4	$ 5	$ 6

Retail therm sales were 2% higher in 2006 due primarily to customer growth. In 2006, retail revenues increased $24 million and purchased energy expense increased $23 million, due primarily to the PGA surcharge increase, which became effective in November 2005. See *Factors Affecting Results of Operations, Rates and Regulation Energy, Energy Cost Adjustment Mechanism*, below.

FACTORS AFFECTING RESULTS OF OPERATIONS

Rates

Energy Cost Adjustment Mechanism

UNS Gas' retail rates include a PGA mechanism intended to address the volatility of natural gas prices and allow UNS Gas to recover its actual commodity costs, including transportation, through a price adjustor. The difference between UNS Gas' actual gas and transportation costs and the cost of gas and transportation recovered through base rates are deferred and recovered or repaid through the PGA mechanism.

The PGA mechanism has two components, the PGA factor and the PGA surcharge or credit. The PGA factor is a mechanism that compares the twelve-month rolling weighted average gas cost to the base cost of gas, and automatically adjusts monthly, subject to limitations on how much the price per therm may change in a twelve-month period. The actual gas and transportation costs that are either under or over collected through the base rate of $0.40 per therm or $4.00 per MMBtu and the PGA factor are charged or credited to a balancing account (PGA bank). In the twelve months ended December 31, 2006, the average PGA factor was approximately $0.33 per therm or $3.33 per MMBtu.

The current annual cap on the maximum increase in the PGA factor is $0.10 per therm in a twelve-month period. As part of its general rate case proceeding with the ACC, UNS Gas requested to remove the cap to allow for more timely recovery of actual gas costs. See *General Rate Case Filing*, below.

When the ACC-designated under or over recovery trigger points of $6.2 million and $4.5 million, respectively, are met, UNS Gas may request a PGA surcharge or credit with the goal of collecting or returning the amount deferred from or to customers over a period deemed appropriate by the ACC.

On December 31, 2006, the PGA bank balance was over-collected by $2 million on the basis as billed to customers. In December 2006, the ACC approved a proposal by UNS Gas that lowered the PGA surcharge to $0.05 per therm. The $0.05 per therm PGA surcharge will remain in effect through April 2007. Based on current projections of gas prices, UNS Gas believes that the lower surcharge amount will allow it to timely recover its gas costs and still provide rate relief to its customers.

Changes in the market price for gas, sales volumes and surcharge amount could significantly change the PGA bank balance in the future.

General Rate Case Filing

UNS Gas' current rates have been in place since August 2003 and were designed to provide a 9.05% return on original cost rate base of $118 million. As a result of increased growth in UNS Gas' service territory and the related increase in capital expenditures and operating costs, such current rates are inadequate for UNS Gas to recover its costs and earn a reasonable rate of return on its investment. In July 2006, UNS Gas filed a general rate case. Below is a table that summarizes UNS Gas' request:

Test year	Year ended December 31, 2005
Original cost rate base	$162 million
Revenue deficiency	$10 million
Total rate increase (over test year revenues)	7%
Cost of debt	6.60%
Cost of equity	11.00%
Hypothetical capital structure	50% equity / 50% debt
Weighted average cost of capital	8.80%

UNS Gas also requested modifications to its PGA mechanism to help address problems posed by volatile gas prices, inappropriate price signals to customers and the potential for over or under collections to result in the accumulation of large bank balances.

In February 2007, ACC staff filed testimony that indicated a revenue deficiency for UNS Gas of approximately $5 million; RUCO's testimony indicated a revenue deficiency of approximately $2 million.

The procedural schedule for the UNS Gas rate case is as follows:

Filing	Date
UNS Gas rebuttal testimony	March 9, 2007
ACC Staff & intervenor rebuttal testimony	March 30, 2007
UNS Gas rejoinder testimony	April 6, 2007
Hearing before ALJ	April 16, 2007

UNS Gas expects the ACC to rule on its rate case in the second half of 2007. Under the terms of the UES Settlement Agreement, new rates cannot go into effect before August 1, 2007.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity Outlook

UNS Gas' capital requirements consist primarily of capital expenditures. In 2006, capital expenditures were $23 million. UNS Gas expects internal cash flows to fund its future operating activities and a large portion of its construction expenditures. If natural gas prices rise and UNS Gas is not allowed to recover its projected gas costs or PGA bank balance on a timely basis, UNS Gas may require additional funding to meet operating and capital requirements. Sources of funding future capital expenditures could include draws on the revolving credit facility, additional credit lines, the issuance of long-term debt, or capital contribution from UniSource Energy. The need for external funding sources is partially dependent on the outcome of UNS Gas' general rate case that was filed in July 2006.

Operating Cash Flow and Capital Expenditures

The table below provides summary information for operating cash flow and capital expenditures:

	2006	2005	2004
		-Millions of Dollars-	
Net Cash Flows – Operating Activities	$ 32	$ 14	$ 21
Capital Expenditures	23	23	19

Forecasted capital expenditures for UNS Gas are as follows:

	2007	2008	2009	2010	2011
			- Millions of Dollars -		
UNS Gas	$38	$33	$27	$28	$26

UNS Gas/UNS Electric Revolver

In August 2006, UNS Gas and UNS Electric amended and restated their existing unsecured revolving credit agreement (UNS Gas/UNS Electric Revolver). The amendment reduced the interest rate payable on borrowings and, upon ACC approval, will increase the amount of the revolving credit facility to $60 million from $40 million, and extend the maturity from April 2008 to August 2011. Currently, either borrower may borrow up to a maximum of $30 million, but the total combined amount borrowed cannot exceed $40 million. Upon ACC approval of the increase in the UNS Gas/UNS Electric Revolver, either borrower may borrow up to a maximum of $45 million so long as the combined amount borrowed does not exceed $60 million. The matter is pending before the ACC.

UNS Gas is only liable for UNS Gas' borrowings, and similarly, UNS Electric is only liable for UNS Electric's borrowings under the UNS Gas/UNS Electric Revolver. UES guarantees the obligations of both UNS Gas and UNS Electric.

UNS Gas and UNS Electric have the option of paying interest at LIBOR plus 1.0% or the greater of the federal funds rate plus 0.5% or the agent bank's reference rate.

The UNS Gas/UNS Electric Revolver contains restrictions on additional indebtedness, liens, mergers and sales of assets; it also contains a maximum leverage ratio and a minimum cash flow to interest coverage ratio for each borrower. As of December 31, 2006, UNS Gas and UNS Electric were each in compliance with the terms of the UNS Gas/UNS Electric Revolver.

If an event of default occurs, the UNS Gas/UNS Electric Revolver may become immediately due and payable. An event of default includes failure to make required payments under the UNS Gas/UNS Electric Revolver, certain change in control transactions, certain bankruptcy events of UNS Gas or UNS Electric, or failure of UES, UNS Gas or UNS Electric to make payments or default on debt greater than $4 million.

UNS Gas expects to draw upon the UNS Gas/UNS Electric Revolver from time to time for seasonal working capital purposes and to fund a portion of its capital expenditures. As of February 23, 2007, UNS Gas had no outstanding borrowings under the UNS Gas/UNS Electric Revolver.

Senior Unsecured Notes

UNS Gas has $100 million of senior unsecured notes outstanding consisting of $50 million of 6.23% Notes due in 2011 and $50 million of 6.23% Notes due in 2015 that are guaranteed by UES. The note purchase agreement for UNS Gas restricts transactions with affiliates, mergers, liens, restricted payments and incurrence of indebtedness, and also contains a minimum net worth test. As of December 31, 2006, UNS Gas was in compliance with the terms of its note purchase agreement.

UNS Gas must meet a leverage test and an interest coverage test to issue additional debt or to pay dividends. However, UNS Gas may, without meeting these tests, refinance existing debt and incur up to $7 million in short-term debt.

Contractual Obligations

UNS Gas Supply Contracts

UNS Gas has a natural gas supply and management agreement with BP Energy Company (BP). Under the contract, BP manages UNS Gas' existing supply and transportation contracts and its incremental requirements. The initial term of the agreement expired in August 2005. The agreement was automatically extended one year and will continue to extend on an annual basis unless either party provides 180 days notice of its intent to terminate. No termination notice has been tendered by either party. Prices for incremental gas supplied by BP will vary based upon the market prices for the period during which the gas is delivered.

UNS Gas hedges its gas supply prices by entering into fixed price forward contracts at various times during the year to provide more stable prices to its customers. These purchases are made up to three years in advance with the goal of hedging at least 45% of the expected monthly gas consumption with fixed prices prior to entering into the month. UNS Gas hedged approximately 48% of its expected monthly consumption for the 2006/2007 winter season (November through March). Additionally, UNS Gas has approximately 36% of its expected gas consumption hedged for April through October 2007, and 29% hedged for the period November 2007 through March 2008.

UNS Gas has firm transportation agreements with El Paso Natural Gas (EPNG) and Transwestern Pipeline Company (Transwestern) with combined capacity sufficient to meet its load requirements.

UNS Gas currently has a transportation agreement with EPNG to serve its Northern and Southern Arizona service territories. This agreement has specific contract volumes in each month and specific receipt point rights from the available supply basins (San Juan and Permian). The average daily capacity rights of UNS Gas is approximately 655,000 therms per day, with an average of 1,095,000 therms per day in the winter season (November through March).

EPNG filed a rate case in 2005 with new, higher rates effective in January 2006, subject to refund. The rate case participants reached a negotiated settlement and filed an agreement with FERC on December 6, 2006. FERC is expected to take action on the settlement agreement in the first half of 2007. UNS Gas' contract with EPNG expires in August 2011, with rights of first refusal for continuation thereafter.

UNS Gas has capacity rights of 250,000 therms per day on the San Juan Lateral and Mainline of the Transwestern pipeline. The Transwestern pipeline principally delivers gas to the portion of UNS Gas' distribution system serving customers in Flagstaff and Kingman, Arizona, and also delivers gas to UNS Gas' facilities serving the Griffith Power Plant in Mohave County. The current contract with Transwestern expires in February 2007. UNS Gas entered into a new firm transportation contract with Transwestern through February 2012 with rights of first refusal for continuation thereafter. The new capacity rights under this agreement are: 250,000 therms per day October through April; 15,000 therms per day in May; and 10,000 therms per day June through September.

Transwestern filed a rate case in October 2006 with new, higher rates to be effective in April 2007. The rate case participants are attempting to negotiate a settlement prior to the new rates becoming effective.

The aggregate annual minimum transportation charges are expected to be approximately $9 million and $2 million for the EPNG and Transwestern contracts, respectively. These costs are passed through to our customers via the PGA.

Dividends on Common Stock

The note purchase agreement for UNS Gas contains restrictions on dividends. UNS Gas may pay dividends so long as (a) no default or event of default exists and (b) it could incur additional debt under the debt incurrence test. See *Senior Unsecured Notes*, above. It is unlikely, however, that UNS Gas will pay dividends in the next few years due to expected cash requirements for capital expenditures.

UNS ELECTRIC

RESULTS OF OPERATIONS

UNS Electric reported net income of $5 million in 2006 and 2005, and $4 million in 2004. Similar to TEP's operations, we expect UNS Electric's operations to be seasonal in nature, with peak energy demand occurring in the summer months.

As of December 31, 2006, UNS Electric had approximately 93,000 retail customers, a 4% increase from last year. Retail kWh sales were 6% higher in 2006 due primarily to customer growth. The table below shows UNS Electric's kWh sales and revenues for 2006, 2005 and 2004.

	Sales			Revenues		
	2006	2005	2004	2006	2005	2004
		-Millions of kWh-			-Millions of Dollars-	
Electric Retail Sales:						
Residential	804	745	692	$ 81	$ 75	$ 70
Commercial	613	591	574	61	60	58
Industrial	191	182	194	15	13	14
Other	3	3	3	1	1	1
Total Electric Retail Sales	1,611	1,521	1,463	$158	$149	$143

The table below provides summary financial information for UNS Electric.

	2006	2005	2004
	-Millions of Dollars-		
Electric Revenues	$158	$149	$143
Other Revenues	2	1	1
Total Operating Revenues	160	150	144
Purchased Energy Expense	106	100	96
Other Operations and Maintenance Expense	26	23	24
Depreciation and Amortization	11	10	9
Taxes other than Income Taxes	4	4	3
Total Other Operating Expenses	147	137	132
Operating Income	13	13	12
Total Interest Expense	5	5	5
Income Tax Expense	3	3	3
Net Income	$ 5	$ 5	$ 4

FACTORS AFFECTING RESULTS OF OPERATIONS

Competition

As required by the ACC order approving UniSource Energy's acquisition of the Citizens' Arizona gas and electric assets, in 2003 UNS Electric filed with the ACC a plan to open its service territories to retail competition by December 31, 2003. The plan addressed all aspects of implementation. It included UNS Electric's unbundled distribution tariffs for both standard offer customers and customers that choose competitive retail access, as well as Direct Access and Settlement Fee schedules. UNS Electric's direct access rates for both transmission and ancillary services would be based upon its FERC Open Access Transmission Tariff. The plan is subject to review and approval by the ACC, which has not yet considered the plan. As a result of the court decisions concerning the ACC's Rules, we are unable to predict when and how the ACC will address this plan. See *Tucson Electric Power Company, Factors Affecting Results of Operations, Competition*, above for information regarding the Arizona Court of Appeals decision.

Rates

Energy Cost Adjustment Mechanism

UNS Electric's retail rates include a PPFAC, which allows for a separate surcharge or surcredit to the base rate for delivered purchased power to collect or return under or over recovery of costs. The ACC has approved a PPFAC surcharge of $0.01825 per kWh to recover transmission costs and the cost of the current full-requirements power supply agreement with PWMT.

General Rate Case Filing

UNS Electric's retail rates were last adjusted in August 2003. As a result of increased growth in UNS Electric's service territory and the related increase in capital expenditures and operating costs, such current rates are inadequate for UNS Electric to recover its costs and earn a reasonable rate of return on its investment. In December 2006, UNS Electric filed a general rate case. Below is a table that summarizes UNS Electric's request:

Test year	12 months ended June 30, 2006
Original cost rate base	$141 million
Revenue deficiency	$8.5 million
Total rate increase (over test year revenues)	5.5%
Cost of long-term debt	8.2%
Cost of equity	11.8%
Actual capital structure	49% equity / 51% debt
Weighted average cost of capital	9.9%

The procedural schedule for the UNS Electric rate case is as follows:

Filing	Date
ACC Staff and Intervenor testimony	June 28, 2007
UNS Electric rebuttal testimony	August 14, 2007
ACC Staff and Intervenor surrebuttal	August 24, 2007
UNS Electric rejoinder testimony	August 31, 2007
Hearing before ALJ	September 10, 2007

UNS Electric also requested the ACC to approve the acquisition of the 90 MW BMGS combustion turbine project under development by UED with a post test year rate base adjustment effective June 1, 2008. The cost of the BMGS is expected to cost $60 million.

UNS Electric expects the ACC to rule on its rate case in late 2007. Under the terms of the UES Settlement Agreement, new rates cannot go into effect before August 1, 2007.

UNS Electric also requested that a new PPFAC surcharge take effect when the current power supply agreement with PWMT expires in May 2008.

Renewable Energy Standard and Tariff

See, *Tucson Electric Power Company, Factors Affecting Results of Operations, Renewable Energy Standard and Tariff*, above.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity Outlook

UNS Electric's capital requirements consist primarily of capital expenditures. In 2006, capital expenditures were $39 million. UNS Electric expects internal cash flows to fund its future operating activities and a portion of its construction expenditures. Sources of funding future capital expenditures could include draws on the revolving credit facility, additional credit lines, the issuance of long-term debt, or capital contributions from UniSource Energy. The need for external funding sources is partially dependent on the outcome of UNS Electric's general rate case that was filed in December 2006.

In June 2006, UniSource Energy contributed $10 million of capital to UNS Electric.

Operating Cash Flow and Capital Expenditures

The table below provides summary information for operating cash flow and capital expenditures.

	2006	2005	2004
		-Millions of Dollars-	
Net Cash Flows – Operating Activities	$ 14	$ 21	$ 19
Capital Expenditures	39	30	19

To improve the reliability of service in Santa Cruz County, UNS Electric completed a 20 MW gas-fired combustion turbine at the Valencia site in 2006, and plans to upgrade its existing 115 kV transmission line over time. The turbine improves reliability while the approval and permitting process for the 345 kV Tucson to Nogales transmission line continues. In 2006, UNS Electric's capital expenditures included $7 million related to the turbine. See *Item 1. Business, TEP Electric Utility Operations, Transmission Access, Tucson to Nogales Transmission Line.*

Forecasted capital expenditures for UNS Electric are as follows:

	2007	2008	2009	2010	2011
			- Millions of Dollars -		
UNS Electric	$43	$40	$42	$27	$34

UNS Gas/UNS Electric Revolver

See *UNS Gas, Liquidity and Capital Resources, UNS Gas/UNS Electric Revolver* above for description of UNS Electric's unsecured revolving credit agreement.

UNS Electric expects to draw upon the UNS Gas/UNS Electric Revolver from time to time for seasonal working capital purposes and to fund a portion of its capital expenditures. At February 23, 2007, UNS Electric had $25 million outstanding under the UNS Gas/UNS Electric Revolver.

Senior Unsecured Notes

UNS Electric has $60 million of 7.61% senior unsecured notes outstanding due in 2008 that are guaranteed by UES. The note purchase agreements for UNS Electric contain certain restrictive covenants, including restrictions on transactions with affiliates, mergers, liens to secure indebtedness, restricted payments, incurrence of indebtedness, and minimum net worth. As of December 31, 2006, UNS Electric was in compliance with the terms of its note purchase agreement.

UNS Electric must meet a leverage test and an interest coverage test to issue additional debt or to pay dividends. However, UNS Electric may, without meeting these tests, refinance existing debt and incur up to $5 million in short-term debt.

Contractual Obligations

UNS Electric Power Supply and Transmission Contracts

UNS Electric has a full requirements power supply agreement with Pinnacle West Marketing and Trading (PWMT), which expires in May 2008. The agreement obligates PWMT to supply all of UNS Electric's power requirements at a fixed price per MWh. Payments under the contract are usage based, with no fixed customer or demand charges. UNS Electric is in the process of securing replacement energy resources when its supply contract ends with PWMT in 2008.

During 2006, UNS Electric entered into various power supply agreements for periods of one to five years beginning in June 2008. Certain of these contracts are at a fixed price per MW and others are indexed to natural gas prices. As of December 31, 2006, UNS Electric estimates its future minimum annual payments under these contracts to be $27 million.

The new UNS Electric power purchase contracts are subject to master agreements whereby UNS Electric may be required to post margin due to changes in contract values or if there has been a material change in creditworthiness. As of December 31, 2006, UNS Electric had not been required to post such credit enhancement.

UNS Electric imports the power it purchases over the Western Area Power Administration's (WAPA) transmission lines. UNS Electric's transmission capacity agreements with WAPA provide for annual rate adjustments and expire in February 2008 and June 2011. The contract that expires in 2008 also contains a capacity adjustment clause. Under the terms of the agreements, UNS Electric's aggregated minimum fixed transmission charges are expected to be $12 million in 2007 through 2011. UNS Electric made payments under these contracts of $8 million in 2006 and $7 million in 2005.

Dividends on Common Stock

The note purchase agreement for UNS Electric contains restrictions on dividends. UNS Electric may pay dividends so long as (a) no default or event of default exists and (b) it could incur additional debt under the debt incurrence test. See *Senior Unsecured Notes*, above. It is unlikely, however, that UNS Electric will pay dividends in the next few years due to expected cash requirements for capital expenditures.

OTHER NON-REPORTABLE BUSINESS SEGMENTS

RESULTS OF OPERATIONS

The table below summarizes the income (loss) for the Other non-reportable segments in the last three years.

	2006	2005	2004
	- Millions of Dollars -		
UniSource Energy Parent Company	$ (6)	$ (6)	$ (5)
Gains on Millennium Investments	-	2	5
Losses on Millennium Investments	(1)	(3)	(4)
Millennium Investments - Net	-	(1)	1
UED	-	-	(1)
Total Other Loss From Continuing Operations	$ (7)	$ (7)	$ (5)
Discontinued Operations – Net of Tax	(2)	(5)	(5)
Total Other Net Loss	$ (9)	$ (12)	$(10)

UniSource Energy Parent Company

UniSource Energy parent company expenses include interest expense (net of tax) related to the UniSource Energy Convertible Senior Notes, the UniSource Credit Agreement, and in 2004 and 2005, a note payable from UniSource Energy to TEP, which was repaid in March 2005.

UED

In 2006, UED purchased two electric generating turbines for $17 million. The turbines will be part of the 90 MW BMGS, to be constructed in Kingman, Arizona, and, pending ACC approval is expected to provide energy to UNS Electric. Construction is planned to begin during the third quarter of 2007 with an estimated completion date of May 2008. Including the purchase of the turbines, the total cost of the project is expected to be approximately $60 million. UED is financing the BMGS project with borrowings from UniSource Energy under an inter-company note payable. At December 31, 2006, there was $22 million outstanding and interest is payable quarterly at LIBOR plus 1.25%.

In 2005, UED had no significant operations.

In 2004, UED recognized an impairment loss on its note receivable from an independent power producer. As UED's recovery of the note receivable from the entity is subordinated to the rights of others, UED wrote off the entire $2 million balance due on the note at the time that Haddington, an investor in the independent power producer, determined that its investment was impaired. In 2004, UED's net loss was $1 million.

Discontinued Operations – Global Solar

Global Solar recorded losses of $2 million in 2006, $5 million in 2005 and $5 million in 2004. On March 31, 2006, Millennium completed the sale of its interest in Global Solar. In these financial statements, UniSource Energy accounts for Global Solar as a discontinued operation and recognizes 100% of Global Solar's losses.

FACTORS AFFECTING RESULTS OF OPERATIONS

Millennium Investments

MEG is in the process of winding down its activities and does not expect to engage in any significant new activities. As of December 31, 2006, the fair value of MEG's trading assets was $11 million and the fair value of MEG's trading liabilities was $5 million.

Nations Energy Corporation (Nations Energy), a wholly-owned subsidiary of Millennium, has been inactive since 2001. As of December 31, 2006, and December 31, 2005, Nations Energy had a deferred tax asset of $3 million related to investment losses that has not been reflected on UniSource Energy's consolidated income tax return.

Millennium is in the process of exiting its remaining investments. At December 31, 2006, the book value of Millennium's investments was $28 million.

LIQUIDITY AND CAPITAL RESOURCES

Millennium made a $5 million dividend payment to UniSource Energy in February 2007 and is expected to make additional dividend payments totaling $10 million to UniSource Energy during the first half of 2007.

In 2006, Millennium funded $2 million to Haddington under an existing commitment. In 2005, Haddington sold one of its investments and Millennium received a $6 million distribution related to the sale. In 2004, Millennium received a $7 million distribution from Haddington related to the gain on a sale of one of its investments. Millennium's remaining commitment is $1 million to Valley Ventures.

In 2006, Millennium received the remaining payment of $5 million on a note receivable from a subsidiary of Mirant Corporation and, in 2005, received a payment of $4 million.

Millennium funded the remainder of its commitment to IPS in 2006. Millennium owns less than 10% of the equity of IPS.

In 2005, Millennium received a $4 million payment from its investment in Carboelectrica Sabinas, S. de R.L. de C.V., (Sabinas) a Mexican limited liability company. The $4 million payment was treated as the return of capital and the book value of the investment in Sabinas was reduced to approximately $14 million. Millennium owns 50% of Sabinas. A $2 million payment due to Millennium in June 2006 was cancelled in exchange for payment by Mimosa, an affiliate of Sabinas, for up to $2 million to obtain a valuation of the interest in coal reserves and associated gas held by Mimosa. This evaluation is being performed under Millennium's direction, primarily to determine the impact of current regulatory changes in Mexico on the value of the Sabinas investment. We expect the evaluation to be completed in 2007.

UniSource Energy has ceased making loans or equity contributions to Millennium. We anticipate that the funding required to fund Millennium's remaining commitments will be provided only out of existing Millennium cash or cash returns from Millennium investments. We believe such cash and returns will be adequate to fund Millennium's remaining commitments.

CRITICAL ACCOUNTING ESTIMATES

In preparing financial statements under Generally Accepted Accounting Principles (GAAP), management exercises judgment in the selection and application of accounting principles, including making estimates and assumptions. UniSource Energy and TEP consider Critical Accounting Estimates to be those that could result in materially different financial statement results if our assumptions regarding application of accounting principles were different. UniSource Energy and TEP describe their Critical Accounting Estimates below. Other significant accounting policies and recently issued accounting standards are discussed in Note 1 of *Notes to Consolidated Financial Statements – Nature of Operations and Summary of Significant Accounting Estimates.*

Accounting for Rate Regulation

TEP, UNS Gas and UNS Electric generally use the same accounting policies and practices used by unregulated companies for financial reporting under GAAP. However, sometimes these principles, such as the Financial Accounting Standards Board's (FASB) Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation (FAS 71), require special accounting treatment for regulated companies to show the effect of regulation. For example, in setting TEP, UNS Gas and UNS Electric's retail rates, the ACC may not allow TEP, UNS Gas or UNS Electric to currently charge their customers to recover certain expenses, but instead may require that these expenses be charged to customers in the future. In this situation, FAS 71 requires that TEP, UNS Gas and UNS Electric defer these items and show them as regulatory assets on the balance sheet until TEP, UNS Gas and UNS Electric are allowed to charge their customers. TEP, UNS Gas and UNS Electric then amortize these items as expense to the income statement as these charges are recovered from customers. Similarly, certain revenue items may be deferred as regulatory liabilities, which are also eventually amortized to the income statement as rates to customers are reduced.

The conditions a regulated company must satisfy to apply the accounting policies and practices of FAS 71 include:

- an independent regulator sets rates;

- the regulator sets the rates to recover specific costs of delivering service; and
- the service territory lacks competitive pressures to reduce rates below the rates set by the regulator.

TEP

Upon approval by the ACC of a settlement agreement (Settlement Agreement) in November 1999, TEP discontinued application of FAS 71 for its generation operations. TEP continues to apply FAS 71 to its cost-based rate regulated operations, which include the transmission and distribution portions of its business.

TEP's transmission and distribution regulatory assets, net of regulatory liabilities, totaled $118 million at December 31, 2006. Regulatory assets of $61 million are not presently included in the rate base and consequently are not earning a return on investment. These regulatory assets are being recovered through the cost of service or are authorized to be collected in future base rates. TEP's transmission and distribution regulatory assets, net of regulatory liabilities, totaled $163 million at December 31, 2005.

TEP regularly assesses whether it can continue to apply FAS 71 to its cost-based rate regulated operations. If TEP stopped applying FAS 71 to its remaining regulated operations, it would write off the related balances of its regulatory assets as an expense and its regulatory liabilities as income on its income statement. Based on the regulatory asset balances, net of regulatory liabilities, at December 31, 2006, if TEP had stopped applying FAS 71 to its remaining regulated operations, it would have recorded an extraordinary after-tax loss of approximately $71 million. While regulatory orders and market conditions may affect cash flows, TEP's cash flows would not be affected if it stopped applying FAS 71 unless a regulatory order limited its ability to recover the cost of its regulatory assets.

UNS Gas and UNS Electric

UNS Gas regulatory liabilities, net of regulatory assets, totaled $13 million at December 31, 2006 compared with regulatory assets, net of regulatory liabilities of $3 million at December 31, 2005. UNS Electric's regulatory liabilities, net of regulatory assets, totaled $12 million at December 31, 2006 and $7 million at December 31, 2005. UNS Electric has $11 million of regulatory liabilities and $1 million of *regulatory assets that are not included in rate base. UNS Gas and UNS Electric regularly assess whether they can continue to apply FAS 71 to their cost-based rate regulated operations. If UNS Gas and UNS Electric stopped applying FAS 71 to their regulated operations, they would write off the related balances of regulatory assets as an expense and regulatory* liabilities as income on their income statements. Based on the balances of regulatory liabilities and assets at December 31, 2006, if UNS Gas and UNS Electric had stopped applying FAS 71 to their regulated operations, UNS Gas would record an extraordinary after-tax gain of $8 million and UNS Electric would record an extraordinary after-tax gain of $7 million. UNS Gas and UNS Electric's cash flows would not be affected if they stopped applying FAS 71 unless a regulatory order limited their ability to recover the cost of their regulatory assets.

Accounting for Asset Retirement Obligations

FAS 143, issued by the FASB, requires entities to record the fair value of a liability for a legal obligation to retire an asset in the period in which the liability is incurred. A legal obligation is a liability that a party is required to settle as a result of an existing or enacted law, statute, ordinance or contract. A legal obligation can also be associated with the retirement of a long-lived asset whose timing and/or method of settlement are conditional on a future event. We are required to record a conditional asset retirement obligation at its estimated fair value if that fair value can be reasonably estimated. When the liability is initially recorded, the entity should capitalize a cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is adjusted to its present value by recognizing accretion expense as an operating expense in the income statement each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss if the actual costs differ from the recorded amount.

TEP

In 2005, TEP implemented FASB Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations (FIN 47). The implementation of FIN 47 required TEP to update an existing inventory, originally created for the implementation of FAS 143, and to determine which, if any, of the conditional asset retirement obligations could be reasonably estimated. The ability to reasonably estimate conditional asset retirement obligations was a matter of management judgment, based upon management's ability to estimate a settlement date or range of settlement dates, a method or potential method of settlement and probabilities associated with the potential dates and methods of settlement of TEP's conditional asset retirement obligations. In determining whether its conditional asset retirement obligations could be reasonably estimated, management considered TEP's past practices, industry practices, management's intent and the estimated economic life of the assets. The fair value of the conditional asset retirement obligations were then estimated using an expected present value technique. Changes in management's assumptions regarding settlement dates, settlement methods or assigned probabilities could have a material effect on the liability recorded by TEP at December 31, 2006 as well as the associated cumulative effect of the change in accounting principle recorded. The liabilities associated with conditional asset retirement obligations will be adjusted on an ongoing basis due to the passage of time and revisions to either the timing or amount of the original estimates of undiscounted cash flows. These adjustments could have a significant impact on the Consolidated Balance Sheets and Consolidated Statements of Income. For more information regarding the implementation and ongoing application of FIN 47, see *Notes 1 and 3 of Notes to Consolidated Financial Statements, Nature of Operations and Summary of Significant Accounting Policies and Accounting Change: Accounting for Asset Retirement Obligations.*

Prior to implementing FAS 143, costs for final removal of all owned generation facilities were accrued as an additional component of depreciation expense. Under FAS 143, only the costs to remove an asset with legally binding retirement obligations will be accrued over time through accretion of the asset retirement obligation and depreciation of the capitalized asset retirement cost. As of December 31, 2006, TEP had a liability of $4 million associated with its final asset retirement obligations.

TEP has identified legal obligations to retire generation plant assets specified in land leases for its jointly-owned Navajo and Four Corners Generating Stations. The land on which these stations reside is leased from the Navajo Nation. The provisions of the leases require the lessees to remove the facilities upon request of the Navajo Nation at the expiration of the leases. TEP also has certain environmental obligations at the San Juan Generating Station. TEP has estimated that its share of the cost to remove the Navajo and Four Corners facilities and settle the San Juan environmental obligations will be approximately $40 million at the date of retirement. No other legal obligations to retire generation plant assets were identified.

In 2004, TEP, Phelps Dodge Energy Services, LLC and PNM Resources, Inc. each purchased from Duke Energy North America, LLC a one-third interest in a limited liability company which owns the natural gas-fired Luna Energy Facility (Luna) in Southern New Mexico. Luna is a 570-MW combined cycle plant and was placed into commercial operation in April 2006. See *Item 1. – Business, Future Generating Resources – TEP*. The new owners assumed asset retirement obligations to remove certain piping and evaporation ponds and to restore the ground to its original condition. TEP has estimated its share to settle the obligations will be approximately $2 million at the date of retirement.

TEP has various transmission and distribution lines that operate under land leases and rights of way that contain end dates and restorative clauses. TEP operates its transmission and distribution lines as if they will be operated in perpetuity and would continue to be used or sold without land remediation. As a result, TEP is not recognizing the costs of final removal of the transmission and distribution lines in the financial statements. As of December 31, 2006, TEP had accrued $80 million for the net cost of removal for the interim retirements from its transmission, distribution and general plant. As of December 31, 2005, TEP had accrued $75 million for these removal costs. The amount is recorded as a regulatory liability.

Amounts recorded under FAS 143 are subject to various assumptions and determinations, such as determining whether a legal obligation exists to remove assets, estimating the fair value of the costs of removal, estimating when final removal will occur, and the credit-adjusted risk-free interest rates to be used to discount future liabilities. Changes that may arise over time with regard to these assumptions and determinations will change amounts recorded in the future as expense for asset retirement obligations.

If TEP retires any asset at the end of its useful life, without a legal obligation to do so, it will record retirement costs at that time as incurred or accrued. TEP does not believe that the implementation of FAS 143 will result in any change in retail rates since all matters relating to the rate-making treatment of TEP's generating assets have been determined pursuant to the Settlement Agreement.

UNS Gas and UNS Electric

UNS Gas and UNS Electric have various transmission and distribution lines that operate under land leases and rights of way that contain end dates and restorative clauses. UNS Gas and UNS Electric operate their transmission and distribution lines as if they will be operated in perpetuity and would continue to be used or sold without land remediation. As a result, UNS Gas and UNS Electric are not recognizing the cost of final removal of the transmission and distribution lines in the financial statements.

For the net cost of removal for interim retirements from transmission, distribution and general plant, UNS Gas accrued $4 million as of December 31, 2006 and $3 million as of December 31, 2005. UNS Electric accrued $2 million as of December 31, 2006 and $1 million as of December 31, 2005. The amounts are recorded as regulatory liabilities.

Pension and Other Postretirement Benefit Plan Assumptions

We record plan assets, obligations, and expenses related to pension and other postretirement benefit plans based on actuarial valuations, which include key assumptions on discount rates, expected returns on plan assets, compensation increases and health care cost trend rates. These actuarial assumptions are reviewed annually and modified as appropriate. The effect of modifications is generally recorded or amortized over future periods. We believe that the assumptions used in recording obligations under the plans are reasonable based on prior experience, market conditions and the advice of plan actuaries.

TEP

As a result of adopting FAS 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*, in December 2006, TEP recognized the underfunded status of our defined benefit pension and other postretirement plans as a liability. The underfunded status was measured as the difference between the fair value of the plans assets and the projected benefit obligation for pension plans or accumulated postretirement benefit obligation for other postretirement benefit plans. We expect volatility in the liability recognized in the balance sheet in future years as the funded status of our plans can change significantly due to discount rate changes and investment and actuarial experience. The adjustment required to recognize the pension liability on adoption of this statement resulted in (i) recognition of a regulatory asset of $32 million representing a reasonable appropriation of the actuarial losses and prior service costs of TEP's pension plans that are probable of recovery in rates by its regulated operations in future periods and (ii) an adjustment to accumulated other comprehensive loss of $17 million for our unregulated operations. We recorded the required increase in our other postretirement benefit obligation as an adjustment to accumulated other comprehensive loss of $8 million as the ACC allows TEP, UNS Gas and UNS Electric to recover other postretirement costs through rates only as benefit payments are made. Any change in the funded status of our plans due to discount rate changes and investment and actuarial experience will be recognized as an adjustment to regulatory assets and other comprehensive income.

TEP discounted its future pension plan obligations at 5.9% at December 31, 2006 and 5.8% at December 31, 2005. TEP discounted its other postretirement plan obligations at a rate of 5.6% at December 31, 2006, and 5.8% at December 31, 2005. TEP determines the discount rate annually based on the rates currently available on high-quality, non-callable, long-term bonds. TEP looks to bonds that receive one of the two highest ratings given by a recognized rating agency whose future cash flows match the timing and amount of expected future benefit payments. For TEP's pension plans, a 25-basis point decrease in the discount rate would increase the projected benefit obligation (PBO) by approximately $7 million and the 2007 plan expense by approximately $1 million. A similar increase in the discount rate would decrease the PBO by approximately $8 million and the 2007 plan expense by approximately $1 million. For TEP's other postretirement benefit plan, a 25-basis point change in the discount rate would increase or decrease the accumulated postretirement benefit obligation (APBO) by approximately $2 million. A 25-basis point change in the discount rate would impact plan expense by approximately $0.1 million.

TEP calculates the market-related value of plan assets using the fair value of plan assets on the measurement date. TEP assumed that its plans' assets would generate a long-term rate of return of 8.3% at December 31, 2006 and 8.5% at December 31, 2005. In establishing its assumption as to the expected return on plan assets, TEP reviews the plans' asset allocation and develops return assumptions for each asset class based on advice from an investment consultant and the plans' actuary that includes both historical performance analysis and forward looking views of the financial markets. Pension expense decreases as the expected rate of return on plan assets increases. A 25-basis point change in the expected return on plan assets would impact pension expense in 2007 by less than $0.5 million.

TEP used an initial health care cost trend rate of 9.0% in valuing its postretirement benefit obligation at December 31, 2006. This rate reflects both market conditions and the plan's experience. Assumed health care cost trend rates have a significant effect on the amounts reported for health care plans. A 1% increase in assumed health care cost trend rates would increase the postretirement benefit obligation by approximately $5 million and the related plan expense in 2007 by less than $1 million. A similar decrease in assumed health care cost trend rates would decrease the postretirement benefit obligation by approximately $4 million and the related plan expense in 2007 by less than $1 million.

TEP will record pension expense of approximately $9 million and other postretirement benefit expense of $5 million ratably through 2007. TEP will make required pension plan contributions of $10 million in 2007. TEP's other postretirement benefit plan is not funded. TEP expects to make benefit payments to retirees under the postretirement benefit plan of approximately $3 million in 2007.

UNS Gas and UNS Electric

UNS Gas and UNS Electric discounted their future pension plan obligations using a rate of 5.9% at December 31, 2006 and December 31, 2005. For UNS Gas and UNS Electric's pension plan, a 25-basis point change in the discount rate would impact the benefit obligation and 2007 pension expense by less than $0.5 million. UNS Gas and UNS Electric will record pension expense of $1 million in 2007. UNS Gas and UNS Electric will make a pension plan contribution of $1 million in 2007.

UNS Gas and UNS Electric discounted its other postretirement plan obligations using a rate of 5.6% at December 31, 2006, compared with 5.8% at December 31, 2005. UNS Gas and UNS Electric will record postretirement medical benefit expense and make benefit payments to retirees under the postretirement benefit plan of approximately $0.1 million in 2007.

Accounting for Derivative Instruments, Trading Activities and Hedging Activities

A derivative financial instrument or other contract derives its value from another investment or designated benchmark. TEP enters into forward contracts to purchase or sell a specified amount of capacity or energy at a specified price over a given period of time, typically for one month, three months, or one year, within established limits to take advantage of favorable market opportunities. In general, TEP enters into forward purchase contracts when market conditions provide the opportunity to purchase energy for its load at prices that are below the marginal cost of its supply resources or to supplement its own resources (e.g., during plant outages and summer peaking periods). TEP enters into forward sales contracts when it forecasts that it has excess supply and the market price of energy exceeds its marginal cost. A portion of TEP's forward contracts are considered to be normal purchases and sales and, therefore, are not required to be marked-to-market. However, some of these forward contracts are considered to be derivatives, which TEP marks-to-market by recording unrealized gains and losses and adjusting the related assets and liabilities on a monthly basis to reflect the market prices at the end of the month. However, some of these forward contracts which are derivatives satisfy the requirements for cash flow hedge accounting and the unrealized gains and losses are recorded in Other Comprehensive Income, a component of Common Stock Equity, rather than being reflected in the income statement. Derivative financial instruments can be accounted for under multiple methods depending upon facts and circumstances, which can lead to variability in earnings.

TEP has a natural gas supply agreement, that expires in February 2007, under which it purchases its gas requirements for its generating units located in Tucson, Arizona at spot market prices. TEP also has agreements to purchase power that are priced using spot market gas prices. These contracts meet the definition of normal purchases and are not required to be marked-to-market. In an effort to minimize price risk on these purchases, TEP enters into commodity price swap agreements under which TEP purchases gas at fixed prices and simultaneously sells gas at spot market prices. The spot market price in the swap agreements is tied to the same index as the purchases under the natural gas supply and purchased power contracts. These swap agreements, which expire during the summer months through 2009, were entered into with the goal of locking in fixed prices on at least 45% and not more than 80% of TEP's expected summer monthly gas risk prior to entering into the month. The swap agreements are marked-to-market on a monthly basis; however, since the agreements satisfy the requirements for cash flow hedge accounting, the unrealized gains and losses are recorded in Other Comprehensive Income rather than being reflected in the income statement.

In June 2006, TEP entered into an interest rate swap in order to reduce the risk associated with unfavorable changes in variable interest rate payments related to changes in LIBOR. The swap has the effect of converting approximately $37 million of variable rate lease payments for the Springerville Common Lease to a fixed rate. The swap is designated as a cash flow hedge. The fair value of the interest rate swap is derived from models based on well recognized financial principles, which provide a reasonable approximation of the fair value of the swap as of the valuation date. Other models can be used to estimate the fair value of the swap and these models, which may use different assumptions or methods, may yield different results. At December 31, 2006, the fair value of the swap is a liability of $2 million.

TEP manages the risk of counterparty default by performing financial credit reviews, setting limits, monitoring exposures, requiring collateral when needed, and using a standardized agreement, which allows for the netting of current period exposures to and from a single counterparty.

UNS Gas does not currently have any contracts that are required to be marked-to-market. UNS Gas does have a natural gas supply and management agreement under which it purchases substantially all of its gas requirements at market prices from BP Energy Company (BP). However, the contract terms allow UNS Gas to lock in fixed prices on a portion of its gas purchases by entering into fixed price forward contracts with BP at various times during the year. This enables UNS Gas to provide more stable prices to its customers. These purchases are made up to three years in advance with the goal of locking in fixed prices on at least 45% and not more than 80% of the expected monthly gas consumption prior to entering into the month. These forward contracts, as well as the main gas supply contract, meet the definition of normal purchases and therefore are not required to be marked-to-market.

UNS Electric presently has a full requirements power supply agreement that enables it to meet its load. The agreement expires May 31, 2008 and UNS Electric is in the process of replacing this energy resource. In order to reduce exposure to energy price risk resulting from the procurement of power, UNS Electric has entered into forward power purchase contracts for specified amounts of energy at specified prices over a given period of time, within established limits. UNS Electric's forward power purchase contracts meet the definition of a derivative and are marked-to-market by recording unrealized gains or losses and adjusting the related assets and liabilities on a monthly basis to reflect the market prices at the end of the month. In December 2006, the ACC issued an order allowing UNS Electric to record the unrealized net gains or losses as a regulatory asset or regulatory liability.

MEG, a wholly-owned subsidiary of Millennium, enters into swap agreements, options and forward contracts relating to Emission Allowances. MEG marks its trading contracts to market by recording unrealized gains and losses and adjusting the related assets and liabilities on a monthly basis to reflect the market prices at the end of the month. In accordance with UniSource Energy's intention to cease making capital contributions to Millennium, Millennium has significantly reduced the holdings and activity of MEG. MEG's activities consist of managing a small number of remaining positions which are expected to close by early 2008.

The market prices used to determine fair values for TEP, UNS Electric and MEG's derivative instruments at December 31, 2006, are estimated based on various factors including broker quotes, exchange prices, over the counter prices and time value. For TEP's forward power sales contracts, a 10% decrease in market prices would result in an increase in unrealized net gains of $3 million, while a 10% increase in market prices would result in a decrease in unrealized net gains of $3 million. For TEP's forward power purchase contracts, a 10% decrease in market prices would result in an increase in unrealized net losses of $3 million, while a 10% increase in market prices would result in a decrease in unrealized net losses of $3 million. For TEP's forward power contracts that are accounted for as cash flow hedges, a 10% decrease in market prices would result in a $1 million increase in unrealized gains reported in Other Comprehensive Income, while a 10% increase in market prices would result in a $1 million decrease in unrealized gains reported in Other Comprehensive Income. For TEP's gas swap agreements, a 10% decrease in market prices would result in a $3 million increase in unrealized net losses reported in Other Comprehensive Income, while a 10% increase in market prices would result in a $3 million decrease in unrealized net losses reported in Other Comprehensive Income. For UNS Electric's forward power purchase contracts, a 10% decrease in market prices would result in a decrease in unrealized net gains reported as a regulatory liability of $10 million, while a 10% increase in market prices would result in an increase in unrealized net gains reported as a regulatory liability of $10 million. For MEG's remaining trading contracts, a 10% decrease in market prices or a 10% increase in market prices would be less than $0.1 million. The unrealized gains and losses are reversed as contracts settle and realized gains or losses are recorded.

Because of the complexity of derivatives, the FASB established a Derivatives Implementation Group (DIG). To date, the DIG has issued more than 100 interpretations to provide guidance in applying Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities (FAS 133). As the DIG or the FASB continues to issue interpretations, TEP, UNS Gas and UNS Electric may change the conclusions they have reached and, as a result, the accounting treatment and financial statement impact could change in the future.

See *Market Risks – Commodity Price Risk* in Item 7A.

Unbilled Revenue – TEP, UNS Gas and UNS Electric

TEP's, UNS Gas's and UNS Electric's retail revenues include an estimate of MWhs/therms delivered but unbilled at the end of each period. Unbilled revenues are dependent upon a number of factors that require management's judgment including estimates of retail sales and customer usage patterns. The unbilled revenue is estimated by comparing the estimated MWhs/therms delivered to the MWhs/therms billed to TEP, UNS Gas and UNS Electric retail customers. The excess of estimated MWhs/therms delivered over MWhs/therms billed is then allocated to the retail customer classes based on estimated usage by each customer class. TEP, UNS Gas and UNS Electric then record revenue for each customer class based on the various bill rates for each customer class. Due to the seasonal fluctuations of TEP's actual load, the unbilled revenue amount increases during the spring and summer months and decreases during the fall and winter months. The unbilled revenue amount for UNS Gas sales increases during the fall and winter months and decreases during the spring and summer months, whereas, the unbilled revenue amount for UNS Electric sales increases during the spring and summer months and decreases during the fall and winter months.

Plant Asset Depreciable Lives – TEP, UNS Gas and UNS Electric

We calculate depreciation expense based on our estimate of the useful lives of our plant assets. The estimated useful lives, and resulting depreciation rates used to calculate depreciation expense for the transmission and distribution businesses of TEP, UNS Gas and UNS Electric have been approved by the ACC in prior rate decisions. Depreciation rates for transmission and distribution cannot be changed without ACC approval.

The estimated remaining useful lives of TEP's generating facilities are based on management's best estimate of the economic life of the units. These estimates are based on engineering estimates, economic analysis, and statistical analysis of TEP's past experience in maintaining the stations. Our generation assets are currently depreciated over periods ranging from 23 to 70 years from the original in-service dates.

During the second quarter of 2005, a study requested by the participants in the San Juan Generating Station was completed which indicated San Juan's economic useful life had changed from previous estimates. As a result of the study and other analysis performed, TEP lengthened the estimated useful life of San Juan from 40 to 60 years beginning April 1, 2005. TEP's annual depreciation expense related to San Juan decreased by $6 million as a result.

During the first quarter of 2004, TEP engaged an independent third party to review the economic estimated useful lives of its owned generating assets in Springerville, Arizona. TEP then hired another independent third party to perform a depreciation study for its generation assets, taking into consideration the newly determined economic useful life for the Springerville assets, and changes in generation plant life information used by the operators and other participants of the joint power plants in which TEP participates. As a result of these analyses, TEP lengthened the useful lives of various generation assets for periods ranging from 11 to 22 years in July 2004. Consequently, depreciation rates and the corresponding depreciation expense have been revised prospectively to reflect the life extensions. The annual impact of these changes in depreciation rates was a reduction in depreciation expense of $9 million.

Deferred Tax Valuation

We record deferred tax liabilities for amounts that will increase income taxes on future tax returns. We record deferred tax assets for amounts that could be used to reduce income taxes on future tax returns. We record a valuation allowance, or reserve, for the deferred tax asset amount that we may not be able to use on future tax returns. We estimate the valuation allowance based on our interpretation of the tax rules, prior tax audits, tax planning strategies, scheduled reversal of deferred tax liabilities, and projected future taxable income.

At December 31, 2006, UniSource Energy had no valuation allowance. At December 31, 2005, UniSource Energy had a valuation allowance of $7 million relating to net operating loss (NOL) carryforward amounts. The $7 million valuation allowance balance at December 31, 2005, relates to losses generated by the Millennium entities. As a result of the sale of Global Solar, the NOL and related valuation allowance were removed from the UniSource Energy consolidated balance sheet. See *Note 6 of Notes to Consolidated Financial Statements.*

As of December 31, 2006 and December 31, 2005, UniSource Energy's deferred income tax assets include $7 million and $9 million, respectively, related to unregulated investment losses of Millennium. These losses have not been reflected on UniSource Energy's consolidated income tax returns. If UniSource Energy were unable to recognize such losses through its consolidated income tax return in the foreseeable future, UniSource Energy would be required to write off these deferred tax assets.

At December 31, 2006 and December 31, 2005, TEP had no valuation allowance.

NEW ACCOUNTING PRONOUNCEMENTS

The FASB recently issued the following Statements of Financial Accounting Standards (FAS), FASB Interpretations (FIN), FASB Staff Positions (FSP), and Emerging Issues Task Force Issues (EITF):

- EITF 06-3, How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (that is, Gross versus Net Presentation), approved June 2006, requires that we disclose our accounting policy regarding presentation of taxes on either a gross (included in revenues and costs) or a net (excluded from revenues) basis. Additionally, we must disclose the amounts of any taxes reported on a gross basis in interim and annual financial statements. EITF 06-3 is effective for interim and annual reporting periods beginning after December 15, 2006. See *Note 6 of Notes to Consolidated Financial Statements* for our disclosures.

- FIN 48, Accounting for Uncertainty in Income Taxes – an interpretation of FAS 109, issued July 2006, requires us to determine whether it is "more-likely-than-not" that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. Once it is determined that a tax position meets the more-likely-than-not recognition threshold, the position is measured to determine the amount of benefit to recognize in the financial statements. Additionally, FIN 48 requires disclosure of a rollforward of total unrecognized tax benefits. FIN 48 is effective for fiscal years beginning after December 15, 2006. TEP recognized between $1 million and $2 million of income as an increase to Common Stock Equity on January 1, 2007 on the adoption of FIN 48.

- FAS 157, Fair Value Measurement, issued September 2006, defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. FAS 157 clarifies that the exchange price is the price in the principal market in which the reporting entity would transact for the asset or liability. We are required to disclose inputs used to develop fair value measurements and the effect of any of our assumptions on earnings or changes in net assets for the period. FAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. We are evaluating the impact of FAS 157 on our financial statements, and will incorporate these additional disclosure requirements in our financial statements for the quarter ended March 31, 2008.

- FSP AUG-AIR-1, Accounting for Planned Major Maintenance Activities, issued September 2006, prohibits the use of the accrue-in-advance method of accounting for planned major maintenance activities effective in fiscal years beginning after December 15, 2006. As we do not accrue planned major maintenance activities in advance, we anticipate no impact on our financial statements from the adoption of this FSP.

- FAS 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, issued September 2006, requires recognition of the overfunded or underfunded status of a defined benefit postretirement plan measured as the difference between the fair value of the plans assets and benefit obligation. FAS 158 is effective for fiscal years ending after December 15, 2006. See *Note 11 of Notes to Consolidated Financial Statements* for the incremental effect of adopting FAS 158.

- In the third quarter of 2006, the Pension Protection Act of 2006 was signed into law, which will be effective January 1, 2008. The new law will affect the manner in which many companies, including UniSource Energy and TEP, administer their pension plans. The legislation will require companies to increase the amount by which they fund their pension plans, increase premiums to the Pension Benefit Guaranty Corporation for defined benefit plans, amend plan documents and provide additional disclosures in regulatory filings and to plan participants. We are currently assessing the impact it may have on our financial statements.

SAFE HARBOR FOR FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K contains forward-looking statements as defined by the Private Securities Litigation Reform Act of 1995. UniSource Energy and TEP are including the following cautionary statements to make applicable and take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statements made by or for UniSource Energy or TEP in this Annual Report on Form 10-K. Forward-looking statements include statements concerning plans, objectives, goals, strategies, future events or performance and underlying assumptions and other statements that are not statements of historical facts. Forward-looking statements may be identified by the use of words such as "anticipates", "estimates", "expects", "intends", "plans", "predicts", "projects", and similar expressions. From time to time, we may publish or otherwise make available forward-looking statements of this nature. All such forward-looking statements, whether written or oral, and whether made by or on behalf of UniSource Energy or TEP, are expressly qualified by these cautionary statements and any other cautionary statements which may accompany the forward-looking statements. In addition, UniSource Energy and TEP disclaim any obligation to update any forward-looking statements to reflect events or circumstances after the date of this report.

Forward-looking statements involve risks and uncertainties, which could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. We express our expectations, beliefs and projections in good faith and believe them to have a reasonable basis. However, we make no assurances that management's expectations, beliefs or projections will be achieved or accomplished. We have identified the following important factors that could cause actual results to differ materially from those discussed in our forward-looking statements. These may be in addition to other factors and matters discussed in other parts of this report:

1. Supply and demand conditions in wholesale energy markets, including volatility in market prices and illiquidity in markets, are affected by a variety of factors, which include the availability of generating capacity in the Western U.S., including hydroelectric resources, weather, natural gas prices, the extent of utility restructuring in various states, transmission constraints, environmental regulations and cost of compliance, FERC regulation of wholesale energy markets, and economic conditions in the Western U.S.

2. Effects of competition in retail and wholesale energy markets.

3. Changes in economic conditions, demographic patterns and weather conditions in our retail service areas.

4. Effects of restructuring initiatives in the electric industry and other energy-related industries.

5. The creditworthiness of the entities with which we transact business or have transacted business.

6. Changes affecting our cost of providing electric and gas service including changes in fuel costs, generating unit operating performance, scheduled and unscheduled plant outages, interest rates, tax laws, environmental laws, and the general rate of inflation.

7. Changes in governmental policies and regulatory actions with respect to financing and rate structures.

8. Changes affecting the cost of competing energy alternatives, including changes in available generating technologies and changes in the cost of natural gas.

9. Changes in accounting principles or the application of such principles to our businesses.

10. Changes in the depreciable lives of our assets.

11. Unanticipated changes in future liabilities relating to employee benefit plans due to changes in market values of retirement plan assets and health care costs.

12. The outcome of any ongoing or future litigation.

13. Ability to obtain financing through debt and/or equity issuance, which can be affected by various factors, including interest rate fluctuations and capital market conditions.

ITEM 7A. – QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risks

We are exposed to various forms of market risk. Changes in interest rates, returns on marketable securities, and changes in commodity prices may affect our future financial results.

For additional information concerning risk factors, including market risks, see Safe *Harbor for Forward-Looking Statements*, above.

Risk Management Committee

We have a Risk Management Committee responsible for the oversight of commodity price risk and credit risk related to the wholesale energy marketing activities of TEP, the emissions and trading activities of MEG, and the fuel and power procurement activities at TEP, UNS Gas and UNS Electric. Our Risk Management Committee, which meets on a quarterly basis and as needed, consists of officers from the finance, accounting, legal, wholesale marketing, transmission and distribution operations, and the generation operations departments of UniSource Energy. To limit TEP, UNS Gas, UNS Electric and MEG's exposure to commodity price risk, the Risk Management Committee sets trading and hedging policies and limits, which are reviewed frequently to respond to constantly changing market conditions. To limit TEP, UNS Gas, UNS Electric and MEG's exposure to credit risk, the Risk Management Committee reviews counterparty credit exposure as well as credit policies and limits.

Interest Rate Risk

TEP is exposed to interest rate risk resulting from changes in interest rates on certain of its variable rate debt obligations. At December 31, 2006 and 2005, TEP's debt included $329 million of tax-exempt variable rate debt. The average interest rate on TEP's variable rate debt (excluding letter of credit fees) was 3.47% in 2006 and 2.48% in 2005. In June 2006, TEP refinanced variable rate lease debt totaling $68 million related to its Springerville Common Facilities Leases. The notes underlying the leases mature in June 2017 and January 2020. The notes were amended to provide that interest will be payable at LIBOR plus 1.5% for the next three years with the spread over LIBOR increasing every three years thereafter to 2% by June 2018. Prior to the refinancing, the interest rate was LIBOR plus 4%. The interest rate in effect on the lease debt was 7.13% at December 31, 2006, and 7.68% at December 31, 2005. A 1% increase (decrease) in average interest rates would result in a decrease (increase) in TEP's pre-tax income by approximately $4 million.

A portion of the rent payable by TEP pursuant to the Springerville Common Facilities Leases is determined by the amount of interest payable on the floating rate lease debt. On June 8, 2006, TEP entered into an interest rate swap to hedge a portion of the interest rate risk associated with the portion of rent determined by the interest rate on this debt. This swap has the effect of fixing the interest rate portion of rent at 7.27% on $37 million of the lease debt.

Marketable Securities Risk

TEP is exposed to fluctuations in the return on its marketable securities, which is comprised of investments in debt securities. At December 31, 2006 and 2005, TEP had marketable debt securities with an estimated fair value of $139 million and $165 million, respectively. At December 31, 2006 and 2005, the fair value exceeded the carrying value by $6 million and $9 million, respectively. These debt securities represent TEP's investments in lease debt underlying certain of TEP's capital lease obligations. Changes in the fair value of such debt securities do not present a material risk to TEP, as TEP intends to hold these investments to maturity.

Commodity Price Risk

We are exposed to commodity price risk primarily relating to changes in the market price of electricity, natural gas, coal and emission allowances.

TEP

Purchases and Sales of Energy

To manage its exposure to energy price risk, TEP enters into forward contracts to buy or sell energy at a specified price and future delivery period. Generally, TEP commits to future sales based on expected excess generating capability, forward prices and generation costs, using a diversified market approach to provide a balance between long-term, mid-term and spot energy sales. TEP generally enters into forward purchases during its summer peaking period to ensure it can meet its load and reserve requirements and account for other contracts and resource contingencies. TEP also enters into limited forward purchases and sales to optimize its resource portfolio and take advantage of locational differences in price. These positions are managed on both a volumetric and dollar basis and are closely monitored using risk management policies and procedures overseen by the Risk

Management Committee. For example, the risk management policies provide that TEP should not take a short position in the third quarter and must have owned generation backing up all forward sales positions at the time the sale is made. TEP's risk management policies also restrict entering into forward positions with maturities extending beyond the end of the next calendar year except for approved hedging purposes.

The majority of TEP's forward contracts are considered to be "normal purchases and sales" of electric energy and are not considered to be derivatives under FAS 133. TEP records revenues on its "normal sales" and expenses on its "normal purchases" in the period in which the energy is delivered. From time to time, however, TEP enters into forward contracts that meet the definition of a derivative under FAS 133. When TEP has derivative forward contracts, it marks them to market using actively quoted prices obtained from brokers for power traded over-the-counter at Palo Verde and at other Southwestern U.S. trading hubs. TEP believes that these broker quotations used to calculate the mark-to-market values represent accurate measures of the fair values of TEP's positions because of the short-term nature of TEP's positions, as limited by risk management policies, and the liquidity in the short-term market.

To adjust the value of its derivative forward power sales and purchases, classified as cash flow hedges, to fair value in Other Comprehensive Income, TEP recorded the following net unrealized gains and losses:

	2006	2005	2004
	- Millions of Dollars -		
Net Unrealized Gain (Loss)	$6	$(1)	$ -

TEP also reported the following net unrealized gains and losses on forward power sales and purchases in Wholesale Sales and Purchased Power.

	2006	2005	2004
	- Millions of Dollars -		
Net Unrealized Gain (Loss)	$1	$(1)	$2

TEP uses sensitivity analysis to measure the impact of an unfavorable change in market prices on the fair value of its derivative forward contracts. As of December 31, 2006, for TEP's forward power sales contracts, a 10% decrease in market prices would result in an increase in unrealized net gains of $3 million, while a 10% increase in market prices would result in a decrease in unrealized net gains of $3 million. For TEP's forward power purchase contracts, a 10% decrease in market prices would result in an increase in unrealized net losses of $3 million, while a 10% increase in market prices would result in a decrease in unrealized net losses of $3 million.

For TEP's forward power contracts that are accounted for as cash flow hedges, a 10% decrease in market prices would result in a $1 million increase in unrealized gains reported in Other Comprehensive Income, while a 10% increase in market prices would result in a $1 million decrease in unrealized gains reported in Other Comprehensive Income. The unrealized gains and losses are reversed as contracts settle and realized gains or losses are recorded.

Natural Gas

TEP is also subject to commodity price risk from changes in the price of natural gas. In addition to energy from its coal-fired facilities, TEP typically uses purchased power, supplemented by generation from its gas-fired units, to meet the summer peak demands of its retail customers and to meet local reliability needs. Some of these purchased power contracts are price indexed to natural gas prices. Short-term and spot power purchase prices are also closely correlated to natural gas prices. Due to its increasing seasonal gas and purchased power usage, TEP hedges a portion of its total natural gas exposure from plant fuel, gas-indexed purchase power and spot market purchases with fixed price contracts for a maximum of three years. TEP purchases its remaining gas fuel needs and purchased power in the spot and short-term markets.

In 2006, the average market price of natural gas was $6.05 per MMBtu, or 16% lower than 2005. The table below summarizes TEP's gas generation output and purchased power for 2006, 2005 and 2004.

	2006	**2005**	**2004**	**2006**	**2005**	**2004**
	-Millions of MWhs-			% of Total Resources		
Gas-Fired Generation	848	368	432	6%	3%	3%
Purchased Power	1,644	1,639	1,322	12%	13%	10%

To adjust the value of its derivative gas swap contracts, classified as cash flow hedges, to fair value in Other Comprehensive Income, TEP recorded the following net unrealized gains and losses:

	2006	2005	2004
	- Millions of Dollars -		
Unrealized Gain (Loss)	$(17)	$11	$3

As of December 31, 2006, for TEP's gas swap agreements, a 10% decrease in market prices would result in a $3 million increase in unrealized losses reported in Other Comprehensive Income, while a 10% increase in market prices would result in a $3 million decrease in unrealized losses reported in Other Comprehensive Income.

Coal

TEP is subject to commodity price risk from changes in the price of coal used to fuel its coal-fired generating plants.

In 2003, TEP amended and extended the long-term coal supply contract for Springerville Units 1 and 2 through 2020 and expects coal reserves to be sufficient to supply the estimated requirements for Units 1 and 2 for their presently estimated remaining lives. During the extension period from 2011 through 2020, the coal price will be determined by the cost of Powder River Basin coal delivered to Springerville Unit 3 subject to a floor and ceiling. Based on current coal market conditions, this range would be from $24 to $30 per ton. TEP estimates its future minimum annual payments under this contract to be $45 million through 2010, the initial contract expiration date, and $14 million from 2011 through 2020. TEP's coal transportation contract at Springerville runs through June of 2011. TEP estimates minimum annual payments under this contract to be $13 million through 2010 and $7 million in 2011.

In December 2006, TEP entered into agreements for the purchase and transportation of coal to Sundt Unit 4 through December 2008. Although TEP expects to pay $20 million annually, the total amount paid under these agreements depends on the number of tons of coal purchased and transported. In 2007, the impact on TEP's total coal-related fuel expense across all of its plants is expected to increase by $17 million, or 9%.

The long-term rail contract for Sundt Unit 4 is in effect until the earliest of 2015, the remaining life of Sundt Unit 4 or the life of the coal mine. This rail contract requires TEP to transport at least 75,000 tons of coal per year through 2015 at an estimated annual cost of $2 million or to make a minimum payment of $1 million.

TEP also participates in jointly-owned generating facilities at Four Corners, Navajo and San Juan, where coal supplies are under long-term contracts administered by the operating agents. In 2003, the Four Corners coal contract was extended through July 2016. This contract requires TEP to purchase minimum amounts of coal at an estimated annual cost of $6 million. TEP expects coal reserves available to these three jointly-owned generating facilities to be sufficient for the remaining lives of the stations.

The contracts to purchase coal for use at the jointly-owned facilities require TEP to purchase minimum amounts of coal at an estimated average annual cost of $21 million for the next five years. See *Item 7. – Management's Discussion and Analysis of Financial Condition and Results of Operations, UniSource Energy Consolidated, Contractual Obligations and Note 6 of Notes to Consolidated Financial Statements – Commitments and Contingencies, TEP Commitments, Purchase and Transportation Commitments.*

UNS Gas

UNS Gas is subject to commodity price risk, primarily from the changes in the price of natural gas purchased for its customers. This risk is mitigated through the PGA mechanism which provides an adjustment to UNS Gas' retail rates to recover the actual costs of gas and transportation. UNS Gas further reduces this risk by purchasing forward fixed price contracts for a portion of its projected gas needs under its Price Stabilization Plan. UNS Gas purchases at least 45% of its estimated gas needs in this manner.

UNS Electric

UNS Electric is currently not exposed to commodity price risk for its purchase of electricity as it has a fixed price full-requirements supply agreement with PWMT and a PPFAC mechanism which fully recovers the costs incurred under such contract on a timely basis. This supply agreement with PWMT expires in May 2008 and UNS Electric is in the process of replacing this energy resource.

During 2006, UNS Electric entered into various power supply agreements for periods of one to five years beginning in June 2008. Certain of these contracts are at a fixed price per MW and others are indexed to natural gas prices. As of December 31, 2006, UNS Electric estimates its future minimum annual payments under these contracts to be $23 million.

Because a portion of the costs under these contracts will vary from period to period based on the market price of gas, the PPFAC, as currently structured, may not provide recovery of the costs incurred under these new contracts on a timely basis.

For UNS Electric's forward power purchase contracts, a 10% decrease in market prices would result in a decrease in unrealized net gains reported as a regulatory liability of $10 million, while a 10% increase in market prices would result in an increase in unrealized net gains reported as a regulatory liability of $10 million.

MEG

MEG trades Emission Allowances and related instruments; however, its current activities consist of managing a small number of remaining positions which are expected to close by early 2008. We manage the market risk of this line of business by setting notional limits by product, as well as limits to the potential change in fair market value under a 33% change in price or volatility. We closely monitor MEG's trading activities, which include swap agreements, options and forward contracts, using risk management policies and procedures overseen by the Risk Management Committee.

MEG marks its trading positions to market on a daily basis using actively quoted prices obtained from brokers and options pricing models for positions that extend through 2007. As of December 31, 2006 and December 31, 2005, the fair value of MEG's trading assets combined with Emission Allowances it holds in escrow was $11 million and $38 million, respectively. The fair value of MEG's trading liabilities was $5 million at December 31, 2006 and $24 million at December 31, 2005. For 2006, MEG reflected a $10 million unrealized loss and a $10 million realized gain on its income statement, compared with an unrealized gain of $11 million and a realized loss of $11 million in the same period last year. For MEG's remaining trading contracts at December 31, 2006, a 10% decrease in market prices or a 10% increase in market prices would be less than $1 million.

Unrealized Gain (Loss) of MEG's Trading Activities
- Millions of Dollars -

Source of Fair Value At December 31, 2006	Maturity 0 – 6 months	Maturity 6 – 12 months	Maturity over 1 yr.	Total Unrealized Gain (Loss)
Prices actively quoted	$4	$ 2	$ -	$6
Prices based on models and other valuation methods	-	3	-	3
Total	$4	$ 5	$ -	$9

Credit Risk

UniSource Energy is exposed to credit risk in its energy-related marketing and trading activities related to potential nonperformance by counterparties. We manage the risk of counterparty default by performing financial credit reviews, setting limits, monitoring exposures, requiring collateral when needed, and using a standard agreement which allows for the netting of current period exposures to and from a single counterparty.

We calculate counterparty credit exposure by adding any outstanding receivable (net of amounts payable if a netting agreement exists) to the mark-to-market value of any forward contracts. As of December 31, 2006, TEP's total credit exposure related to its wholesale marketing and gas hedging activities was approximately $34 million. Approximately $2 million of TEP's exposure is to non-investment grade companies. TEP had five counterparties with exposures of greater than 10% of its total credit exposure, totaling approximately $23 million. MEG's total credit exposure related to its trading activities was $5 million and was concentrated primarily with two counterparties. MEG has no credit exposure to non-investment grade counterparties.

UNS Gas is subject to credit risk from non-performance by its supply counterparty, BP Energy (BP), to the extent that this contract has a mark-to-market value in favor of UNS Gas. As of December 31, 2006, UNS Gas has purchased under fixed price contracts approximately 48% of the expected monthly consumption for the 2006/2007 winter season (November through March) and approximately 29% of its expected consumption for the 2007/2008 winter season. At December 31, 2006, UNS Gas had no credit exposure under its supply contract with BP.

UNS Electric has begun to enter into energy purchase agreements to replace the full requirements contract it has with PWMT that expires in May 2008. To the extent that such contracts have a positive mark-to-market value, UNS Electric would be exposed to credit risk under those contracts. At December 31, 2006, UNS Electric had less than $1 million in credit exposure under such contracts.

ITEM 8. – CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Management's Report on Internal Controls Over Financial Reporting

UniSource Energy Corporation's management is responsible for establishing and maintaining adequate internal control over financial reporting. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of the UniSource Energy Corporation's internal control over financial reporting as of December 31, 2006. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework.

Based on management's assessment using those criteria, management has concluded that, as of December 31, 2006, UniSource Energy Corporation's internal control over financial reporting was effective.

Our management's assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2006 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report which appears herein.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of
UniSource Energy Corporation:

We have completed integrated audits of UniSource Energy Corporation's 2006 and 2005 consolidated financial statements and of its internal control over financial reporting for each of the three years in the period ended December 31, 2006, in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements and financial statement schedule

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) and the financial statement schedule listed in the index appearing under Item 15(a) (2), respectively present fairly, in all material respects, the financial position of UniSource Energy Corporation and its subsidiaries at December 31, 2006 and December 31, 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the Index appearing under Item 15(a)(2) present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As described in Note 12 to the consolidated financial statements, the company changed the manner in which it accounts for pension and post-retirement obligations as a result of implementing Financial Accounting Standards Board Standard No. 158 as of December 31, 2006.

As described in Note 3 to the consolidated financial statements, the company changed the manner in which it accounts for asset retirement costs as a result of implementing Financial Accounting Standards Board Interpretation No.47 as of December 31, 2005.

Internal control over financial reporting

Also, in our opinion, management's assessment, included in Management's Report on Internal Controls Over Financial Reporting appearing under Item 8, that the Company maintained effective internal control over financial reporting as of December 31, 2006 based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control - Integrated Framework issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Chicago, Illinois
February 26, 2007

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of
Tucson Electric Power Company:

In our opinion, the accompanying consolidated financial statements listed in the index appearing under Item 15(a)(1) and financial statement schedule listed in index appearing under Item 15(a)(2), respectively present fairly, in all material respects, the financial position of Tucson Electric Power Company and its subsidiaries at December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the Index appearing under Item 15(a)(2) present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As described in Note 12 to the consolidated financial statements, the company changed the manner in which it accounts for pension and post-retirement obligations as a result of implementing Financial Accounting Standards Board Standard No. 158 as of December 31, 2006.

As described in Note 3 to the consolidated financial statements, the company changed the manner in which it accounts for asset retirement costs as a result of implementing Financial Accounting Standards Board Interpretation No. 47 as of December 31, 2005.

Chicago, Illinois
February 26, 2007

UNISOURCE ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF INCOME

	Years Ended December 31,		
	2006	2005	**2004**
	- Thousands of Dollars - (Except Per Share Amounts)		
Operating Revenues			
Electric Retail Sales	$ **932,307**	$ 895,411	$ 862,258
Electric Wholesale Sales	**187,994**	178,667	160,154
Gas Revenue	**159,598**	135,909	126,666
Other Revenues	**36,970**	14,069	15,910
Total Operating Revenues	**1,316,869**	1,224,056	1,164,988
Operating Expenses			
Fuel	**257,515**	226,278	212,514
Purchased Energy	**329,516**	324,351	250,668
Other Operations and Maintenance	**247,069**	215,600	243,675
Depreciation and Amortization	**130,502**	132,577	132,419
Amortization of Transition Recovery Asset	**65,985**	56,418	50,153
Taxes Other Than Income Taxes	**46,136**	47,328	47,866
Total Operating Expenses	**1,076,723**	1,002,552	937,295
Operating Income	**240,146**	221,504	227,693
Other Income (Deductions)			
Interest Income	**19,210**	19,838	20,192
Other Income	**7,453**	10,985	15,030
Other Expense	**(1,887)**	(2,155)	(6,439)
Total Other Income (Deductions)	**24,776**	28,668	28,783
Interest Expense			
Long-Term Debt	**75,039**	76,762	80,968
Interest on Capital Leases	**72,586**	79,098	85,912
Loss on Extinguishment of Debt	**1,080**	5,261	1,990
Other Interest Expense	**7,922**	3,153	1,947
Interest Capitalized	**(4,884)**	(3,978)	(2,509)
Total Interest Expense	**151,743**	160,296	168,308
Income Before Income Taxes, Discontinued Operations, and Cumulative Effect of Accounting Change	**113,179**	89,876	88,168
Income Tax Expense	**43,936**	37,623	37,186
Income Before Discontinued Operations and Cumulative Effect of Accounting Change	**69,243**	52,253	50,982
Discontinued Operations - Net of Tax	**(1,796)**	(5,483)	(5,063)
Cumulative Effect of Accounting Change - Net of Tax	**-**	(626)	-
Net Income	$ **67,447**	$ 46,144	$ 45,919
Weighted-average Shares of Common Stock Outstanding (000)	**35,264**	34,798	34,380
Basic Earnings per Share			
Income Before Discontinued Operations and Cumulative Effect of Accounting Chang	**$1.96**	$1.51	$1.49
Discontinued Operations - Net of Tax	**$(0.05)**	$(0.16)	$(0.15)
Cumulative Effect of Accounting Change - Net of Tax	**-**	$(0.02)	-
Net Income	**$1.91**	$1.33	$1.34
Diluted Eamings per Share			
Income Before Discontinued Operations and Cumulative Effect of Accounting Chang	**$1.85**	$1.44	$1.45
Discontinued Operations - Net of Tax	**$(0.05)**	$(0.14)	$(0.14)
Cumulative Effect of Accounting Change - Net of Tax	**-**	$(0.02)	-
Net Income	**$1.80**	$1.28	$1.31
Dividends Declared per Share	**$0.84**	$0.76	$0.64

See Notes to Consolidated Financial Statements.

UNISOURCE ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2006	2005	2004
	- Thousands of Dollars -		
Cash Flows from Operating Activities			
Cash Receipts from Electric Retail Sales	**$ 1,008,071**	$ 975,378	$ 931,450
Cash Receipts from Electric Wholesale Sales	**254,322**	227,095	204,902
Cash Receipts from Gas Sales	**173,243**	145,281	136,797
Sale of Excess Emission Allowances	**7,254**	15,354	2,760
Other Cash Receipts	**25,482**	9,107	14,323
MEG Cash Receipts from Trading Activity	**2,704**	72,441	170,506
Interest Received	**22,231**	23,194	22,608
Performance Deposits	**5,690**	4,702	(6,487)
Income Tax Refunds Received	**553**	1,484	5,427
Deposit-Second Mortgage Indenture	**-**	-	17,040
Fuel Costs Paid	**(244,690)**	(223,672)	(208,549)
Purchased Energy Costs Paid	**(383,943)**	(369,218)	(286,115)
Wages Paid, Net of Amounts Capitalized	**(100,368)**	(93,220)	(87,778)
Payment of Other Operations and Maintenance Costs	**(137,941)**	(130,108)	(116,621)
MEG Cash Payments for Trading Activity	**(812)**	(79,990)	(162,609)
Capital Lease Interest Paid	**(63,644)**	(67,707)	(70,752)
Taxes Other Than Income Paid, Net of Amounts Capitalized	**(144,526)**	(140,013)	(139,257)
Interest Paid, Net of Amounts Capitalized	**(67,006)**	(72,481)	(75,957)
Income Taxes Paid	**(66,070)**	(10,147)	(20,483)
Net Cash Used by Operating Activities of Discontinued Operations	**(2,710)**	(6,151)	(9,622)
Excess Tax Benefit from Stock Option Exercises	**(1,501)**	(2,527)	-
Other Cash Payments	**(3,680)**	(4,919)	(14,604)
Net Cash Flows - Operating Activities	**282,659**	273,883	306,979
Cash Flows from Investing Activities			
Capital Expenditures	**(238,261)**	(203,362)	(166,861)
Payments for Investment in Lease Debt and Equity	**(48,025)**	-	(4,499)
Sale of Subsidiary	**16,000**	-	-
Proceeds from Investment in Lease Debt and Equity	**22,158**	13,646	11,590
Return of Investment from Millennium	**4,835**	15,236	10,120
Other Proceeds from Investing Activities	**3,263**	8,848	2,716
Investments in and Loans to Equity Investees	**(4,518)**	(4,870)	(4,095)
Net Cash Used by Investing Activities of Discontinued Operations	**(46)**	(66)	(156)
Other Payments for Investing Activities	**(1,487)**	-	(5,004)
Net Cash Flows - Investing Activities	**(246,081)**	(170,568)	(156,189)
Cash Flows from Financing Activities			
Proceeds from Borrowings Under Revolving Credit Facilities	**194,000**	45,000	20,000
Payments for Borrowings Under Revolving Credit Facilities	**(126,000)**	(40,000)	(20,000)
Proceeds from Issuance of Long-Term Debt	**30,000**	240,000	-
Repayment of Long-Term Debt	**(93,250)**	(285,516)	(28,732)
Payments of Capital Lease Obligations	**(61,197)**	(52,907)	(49,378)
Common Stock Dividends Paid	**(29,499)**	(26,339)	(21,879)
Payment of Debt Issue Costs	**(2,092)**	(12,431)	(9,364)
Proceeds from Stock Options Exercised	**4,861**	10,691	6,970
Excess Tax Benefit from Stock Option Exercises	**1,501**	2,527	-
Other Proceeds from Financing Activities	**4,660**	11,906	8,007
Other Payments for Financing Activities	**-**	(5,595)	(3,652)
Net Cash Flows - Financing Activities	**(77,016)**	(112,664)	(98,028)
Net (Decrease) Increase in Cash and Cash Equivalents	**(40,438)**	(9,349)	52,762
Cash and Cash Equivalents, Beginning of Year	**144,679**	154,028	101,266
Cash and Cash Equivalents, End of Year	**$ 104,241**	$ 144,679	$ 154,028

See Note 17 for supplemental cash flow information.

See Notes to Consolidated Financial Statements.

UNISOURCE ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS

	December 31, 2006	2005
ASSETS	- Thousands of Dollars -	
Utility Plant		
Plant in Service	**$ 3,410,638**	$ 3,167,900
Utility Plant under Capital Leases	**702,337**	723,900
Construction Work in Progress	**135,431**	160,186
Total Utility Plant	**4,248,406**	4,051,986
Less Accumulated Depreciation and Amortization	**(1,492,842)**	(1,408,158)
Less Accumulated Amortization of Capital Lease Assets	**(495,944)**	(472,367)
Total Utility Plant - Net	**2,259,620**	2,171,461
Investments and Other Property		
Investments in Lease Debt and Equity	**181,222**	156,301
Noncurrent Assets of Subsidiary Held for Sale	**-**	13,065
Other	**66,194**	58,468
Total Investments and Other Property	**247,416**	227,834
Current Assets		
Cash and Cash Equivalents	**104,241**	144,679
Trade Accounts Receivable	**124,789**	99,338
Unbilled Accounts Receivable	**58,499**	53,920
Allowance for Doubtful Accounts	**(16,859)**	(15,037)
Materials and Fuel Inventory	**73,628**	65,716
Trading Assets	**26,387**	36,418
Current Regulatory Assets	**9,549**	15,563
Deferred Income Taxes - Current	**57,912**	50,389
Interest Receivable - Current	**7,782**	9,830
Current Assets of Subsidiary Held for Sale	**-**	16,639
Other	**9,982**	17,717
Total Current Assets	**455,910**	495,172
Regulatory and Other Assets		
Transition Recovery Asset	**101,626**	167,611
Income Taxes Recoverable Through Future Revenues	**34,749**	39,936
Other Regulatory Assets	**54,848**	20,944
Other Assets	**33,240**	57,253
Total Regulatory and Other Assets	**224,463**	285,744
Total Assets	**$ 3,187,409**	$ 3,180,211

See Notes to Consolidated Financial Statements.

(Consolidated Balance Sheets Continued)

UNISOURCE ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS

	December 31, 2006	December 31, 2005
CAPITALIZATION AND OTHER LIABILITIES	- Thousands of Dollars -	
Capitalization		
Common Stock Equity	**$ 654,149**	$ 616,741
Capital Lease Obligations	**588,771**	665,737
Long-Term Debt	**1,171,170**	1,212,420
Total Capitalization	**2,414,090**	2,494,898
Current Liabilities		
Current Obligations under Capital Leases	**59,090**	48,804
Borrowing under Revolving Credit Facilities	**50,000**	5,000
Current Maturities of Long-Term Debt	**6,000**	5,000
Accounts Payable	**102,829**	98,085
Income Taxes Payable	**16,429**	29,826
Interest Accrued	**52,392**	57,386
Trading Liabilities	**16,537**	27,300
Taxes Accrued	**35,431**	34,978
Accrued Employee Expenses	**22,886**	18,825
Customer Deposits	**19,767**	15,463
Current Regulatory Liabilities	**10,707**	-
Current Liabilities of Subsidiary Held for Sale	**-**	2,206
Other	**3,852**	3,933
Total Current Liabilities	**395,920**	346,806
Deferred Credits and Other Liabilities		
Deferred Income Taxes - Noncurrent	**126,883**	148,104
Regulatory Liability - Net Cost of Removal for Interim Retirements	**85,394**	78,535
Other Regulatory Liabilities	**9,609**	4,311
Other	**155,513**	107,557
Total Deferred Credits and Other Liabilities	**377,399**	338,507
Commitments and Contingencies (Note 6)		
Total Capitalization and Other Liabilities	**$ 3,187,409**	$ 3,180,211

See Notes to Consolidated Financial Statements.

(Consolidated Balance Sheets Concluded)

UNISOURCE ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CAPITALIZATION

			December 31, 2006	2005
COMMON STOCK EQUITY			- Thousands of Dollars -	
Common Stock--No Par Value			**$ 697,426**	$ 689,185
	2006	2005		
Shares Authorized	**75,000,000**	75,000,000		
Shares Outstanding	**35,189,645**	34,874,450		
Accumulated Deficit			**(27,913)**	(65,861)
Accumulated Other Comprehensive Loss			**(15,364)**	(6,583)
Total Common Stock Equity			**654,149**	616,741
PREFERRED STOCK				
No Par Value, 1,000,000 Shares Authorized, None Outstanding			**-**	-
CAPITAL LEASE OBLIGATIONS				
Springerville Unit 1			**381,446**	431,493
Springerville Coal Handling Facilities			**112,177**	122,353
Springerville Common Facilities			**106,837**	106,136
Sundt Unit 4			**46,140**	53,924
Other			**1,261**	635
Total Capital Lease Obligations			**647,861**	714,541
Less Current Maturities			**(59,090)**	(48,804)
Total Long-Term Capital Lease Obligations			**588,771**	665,737
LONG-TERM DEBT				
Issue	**Maturity**	**Interest Rate**		
UniSource Energy:				
Convertible Senior Notes	2035	4.50%	**150,000**	150,000
Credit Agreement - Term Loan	2011	Variable	**27,000**	86,250
Tucson Electric Power Company:				
Variable Rate IDBs	2011	Variable*	**328,600**	328,600
Collateral Trust Bonds	2008	7.50%	**138,300**	138,300
Unsecured IDBs	2020 - 2033	5.85% to 7.13%	**354,270**	354,270
UNS Gas and Electric:				
Senior Unsecured Notes	2008 - 2015	6.23% to 7.61%	**160,000**	160,000
Credit Agreement - Revolving Credit Facility	2008	Variable	**19,000**	-
Total Stated Principal Amount			**1,177,170**	1,217,420
Less Current Maturities			**(6,000)**	(5,000)
Total Long-Term Debt			**1,171,170**	1,212,420
Total Capitalization			**$ 2,414,090**	$ 2,494,898

* TEP's Variable Rate industrial development bonds (IDBs) are backed by letters of credit (LOCs) issued pursuant to TEP's Credit Agreement which expires in August 2011. Although the Variable Rate IDBs mature between 2018 and 2022, the above maturity reflects a redemption or repurchase of such bonds in 2011 as though the LOCs terminate without replacement upon expiration of the TEP Credit Agreement. Weighted average interest rates on variable rate tax-exempt debt ranged from 2.95 % to 3.96% during 2006 and 1.52% to 3.55% during 2005, and the average interest rate on such debt was 3.47% in 2006 and 2.48% in 2005.

UniSource Energy also has stock options outstanding. See Note 13.

See Notes to Consolidated Financial Statements.

UNISOURCE ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME

	Common Shares Outstanding*	Common Stock	Accumulated Deficit	Accumulated Other Comprehensive Loss	Total Stockholders' Equity
			- In Thousands -		
Balances at December 31, 2003	**33,788**	**$ 668,022**	**$ (109,706)**	**$ (1,844)**	**$ 556,472**
Comprehensive Income:					
2004 Net Income	-	-	45,919	-	45,919
Minimum Pension Liability (net of $1,430 income taxes)	-	-	-	(10,460)	(10,460)
Unrealized Gain on Cash Flow Hedges (net of $960 income taxes)	-	-	-	1,465	1,465
Reclassification of Unrealized Gains and Losses on Cash Flow Hedges to Net Income (net of $68 income taxes)	-	-	-	104	104
Total Comprehensive Income					37,028
Dividends Declared	-	-	(21,879)	-	(21,879)
Shares Issued under Stock Compensation Plans	63	1,307	-	-	1,307
Shares Distributed by Deferred Compensation Trust	4	50	-	-	50
Shares Issued for Stock Options	400	6,117	-	-	6,117
Tax Benefit Realized from Stock Options Exercised	-	1,459	-	-	1,459
Other	-	164	-	-	164
Balances at December 31, 2004	**34,255**	**677,119**	**(85,666)**	**(10,735)**	**580,718**
Comprehensive Income:					
2005 Net Income	-	-	46,144	-	46,144
Minimum Pension Liability Adjustment (net of $1,378 income taxes)	-	-	-	(2,101)	(2,101)
Unrealized Gain on Cash Flow Hedges (net of $6,503 income taxes)	-	-	-	9,918	9,918
Reclassification of Unrealized Gains and Losses on Cash Flow Hedges to Net Income (net of $2,403 income taxes)	-	-	-	(3,665)	(3,665)
Total Comprehensive Income					50,296
Dividends Declared	-	-	(26,339)	-	(26,339)
Shares Issued under Stock Compensation Plans	36	-	-	-	-
Shares Distributed by Deferred Compensation Trust	-	1	-	-	1
Shares Issued for Stock Options	583	9,411	-	-	9,411
Tax Benefit Realized from Stock Options Exercised	-	2,527	-	-	2,527
Other	-	127	-	-	127
Balances at December 31, 2005	**34,874**	**689,185**	**(65,861)**	**(6,583)**	**616,741**
Comprehensive Income:					
2006 Net Income	-	-	67,447	-	67,447
Minimum Pension Liability Adjustment (net of $8,915 income taxes)	-	-	-	13,597	13,597
Unrealized Loss on Cash Flow Hedges (net of $4,897 income taxes)	-	-	-	(7,469)	(7,469)
Reclassification of Unrealized Gains and Losses on Cash Flow Hedges to Net Income (net of $77 income taxes)	-	-	-	(117)	(117)
Total Comprehensive Income					73,458
Adjustment to Initially Recognize the Funded Status of Employee Benefit Plans (net of $9,698 income taxes)	-	-	-	(14,792)	(14,792)
Dividends Declared	-	-	(29,499)	-	(29,499)
Shares Issued under Stock Compensation Plans	11	-	-	-	-
Shares Issued for Stock Options	305	4,859	-	-	4,859
Tax Benefit Realized from Stock Options Exercised	-	1,501	-	-	1,501
Other	-	1,881	-	-	1,881
Balances at December 31, 2006	**35,190**	**$ 697,426**	**$ (27,913)**	**$ (15,364)**	**$ 654,149**

* UniSource Energy has 75 million authorized shares of Common Stock

We describe limitations on our ability to pay dividends in Note 10.

See Notes to Consolidated Financial Statements.

TUCSON ELECTRIC POWER COMPANY
CONSOLIDATED STATEMENTS OF INCOME

	Years Ended December 31,		
	2006	**2005**	**2004**
	- Thousands of Dollars -		
Operating Revenues			
Electric Retail Sales	**$ 774,470**	$ 746,876	$ 719,341
Electric Wholesale Sales	**187,750**	178,428	159,918
Other Revenues	**35,502**	12,166	10,039
Total Operating Revenues	**997,722**	937,470	889,298
Operating Expenses			
Fuel	**257,515**	226,278	212,514
Purchased Power	**108,818**	132,883	72,558
Other Operations and Maintenance	**198,573**	168,056	190,347
Depreciation and Amortization	**112,346**	114,704	117,109
Amortization of Transition Recovery Asset	**65,985**	56,418	50,153
Taxes Other Than Income Taxes	**38,834**	39,790	39,933
Total Operating Expenses	**782,071**	738,129	682,614
Operating Income	**215,651**	199,341	206,684
Other Income (Deductions)			
Interest Income	**16,429**	18,884	20,021
Interest Income - Note Receivable from UniSource Energy	**-**	1,684	9,329
Other Income	**7,147**	4,182	6,520
Other Expense	**(3,029)**	(1,685)	(4,600)
Total Other Income (Deductions)	**20,547**	23,065	31,270
Interest Expense			
Long-Term Debt	**51,422**	56,243	69,904
Interest on Capital Leases	**72,556**	79,064	85,869
Loss on Extinguishment of Debt	**685**	5,261	1,990
Other Interest Expense	**6,436**	2,597	1,263
Interest Capitalized	**(4,124)**	(3,559)	(2,014)
Total Interest Expense	**126,975**	139,606	157,012
Income Before Income Taxes and Cumulative Effect of Accounting Change	**109,223**	82,800	80,942
Income Tax Expense	**42,478**	33,907	34,815
Income Before Cumulative Effect of Accounting Change	**66,745**	48,893	46,127
Cumulative Effect of Accounting Change - Net of Tax	**-**	(626)	-
Net Income	**$ 66,745**	$ 48,267	$ 46,127

See Notes to Consolidated Financial Statements.

TUCSON ELECTRIC POWER COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2006	**2005**	**2004**
	- Thousands of Dollars -		
Cash Flows from Operating Activities			
Cash Receipts from Electric Retail Sales	**$ 840,601**	$ 815,624	$ 780,335
Cash Receipts from Electric Wholesale Sales	**254,322**	227,031	204,643
Interest Received	**18,808**	21,073	21,928
Interest Received from UniSource Energy	**-**	11,013	-
Income Tax Refunds Received	**-**	713	3,712
Deposit-Second Mortgage Indenture	**-**	-	17,040
Sale of Excess Emission Allowances	**7,254**	15,354	2,760
Other Cash Receipts	**23,238**	3,696	8,319
Fuel Costs Paid	**(244,632)**	(223,672)	(208,549)
Purchased Power Costs Paid	**(182,626)**	(179,682)	(115,323)
Wages Paid, Net of Amounts Capitalized	**(77,627)**	(74,627)	(68,832)
Payment of Other Operations and Maintenance Costs	**(121,744)**	(111,112)	(99,382)
Capital Lease Interest Paid	**(63,615)**	(67,673)	(70,748)
Taxes Other Than Income Paid, Net of Amounts Capitalized	**(109,952)**	(105,741)	(102,648)
Interest Paid, Net of Amounts Capitalized	**(44,100)**	(56,341)	(65,504)
Income Taxes Paid	**(70,457)**	(28,900)	(21,402)
Other Cash Payments	**(2,242)**	(3,743)	(11,198)
Net Cash Flows - Operating Activities	**227,228**	243,013	275,151
Cash Flows from Investing Activities			
Capital Expenditures	**(156,180)**	(149,906)	(129,505)
Payments for Investments in Lease Debt and Equity	**(48,025)**	-	(4,499)
Proceeds from Investments in Lease Debt and Equity	**22,158**	13,646	11,590
Proceeds from Sale of Land	**1,026**	-	-
Other Proceeds from Investing Activities	**59**	7,355	1,652
Other Payments for Investing Activities	**(1,004)**	-	(5,000)
Net Cash Flows - Investing Activities	**(181,966)**	(128,905)	(125,762)
Cash Flows from Financing Activities			
Proceeds from Borrowings Under Revolving Credit Facility	**135,000**	40,000	20,000
Payments for Borrowings Under Revolving Credit Facility	**(105,000)**	(40,000)	(20,000)
Dividends Paid to UniSource Energy	**(62,000)**	(46,000)	(31,500)
Payments of Capital Lease Obligations	**(61,111)**	(52,826)	(49,431)
Equity Investment from UniSource Energy	**-**	110,000	-
Proceeds from Repayment of UniSource Energy Note	**-**	95,393	-
Repayments of Long-Term Debt	**-**	(281,766)	(28,725)
Payment of Debt Issue Costs	**(1,631)**	(5,235)	(8,890)
Other Proceeds from Financing Activities	**16,852**	8,297	18,419
Other Payments for Financing Activities	**(1,094)**	(1,745)	(1,317)
Net Cash Flows - Financing Activities	**(78,984)**	(173,882)	(101,444)
Net (Decrease) Increase in Cash and Cash Equivalents	**(33,722)**	(59,774)	47,945
Cash and Cash Equivalents, Beginning of Year	**53,433**	113,207	65,262
Cash and Cash Equivalents, End of Year	**$ 19,711**	$ 53,433	$ 113,207

See Note 17 for supplemental cash flow information.

See Notes to Consolidated Financial Statements.

TUCSON ELECTRIC POWER COMPANY
CONSOLIDATED BALANCE SHEETS

	December 31, 2006	December 31, 2005
ASSETS	- Thousands of Dollars -	
Utility Plant		
Plant in Service	$ 3,035,494	$ 2,861,511
Utility Plant under Capital Leases	701,631	723,195
Construction Work in Progress	92,125	132,427
Total Utility Plant	3,829,250	3,717,133
Less Accumulated Depreciation and Amortization	(1,446,229)	(1,378,362)
Less Accumulated Amortization of Capital Lease Assets	(495,634)	(472,149)
Total Utility Plant - Net	1,887,387	1,866,622
Investments and Other Property		
Investments in Lease Debt and Equity	181,222	156,301
Other	30,161	27,013
Total Investments and Other Property	211,383	183,314
Current Assets		
Cash and Cash Equivalents	19,711	53,433
Trade Accounts Receivable	97,512	78,487
Unbilled Accounts Receivable	35,115	29,658
Allowance for Doubtful Accounts	(16,303)	(14,528)
Intercompany Accounts Receivable	16,329	5,807
Materials and Fuel Inventory	63,629	57,815
Current Regulatory Assets	9,549	9,663
Deferred Income Taxes - Current	57,151	51,859
Interest Receivable - Current	7,782	9,747
Trading Assets	15,447	12,338
Other	8,833	10,240
Total Current Assets	314,755	304,519
Regulatory and Other Assets		
Transition Recovery Asset	101,626	167,611
Income Taxes Recoverable Through Future Revenues	34,749	39,936
Other Regulatory Assets	51,594	20,634
Other Assets	21,569	34,583
Total Regulatory and Other Assets	209,538	262,764
Total Assets	$ 2,623,063	$ 2,617,219

See Notes to Consolidated Financial Statements.

(Consolidated Balance Sheets Continued)

TUCSON ELECTRIC POWER COMPANY
CONSOLIDATED BALANCE SHEETS

	December 31, 2006	2005
CAPITALIZATION AND OTHER LIABILITIES	- Thousands of Dollars -	
Capitalization		
Common Stock Equity	**$ 554,714**	$ 558,646
Capital Lease Obligations	**588,424**	665,299
Long-Term Debt	**821,170**	821,170
Total Capitalization	**1,964,308**	2,045,115
Current Liabilities		
Current Obligations under Capital Leases	**58,999**	48,718
Borrowing Under Revolving Credit Facility	**30,000**	-
Accounts Payable	**69,019**	62,974
Intercompany Accounts Payable	**10,743**	9,362
Income Taxes Payable	**8,409**	17,111
Interest Accrued	**45,613**	50,230
Taxes Accrued	**27,227**	27,260
Accrued Employee Expenses	**21,102**	17,080
Trading Liabilities	**11,163**	2,923
Other	**14,278**	10,688
Total Current Liabilities	**296,553**	246,346
Deferred Credits and Other Liabilities		
Deferred Income Taxes - Noncurrent	**155,253**	161,070
Regulatory Liability - Net Cost of Removal for Interim Retirements	**79,876**	74,825
Other	**127,073**	89,863
Total Deferred Credits and Other Liabilities	**362,202**	325,758
Commitments and Contingencies (Note 6)		
Total Capitalization and Other Liabilities	**$ 2,623,063**	$ 2,617,219

See Notes to Consolidated Financial Statements.

(Consolidated Balance Sheets Concluded)

TUCSON ELECTRIC POWER COMPANY
CONSOLIDATED STATEMENTS OF CAPITALIZATION

			December 31, 2006	December 31, 2005
COMMON STOCK EQUITY			- Thousands of Dollars -	
Common Stock--No Par Value			**$ 795,971**	$ 795,971
	2006	**2005**		
Shares Authorized	**75,000,000**	75,000,000		
Shares Outstanding	**32,139,434**	32,139,555		
Capital Stock Expense			**(6,357)**	(6,357)
Accumulated Deficit			**(219,640)**	(224,385)
Accumulated Other Comprehensive Loss			**(15,260)**	(6,583)
Total Common Stock Equity			**554,714**	558,646
PREFERRED STOCK				
No Par Value, 1,000,000 Shares Authorized, None Outstanding			**-**	-
CAPITAL LEASE OBLIGATIONS				
Springerville Unit 1			**381,446**	431,493
Springerville Coal Handling Facilities			**112,177**	122,353
Springerville Common Facilities			**106,837**	106,136
Sundt Unit 4			**46,140**	53,924
Other Leases			**823**	111
Total Capital Lease Obligations			**647,423**	714,017
Less Current Maturities			**(58,999)**	(48,718)
Total Long-Term Capital Lease Obligations			**588,424**	665,299
LONG-TERM DEBT				
Issue	**Maturity**	**Interest Rate**		
Variable Rate IDBs	2011	Variable*	**328,600**	328,600
Collateral Trust Bonds	2008	7.50%	**138,300**	138,300
Unsecured IDBs	2020 - 2033	5.85% to 7.13%	**354,270**	354,270
Total Stated Principal Amount			**821,170**	821,170
Less Current Maturities			**-**	-
Total Long-Term Debt			**821,170**	821,170
Total Capitalization			**$ 1,964,308**	$ 2,045,115

* TEP's Variable Rate industrial development bonds (IDBs) are backed by letters of credit (LOCs) issued pursuant to TEP's Credit Agreement which expires in August 2011. Although the Variable Rate IDBs mature between 2018 and 2022, the above maturity reflects a redemption or repurchase of such bonds in 2011 as though the LOCs terminate without replacement upon expiration of the TEP Credit Agreement. Weighted average interest rates on this variable rate tax-exempt debt ranged from 2.95% to 3.96% during 2006 and 1.52% to 3.55% during 2005, and the average interest rate on such debt was 3.47% in 2006 and 2.48% in 2005.

See Notes to Consolidated Financial Statements.

TUCSON ELECTRIC POWER COMPANY
CONSOLIDATED STATEMENT OF CHANGES IN STOCKHOLDER'S EQUITY AND COMPREHENSIVE INCOME

	Common Stock	Capital Stock Expense	Accumulated Deficit	Accumulated Other Comprehensive Loss	Total Stockholder's Equity
			- Thousands of Dollars -		
Balances at December 31, 2003	**$ 655,534**	**$ (6,357)**	**$ (241,279)**	**$ (1,844)**	**$ 406,054**
Comprehensive Income:					
2004 Net Income	-	-	46,127	-	46,127
Minimum Pension Liability Adjustment (net of $1,430 income taxes)	-	-	-	(10,460)	(10,460)
Unrealized Gain on Cash Flow Hedges (net of $960 income taxes)	-	-	-	1,465	1,465
Reclassification of Unrealized Gains and Losses on Cash Flow Hedges to Net Income (net of $68 income taxes)	-	-	-	104	104
Total Comprehensive Income					37,236
Dividends Paid	-	-	(31,500)	-	(31,500)
Capital Contribution from UniSource Energy	2,720	-	-	-	2,720
Balances at December 31, 2004	**658,254**	**(6,357)**	**(226,652)**	**(10,735)**	**414,510**
Comprehensive Income:					
2005 Net Income	-	-	48,267	-	48,267
Minimum Pension Liability Adjustment (net of $1,378 income taxes)	-	-	-	(2,101)	(2,101)
Unrealized Gain on Cash Flow Hedges (net of $6,503 income taxes)	-	-	-	9,918	9,918
Reclassification of Unrealized Gains and Losses on Cash Flow Hedges to Net Income (net of $2,403 income taxes)	-	-	-	(3,665)	(3,665)
Total Comprehensive Income					52,419
Dividends Paid	-	-	(46,000)	-	(46,000)
Capital Contribution from UniSource Energy	25,261	-	-	-	25,261
Capital Contribution from UniSource Energy	112,456	-	-	-	112,456
Balances at December 31, 2005	**795,971**	**(6,357)**	**(224,385)**	**(6,583)**	**558,646**
Comprehensive Income:					
2006 Net Income	-	-	66,745	-	66,745
Minimum Pension Liability Adjustment (net of $8,915 income taxes)	-	-	-	13,597	13,597
Unrealized Loss on Cash Flow Hedges (net of $4,897 income taxes)	-	-	-	(7,469)	(7,469)
Reclassification of Unrealized Gains and Losses on Cash Flow Hedges to Net Income (net of $77 income taxes)	-	-	-	(117)	(117)
Total Comprehensive Income					72,756
Adjustment to Initially Recognize the Funded Status of Employee Benefit Plans (net of $9,630 income taxes)	-	-	-	(14,688)	(14,688)
Dividends Paid	-	-	(62,000)	-	(62,000)
Balances at December 31, 2006	**$ 795,971**	**$ (6,357)**	**$ (219,640)**	**$ (15,260)**	**$ 554,714**

We describe limitations on TEP's ability to pay dividends in Note 10.

See Notes to Consolidated Financial Statements.

NOTE 1. NATURE OF OPERATIONS AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

NATURE OF OPERATIONS

UniSource Energy Corporation (UniSource Energy) is a holding company that has no significant operations of its own. Operations are conducted by UniSource Energy's subsidiaries, each of which is a separate legal entity with its own assets and liabilities. UniSource Energy owns the common stock of Tucson Electric Power Company (TEP), UniSource Energy Services, Inc. (UES), Millennium Energy Holdings, Inc. (Millennium) and UniSource Energy Development Company (UED).

TEP, a regulated public utility, is UniSource Energy's largest operating subsidiary and represented approximately 82% of UniSource Energy's assets as of December 31, 2006. TEP generates, transmits and distributes electricity to approximately 392,000 retail electric customers in a 1,155 square mile area in Southern Arizona. TEP also sells electricity to other utilities and power marketing entities primarily located in the Western U.S. In addition, TEP operates Springerville Unit 3 on behalf of Tri-State Generation and Transmission Association, Inc. (Tri-State).

UES holds the common stock of UNS Gas, Inc. (UNS Gas) and UNS Electric, Inc. (UNS Electric). UNS Gas is a gas distribution company with 145,000 retail customers in Mohave, Yavapai, Coconino, and Navajo counties in Northern Arizona, as well as Santa Cruz County in Southeast Arizona. UNS Electric is an electric transmission and distribution company with approximately 93,000 retail customers in Mohave and Santa Cruz counties.

Millennium invests in unregulated energy related businesses. On March 31, 2006, UniSource Energy completed the sale of all of the capital stock of Global Solar, Inc. (Global Solar), Millennium's largest subsidiary, to a third party. We present Global Solar's assets, liabilities and related operations throughout this report as a discontinued operation. See Note 16.

UED is facilitating the expansion of the Springerville Generating Station and other generation resources.

We conduct our business in three primary business segments – TEP, UNS Gas and UNS Electric.

References to "we" and "our" are to UniSource Energy and its subsidiaries, collectively.

BASIS OF PRESENTATION

We account for our investments in subsidiaries using the consolidation method when we hold a majority of a subsidiary's voting stock and we can exercise control over the subsidiary. The accounts of the subsidiary and parent are combined, and intercompany balances and transactions are eliminated.

We use the equity method to report corporate joint ventures, partnerships, and affiliated company investments when we can demonstrate the ability to exercise significant influence over the operating and financial policies of an investee company. Equity method investments appear on a single line item on the balance sheet and net income (loss) from the entity is reflected in Other Income on the income statements.

UniSource Energy held the following equity investments at December 31, 2006:

Investee	% Owned
UniSource Energy	
Carboelectrica Sabinas, S. de R.L. de C.V.	50.0%
Haddington Energy Partners II, LP	31.6%
Valley Ventures III, LP	15.0%
Infinite Power Solutions, Inc.	8.9%
TEP	
Inncom International, Inc.	16.7%
Springerville Unit 1 Lease	14.0%

USE OF ACCOUNTING ESTIMATES

We make estimates and assumptions to prepare financial statements under accounting principles generally accepted in the U.S. (GAAP). These estimates and assumptions affect:

- A portion of the reported amounts of assets and liabilities at the dates of the financial statements;
- Our disclosures about contingent assets and liabilities at the dates of the financial statements; and
- A portion of revenues and expenses reported during the periods.

Because these estimates involve judgments, the actual amounts may differ from the estimates.

ACCOUNTING FOR RATE REGULATION

The Arizona Corporation Commission (ACC) and the Federal Energy Regulatory Commission (FERC) regulate portions of TEP's, UNS Gas' and UNS Electric's utility accounting practices and rates. The ACC authorizes certain rates charged to retail customers, the issuance of securities, and transactions with affiliated parties. The FERC regulates TEP's and UNS Electric's rates for wholesale power sales and transmission services.

TEP, UNS Gas and UNS Electric generally use the same accounting policies and practices used by unregulated companies. Sometimes these principles, such as Financial Accounting Standards Board's (FASB) Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation* (FAS 71), require special accounting treatment for regulated companies to show the effect of regulation. For example, the ACC may not allow TEP, UNS Gas or UNS Electric to currently charge their customers to recover certain expenses, but instead may require that they charge these expenses to customers in the future. In this situation, FAS 71 requires that TEP, UNS Gas and UNS Electric defer these items and show them as regulatory assets on the balance sheet until they are allowed to charge their customers. TEP, UNS Gas and UNS Electric then amortize these items as expense as they recover these charges from customers. Similarly, certain revenue items may be deferred as regulatory liabilities, which are also eventually amortized to the income statement as rates to customers are reduced.

The conditions a regulated company must satisfy to apply the accounting policies and practices of FAS 71 include:

- an independent regulator sets rates;
- the regulator sets the rates to recover specific costs of providing service; and
- the service territory lacks competitive pressures to reduce rates below the rates set by the regulator.

CASH AND CASH EQUIVALENTS

We define Cash and Cash Equivalents as cash (unrestricted demand deposits) and all highly liquid investments purchased with an original maturity of three months or less.

RESTRICTED CASH

Restricted cash represents cash deposits that have withdrawal restrictions, or are set aside for a specific use and not available for general current operations. Cash deposits that are restricted for a period of less than one year, or that are restricted as to use but are available to meet specific current operational requirements, are classified on the balance sheet as Other Current Assets. Balances that are restricted as to withdrawal for more than one year or are designated for a purpose other than current operations are classified on the balance sheet as Investments and Other Property, Other. At December 31, 2006, restricted cash includes cash on deposit in support of our self-insured medical and workman's compensation plans, amounts on deposit for credit enhancement with counterparties and deposits to meet contractual and regulatory requirements.

UTILITY PLANT

TEP, UNS Gas and UNS Electric report utility plant at cost. Costs included in Utility Plant are:

- Material and labor,

- Contractor services,
- Construction overhead (where applicable), and
- An Allowance for Funds Used During Construction (AFUDC) or capitalized interest during construction.

AFUDC reflects the cost of financing construction for transmission and distribution projects with borrowed and equity funds.

The component of AFUDC attributable to borrowed funds is included as a reduction of Other Interest Expense on the income statement. The equity component is included in Other Income. The interest capitalized during construction of TEP's generation-related construction projects is included as a reduction of Other Interest Expense.

The table below summarizes TEP's cost of capital, average capitalized interest rates, AFUDC and capitalized interest for the last three years. The imputed cost of capital on transmission and distribution construction expenditures reflects the cost of using borrowed and equity funds to finance construction, and the average capitalized interest rate applies to generation-related construction expenditures. AFUDC and capitalized interest are presented in millions of dollars.

	TEP		
	2006	2005	2004
Cost of capital on transmission and distribution construction expenditures	8.59%	8.20%	8.67%
AFUDC - Debt (in Millions)	$ 1	$ 1	$ 1
AFUDC - Equity (in Millions)	$ 1	$ 1	$ 1
Average capitalized interest rate during generation-related construction	5.72%	4.78%	4.38%
Capitalized interest (in Millions)	$ 3	$ 3	$ 1

The tables below summarize UNS Gas and UNS Electric's cost of capital and AFUDC for the last three years. The imputed cost of capital reflects the cost of using borrowed and equity funds to finance construction.

	UNS Gas		
	2006	2005	2004
Cost of capital on construction expenditures	8.29%	7.83%	7.85%
AFUDC - Debt (in Millions)	$ 0.1	$ 0.2	$ 0.3
AFUDC - Equity (in Millions)	$ 0.1	$ 0.2	$ 0.3

	UNS Electric		
	2006	2005	2004
Cost of capital on construction expenditures	10.93%	9.03%	8.73%
AFUDC - Debt (in Millions)	$ 0.6	$ 0.2	$ 0.2
AFUDC - Equity (in Millions)	$ 0.5	$ 0.2	$ 0.2

Depreciation

TEP, UNS Gas and UNS Electric compute depreciation for owned utility plant on a straight-line basis at rates based on the economic lives of the assets. See Note 7. The ACC approves depreciation rates for all plant except TEP's deregulated generation assets. The depreciable lives for TEP's generation plant are based on remaining useful lives. Note 7 discusses changes made to the depreciable lives of TEP's generation plant. The depreciation rates for generation plant reflect interim retirements. Interim retirements of generation plant, together with removal costs less salvage, are charged to accumulated depreciation. The costs of planned major maintenance activities are recorded as the costs are actually incurred. Planned major maintenance activities include the scheduled overhauls at TEP's generation plants. We expense minor replacements and repairs as incurred.

The depreciable lives for transmission, distribution, general and intangible plant are based on average lives. The rates reflect estimated removal costs, net of estimated salvage value for interim retirements. Retirements of transmission plant, distribution plant, general plant and intangible plant, together with the cost of removal less salvage, are charged to accumulated depreciation. Amounts collected through revenues for the net cost of removal of interim retirements for transmission, distribution, general and intangible plant which are not yet expended, are reflected as a regulatory liability.

We have summarized the average annual depreciation rates for all utility plants below.

Year	TEP	UNS Gas	UNS Electric
2006	3.11%	2.91%	4.17%
2005	3.40%	3.15%	4.68%
2004	3.80%	2.81%	4.38%

Computer Software Costs

TEP, UNS Gas and UNS Electric capitalize all costs incurred to purchase computer software and amortize those costs over the estimated economic life of the product. If the software is no longer useful, we immediately charge capitalized computer software costs to expense. TEP amortized capitalized computer software costs of $7 million in 2006 and $8 million in both 2005 and 2004.

TEP Utility Plant under Capital Leases

TEP financed the following generation assets with capital leases:

- Springerville Common Facilities,
- Springerville Unit 1,
- Springerville Coal Handling Facilities, and
- Sundt Unit 4.

The following table shows the amount of lease expense incurred for TEP's generation-related capital leases. We describe the lease terms in *TEP Capital Lease Obligations* in Note 8.

	Years Ended December 31,		
	2006	**2005**	**2004**
	-Millions of Dollars-		
Lease Expense:			
Interest Expense on Capital Leases	**$ 72**	$ 79	$ 86
Amortization of Capital Lease Assets – Included in:			
Operating Expenses – Fuel	**4**	5	4
Operating Expenses – Depreciation and Amortization	**22**	23	18
Total Lease Expense	**$ 98**	$107	$108

ASSET RETIREMENT OBLIGATIONS

FASB Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations* (FAS 143) requires entities to record the fair value of a liability for a legal obligation to retire an asset in the period in which the liability is incurred. FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations* (FIN 47), requires entities to record the fair value of a liability for a legal obligation to perform asset retirement activity in which the timing and (or) method of settlement depends on a future event that may or may not be within the control of the entity.

We record a liability for the fair value of a conditional asset retirement obligation as follows:

- when we are able to reasonably estimate the fair value of any future obligation to retire as a result of an existing or enacted law, statute, ordinance or contract; or

- if we can reasonably estimate the fair value.

When the liability is initially recorded, we capitalize the cost by increasing the carrying amount of the related long-lived asset. Over time, we adjust the liability to its present value by recognizing accretion expense as an operating expense in the income statement each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, we either settle the obligation for its recorded amount or incur a gain or loss if the actual costs differ from the recorded amount.

EVALUATION OF ASSETS FOR IMPAIRMENT

TEP, UNS Gas and
UNS Electric evaluate their Utility Plant and other long-lived assets for impairment whenever events or circumstances indicate that the value of the assets may be impaired. If the fair value of the asset determined based on the undiscounted expected future cash flows is less than the carrying value of the asset, an impairment charge would be recorded.

Millennium evaluates its investments for impairment at the end of each quarter. Investments are considered to be impaired when a decline in fair value is judged to be other-than-temporary. If the fair value is determined to be other-than-temporary, an impairment loss would be recorded.

INVESTMENTS IN LEASE DEBT

TEP's investments in lease debt are considered to be held-to-maturity investments because TEP has the ability and intent to hold until maturity. TEP records these investments at amortized costs and recognizes interest income. TEP presents these investments in Investments in Lease Debt on the balance sheet and classifies them as investing activities on its cash flow statements.

DEBT

We defer costs related to the issuance of debt. These costs include underwriters' commissions, discounts or premiums, and other costs such as legal, accounting and regulatory fees and printing costs. We amortize these costs over the life of the debt using the straight-line method, which approximates the effective interest method.

TEP recognizes gains and losses on reacquired debt associated with the generation portion of its operations as incurred. TEP defers and amortizes the gains and losses on reacquired debt associated with its regulated operations to interest expense over the remaining life of the original debt.

UTILITY OPERATING REVENUES

TEP and UES record utility operating revenues when services are provided or commodities are delivered to customers. Operating revenues include unbilled revenues which are earned (service has been provided) but not billed by the end of an accounting period.

We estimate unbilled sales for the month by estimating the number of billed and unbilled kWhs or therms, as applicable, for each billing cycle. We then allocate current month estimated unbilled kWhs or therms by customer class. Finally, we record new unbilled revenue estimates and reverse unbilled revenue estimates from the prior month.

We record an Allowance for Doubtful Accounts to reduce accounts receivable for revenue amounts that are estimated to become uncollectible. TEP, UNS Gas and UNS Electric establish an allowance for doubtful accounts receivable based on historical experience and any specific customer collection issues identified. TEP's Allowance for Doubtful Accounts was $16 million at December 31, 2006 and $15 million at December 31, 2005. UNS Gas and UNS Electric's combined Allowance for Doubtful Accounts was less than $1 million at December 31, 2006 and 2005.

FUEL AND PURCHASED ENERGY COSTS

TEP

TEP records fuel inventory, primarily coal, at weighted average cost. TEP uses full absorption costing, under which, all handling and procurement costs are included in the cost of the inventory. Examples of these costs include direct material, direct labor, overhead costs and mine reclamation expenses. TEP has long-term contracts for the purchase and transportation of coal with various expiration dates from 2008 through 2020. If certain minimum quantities of coal are not purchased, the contracts require TEP to pay a take-or-pay fee. TEP expenses such fees as they are incurred. TEP recorded take-or-pay fees of less than $0.1 million in 2006, 2005 and 2004. See *Purchase and Transportation Commitments* in Note 6, below.

UNS Gas

UNS Gas defers differences between actual gas purchase costs and the revenues received to recover such costs under a Purchased Gas Adjustor (PGA) mechanism. The PGA mechanism addresses the volatility of natural gas prices and allows UNS Gas to recover its commodity costs through a price adjustor. We may change the PGA charge monthly based on an ACC approved mechanism that compares the twelve-month rolling average gas cost to the base cost of gas, subject to limitations on how much the price per therm may change in a twelve-month period. The difference between the actual cost of UNS Gas' gas supplies and transportation contracts and that currently allowed by the ACC is deferred and recovered or repaid through the PGA mechanism. When under or over recovery trigger points are met, UNS Gas may request a PGA surcharge or credit with the goal of collecting or returning the amount deferred from or to customers over a twelve-month period. UNS Gas had a liability for over recovered purchased gas costs of $11 million at December 31, 2006 which is included in Current Liabilities – Current Regulatory Liabilities on our consolidated balance sheet and an asset for under recovered purchased gas costs of $6 million at December 31, 2005 which is included in Regulatory and Other Assets – Other Regulatory Assets. See Note 2 Regulatory Matters.

UNS Electric

UNS Electric defers differences between purchased energy costs and the recovery of such costs in revenues. Future billings are adjusted for such deferrals through use of a Purchased Power and Fuel Adjustment Clause (PPFAC) approved by the ACC. The PPFAC allows for a revenue surcharge or credit (that adjusts the customer's base rate for delivered purchased power) to collect or return under or over recovery of costs. UNS Electric had a liability for over recovered purchased power costs of $6 million at December 31, 2006 and $4 million at December 31, 2005 that is included in Deferred Credits and Other Liabilities – Regulatory Liabilities on our consolidated balance sheet. See Note 2 Regulatory Matters.

INCOME TAXES

GAAP requires us to report some of our assets and liabilities differently for our financial statements than we do for income tax purposes. We report the tax effects of differences in these items as deferred income tax assets or liabilities in our balance sheets. We measure these tax assets and liabilities using current income tax rates. Federal Investment Tax Credits (ITC) as well as applicable state income tax credits are accounted for as a reduction of income tax expense in the year in which the credit arises.

We allocate income taxes to the subsidiaries based on their taxable income and deductions as reported in the consolidated tax return filings.

EMISSIONS ALLOWANCES

The Environmental Protection Agency (EPA) issues emissions allowances to qualifying utilities based on past operational history. Each allowance permits emission of one ton of sulfur dioxide (SO_2) in its vintage year or a subsequent year. TEP receives an allotment of these allowances annually, but UNS Electric does not receive any since it has no coal-fired generation. When issued from the EPA, these allowances have no book value for accounting purposes but may be sold if TEP does not need them for operations. TEP also may purchase additional allowances if needed. The gains from sales of excess allowances are reflected as a reduction of Other Operations and Maintenance expense on TEP's income statement and are recognized when title passes.

DERIVATIVE FINANCIAL INSTRUMENTS

TEP uses derivative financial instruments including forward power sales and purchases and gas swaps to manage exposure to energy price risk. TEP entered into an interest rate swap to reduce the risk associated with unfavorable changes in the variable interest rate on the Springerville Common Lease. UNS Electric enters into forward power purchase agreements that meet the definition of derivatives. MEG enters into swap agreements, options and forward contracts relating to Emission Allowances. TEP, UNS Electric and MEG record derivative instruments at fair value. To reflect the market prices at the end of the month, TEP, UNS Electric and MEG record unrealized gains and losses and adjust the related assets and liabilities on a monthly basis. In December 2006, the ACC granted UNS Electric an accounting order to record the unrealized gains and losses as a regulatory asset or a regulatory liability. As these contracts settle, the actual costs of the power purchased are charged to the PPFAC. Certain of TEP's derivatives meet the criteria for cash flow hedge accounting. See Note 5, Accounting for Derivative Instruments, Trading Activities and Hedging Activities.

We report TEP, UNS Electric and MEG's derivative activities as follows:

	Financial Statement Line	
	Net Unrealized Gains and Losses	**Net Realized Gains and Losses**
TEP Forward Power Sales – Cash Flow Hedges	Other Comprehensive Income	Electric Wholesale Sales
TEP Forward Power Purchases – Cash Flow Hedges	Other Comprehensive Income	Purchased Power
TEP Forward Power Sales	Electric Wholesale Sales	Electric Wholesale Sales
TEP Forward Power Purchases	Purchased Power	Purchased Power
TEP Gas Price Swaps – Cash Flow Hedges	Other Comprehensive Income	Fuel Expense
TEP Interest Rate Swap	Other Comprehensive Income	Interest on Capital Leases
UNS Electric Forward Power Purchases	Deferred Credits and Other Liabilities - Other Regulatory Liabilities	Purchased Energy
MEG Trading Activities	Other Operating Revenues	Other Operating Revenues

Although we report MEG's realized gains and losses on trading activities on a net basis in our income statement, we report the related cash receipts and cash payments separately in our statement of cash flows.

We report TEP, UNS Electric and MEG's derivative assets and liabilities as follows:

	Balance Sheet Line	
	Assets	**Liabilities**
TEP – Current	Trading Assets	Trading Liabilities
TEP – Noncurrent	Other Assets	Other Liabilities
UNS Electric – Noncurrent	Other Assets	Other Liabilities
MEG – Current	Trading Assets	Trading Liabilities

SHARE-BASED COMPENSATION

Effective January 1, 2005, we prospectively adopted Statement of Financial Accounting Standards No. 123(R), *Share Based Payment* (FAS 123(R)). Before January 1, 2005, we accounted for our share-based compensation under the principles of APB Opinion No. 25, *Accounting for Stock Issued to Employees* (APB 25), and related interpretations and applied the disclosure only guidance in Financial Accounting Standards No. 123, *Accounting for Stock-Based Compensation.* Our share-based compensation plans are described more fully in Note 13.
All our stock options were granted with an exercise price equal to the market value of the stock at the date of the grant. Accordingly, before January 1, 2005, under the provisions of APB 25, no compensation expense was recorded for these awards. However, compensation expense was recognized for restricted stock, stock unit and performance share awards over the performance/vesting period. Beginning January 1, 2005, under the provisions

of FAS 123(R), we began recognizing compensation expense over the vesting period for the fair value of new stock options granted.

The following table illustrates the effect on UniSource Energy's Net Income and earnings per share and TEP's Net Income as if we had applied the fair value recognition provisions of FAS 123 to all share-based employee compensation awards that vested during the year ended December 31, 2004:

	UniSource Energy	TEP
	-Thousand of Dollars- (except per share amounts)	
Net Income – As Reported	$ 45,919	$ 46,127
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects	1,535	1,355
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(2,314)	(2,116)
Pro Forma Net Income	$ 45,140	$ 45,366
Earnings per Share:		
Basic – As Reported	$ 1.34	
Basic – Pro Forma	$ 1.31	
Diluted – As Reported	$ 1.31	
Diluted – Pro Forma	$ 1.29	

NEW ACCOUNTING STANDARDS

The FASB recently issued the following Statements of Financial Accounting Standards (FAS), FASB Interpretations (FIN), FASB Staff Positions (FSP), and Emerging Issues Task Force Issues (EITF):

- EITF 06-3, *How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (that is, Gross versus Net Presentation)*, approved June 2006, requires that we disclose our accounting policy regarding presentation of taxes on either a gross (included in revenues and costs) or a net (excluded from revenues) basis. Additionally, we must disclose the amounts of any taxes reported on a gross basis in interim and annual financial statements. EITF 06-3 is effective for interim and annual reporting periods beginning after December 15, 2006. See Note 11 for our disclosures.

- FIN 48, *Accounting for Uncertainty in Income Taxes – an interpretation of FAS 109*, issued July 2006, requires us to determine whether it is "more-likely-than-not" that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. Once it is determined that a tax position meets the more-likely-than-not recognition threshold, the position is measured to determine the amount of benefit to recognize in the financial statements. Additionally, FIN 48 requires disclosure of a rollforward of total unrecognized tax benefits. FIN 48 is effective for fiscal years beginning after December 15, 2006. TEP recognized between $1 million and $2 million of income as an increase to Common Stock Equity on January 1, 2007 on the adoption of FIN 48.

- FAS 157, *Fair Value Measurement*, issued September 2006, defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. FAS 157 clarifies that the exchange price is the price in the principal market in which the reporting entity would transact for the asset or liability. We are required to disclose inputs used to develop fair value measurements and the effect of any of our assumptions on earnings or changes in net assets for the period. FAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. We are evaluating the impact of FAS 157 on our financial statements, and will incorporate these additional disclosure requirements in our financial statements for the quarter ended March 31, 2008.

- FSP AUG-AIR-1, *Accounting for Planned Major Maintenance Activities*, issued September 2006, prohibits the use of the accrue-in-advance method of accounting for planned major maintenance activities effective in fiscal years beginning after December 15, 2006. As we do not accrue planned major maintenance activities in advance, we anticipate no impact on our financial statements from the adoption of this FSP.

- FAS 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*, issued September 2006, requires recognition of the overfunded or underfunded status of a defined benefit postretirement plan measured as the difference between the fair value of the plans assets and benefit obligation. FAS 158 is effective for fiscal years ending after December 15, 2006. See Note 12 for the incremental effect of adopting FAS 158.

- In the third quarter of 2006, the Pension Protection Act of 2006 was signed into law, which will be effective January 1, 2008. The new law will affect the manner in which many companies, including UniSource Energy and TEP, administer their pension plans. The legislation will require companies to increase the amount by which they fund their pension plans, increase premiums to the Pension Benefit Guaranty Corporation for defined benefit plans, amend plan documents and provide additional disclosures in regulatory filings and to plan participants. We are currently assessing the impact it may have on our financial statements.

RECLASSIFICATIONS

We reclassified prior year financial statements and footnotes for comparative purposes. These reclassifications had no effect on Net Income.

NOTE 2. REGULATORY MATTERS

TEP RATES AND REGULATION

Upon approval of the TEP Settlement Agreement in 1999, TEP discontinued regulatory accounting under FAS 71 for its generation operations. TEP continues to report its transmission and distribution operations under FAS 71.

TEP Settlement Agreement

In 1999, the ACC approved the Rules for the introduction of retail electric competition in Arizona, as well as the Settlement Agreement between TEP and certain customer groups related to the implementation of retail electric competition in Arizona.

The Rules and the Settlement Agreement established:

- a period from November 1999 through 2008 for TEP to transition its generation assets from a cost of service based rate structure to a market, or competitive, rate structure;
- the recovery through rates during the transition period of $450 million of stranded generation costs through a fixed competitive transition charge (Fixed CTC);
- capped rates for TEP retail customers through 2008;
- an ACC interim review of TEP retail rates in 2004;
- unbundling of electric services with separate rates or prices for generation, transmission, distribution, metering, meter reading, billing and collection, and ancillary services;
- a process for ESPs to become licensed by the ACC to sell generation services at market prices to TEP retail customers;
- access for TEP retail customers to buy market priced generation services from ESPs beginning in 2000 (currently, no TEP customers are purchasing generation services from ESPs);
- transmission and distribution services would remain subject to regulation on a cost of service basis; and

- beginning in 2009, TEP's generation would be market-based and its retail customers would pay the market rate for generation services.

2004 General Rate Case Information

In June 2004, as required by the Settlement Agreement, TEP filed general rate case information with the ACC. While TEP's filing did not propose any change in retail rates, the filing, with a test year ended December 31, 2003, showed that TEP was experiencing a revenue deficiency of $111 million, reflecting the need for an increase in retail rates of 16%.

Beginning in May 2005, TEP filed a series of pleadings with the ACC to resolve the uncertainty surrounding the methodology that will be applied to determine TEP's rates for generation service after 2008.

2006 Proceedings

In April 2006, the ACC ordered that a procedure be established to allow for a review of:

- the Settlement Agreement and its effect on how TEP's rates for generation services will be determined after December 31, 2008;
- TEP's proposed amendments to the Settlement Agreement; and
- demand-side management (DSM), renewable energy standards (RES), and time of use tariffs (TOU).

In August 2006, TEP filed testimony in the ACC proceedings stating that TEP believes it is entitled to charge market-based generation service rates in 2009 and is in compliance with the Settlement Agreement. In addition, TEP offered a Market Phase-in proposal and a Cost-of-Service Proposal as alternatives to charging market-based generation service rates after December 31, 2008.

Transition Recovery Asset

TEP's Transition Recovery Asset consists of generation-related regulatory assets and a portion of TEP's generation plant asset costs. Transition costs being recovered through the Fixed CTC include: (1) the Transition Recovery Asset; (2) generation-related plant assets included in Plant in Service on the balance sheet; and (3) excess capacity deferrals related to operating and capital costs associated with Springerville Unit 2 which were amortized as an off-balance sheet regulatory asset through 2003. These transition costs were amortized as follows:

	Years Ended December 31,		
	2006	**2005**	**2004**
	-Millions of Dollars-		
Amortization of Transition Costs Being Recovered through the Fixed CTC:			
Transition Costs Being Recovered through the Fixed CTC, beginning of year	**$ 185**	$ 247	$ 302
Amortization of Transition Recovery Asset Recorded on the Income Statement	**(66)**	(56)	(50)
Amortization of Generation-Related Plant Assets	**(7)**	(6)	(5)
Transition Costs Being Recovered through the Fixed CTC, end of year	**$ 112**	$ 185	$ 247

We amortized the portion of the Transition Recovery Asset that is recorded on the balance sheet as follows:

	Years Ended December 31,		
	2006	**2005**	**2004**
	-Millions of Dollars-		
Amortization of Transition Recovery Asset Recorded on the Balance Sheet:			
Transition Recovery Asset, beginning of year	**$ 168**	$ 224	$ 274
Amortization of Transition Recovery Asset Recorded on the Income Statement	**(66)**	(56)	(50)
Transition Recovery Asset, end of year	**$ 102**	$ 168	$ 224

The remaining transition costs being recovered through the Fixed CTC differ from the Transition Recovery Asset recorded on the balance sheet as follows:

	December 31,	
	2006	**2005**
	-Millions of Dollars-	
Transition Costs Being Recovered through the Fixed CTC, end of year	**$ 112**	$ 185
Unamortized Generation-Related Plant Assets	**(10)**	(17)
Transition Recovery Asset, end of year	**$ 102**	$ 168

We will amortize the remaining Transition Recovery Asset balance as costs are recovered through rates until TEP has recovered $450 million of transition costs or until December 31, 2008, whichever occurs first.

Other Regulatory Assets and Liabilities

In addition to the Transition Recovery Asset related to TEP's generation assets, we recover the following regulatory assets and liabilities through TEP's transmission and distribution businesses:

	December 31,	
	2006	**2005**
	-Millions of Dollars-	
Current Regulatory Assets		
Property Tax Deferrals	**$ 9**	$ 9
Self-Insured Medical Deferrals	**1**	1
Total Current Regulatory Assets	**10**	10
Income Taxes Recoverable through Future Revenues	**35**	40
Other Regulatory Assets		
Pension Asset	**32**	-
Deregulation Costs	**13**	13
Unamortized Loss on Reacquired Debt	**7**	8
Total Other Regulatory Assets	**$ 52**	$ 21
Other Regulatory Liabilities		
Net Cost of Removal for Interim Retirements	**$ 80**	$ 75

Regulatory assets are either being collected in rates or are expected to be collected through rates in a future period, as described below:

- Property Tax, Self-Insured Medical Deferrals are recorded based on historical ratemaking treatment allowing TEP to recover property taxes and self-insured medical costs. While these assets do not earn a return, they are fully recovered in rates over an approximate one-year period.

- Income Taxes Recoverable Through Future Revenues are currently earning a return and are approved by the ACC.
- Pension Assets were recorded in 2006 as based on past regulatory actions, TEP expects to recover in rates the transmission and distribution portion of the underfunded Salaried and Union pension plans. TEP does not earn a return on these costs.
- Deregulation costs were incurred to comply with various ACC deregulation orders. TEP received ACC approval to defer these costs. The recovery period will be determined in TEP's next rate case. TEP does not earn a return on these costs.
- Unamortized Loss on Reacquired Debt Costs related to TEP's regulated business are, in accordance with FERC guidelines, amortized over the remaining life of the related debt instruments. While the asset is not included in rate base, the amortization is included in the ratemaking calculation of the cost of debt. TEP does not earn a return on these costs.

Regulatory liabilities represent items that we expect to pay to customers through billing reductions in future periods or use for the purpose for which they were collected from customers, as described below:

- Net cost of Removal for Interim Retirements represents an estimate of the cost of future asset retirement obligations.

Income Statement Impact of Applying FAS 71

The amortization of TEP's regulatory assets affected UniSource Energy's and TEP's income statements as follows:

	Years Ended December 31,		
	2006	**2005**	**2004**
	-Millions of Dollars-		
Operating Expenses			
Amortization of Transition Recovery Asset	**$ 66**	$ 56	$ 50
Depreciation related to Net Cost of Removal of Interim Retirements	**5**	7	7
Interest Expense			
Long-Term Debt	**1**	2	-
Income Taxes	**5**	5	5
Total	**$ 77**	$ 70	$ 62

If TEP had not applied FAS 71 in these years, the above amounts would have been reflected in the income statements in prior periods. The reclassification of TEP's generation-related regulatory assets to the Transition Recovery Asset shortened the amortization period for these assets to nine years.

Future Implications of Discontinuing Application of FAS 71

TEP continues to apply FAS 71 to its regulated operations, which include the transmission and distribution portions of its business. TEP regularly assesses whether it can continue to apply FAS 71 to these operations. If TEP stopped applying FAS 71 to its remaining regulated operations, it would write-off the related balances of its regulatory assets as an expense and its regulatory liabilities as income on its income statement. Based on the regulatory asset balances, net of regulatory liabilities, at December 31, 2006, if TEP had stopped applying FAS 71 to its remaining regulated operations, it would have recorded an extraordinary after-tax loss of approximately $71 million. While regulatory orders and market conditions may affect cash flows, TEP's cash flows would not be affected if we stopped applying FAS 71.

UNS GAS RATES AND REGULATION

Energy Cost Adjustment Mechanism

UNS Gas' retail rates include a PGA mechanism intended to address the volatility of natural gas prices and allow UNS Gas to recover its actual commodity costs, including transportation, through a price adjustor. The difference between UNS Gas' actual gas and transportation costs and the cost of gas and transportation recovered through base rates are deferred and recovered or repaid through the PGA mechanism.

The PGA mechanism has two components, the PGA factor and the PGA surcharge or credit. The PGA factor compares the twelve-month rolling weighted average gas cost to the base cost of gas, and automatically adjusts monthly, subject to limitations, on how much the price per therm may change in a twelve-month period. The actual gas and transportation costs that are either under- or over-collected through the base rate of $0.40 per therm or $4.00 per MMBtu and the PGA factor are charged or credited to a balancing account (PGA bank).

The current annual cap on the maximum increase in the PGA factor is $0.10 per therm in a twelve-month period. In January 2006, UNS Gas filed a request with the ACC to increase the cap to allow for more timely recovery of actual gas costs. In July 2006, UNS Gas requested this application be consolidated with its general rate case proceeding. See *General Rate Case Filing*, below.

When ACC-designated under- or over-recovery trigger points of $6.2 million and $4.5 million, respectively, are met, UNS Gas may request a PGA surcharge or credit with the goal of collecting or returning the amount deferred from or to customers over a period deemed appropriate by the ACC.

In 2005, the ACC approved the PGA surcharges from November 2005 to April 2007. In December 2006, the ACC approved a proposal by UNS Gas that lowered the PGA surcharge to $0.05 per therm in December 2006. The $0.05 per therm PGA surcharge will remain in effect through April 2007.

Surcharge Amount Per Therm	Period In Effect
$0.15	November 2005 – February 2006
$0.25	March 2006 – April 2006
$0.30	May 2006 – June 2006
$0.35	July 2006 – September 2006
$0.25	October 2006 – November 2006
$0.05	December 2006 – April 2007

Based on current projections of gas prices, UNS Gas believes that the lower surcharge amount will allow it to timely recover its gas costs and still provide rate relief to its customers. However, changes in the market price for gas, sales volumes and surcharge amount could significantly change the PGA bank balance in the future.

The following table shows the balance of purchased gas costs:

	December 31, 2006	December 31, 2005
	-Millions of Dollars-	
(Over)/Under Recovered Purchased Gas Costs – Regulatory Basis as Billed to Customers	**$ (2)**	$ 16
Estimated Purchased Gas Costs Recovered through Accrued Unbilled Revenues	**(9)**	(10)
(Over)/Under Recovered Purchased Gas Costs (PGA) Included on the Balance Sheet	**$ (11)**	$ 6

Other Regulatory Assets and Liabilities

In addition to the Under/(Over) Recovered Purchased Power Costs, UNS Gas has the following Regulatory Assets and Liabilities:

	December 31, 2006	December 31, 2005
Other Regulatory Assets		
Pension Assets	$ 1	$ -
Other Regulatory Assets	1	-
Total Other Regulatory Assets	2	-
Other Regulatory Liabilities		
Net Cost of Removal for Interim Retirements	$ 4	$ 3

Regulatory assets are either being collected in rates or are expected to be collected through rates in a future period, as described below:

- Pension Assets were recorded in 2006 as based on past regulatory actions, UNS Gas expects to recover in rates the UNS Gas portion of the underfunded pension plan for UNS Gas employees. UNS Gas does not earn a return on these costs.
- Other Regulatory assets relate primarily to UNS Gas' low income assistance program. These deferrals were authorized by the ACC and are included in rate base and consequently earn a return.

Regulatory liabilities represent items that we expect to pay to customers through billing reductions in future periods or use for the purpose for which they were collected from customers, as described below:

- Net cost of Removal for Interim Retirements represents an estimate of the cost of future asset retirement obligations.

General Rate Case Filing

In July 2006, UNS Gas filed a general rate with the ACC requesting a total rate increase of 7% to cover a revenue deficiency of $10 million. This increase is necessary because of the growth in UNS Gas' service territory and the related increase in capital expenditures and operating costs.

UNS Gas also requested modifications to its PGA mechanism to help address problems posed by volatile gas prices, inappropriate price signals to customers and the potential for over- or under-collections to result in the accumulation of large bank balances.

UNS Gas expects the ACC to rule on its rate case in the second half of 2007. Under the terms of the UES Settlement Agreement, new rates cannot go into effect before August 1, 2007.

Income Statement Impact of Applying FAS 71

If UNS Gas had not applied FAS 71, net income would have been $11 million higher in 2006 as UNS Gas would have been able to recognize over-recovered gas costs as a credit to the income statement rather than record a regulatory liability. In 2005, net income would have been $2 million lower had UNS Gas not been able to defer under-recovered gas costs as a regulatory asset.

Future Implications of Discontinuing Application of FAS 71

UNS Gas regulatory liabilities exceeded its regulatory assets by $13 million at December 31, 2006. Regulatory assets exceeded regulatory liabilities by $3 million at December 31, 2005. UNS Gas regularly assesses whether it can continue to apply FAS 71. If UNS Gas stopped applying FAS 71 to its regulated operations, UNS Gas would write-off the related balance of its regulatory assets as an expense and write-off its regulatory liabilities as income on its income statement. Based on the regulatory asset and liability balances, if UNS Gas had stopped applying FAS 71 to its regulated operations, UNS Gas would have recorded an extraordinary after-tax gain of $8 million at December 31, 2006. Discontinuing application of FAS 71 would not affect UNS Gas cash flows.

UNS ELECTRIC RATES AND REGULATION

Energy Cost Adjustment Mechanism

UNS Electric's retail rates include a PPFAC, which allows for a separate surcharge or surcredit to the base rate for delivered purchased power to collect or return under- or over-recovery of costs. The ACC approved a PPFAC surcharge of $0.01825 per kWh to recover transmission costs and the cost of the current full-requirements power supply agreement with PWMT.

General Rate Case Filing

In December 2006, UNS Electric filed a general rate case with the ACC requesting a total rate increase of 5.5% to cover a revenue deficiency of $9 million. The increase is necessary because of the growth in UNS Electric's service territory and the related increase in capital expenditures and operating costs.

UNS Electric expects the ACC to rule on its rate case in late 2007. Under the terms of the UES Settlement Agreement, new rates cannot go into effect before August 1, 2007.

UNS Electric also requested that a new PPFAC surcharge take effect when the current power supply agreement with PWMT expires in May 2008.

Regulatory Assets and Liabilities

UNS Electric's regulatory assets and liabilities were as follows:

	December 31,	
	2006	**2005**
	-Millions of Dollars-	
Current Regulatory Assets		
Pension Asset	**$ 1**	$ -
Current Regulatory Liabilities		
Deferred Environmental Portfolio Surcharge	**$ 2**	$ 2
Other Regulatory Liabilities		
Over Recovered Purchase Power Costs	**6**	4
Derivatives	**3**	-
Net Cost of Removal for Interim Retirements	**2**	1
Net Regulatory Liabilities	**$ 12**	$ 7

Regulatory assets are either being collected in rates or are expected to be collected through rates in a future period, as described below:

- Pension Assets were recorded in 2006 as based on past regulatory actions, UNS Electric expects to recover in rates the UNS Electric portion of the underfunded pension plan for UNS Electric employees. UNS Electric does not earn a return on these costs.

Regulatory liabilities represent items that we expect to pay to customers through billing reductions in future periods or use for the purpose for which they were collected from customers, as described below.

- Deferred Environmental Friendly Portfolio Surcharge represents amounts the ACC has authorized UNS Electric to collect, through customer billings, for environmental improvement projects. The amounts are deferred until they are spent on their intended use.
- UNS Electric defers differences between purchased energy costs and the recovery of such costs in revenues. Future billings are adjusted for such deferrals through use of a Purchased Power and Fuel Adjustment Clause (PPFAC) approved by the ACC. The PPFAC allows for a revenue surcharge or surcredit (that adjusts the customer's base rate for delivered purchased power) to collect or return under- or over-recovery of costs.
- In December 2006, the ACC granted UNS Electric an Accounting Order authorizing regulatory deferral of unrealized gains and losses on derivative forward purchase contracts that are required to be marked-to-market under FAS 133.
- Net cost of Removal for Interim Retirements represents an estimate of future asset retirement obligations.

Income Statement Impact of Applying FAS 71

If UNS Electric had not applied FAS 71, net income would have been $3 million higher in 2006 and $1 million higher in 2005, as UNS Electric would have been able to recognize over-recovered purchased power costs as a credit to the income statement rather than record an increase to regulatory liabilities.

Future Implications of Discontinuing Application of FAS 71

UNS Electric regularly assesses whether it can continue to apply FAS 71 to its operations. If UNS Electric stopped applying FAS 71 to its regulated operations, it would write-off the related balances of their regulatory assets as an expense and would write-off its regulatory liabilities as income on their income statement. Based on the regulatory asset and liability balances, if UNS Electric had stopped applying FAS 71 to its regulated operations, it would have recorded an extraordinary after-tax gain of $7 million at December 31, 2006. Discontinuing application of FAS 71 would not affect UNS Electric's cash flows.

NOTE 3. ACCOUNTING CHANGE: ACCOUNTING FOR ASSET RETIREMENT OBLIGATIONS

In 2005, TEP implemented FIN 47. The implementation of FIN 47 required TEP to update an existing inventory, originally created for the implementation of FAS 143, and to determine which, if any, of the conditional asset retirement obligations could be reasonably estimated. The significant conditional asset retirement obligations identified include:

- The removal and disposal of asbestos at the Sundt Generating Station
- Remediation of the evaporative ponds upon decommissioning of our generating stations
- The disposal of equipment contaminated with polychlorinated biphenlys (PCBs) in our distribution system.

In determining whether its conditional asset retirement obligations could be reasonably estimated, management considered TEP's past practices, industry practices, management's intent and the estimated economic life of the assets. Management then estimated the fair value of the conditional asset retirement obligations using an expected present value technique.

Upon implementation of FIN 47, we recorded an asset retirement obligation of $16 million at its net present value of $3 million, increased depreciable assets by an immaterial amount for asset retirement costs and recognized the cumulative effect of accounting change as a loss of less than $1 million net of tax. Had FIN 47 been in effect in 2004, there would be no change in reported financial results.

NOTE 4. SEGMENT AND RELATED INFORMATION

We have three reportable segments that are determined based on the way we organize our operations and evaluate performance:

(1) TEP, a vertically integrated electric utility business, is our largest subsidiary.
(2) UNS Gas is a regulated gas distribution utility business.
(3) UNS Electric is a regulated electric distribution utility business.

The UniSource Energy, UES and Millennium holding companies, UED, and several other subsidiaries and equity investments, which are not considered reportable segments, are included in All Other. All Other also includes the discontinued operations of Global Solar. As discussed in Note 16, at March 31, 2006, Millennium sold all of the common stock of Global Solar and the results of operations of Global Solar are reported as a discontinued operation for all periods presented. Through affiliates, Millennium holds investments in several unregulated energy and emerging technology companies. UED develops generating resources and performs other project development activities.

Significant revenues and expenses included in All Other include the following:

- In 2006, Millennium recorded an after-tax loss of approximately $2 million related to the discontinued operations and disposal of Global Solar.
- In 2005, Millennium recorded an after-tax gain of $2 million related to a gain on the sale of an investment by one of its investees. Millennium also recognized an impairment loss of $1 million in 2005 related to the sale of one of its investments in January 2006.
- In 2004, Millennium recorded an after-tax gain of $3 million related to gains and losses on sales of investments by its investees.
- In 2004, UED recognized an impairment loss on the entire $2 million balance of a note receivable.

Reconciling adjustments consist of the elimination of intercompany activity and balances. Millennium's subsidiaries recorded revenue from transactions with TEP of $14 million in 2006, $12 million in 2005 and $13 million in 2004. TEP's related expense is reported in Other Operations and Maintenance expense on its income statement. Millennium's revenue and TEP's related expense are eliminated in UniSource Energy consolidation. Other significant reconciling adjustments include the elimination of investments in subsidiaries held by UniSource Energy, the intercompany note between UniSource Energy and TEP, the related interest income and expense on the note and reclassifications of deferred tax assets and liabilities. UniSource Energy repaid the intercompany note in 2005. See Note 8.

Our portion of the net income (loss) of the entities in which TEP and Millennium own a voting interest or have the ability to exercise significant influence is shown below in Net Income (Loss) from Equity Method Entities.

We disclose selected financial data for our reportable segments in the following tables:

	Reportable Segments					
2006	TEP	UNS Gas	UNS Electric	All Other	Reconciling Adjustments	UniSource Energy
Income Statement			-Millions of Dollars-			
Operating Revenues – External	$ 996	$ 162	$ 160	$ (1)	$ -	**$1,317**
Operating Revenues – Intersegment	2	-	-	15	(17)	**-**
Depreciation and Amortization	112	7	11	1	-	**131**
Amortization of Transition Recovery Asset	66	-	-	-	-	**66**
Interest Income	16	-	-	3	-	**19**
Interest Expense	127	7	5	13	-	**152**
Income Tax Expense (Benefit)	42	3	3	(4)	-	**44**
Discontinued Operations – Net of Tax	-	-	-	(2)	-	**(2)**
Net Income (Loss)	67	4	5	(9)	-	**67**
Cash Flow Statement						
Net Cash Flows – Operating Activities	227	32	14	10	-	**283**
Net Cash Flows – Investing Activities – Capital Expenditures	(156)	(23)	(39)	(20)	-	**(238)**
Net Cash Flows – Investing Activities – Investments in and Loans to Equity Method Entities	-	-	-	(5)	-	**(5)**
Net Cash Flows – Investing Activities – Other	(26)	-	-	23	-	**(3)**
Net Cash Flows – Financing Activities	(79)	(4)	22	(14)	(2)	**(77)**
Balance Sheet						
Total Assets	2,623	253	195	1038	(922)	**3,187**
Investments in Equity Method Entities	3	-	-	27	-	**30**

	Reportable Segments					
2005	TEP	UNS Gas	UNS Electric	All Other	Reconciling Adjustments	UniSource Energy
Income Statement			-Millions of Dollars-			
Operating Revenues – External	$ 935	$ 138	$ 150	$ 1	$ -	**$ 1,224**
Operating Revenues – Intersegment	2	-	-	13	(15)	**-**
Depreciation and Amortization	115	7	10	1	-	**133**
Amortization of Transition Recovery Asset	56	-	-	-	-	**56**
Interest Income	21	-	-	-	(1)	**20**
Net Income from Equity Method Entities	-	-	-	2	-	**2**
Interest Expense	140	6	5	11	(2)	**160**
Income Tax Expense (Benefit)	34	3	3	(2)	-	**38**
Discontinued Operations – Net of Tax	-	-	-	(5)	-	**(5)**
Net Income (Loss)	48	5	5	(12)	-	**46**
Cash Flow Statement						
Net Cash Flows – Operating Activities	243	14	21	(4)	-	**274**
Net Cash Flows – Investing Activities – Capital Expenditures	(150)	(23)	(30)	-	-	**(203)**
Net Cash Flows – Investing Activities – Investments in and Loans to Equity Method Entities	-	-	-	(5)	-	**(5)**
Net Cash Flows – Investing Activities – Other	21	-	-	17	-	**38**
Net Cash Flows – Financing Activities	(174)	15	8	39	(1)	**(113)**
Balance Sheet						
Total Assets	2,617	233	161	1,043	(874)	**3,180**
Investments in Equity Method Entities	2	-	-	25	-	**27**

2004	TEP	UNS Gas	UNS Electric	All Other	Reconciling Adjustments	UniSource Energy
Income Statement						
Operating Revenues – External	$ 887	$ 129	$ 144	$ 5	$ -	**$ 1,165**
Operating Revenues – Intersegment	2	-	-	14	(16)	**-**
Depreciation and Amortization	117	5	9	1	-	**132**
Amortization of Transition Recovery Asset	50	-	-	-	-	**50**
Interest Income	29	-	-	-	(9)	**20**
Net Loss from Equity Method Entities	-	-	-	6	-	**6**
Interest Expense	157	6	5	9	(9)	**168**
Income Tax Expense (Benefit)	35	4	3	(5)	-	**37**
Discontinued Operations – Net of Tax	-	-	-	(5)	-	**(5)**
Net Income (Loss)	46	6	4	(10)	-	**46**
Cash Flow Statement						
Net Cash Flows – Operating Activities	275	21	19	(3)	(5)	**307**
Net Cash Flows – Investing Activities – Capital Expenditures	(130)	(19)	(19)	-	1	**(167)**
Net Cash Flows – Investing Activities – Investments in and Loans to Equity Method Entities	-	-	-	(4)	-	**(4)**
Net Cash Flows – Investing Activities – Other	4	-	-	11	-	**15**
Net Cash Flows – Financing Activities	(101)	(1)	(2)	2	4	**(98)**
Balance Sheet						
Total Assets	2,742	201	135	961	(852)	**3,187**
Investments in Equity Method Entities	2	-	-	34	-	**36**

NOTE 5. ACCOUNTING FOR DERIVATIVE INSTRUMENTS, TRADING ACTIVITIES AND HEDGING ACTIVITIES

TEP INTEREST RATE SWAP

In June 2006, TEP entered into an interest rate swap to reduce the risk of unfavorable changes in variable interest rates related to changes in LIBOR. The swap has the effect of converting approximately $37 million of variable rate lease payments for the Springerville Common Lease to a fixed rate through January 1, 2020. The swap is designated as a cash flow hedge for accounting purposes. The changes in interest payments related to changes in LIBOR were completely offset by the interest rate swap in the last half of 2006. At December 31, 2006, the fair value of the swap of approximately $2 million is recorded in Other Liabilities and the unrealized loss is recorded in Other Comprehensive Income, a component of Common Stock Equity. Amounts accumulated in Other Comprehensive Income will be reclassified to Interest on Capital Leases over the term of the lease. At December 31, 2006, we expect less than $1 million to be reclassified into earnings over the next 12 months.

TEP FUEL AND POWER TRANSACTIONS

TEP enters into forward contracts to purchase or sell a specified amount of capacity or energy at a specified price over a given period of time, within established limits to take advantage of favorable market opportunities and reduce exposure to energy price risk resulting from generation and procurement of power. In general, TEP enters into forward power purchase contracts when market conditions provide the opportunity to purchase energy for its load at prices that are below the marginal cost of its supply resources or to supplement its own resources (e.g., during plant outages and summer peaking periods). TEP enters into forward power sales contracts when it forecasts that it has excess supply and the market price of energy exceeds its marginal cost. In addition, TEP has natural gas supply agreements under which it purchases all of its gas requirements at spot market prices. In an effort to minimize price risk on these purchases, TEP enters into price swap agreements under which TEP purchases gas at fixed prices and simultaneously sells gas at spot market prices.

All of TEP's forward power sale contracts and forward power purchase contracts meet the accounting definition of a derivative. Under the accounting rules, TEP has three types of derivatives related to forward purchase and sales contracts.

- **Normal Purchase and Sale** - A portion of TEP's forward power contracts are considered to be normal purchases and sales and, therefore, are not required to be marked to market.

- **Cash Flow Hedges** - Some of TEP's forward power contracts and all of the gas swap agreements are accounted for as cash flow hedges. Unrealized gains and losses resulting from the change in the fair value of derivatives that meet the criteria for cash flow hedge accounting are recorded in Other Comprehensive Income, rather than in current earnings. Unrealized gains and losses are reclassified into earnings when the related transactions settle or terminate. There were no gains or losses recognized in Net Income related to hedge ineffectiveness because all cash flow hedges are considered to be effective.

- **Mark-to-Market** - The change in fair value of forward power contracts, which are not accounted for as normal purchases and sales or cash flow hedges, is recorded in Net Income.

The settlement of forward power purchase and sales contracts that do not result in physical delivery are recorded net as a component of Electric Wholesale Sales in TEP's income statement. During 2006, approximately $78 million in sales were netted against approximately $75 million in purchases. During 2005, $15 million in sales were netted against $16 million in purchases and in 2004, $5 million in sales were netted against approximately $5 million in purchases.

The net unrealized gains and losses from TEP's fuel and power related derivative activities were as follows:

	Years Ended December 31, 2006	2005	2004
	-Millions of Dollars-		
Net Unrealized Gain on Forward Power Sales – Derivative Contracts	$ 7	$ 1	$ 2
Net Unrealized (Loss) on Forward Power Purchases – Derivative Contracts	(6)	(2)	-
Pre-Tax Unrealized Gain (Loss) on Derivative Contracts Recorded in Earnings	$ 1	$ (1)	$ 2
Net Unrealized Gain (Loss) on Forward Power Sales – Cash Flow Hedges	$ 6	$ (1)	$ -
Net Unrealized (Loss) Gain on Gas Price Swaps – Cash Flow Hedges	(17)	11	3
Pre-Tax Unrealized (Loss) Gain on Cash Flow Hedges	$ (11)	$ 10	$ 3
After Tax Unrealized (Loss) Gain on Cash Flow Hedges Recorded in OCI	$ (7)	$ 6	$ 2

The fair value of TEP's fuel and power related derivative assets and liabilities were as follows:

	December 31, 2006		December 31, 2005	
	Derivative Contracts	Cash Flow Hedges	Derivative Contracts	Cash Flow Hedges
	-Millions of Dollars-			
Derivative Assets – Current	$ 9	$ 6	$ 2	$ 10
Derivative Liabilities – Current	(9)	(3)	(2)	(1)
Net Current Derivative Assets	$ -	$ 3	$ -	$ 9
Derivative Assets – Noncurrent	$ -	$ -	$ -	$ 4
Derivative Liabilities – Noncurrent	-	(1)	-	(1)
Net Noncurrent Derivative Assets	$ -	$ (1)	$ -	$ 3

At December 31, 2006, the contracts accounted for as cash flow hedges will settle through the fourth quarter of 2009. Amounts presented as Cash Flow Hedges, Derivative Assets – Current and Derivative Liabilities – Current, are expected to be reclassified into earnings within the next twelve months. TEP reclassified less than $1 million of net unrealized gains and losses into earnings from Other Comprehensive Income during 2006. TEP reclassified $6 million of net unrealized gains and losses into earnings from Other Comprehensive Income during 2005.

UNS GAS SUPPLY TRANSACTIONS

UNS Gas does not currently have any contracts that are required to be marked-to-market. UNS Gas purchases substantially all of its gas requirements at market prices under a natural gas supply and management agreement with BP Energy Company (BP). However, the contract terms allow UNS Gas to lock in fixed prices on a portion of its expected forward gas purchases from BP. This enables UNS Gas to provide more stable prices to its customers. These purchases are made up to three years in advance with the goal of locking in fixed prices on at least 45% of the expected monthly gas consumption prior to entering into the month. These forward purchases, as well as the main gas supply contract, meet the definition of normal purchases and therefore are not required to be marked-to-market.

UNS ELECTRIC POWER SUPPLY TRANSACTIONS

UNS Electric purchases all of its electricity under a full requirements power supply agreement that will expire May 31, 2008. UNS Electric is in the process of replacing this energy resource for periods after May 2008. In order to reduce the risk of unfavorable changes in future power procurement prices, UNS Electric has entered into forward power purchase contracts for specified amounts of energy at specified prices over a given period of time. UNS Electric's forward power purchase contracts meet the definition of a derivative and are required to be marked to market each reporting period. However, in December 2006, the ACC granted UNS Electric an accounting order to record the unrealized gains and losses as a regulatory asset or a regulatory liability.

The fair value of UNS Electric's derivative asset is $3 million as of December 31, 2006. During 2006, UNS Electric recorded net unrealized gains of $3 million in Deferred Credits and Other Liabilities - Other Regulatory Liabilities. UNS Electric did not have any derivatives during 2005.

At December 31, 2006, the settlement dates of contracts accounted for as cash flow hedges extended through the fourth quarter of 2013. UNS Electric does not have any current Derivative Assets or Liabilities that are expected to be reclassified into earnings within the next twelve months.

MEG TRADING TRANSACTIONS

MEG, a wholly-owned subsidiary of Millennium, enters into swap agreements, options and forward contracts relating to Emissions Allowances. MEG marks its trading contracts to market by recording unrealized gains and losses and adjusting the related assets and liabilities on a monthly basis to reflect the market prices at the end of the month.

MEG had a net loss from trading activities of less than $1 million in 2006 and 2005. MEG had a net gain from trading activities of $1 million in 2004.

The fair value of MEG's derivative assets and liabilities were as follows:

	December 31, **2006**	December 31, **2005**
	-Millions of Dollars-	
MEG:		
Trading Assets – Current	**$ 11**	$ 24
Trading Liabilities – Current	**(5)**	(24)
Net Current Trading Assets	**$ 6**	$ -
Trading Assets – Noncurrent	**$ -**	$ 14
Trading Liabilities – Noncurrent	**-**	(1)
Net Noncurrent Trading Assets	**$ -**	$ 13

CONCENTRATION OF CREDIT RISK

The use of contractual arrangements to manage the risks associated with changes in energy commodity prices creates credit risk exposure resulting from the possibility of nonperformance by counterparties pursuant to the terms of their contractual obligations. TEP, UNS Gas and UNS Electric enter into contracts for the physical delivery of energy and gas which contain remedies in the event of non-performance by the supply counterparties. In addition, volatile energy prices can create significant credit exposure from energy market receivables and mark-to-market valuations. As of December 31, 2006, TEP had total credit exposure of $34 million related to its wholesale marketing and gas hedging activities, of which five counterparties individually composed greater than 10% of the total credit exposure. As of December 31, 2006, MEG had total credit exposure related to its trading activities of $5 million and was concentrated primarily with two counterparties. As of December 31, 2006, UNS Gas had no credit exposure related to its forward contracts with its gas supply counterparty. As of December 31, 2006, UNS Electric had a total credit exposure related to its forward power purchase contracts of less than $1 million, primarily related to its relationship with two counterparties. TEP calculates counterparty credit exposure by adding any outstanding receivables (net of amounts payable if a netting agreement exists) to the mark-to-market value of any forward contracts.

NOTE 6. COMMITMENTS AND CONTINGENCIES

TEP COMMITMENTS

Purchase and Transportation Commitments

TEP has several long-term coal purchase and transportation contracts with various expiration dates from 2008 and through 2020. Amounts paid under these contracts depend on the number of tons of coal purchased and transported. Some of these contracts (i) include a price adjustment clause that will affect the future cost of coal and (ii) require TEP to pay a take-or-pay charge or liquidated damages if certain minimum quantities of coal are not purchased and/or transported. Current fuel requirements are in excess of the take-or-pay minimums. TEP made payments under these contracts of $184 million in 2006 and $175 million in 2005 and 2004.

In November 2005, TEP entered into a natural gas Transportation Supply Agreement (TSA) with El Paso Natural Gas (EPNG) to fuel TEP's portion of the Luna facility. The contract began in February 2006 and has an initial term of three years. TEP made payments under this contract of $2 million in 2006.

Tri-State Generation and Transmission Association, Inc. (Tri-State) leases Springerville Unit 3, a 400 MW coal-fired generating facility at TEP's existing Springerville Generating Station, from a financial owner. TEP provides operating, maintenance and other services to Springerville Unit 3 under a 99-year operating agreement subject to cancellation by either party with 30 days notice. TEP also agreed to purchase up to 100 MW of Tri-State system capacity for no more than five years beginning September 1, 2006. Tri-State may reduce the 100 MW available to TEP in 25 MW increments by submitting written notice to TEP at least 90 days in advance. To date, TEP has received no such notice. TEP made minimum capacity payments under this contract of $10 million in 2006.

At December 31, 2006, TEP estimates that future minimum payments under the contracts for purchased power, coal, and gas referred to above are as follows:

	Minimum Purchase Obligations
	-Millions of Dollars-
2007	$ 135
2008	123
2009	111
2010	111
2011	63
Total 2007 – 2011	543
Thereafter	242
Total	$ 785

Operating Leases

TEP's consolidated operating lease expense, which is primarily for office facilities and computer equipment, with varying terms, provisions, and expiration dates, was $1 million in each of the years 2006, 2005 and 2004. TEP's estimated future minimum payments under non-cancelable operating leases are approximately $1 million per year from 2007 to 2010.

Environmental Regulation

Federal Clean Air Act Amendments

TEP generating facilities are subject to EPA limits on the amount of sulfur dioxide (SO_2) and nitrogen oxide (NOx) emissions into the atmosphere. TEP capitalized $1 million in each of 2006 and 2005, and $9 million in 2004 in construction costs to comply with environmental requirements and expects to capitalize $18 million in 2007 and $42 million in 2008. In addition, TEP recorded operating expenses of $10 million in 2006, $11 million in 2005 and $9 million in 2004 related to environmental compliance, including the cost of lime used to scrub the stacks. TEP expects environmental expenses to be $11 million in each of the years 2007 and 2008.

In 1993, the EPA allocated TEP's generating units SO_2 Emissions Allowances based on past operational history. Beginning in 2000, TEP's generating units were required to hold Emissions Allowances equal to the level of emissions in the compliance year or pay penalties and offset excess emissions in future years. To date TEP has had sufficient Emissions Allowances to comply with the SO_2 regulations. However, due to potential changes in the legislation affecting SO_2 emission levels, TEP may have to purchase additional Emissions Allowances for future compliance in years 2011 or beyond.

Mercury Emissions

In 2005, the EPA adopted regulations relating to mercury emissions requiring states to develop rules for implementing federal requirements. Arizona adopted its mercury emission limits in 2007 and TEP must meet these limits by 2013. TEP is analyzing the potential impact of the Arizona regulations on its operations but does not expect the capital costs to exceed $5 million. TEP is also monitoring the New Mexico and Navajo Nation mercury emission regulations affecting plants for which TEP has an ownership share. Until these state procedures are adopted, TEP cannot determine if it will be significantly affected.

Greenhouse Gas Emissions

Federal, state and local legislative and regulatory bodies are considering the regulation of greenhouse gas emissions. At this time, we do not know whether any such regulations will be adopted, the scope of such regulations or how any such regulations could affect our operations.

Regional Haze

The EPA's Regional Haze Rule requires states to develop plans to restore visibility in various areas to their natural conditions by 2064. State plans, which must be submitted to the EPA in December 2007, could require pollution control upgrades at some of TEP's power plants. The level of control required, if any, will not be known until the state plans are submitted and approved by EPA. If required, controls must be in place by 2013 or later.

TEP may incur additional costs to comply with recent and future changes in federal and state environmental laws, regulations and permit requirements at existing electric generating facilities. Compliance with these changes may reduce operating efficiency.

Tucson to Nogales Transmission Line

TEP and UNS Electric are parties to a project development agreement for the joint construction of an approximately 60-mile transmission line from Tucson to Nogales, Arizona. This project was initiated in response to an order by the ACC to improve reliability to UNS Electric's retail customers in Nogales, Arizona.

In 2002, the ACC approved the location and construction of the proposed 345-kV line along the Western Corridor route subject to a number of conditions, including obtaining all required permits from state and federal agencies. TEP is currently seeking approvals for the project from the Department of Energy (DOE), the US Forest Service, the Bureau of Land Management, and the International Boundary and Water Commission.

The DOE has completed a Final Environmental Impact Statement (EIS) for the project in which it would accept any of the routes in the EIS, but the U.S. Forest Service has indicated the Central route as its preferred alternative, rather than the Western Corridor route.

Based on the alternative proposals and passage of time since it approved the location of the line, the ACC, in January 2005, ordered TEP to review the status of electric service reliability in Nogales, Arizona and the need for the 345-kV line. The ACC also indicated that it would review any new information regarding the location of the proposed transmission line. In December 2005, an Administrative Law Judge (ALJ) for the ACC issued a recommended opinion and order reaffirming the ACC's original position requiring the construction of the Tucson to Nogales transmission line. After a hearing on the issue, the ACC directed the ALJ to amend the recommendation to direct the Line Siting Committee of the ACC to gather facts related to options for improving service reliability in Nogales, Arizona. TEP expects the ACC to address the ALJ's amended recommended opinion and order in 2007.

If TEP does not receive the required approvals it may need to expense a portion of the $11 million of costs that have been capitalized related to the project.

TEP Guarantee Home Program

TEP provides incentives to new home builders to construct TEP Guarantee Homes that meet the highest construction and energy-efficiency standards available. TEP made builder incentive payments of $2 million in 2006 and $1 million in 2005 and 2004. TEP has commitments to make payments under this program of $2 million in 2007 and less than $0.5 million in 2008.

UNS GAS COMMITMENTS

UNS Gas has firm transportation agreements with El Paso Natural Gas (EPNG) and Transwestern Pipeline Company (Transwestern) with combined capacity sufficient to meet its load requirements. The EPNG contract expires in August 2011 and the Transwestern contract expires in February 2012. EPNG provides gas transportation service under a converted full requirements contract in which UNS Gas pays a fixed reservation charge. The minimum expected annual payment is $7 million. UNS Gas made payments under the EPNG and Transwestern contracts of $10 million in 2006 and $7 million in 2005 and 2004.

At December 31, 2006, UNS Gas estimates its future minimum payments under these contracts to be:

	Minimum Purchase Obligations
	-Millions of Dollars-
2007	$ 12
2008	11
2009	11
2010	11
2011	8
Total 2007 – 2011	53
Thereafter	-
Total	$ 53

See Note 8 for a description of the UNS Gas and UNS Electric long-term debt.

UNS ELECTRIC COMMITMENTS

UNS Electric imports the power it purchases over the Western Area Power Administration's (WAPA) transmission lines. UNS Electric's transmission capacity agreements with WAPA provide for annual rate adjustments and expire in February 2008 and June 2011. The contract that expires in 2008 also contains a capacity adjustment clause. UNS Electric made payments under these contracts of $8 million in 2006, $7 million in 2005, and $6 million in 2004.

UNS Electric's all requirements contract expires in 2008. During 2006, UNS Electric entered into agreements to purchase power beginning in 2008 through 2011. The contracts are valued based on either fixed prices or indexed to NYMEX natural gas prices as of December 31, 2006.

At December 31, 2006, UNS Electric estimates its future minimum payments under these contracts to be:

	Minimum Purchase Obligations
	-Millions of Dollars-
2007	$ 8
2008	30
2009	38
2010	26
2011	15
Total 2007 – 2011	117
Thereafter	16
Total	$ 133

UNS GAS and UNS ELECTRIC OPERATING LEASES

UNS Gas and UNS Electric's combined operating lease expense which is primarily for office facilities and computer equipment, with varying terms, provisions, and expiration dates was $1 million in each of the years 2006, 2005 and 2004. UNS Gas and UNS Electric's estimated future minimum payments under non-cancelable operating leases are approximately $1 million per year from 2007 to 2011 and $2 million thereafter.

MILLENNIUM COMMITMENTS

Millennium has a remaining obligation to fund its subsidiaries for capital and operations up to an additional $1 million over the next two years.

UED COMMITMENTS

In October 2006, UED purchased two electric generating turbines for $17 million. The turbines will be part of a 90 MW power project to be constructed in Kingman, Arizona in UNS Electric's service area. Construction is expected to begin during the third quarter of 2007 with an estimated completion date of May 2008. Including installation and refurbishment of the turbines, the total cost of the project for UED is expected to be $60 million, of which $40 million remains unpaid.

TEP CONTINGENCIES

Litigation and Claims Related to San Juan Generating Station

Public Service Company of New Mexico (PNM), operator of San Juan, and the coal supplier to San Juan have been participating in sessions sponsored by the Environmental Protection Agency (EPA) to consider rulemaking for the disposal of coal combustion products because of claims by third parties that San Juan has contaminated water resources in the region as a result of disposing of fly ash in the surface mine pits adjacent to the generating station. A contractor for the EPA has determined that there is no conclusive evidence that contamination can be attributed to fly ash disposal. TEP owns 50% of San Juan Units 1 and 2, which equates to 19.8% of the total San Juan Generating Station. TEP does not believe that this issue will have a material adverse impact on TEP or its operations.

Claims Related to San Juan Coal Company

San Juan Coal Company, the coal supplier to San Juan, through leases with the federal government and the State of New Mexico, owns coal interests with respect to an underground mine. Certain gas producers have oil and gas leases with the federal government, the State of New Mexico and private parties in the area of the underground mine. These gas producers allege that San Juan Coal Company's underground coal mining operations have or will interfere with their gas production and will reduce the amount of natural gas that they would otherwise be entitled to recover. San Juan Coal Company has compensated certain gas producers for any remaining gas production from a well when it was determined that mining activity was close enough to warrant shutting down the well. These settlements, however, do not resolve all potential claims by gas producers in the underground mine area. TEP cannot estimate the outcome of any future claims by these gas producers on the cost of coal at San Juan.

Litigation and Claims Related to Navajo Generating Station

In 2004, Peabody Western Coal Company (Peabody), the coal supplier to the Navajo Generating Station, filed a complaint in the Circuit Court for the City of St. Louis, Missouri (Circuit Court) against the participants at Navajo, including TEP, for reimbursement of royalties and other costs and breach of the coal supply agreement. Because TEP owns 7.5% of the Navajo Generating Station, its share of the current claimed damages would be approximately $35 million. TEP believes these claims are without merit and intends to continue to contest them.

Postretirement and Pension Benefit Costs at Navajo Generating Station

Peabody contends that the Navajo Generating Station participants are responsible under the coal supply agreements for postretirement benefit costs payable to the coal supplier's employees. In 1996, SRP filed a lawsuit in Maricopa County Superior Court on behalf of the participants at Navajo Generating Station, including TEP, seeking declaratory judgment that the participants are not responsible for these costs. The Navajo participants and Peabody have agreed to stay the discovery process in this litigation to allow the parties additional time to negotiate a potential settlement. We expect resolution of this matter in 2007. To the extent that amounts become estimable and payment probable, TEP will record a liability for additional postretirement benefit costs for the Navajo Generating Station.

Environmental Reclamation at Remote Generating Stations

TEP currently pays on-going reclamation costs related to the coal mines which supply the remote generating stations, and it is probable that TEP will have to pay a portion of final reclamation costs upon mine closure. When a reasonable estimate of final reclamation costs is available, the liability will be recognized as a cost of coal over the remaining term of the corresponding coal supply agreement. TEP estimates its undiscounted final reclamation liability to be $41 million, and the present value of TEP's liability for final reclamation approximates $11 million at the expiration dates of the coal supply agreements. TEP recorded reclamation costs of $1 million in 2006 and 2005 and $0.5 million in 2004 in Fuel Expense.

Amounts recorded for final reclamation are subject to various assumptions and determinations, such as estimating the costs of reclamation, estimating when final reclamation will occur, and the credit-adjusted risk-free interest rate to be used to discount future liabilities. Changes that may arise over time with regard to these assumptions and determinations will change amounts recorded in the future as expense for post-term reclamation. TEP does not believe that recognition of its final reclamation obligations will be material to TEP in any single year since recognition occurs over the remaining lives of its coal supply agreements.

TEP Wholesale Accounts Receivable and Allowances

TEP's Accounts Receivable from Electric Wholesale Sales, includes $16 million of receivables at December 31, 2006 and December 31, 2005 related to sales to the California Power Exchange (CPX) and the California Independent System Operator (CISO) in 2001 and 2000. TEP's Allowance for Doubtful Accounts on the balance sheet includes $13 million at December 31, 2006 and December 31, 2005 related to these sales. There are several outstanding legal issues, complaints and lawsuits concerning the California energy crisis related to the FERC, wholesale power suppliers, Southern California Edison Company, Pacific Gas and Electric Company, the

CPX and the CISO. We cannot predict the outcome of these issues or lawsuits. We believe, however, that TEP is adequately reserved for its transactions with the CPX and the CISO.

GUARANTEES AND INDEMNITIES

In the normal course of business, UniSource Energy and certain subsidiaries enter into various agreements providing financial or performance assurance to third parties on behalf of certain subsidiaries. We enter into these agreements primarily to support or enhance the creditworthiness of a subsidiary on a stand-alone basis. The most significant of these guarantees are:

- UES' guarantee of $160 million of aggregate principal amount of senior unsecured notes issued by UNS Gas and UNS Electric to purchase the Citizens Arizona gas and electric utility assets,
- UES' guarantee of a $40 million unsecured revolving credit agreement for UNS Gas and UNS Electric,
- UniSource Energy's guarantee of approximately $5 million in natural gas transportation and supply payments in addition to building and equipment lease payments for UNS Gas and UNS Electric.

To the extent liabilities exist under the contracts subject to these guarantees, such liabilities are included in our consolidated balance sheets.

In addition, we have indemnified the purchasers of interests in certain investments from additional taxes due for years before the sale of such investments. The terms of the indemnifications do not include a limit on potential future payments; however, we believe that we have abided by all tax laws and paid all tax obligations. We have not made any payments under the terms of these indemnifications to date.

We believe that the likelihood UniSource Energy or UES would be required to perform or otherwise incur any significant losses associated with any of these guarantees or indemnities is remote.

NOTE 7. UTILITY PLANT AND JOINTLY-OWNED FACILITIES

UTILITY PLANT

The following table shows Utility Plant in Service by company and major class at December 31:

	2006 - Millions of Dollars -			
	TEP	UNS Gas	UNS Electric	UniSource Energy
Plant in Service:				
Electric Generation Plant	$1,302	$ -	$ 17	$ 1,319
Electric Transmission Plant	566	-	18	584
Electric Distribution Plant	931	-	119	1,050
Gas Distribution Plant	-	168	-	168
Gas Transmission Plant	-	18	-	18
General Plant	154	16	10	180
Intangible Plant	78	1	7	86
Electric Plant Held for Future Use	4	1	-	5
Total Plant in Service	$3,035	$ 204	$ 171	$ 3,410
Utility Plant under Capital Leases	$ 702	$ -	$ 1	$ 703

	2005 - Millions of Dollars - TEP	UNS Gas	UNS Electric	UniSource Energy
Plant in Service:				
Electric Generation Plant	$1,233	$ -	$ 5	$ 1,238
Electric Transmission Plant	543	-	15	558
Electric Distribution Plant	883	-	92	975
Gas Distribution Plant	-	151	-	151
Gas Transmission Plant	-	18	-	18
General Plant	140	9	7	156
Intangible Plant	58	1	7	66
Electric Plant Held for Future Use	5	1	-	6
Total Plant in Service	$2,862	$ 180	$ 126	$ 3,168
Utility Plant under Capital Leases	$ 723	$ -	$ 1	$ 724

Intangible Plant primarily represents computer software costs. TEP's unamortized computer software costs were $32 million as of December 31, 2006 and $18 million as of December 31, 2005. UNS Gas' unamortized computer software costs were $1 million as of December 31, 2006 and $1 million as of December 31, 2005. UNS Electric's unamortized computer software costs were $1 million as of December 31, 2006 and $2 million as of December 31, 2005.

All TEP Utility Plant under Capital Leases is used in TEP's generation operations.

The following table reconciles the gross investment in utility plant to net investment in utility plant, segregated between regulated and non-regulated utility plant.

As of December 31, 2006	**TEP** T&D	Gen*	Total Plant	**UNS Gas** Total Plant	**UNS Electric** Total Plant	**UniSource Energy Consolidated** All Other	TEP Gen*	Total Plant
	-Millions of Dollars-							
Gross Plant in Service	$1,733	$1,302	$3,035	$ 204	$ 171	$2,108	$1,302	$3,410
Less Accumulated Depreciation and Amortization	875	571	1,446	16	31	922	571	1,493
Net Plant in Service	$ 858	$ 731	$1,589	$ 188	$ 140	$1,186	$ 731	$1,917

As of December 31, 2005	**TEP** T&D	Gen*	Total Plant	**UNS Gas** Total Plant	**UNS Electric** Total Plant	**UniSource Energy Consolidated** All Other	TEP Gen*	Total Plant
	-Millions of Dollars-							
Gross Plant in Service	$1,629	$1,233	$2,862	$ 180	$ 126	$1,935	$1,233	$3,168
Less Accumulated Depreciation and Amortization	817	561	1,378	10	20	847	561	1,408
Net Plant in Service	$ 812	$ 672	$1,484	$ 170	$ 106	$1,088	$ 672	$1,760

*The ACC does not set rates on TEP's generation operations on a cost-of-service basis, and; therefore, these operations are not accounted for under the provisions of FAS 71. Rates for the remaining utility operations appearing in this table are set by the ACC on a cost-of-service basis, and are accounted for under the provisions of FAS 71. The category T&D includes all transmission and distribution Plant in Service. The category Gen includes the generation assets.

The depreciable lives currently used by TEP are as follows:

Major Class of Utility Plant in Service	Depreciable Lives
Electric Generation Plant	23-70 years
Electric Transmission Plant	10-50 years
Electric Distribution Plant	24-60 years
General Plant	5-45 years
Intangible Plant	3-10 years

During the second quarter 2005, the results of a study requested by the participants in the San Juan Generating Station (San Juan) indicated San Juan's economic useful life had changed from previous estimates. As a result of the study and other analysis performed, TEP lengthened the estimated useful life of San Juan from 40 to 60 years beginning April 1, 2005. This change in the estimated useful life reduces annual depreciation expense by $6 million.

See *TEP Utility Plant* in Note 1 and *TEP Capital Lease Obligations* in Note 8.

The depreciable lives currently used by UES are as follows:

Major Class of Utility Plant in Service	Depreciable Lives
Electric Generation Plant	23-40 years
Electric Transmission Plant	11-45 years
Electric Distribution Plant	14-26 years
Gas Distribution Plant	17-48 years
Gas Transmission Plant	37-55 years
General Plant	3-33 years

JOINTLY-OWNED FACILITIES

At December 31, 2006, TEP's interests in jointly-owned generating stations and transmission systems were as follows:

	Percent Owned by TEP	Plant in Service *	Construction Work in Progress	Accumulated Depreciation
		-Millions of Dollars-		
San Juan Units 1 and 2	50.0%	$ 307	$ 3	$ 219
Navajo Station Units 1, 2 and 3	7.5	133	2	74
Four Corners Units 4 and 5	7.0	83	2	66
Transmission Facilities	7.5 to 95.0	287	-	179
Luna Energy Facility	33.3	49	-	1
Total		$ 859	$ 7	$ 539

*Included in Utility Plant shown above.

TEP has financed or provided funds for the above facilities and TEP's share of their operating expenses is reflected in the income statements. See Note 6 for commitments related to TEP's jointly-owned facilities.

NOTE 8. DEBT, CREDIT FACILITIES, AND CAPITAL LEASE OBLIGATIONS

Long-term debt matures more than one year from the date of the financial statements. We summarize UniSource Energy and TEP's long-term debt in the statements of capitalization.

UNISOURCE ENERGY DEBT

Convertible Senior Notes

In March 2005, UniSource Energy issued $150 million of 4.50% Convertible Senior Notes (Convertible Senior Notes) due 2035. The Convertible Senior Notes are unsecured and are not guaranteed by TEP or any other UniSource Energy subsidiary. Each $1,000 of Convertible Senior Notes is convertible into 26.6667 shares of UniSource Energy Common Stock at any time, representing a conversion price of approximately $37.50 per share of our Common Stock, subject to adjustment in certain circumstances.

Beginning on March 5, 2010, UniSource Energy will have the option to redeem the Convertible Senior Notes, in whole or in part, for cash, at a price equal to 100% of the principal amount plus accrued interest. Holders of the Convertible Senior Notes may require UniSource Energy to repurchase the Convertible Senior Notes, in whole or in part, for cash on March 1, 2015, 2020, 2025 and 2030, or if certain change of control transactions occur, or if our common stock is no longer listed on a national securities exchange. The repurchase price will be 100% of the principal amount of the Convertible Senior Notes plus accrued interest.

Certain of the Convertible Senior Notes features are considered to be embedded derivatives. Based on accounting requirements, we concluded that the embedded derivatives either do not have any value or they are not required to be separated from the debt and accounted for separately.

In March 2005, UniSource Energy used $106 million of the net proceeds from this offering to repay the $95 million promissory note to TEP plus accrued interest of $11 million. TEP used these funds, along with borrowings under its revolving credit facility to repurchase and redeem $225 million of industrial development bonds (IDBs). See *TEP Debt – Unsecured IDBs*, below.

Intercompany Notes Payable

In 1998, TEP and UniSource Energy exchanged all the outstanding common stock of TEP on a share-for-share basis for the Common Stock of UniSource Energy in a transaction which resulted in UniSource Energy becoming a holding company with TEP as its subsidiary. Following the share exchange, TEP transferred the stock of Millennium to UniSource Energy for a $95 million promissory note due in 2008. On March 1, 2005, UniSource Energy used $106 million of the $146 million of net proceeds from the convertible debt offering, as discussed above, to repay the $95 million promissory note to TEP plus accrued interest of $11 million. Approximately $25 million of this note represented a gain to TEP. TEP did not record this gain in income. Instead, this gain was reflected as an increase in TEP's common stock equity when UniSource Energy repaid the note.

TEP DEBT

1941 Mortgage IDBs

In March 2005, TEP redeemed, at par, all of the remaining $52 million of its 1941 Mortgage IDBs.

Unsecured IDBs

In May 2005, TEP purchased $221 million of fixed rate Unsecured IDBs at a price of $101.50 per $100 principal amount and redeemed, at par, the remaining $4 million of bonds outstanding under those series. In connection with the repurchase, TEP recognized a loss of approximately $3 million related to previously deferred debt costs. TEP does not plan to cancel the IDBs that it repurchased, but is holding the bonds as treasury bonds. This means the bonds remain outstanding under their indentures but are not reflected as debt on the balance sheet. TEP may choose to cancel or resell these treasury bonds to third parties in the future.

Mortgage Indentures

In June 2005, TEP terminated its 1941 Mortgage Indenture. TEP's remaining mortgage is its 1992 Mortgage Indenture.

TEP's indenture creates liens on and security interests in most of TEP's utility plant assets, with the exception of Springerville Unit 2. San Carlos Resources Inc., a wholly-owned subsidiary of TEP, holds title to Springerville Unit 2. Utility Plant under Capital Leases is not subject to such liens or available to TEP creditors, other than the lessors. The net book value of TEP's utility plant subject to the lien of the indenture was approximately $1 billion at December 31, 2006.

TEP CAPITAL LEASE OBLIGATIONS

The terms of TEP's capital leases are as follows:

- The Sundt Lease has an initial term to January 2011 and provides for renewal periods of two or more years through 2020.
- The Springerville Common Facilities Leases have an initial term to December 2017 for one lease and January 2021 for the other two leases, subject to optional renewal periods of two or more years through 2025.
- The Springerville Unit 1 Leases have an initial term to January 2015 and provide for renewal periods of three or more years through 2030.
- The Springerville Coal Handling Facilities Leases have an initial term to April 2015 and provide for one renewal period of six years, then additional renewal periods of five or more years through 2035.

TEP has agreed with the owners of Springerville Units 3 and 4 that, upon expiration of the Springerville Coal Handling Facilities and Common Leases, TEP is obligated to acquire the facilities at fixed prices of $120 million in 2015, $38 million in 2017, and $68 million in 2021. Upon such acquisitions by TEP, each of the owners of Unit 3 and Unit 4 have the obligation to purchase from TEP a 17% and 14% interest, respectively, in such facilities. On or before the Sundt and Springerville Unit 1 Lease expiration dates, TEP will determine if it will purchase the assets at the fair market value or renegotiate the lease terms.

In January 2007, TEP made the following scheduled lease payments: Sundt Lease $11 million; Springerville Common Facilities Leases $2 million; Springerville Unit 1 Leases $70 million; and Springerville Coal Handling Facilities Leases $4 million.

Investments in Springerville Lease Debt and Equity

In June 2006, TEP purchased a 14% undivided equity ownership interest in the Springerville Unit 1 Lease and now is the owner participant under the leveraged lease arrangements relating to such undivided interest. As a result, TEP amended the Springerville Unit 1 Lease related to the 14% interest to reduce rental (lease) payments to equal the scheduled principal and interest payments for debt issued in respect of such interest. TEP recorded a $19 million reduction to the capital lease obligation and capital lease asset.

TEP held an investment in Springerville Unit 1 lease debt totaling $82 million at December 31, 2006 and $91 million at December 31, 2005. TEP also held an investment in Springerville Coal Handling Facilities lease debt totaling $52 million at December 31, 2006 and $65 million at December 31, 2005.

Springerville Common Lease Debt Refinancing

In 1985, TEP sold and leased back its undivided one-half ownership interest in the common facilities at the Springerville Generating Station. TEP refinanced the lease debt totaling $68 million in June 2006, and the leases were amended to remove the requirement that the notes be periodically refinanced to avoid the occurrence of a special event of loss. The lease debt now matures when the leases expire. Interest is payable at LIBOR plus 1.5% for the next three years with the spread over LIBOR increasing every three years thereafter to 2% by June 2018. Prior to the refinancing, the interest rate was LIBOR plus 4%. The refinancing had no impact on the Springerville Common Facilities capital lease obligation or asset.

A portion of the rent payable by TEP pursuant to the Springerville Common Facilities Leases is determined by the amount of interest payable on the underlying floating rate lease debt. In June 2006, TEP entered into an interest rate swap to hedge a portion of the interest rate risk associated with the portion of rent determined by the interest rate on this debt. This swap has the effect of fixing the interest portion of rent at a rate of 7.27% on $37 million of the lease debt. The interest rate swap has been recorded by TEP as a cash flow hedge for financial reporting purposes. See Note 5.

UNS GAS AND UNS ELECTRIC LONG-TERM DEBT

Senior Unsecured Notes

In 2003, UNS Gas and UNS Electric issued a total of $160 million of senior unsecured notes in a private placement. UNS Gas issued $50 million of 6.23% notes due August 11, 2011 and $50 million of 6.23% notes due August 11, 2015. UNS Electric issued $60 million of 7.61% notes due August 11, 2008. All three series of notes may be prepaid with a make-whole call premium reflecting a discount rate equal to an equivalent maturity U.S. Treasury security yield plus 50 basis points. UES guarantees the notes. UNS Gas and UNS Electric incurred a total of $2 million in debt costs related to the issuance of the notes. We deferred these costs and are amortizing them over the life of the notes.

The note purchase agreements for both UNS Gas and UNS Electric contain certain restrictive covenants, including restrictions on transactions with affiliates, mergers, additional indebtedness, dividend restrictions, and minimum net worth requirements.

As of December 31, 2006, UNS Gas and UNS Electric complied with the terms of the note purchase agreements.

MATURITIES AND SINKING FUND REQUIREMENTS

Long-term debt, including sinking funds, term loan payments, revolving credit facilities, and capital lease obligations mature on the following dates:

	TEP Variable Rate IDBs Supported by LOCs	TEP Scheduled Debt Retirements	TEP Capital Lease Obligations	TEP Total	UNS Gas	UNS Electric	UniSource Energy	Total
			- Millions of Dollars -					
2007	$ -	$ -	$ 125	$ 125	$ -	$ -	$ 6	$ 131
2008	-	138	118	256	-	79	6	341
2009	-	-	63	63	-	-	6	69
2010	-	-	93	93	-	-	6	99
2011	329	-	108	437	50	-	3	490
Total 2007 – 2011	329	138	507	974	50	79	27	1,130
Thereafter	-	354	540	894	50	-	150	1,094
Less: Imputed Interest	-	-	(400)	(400)	-	-	-	(400)
Total	$ 329	$ 492	$ 647	$1,468	$ 100	$ 79	$ 177	$ 1,824

TEP's Variable Rate IDBs are backed by letters of credit (LOC) issued pursuant to TEP's Credit Agreement which expires in August 2011. Although the Variable Rate IDBs mature between 2018 and 2022, the above table reflects a redemption or repurchase of such bonds in 2011 as though the LOCs terminate without replacement upon expiration of the TEP Credit Agreement.

Effective with commercial operation of Springerville Unit 3 on September 1, 2006, Tri-State is reimbursing TEP for various operating costs related to the common facilities on an ongoing basis, including 14% of the Springerville Common Lease payments and 17% of the Springerville Coal Handling Facilities Lease payments. TEP remains the obligor under these capital leases, and Capital Lease Obligations do not reflect any reduction associated with this reimbursement.

UNISOURCE ENERGY CREDIT AGREEMENT

In August 2006, UniSource Energy amended its existing unsecured credit agreement (UniSource Credit Agreement). As amended, the UniSource Credit Agreement includes a $30 million term loan facility and a $70 million revolving credit facility. The UniSource Credit Agreement expires on August 11, 2011.

The UniSource Credit Agreement requires quarterly principal payments of $1.5 million on the outstanding term loan with the balance due at maturity. At December 31, 2006, there was $27 million outstanding under the term loan facility and $20 million outstanding under the revolving credit facility at a weighted average interest rate of 6.67%. In January 2007, UniSource Energy repaid the $20 million outstanding under its revolving credit facility.

We have the option of paying interest on the term loan and on borrowings under the revolving credit facility at adjusted LIBOR plus 1.25% or the sum of the greater of the federal funds rate plus 0.5% or the agent bank's reference rate and 0.25%.

The UniSource Credit Agreement restricts additional indebtedness, liens, mergers, sales of assets, and certain investments and acquisitions. We must also meet: (1) a minimum cash flow to interest coverage ratio for UniSource Energy on a standalone basis and (2) a maximum leverage ratio on a consolidated basis. We may pay dividends if, after giving effect to the dividend payment, we have more than $15 million of unrestricted cash and unused revolving credit. As of December 31, 2006, we were in compliance with the terms of the UniSource Credit Agreement.

TEP CREDIT AGREEMENT

In August 2006, TEP amended its credit agreement (TEP Credit Agreement). The amendment reduced the interest rate and fees payable on TEP's borrowings and letters of credit, increased the amount of its revolving credit facility from $60 million to $150 million, and extended the maturity to August 2011. In addition to the revolving credit facility, the TEP Credit Agreement includes a $341 million LOC facility which supports the $329 million of tax-exempt Variable Rate IDBs. The TEP Credit Agreement is secured by 1992 Mortgage Bonds. The ACC approved the increase in the amount and term of the revolving credit facility in December 2006.

Interest rates and fees under the TEP Credit Agreement are based on a pricing grid tied to TEP's credit ratings. Letter of credit fees are 0.55% per annum and amounts drawn under a letter of credit would bear interest at LIBOR plus 0.55% per annum. TEP has the option of paying interest on borrowings under the revolving credit facility at LIBOR plus 0.55% or the greater of the federal funds rate plus 0.5% or the agent bank's reference rate.

The TEP Credit Agreement restricts additional indebtedness, liens, sale of assets and sale-leasebacks agreements. The TEP Credit Agreement also requires TEP to meet a minimum cash coverage ratio and a maximum leverage ratio. If TEP complies with the terms of the TEP Credit Agreement, TEP may pay dividends to UniSource Energy. As of December 31, 2006, TEP was in compliance with the terms of the TEP Credit Agreement.

As of December 31, 2006, TEP had $30 million outstanding under its Revolving Credit Facility included in Current Liabilities in the UniSource Energy and TEP Consolidated Balance Sheets.

UNS GAS/UNS ELECTRIC REVOLVER

In August 2006, UNS Gas and UNS Electric amended their unsecured revolving credit agreement (the UNS Gas/UNS Electric Revolver). The amendment reduced the interest rate payable on borrowings and, upon ACC approval, will increase the amount of the revolving credit facility to $60 million from $40 million, and extend the maturity from April 2008 to August 2011. Either UNS Gas or UNS Electric may borrow up to a maximum of $30 million, but the combined amount borrowed cannot exceed $40 million. Upon ACC approval of the increase in the revolving credit facility, either borrower may borrow up to a maximum of $45 million, so long as the combined amount borrowed does not exceed $60 million. This matter is pending before the ACC.

UNS Gas is only liable for UNS Gas' borrowings, and similarly, UNS Electric is only liable for UNS Electric's borrowings under the UNS Gas/UNS Electric Revolver. UES guarantees the obligations of both UNS Gas and UNS Electric.

UNS Gas and UNS Electric each have the option of paying interest at LIBOR plus 1.0% or the greater of the federal funds rate plus 0.5% or the agent bank's reference rate.

The UNS Gas/UNS Electric Revolver contains restrictions on additional indebtedness, liens, mergers and sales of assets. The UNS Gas/UNS Electric Revolver also contains a maximum leverage ratio and a minimum cash flow to interest coverage ratio for each borrower. As of December 31, 2006, UNS Gas and UNS Electric were each in compliance with the terms of the UNS Gas/UNS Electric Revolver.

As of December 31, 2006, UNS Gas had no borrowings outstanding and UNS Electric had $19 million of borrowings outstanding under the UNS Gas/UNS Electric Revolver included in Long-Term Debt in the UniSource Energy Consolidated Balance Sheets.

NOTE 9. FAIR VALUE OF FINANCIAL INSTRUMENTS

The carrying values and fair values of our financial instruments are as follows:

	December 31, 2006		2005	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	-Millions of Dollars-			
Assets:				
TEP Springerville Lease Debt Securities	**$ 133**	**$ 139**	$ 156	$ 165
TEP Springerville Lease Equity	**48**	**48**	-	-
Liabilities:				
UniSource Energy Convertible Senior Notes	**150**	**164**	150	152
UniSource Energy Credit Agreement - Term Loan	**27**	**27**	86	86
TEP Secured Variable Rate IDBs	**329**	**329**	329	329
TEP Collateral Trust Bonds	**138**	**142**	138	146
TEP Unsecured IDBs - Fixed Rate	**354**	**359**	354	361
UNS Gas Senior Unsecured Notes	**100**	**102**	100	105
UNS Electric Senior Unsecured Notes	**60**	**60**	60	62
UNS Electric Credit Agreement - Revolving Credit Facility	**19**	**19**	-	-

See Note 8 for a description of TEP's investment in Springerville Lease Debt and Equity. TEP intends to hold the $133 million investment in Springerville Lease Debt Securities to maturity (Springerville Coal Handling Facilities lease debt totaling $52 million matures through July 1, 2011, and Springerville Unit 1 lease debt totaling $82 million matures through January 1, 2013). This investment is stated at amortized cost, which means the purchase cost has been adjusted for the amortization of the premium and discount to maturity.

- TEP considers the purchase price of the Springerville Lease Equity to be a reasonable estimate of its fair value.
- UniSource Energy and TEP used quoted market prices to determine the fair value of the UNS Convertible Senior Notes and TEP's tax-exempt fixed rate obligations (Unsecured IDBs).
- TEP considers the principal amounts of variable rate debt outstanding to be reasonable estimates of their fair value.

We determined the fair value of our remaining financial instruments (TEP Springerville Lease Debt Securities, TEP Collateral Trust Bonds, and UNS Gas and UNS Electric Senior Unsecured Notes) by calculating the present value of the cash flows using a discount rate consistent with market yields generally available as of December 31, 2006 and December 31, 2005 for bonds with similar characteristics with respect to credit rating and time-to-maturity. The use of different market assumptions and/or estimation methodologies may yield different estimated fair value amounts.

The carrying amounts of our current assets and liabilities approximate fair value.

NOTE 10. STOCKHOLDERS' EQUITY

DIVIDEND LIMITATIONS

UniSource Energy

In February 2007, UniSource Energy declared a first quarter dividend to shareholders of $0.225 per share of UniSource Energy Common Stock. The dividend, totaling approximately $8 million, will be paid on March 14, 2007 to common shareholders of record as of February 20, 2007. In 2006, UniSource Energy paid quarterly dividends to the shareholders of $0.21 per share, for a total of $0.84 per share, or $29 million for the year. In 2005, UniSource Energy paid quarterly dividends to the shareholders of $0.19 per share, for a total of $0.76 per share, or $26 million, for the year. During 2004, UniSource Energy paid quarterly dividends to the shareholders of $0.16 per share, for a total of $0.64 per share, or $22 million, for the year.

Our ability to pay cash dividends on Common Stock outstanding depends, in part, upon cash flows from our subsidiaries: TEP, UES, Millennium and UED, as well as compliance with various debt covenant requirements. As of December, 31, 2006, we complied with the terms of all such debt covenant requirements.

TEP

TEP paid dividends of $62 million in 2006, $46 million in 2005, and $32 million in 2004. UniSource Energy is the holder of TEP's common stock. TEP met the requirements discussed below before paying these dividends.

As a result of the capital contribution, the intercompany note repayment, and the bond purchases and redemptions, TEP's ratio of equity to total capitalization (excluding capital leases) reached 40%. As of December 31, 2006 and December 31, 2005, TEP met this ACC requirement that allowed TEP to dividend up to 100% of its current year Net Income to UniSource Energy.

In May 2005, UniSource Energy contributed $110 million of capital to TEP.

Bank Credit Agreement

TEP's new Credit Agreement as of August 2006 allows TEP to pay dividends as long as TEP complies with the agreement and certain financial covenants.

Federal Power Act

This Act states that dividends shall not be paid out of funds properly included in capital accounts. TEP's 2006, 2005 and 2004 dividends were paid from current year earnings.

UNS Gas and UNS Electric

Restrictions placed on UNS Gas and UNS Electric limit UES' ability to pay dividends. The 2003 UES Settlement Agreement allows UNS Gas and UNS Electric to pay dividends greater than 75% of its earnings to UniSource Energy when the ratio of common equity to total capitalization reaches 40%. As of December 31, 2006 and December 31, 2005, both UNS Gas and UNS Electric met this ratio requirement. Additionally, the terms of the senior unsecured note agreements entered into by both UNS Gas and UNS Electric contain dividend restrictions. See Note 8. UES did not pay any dividends to UniSource Energy in 2006 or 2005.

UniSource Energy made the following capital contributions to UNS Gas and UNS Electric:

	2006	2005
	-Millions of Dollars-	
UNS Gas	$ -	$ 16
UNS Electric	10	4

Millennium and UED

Neither Millennium nor UED paid dividends to UniSource Energy in 2006, 2005 or 2004. Millennium and UED have no dividend restrictions. In February 2007, Millennium paid a $5 million dividend to UniSource Energy.

UNISOURCE ENERGY SHAREHOLDER RIGHTS PLAN

In March 1999, UniSource Energy adopted a Shareholder Rights Plan. As of April 1, 1999, each Common Stock shareholder receives one Right for each share held. Each Right initially allows shareholders to purchase UniSource Energy's Series X Preferred Stock at a specified purchase price. However, the Rights are exercisable only if a person or group (the "acquirer") acquires or commences a tender offer to acquire 15% or more of UniSource Energy Common Stock. Each Right would entitle the holder (except the acquirer) to purchase a number of shares of UniSource Energy Common or Preferred Stock (or, in the case of a merger of UniSource Energy into another person or group, common stock of the acquiring person) having a fair market value equal to twice the specified purchase price. At any time until any person or group has acquired 15% or more of the Common Stock, UniSource Energy may redeem the Rights at a redemption price of $0.001 per Right. The Rights trade automatically with the Common Stock when it is bought and sold. The Rights expire on March 31, 2009.

NOTE 11. INCOME AND OTHER TAXES

INCOME TAXES

We record deferred income tax liabilities for amounts that will increase income taxes on future tax returns. We record deferred income tax assets for amounts that could be used to reduce income taxes on future tax returns. We record a deferred tax assets valuation allowance for the amount of deferred income tax assets that we may not be able to use on future tax returns. We estimate the valuation allowance based on our interpretation of the tax rules, prior tax audits, tax planning strategies, scheduled reversal of deferred income tax liabilities, and projected future taxable income.

Deferred tax assets (liabilities) consist of the following:

	UniSource Energy		TEP	
	December 31,		December 31,	
	2006	2005	2006	2005
	-Millions of Dollars-			
Gross Deferred Income Tax Liabilities				
Plant – Net	$ (327)	$ (440)	$ (312)	$ (429)
Income Taxes Recoverable Through Future Revenues Regulatory Asset	(15)	(16)	(15)	(16)
Transition Recovery Asset	(40)	(66)	(40)	(66)
Derivative Financial Instruments	(1)	(5)	-	(5)
Pensions	(3)	(1)	(3)	(1)
Unbilled Revenue	(3)	(6)	(3)	(6)
Other	(7)	(26)	(6)	(14)
Gross Deferred Income Tax Liability	(396)	(560)	(379)	(537)
Gross Deferred Income Tax Assets				
Capital Lease Obligations	181	297	181	297
Net Operating Loss Carryforwards (NOL)	-	7	-	-
Capital Loss Carryforwards	15	-	-	-
Alternative Minimum Tax Credit (AMT)	48	77	34	62
Accrued Postretirement Benefits	26	21	26	21
Emission Allowance Inventory	13	13	13	13
Coal Contract Termination Fees	10	12	10	12
Unregulated Investment Losses	7	11	-	-
Vacation & Sick Accrual	3	3	3	3
Customer Advances	11	8	2	3
Other	13	20	12	17
Gross Deferred Income Tax Asset	327	469	281	428
Deferred Tax Assets Valuation Allowance	-	(7)	-	-
Net Deferred Income Tax Liability	$ (69)	$ (98)	$ (98)	$ (109)

The balance sheets display the net deferred income tax liability as follows:

	UniSource Energy		TEP	
	December 31,		December 31,	
	2006	2005	2006	2005
	-Millions of Dollars-			
Deferred Income Taxes – Current Assets	**$ 58**	$ 49	**$ 57**	$ 51
Deferred Income Taxes – Noncurrent Liabilities	**(127)**	(147)	**(155)**	(160)
Net Deferred Income Tax Liability	**$ (69)**	$ (98)	**$ (98)**	$ (109)

There is no valuation allowance at December 31, 2006. The valuation allowance of $7 million at December 31, 2005, which reduces the Deferred Tax Asset balance, relates to Global Solar's Net Operating Loss (NOL). Global Solar was sold at a capital loss in March 2006 and is no longer included in the consolidated income tax return.

As of December 31, 2006, UniSource Energy's deferred income tax assets include $15 million related to capital loss carryforwards. UniSource Energy expects to fully utilize the capital loss carryforwards prior to the expiration dates of the carryforwards; therefore no valuation allowance is required.

As of December 31, 2006, UniSource Energy's deferred income tax assets include $7 million related to unregulated investment losses of Millennium. These losses have not been reflected on our consolidated income tax returns. If UniSource Energy were unable to recognize such losses through its consolidated income tax return in the foreseeable future, it would have to write-off these deferred tax assets. Millennium restructured its ownership in one of these investments in 2005. As a result of this restructuring, Millennium liquidated this investment for tax purposes resulting in a taxable loss that was reflected on our consolidated income tax return for 2005. Millennium is in the process of restructuring its ownership in its remaining investments and expects to dispose of its interests in the foreseeable future.

TEP's net intercompany tax receivable from affiliates equaled $10 million at December 31, 2006 and its net intercompany tax payable to affiliates equaled $4 million at December 31, 2005. TEP includes these amounts under intercompany accounts on its balance sheet.

The tax effect of the exercise of certain employee stock options that are recognized differently for financial reporting and tax purposes was not recorded as a timing difference, but rather was credited to shareholder's equity. This resulted in a $2 million increase for 2006 and an $2 million increase for 2005 to the capital of UniSource Energy.

Income tax expense (benefit) included in the income statements consists of the following:

	UniSource Energy			TEP		
	Years Ended December 31,					
	2006	**2005**	**2004**	**2006**	**2005**	**2004**
	-Millions of Dollars-					
Current Tax Expense						
Federal	**$ 37**	$ 19	$ 24	**$ 32**	$ 16	$ 28
State	**12**	10	8	**10**	11	8
Total	**49**	29	32	**42**	27	36
Deferred Tax Expense (Benefit)						
Federal	**-**	13	6	**5**	13	-
State	**(5)**	(3)	(2)	**(5)**	(5)	(2)
Total	**(5)**	10	4	**-**	8	(2)
Increase (Reduction) in Valuation Allowance	**-**	(1)	1	**-**	(1)	1
Total Federal and State Income Tax Expense Before Discontinued Operation and Cumulative Effect of Accounting Change	**44**	38	37	**42**	34	35
Tax on Discontinued Operation	**(2)**	(5)	(3)	**-**	-	-
Total Federal and State Income Tax Expense Including Discontinued Operation and Cumulative Effect of Accounting Change	**$ 42**	$ 33	$ 34	**$ 42**	$ 34	$ 35

The differences between the income tax expense and the amount obtained by multiplying pre-tax income by the U.S. statutory federal income tax rate of 35% are as follows:

	UniSource Energy			TEP		
	Years Ended December 31,					
	2006	2005	2004	2006	2005	2004
	-Millions of Dollars-					
Federal Income Tax Expense at Statutory Rate	**$ 40**	$ 32	$ 31	**$ 38**	$ 29	$ 28
State Income Tax Expense, Net of Federal Deduction	**5**	5	4	**5**	4	4
Depreciation Differences (Flow Through Basis)	**2**	3	3	**2**	3	3
Federal/State Credits	**(2)**	(1)	(1)	**(2)**	(1)	(1)
Increase (Reduction) in Valuation Allowance	**-**	(1)	1	**-**	(1)	1
Other	**(1)**	-	(1)	**(1)**	-	-
Total Federal and State Income Tax Expense Before Discontinued Operation and Cumulative Effect of Accounting Change	**$ 44**	$ 38	$ 37	**$ 42**	$ 34	$ 35

The Total Federal and State Income Tax Expense in the tables above is included on UniSource Energy and TEP's income statements.

At December 31, 2006, UniSource Energy and TEP had, for federal and state income tax filing purposes, the following carryforward amounts:

	UniSource Energy		TEP	
	Amount -Millions of Dollars-	Expiring Year	Amount -Millions of Dollars-	Expiring Year
Capital Loss	**$ 37**	**2010-2011**	**$ -**	**-**
AMT Credit	**48**	**-**	**34**	**-**

OTHER TAX MATTERS

Income Tax Assessments

On its 2002 tax return, TEP filed for an automatic change in accounting method relating to the capitalization of indirect costs to the production of electricity and self-constructed assets. We also used the new accounting method on the 2003 and 2004 returns for TEP, UNS Gas and UNS Electric.

In 2005, the Internal Revenue Service issued a ruling which draws into question the ability of electric and gas utilities to use the new accounting method. As a result, TEP, UNS Gas and UNS Electric amended their 2002, 2003 and 2004 tax returns to remove the benefit previously claimed using the accounting method. In September 2006, TEP and UNS Electric remitted tax and interest of $23 million and $1 million, respectively to the IRS. In October 2006, TEP, UNS Gas and UNS Electric remitted $8 million, $0.1 million and $0.3 million, respectively to state tax authorities. Payment of interest that had previously not been accrued resulted in $3 million of expense. In December 2006, the IRS issued final notice disallowing the use of the accounting method. We are filing a protest and will proceed to appeals.

In 2004, the Company settled the audit of state income tax returns for the period 1990 - 2000 with the Arizona Department of Revenue. As a result, UniSource Energy and TEP recorded $1 million of income in 2004.

Sales Tax Assessments

In 2004, the City of Tucson issued its assessment for the 1998 – 2001 sales tax audit. After reviewing the audit findings, as well as assessing their impact on years following the audit period, TEP recorded a combined $1 million of sales tax and interest expense in 2005. The audit was settled during the first quarter of 2005.

OTHER TAXES

TEP and UES act as conduits or collection agents for excise tax (sales tax) as well as franchise fees and regulatory assessments. They record liabilities payable to governmental agencies when they bill their customers for these amounts. Neither the amounts billed nor payable are reflected in the income statement.

NOTE 12. EMPLOYEE BENEFIT PLANS

PENSION BENEFIT PLANS

TEP, UNS Gas and UNS Electric maintain noncontributory, defined benefit pension plans for substantially all regular employees and certain affiliate employees. Employees receive benefits based on their years of service and average compensation. TEP, UNS Gas and UNS Electric fund the plans by contributing at least the minimum amount required under Internal Revenue Service regulations. Additionally, we provide supplemental retirement benefits to certain employees whose benefits are limited by IRS benefit or compensation limitations.

In 2007, TEP expects to contribute $10 million and UNS Gas and UNS Electric expect to contribute $1 million to the pension plans.

OTHER POSTRETIREMENT BENEFIT PLANS

TEP provides limited health care and life insurance benefits for retirees. All regular employees may become eligible for these benefits if they reach retirement age while working for TEP or an affiliate. UNS Gas and UNS Electric provide postretirement medical benefits for current retirees and a small group of active employees.

INCREMENTAL EFFECT OF APPLYING FAS 158

As a result of adopting FAS 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*, in December 2006, we recognized the underfunded status of our defined benefit pension and other postretirement plans as a liability. The underfunded status was measured as the difference between the fair value of the plans assets and the projected benefit obligation for pension plans or accumulated postretirement benefit obligation for other postretirement benefit plans. The adjustment required to recognize the pension liability on adoption of this statement resulted in recognition of a regulatory asset for our regulated operations and an adjustment to Accumulated Other Comprehensive Loss for our unregulated operations. We recorded the required increase in our other postretirement obligation as an adjustment to Accumulated Other Comprehensive Loss as the ACC allows TEP, UNS Gas and UNS Electric to recover other postretirement costs through rates only as benefit payments are made.

The following table presents the incremental effect of applying FAS 158, in combination with FAS 71, as well as the change to the additional minimum pension liability, on individual line items in TEP's balance sheet at December 31, 2006:

TEP Balance Sheet Line Items:	Before Application of FAS 158: Preliminary Balances at December 31, 2006	Before Application of FAS 158: Application of Pre-FAS158 Accounting Guidance	FAS 158 Adjustment	Balances at December 31, 2006 After Application of FAS 158
	- Millions of Dollars -			
Other Assets	$ 29	$ 9	$ (16)	$ 22
Other Regulatory Assets	20	4	28	52
Total Assets	2,598	13	12	2,623
Deferred Income Taxes - Noncurrent	156	9	(10)	155
Other Liabilities	100	(9)	36	127
Total Deferred Credits and Other Liabilities	336	-	26	362
Accumulated Other Comprehensive Loss (Net of Tax)	16	14	(15)	15
Total Stockholders' Equity	556	14	(15)	555

Prior to the application of FAS 158, the accounting guidance (Pre-FAS 158) required TEP to adjust its minimum pension liability in Accumulated Other Comprehensive Loss to reflect the underfunded status of its plans based on the accumulated benefit obligation. After the adoption of FAS 158 and before applying the provisions of FAS 71, TEP had an accumulated comprehensive loss balance (net of tax) of $35 million attributable to its pension and other postretirement benefit obligations. TEP subsequently recorded a regulatory asset of $32 million and an offsetting reduction on an after-tax basis of accumulated other comprehensive loss of $19 million, representing a reasonable approximation of the actuarial losses and prior service costs of TEP's pension plans that are probable of recovery in rates by its regulated operations in future periods.

UNS Gas and UNS Electric were not required to record a minimum pension liability under pre-FAS 158 accounting guidance. Following the adoption of FAS 158, UNS Gas and UNS Electric recorded a combined regulatory pension asset and increase in pension liability of $3 million. The impact of FAS 158 on the postretirement plans of UNS Gas and UNS Electric was less than $1 million.

The pension and other postretirement benefit related amounts (excluding tax balances) included in the UniSource Energy balance sheet are:

	Pension Benefits		Other Postretirement Benefits	
	Years Ended December 31,			
	2006	2005	2006	2005
	-Millions of Dollars-			
Regulatory Pension Asset included in Other Regulatory Assets	$ 35	-	-	-
Prepaid Pension Costs included in Other Assets	-	18	-	-
Intangible Assets included in Other Assets	-	6	-	-
Accrued Benefit Liability included in Accrued Employee Expenses	-	-	(3)	(3)
Accrued Benefit Liability included in Other Liabilities	(42)	(37)	(63)	(51)
Accumulated Other Comprehensive Loss	17	24	8	-
Net Amount Recognized	$ 10	$ 11	$ (58)	$ (54)

The table above includes a combined accrued pension benefit liability of less than $4 million and a postretirement benefit liability of less than $2 million for UNS Gas and UNS Electric, for each period presented, in addition to the minimal FAS 158 impact previously noted.

OBLIGATIONS AND FUNDED STATUS

We measured the actuarial present values of all pension benefit obligations and other postretirement benefit plans at December 1. FAS 158 requires the measurement date to be changed to the end of the year effective December 31, 2008. The tables below include TEP, UNS Gas and UNS Electric plans. The change in projected benefit obligation and plan assets and reconciliation of the funded status are as follows:

	Pension Benefits		Other Postretirement Benefits	
	Years Ended December 31,			
	2006	**2005**	**2006**	**2005**
	-Millions of Dollars-			
Change in Projected Benefit Obligation				
Benefit Obligation at Beginning of Year	**$ 208**	$ 188	**$ 70**	$ 70
Actuarial (Gain) Loss	**-**	9	**(7)**	(4)
Interest Cost	**12**	11	**4**	4
Service Cost	**7**	6	**2**	2
Benefits Paid	**(9)**	(6)	**(3)**	(2)
Projected Benefit Obligation at End of Year	**218**	208	**66**	70
Change in Plan Assets				
Fair Value of Plan Assets at Beginning of Year	**149**	136	**-**	-
Actual Return on Plan Assets	**21**	12	**-**	-
Benefits Paid	**(9)**	(6)	**(3)**	(2)
Employer Contributions	**15**	7	**3**	2
Fair Value of Plan Assets at End of Year	**176**	149	**-**	-
Funded Status at End of Year	**$ (42)**	$ (59)	**$ (66)**	$ (70)

The tables above include a combined pension benefit obligation of less than $8 million and plan assets of less than $4 million for UNS Gas and UNS Electric for all periods presented.

The following table provides the components of UniSource Energy's accumulated other comprehensive loss and regulatory assets that have not been recognized as components of periodic benefit cost as of December 31, 2006:

	Pension Benefits	Other Postretirement Benefits
	-Millions of Dollars-	
Net Loss	**$ 43**	**$ 15**
Prior Service Cost (Benefit)	**9**	**(7)**

The accumulated benefit obligation for all defined benefit pension plans was $184 million at December 31, 2006 and $173 million at December 31, 2005. Changes in actuarial assumptions including an increase in the discount rate impacted the accumulated benefit obligation.

	December 31, 2006	December 31, 2005
	-Millions of Dollars-	
Information for Pension Plans with an Accumulated Benefit Obligation in Excess of Plan Assets:		
Projected Benefit Obligation at End of Year	$ 116	$ 208
Accumulated Benefit Obligation at End of Year	100	173
Fair Value of Plan Assets at End of Year	89	149

The components of net periodic benefit costs and other amounts recognized in other comprehensive income are as follows:

	Pension Benefits			Other Postretirement Benefits		
	Years Ended December 31,					
	2006	2005	2004	2006	2005	2004
	-Millions of Dollars-					
Components of Net Periodic Cost						
Service Cost	**$ 7**	$ 7	$ 6	**$ 2**	$ 2	$ 2
Interest Cost	**12**	11	10	**4**	4	3
Expected Return on Plan Assets	**(13)**	(11)	(10)	**-**	-	-
Prior Service Cost Amortization	**2**	2	2	**(1)**	(1)	(1)
Recognized Actuarial Loss	**3**	3	2	**1**	2	2
Net Periodic Benefits Cost	**$ 11**	$ 12	$ 10	**$ 6**	$ 7	$ 6

For all pension plans, we amortize prior service costs on a straight-line basis over the average remaining service period of employees expected to receive benefits under the plan. We will amortize $2 million estimated net loss and $2 million prior service cost from accumulated other comprehensive income and other regulatory assets into net periodic benefit cost in 2007. The estimated net loss and prior service benefit for the defined benefit postretirement plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost in 2007 are $1 million and $2 million, respectively.

	Pension Benefits		Other Postretirement Benefits	
	2006	2005	2006	2005
Weighted-Average Assumptions Used to Determine Benefit Obligations as of December 1,				
Discount Rate	5.9%	5.8%	5.6%	5.8%
Rate of Compensation Increase	3.0 – 5.0%	3.0 – 5.0%	N/A	N/A

	Pension Benefits		Other Postretirement Benefits	
	2006	2005	2006	2005
Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31,				
Discount Rate	5.8– 5.9%	6.0 – 6.1%	5.8%	5.9%
Rate of Compensation Increase	3.0 – 5.0%	3.0 – 5.0%	N/A	N/A
Expected Return on Plan Assets	8.3%	8.5%	N/A	N/A

Net periodic benefit cost is subject to various assumptions and determinations, such as the discount rate, the rate of compensation increase, and the expected return on plan assets. We estimated the expected return on plan assets based on a review of the plans' asset allocations. We also consulted with a third-party investment consultant and the plans' actuary who consider factors such as:

- market and economic indicators
- historical market returns

- correlations and volatility
- central banks' and government treasury departments' forecasts and objectives, and
- recent professional or academic research.

Changes that may arise over time with regard to these assumptions and determinations will change amounts recorded in the future as net periodic benefit cost.

	December 31,	
	2006	2005
Assumed Health Care Cost Trend Rates		
Health Care Cost Trend Rate Assumed for Next Year	9%	10%
Ultimate Health Care Cost Trend Rate Assumed	5%	5%
Year that the Rate Reaches the Ultimate Trend Rate	2013	2013

Assumed health care cost trend rates significantly affect the amounts reported for health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects on the December 31, 2006 amounts:

	One-Percentage-Point Increase	One-Percentage-Point Decrease
	-Millions of Dollars-	
Effect on Total of Service and Interest Cost Components	$ 1	$ -
Effect on Postretirement Benefit Obligation	5	(4)

PENSION PLAN ASSETS

TEP, UNS Gas and UNS Electric calculate the fair value of plan assets on December 1, the measurement date. TEP's pension plan asset allocations at December 31, 2006 and 2005 by asset category follow:

	Plan Assets December 31,	
	2006	2005
Asset Category		
Equity Securities	67%	68%
Debt Securities	23%	21%
Real Estate	10%	10%
Other	0%	1%
Total	100%	100%

TEP's investment policy for the pension plans targets exposure to the various asset classes in the following allocations: equity securities 65%, debt securities 23% and real estate 12%. TEP rebalances the portfolio when the portfolio allocation is not within the desired range of exposure. The plan seeks to provide returns in excess of a portfolio benchmark. A third party investment consultant tracks the plan's portfolio relative to the benchmark and provides quarterly investment reviews which consist of a performance and risk assessment on all investment managers and on the portfolio.

Investment managers for the plan may use derivative financial instruments for risk management purposes or as a part of their investment strategy. Currency hedges have also been used for defensive purposes. Real estate managers use leverage but it is limited by investment policy.

The UNS Gas and UNS Electric pension plan provides exposure to equity and debt securities by investing in a balanced fund. At December 31, 2006, the fund held 64% equity securities, 31% fixed income securities, and 5% cash. The fund will hold no more than 75% of its total assets in equity securities.

ESTIMATED FUTURE BENEFIT PAYMENTS

TEP expects to pay the following benefit payments, which reflect future service, as appropriate.

	Pension Benefits	Other Postretirement Benefits
	-Millions of Dollars-	
2007	$ 6	$ 3
2008	6	4
2009	8	4
2010	9	5
2011	10	5
Years 2012-2016	68	31

UNS Gas and UNS Electric expect to pay pension and postretirement benefits of approximately $1 million in 2007 through 2011 and $3 million in 2012 through 2016.

DEFINED CONTRIBUTION PLANS

TEP, UNS Gas and UNS Electric offer defined contribution savings plans to all eligible employees and certain affiliate employees. The Internal Revenue Code identifies the plans as qualified 401(k) plans. Participants direct the investment of contributions to certain funds in their account. TEP, UNS Gas, and UNS Electric match part of a participant's contributions to the plans. TEP made matching contributions to these plans of approximately $4 million in 2006 and $3 million in 2005 and 2004. UNS Gas and UNS Electric made matching contributions of less than $0.5 million in each of 2006, 2005, and 2004.

NOTE 13. SHARE-BASED COMPENSATION PLANS

On May 5, 2006, UniSource Energy shareholders approved the 2006 Omnibus Stock and Incentive Plan (Plan), a new share-based compensation plan. This Plan supersedes and replaces prior equity compensation plans or programs maintained by UniSource Energy. The total number of shares which may be awarded under the Plan cannot exceed 2.25 million shares. Any prior stock option plans of UniSource Energy remain nominally in effect until all stock options granted under such prior plans have been exercised, forfeited, canceled, expired or otherwise terminated in accordance with the terms of such grants.

Awards granted under these compensation plans and the compensation expense recognized are described below.

STOCK OPTIONS

Stock options are granted on a scheduled basis with an exercise price equal to the fair market value of the stock on the date of grant, vest over three years, become exercisable in one-third increments on each anniversary date of the grant and expire on the tenth anniversary of the grant. Compensation expense equal to the fair value of the option at the grant date is recorded on a straight-line basis over the vesting period. For awards granted to retirement eligible officers, compensation expense is recorded immediately. We discuss the compensation expense recorded for each share-based award below.

The fair value of each option award is estimated on the date of grant using the Black-Scholes-Merton option pricing model with the assumptions noted in the following table. The expected term of options granted is derived using the "simplified" method in accordance with Staff Accounting Bulletin 107, *Topic 14: Share-Based Payment* where the expected term equals the time from grant to reaching the midpoint between vesting and the contractual term considering the vesting tranches. The risk-free rate is based on the rate available on a U.S. Treasury Strip with a maturity equal to the expected term of the option at the time of the grant. Expected volatility is based on historical volatility for UniSource Energy's stock. The expected dividend yield on a share of stock is calculated using the historical dividend yield with the implicit assumption that current dividend yields will continue in the future.

	2006	2005
Expected term (years)	6	6
Risk-free rate	4.97%	4.00%
Expected volatility	22.57%	22.94%
Expected dividend yield	2.45%	2.54%
Weighted-average grant-date fair value of options granted during the period	$7.38	$7.39

A summary of the stock option activity follows:

	2006		**2005**		**2004**	
	Shares	**Weighted Average Exercise Price**	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Options Outstanding, Beginning of Year	1,537,041	$ 16.75	2,076,055	$ 16.19	2,478,551	$ 16.04
Granted	187,640	$ 30.55	50,000	$ 33.55	-	-
Exercised	(304,301)	$ 15.97	(581,549)	$ 16.18	(400, 003)	$ 15.29
Forfeited	(32,052)	$ 25.14	(7,465)	$ 17.87	(2,493)	$ 13.66
Options Outstanding, End of Year	1,388,328	$ 18.59	1,537,041	$ 16.75	2,076,055	$ 16.19
Options Exercisable, End of Year	1,187,955	$ 16.49	1,479,569	$ 16.18	2,053,784	$ 16.17

Weighted Average Remaining Contractual Life at December 31, 2006: 4.8 years

Weighted Average Remaining Contractual Life of Fully Vested Shares at December 31, 2006: 4.0 years

Exercise prices for stock options outstanding and exercisable as of December 31, 2006 ranged from $11.00 to $33.55, summarized as follows:

	Options Outstanding			**Options Exercisable**	
Range of Exercise Prices	**Number of Shares**	**Weighted-Average Remaining Contractual Life**	**Weighted-Average Exercise Price**	**Number of Shares**	**Weighted-Average Exercise Price**
$11.00 - $15.56	555,348	2.8 years	$14.29	555,348	$14.29
$16.78 - $18.84	615,940	4.9 years	$18.01	615,940	$18.01
$30.55 - $33.55	217,040	9.2 years	$31.24	16,667	$33.55

We recognized compensation expense of $1 million in 2006 and less than $0.1 million for the options issued in 2005. As discussed in Note 1, before January 1, 2005, we applied APB 25 to account for our stock option plans. We did not recognize any compensation expense for these options because our stock options were granted with an exercise price equal to the market value of the stock at the grant date. We previously adopted the disclosure-only provisions of FAS 123. We present, in Note 1, the effect on net income and earnings per share as if the company had applied the fair value recognition provisions of FAS 123.

Stock options awarded on January 1, 2002 accrue dividend equivalents that we pay in cash on the earlier of the date of exercise of the underlying option or the date the option expires. We recognize compensation expense as dividends are declared. In 2006, 2005 and 2004, we recognized compensation expense of less than $1 million for dividend equivalents on stock option grants. We did not capitalize any compensation costs associated with these awards during the years ended December 31, 2006, 2005, and 2004.

We summarize the status of nonvested stock options as of December 31, 2006, and changes during 2006 below:

Nonvested Shares	Shares	Weighted-Average Grant-Date Fair Value
Nonvested at January 1, 2006	57,473	$6.84
Granted	187,640	$7.38
Vested	(24,140)	$6.08
Forfeited	(20,600)	$7.38
Nonvested at December 31, 2006	200,373	$7.38

As of December 31, 2006, total unrecognized compensation cost related to nonvested stock options granted under the Plan was $1 million. We expect that cost to be recognized over the remaining vesting period that is through April 2009. The total fair value of shares vested was $0.1 million during the year ended December 31, 2006, less than $0.1 million during the year ended December 31, 2005 and approximately $2 million during the year ended December 31, 2004.

The actual tax benefit realized from the exercise of share-based payment arrangements totaled $2 million in 2006, $3 million in 2005 and $1 million in 2004.

RESTRICTED STOCK AND STOCK UNITS

Restricted stock and stock units are generally granted under the Plan to non-employee directors. Restricted stock is an award of Common Stock that is subject to forfeiture if the restrictions specified in the award are not satisfied. Stock units are a non-voting unit of measure that is equivalent to one share of Common Stock. The directors may elect to receive stock units in lieu of restricted stock. Restricted stock generally vests over periods ranging from one to three years and are payable in Common Stock. Stock units vest either immediately or over periods ranging from one to three years. Compensation expense equal to the fair market value on the grant date is recognized over the vesting period. Fully vested but undistributed stock unit awards accrue dividend equivalent stock units based on the fair market value of common shares on the date the dividend is paid. Compensation expense is recognized when dividends are paid.

We did not grant any restricted stock awards to directors in 2006. In 2005, we granted 3,264 restricted stock awards to directors at a fair value of $24.51 per share on the grant date. In 2004, we granted 3,240 restricted stock awards to directors at a fair value of $24.68 per share on the grant date.

In 2006, we granted 17,151 stock unit awards to directors at a fair value of $30.76 per share on the grant date. In 2005, we granted 13,213 stock unit awards at a fair value of $29.72 per share on the grant date. In 2004, we granted 3,240 stock unit awards at a fair value of $24.68 per share on the grant date.

A summary of the status of nonvested restricted stock awards and stock unit awards as of December 31, 2006, and changes during 2006 is presented below:

Nonvested Restricted Stock/Stock Units	Shares	Weighted-Average Grant-Date Fair Value
Nonvested at January 1, 2006	21,122	$26.98
Granted	17,151	$30.76
Vested	(17,356)	$28.66
Forfeited	-	-
Nonvested at December 31, 2006	20,917	$28.68

We recorded compensation expense for the awards described above of $1 million in 2006 and less than $1 million in 2005 and 2004. As of December 31, 2006, total unrecognized compensation cost related to nonvested restricted stock awards and stock unit awards granted was $1 million. We expect that cost to be recognized over the remaining vesting period that is through December 2007. The total fair value of restricted stock awards and stock unit awards vested during the year ended December 31, 2006 was $0.5 million and during the years ended December 31, 2005 and 2004 was approximately $0.1 million.

PERFORMANCE SHARES

On May 5, 2006, the Compensation Committee of the UniSource Energy Board of Directors granted 45,520 performance share awards (targeted shares) to Officers at a grant date fair value of $28.39 per share (market price of $30.55 less the present value of expected dividends of $2.16). The performance share awards are paid out in shares of UniSource Energy common stock based on UniSource Energy's performance over the period of January 1, 2006 through December 31, 2008. The performance criteria specified in the awards is determined based on targeted UniSource Energy cumulative Earnings per Share and cumulative Cash Flow from Operations during the performance period. The performance shares vest ratably over the performance period and any unearned awards are forfeited.

Nonvested Performance Shares	Shares	Weighted-Average Grant-Date Fair Value
Nonvested at January 1, 2006	-	-
Granted	45,520	$28.39
Vested	-	-
Forfeited	(5,000)	$28.39
Nonvested at December 31, 2006	40,520	$28.39

Compensation expense equal to the fair market value on the grant date less the present value of expected dividends is recognized over the vesting period if it is probable that the performance criteria will be met. We recorded compensation expense of $0.3 million during 2006 for performance share awards. As of December 31, 2006, total unrecognized compensation cost related to nonvested performance share awards was $1 million. We expect that cost to be recognized over the remaining vesting period that is through December 2008.

NOTE 14. UNISOURCE ENERGY EARNINGS PER SHARE (EPS)

We compute basic EPS by dividing Net Income by the weighted average number of common shares outstanding during the period. Except when the effect would be anti-dilutive, the diluted EPS calculation includes the impact of shares that could be issued upon exercise of outstanding stock options, contingently issuable shares under equity-based awards or common shares that would result from the conversion of convertible notes. The numerator in calculating diluted earnings per share is Net Income adjusted for the interest on convertible notes (net of tax) that would not be paid if the notes were converted to common shares.

The following table shows the effects of potential dilutive common stock on the weighted average number of shares:

	Years Ended December 31,		
	2006	**2005**	**2004**
	- In Thousands-		
Numerator			
Net Income	**$ 67,447**	$ 46,144	$ 45,919
Income from Assumed Conversion of Convertible Senior Notes	**4,390**	3,654	-
Adjusted Numerator	**$ 71,837**	$ 49,798	$ 45,919
Denominator:			
Weighted-average Shares of Common Stock Outstanding	**35,264**	34,798	34,380
Effect of Diluted Securities			
Convertible Senior Notes	**4,000**	3,345	-
Options and Stock Issuable under Employee Benefit Plans and the Directors' Plan	**601**	708	661
Total Shares	**39,865**	38,851	35,041

Stock options to purchase an average of 67,000 shares of Common Stock were outstanding during the year ended December 31, 2006 but were not included in the computation of EPS because the stock option's exercise price was greater than the average market price of the Common Stock. There were no outstanding options excluded from the computation of EPS during the years ended December 31, 2005 and 2004.

NOTE 15. RELATED PARTIES

UniSource Energy incurs corporate costs that are allocated to its subsidiaries, including TEP. Corporate costs are allocated based on a weighted-average residual allocation factor. Management believes this method of allocation is reasonable and approximates the cost that TEP and its other affiliates would have incurred as stand-alone entities. Charges allocated to TEP were $7 million in 2006, $5 million in 2005 and $12 million in 2004.

TEP provides all corporate services (finance, accounting, tax, information technology services, etc.) to UniSource Energy, UNS Gas and UNS Electric as well as to UniSource Energy's non-utility businesses. Costs are directly assigned to the benefiting entity where possible. Common costs are allocated on a cost-causative basis. Management believes this method of allocation is reasonable. The charges by TEP to the other companies were $9 million in 2006, $8 million in 2005 and $7 million in 2004.

Global Solar, previously Millennium's largest subsidiary, develops and manufactures light weight thin-film photovoltaic cells and panels. Global Solar is reflected in these financial statements as a discontinued operation. See Note 16. Global Solar did not record any revenue from transactions with TEP in 2006. Global Solar recorded revenue from transactions with TEP of less than $1 million in 2005 and $4 million in 2004.

Southwest Energy Solutions, Inc. (SES), a subsidiary of Millennium, provides a supplemental workforce for TEP and UNS Electric. Types of services provided for TEP include dusk to dawn lighting, facilities maintenance, meter reading, transmission and distribution, and general supplemental support. SES bills TEP for these services. Management believes that the charges for services are reasonable and approximate the cost that TEP would have incurred if it performed these services directly. SES charged TEP $14 million in 2006, $12 million in 2005 and $13 million in 2004 for these services. SES provides meter reading services for UNS Electric. SES charged UNS Electric less than $1 million for these services in 2006, 2005 and 2004.

Haddington Energy Partners II, LP (Haddington) funds energy-related investments. A member of the UniSource Energy Board of Directors has an investment in Haddington and is a managing director of the general partner of the limited partnership.

Valley Ventures III, LP (Valley Ventures) is a venture capital fund that invests in information technology, microelectronics and biotechnology, primarily within the southwestern U.S. Another member of the UniSource

Energy Board of Directors was a general partner of the company that manages the fund until January 1, 2006, at which time the Board member ended his role and interest as a general partner but maintained a non-voting financial interest in the company.

Carboelectrica Sabinas, S. de R.L. de C.V. (Sabinas) is a Mexican limited liability company created to develop up to 800 megawatts (MW) of coal-fired generation in the Sabinas region of Coahuila, Mexico. Millennium owns 50% of Sabinas. Altos Hornos de Mexico, S.A. de C.V. (AHMSA) and affiliates own the other 50%. UniSource Energy's Chairman, President and Chief Executive Officer is on the board of directors of AHMSA. As of December 31, 2006, Millennium's remaining investment in Sabinas is $14 million.

NOTE 16. DISCONTINUED OPERATION

In January 2006, UniSource Energy's Board of Directors approved a plan to dispose of its investment in Global Solar to a third party. Global Solar appears in these financial statements as a discontinued operation.

On March 31, 2006, UniSource Energy sold all of the capital stock of Global Solar to a third party. UniSource Energy received $16 million in cash as part of the transaction; a portion of the proceeds was used to satisfy $10 million of secured promissory notes held by a UniSource Energy subsidiary. In addition to the cash purchase price, UniSource Energy received a ten-year option to purchase between 5 and 10 percent of the common stock of Global Solar. The option is only exercisable after the seventh anniversary of the closing or upon the occurrence of certain events including a sale of all or substantially all of the assets of Global Solar, a merger, a change of control transaction, an initial public offering of Global Solar common stock or the payment by Global Solar of dividends in excess of specified amounts. For accounting purposes, no value was assigned to this repurchase option.

Listed below are the major classes of assets and liabilities related to the sale of Global Solar as of December 31:

	2005
	-Millions of Dollars-
Assets	
Property, Plant and Equipment, net	$ 10
Goodwill	3
Noncurrent Assets of Subsidiary Held for Sale	$ 13
Trade Accounts Receivable	$ 1
Inventory	4
Deferred Income Taxes - Current	12
Current Assets of Subsidiary Held for Sale	$ 17
Liabilities	
Accounts Payable	$ 2
Current Liabilities of Subsidiary Held for Sale	$ 2

The following summarizes the amounts included in Discontinued Operation – Net of Tax for all periods presented:

	Years Ended December 31,		
	2006	**2005**	**2004**
Revenues from Discontinued Operation	**$ 1**	$ 5	$ 4
Loss from Discontinued Operation Before Income Taxes	**(4)**	(10)	(8)
Income Tax Benefit	**(2)**	(5)	(3)
Discontinued Operation – Net of Tax	**$ (2)**	$ (5)	$ (5)

NOTE 17. SUPPLEMENTAL CASH FLOW INFORMATION

A reconciliation of net income to net cash flows from operating activities follows:

	UniSource Energy		
	Years Ended December 31,		
	2006	**2005**	**2004**
	-Thousands of Dollars-		
Net Income	**$ 67,447**	$ 46,144	$ 45,919
Adjustments to Reconcile Net Income To Net Cash Flows from Operating Activities			
Discontinued Operations – Net of Tax	**1,796**	5,483	5,063
Cumulative Effect of Accounting Change-Net of Tax	**-**	626	-
Depreciation and Amortization Expense	**130,502**	132,577	132,419
Depreciation Recorded to Fuel and Other O&M Expense	**7,604**	6,496	6,175
Amortization of Transition Recovery Asset	**65,985**	56,418	50,153
Net Unrealized Gain on TEP Forward Electric Sales	**(7,115)**	(604)	(1,509)
Net Unrealized Loss on TEP Forward Electric Purchases	**6,186**	1,863	250
Net Unrealized Loss (Gain) on MEG Trading Activities	**9,955**	(10,764)	(551)
Amortization of Deferred Debt-Related Costs included in Interest Expense	**4,622**	4,730	3,423
Loss on Reacquired Debt	**1,080**	5,261	1,990
Provision for Bad Debts	**3,439**	2,696	2,821
Deferred Income Taxes	**(5,530)**	7,851	5,303
Gain from Equity Method Investment Entities	**(386)**	(2,387)	(7,326)
Gain on Sale of Real Estate	**(470)**	-	(725)
Excess Tax Benefit from Stock Option Exercises	**(1,501)**	(2,527)	-
Other	**2,599**	(4,797)	3,616
Changes in Assets and Liabilities which Provided (Used) Cash Exclusive of Changes Shown Separately			
Accounts Receivable	**(33,335)**	985	(13,810)
Materials and Fuel Inventory	**(7,912)**	(8,433)	(2,103)
Accounts Payable	**5,729**	5,923	30,162
Income Taxes Payable	**(11,896)**	13,598	4,233
Interest Accrued	**7,814**	8,282	9,890
Taxes Accrued	**453**	541	11,451
Other Current Assets	**28,937**	45,016	(50,855)
Other Current Liabilities	**(527)**	(40,800)	53,344
Other Deferred Credits and Other Liabilities	**9,893**	5,856	10,228
Deposit – Mortgage Indenture	**-**	-	17,040
Net Cash Used by Operating Activities of Discontinued Operations	**(2,710)**	(6,151)	(9,622)
Net Cash Flows – Operating Activities	**$ 282,659**	$ 273,883	$ 306,979

	TEP		
	Years Ended December 31,		
	2006	2005	2004
	-Thousands of Dollars-		
Net Income	**$ 66,745**	$ 48,267	$ 46,127
Adjustments to Reconcile Net Income			
To Net Cash Flows from Operating Activities			
Cumulative Effect of Accounting Change-Net of Tax	**-**	626	-
Depreciation and Amortization Expense	**112,346**	114,704	117,109
Depreciation Recorded to Fuel and Other O&M Expense	**6,320**	6,417	6,175
Amortization of Transition Recovery Asset	**65,985**	56,418	50,153
Net Unrealized Gain on Forward Electric Sales	**(7,115)**	(604)	(1,509)
Net Unrealized Loss on Forward Electric Purchases	**6,186**	1,863	250
Amortization of Deferred Debt-Related Costs included in Interest Expense	**3,356**	3,687	3,114
Loss on Reacquired Debt	**685**	5,261	1,990
Provision for Bad Debts	**1,869**	1,964	1,691
Deferred Income Taxes	**(233)**	6,555	(1,011)
Gains from Equity Method Investment Entities	**(377)**	(338)	(168)
Interest Accrued on Note Receivable from UniSource Energy	**-**	(1,684)	(9,329)
Gain on Sale of Real Estate	**(470)**	-	(725)
Other	**4,569**	(13,707)	(3,219)
Changes in Assets and Liabilities which Provided (Used) Cash Exclusive of Changes Shown Separately			
Accounts Receivable	**(45,185)**	(6,779)	(23,774)
Materials and Fuel Inventory	**(5,814)**	(6,608)	(1,100)
Accounts Payable	**(267)**	3,804	24,958
Interest Accrued	**8,191**	5,295	10,264
Interest Received from UniSource Energy	**-**	11,013	-
Income Taxes Payable	**(8,702)**	(704)	6,728
Taxes Accrued	**(33)**	137	13,303
Other Current Assets	**3,486**	1,491	(5,328)
Other Current Liabilities	**7,858**	660	4,790
Other Deferred Credits and Other Liabilities	**7,828**	5,275	17,622
Deposit – Mortgage Indenture	**-**	-	17,040
Net Cash Flows – Operating Activities	**$227,228**	$243,013	$275,151

Non-cash investing and financing activities of UniSource Energy and TEP that affected recognized assets and liabilities but did not result in cash receipts or payments were as follows:

	Years Ended December 31,		
	2006	2005	2004
	-Thousands of Dollars-		
Capital Lease Obligations	**$ 12,808**	$ 12,720	$ 12,273
Preliminary Engineering Fees	**-**	3,691	-

The non-cash change in capital lease obligations represents interest accrued for accounting purposes in excess of interest payments in 2006, 2005 and 2004.

The non-cash preliminary engineering fees represent costs incurred related to potential capital projects that are recorded in other assets and subsequently reclassified to construction work in progress upon affirmation the capital project will be undertaken.

NOTE 18. QUARTERLY FINANCIAL DATA (UNAUDITED)

Our quarterly financial information is unaudited but, in management's opinion, includes all adjustments necessary for a fair presentation. Our utility businesses are seasonal in nature. Peak sales periods for TEP and UNS Electric generally occur during the summer months and peak sales periods for UNS Gas generally occur during the winter months. Accordingly, comparisons among quarters of a year may not represent overall trends and changes in operations.

	UniSource Energy			
	First	Second	Third	Fourth
	-Thousands of Dollars- (except per share data)			
2006				
Operating Revenue	$304,953	$318,396	$375,640	$317,880
Operating Income	64,088	47,791	80,635	47,632
Income (Loss) Before Discontinued Operations	19,491	9,998	28,203	11,551
Discontinued Operations – Net of Tax	(2,669)	-	-	873
Net Income (Loss)	16,822	9,998	28,203	12,424
Basic EPS				
Income (Loss) Before Discontinued Operations	0.56	0.28	0.80	0.33
Discontinued Operations – Net of Tax	(0.08)	-	-	0.02
Net Income (Loss)	0.48	0.28	0.80	0.35
Diluted EPS				
Income (Loss) Before Discontinued Operations	0.52	0.28	0.73	0.32
Discontinued Operations – Net of Tax	(0.07)	-	-	0.02
Net Income (Loss)	0.45	0.28	0.73	0.34
2005				
Operating Revenue	$260,672	$299,293	$346,998	$317,093
Operating Income	32,249	57,266	61,832	70,157
Income (Loss) Before Discontinued Operations and Cumulative Effect of Accounting Change	(2,377)	11,079	19,801	23,750
Discontinued Operations – Net of Tax	(1,406)	(1,611)	(1,404)	(1,062)
Cumulative Effect of Accounting Change – Net of Tax	-	-	-	(626)
Net Income (Loss)	(3,783)	9,468	18,397	22,062
Basic EPS				
Income (Loss) Before Discontinued Operations and Cumulative Effect of Accounting Change	(0.07)	0.32	0.57	0.68
Discontinued Operations – Net of Tax	(0.04)	(0.05)	(0.04)	(0.03)
Cumulative Effect of Accounting Change – Net of Tax	-	-	-	(0.02)
Net Income (Loss)	(0.11)	0.27	0.53	0.63
Diluted EPS				
Income (Loss) Before Cumulative Effect of Accounting Change	(0.07)	0.31	0.53	0.63
Discontinued Operations – Net of Tax	(0.04)	(0.04)	(0.04)	(0.03)
Cumulative Effect of Accounting Change – Net of Tax	-	-	-	(0.02)
Net Income (Loss)	(0.11)	0.27	0.49	0.58

	TEP			
	First	Second	Third	Fourth
	-Thousands of Dollars-			
2006				
Operating Revenue	$208,342	$ 252,633	$ 303,965	$232,782
Operating Income	53,971	44,955	77,493	39,232
Net Income	16,587	11,220	29,601	9,337
2005				
Operating Revenue	$181,906	$ 236,879	$ 282,234	$236,451
Operating Income	23,121	54,125	58,874	63,221
Interest Income – Note Receivable from UniSource Energy	1,684	-	-	-
Income (Loss) Before Cumulative Effect of Accounting Change	(4,690)	12,148	20,364	21,071
Cumulative Effect of Accounting Change – Net of Tax	-	-	-	(626)
Net Income	(4,690)	12,148	20,364	20,445

EPS is computed independently for each of the quarters presented. Therefore, the sum of the quarterly EPS amounts may not equal the total for the year.

The principal unusual items for TEP and UniSource Energy include:

TEP and UniSource Energy

- **Third Quarter 2005:** TEP recognized a $1 million income tax benefit due to anticipated use of previously reserved ITC carryforwards.

UniSource Energy

- **First Quarter 2006:** On March 31, 2006, Millennium sold Global Solar for $16 million in cash and an option to purchase, under certain conditions, 5% to 10% of Global Solar at a future date. The option is exercisable, upon the occurrence of certain events, beginning in April 2013 and expires in April 2016. In the first quarter of 2006, UniSource Energy recorded an after-tax loss of approximately $3 million related to the discontinued operations and disposal of Global Solar.

- **Fourth Quarter 2005:** Millennium recognized a $4 million pre-tax gain from the sale of a Haddington investment and Millennium recognized a $2 million impairment loss upon sale of its MicroSat investment. UES collected $1 million of previously fully reserved accounts receivable related to amounts owed from Citizens in relation to the 2003 Citizens purchase. UES recognized a $1 million pre-tax gain in non-operating income for this collection.

UniSource Energy
Schedule II - Valuation and Qualifying Accounts

Description	Beginning Balance	Additions-Charged to Income	Deductions	Ending Balance
Year Ended December 31,		-Millions of Dollars-		
Deferred Tax Assets Valuation Allowance [1]				
2006	$ 7	$ -	$ 7	$ -
2005	8	-	1	7
2004	7	1	-	8
Allowance for Doubtful Accounts [2]				
2006	$15	$ 4	$ 2	$17
2005	17	3	5	15
2004	12	7	2	17

[1] The deferred tax assets valuation allowance reduces the deferred tax asset balance. It relates to NOL and ITC carryforward amounts. The $7 million valuation allowance at December 31, 2005, relates to losses generated by Global Solar. Global Solar was sold in March 2006 and is no longer included in our consolidated tax returns. The decrease in 2005 of $1 million relates to TEP's anticipated utilization of ITC carryforward. UniSource Energy and TEP charged $1 million to income in 2004 related to TEP's ITC carryforwards that may expire before utilization.

[2] TEP, UNS Gas and UNS Electric record additions to the Allowance for Doubtful Accounts based on historical experience and any specific customer collection issues identified. Deductions principally reflect amounts charged off as uncollectible, less amounts recovered. Balances related primarily to TEP reserves for sales to the CPX and CISO in 2000 and 2001. See Note 6 of *Notes to Consolidated Financial Statements*.

TEP
Schedule II - Valuation and Qualifying Accounts

Description	Beginning Balance	Additions-Charged to Income	Deductions	Ending Balance
Year Ended December 31,		-Millions of Dollars-		
Deferred Tax Assets Valuation Allowance [1]				
2006	$ -	$ -	$ -	$ -
2005	1	-	1	-
2004	-	1	-	1
Allowance for Doubtful Accounts [2]				
2006	$ 15	$ 2	$ 1	$ 16
2005	14	2	1	15
2004	11	5	2	14

[1] The deferred tax assets valuation allowance reduces the deferred tax asset balance. It relates to NOL and ITC carryforward amounts. The 2005 reduction of $1 million related to TEP's anticipated utilization of ITC carryforwards. TEP charged $1 million to income in 2004 related to ITC carryforwards that may expire before utilization.

[2] TEP records additions to the Allowance for Doubtful Accounts based on historical experience and any specific customer collection issues identified. Deductions principally reflect amounts charged off as uncollectible, less amounts recovered. Balances related primarily to TEP reserves for sales to the CPX and CISO in 2000 and 2001. See Note 11 of Notes to Consolidated Financial Statements.

ITEM 9. – CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. – CONTROLS AND PROCEDURES

UniSource Energy and TEP's Chief Executive Officer and Chief Financial Officer supervised and participated in UniSource Energy and TEP's evaluation of their disclosure controls and procedures as such term is defined under Rule 13a – 15(e) or Rule 15d – 15(e) under the Securities Exchange Act of 1934, as amended (the Exchange Act), as of December 31, 2006. Disclosure controls and procedures are controls and procedures designed to ensure that information required to be disclosed in UniSource Energy and TEP's periodic reports filed or submitted under the Exchange Act, is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms. These disclosure controls and procedures are also designed to ensure that information required to be disclosed by UniSource Energy and TEP in the reports that they file or submit under the Act is accumulated and communicated to management, including the principal executive and principal financial officers, or person performing similar functions, as appropriate to allow timely decisions regarding required disclosure. Based upon the evaluation performed, UniSource Energy and TEP's Chief Executive Officer and Chief Financial Officer concluded that UniSource Energy and TEP's disclosure controls and procedures are effective.

While UniSource Energy and TEP continually strive to improve their disclosure controls and procedures to enhance the quality of their financial reporting, there has been no change in UniSource Energy or TEP's internal control over financial reporting during the fourth quarter of 2006, that has materially affected, or is reasonably likely to materially affect, UniSource Energy or TEP's internal control over financial reporting.

UniSource Energy's Management's Report on Internal Control Over Financial Reporting Under 404 of Sarbanes-Oxley appears as the first report under Item 8 in UniSource Energy's and TEP's 2006 Annual Report on Form 10-K and the Report of Independent Registered Public Accounting Firm appears as the second report under Item 8.

ITEM 9B. – OTHER INFORMATION

None.

PART III

ITEM 10. – DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANTS

Directors

Certain of the individuals serving as Directors of UniSource Energy also serve as the Directors of TEP. Information concerning Directors will be contained under *Election of Directors* in UniSource Energy's Proxy Statement relating to the 2007 Annual Meeting of Shareholders, which will be filed with the SEC not later than 120 days after December 31, 2006, which information is incorporated herein by reference.

Executive Officers – UniSource Energy

Executive Officers of UniSource Energy, who are elected annually by UniSource Energy's Board of Directors, are as follows:

Name	Age	Position(s) Held	Executive Officer Since
James S. Pignatelli	63	Chairman, President and Chief Executive Officer	1998
Michael J. DeConcini	42	Senior Vice President and Chief Operating Officer, Transmission and Distribution	1999
Raymond S. Heyman	51	Senior Vice President and General Counsel	2005
Kevin P. Larson	50	Senior Vice President, Chief Financial Officer and Treasurer	2000
Dennis R. Nelson	56	Senior Vice President, Utility Services	1998
Kentton C. Grant	48	Vice President, Finance and Rates	2007
Arie Hoekstra	59	Vice President, Generation	2007
David G. Hutchens	40	Vice President, Wholesale Energy	2007
Karen G. Kissinger	52	Vice President, Controller and Chief Compliance Officer	1998
Steven W. Lynn	60	Vice President, Communications and Government Relations	2003
Thomas A. McKenna	58	Vice President, Engineering	2007
Herlinda H. Kennedy	45	Corporate Secretary	2006

James S. Pignatelli Mr. Pignatelli joined TEP as Senior Vice President in August 1994 and was elected Senior Vice President and Chief Operating Officer in 1996. He was named Senior Vice President and Chief Operating Officer of UniSource Energy in January 1998, and Executive Vice President and Chief Operating Officer of TEP in March 1998. On June 23, 1998, Mr. Pignatelli was named Chairman, President and CEO of UniSource Energy and TEP. Prior to joining TEP, he was President and Chief Executive Officer from 1988 to 1993 of Mission Energy Company, a subsidiary of SCE Corp.

Michael J. DeConcini Mr. DeConcini joined TEP in 1988 and served in various positions in finance, strategic planning and wholesale marketing. He was Manager of TEP's Wholesale Marketing Department in 1994, adding Product Development and Business Development in 1997. In November 1998, he was elected Vice President of MEH and elected Vice President, Strategic Planning of UniSource Energy in February 1999. He was named Senior Vice President, Investments and Planning of UniSource Energy in October 2000. Mr. DeConcini was elected Senior Vice President and Chief Operating Officer of the Energy Resources business unit of TEP, effective January 1, 2003. In August 2006, he was named Senior Vice President and Chief Operating Officer, Transmission and Distribution.

Raymond S. Heyman Mr. Heyman was elected to the position of Senior Vice President and General Counsel of TEP and UniSource Energy in September 2005. Prior to joining TEP, Mr. Heyman was a member from 1995 - 2005 of the Phoenix, Arizona law firm Roshka, Heyman & DeWulf, PLC, and has represented UniSource Energy, TEP and UES in proceedings before the Arizona Corporation Commission, as well as in other legal and regulatory matters.

Kevin P. Larson Mr. Larson joined TEP in 1985 and thereafter held various positions in its finance department and at TEP's investment subsidiaries. In January 1991, he was elected

Assistant Treasurer of TEP and named Manager of Financial Programs. He was elected Treasurer of TEP in August 1994 and Vice President in March 1997. In October 2000, he was elected Vice President and Chief Financial Officer of both UniSource Energy and TEP and remains Treasurer of both organizations. He was named Senior Vice President in September 2005.

Dennis R. Nelson Mr. Nelson joined TEP as a staff attorney in 1976. He was manager of the Legal Department from 1985 to 1990. He was elected Vice President, General Counsel and Corporate Secretary in January 1991. He was named Vice President, General Counsel and Corporate Secretary of UniSource Energy in January 1998. Mr. Nelson was named Senior Vice President and General Counsel of TEP in November 1998. In 1998, he was named Chief Operating Officer, Corporate Services of TEP. In 2000, he was named Senior Vice President, Governmental Affairs of UniSource Energy and Senior Vice President and Chief Operating Officer of the Energy Resources business unit of TEP. Mr. Nelson was elected Senior Vice President of Utility Services in 2003 and named Senior Vice President and Chief Operating Officer of UES in August 2003.

Kentton C. Grant Mr. Grant joined TEP in 1995 and was named Director of Capital Resources and Assistant Treasurer in 1997. He was promoted to Manager of Financial Planning in 1998 and General Manager of Financial Planning in 2003. In January 2007, Mr. Grant was elected Vice President of Finance and Rates at UniSource Energy and TEP. Prior to joining TEP, Mr. Grant worked as a staff member at the Public Utility Commission of Texas.

Arie Hoekstra Mr. Hoekstra joined TEP in 1979 as a Maintenance Superintendent. He was promoted to Manager of Tucson Power Production in 1983 and Manager of Springerville Power Production in 1995. He was named General Manager of Energy Resources – Power Production in 2003. In January 2007, Mr. Hoekstra was elected Vice President of Generation at UniSource Energy and TEP. Prior to joining TEP, Mr. Hoekstra worked in various roles for Arizona Public Service Company and Westinghouse Electric Corporation.

David G. Hutchens Mr. Hutchens joined TEP in 1995 and was named Supervisor of Wholesale Power Operations in 1999. He was promoted to Manager of Wholesale Marketing in 2001 and General Manager of Fuels and Wholesale Power in 2003. In January 2007, Mr. Hutchens was elected Vice President of Wholesale Marketing at UniSource Energy and TEP, and Vice President of UNS Gas. Prior to joining TEP, Mr. Hutchens served in the United States Navy, achieving the rank of Lieutenant.

Karen G. Kissinger Ms. Kissinger joined TEP as Vice President and Controller in January 1991. She was named Vice President, Controller and Principal Accounting Officer of UniSource Energy in January 1998. In November 1998, Ms. Kissinger was also named Chief Information Officer of TEP. She was named Chief Compliance Officer of UniSource Energy and TEP, effective January 1, 2003.

Steven W. Lynn Mr. Lynn joined TEP in 2000 as Manager of Corporate Relations for UniSource Energy and was named Manager of Corporate Relations of both TEP and UniSource Energy during 2000. In January 2003, he was elected Vice President of Communications and Government Relations at UniSource Energy and TEP. Prior to joining TEP, Mr. Lynn was an owner-partner from 1984 - 2000 of Nordensson Lynn & Associates, Inc., a Tucson-based advertising, marketing and public relations firm.

Thomas A. McKenna Mr. McKenna joined Nations Energy Corporation (a wholly-owned subsidiary of Millennium) in 1998, as Director of Project Development. In 2001, he was named Manager of Project Development for UniSource Energy. In January 2007, Mr. McKenna was elected Vice President of Engineering at UniSource Energy and TEP, and Vice President of UNS Electric. Prior to joining UniSource Energy, Mr. McKenna was a Vice President of Sargent & Lundy Engineers.

Herlinda H. Kennedy Ms. Kennedy joined TEP as an administrative assistant in 1980. She was promoted to Assistant to the CEO in 1986. Ms. Kennedy was named assistant Corporate Secretary of TEP and UniSource Energy in 1999 and was elected Corporate Secretary of UniSource Energy and TEP in September 2006.

Executive Officers - TEP

Executive Officers of TEP, who are elected annually by TEP's Board of Directors, are:

Name	Age	Position(s) Held	Executive Officer Since
James S. Pignatelli	63	Chairman, President and Chief Executive Officer	1994
Michael J. DeConcini	42	Senior Vice President and Chief Operating Officer, Transmission and Distribution	2003
Raymond S. Heyman	51	Senior Vice President and General Counsel	2005
Kevin P. Larson	50	Senior Vice President, Chief Financial Officer and Treasurer	1994
Kennton C. Grant	48	Vice President, Finance and Rates	2007
Thomas N. Hansen	56	Vice President, Environmental Services, Conservation and Renewable Energy	1992
Arie Hoekstra	59	Vice President, Generation	2007
David G. Hutchens	40	Vice President, Wholesale Energy	2007
Karen G. Kissinger	52	Vice President, Controller and Chief Compliance Officer	1991
Steven W. Lynn	60	Vice President, Communications and Government Relations	2003
Thomas A. McKenna	58	Vice President, Engineering	2007
Herlinda H. Kennedy	45	Corporate Secretary	2006

James S. Pignatelli *See description shown under UniSource Energy Corporation above.*

Michael J. DeConcini *See description shown under UniSource Energy Corporation above.*

Raymond S. Heyman *See description shown under UniSource Energy Corporation above.*

Kevin P. Larson *See description shown under UniSource Energy Corporation above.*

Kentton C. Grant *See description shown under UniSource Energy Corporation above.*

Thomas N. Hansen Mr. Hansen joined TEP in December 1992 as Vice President, Power Production. Prior to joining TEP, Mr. Hansen was Century Power Corporation's Vice President, Operations from 1989 and Plant Manager at Springerville from 1987 through 1988. In 1994, he was named Vice President / Technical Advisor. In 2007, he was named Vice President, Environmental Services, Conservation and Renewable Energy.

Arie Hoekstra *See description shown under UniSource Energy Corporation above.*

David G. Hutchens *See description shown under UniSource Energy Corporation above.*

Karen G. Kissinger *See description shown under UniSource Energy Corporation above.*

Steven W. Lynn *See description shown under UniSource Energy Corporation above.*

Thomas A. McKenna *See description shown under UniSource Energy Corporation above.*

Herlinda H. Kennedy *See description shown under UniSource Energy Corporation above.*

Information required by Items 405, 406 and 407 (c)(3), (d)(4) and (d)(5) of SEC Regulation S-K will be included in UniSource Energy's Proxy Statement relating to the 2007 Annual Meeting of Shareholders, which will be filed with the SEC not later than 120 days after December 31, 2006, which information is incorporated herein by reference.

ITEM 11. – EXECUTIVE COMPENSATION

Information concerning Executive Compensation will be contained in UniSource Energy's Proxy Statement relating to the 2007 Annual Meeting of Shareholders, which will be filed with the SEC not later than 120 days after December 31, 2006, which information is incorporated herein by reference.

ITEM 12. – SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

General

At February 23, 2007, UniSource Energy had outstanding 35 million shares of Common Stock. As of February 23, 2007, the number of shares of Common Stock beneficially owned by all directors and officers of UniSource Energy as a group amounted to approximately 4% of the outstanding Common Stock.

At February 23, 2007, UniSource Energy owned 100% of the outstanding shares of common stock of TEP.

Security Ownership of Certain Beneficial Owners

Information concerning the security ownership of certain beneficial owners of UniSource Energy will be contained in UniSource Energy's Proxy Statement relating to the 2007 Annual Meeting of Shareholders, which will be filed with the SEC not later than 120 days after December 31, 2006, which information is incorporated herein by reference.

Security Ownership of Management

Information concerning the security ownership of the Directors and Executive Officers of UniSource Energy and TEP will be contained in UniSource Energy's Proxy Statement relating to the 2007 Annual Meeting of Shareholders, which will be filed with the SEC not later than 120 days after December 31, 2006, which information is incorporated herein by reference.

Securities Authorized for Issuance Under Equity Compensation Plans

Information concerning securities authorized for issuance under equity compensation plans will be contained in UniSource Energy's Proxy Statement relating to the 2007 Annual Meeting of Shareholders, which will be filed with the SEC not later than 120 days after December 31, 2006, which information is incorporated herein by reference.

ITEM 13. – CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Information concerning certain relationships and related transactions, and director independence of UniSource Energy and TEP will be contained under Transactions with Management and Others, Director Independence and Compensation Committee Interlocks and Insider Participation in UniSource Energy's Proxy Statement relating to the 2007 Annual Meeting of Shareholders, which will be filed with the SEC not later than 120 days after December 31, 2006, which information is incorporated herein by reference.

ITEM 14. – PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information concerning principal accountant fees and services will be contained in UniSource Energy's Proxy Statement relating to the 2007 Annual Meeting of Shareholders, which will be filed with the SEC not later than 120 days after December 31, 2006, which information is incorporated herein by reference.

PART IV

ITEM 15. – EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

Reference is made to the Exhibit Index commencing on page 150.

SIGNATURES

Pursuant to the requirements of Section 13 and 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

UNISOURCE ENERGY CORPORATION

Date: February 28, 2007

By: /s/ Kevin P. Larson
Kevin P. Larson
Senior Vice President and Principal Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Date: February 28, 2007 — /s/ James S. Pignatelli*
James S. Pignatelli
Chairman of the Board, President and Principal Executive Officer

Date: February 28, 2007 — /s/ Kevin P. Larson
Kevin P. Larson
Principal Financial Officer

Date: February 28, 2007 — /s/ Karen G. Kissinger*
Karen G. Kissinger
Principal Accounting Officer

Date: February 28, 2007 — /s/ Lawrence J. Aldrich*
Lawrence J. Aldrich
Director

Date: February 28, 2007 — /s/ Barbara Baumann*
Barbara Baumann
Director

Date: February 28, 2007 — /s/ Larry W. Bickle*
Larry W. Bickle
Director

Date: February 28, 2007 — /s/ Elizabeth T. Bilby*
Elizabeth T. Bilby
Director

Date: February 28, 2007 — /s/ Harold W. Burlingame*
Harold W. Burlingame
Director

Date: February 28, 2007 — /s/ John L. Carter*
John L. Carter

Director

Date:	February 28, 2007	/s/	Robert A. Elliott* Robert A. Elliott Director
Date:	February 28, 2007	/s/	Daniel W.L. Fessler* Daniel W.L. Fessler
Date:	February 28, 2007	/s/	Kenneth Handy* Kenneth Handy Director
Date:	February 28, 2007	/s/	Warren Y. Jobe* Warren Y. Jobe Director
Date:	February 28, 2007	/s/	Joaquin Ruiz* Joaquin Ruiz Director
Date:	February 28, 2007	By: /s/	Kevin P. Larson Kevin P. Larson As attorney-in-fact for each of the persons indicated

SIGNATURES

Pursuant to the requirements of Section 13 and 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

TUCSON ELECTRIC POWER COMPANY

Date: February 28, 2007

By: /s/ Kevin P. Larson
Kevin P. Larson
Senior Vice President and Principal Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Date: February 28, 2007

/s/ James S. Pignatelli*
James S. Pignatelli
Chairman of the Board, President and Principal Executive Officer

Date: February 28, 2007

/s/ Kevin P. Larson
Kevin P. Larson
Principal Financial Officer

Date: February 28, 2007

/s/ Karen G. Kissinger*
Karen G. Kissinger
Principal Accounting Officer

Date: February 28, 2007

/s/ Lawrence J. Aldrich*
Lawrence J. Aldrich
Director

Date: February 28, 2007

/s/ Barbara Baumann*
Barbara Baumann
Director

Date: February 28, 2007

/s/ Larry W. Bickle*
Larry W. Bickle
Director

Date: February 28, 2007

/s/ Elizabeth T. Bilby*
Elizabeth T. Bilby
Director

Date: February 28, 2007

/s/ Harold W. Burlingame*
Harold W. Burlingame
Director

Date: February 28, 2007

/s/ John L. Carter*
John L. Carter

Director

Date:	February 28, 2007	/s/	Robert A. Elliott* Robert A. Elliott Director
Date:	February 28, 2007	/s/	Daniel W.L. Fessler* Daniel W.L. Fessler
Date:	February 28, 2007	/s/	Kenneth Handy* Kenneth Handy Director
Date:	February 28, 2007	/s/	Warren Y. Jobe* Warren Y. Jobe Director
Date:	February 28, 2007	/s/	Joaquin Ruiz* Joaquin Ruiz Director
Date:	February 28, 2007	By: /s/	Kevin P. Larson Kevin P. Larson As attorney-in-fact for each of the persons indicated

EXHIBIT INDEX

*2(a)	--	Agreement and Plan of Exchange, dated as of March 20, 1995, between TEP, UniSource Energy and NCR Holding, Inc.
*3(a)	--	Restated Articles of Incorporation of TEP, filed with the ACC on August 11, 1994, as amended by Amendment to Article Fourth of our Restated Articles of Incorporation, filed with the ACC on May 17, 1996. (Form 10-K for year ended December 31, 1996, File No. 1-5924 -- Exhibit 3(a).)
*3(b)	--	Bylaws of TEP, as amended May 20, 1994. (Form 10-Q for the quarter ended June 30, 1994, File No. 1-5924 -- Exhibit 3.)
*3(c)	--	Amended and Restated Articles of Incorporation of UniSource Energy. (Form 8-A/A, dated January 30, 1998, File No. 1-13739 -- Exhibit 2(a).)
*3(d)	--	Bylaws of UniSource Energy, as amended December 11, 1997. (Form 8-A, dated December 23, 1997, File No. 1-13739 -- Exhibit 2(b).)
*4(a)(1)	--	Installment Sale Agreement, dated as of December 1, 1973, among the City of Farmington, New Mexico, Public Service Company of New Mexico and TEP. (Form 8-K for the month of January 1974, file No. 0-269 -- Exhibit 3.)
*4(a)(2)	--	Ordinance No. 486, adopted December 17, 1973, of the City of Farmington, New Mexico. (Form 8-K for the month of January 1974, File No. 0-269 -- Exhibit 4.)
*4(a)(3)	--	Amended and Restated Installment Sale Agreement dated as of April 1, 1997, between the City of Farmington, New Mexico and TEP relating to Pollution Control Revenue bonds, 1997 Series A (Tucson Electric Power Company San Juan Project). (Form 10-Q for the quarter ended March 31,1997, File No. 1-5924 -- Exhibit 4(a).)
*4(a)(4)	--	City of Farmington, New Mexico Ordinance No. 97-1055, adopted April 17, 1997, authorizing Pollution Control Revenue bonds, 1997 Series A (Tucson Electric Power Company San Juan Project). (Form 10-Q for the quarter ended March 31, 1997, File No. 1-5924 -- Exhibit 4(b).)
*4(b)(1)	--	Loan Agreement, dated as of October 1, 1982, between the Pima County Authority and TEP relating to Floating Rate Monthly Demand Industrial Development Revenue Bonds, 1982 Series A (Tucson Electric Power Company Sundt Project). (Form 10-Q for the quarter ended September 30, 1982, File No. 1-5924 -- Exhibit 4(a).)
*4(b)(2)	--	Indenture of Trust, dated as of October 1, 1982, between the Pima County Authority and Morgan Guaranty authorizing Floating Rate Monthly Demand Industrial Development Revenue Bonds, 1982 Series A (Tucson Electric Power Company Sundt Project). (Form 10-Q for the quarter ended September 30, 1982, File No. 1-5924 -- Exhibit 4(b).)
*4(b)(3)	--	First Supplemental Loan Agreement, dated as of March 31, 1992, between the Pima County Authority and TEP relating to Industrial Development Revenue Bonds, 1982 Series A (Tucson Electric Power Company Sundt Project). (Form S-4, Registration No. 33-52860 -- Exhibit 4(h)(3).)
*4(b)(4)	--	First Supplemental Indenture of Trust, dated as of March 31, 1992, between the Pima County Authority and Morgan Guaranty relating to Industrial Development Revenue Bonds, 1982 Series A (Tucson Electric Power Company Sundt Project). (Form S-4, Registration No. 33-52860 -- Exhibit 4(h)(4).)
*4(c)(1)	--	Loan Agreement, dated as of December 1, 1982, between the Pima County Authority and TEP relating to Floating Rate Monthly Demand Industrial Development Revenue Bonds, 1982 Series A (Tucson Electric Power Company Projects). (Form 10-K for the year ended December 31, 1982, File No. 1-5924 -- Exhibit 4(k)(1).)

*4(c)(2) -- Indenture of Trust dated as of December 1, 1982, between the Pima County Authority and Morgan Guaranty authorizing Floating Rate Monthly Demand Industrial Development Revenue Bonds, 1982 Series A (Tucson Electric Power Company Projects). (Form 10-K for the year ended December 31, 1982, File No. 1-5924 -- Exhibit 4(k)(2).)

*4(c)(3) -- First Supplemental Loan Agreement, dated as of March 31, 1992, between the Pima County Authority and TEP relating to Industrial Development Revenue Bonds, 1982 Series A (Tucson Electric Power Company Projects). (Form S-4, Registration No. 33-52860 -- Exhibit 4(i)(3).)

*4(c)(4) -- First Supplemental Indenture of Trust, dated as of March 31, 1992, between the Pima County Authority and Morgan Guaranty relating to Industrial Development Revenue Bonds, 1982 Series A (Tucson Electric Power Company Projects). (Form S-4, Registration No. 33-52860 -- Exhibit 4(i)(4).)

*4(d)(1) -- Loan Agreement, dated as of December 1, 1983, between the Apache County Authority and TEP relating to Floating Rate Monthly Demand Industrial Development Revenue Bonds, 1983 Series A (Tucson Electric Power Company Springerville Project). (Form 10-K for the year ended December 31, 1983, File No. 1-5924 -- Exhibit 4(l)(1).)

*4(d)(2) -- Indenture of Trust, dated as of December 1, 1983, between the Apache County Authority and Morgan Guaranty authorizing Floating Rate Monthly Demand Industrial Development Revenue Bonds, 1983 Series A (Tucson Electric Power Company Springerville Project). (Form 10-K for the year ended December 31, 1983, File no. 1-5924 -- Exhibit 4(l)(2).)

*4(d)(3) -- First Supplemental Loan Agreement, dated as of December 1, 1985, between the Apache County Authority and TEP relating to Floating Rate Monthly Demand Industrial Development Revenue Bonds, 1983 Series A (Tucson Electric Power Company Springerville Project). (Form 10-K for the year ended December 31, 1987, File No. 1-5924 -- Exhibit 4(k)(3).)

*4(d)(4) -- First Supplemental Indenture, dated as of December 1, 1985, between the Apache County Authority and Morgan Guaranty relating to Floating Rate Monthly Demand Industrial Development Revenue Bonds, 1983 Series A (Tucson Electric Power Company Springerville Project). (Form 10-K for the year ended December 31, 1987, File No. 1-5924 -- Exhibit 4(k)(4).)

*4(d)(5) -- Second Supplemental Loan Agreement, dated as of March 31, 1992, between the Apache County Authority and TEP relating to Industrial Development Revenue Bonds, 1983 Series A (Tucson Electric Power Company Springerville Project). (Form S-4, Registration No. 33-52860 -- Exhibit 4(k)(5).)

*4(d)(6) -- Second Supplemental Indenture of Trust, dated as of March 31, 1992, between the Apache County Authority and Morgan Guaranty relating to Industrial Development Revenue Bonds, 1983 Series A (Tucson Electric Power Company Springerville Project). (Form S-4, Registration No. 33-52860 -- Exhibit 4(k)(6).)

*4(e)(1) -- Loan Agreement, dated as of December 1, 1983, between the Apache County Authority and TEP relating to Variable Rate Demand Industrial Development Revenue Bonds, 1983 Series B (Tucson Electric Power Company Springerville Project). (Form 10-K for the year ended December 31, 1983, File No. 1-5924 -- Exhibit 4(m)(1).)

*4(e)(2) -- Indenture of Trust dated as of December 1, 1983, between the Apache County Authority and Morgan Guaranty authorizing Variable Rate Demand Industrial Development Revenue Bonds. 1983 Series B (Tucson Electric Power Company Springerville Project). (Form 10-K for the year ended December 31, 1983, File No. 1-5924 -- Exhibit 4(m)(2).)

*4(e)(3) -- First Supplemental Loan Agreement, dated as of December 1, 1985, between the Apache County Authority and TEP relating to Floating Rate Monthly Demand Industrial Developmental Revenue Bonds, 1983 Series B (Tucson Electric Power Company Springerville Project). (Form 10-K for the year ended December 31, 1987, File No. 1-5924 -- Exhibit 4(l)(3).)

*4(e)(4) -- First Supplemental Indenture, dated as of December 1, 1985, between the Apache County Authority and Morgan Guaranty relating to Floating Rate Monthly Demand Industrial Development Revenue Bonds, 1983 Series B (Tucson Electric Power Company Springerville Project). (Form 10-K for the year ended December 31, 1987, File No. 1-5924 -- Exhibit 4(l)(4).)

*4(e)(5) -- Second Supplemental Loan Agreement, dated as of March 31, 1992, between the Apache County Authority and TEP relating to Industrial Development Revenue Bonds, 1983 Series B (Tucson Electric Power Company Springerville Project). (Form S-4, Registration No. 33-52860 -- Exhibit 4(l)(5).)

*4(e)(6) -- Second Supplemental Indenture of Trust, dated as of March 31, 1992, between the Apache County Authority and Morgan Guaranty relating to Industrial Development Revenue Bonds, 1983 Series B (Tucson Electric Power Company Springerville Project). (Form S-4, Registration No. 33-52860 -- Exhibit 4(l)(6).)

*4(f)(1) -- Loan Agreement, dated as of December 1, 1983, between the Apache County Authority and TEP relating to Variable Rate Demand Industrial Development Revenue Bonds, 1983 Series C (Tucson Electric Power Company Springerville Project). (Form 10-K for year ended December 31, 1983, File No. 1-5924 -- Exhibit 4(n)(1).)

*4(f)(2) -- Indenture of Trust dated as of December 1, 1983, between the Apache County Authority and Morgan Guaranty authorizing Variable Rate Demand Industrial Development Revenue Bonds, 1983 Series C (Tucson Electric Power Company Springerville Project). (Form 10-K for the year ended December 31, 1983, File No. 1-5924 -- Exhibit 4(n)(2).)

*4(f)(3) -- First Supplemental Loan Agreement, dated as of December 1, 1985, between the Apache County Authority and TEP relating to Floating Rate Monthly Demand Industrial Development Revenue Bonds, 1983 Series C (Tucson Electric Power Company Springerville Project). (Form 10-K for the year ended December 31, 1987, File No. 1-5924 -- Exhibit 4(m)(3).)

*4(f)(4) -- First Supplemental Indenture, dated as of December 1, 1985, between the Apache County Authority and Morgan Guaranty relating to Floating Rate Monthly Demand Industrial Development Revenue Bonds, 1983 Series C (Tucson Electric Power Company Springerville Project). (Form 10-K for the year ended December 31, 1987, File No. 1-5924 -- Exhibit 4(m)(4).)

*4(f)(5) -- Second Supplemental Loan Agreement, dated as of March 31, 1992, between the Apache County Authority and TEP relating to Industrial Development Revenue Bonds, 1983 Series C (Tucson Electric Power Company Springerville Project). (Form S-4, Registration No. 33-52860 -- Exhibit 4(m)(5).)

*4(f)(6) -- Second Supplemental Indenture of Trust, dated as of March 31, 1992, between the Apache County Authority and Morgan Guaranty relating to Industrial Development Revenue Bonds, 1983 Series C (Tucson Electric Power Company Springerville Project). (Form S-4, Registration No. 33-52860 -- Exhibit 4(m)(6).)

*4(g) -- Reimbursement Agreement, dated as of September 15, 1981, as amended, between TEP and Manufacturers Hanover Trust Company. (Form 10-K for the year ended December 31, 1984, File No. 1-5924 -- Exhibit 4(o)(4).)

*4(h)(1) -- Loan Agreement, dated as of December 1, 1985, between the Apache County Authority and TEP relating to Variable Rate Demand Industrial Development Revenue Bonds, 1985 Series A (Tucson Electric Power Company Springerville Project). (Form 10-K for the year ended December 31, 1985, File No. 1-5924 -- Exhibit 4(r)(1).)

*4(h)(2) -- Indenture of Trust dated as of December 1, 1985, between the Apache County Authority and Morgan Guaranty authorizing Variable Rate Demand Industrial Development Revenue Bonds, 1985 Series A (Tucson Electric Power Company Springerville Project). (Form 10-K for the year ended December 31, 1985, File No. 1-5924 -- Exhibit 4(r)(2).)

*4(h)(3)	--	First Supplemental Loan Agreement, dated as of March 31, 1992, between the Apache County Authority and TEP relating to Industrial Development Revenue Bonds, 1985 Series A (Tucson Electric Power Company Springerville Project). (Form S-4, Registration No. 33-52860 -- Exhibit 4(o)(3).)
*4(h)(4)	--	First Supplemental Indenture of Trust, dated as of March 31, 1992, between the Apache County Authority and Morgan Guaranty relating to Industrial Development Revenue Bonds, 1985 Series A (Tucson Electric Power Company Springerville Project). (Form S-4, Registration No. 33-52860 -- Exhibit 4(o)(4).)
*4(i)(1)	--	Indenture of Mortgage and Deed of Trust dated as of December 1, 1992, to Bank of Montreal Trust Company, Trustee. (Form S-1, Registration No. 33-55732 -- Exhibit 4(r)(1).)
*4(i)(2)	--	Supplemental Indenture No. 1 creating a series of bonds designated Second Mortgage Bonds, Collateral Series A, dated as of December 1, 1992. (Form S-1, Registration No. 33-55732 -- Exhibit 4(r)(2).)
*4(i)(3)	--	Supplemental Indenture No. 2 creating a series of bonds designated Second Mortgage Bonds, Collateral Series B, dated as of December 1, 1997. (Form 10-K for year ended December 31, 1997, File No. 1-5924 -- Exhibit 4(m)(3).)
*4(i)(4)	--	Supplemental Indenture No. 3 creating a series of bonds designated Second Mortgage Bonds, Collateral Series, dated as of August 1, 1998. (Form 10-Q for the quarter ended June 30, 1998, File No. 1-5924 -- Exhibit 4(c).)
*4(i)(5)	--	Supplemental Indenture No. 4 creating a series of bonds designated Second Mortgage Bonds, Collateral Series C, dated as of November 1, 2002. (Form 8-K dated November 27, 2002, File Nos. 1-05924 and 1-13739 -- Exhibit 99.2.)
*4(i)(6)	--	Supplemental Indenture No. 5 creating a series of bonds designated Second Mortgage Bonds, Collateral Series D, dated as of March 1, 2004. (Form 8-K dated March 31, 2004, File Nos. 1-05924 and 1-13739 -- Exhibit 10 (b).)
*4(i)(7)	--	Supplemental Indenture No. 6 creating a series of bonds designated Second Mortgage Bonds, Collateral Series E, dated as of May 1, 2005. (Form 10-Q for the quarter ended March 31, 2005, File Nos. 1-5924 and 1-13739 – Exhibit 4(b).)
*4(i)(8)	--	Supplemental Indenture No. 7 creating a series of bonds designated First Mortgage Bonds, Collateral Series F, dated as of December 1, 2006. (Form 8-K dated December 22, 2006, File Nos. 1-5924 and 1-13739 – Exhibit 4.1.)
*4(j)(1)	--	Loan Agreement, dated as of April 1, 1997 between Coconino County, Arizona Pollution Control Corporation and TEP relating to Pollution Control Revenue Bonds, 1997 Series A (Tucson Electric Power Company Navajo Project). (Form 10-Q for the quarter ended March 31, 1997, File No. 1-5924 -- Exhibit 4(c).)
*4(j)(2)	--	Indenture of Trust, dated as of April 1, 1997, between Coconino County, Arizona Pollution Control Corporation and First Trust of New York, National Association, authorizing Pollution Control Revenue Bonds, 1997 Series A (Tucson Electric Power Company Navajo Project). (Form 10-Q for the quarter ended March 31, 1997, File No. 1-5924 -- Exhibit 4(d).)
*4(k)(1)	--	Loan Agreement, dated as of April 1, 1997, between Coconino County, Arizona Pollution Control Corporation and TEP relating to Pollution Control Revenue Bonds, 1997 Series B (Tucson Electric Power Company Navajo Project). (Form 10-Q for the quarter ended March 31, 1997, File No. 1-5924 -- Exhibit 4(e).)
*4(k)(2)	--	Indenture of Trust, dated as of April 1, 1997, between Coconino County, Arizona Pollution Control Corporation and First Trust of New York, National Association, authorizing Pollution Control Revenue Bonds, 1997 Series B (Tucson Electric Power Company Navajo Project). (Form 10-Q for the quarter ended March 31, 1997, File No. 1-5924 -- Exhibit 4(f).)

*4(l)(1) -- Loan Agreement, dated as of September 15, 1997, between The Industrial Development Authority of the County of Pima and TEP relating to Industrial Development Revenue Bonds, 1997 Series A (Tucson Electric Power Company Project). (Form 10-Q for the quarter ended September 30, 1997, File No. 1-5924 -- Exhibit 4(a).)

*4(l)(2) -- Indenture of Trust, dated as of September 15, 1997, between The Industrial Development Authority of the County of Pima and First Trust of New York, National Association, authorizing Industrial Development Revenue Bonds, 1997 Series A (Tucson Electric Power Company Project). (Form 10-Q for the quarter ended September 30, 1997, File No. 1-5924 -- Exhibit 4(b).)

*4(m)(1) -- Loan Agreement, dated as of March 1, 1998, between The Industrial Development Authority of the County of Apache and TEP relating to Pollution Control Revenue Bonds, 1998 Series A (Tucson Electric Power Company Project). (Form 10-Q for the quarter ended March 31, 1998, File No. 1-5924 -- Exhibit 4(a).)

*4(m)(2) -- Indenture of Trust, dated as of March 1, 1998, between The Industrial Development Authority of the County of Apache and First Trust of New York, National Association, authorizing Pollution Control Revenue Bonds, 1998 Series A (Tucson Electric Power Company Project). (Form 10-Q for the quarter ended March 31, 1998, File No. 1-5924 -- Exhibit 4(b).)

*4(n)(1) -- Loan Agreement, dated as of March 1, 1998, between The Industrial Development Authority of the County of Apache and TEP relating to Pollution Control Revenue Bonds, 1998 Series B (Tucson Electric Power Company Project). (Form 10-Q for the quarter ended March 31, 1998, File No. 1-5924 -- Exhibit 4(c).)

*4(n)(2) -- Indenture of Trust, dated as of March 1, 1998, between The Industrial Development Authority of the County of Apache and First Trust of New York, National Association, authorizing Pollution Control Revenue Bonds, 1998 Series B (Tucson Electric Power Company Project). (Form 10-Q for the quarter ended March 31, 1998, File No. 1-5924 -- Exhibit 4(d).)

*4(o)(1) -- Loan Agreement, dated as of March 1, 1998, between The Industrial Development Authority of the County of Apache and TEP relating to Industrial Development Revenue Bonds, 1998 Series C (Tucson Electric Power Company Project). (Form 10-Q for the quarter ended March 31, 1998, File No. 1-5924 -- Exhibit 4(e).)

*4(o)(2) -- Indenture of Trust, dated as of March 1, 1998, between The Industrial Development Authority of the County of Apache and First Trust of New York, National Association, authorizing Industrial Development Revenue Bonds, 1998 Series C (Tucson Electric Power Company Project). (Form 10-Q for the quarter ended March 31, 1998, File No. 1-5924 -- Exhibit 4(f).)

*4(p)(1) -- Indenture of Trust, dated as of August 1, 1998, between TEP and the Bank of Montreal Trust Company. (Form 10-Q for the quarter ended June 30, 1998, File No. 1-5924 -- Exhibit 4(d).)

*4(q)(1) -- Rights Agreement dated as of March 5, 1999, between UniSource Energy Corporation and The Bank of New York, as Rights Agent. (Form 8-K dated March 5, 1999, File No. 1-13739 -- Exhibit 4.)

*4(r)(1) -- Amended and Restated TEP Credit Agreement dated as of August 11, 2006, among TEP, the Lenders Party Thereto, the Issuing Banks Party Thereto, Union Bank of California, N.A., as Lead Arranger and Administrative Agent, The Bank of New York and JPMorgan Chase, N.A., as Co-Syndication Agents, and Wells Fargo Bank, National Association, and ABN Amro Bank N.V. as Co-Documentation Agents. (Form 8-K dated August 15, 2006, File Nos. 1-5924 and 1-13739 -- Exhibit 4.3.)

*4(s)(1) -- Note Purchase and Guaranty Agreement dated August 11, 2003 among UNS Gas, Inc., and UniSource Energy Services, Inc., and certain institutional investors. (Form 8-K dated August 21, 2003, File Nos. 1-5924 and 1-13739 -- Exhibit 99.2.)

*4(t)(1) -- Note Purchase and Guaranty Agreement date August 11, 2003 among UNS Electric, Inc., and UniSource Energy Services, Inc., and certain institutional investors. (Form 8-K dated August 21, 2003, File Nos. 1-5924 and 1-13739 -- Exhibit 99.3.)

*4(u)(1) -- Indenture dated as of March 1, 2005, to The Bank of New York, as Trustee. (Form 8-K dated March 3, 2005, File Nos. 1-5924 and 1-13739 -- Exhibit 4.1).

*4(v)(1) -- Registration Rights Agreement dated as of March 1, 2005, between UniSource Energy Corporation and Credit Suisse First Boston LLC, as representative of the several initial purchasers. (Form 8-K dated March 3, 2005, File Nos. 1-5924 and 1-13739 -- Exhibit 4.2).

*4(w)(1) -- Amended and Restated Credit Agreement dated as of August 11, 2006, among UniSource Energy, the Lenders Party Hereto, Union Bank of California, N.A., as Lead Arranger and Administrative Agent, The Bank of New York and JPMorgan Chase, N.A., as Co-Syndication Agents, and Wells Fargo Bank, National Association, and ABN Amro Bank N.V. as Co-Documentation Agents. (Form 8-K dated August 15, 2006, File Nos. 1-5924 and 1-13739 -- Exhibit 4.1.)

*4(x)(1) -- Amended and Restated Credit Agreement dated as of August 11, 2006, among UNS Electric and UNS Gas, UniSource Energy Services as Guarantor, and the Banks Named Herein and the Other Lenders from Time to Time party Hereto, Union Bank of California, N.A., as Lead Arranger and Administrative Agent, The Bank of New York and JPMorgan Chase, N.A., as Co-Syndication Agents, and Wells Fargo Bank, National Association, and ABN Amro Bank N.V. as Co-Documentation Agents. (Form 8-K dated August 15, 2006, File Nos. 1-5924 and 1-13739 -- Exhibit 4.4.)

*10(a)(1) -- Lease Agreements, dated as of December 1, 1984, between Valencia and United States Trust Company of New York, as Trustee, and Thomas B. Zakrzewski, as Co-Trustee, as amended and supplemented. (Form 10-K for the year ended December 31, 1984, File No. 1-5924 -- Exhibit 10(d)(1).)

*10(a)(2) -- Guaranty and Agreements, dated as of December 1, 1984, between TEP and United States Trust Company of New York, as Trustee, and Thomas B. Zakrzewski, as Co-Trustee. (Form 10-K for the year ended December 31, 1984, File No. 1-5924 -- Exhibit 10(d)(2).)

*10(a)(3) -- General Indemnity Agreements, dated as of December 1, 1984, between Valencia and TEP, as Indemnitors; General Foods Credit Corporation, Harvey Hubbell Financial, Inc. and J.C. Penney Company, Inc. as Owner Participants; United States Trust Company of New York, as Owner Trustee; Teachers Insurance and Annuity Association of America as Loan Participant; and Marine Midland Bank, N.A., as Indenture Trustee. (Form 10-K for the year ended December 31, 1984, File No. 1-5924 -- Exhibit 10(d)(3).)

*10(a)(4) -- Tax Indemnity Agreements, dated as of December 1, 1984, between General Foods Credit Corporation, Harvey Hubbell Financial, Inc. and J.C. Penney Company, Inc., each as Beneficiary under a separate Trust Agreement dated December 1, 1984, with United States Trust of New York as Owner Trustee, and Thomas B. Zakrzewski as Co-Trustee, Lessor, and Valencia, Lessee, and TEP, Indemnitors. (Form 10-K for the year ended December 31, 1984, File No. 1-5924 -- Exhibit 10(d)(4).)

*10(a)(5) -- Amendment No. 1, dated December 31, 1984, to the Lease Agreements, dated December 1, 1984, between Valencia and United States Trust Company of New York, as Owner Trustee, and Thomas B. Zakrzewski as Co-Trustee. (Form 10-K for the year ended December 31, 1986, File No. 1-5924 -- Exhibit 10(e)(5).)

*10(a)(6) -- Amendment No. 2, dated April 1, 1985, to the Lease Agreements, dated December 1, 1984, between Valencia and United States Trust Company of New York, as Owner Trustee, and Thomas B. Zakrzewski as Co-Trustee. (Form 10-K for the year ended December 31, 1986, File No. 1-5924 -- Exhibit 10(e)(6).)

*10(a)(7) -- Amendment No. 3 dated August 1, 1985, to the Lease Agreements, dated December 1, 1984, between Valencia and United States Trust Company of New York, as Owner Trustee, and

Thomas Zakrzewski as Co-Trustee. (Form 10-K for the year ended December 31, 1986, File No. 1-5924 -- Exhibit 10(e)(7).)

*10(a)(8)	--	Amendment No. 4, dated June 1, 1986, to the Lease Agreement, dated December 1, 1984, between Valencia and United States Trust Company of New York as Owner Trustee, and Thomas Zakrzewski as Co-Trustee, under a Trust Agreement dated as of December 1, 1984, with General Foods Credit Corporation as Owner Participant. (Form 10-K for the year ended December 31, 1986, File No. 1-5924 -- Exhibit 10(e)(8).)
*10(a)(9)	--	Amendment No. 4, dated June 1, 1986, to the Lease Agreement, dated December 1, 1984, between Valencia and United States Trust Company of New York as Owner Trustee, and Thomas Zakrzewski as Co-Trustee, under a Trust Agreement dated as of December 1, 1984, with J.C. Penney Company, Inc. as Owner Participant. (Form 10-K for the year ended December 31, 1986, File No. 1-5924 -- Exhibit 10(e)(9).)
*10(a)(10)	--	Amendment No. 4, dated June 1, 1986, to the Lease Agreement, dated December 1, 1984, between Valencia and United States Trust Company of New York as Owner Trustee, and Thomas Zakrzewski as Co-Trustee, under a Trust Agreement dated as of December 1, 1984, with Harvey Hubbell Financial Inc. as Owner Participant. (Form 10-K for the year ended December 31, 1986, File No. 1-5924 -- Exhibit 10(e)(10).)
*10(a)(11)	--	Lease Amendment No. 5 and Supplement No. 2, to the Lease Agreement, dated July 1, 1986, between Valencia, United States Trust Company of New York as Owner Trustee, and Thomas Zakrzewski as Co-Trustee and J.C. Penney as Owner Participant. (Form 10-K for the year ended December 31, 1986, File No. 1-5924 -- Exhibit 10(e)(11).)
*10(a)(12)	--	Lease Amendment No. 5, to the Lease Agreement, dated June 1, 1987, between Valencia, United States Trust Company of New York as Owner Trustee, and Thomas Zakrzewski as Co-Trustee and General Foods Credit Corporation as Owner Participant. (Form 10-K for the year ended December 31, 1988, File No. 1-5924 -- Exhibit 10(f)(12).)
*10(a)(13)	--	Lease Amendment No. 5, to the Lease Agreement, dated June 1, 1987, between Valencia, United States Trust Company of New York as Owner Trustee, and Thomas Zakrzewski as Co-Trustee and Harvey Hubbell Financial Inc. as Owner Participant. (Form 10-K for the year ended December 31, 1988, File No. 1-5924 -- Exhibit 10(f)(13).)
*10(a)(14)	--	Lease Amendment No. 6, to the Lease Agreement, dated June 1, 1987, between Valencia, United States Trust Company of New York as Owner Trustee, and Thomas Zakrzewski as Co-Trustee and J.C. Penney Company, Inc. as Owner Participant. (Form 10-K for the year ended December 31, 1988, File No. 1-5924 -- Exhibit 10(f)(14).)
*10(a)(15)	--	Lease Supplement No. 1, dated December 31, 1984, to Lease Agreements, dated December 1, 1984, between Valencia, as Lessee and United States Trust Company of New York and Thomas B. Zakrzewski, as Owner Trustee and Co-Trustee, respectively (document filed relates to General Foods Credit Corporation; documents relating to Harvey Hubbell Financial, Inc. and JC Penney Company, Inc. are not filed but are substantially similar). (Form S-4 Registration No. 33-52860 -- Exhibit 10(f)(15).)
*10(a)(16)	--	Amendment No. 1, dated June 1, 1986, to the General Indemnity Agreement, dated as of December 1, 1984, between Valencia and TEP, as Indemnitors, General Foods Credit Corporation, as Owner Participant, United States Trust Company of New York, as Owner Trustee, Teachers Insurance and Annuity Association of America, as Loan Participant, and Marine Midland Bank, N.A., as Indenture Trustee. (Form 10-K for the year ended December 31, 1986, File No. 1-5924 -- Exhibit 10(e)(12).)
*10(a)(17)	--	Amendment No. 1, dated June 1, 1986, to the General Indemnity Agreement, dated as of December 1, 1984, between Valencia and TEP, as Indemnitors, J.C. Penney Company, Inc., as Owner Participant, United States Trust Company of New York, as Owner Trustee, Teachers Insurance and Annuity Association of America, as Loan Participant, and Marine Midland Bank, N.A., as Indenture Trustee. (Form 10-K for the year ended December 31, 1986, File No. 1-5924 -- Exhibit 10(e)(13).)

*10(a)(18) -- Amendment No. 1, dated June 1, 1986, to the General Indemnity Agreement, dated as of December 1, 1984, between Valencia and TEP, as Indemnitors, Harvey Hubbell Financial, Inc., as Owner Participant, United States Trust Company of New York, as Owner Trustee, Teachers Insurance and Annuity Association of America, as Loan Participant, and Marine Midland Bank, N.A., as Indenture Trustee. (Form 10-K for the year ended December 31, 1986, File No. 1-5924 -- Exhibit 10(e)(14).)

*10(a)(19) -- Amendment No. 2, dated as of July 1, 1986, to the General Indemnity Agreement, dated as of December 1, 1984, between Valencia and TEP, as Indemnitors, J.C. Penney Company, Inc., as Owner Participant, United States Trust Company of New York, as Owner Trustee, Teachers Insurance and Annuity Association of America, as Loan Participant, and Marine Midland Bank, N.A., as Indenture Trustee. (Form S-4, Registration No. 33-52860 -- Exhibit 10(f)(19).)

*10(a)(20) -- Amendment No. 2, dated as of June 1, 1987, to the General Indemnity Agreement, dated as of December 1, 1984, between Valencia and TEP, as Indemnitors, General Foods Credit Corporation, as Owner Participant, United States Trust Company of New York, as Owner Trustee, Teachers Insurance and Annuity Association of America, as Loan Participant, and Marine Midland Bank, N.A., as Indenture Trustee. (Form S-4, Registration No. 33-52860 -- Exhibit 10(f)(20).)

*10(a)(21) -- Amendment No. 2, dated as of June 1, 1987, to the General Indemnity Agreement, dated as of December 1, 1984, between Valencia and TEP, as Indemnitors, Harvey Hubbell Financial, Inc., as Owner Participant, United States Trust Company of New York, as Owner Trustee, Teachers Insurance and Annuity Association of America, as Loan Participant, and Marine Midland Bank, N.A., as Indenture Trustee. (Form S-4, Registration No. 33-52860 -- Exhibit 10(f)(21).)

*10(a)(22) -- Amendment No. 3, dated as of June 1, 1987, to the General Indemnity Agreement, dated as of December 1, 1984, between Valencia and TEP, as Indemnitors, J.C. Penney Company, Inc., as Owner Participant, United States Trust Company of New York, as Owner Trustee, Teachers Insurance and Annuity Association of America, as Loan Participant, and Marine Midland Bank, N.A., as Indenture Trustee. (Form S-4, Registration No. 33-52860 -- Exhibit 10(f)(22).)

*10(a)(23) -- Supplemental Tax Indemnity Agreement, dated July 1, 1986, between J.C. Penney Company, Inc., as Owner Participant, and Valencia and TEP, as Indemnitors. (Form 10-K for the year ended December 31, 1986, File No. 1-5924 -- Exhibit 10(e)(15).)

*10(a)(24) -- Supplemental General Indemnity Agreement, dated as of July 1, 1986, among Valencia and TEP, as Indemnitors, J.C. Penney Company, Inc., as Owner Participant, United States Trust Company of New York, as Owner Trustee, Teachers Insurance and Annuity Association of America, as Loan Participant, and Marine Midland Bank, N.A., as Indenture Trustee. (Form 10-K for the year ended December 31, 1986, File No. 1-5924 -- Exhibit 10(e)(16).)

*10(a)(25) -- Amendment No. 1, dated as of June 1, 1987, to the Supplemental General Indemnity Agreement, dated as of July 1, 1986, among Valencia and TEP, as Indemnitors, J.C. Penney Company, Inc., as Owner Participant, United States Trust Company of New York, as Owner Trustee, Teachers Insurance and Annuity Association of America, as Loan Participant, and Marine Midland Bank, N.A., as Indenture Trustee. (Form S-4, Registration No. 33-52860 -- Exhibit 10(f)(25).)

*10(a)(26) -- Valencia Agreement, dated as of June 30, 1992, among TEP, as Guarantor, Valencia, as Lessee, Teachers Insurance and Annuity Association of America, as Loan Participant, Marine Midland Bank, N.A., as Indenture Trustee, United States Trust Company of New York, as Owner Trustee, and Thomas B. Zakrzewski, as Co-Trustee, and the Owner Participants named therein relating to the Restructuring of Valencia's lease of the coal-handling facilities at the Springerville Generating Station. (Form S-4, Registration No. 33-52860 -- Exhibit 10(f)(26).)

*10(a)(27) -- Amendment, dated as of December 15, 1992, to the Lease Agreements, dated December 1, 1984, between Valencia, as Lessee, and United States Trust Company of New York, as Owner Trustee, and Thomas B. Zakrzewski, as Co-Trustee. (Form S-1, Registration No. 33-55732 -- Exhibit 10(f)(27).)

*10(b)(1) -- Lease Agreements, dated as of December 1, 1985, between TEP and San Carlos Resources Inc. (San Carlos) (a wholly-owned subsidiary of the Registrant) jointly and severally, as Lessee, and Wilmington Trust Company, as Trustee, as amended and supplemented. (Form 10-K for the year ended December 31, 1985, File No. 1-5924 -- Exhibit 10(f)(1).)

*10(b)(2) -- Tax Indemnity Agreements, dated as of December 1, 1985, between Philip Morris Credit Corporation, IBM Credit Financing Corporation and Emerson Finance Co., each as beneficiary under a separate trust agreement, dated as of December 1, 1985, with Wilmington Trust Company, as Owner Trustee, and William J. Wade, as Co-Trustee, and TEP and San Carlos, as Lessee. (Form 10-K for the year ended December 31, 1985, File No. 1-5924 -- Exhibit 10(f)(2).)

*10(b)(3) -- Participation Agreement, dated as of December 1, 1985, among TEP and San Carlos as Lessee, Philip Morris Credit Corporation, IBM Credit Financing Corporation, and Emerson Finance Co. as Owner Participants, Wilmington Trust Company as Owner Trustee, The Sumitomo Bank, Limited, New York Branch, as Loan Participant, and Bankers Trust Company, as Indenture Trustee. (Form 10-K for the year ended December 31, 1985, File No. 1-5924 -- Exhibit 10(f)(3).)

*10(b)(4) -- Restructuring Commitment Agreement, dated as of June 30, 1992, among TEP and San Carlos, jointly and severally, as Lessee, Philip Morris Credit Corporation, IBM Credit Financing Corporation and Emerson Capital Funding, William J. Wade, as Owner Trustee and Co-Trustee, respectively, The Sumitomo Bank, Limited, New York Branch, as Loan Participant and United States Trust Company of New York, as Indenture Trustee. (Form S-4, Registration No. 33-52860 -- Exhibit 10(g)(4).)

*10(b)(5) -- Lease Supplement No.1, dated December 31, 1985, to Lease Agreements, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee Trustee and Co-Trustee, respectively (document filed relates to Philip Morris Credit Corporation; documents relating to IBM Credit Financing Corporation and Emerson Financing Co. are not filed but are substantially similar). (Form S-4, Registration No. 33-52860 -- Exhibit 10(g)(5).)

*10(b)(6) -- Amendment No. 1, dated as of December 15, 1992, to Lease Agreements, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, as Lessor. (Form S-1, Registration No. 33-55732 -- Exhibit 10(g)(6).)

*10(b)(7) -- Amendment No. 1, dated as of December 15, 1992, to Tax Indemnity Agreements, dated as of December 1, 1985, between Philip Morris Credit Corporation, IBM Credit Financing Corporation and Emerson Capital Funding Corp., as Owner Participants and TEP and San Carlos, jointly and severally, as Lessee. (Form S-1, Registration No. 33-55732 -- Exhibit 10(g)(7).)

*10(b)(8) -- Amendment No. 2, dated as of December 1, 1999, to Lease Agreement, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, under a Trust Agreement with Philip Morris Capital Corporation as Owner Participant. (Form 10-K for the year ended December 31, 1999, File No. 1-5924 -- Exhibit 10(b)(8).)

*10(b)(9) -- Amendment No. 2, dated as of December 1, 1999, to Lease Agreement, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, under a Trust Agreement with IBM Credit Financing Corporation as Owner Participant. (Form 10-K for the year ended December 31, 1999, File No. 1-5924 -- Exhibit 10(b)(9).)

*10(b)(10) -- Amendment No. 2, dated as of December 1, 1999, to Lease Agreement, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, under a Trust Agreement with Emerson Finance Co. as Owner Participant. (Form 10-K for the year ended December 31, 1999, File No. 1-5924 -- Exhibit 10(b)(10).)

*10(b)(11) -- Amendment No. 2, dated as of December 1, 1999, to Tax Indemnity Agreement, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Philip Morris Capital Corporation as Owner Participant, beneficiary under a Trust Agreement dated as of December 1, 1985, with Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, together as Lessor. (Form 10-K for the year ended December 31, 1999, File No. 1-5924 -- Exhibit 10(b)(11).)

*10(b)(12) -- Amendment No. 2, dated as of December 1, 1999, to Tax Indemnity Agreement, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and IBM Credit Financing Corporation as Owner Participant, beneficiary under a Trust Agreement dated as of December 1, 1985, with Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, together as Lessor. (Form 10-K for the year ended December 31, 1999, File No. 1-5924 -- Exhibit 10(b)(12).)

*10(b)(13) -- Amendment No. 2, dated as of December 1, 1999, to Tax Indemnity Agreement, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Emerson Finance Co. as Owner Participant, beneficiary under a Trust Agreement dated as of December 1, 1985, with Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, together as Lessor. (Form 10-K for the year ended December 31, 1999, File No. 1-5924 -- Exhibit 10(b)(13).)

*10(b)(14) -- Amendment No. 3 dated as of June 1, 2003, to Lease Agreements, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, under a Trust Agreement with Philip Morris Capital Corporation as Owner Participant.

*10(b)(15) -- Amendment No. 3 dated as of June 1, 2003, to Lease Agreements, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, under a Trust Agreement with IBM Credit, LLC as Owner Participant.

*10(b)(16) -- Amendment No. 3 dated as of June 1, 2003, to Lease Agreements, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, under a Trust Agreement with Emerson Finance Co. as Owner Participant.

*10(b)(17) -- Amendment No. 3 dated as of June 1, 2003, to Tax Indemnity Agreement, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Philip Morris Capital Corporation as Owner Participant, beneficiary under a Trust Agreement dated as of December 1, 1985, with Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, together as Lessor.

*10(b)(18) -- Amendment No. 3 dated as of June 1, 2003, to Tax Indemnity Agreement, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and IBM Credit, LLC as Owner Participant, beneficiary under a Trust Agreement dated as of December 1, 1985, with Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, together as Lessor.

*10(b)(19) -- Amendment No. 3 dated as of June 1, 2003, to Tax Indemnity Agreement, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Emerson Finance Co. as Owner Participant, beneficiary under a Trust Agreement dated as of December 1, 1985, with Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, together as Lessor.

*10(b)(20) -- Amendment No. 4, dated as of June 1, 2006, to Lease Agreement, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Wilmington Trust Company and William J. Wade, as Owner Trustee and Cotrustee, respectively, under a Trust Agreement with Philip Morris Capital Corporation as Owner Participant.

*10(b)(21) -- Amendment No. 4, dated as of June 1, 2006, to Lease Agreement, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Wilmington Trust Company and William J. Wade, as Owner Trustee and Cotrustee, respectively, under a Trust Agreement with Selco Service Corporation as Owner Participant.

*10(b)(22) -- Amendment No. 4, dated as of June 1, 2006, to Lease Agreement, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Wilmington Trust Company and William J. Wade, as Owner Trustee and Cotrustee, respectively, under a Trust Agreement with Emerson Finance LLC as Owner Participant.

*10(b)(23) -- Amendment No. 4, dated as of June 1, 2006 to Tax Indemnity Agreement, dated as of December 1, 1985, between TEP and San Carlos, as Lessee, and Philip Morris Capital Corporation as Owner Participant, beneficiary under a Trust Agreement, dated as of December 1, 1985, with Wilmington Trust Company and William J. Wade, as Owner Trustee and Cotrustee, respectively, together as Lessor.

*10(b)(24) -- Amendment No. 4, dated as of June 1, 2006 to Tax Indemnity Agreement , dated as of December 1, 1985, between TEP and San Carlos, as Lessee, and Selco Service Corporation as Owner Participant, beneficiary under a Trust Agreement, dated as of December 1, 1985, with Wilmington Trust Company and William J. Wade, as Owner Trustee and Cotrustee, respectively, together as Lessor.

*10(b)(25) -- Amendment No. 4, dated as of June 1, 2006 to Tax Indemnity Agreement , dated as of December 1, 1985, between TEP and San Carlos, as Lessee, and Emerson Finance LLC as Owner Participant, beneficiary under a Trust Agreement, dated as of December 1, 1985, with Wilmington Trust Company and William J. Wade, as Owner Trustee and Cotrustee, respectively, together as Lessor.

*10(c)(1) -- Amended and Restated Participation Agreement, dated as of November 15, 1987, among TEP, as Lessee, Ford Motor Credit Company, as Owner Participant, Financial Security Assurance Inc., as Surety, Wilmington Trust Company and William J. Wade in their respective individual capacities as provided therein, but otherwise solely as Owner Trustee and Co-Trustee under the Trust Agreement, and Morgan Guaranty, in its individual capacity as provided therein, but Secured Party. (Form 10-K for the year ended December 31, 1987, File No. 1-5924 -- Exhibit 10(j)(1).)

*10(c)(2) -- Lease Agreement, dated as of January 14, 1988, between Wilmington Trust Company and William J. Wade, as Owner Trust Agreement described therein, dated as of November 15, 1987,between such parties and Ford Motor Credit Company, as Lessor, and TEP, as Lessee. (Form 10-K for the year ended December 31, 1987, File No.1-5924 -- Exhibit 10(j)(2).)

*10(c)(3) -- Tax Indemnity Agreement, dated as of January 14, 1988, between TEP, as Lessee, and Ford Motor Credit Company, as Owner Participant, beneficiary under a Trust Agreement, dated as of November 15, 1987, with Wilmington Trust Company and William J. Wade, Owner Trustee and Co-Trustee, respectively, together as Lessor. (Form 10-K for the year ended December 31, 1987, File No. 1-5924 -- Exhibit 10(j)(3).)

*10(c)(4) -- Loan Agreement, dated as of January 14, 1988, between the Pima County Authority and Wilmington Trust Company and William J. Wade in their respective individual capacities as expressly stated, but otherwise solely as Owner Trustee and Co-Trustee, respectively, under and pursuant to a Trust Agreement, dated as of November 15, 1987, with Ford Motor Credit Company as Trustor and Debtor relating to Industrial Development Lease Obligation Refunding Revenue Bonds, 1988 Series A (TEP's Sundt Project). (Form 10-K for the year ended December 31, 1987, File No. 1-5924 -- Exhibit 10(j)(4).)

*10(c)(5)	--	Indenture of Trust, dated as of January 14, 1988, between the Pima County Authority and Morgan Guaranty authorizing Industrial Development Lease Obligation Refunding Revenue Bonds, 1988 Series A (Tucson Electric Power Company Sundt Project). (Form 10-K for the year ended December 31, 1987, File No. 1-5924 -- Exhibit 10(j)(5).)
*10(c)(6)	--	Lease Amendment No. 1, dated as of May 1, 1989, between TEP, Wilmington Trust Company and William J. Wade as Owner Trustee and Co-Trustee, respectively under a Trust Agreement dated as of November 15, 1987 with Ford Motor Credit Company. (Form 10-K for the year ended December 31, 1990, File No. 1-5924 -- Exhibit 10(i)(6).)
*10(c)(7)	--	Lease Supplement, dated as of January 1, 1991, between TEP, Wilmington Trust Company and William J. Wade as Owner Trustee and Co-Trustee, respectively, under a Trust Agreement dated as of November 15, 1987, with Ford. (Form 10-K for the year ended December 31, 1991, File No. 1-5924 -- Exhibit 10(i)(8).)
*10(c)(8)	--	Lease Supplement, dated as of March 1, 1991, between TEP, Wilmington Trust Company and William J. Wade as Owner Trustee and Co-Trustee, respectively, under a Trust Agreement dated as of November 15, 1987, with Ford. (Form 10-K for the year ended December 31, 1991, File No. 1-5924 -- Exhibit 10(i)(9).)
*10(c)(9)	--	Lease Supplement No. 4, dated as of December 1, 1991, between TEP, Wilmington Trust Company and William J. Wade as Owner Trustee and Co-Trustee, respectively, under a Trust Agreement dated as of November 15, 1987, with Ford. (Form 10-K for the year ended December 31, 1991, File No. 1-5924 -- Exhibit 10(i)(10).)
*10(c)(10)	--	Supplemental Indenture No. 1, dated as of December 1, 1991, between the Pima County Authority and Morgan Guaranty relating to Industrial Lease Development Obligation Revenue Project. (Form 10-K for the year ended December 31, 1991, File No. 1-5924 -- Exhibit 10(I)(11).)
*10(c)(11)	--	Restructuring Commitment Agreement, dated as of June 30, 1992, among TEP, as Lessee, Ford Motor Credit Company, as Owner Participant, Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, and Morgan Guaranty, as Indenture Trustee and Refunding Trustee, relating to the restructuring of the Registrant's lease of Unit 4 at the Sundt Generating Station. (Form S-4, Registration No. 33-52860 -- Exhibit 10(i)(12).)
*10(c)(12)	--	Amendment No. 1, dated as of December 15, 1992, to Amended and Restated Participation Agreement, dated as of November 15, 1987, among TEP, as Lessee, Ford Motor Credit Company, as Owner Participant, Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, Financial Security Assurance Inc., as Surety, and Morgan Guaranty, as Indenture Trustee. (Form S-1, Registration No. 33-55732 -- Exhibit 10(h)(12).)
*10(c)(13)	--	Amended and Restated Lease, dated as of December 15, 1992, between TEP as Lessee and Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, as Lessor. (Form S-1, Registration No. 33-55732 -- Exhibit 10(h)(13).)
*10(c)(14)	--	Amended and Restated Tax Indemnity Agreement, dated as of December 15, 1992, between TEP as Lessee and Ford Motor Credit Company, as Owner Participant. (Form S-1, Registration No. 33-55732 -- Exhibit 10(h)(14).)
*10(d)	--	Participation Agreement, dated as of June 30, 1992, among TEP, as Lessee, various parties thereto, as Owner, Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, and LaSalle National Bank, as Indenture Trustee relating to TEP's lease of Springerville Unit 1. (Form S-1, Registration No. 33-55732 -- Exhibit 10(u).)
*10(e)	--	Lease Agreement, dated as of December 15, 1992, between TEP, as Lessee and Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, as Lessor. (Form S-1, Registration No. 33-55732 -- Exhibit 10(v).)

*10(f)	--	Tax Indemnity Agreements, dated as of December 15, 1992, between the various Owner Participants parties thereto and TEP, as Lessee. (Form S-1, Registration No. 33-55732 -- Exhibit 10(w).)
*10(g)	--	Restructuring Agreement, dated as of December 1, 1992, between TEP and Century Power Corporation. (Form S-1, Registration No. 33-55732 -- Exhibit 10(x).)
+*10(h)	--	1994 Omnibus Stock and Incentive Plan of UniSource Energy. (Form S-8 dated January 6, 1998, File No. 333-43767.)
+*10(i)	--	Management and Directors Deferred Compensation Plan of UniSource Energy. (Form S-8 dated January 6, 1998, File No. 333-43769.)
+*10(j)	--	TEP Supplemental Retirement Account for Classified Employees. (Form S-8 dated May 21, 1998, File No. 333-53309.)
+*10(k)	--	TEP Triple Investment Plan for Salaried Employees. (Form S-8 dated May 21, 1998, File No. 333-53333.)
+*10(l)	--	UniSource Energy Management and Directors Deferred Compensation Plan. (Form S-8 dated May 21, 1998, File No. 333-53337.)
+10(m)	--	Officer Change in Control Agreement between TEP and Karen G. Kissinger, dated as of December 4, 1998 (including a schedule of other officers who are covered by substantially identical agreements.)
+10(n)	--	Notice of Termination of Change in Control Agreement from TEP to Karen G. Kissinger, dated as of March 3, 2005 (including a schedule of other officers who received substantially identical notices.)
+*10(o)	--	Amended and Restated UniSource Energy 1994 Outside Director Stock Option Plan of UniSource Energy. (Form S-8 dated September 9, 2002, File No. 333-99317.)
*10(p)(1)	--	Asset Purchase Agreement dated as of October 29, 2002, by and between UniSource Energy and Citizens Communications Company relating to the Purchase of Citizens' Electric Utility Business in the State of Arizona. (Form 8-K dated October 31, 2002. File No. 1-13739 -- Exhibit 99-1.)
*10(p)(2)	--	Asset Purchase Agreement dated as of October 29, 2002, by and between UniSource Energy and Citizens Communications Company relating to the Purchase of Citizens' Gas Utility Business in the State of Arizona. (Form 8-K dated October 31, 2002. File No. 1-13739 -- Exhibit 99-2.)
*+10(q)	--	UniSource Energy 2006 Omnibus Stock and Incentive Plan (Form S-8 dated January 31, 2007. File No. 333-140353.)
12(a)	--	Computation of Ratio of Earnings to Fixed Charges – TEP.
12(b)	--	Computation of Ratio of Earnings to Fixed Charges – UniSource Energy.
21	--	Subsidiaries of the Registrants.
23	--	Consent of Independent Registered Public Accounting Firm.
24(a)	--	Power of Attorney – UniSource Energy.
24(b)	--	Power of Attorney – TEP.
31(a)	--	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act – UniSource Energy, by James S. Pignatelli.

31(b)	--	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act – UniSource Energy by Kevin P. Larson.
31(c)	--	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act – TEP, by James S. Pignatelli.
31(d)	--	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act – TEP, by Kevin P. Larson.
**32	--	Statements of Corporate Officers (pursuant to Section 906 of the Sarbanes-Oxley Act of 2002).

(*) Previously filed as indicated and incorporated herein by reference.

(+) Management contracts or compensatory plans or arrangements required to be filed as exhibits to this Form 10-K by item 601(b)(10)(iii) of Regulation S-K.

** Pursuant to Item 601(b)(32)(ii) of Regulation S-K, this certificate is not being "filed" for purposes of Section 18 of the Exchange act of 1934, as amended.

Direct Testimony of Dallas J. Dukes

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON - CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103.	DOCKET NO. E-01933A-05-0650
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-01933A-07-____

Direct Testimony of

Dallas J. Dukes

on Behalf of

Tucson Electric Power Company

July 2, 2007

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I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Dallas J. Dukes and my business address is One South Church Avenue, Tucson, Arizona, 85702.

Q. By whom are you employed and what are your duties and responsibilities?

A. I am the Director of Rates and Revenue Requirements for Tucson Electric Power Company ("TEP" or the "Company"). As Director of Rates and Revenue Requirements, I am responsible for monitoring and determining revenue requirements, customer pricing and rates structures for all the regulated utility subsidiaries of UniSource Energy Corporation ("UniSource Energy").

Q. Please describe your background and work experience.

A. I hold a Bachelors of Science degree in Accounting from Indiana University. I am also a Certified Public Accountant licensed in the State of Indiana. I have over fifteen years experience as an accountant within the utility industry. Before assuming my current position, I was employed as the Director of Accounting for TEP.

Prior to working for TEP, I was employed by Citizens Gas & Coke Utility ("Citizens Gas"), for approximately five years. Citizens Gas serves approximately 265,000 customers in the Indianapolis, Indiana area. The majority of my time at Citizens Gas was spent as the Controller.

Before then, I was the Controller and Director of Regulatory Affairs for Fountaintown Natural Gas Company, and Southeastern Indiana Natural Gas Company. Prior to that, I was employed by the Indiana Office of Utility Consumer Counselor ("OUCC") for approximately seven years. The majority of my time at the OUCC was spent as a Principal Accountant. My primary duties at the OUCC were to perform professional investigative audits and to represent the public's interest as an expert witness in proceedings before the Indiana Utility Regulatory Commission.

Q. What is the purpose of your Direct Testimony?

A. In my Direct Testimony I support the Company's request for a rate increase by discussing multiple pro forma operating expense adjustments, the pro forma rate base adjustment cash working capital and schedules as summarized below.

Q. Could you please summarize your testimony?

A. I am supporting the Company's request for a rate increase under the Market Methodology and Cost of Service ("COS") Methodology as discussed in the direct testimony of the Company's witness, James S. Pignatelli, by sponsoring Schedules A-1 Market, A-2 Market, A-5 Market, B-5 Market (page 3), C-1 Market, C-2 Market, A-1 COS, A-2 COS, A-5 COS, B-5 COS (page 3), C-1 COS, C-2 COS, and the pro forma accounting adjustments reflected on Schedules C "Market" and Schedule C "COS" listed below:

(i) Stranded Costs & Fixed Cost Transition Charge;

(ii) SlimFast Contract Cancellation Fee;

(iii) Generating Facilities – Operating Lease;

(iv) Heavy Equipment – Operating Lease;

(v) Railcar – Operating Lease;

(vi) Springerville Unit 1;

(vii) Renewable Resources;

(viii) Rate Case Expense;

(ix) Membership Dues;

(x) Advertising & Sponsorship;

(xi) Outside Services;

(xii) Customer Care and Billing ("CC&B") Normalizations;

(xiii) Out of Period Expenses;

(xiv) Lime Usage Costs;

(xv) Tri-State Fuel Oil Sales;

(xvi) Bad Debt Expense;

(xvii) Luna O&M;

(xviii) Capital Cost Allocations;

(xix) Corporate Cost Allocations;

(xx) Building Usage Allocation.

I am also supporting the Company's request for a rate increase under the "Hybrid Methodology" as discussed in the direct testimony of the Company's witness, James S. Pignatelli by sponsoring Schedules A-1 Hybrid, A-2 Hybrid, A-5 Hybrid, C-1 Hybrid, C-2 Hybrid and the pro forma accounting adjustments reflected on Schedules C Hybrid listed below:

(i) Navajo Operating Expenses Removal;

(ii) Four Corners Operating Expenses Removal.

Q. Please describe the information contained in summary Schedule A-1 Market and Schedule A-1 COS.

A. Schedule A-1 Market and Schedule A-1 COS summarize the increases in revenue requirement that the Company is seeking as a rate increase in each case. Lines 1 through 8 of both Schedule A-1s present the data utilized in determining the Company's revenue requirement. The data is presented pursuant to three valuation methodologies: (1) original cost; (2) reconstruction cost new less depreciation ("RCND"); and (3) fair value. The fair value is determined by adding together the original cost and RCND rate base amounts and dividing that total by two. This gives equal weight to both methods in determining the fair value amount. This method of determining the fair value is consistent with prior Arizona Corporation Commission ("Commission") decisions.

The test year that the Company utilized for this rate case is the twelve months ending December 31, 2006. As set forth in Schedule A-1 Market, the original cost rate base is $540 million and the RCND rate base is $1,013 million. Pursuant to historical Commission practice, the fair value rate base is considered to be $777 million. In Schedule A-1 COS, the original cost rate base is $983 million and the RCND rate base is $1,849 million. Pursuant to historical Commission practice, the fair value rate base is considered to be $1,416 million.

Schedule A-1 Market supports a finding that the Company has an operating income deficiency of $161 million and is therefore requesting an increase in revenues of $268 million. Schedule A-1 COS supports a finding that the Company has an operating income deficiency of $95 million and is therefore requesting an increase in revenues of $158 million. Lines 9 through 13 of Schedule A-1s present how the revenue increase would be allocated among the Company's customers by class.

II. PRO FORMA ADJUSTMENTS.

Q. Please explain the consideration of pro forma adjustments in the rate case process.

A. Public utility rates are based on the reasonable and prudently incurred costs of providing safe, reliable service. The revenue requirement underlying rates is developed on the basis of a test year that reflects a level of operating revenues and expenses, and net plant investment that is representative of normal conditions that are expected to exist during the time that resulting rates may be in effect. This affords the utility a reasonable opportunity to achieve a fair rate of return, as authorized by the Commission. Pro forma adjustments are made to recorded test year amounts that are not required for the provision of service or that are not representative of the levels expected to occur during the period in which the new rates will be in effect. Such adjustments may be made in the form of eliminations, annualizations, or normalizations.

Elimination adjustments are made to remove out-of-period or non-recurring transactions, or items that are not costs or revenues related to the provision of utility service; thus, not eligible for reflection in revenue requirements.

Annualization adjustments are made to reflect the full, twelve-month revenue or expense level of certain components of operating income. They are typically computed using end-of-test year quantities and the most current known and measurable prices and rates. Examples in this case include restating test year operating revenues to reflect customer levels at the end of the test year, adjusting payroll expense to reflect current salary rates and changes in employee levels during the test year, and adjusting recorded depreciation expense to reflect the full effect of plant additions and retirements during the test year.

Normalization adjustments reflect that the recorded test year operating revenues and expenses may not be representative of a normal level for ratemaking purposes. Certain events may have affected recorded transactions in an atypical manner. Moreover, some transactions eligible for reflection in revenue requirements are incurred at intervals less frequently than annually, provide benefits extending beyond a single year, or reoccur in significantly different amounts each year. As a result, the amounts recorded in the test year may not be viewed as "normal," thus requiring a restatement for ratemaking purposes. Normalization adjustments are made in instances when a test year level of revenues or expenses is not representative of what would be expected on an on-going basis. Examples in this case include the adjustment for bad debt expense, the overtime factor implicit in the payroll adjustment, and the adjustment to normalize the level of postage expense.

Q. Were the pro forma adjustments that you are sponsoring in your testimony prepared by you or under your supervision?

A. Yes, they were.

III. RATE BASE ADJUSTMENTS.

Q. What rate base adjustments are you sponsoring?

A. I am sponsoring the cash working capital request within all three filing methodologies.

Q. What is Cash Working Capital?

A. The receipt of customer revenues for the provision of service, and the disbursement of cash for the payment of the various costs of providing service rarely occur simultaneously. This is the fundamental consideration underlying the concept of Cash Working Capital. Cash Working Capital is generally viewed as the component of working capital that represents the amount of invested cash required to pay day-to-day operating expenses incurred in rendering service to customers. It may either increase or decrease rate base. If the computation of Cash Working Capital produces a positive result, then it indicates that there is an additional investment for which a return is warranted. Thus, that amount is added to rate base. If the computation produces a negative result, then it implies non-investor funding of Cash Working Capital, requiring a rate base deduction.

Q. How did you compute the Cash Working Capital amount included in the Working Capital adjustment?

A. Under my direction, a comprehensive lead-lag study was prepared.

Q. What period does the current lead-lag study cover?

A. The lead-lag study for this Application covers the calendar year 2006. The resulting leads and lags are applied to test year adjusted operating expenses.

Q. What is a lead-lag study?

A. A lead-lag study is a detailed analysis of the dynamic movement of funds throughout the organization, between the receivable and payable balance sheet accounts and related revenues and expenses that are reflected in the operating income component of revenue requirements. The method is generally viewed as the most accurate measure of Cash Working Capital. The Commission has stated a clear preference for the use of lead-lag studies in support of requested working capital amounts in rate cases.

The focal point of all lead-lag studies is the "point of service." That is the instant in time when customers receive service and when, coincidentally, the utility incurs the cost of providing that service. A lead-lag study measures the average length of time between the provision of service and the ultimate receipt of payment from the customer ("revenue lag"). The result is compared with the average length of time between the point at which the utility incurs a cost of providing that service and the date upon which it makes the related cash disbursement ("payment lead" if payment precedes the cost benefit, or "payment lag" is the payment occurs after the cost benefit). Cash Working Capital reflects the effect on costs of service of the difference between the revenue lag and payment leads or lags.

As may be seen on page 3 of Schedule B-5, a lead-lag study computes the Cash Working Capital associated with each component of cost of service. The revenue lag is constant for all cost categories. The various major expenses are analyzed separately for purposes of developing a specific payment lead or lag. Once the applicable expense lead or lag is known, it is compared with the revenue lag to determine the net lead or lag for that study category. After dividing the net lead or lag by 365 days to arrive at an annual percentage factor, the result is multiplied by the corresponding adjusted test year expense amount to quantify the Cash Working Capital requirement associated with that cost of service item. Consistent with past Commission policy, the effect of non-cash expenses such as depreciation and deferred income taxes are reflected in the study at a zero requirement.

Q. How was the average revenue lag computed?

A. The revenue lag is comprised of three distinct parts: the service lag, the billing lag, and the customer payment lag.

The service lag is measured from the midpoint of the period of service to the end of the period, the date upon which meters are read. A key underlying assumption is that service is taken uniformly throughout the period. With each customer being billed under twelve monthly billing cycles during the year, the average service lag is computed as 15.21 days [365 days / (12 X 2)].

The billing lag is typically measured from the meter read date to the date customer bills are prepared and balances entered into accounts receivable. The billing lag was computed based on actual meter read dates and bill mailing schedules used by TEP during the calendar year 2006.

The customer payment lag is measured from the point at which the customer bill enters accounts receivable to the date that either a payment is received or the account is written off as uncollectible. That lag was determined by computing the average accounts receivable turnover for eight months during the calendar year 2006. The accounts receivable turnover measures the average time during which a balance remains in accounts receivable and is computed by dividing the sum of the daily ending balances of accounts receivable by the sum of revenues billed and charged to accounts receivable during the study month.

Q. How were the payment leads and lags computed?

A. The payment leads and lags were developed based on analyses of actual payment history, contractual and statutory payment dates, and samples of expenditures.

Q. What was the overall results of the lead-lag study?

A. The study showed that there was negative cash working capital in the amount of approximately $25 million in the COS filing, $23 million in the Hybrid filing and $25 million in the Market filing. Corresponding decreases were made as pro forma adjustments to rate base.

IV. <u>OPERATING INCOME ADJUSTMENTS - MARKET AND COST OF SERVICE METHODOLOGIES.</u>

Q. Please explain the Stranded Costs and Competition Transition Charge Revenue Adjustment.

A. A key element of the 1999 Settlement Agreement that resulted in the opening of TEP's service territory to retail competition was the determination of how the Company's estimated stranded generation costs should be treated. The 1999 Settlement Agreement gave rise to a deferred charge on the balance sheet in the initial amount of $450 million, which became known as the Transition Recovery Asset ("TRA"). The TRA was comprised of $450 million of generation-related regulatory assets and liabilities and a portion of generation plant costs. The 1999 Settlement Agreement also provided for the implementation of a fixed revenue stream per kWh of electricity sold, to recover the costs accumulated in the TRA. This revenue stream was called the Fixed Competition Transition Charge ("CTC").

In accordance with the 1999 Settlement Agreement, the Fixed CTC was set at a rate intended to recover the balance of the TRA over a nine-year period ending December 31, 2008. The TRA is self-amortizing so that the rate of amortization is based on the Fixed CTC revenues – the greater the revenues, the more rapid the amortization of the TRA – thereby producing a constant designated rate of return on the unamortized balance. Should the TRA balance be fully recovered prior to the end of 2008, the Fixed CTC will be terminated early. In no event will it continue beyond the end of 2008.

Because the TRA and CTC are uniquely interrelated, and separately administered under the terms of the 1999 Settlement Agreement, it is anticipated that the TRA balance will be fully recovered at or near the time that rates set in this proceedings will go into effect. This adjustment removes the amounts associated with both the TRA and Fixed CTC from the recorded test year's operating revenues and expenses. This is consistent with both TEP's and Staff's treatment of the TRA and the Fixed CTC revenues in the 2004 Rate Review (Docket No. E-01933A-04-0408.)

Q. **Please explain the SlimFast Contract Fee adjustment.**

A. The customer, SlimFast, closed its operations within Tucson during the test year. This triggered a requirement in SlimFast's contract to pay a termination fee of $300,000. This termination fee was recorded during the test year. Because this termination fee is non-recurring, it has been removed from test year operating revenues.

Q. Please explain the Generating Facilities - Operating Lease adjustment.

A. For ratemaking purposes, and in accordance with Commission Decision No. 58497 (January 13, 1994), TEP uses a levelized annual payment methodology for recovering the costs incurred in connection with the Sundt, Springerville Common Facilities, and Springerville Coal Handling Facilities leases. The Company records these leases as capital leases in its public financial statements prepared in accordance with U.S. generally accepted accounting principles ("GAAP"), recording a depreciated capitalized lease asset and interest expense on a capitalized lease obligation. Under prior Commission decisions, the Company is required to recover these lease costs as if the leases were operating leases with levelized payments. This adjustment replaces the total amount of depreciation and interest on these leases included in test year operating expenses with a level annual amount. The pro forma level annual amounts computed in this adjustment are charged to the same operating expense accounts (Acct. No. 501 Fuel Expense and Acct. No. 507 Rent Expense) where the actual depreciation and interest expense were being removed. Since the recovery of non-fuel costs for Springerville Unit No. 1 is established by the fixed-cost recovery factor described in Mr. David G. Hutchens' Direct Testimony, the 50% portion of the Springerville Coal Handling lease applicable to Unit No. 1 rent expense is excluded from the adjustment calculation.

Q. Please explain the Heavy Equipment - Operating Lease adjustment.

A. As noted above, the Company is required to recover these capital lease costs as if they were operating leases with levelized payments. This adjustment replaces the total amount of depreciation and interest on a capital lease for an ash hauling truck with a levelized payment. This adjustment also includes the annualization of two operating leases entered during the test year.

Q. Please explain the Railcar - Operating Lease adjustment.

A. This adjustment reduces expense to reflect that a capital lease for rail cars ended during the test year. The rail cars associated with that lease also incurred significant non-recurring expenditures during the test year to prepare the cars to be turned back over to the leaseholders. This adjustment removes those expenses from pro forma test year operating expense. This adjustment also includes the annualization of two operating leases entered during the test year for new rail cars.

Q. What is the Springerville Unit No. 1 Expense adjustment?

A. As described in Mr. Hutchens' Direct Testimony, the Commission has chosen in the past to provide recovery of the Springerville Unit No. 1 non-fuel costs (lease payments, amortization of leasehold improvements, operating costs, and an allocable portion of the Springerville coal handling costs) through a levelized payment stream similar to a purchased power arrangement. The Company's adjustment increases the non-fuel operating costs of Springerville Unit No. 1 based on the recommend fixed cost factor per kW being sponsored by Mr. Hutchens.

Q. Please explain the Renewable Resources adjustment.

A. The Renewables Resources adjustments removes all plant in service, revenues and expenses associated with renewable resource costs and recovery so that this activity can be evaluated independently under the Company's proposed Demand-Side Management ("DSM") Adjustor Mechanism. The adjustment to test year rate base removes the photovoltaic plant in service and accumulated depreciation from rate base. The adjustment to test year operating revenues removes the Environmental Portfolio

Surcharge billed to retail customers (authorized by Commission Decision No. 63353), DSM revenues billed to retail customers, Other Electric Revenues from sales of solar kits and emission allowances, and revenue associated with GreenWatts sales. The adjustment to test year operating expense removes the activity associated with renewables revenues and compliance with the Commission's Environmental Portfolio Standard. Activities related to renewable resources and the DSM Adjustor Mechanism describes matters in the Direct Testimony of TEP witness Mr. Thomas Hansen.

Q. Please explain the Rate Case Expense adjustment.

A. The Rate Case Expense adjustment addresses the outside costs already incurred and expected to be incurred in connection with this rate case. This amount is an estimate of the anticipated final cost and will be updated before this proceeding concludes. The adjustment amortizes the balance to expense over three years.

Q. Please explain the Membership Dues Expense adjustment.

A. This adjustment removes the portion of membership dues paid to Edison Electric Institute for legislative advocacy and other dues paid to organizations we have voluntarily excluded from pro forma operating expenses.

Q. Please explain the Advertising & Sponsorships adjustment.

A. This adjustment reduces test year expenses to exclude the amounts paid for sponsoring the Tucson Electric Power Ball Park and the scoreboard at the University of Arizona.

Q. Please explain the Outside Services adjustment.

A. This adjustment removes the non-recurring consulting agreement expenditures paid during the test year.

Q. Please explain the Customer Care and Billing ("CC&B") Normalization adjustment.

A. The CC&B system was put into full operations during the test year replacing the Customer Information System Plus ("CIS Plus"). This adjustment was necessary to annualize the increased support costs related to the new system.

Q. Please explain the Out of Period Expenses adjustment.

A. In preparation for this filing, we reviewed expense accounts and material transactions in an attempt to identify expenditures that were not reflective of on-going recurring business activity at TEP and/or that belonging in other periods. In doing so, we identified certain expenses that belonged in a prior period and this adjustment reflects those corrections.

Q. Please explain the Lime Usage Costs adjustments.

A. This adjustment reduces Test-Year expenses related to increased scrubbing costs incurred at Springerville Unit No. 2 during the Test Year associated with the construction of Springerville Unit No. 3. The increased scrubbing costs at Unit No. 1 are corrected in the Springerville Unit No. 1 adjustment to an annual allowance based on the rated capacity of the generating facility and a fixed cost per kilowatt month cost recovery rate.

Q. Please explain the Tri-State Fuel Oil Sales adjustments.

A. This adjustment is to remove the impact of fuel oil sales to Tri-State Generation and Transmission Association during the test year for test runs of Springerville Unit No. 3.

Q. Please explain the Bad Debt Expense adjustment.

A. Bad debt expense is adjusted to a level reflective of final, pro forma weather-normalized, customer-annualized test year operating revenues, and the average percentage of account write-offs experienced during the past three years. Since there is no provision in the Fixed CTC or the EPS surcharge to recover any such amounts that become uncollectible, the Fixed CTC revenues and surcharge revenues removed in earlier rate case adjustments herein are added back to the pro forma revenue base used in computing this adjustment.

Q. Please explain the Luna O&M adjustment.

A. As described in Mr. Hutchens' Direct Testimony, the Company proposes recovering the non-fuel operating cost of its Luna Energy Facility through a market-based capacity charge. Accordingly, the operating cost incurred during the Test Year are being removed through this adjustment.

V. COST RESPONSIBILITY AND ALLOCATIONS.

Q. Briefly describe how costs associated with TEP's administrative and operational support of affiliates are treated in this rate application.

A. Costs that are incurred at TEP for the benefit of affiliates are either charged directly to affiliates, or a portion thereof is allocated to affiliates. The costs that are charged directly to affiliates from TEP are called "Direct Charges." Costs that are allocated to affiliates and that are beneficial to all UniSource Energy companies are called "Indirect Allocations."

A. Direct Charges.

Q. How does TEP charge affiliates for administrative and/or other operational activities that are undertaken on its behalf?

A. TEP administrative and/or operational labor, performed specifically for the benefit of an affiliate, is charged directly to the specific affiliate. Specific activity tracking processes with pre-defined accounting (tasks) are established to capture and charge time spent by TEP departments in direct support of affiliates. The labor loads (FICA, pensions and benefits) associated with these direct labor charges are also passed on to affiliates, as is a rental charge for use of intangible and general plant (referred to as a "Building Usage").

Non-labor charges are handled in a similar manner. As costs in direct support of affiliates are incurred, the TEP department that manages the related function will pay the bill but will then pass the cost through to the affiliate (through specific tasks on a voucher request, for example.) Occasionally, a TEP department may still manage a cost for an affiliate, but the cost is treated and expensed as a Direct Cost. When this occurs, the cost is invoiced and billed directly to the affiliate; TEP does not initially pay the bill.

B. Indirect Allocations.

Q. What is an Indirect Allocation?

A. An indirect allocation is used to appropriately charge affiliates for their fair share of a system or a process that is common or beneficial to the entire organization. There are various system allocations included as part of the indirect allocations, such as a customer service cost allocation, operating systems allocation and the allocation of corporate costs that benefit the entire organization.

Q. How are system costs determined and split among the UniSource Energy companies?

A. Costs necessary to maintain and manage a particular information technology system are accumulated in individual projects. The dollars are then allocated, and charged, to the UniSource Energy companies based on usage. For example, all financial plant and general ledger transactions are maintained in the Oracle system for TEP, UNS Gas, Inc. and UNS Electric, Inc. Amounts associated with the cost of running the Oracle system are tracked in individual projects. The dollars accumulated in the specific Oracle projects are then allocated to the appropriate companies based on the number of Oracle transactions supporting each particular company.

Q. How are corporate-related costs that are included as part of the indirect allocations treated?

A. Corporate-related costs are primarily employee expenses, including salary and benefits, which are accumulated as part of the UNS Allocation. Corporate-related costs also include audit fees, legal expenses and investor relations. These are costs that are common or beneficial to the entire organization and the dollars are accumulated and allocated, or charged, to the various UniSource Energy companies based on the Massachusetts three-factor formula ("Massachusetts formula"). The holding company order approved for UniSource Energy and issued by the Commission in Decision No. 60480 (November 25, 1997) approved an allocation policy which specifies the use of the Massachusetts formula. The formula is updated annually and, for this rate application, was calculated using end of calendar year 2006 data.

Q. Please explain the Massachusetts formula.

A. The Massachusetts formula is based on the average of three equally-weighted components: (i) payroll; (ii) plant and tangible assets; and (iii) total revenues. The Massachusetts formula is a common and accepted allocation methodology.

Q. Please explain the Capital Cost Allocation adjustment.

A. The Capital Cost Allocation adjustment was necessary to normalize the level of administrative and general charges capitalized during the test year. The charges capitalized were for services performed by TEP personnel in support areas like Information Services, Plant Accounting, and Operational Systems Support. The charges are accumulated within individual tasks and projects that are set up for activities performed for the direct benefit of TEP.

A study was performed during the test year to evaluate the time spent by these service areas in support of capital activities. A new capitalization rate was determined and put into effect in the third quarter of 2006. This new rate was used to normalize test year activity and more properly reflect the known capitalization rate going forward.

Q. Please explain the Corporate Cost Allocations adjustment.

A. As explained above, costs that are common or beneficial to the entire UniSource Energy organization are accumulated in specific tasks and projects and are then allocated or charged to the various UniSource Energy companies based on the Massachusetts three-factor formula. In this adjustment, the charges to be allocated were reviewed and those that were non-recurring or not reflective of on-going expense levels were removed. Charges that were incurred during the test year that should have been included within the allocation were added to the pool. The labor and benefits charged to the pool were adjusted to reflect the rates and levels at the end of the test year. We then calculated the pro forma allocation to TEP based on the Massachusetts three-factor formula. The three-factor formula was calculated using end of calendar year 2006 data.

Q. Please explain the Building Usage Allocation adjustment.

A. The cost to maintain and operate the administrative and operational facilities of TEP is accumulated within individual projects, similar to system costs as described above. These accumulated costs are then applied to regular payroll charges in the form of a burden rate. The Building Usage Allocation adjustment is being made to reduce the test year expense of TEP to reflect normalized activity of TEP employees being performed for and charged to affiliates and applying the most recent burden rate available.

VI. SUMMARY OF MARKET AND COST OF SERVICE SCHEDULES.

A. Schedules A-1s Market and COS, A-2s Market and COS, A-5s Market and COS.

Q. Have you described Schedules A-1s Market and COS earlier in your testimony?

A. Yes. Again Schedule A-1 is a summary of the increase in revenue requirement that TEP is seeking as a rate increase in this case.

Q. Please describe the information contained in Schedules A-2s Market and COS.

A. Schedules A-2s Market and COS present a summary of the results of operations for the test year and two prior calendar years, compared with the projected year. Lines 1-16 of Schedules A-2s Market and COS set forth the summary of operations for the years ending December 31, 2004 and December 31, 2005, and the test year ending December 31, 2006. Schedule A-2 also presents projected results of operations for the year ending December 31, 2007 under the headings "present rates" and "proposed rates."

Q. Please describe the information contained in Schedules A-5s Market and COS.

A. Schedules A-5s Market and COS present statements of changes in financial position for the years ending December 31, 2004 and December 31, 2005, the test year ending December 31, 2006 and the projected year ending December 31, 2007.

B. Schedules B-5s, Page 3, Market and COS.

Q. Please explain Schedules B-5s, Page 3, Market and COS.

A. Schedules B-5's Market and COS summarizes the calculation of cash working capital through a lead/lag study.

C. <u>Schedules C-1s Market and COS, C-2s Market and COS.</u>

Q. Please describe the C Schedules.

A. Section C, comprised of Schedule Nos. C-1 through C-3, presents the development of the net operating income or "return" component of revenue requirements submitted for Commission consideration in this rate case filing.

Q. Please explain Schedules C-1s Market and COS.

A. Schedules C-1s Market and COS show the actual Income Statement for the test year and summarize the effect of the proposed pro forma adjustments to recorded operating revenues and expenses, and the resulting adjusted net operating income.

Q. What is the purpose of Schedules C-2s Market and COS?

A. Schedules C-2s Market and COS present the detailed pro forma adjustments that reflect the full annual impact of operating changes, annualizations, normalizations, and other adjustments made to revenues and expenses as explained previously in this testimony.

VII. <u>OPERATING INCOME ADJUSTMENTS – HYBRID METHODOLOGY.</u>

Q. Are there adjustments to Plant in Service proposed in the Hybrid Methodology that impact the operating income expenses in the Hybrid Methodology?

A. Yes. Two generating stations are proposed to be removed from cost of service based rate base in the Hybrid Methodology, as more fully described in the Direct Testimony of Mr. Hutchens. The adjustments to rate base and the associated adjustments to depreciation expense, property tax expense, ADIT, working capital and income taxes are discussed in the Direct Testimony of Ms. Kissinger. I have included the remaining adjustments, Navajo Operating Expenses Removal and Four Corners Operating Expenses Removal to remove cost incurred during the test year related to operating and maintaining these facilities.

VIII. SUMMARY OF HYBRID PROPOSAL SCHEDULES.

A. Schedules A-1 Hybrid, A-2 Hybrid, A-5 Hybrid.

Q. Please describe the information contained in summary Schedule A-1 Hybrid.

A. Schedule A-1 Hybrid summarizes the increase in revenue requirement that the Company is seeking as a rate increase under its Hybrid Methodology. Lines 1 through 8 of Schedule A-1 Hybrid present the data utilized in determining the Company's revenue requirement. The data is presented pursuant to three valuation methodologies: (1) original cost; (2) reconstruction cost new less depreciation ("RCND"); and (3) fair value. The fair value is determined by adding together the original cost and RCND rate base amounts and dividing that total by two. This gives equal weight to both methods in determining the fair value amount. This method of determining the fair value is consistent with historic Commission practice.

The test year that the Company utilized for this rate case is the twelve months ending December 31, 2006. As set forth in Schedule A-1 Hybrid, the original cost rate base is $921 million and the RCND rate base is $1,705 million. Pursuant to Commission practice, the fair value rate base is considered to be $1,313 million.

Schedule A-1 Hybrid supports a finding that the Company has an operating income deficiency of $128 million and is therefore requesting an increase in revenues of $213 million. Lines 9 through 15 of Schedule A-1 Hybrid present how the revenue increase would be allocated among the Company's customers by class.

Q. Please describe the information contained in Schedule A-2 Hybrid.

A. Schedule A-2 Hybrid presents a summary of the results of operations for the test year and two prior calendar years, compared with the projected year. Lines 1-16 of Schedule A-2 Hybrid set forth the summary of operations for the years ending December 31, 2004 and December 31, 2005, and the test year ending December 31, 2006. Schedule A-2 Hybrid also presents projected results of operations for the year ending December 31, 2007 under the headings "present rates" and "proposed rates."

Q. Please describe the information contained in Schedule A-5 Hybrid.

A. Schedule A-5 Hybrid presents statements of changes in financial position for the years ending December 31, 2004 and December 31, 2005, the test year ending December 31, 2006 and the projected year ending December 31, 2007.

B. <u>Schedules B-5s, Page 3, Hybrid.</u>

Q. Please explain Schedules B-5s, Page 3, Hybrid.

A. Schedules B-5's Market and COS summarizes the calculation of cash working capital through a lead/lag study.

C. <u>Schedules C-1 Hybrid, C-2 Hybrid.</u>

Q. Please describe the C Schedules Hybrid.

A. Section C, comprised of Schedule Nos. C-1 through C-3 Hybrid, presents the development of the net operating income or "return" component of revenue requirements for the Hybrid Methodology submitted for Commission consideration in this rate case filing.

Q. Please explain Schedule C-1 Hybrid.

A. Schedule C-1 Hybrid begins with the adjusted column from Schedule C-1 COS and is labeled "Adjusted (Original)". Then Schedule C-1 Hybrid contains a column that summarizes the proposed pro forma income adjustments directly related to the Company's Hybrid Methodology. These two columns are netted to produce the column labeled "Hybrid Adjusted.

Q. What is the purpose of Schedule C-2 Hybrid?

A. Schedule C-2 Hybrid presents the detailed pro forma adjustments that reflect the full annual impact of the Hybrid Methodology to operating income.

Q. Does this conclude your Direct Testimony?

A. Yes it does.

Direct Testimony of Dawn Sabers

BEFORE THE ARIZONA CORPORATION COMMISSION

<u>COMMISSIONERS</u>
MIKE GLEASON- CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103.	DOCKET NO. E-01933A-05-0650
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-01933A-07-____

Direct Testimony of

Dawn Sabers

on Behalf of

Tucson Electric Power Company

July 2, 2007

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I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Dawn Sabers and my business address is 4350 East Irvington Road, Tucson, Arizona, 85714.

Q. By whom are you employed and what is your position?

A. I am Assistant Controller and General Manager of Corporate Accounting for Tucson Electric Power Company ("TEP" or "Company").

Q. What are your duties and responsibilities as Assistant Controller and General Manager of Corporate Accounting?

A. My present functional areas of responsibility include internal and external financial reporting, payroll and accounts payable for all of UniSource Energy Corporation's ("UniSource Energy") wholly-owned entities.

Q. Would you please describe your education, background and experience?

A. I received a Bachelor of Science Degree with a double major in Accounting and Management Information Systems from the University of Arizona in 1985. I am a Certified Public Accountant licensed to practice in the State of Arizona. I am a member of the American Institute of Certified Public Accountants and the Arizona State Society of Certified Public Accountants. Before assuming my current position, I was employed as the Director of Securities and Exchange Commission Reporting and Accounting Research for TEP.

Before joining TEP in 1994, I was employed by Deloitte Haskins & Sells, and its successor by merger, Deloitte & Touche, in the audit department for approximately eight and one-half years. I have over 20 years of utility auditing and accounting experience.

Q. What is the purpose of your Direct Testimony in this proceeding?

A. My Direct Testimony supports TEP's pro forma adjusted operating expense requested in this proceeding. Specifically, I am the sponsoring witness for the following pro forma accounting adjustments reflected on Schedule C-2:

- Payroll Expense;
- Payroll Tax Expense;
- Incentive Compensation;
- Pension; and
- Retiree Medical Plan.

Additionally, I will discuss a proposed change in the ratemaking treatment for costs incurred in connection with the Retiree Medical Plan and other employee costs.

II. OPERATING INCOME ADJUSTMENTS.

Q. Were the pro forma adjustments that you are sponsoring in your Direct Testimony prepared by you or under your supervision?

A. Yes, they were.

Q. Please explain the Payroll Expense Adjustment.

A. The Payroll Expense Adjustment is intended to reflect a normal level of salaries and wages in operating expenses. The Payroll Expense Adjustment causes the test year to reflect an average of O&M wages for 2005 and 2006. Additionally, the Payroll Expense Adjustment reflects the known and measurable wage increase as of January 1, 2007.

Q. Please explain the Payroll Tax Expense Adjustment.

A. The Payroll Tax Expense Adjustment reflects the employer's taxes (Social Security and Medicare) that correspondingly increase as a result of the increased expense from the Payroll Adjustment. Mechanically, TEP's average effective employer's tax rate for 2005 and 2006 was applied to the increased payroll expense reflected in the Payroll Adjustment. The Payroll Tax Expense Adjustment also reflects the increase in employer's tax expense as a result of the known and measurable increase in the wage base limit for social security tax effective January 1, 2007.

Q. Please explain the Incentive Compensation Adjustment.

A. TEP's Performance Enhancement Plan ("PEP") is based on specific, pre-established goals with awards measured on specific company performance, and is designed to award non-union employees for their contributions to TEP. The payout is determined based on year-end results and payments are made to employees the following year (usually in the first quarter). The Incentive Compensation Adjustment causes the test year to reflect the average annual incentive compensation expense for the periods 2003 to 2006.

Q. How does the PEP benefit customers?

A. Incentive compensation is an integral part of TEP's compensation and benefits program. Even though this compensation is "at-risk" compensation for employees, it contributes to the employment package offered by TEP which allows TEP to be competitive in attracting and retaining highly qualified employees. Retention of employees helps to reduce costs by having a more experienced work force and by decreasing new employee training needs. TEP's PEP provides a tool to encourage and reward alignment of the employee's goals with TEP's goals. TEP's goals include cost containment and providing strong customer service to its customers. TEP witness Michael DeConcini's Direct Testimony provides an additional discussion of the importance of cost containment throughout the years. One way this has been accomplished is through the use of an incentive program. These goals directly benefit the customer.

Q. Which employees are eligible for incentive compensation?

A. All non-union employees are eligible for incentive compensation under the PEP. Any form of compensation provided to the union work force must be collectively bargained. Currently, the union workforce is not comfortable with the "at risk" component of an incentive program or the ability to reward one employee more than another, as TEP's incentive program is designed to do. Rather, the union has negotiated pay scales to increase base wages.

Q. Please explain the Pension Adjustment.

A. The Pension Adjustment adjusts operating expenses for the test year based on the most recent pension actuarial valuation (the latest estimate of the pension expense amount).

III. <u>ACCRUAL BASIS ACCOUNTING AND ESTIMATES.</u>

Q. Please explain accrual accounting.

A. Accrual accounting is a key fundamental underlying generally accepted accounting principles ("GAAP"). Accrual accounting means that, in reporting financial transactions, revenues are recognized when they are earned, regardless of when cash is collected, and expenses are recorded in the period benefited, regardless of when payment is made. Accrual accounting supports the "matching principle" in which expenses are reported in the same period as the revenues that the expenses support. For ratemaking purposes, accrual accounting is used to ensure that the full cost of service is captured when determining the revenue requirements.

Accrual accounting has long been recognized as the standard for regulatory accounting and ratemaking in the public utility industry. Specifically, A.A.C. R14-2-103 requires all electric utilities in Arizona to adopt the Uniform System of Accounts ("USOA") of the Federal Energy Regulatory Commission ("FERC") for regulatory and reporting purposes. The USOA is based on accrual accounting. Accrual accounting is also consistent with the objective of creating intergenerational equity to avoid customer cross subsidization, and to obtain correct measures of the cost to provide safe and reliable service in a designated test year.

Q. Do financial statements prepared in accordance with GAAP include estimates?

A. Yes, accrual accounting requires the use of estimates. Estimates are an integral part of preparing financial statements in accordance with GAAP. Estimates are also required in regulatory accounting and reporting.

Q. Do test year amounts used for ratemaking typically include estimates?

A. Yes. Estimates are critical to the process of capturing the appropriate cost levels for a reporting period, such as a test year.

IV. <u>ACCRUAL ACCOUNTING (GAAP) FOR THE RETIREE MEDICAL PLAN.</u>

Q. Please explain the Retiree Medical Plan Adjustment.

A. The Retiree Medical Plan Adjustment adjusts operating expenses for the test year based on the most recent Retiree Medical Plan actuarial valuation (the latest estimate of the accrued period expense); and includes a component related to the amortization of the January 1, 2006 accrued liability ("Transition Obligation"). The amortization of the Transition Obligation reflects the transition from the cash basis to accrual basis for ratemaking.

Q. Please explain the proposed treatment of the Retiree Medical Plan in this filing.

A. For ratemaking purposes, the Arizona Corporation Commission ("Commission") has historically required post-retirement costs, such as TEP's Retiree Medical Plan costs, to be reflected in revenue requirements on a cash basis. In this rate proceeding, we propose a transition to accrual accounting.

Q. Why is TEP proposing accrual accounting for the Retiree Medical Plan?

A. Accrual accounting provides a better measure of the cost of service than cash basis accounting does. Our filing reflects the following:

(1) Accrued Period Expense:

TEP includes the actuarially determined expense (accrued expense), rather than merely reflecting cash payments made during the period as the period expense. The intent of the actuarially determined expense is to properly reflect the expense incurred in the test year. Using the actuarially determined expense provides a better measure of the cost of providing service to customers, rather than using payments made during the test year (cash basis).

(2) Transition Obligation Amortization:

The pro forma adjustment reflects the amortization of the Transition Obligation. The Transition Obligation represents the accumulated difference between using the cash basis rather than the accrual basis for ratemaking purposes since 1993. In January 1993, TEP adopted Statement of Financial Accounting Standards No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions* ("FAS 106") for GAAP purposes. The January 1, 2006 calculated accrued liability is based on the most recent actuarial valuation.

Q. Why, in recent rate case filings, did UNS Gas, Inc. and UNS Electric, Inc. (both affiliates of TEP) request the cash basis, rather than the accrual basis, for the rate treatment of retiree medical benefits?

A. UNS Gas, Inc. ("UNS Gas") and UNS Electric, Inc. ("UNS Electric") operate differently and have a unique set of circumstances from TEP. The use of the cash basis, rather than accrual basis, for retiree medical benefits expense for both UNS Gas and UNS Electric will not cause significant intergenerational ratemaking issues because the expense is relatively small (the difference between cash and accrual basis for each UNS Gas and UNS Electric was less than $100,000 for their test year filings).

Q. Why should the Commission adopt TEP's proposed accrual methodology when it denied similar recovery proposals by some other utilities?

A. Each utility operates its business differently and presents a unique set of circumstances. TEP believes that the actuarially determined expense more fairly represents the cost of service as it reflects the accrual basis of accounting.

Q. What are the ramifications of continuing to use the cash basis for the Retiree Medical Plan rather than the accrual basis for ratemaking?

A. The revenue requirement will not reflect the current cost of service. This will cause intergenerational differences because future ratepayers will be burdened with paying the retirement medical costs for employees who are providing electrical service to current ratepayers.

A. <u>Accrued Period Expense.</u>

Q. Has TEP calculated the accrual expense for the Retiree Medical Plan in accordance with GAAP?

A. Yes. In accordance with GAAP, TEP records the accrued expense calculated by the actuary to record the Retiree Medical Plan expense.

Q. Is the GAAP accrued expense for the Retiree Medical Plan included in the test year reasonable?

A. Yes. An independent actuary estimates the current period cost based on assumptions and employee population data supplied by TEP.

Q. Are the assumptions used by the actuary reasonable, unbiased and supportable?

A. Yes. The assumptions used for TEP are intended to produce a realistic assessment of the cost of the program. The actuary ensures that the assumptions are reasonable and supportable based on experience for the plan and the range of assumptions used for other plans. Additionally, we ensure that our discount rate, one of the assumptions, is within the range of discount rates used by other utilities included in an Edison Electric Institute Accounting Standards Committee Survey.

Q. Is the actuarial valuation dependent on significant assumptions concerning future conditions?

A. Yes. Using assumptions for estimates is a basic accounting and ratemaking concept. For example, depreciation rates are set based on expected useful lives, sometimes predicting use of 40 years. Estimates are critical for capturing cost of service for ratemaking.

Q. Are there other accounting estimates that use any assumptions similar to those used in the Retiree Medical Plan actuarial valuation?

A. Yes, Statement of Financial Accounting Standards No. 87, *Employers' Accounting for Pensions* ("FAS 87") for pensions, long accepted by the Commission for ratemaking, depends on many of the same assumptions as FAS 106, such as life expectancy, employee turnover, retirement date, discount rate and the design of the benefit plan.

B. Transition Obligation Amortization.

Q. What is the Transition Obligation and how much is it?

A. The Transition Obligation represents the benefits accrued through January 1, 2006 which have not yet been paid to retirees nor reflected in the actual test year expense. The Transition Obligation represents the difference between the cash basis and the accrual basis of accounting that has accumulated since 1993 when accrual accounting for the Retiree Medical Plan was adopted for GAAP purposes.

Q. What amortization period is TEP proposing for the Transition Obligation?

A. TEP is proposing an amortization period of 15 years which represents the average remaining service for current employees. The average TEP employee is 46 years old and the average retirement age is 61.

Q. What guidance does GAAP provide for the amortization of a transition obligation?

A. GAAP guidance provides that the amortization period for a transition obligation should be calculated as the average remaining service period for the current employees.

Q. Has the Commission recognized other transition obligations as recoverable costs?

A. Yes. When TEP adopted the provisions of FAS 87 for pensions, a similar transition obligation existed. The Commission recognized the transition obligation as a proper component of pension expense and permitted recovery in rates.

C. <u>Funding Conditions.</u>

Q. If the Commission were to approve recovery of TEP's Retiree Medical Plan on an accrual rather than a cash basis for ratemaking purposes, what funding conditions would TEP be willing to agree to?

A. TEP would be willing to adhere to the same funding conditions that the Commission required other utilities to follow in order to get accrual accounting for ratemaking purposes for FAS 106 costs. These utilities include:

- Southwest Gas Corporation (Decision No. 60352);
- Paradise Valley Water Company (Decision No. 60220); and
- Agua Fria Water Division, Sun City Sewer Company, Sun City Water Company and Sun City West Utilities Company (Decision No. 60172).

The funding conditions can be summarized as follows:

- The Company must fund the Retiree Medical Plan no less frequently than quarterly, and the amount of each payment must represent a ratable portion of the annual accrual expense;

- Funding deposits must be made in cash to an irrevocable, independently managed external trust;
- To the extent allowed by law, the Company must maintain a tax deductible status for the Retiree Medical Plan expense and a tax exempt status for the earnings for the trust;
- Investments made by the trustee of the trust must be compatible with meeting the Retiree Medical Plan obligations as they come due;
- Any accumulated excess of accrual-based over cash-based revenues intended to cover Retiree Medical Plan expenses is subject to refund, to the extent the plan's assets cannot be used for retiree medical expenses or have been used for unauthorized, non-plan purposes;
- Disbursements from the trust fund should be limited to payments for the benefits of retirees in accordance with the Company's benefit plans, administrative costs of the trust, and other purposes authorized by the Commission; and
- Upon termination of the trust and satisfaction of all Retiree Medical Plan obligations, any residual funds are to be utilized only as approved by the Commission.

Q. When would TEP begin to comply with the above funding conditions?

A. TEP would comply with the funding conditions starting with the first full calendar quarter after the Commission approves recovery on an accrual basis.

D. <u>Prudent Cost-Saving Measures.</u>

Q. Has TEP made any modifications to the Retiree Medical Plan during the past 10 years as a cost saving measure?

A. Yes. TEP has:

- Implemented a monthly premium cost share program based on years of service for employees who retire on or after January 1, 2003;
- Required retirees eligible for Medicare supplement coverage on or after January 1, 2002 to be responsible for any amount above $125 per month;
- Terminated Medicare supplement coverage for unclassified employees who retire on or after January 1, 2002; and
- Required union employees who retire on or after January 7, 2003 to be responsible for any Medicare supplement coverage above $109 per month.

V. ACCRUAL ACCOUNTING FOR OTHER EMPLOYEE COSTS.

Q. Are there other employee costs that have historically been reflected on a cash basis rather than an accrual basis for ratemaking?

A. Yes. Historically the Commission has required TEP to reflect the costs related to the Long-Term Disability Plan and the Worker's Compensation Plan in revenue requirements on a cash basis rather than an accrual basis.

Q. Please explain the proposed ratemaking treatment for the costs related to the Long-Term Disability Plan and the Worker's Compensation Plan.

A. Similar to the proposed ratemaking treatment for the Retiree Medical Plan, we propose the preferred accrual method. As a result, there will be consistency as accrual accounting will be used for <u>all</u> employee costs for ratemaking purposes.

When the ratemaking treatment (accrual method) is the same as the GAAP treatment (accrual method), no adjustment is necessary.

Q. Does TEP propose the same funding conditions for these plans as TEP proposed for the Retiree Medical Plan?

A. No. Because the amounts for the Long-term Disability and Worker's Compensation Plans are relatively small (the difference between cash and accrual basis for the current test year is less than $400,000), the funding conditions discussed above would not make sense for these plans.

Q. Would any of the adjustments included in your testimony change if TEP's generation were market-based rather than cost-based?

A. No, the adjustments would not change but they would be jurisdictionally allocated under the Market Methodology.

Q. Does this conclude your direct testimony?

A. Yes it does.

Direct Testimony of Thomas Hansen

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON - CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103.	DOCKET NO. E-01933A-05-0650
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-01933A-07-____

Direct Testimony of

Thomas N. Hansen

on Behalf of

Tucson Electric Power Company

July 2, 2007

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I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Thomas N. Hansen. My address is 255 South Washington, St. Johns, Arizona, 85936.

Q. What is your employment position?

A. I am the Vice President, Environmental Services, Conservation and Renewable Energy for Tucson Electric Power Company ("TEP" or the "Company").

Q. On whose behalf are you filing your direct testimony in this proceeding?

A. My testimony is filed on behalf of TEP.

Q. Please summarize your educational and professional background.

A. I received a Bachelor of Science degree in Electrical Engineering with an emphasis in Computer Science from Lehigh University in 1971. In 1972, I received a Masters of Science degree in Electrical Engineering with emphasis in inertial guidance, laser communications and rocket propulsion systems with a minor in geophysics from Stanford University. I was employed by Bechtel Power Corporation from 1972 to 1984, designing, building and operating electric generation stations of fossil, nuclear and renewable fuel sources, totaling over 6,500 MW of generation capacity. I was hired in 1984, by Alamito Company to manage its generation assets in Arizona and New Mexico, as well as generating plants later acquired in numerous other locations. I had different levels of management responsibility for about 3,500 MW of fossil and renewable fueled generation through 1992. I was hired in 1992 by TEP as Vice President of Power Production and served in that role through 1994 when I accepted the role of Vice President and Technical Advisor to the Chief Executive Officer, developing the technologies needed to transition the TEP generation portfolio to one that is more distributed, and less dependent upon imported sources of primary energy. I served in that role until 2007 when I was named to my current position as Vice President of Environmental Services, Conservation and Renewable Energy. I have held a Registered Electrical Engineering License in California since 1973 and a similar license in Arizona since 1975, as well as a Registered Mechanical Engineering License in Arizona since 1979. From 1982 through 1984, I held all electrical, mechanical, instrumentation, steamfitting and plumbing New Mexico contractors' licenses as the qualifying party for Bechtel in New Mexico.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to (i) support the Company's request for a cost-recovery mechanism for the programs identified in TEP's Demand-Side Management ("DSM") Portfolio and, (ii) explain the process whereby TEP proposes to request a cost-recovery mechanism for its compliance with the Renewable Energy Standard and Tariff ("REST") rules. TEP is requesting that both cost-recovery mechanisms be in place prior to the implementation of their associated programs.

I would also note that the Company is proposing two rate designs that will support reduction of annual peak hour demand and annual energy consumption in this proceeding: (i) Time-of-Use rates, and (ii) the Lifeline Rate Block. Those rate design proposals will be addressed in the Direct Testimony of TEP witness Mr. D. Bentley Erdwurm.

Q. Please summarize your testimony.

A. My testimony describes TEP's proposed cost recovery mechanism for its DSM Portfolio, including energy efficiency and peak-demand reduction program expenses, all of which will be recovered together in one line item labeled the DSM Adjustor Mechanism. Specifically, the testimony first describes the base DSM Adjustor Mechanism introduced in consolidated Docket No. E-01933A-05-0650 (the "1999 Settlement Agreement Amendment Case"). It then turns to the concepts of a proposed incentive mechanism for certain energy efficient capital expenditures ("Efficiency Enhanced Financial Incentive") and a performance-incentive mechanism designed to better ensure that successful energy efficiency programs do not preclude the Company from recovering its fixed costs ("DSM Performance Incentive"). I shall then describe the process that TEP will follow to seek approval of a cost-recovery mechanism for the Renewable Energy Action Plan ("REAP") / REST programs.

II. COST RECOVERY MECHANISM FOR DEMAND-SIDE MANAGEMENT (AND ENERGY EFFICIENCY EXPENSES).

Q. Please explain the Company's proposed DSM Adjustor Mechanism.

A. The Company proposes an annually adjusted DSM Adjustor Mechanism that will be implemented to provide cost recovery for Commission-approved DSM programs and expenditures. All DSM costs, including those currently in base rates, will be put into the DSM Adjustor Mechanism for recovery as a per-kWh charge line item on customer bills. In addition, the Efficient Equipment Enhanced Financial Incentive will be recovered through the line item DSM Adjustor Mechanism. Finally, the DSM Performance Incentive would also be recovered through the DSM Adjustor Mechanism.

Q. What is the purpose of the DSM Adjustor Mechanism?

A. The DSM Adjustor Mechanism will allow for timely recovery of DSM-approved costs that the Company incurs with regard to successful implementation of energy efficiency and demand reduction programs. It will also provide a mechanism by which the Commission, as well as the Company's customers, can readily identify those expenses associated with energy efficiency and demand reduction.

Q. Is TEP's proposed DSM Adjustor Mechanism the same under each of the Cost-of-Service, Market and Hybrid Methodologies?

A. Yes. DSM cost recovery is independent of the rate method adopted by the Commission in this proceeding. The DSM Adjustor Mechanism is designed to compliment any of the methodologies proposed by the Company in this proceeding.

Q. Have interested parties made any comments about TEP's proposed DSM Adjustor Mechanisms in prior proceedings?

A. Yes. In the 1999 Settlement Agreement Case, parties suggested that any DSM Adjustor Mechanism proposed by the Company should be considered in a rate case. Therefore, the Company is filing information regarding, and requesting approval of, the DSM Adjustor Mechanism in this rate case proceeding.

Q. Please describe the DSM Adjustor Mechanism and how it will work.

A. All DSM program costs will be recovered through the DSM Adjustor Mechanism rather than through base rates. The DSM Adjustor Mechanism is a per-kWh charge line item that will appear on customers' bills. Where a customer has a flat-energy consumption rate, the basic DSM Adjustor Mechanism Rate calculated will also be a flat amount per kWh of all energy consumed per month. Where a customer has a tiered rate, the DSM Adjustor Mechanism Rate will also be tiered.

On an annual basis, on or before June 1st, the Company will submit to the Commission actual DSM program cost and program performance information for the prior year. The filing will include an estimate of the successive-year revenue requirements information for the DSM program offerings. The DSM Adjustor Mechanism rate would then be calculated by:

- First determining the difference between DSM program revenues received in the prior year through the DSM Adjustor Mechanism and the actual DSM program costs for the prior year;
- Then adding the forecast DSM program costs for the next year;
- Then adding the revenue to be recovered from the DSM Performance Incentive Mechanism;
- Then adding the revenue to be recovered from the Efficiency Enhanced Financial Incentive;
- This sum is then divided by the appropriate tiered and flat forecast annual electric sales for the next year after the DSM program effects are considered;
- The result would be the rate per kWh to be used for the next year's DSM Adjustor Mechanism.

Exhibits TNH-1, TNH-2 and TNH-3 to my Direct Testimony provide the calculation details and an example calculation for the DSM Adjustor Mechanism and by this reference are incorporated herein.

Q. What programs and related costs will be included in the DSM Adjustor Mechanism?

A. The DSM Adjustor Mechanism will recover all costs related to specific DSM programs, the Efficiency Enhanced Financial Incentive, and the DSM Performance Incentive. Specific DSM program costs include program design, development and implementation costs plus marketing, and advertising, program management costs, outside implementation contractors, measurement and evaluation costs and general and administrative overhead. The DSM Adjustor Mechanism will also recover costs of developing a DSM Customer Information System over the five years subsequent to implementation of the system. Marketing costs include education and outreach programs. The DSM Adjustor Mechanism will also recover any DSM incentive payments made directly to customers or equipment vendors.

In addition, in the separate DSM docket, TEP sought approval for cost recovery of the marketing baseline study for its proposed DSM portfolio. Such recovery is appropriate through the DSM Adjustor Mechanism.

Similar to what was agreed upon in Docket No. G-04204-06-0463 by Commission Staff and UNS Gas, Inc., TEP requests that 25 percent of expected new program expenses and 100 percent of existing program costs be included in the initial DSM Adjustor Mechanism. Costs related to the baseline study described in the Direct Testimony of TEP Witness Ms. Denise Smith in the DSM Portfolio docket will be included in the DSM Adjustor Mechanism in its second year.

In addition, in TEP's last rate case, the Commission approved an annual expenditure of $3.1 million for DSM. A portion of the $3.1 million, $2.25 million, was diverted to fund the Environmental Portfolio Standard ("EPS"). TEP proposes that the money currently diverted to the EPS be reverted back to DSM and that the entire DSM expenditure amount be removed from base rates. All DSM expenditures will then flow through the DSM Adjustor Mechanism. In the first DSM program year there would be no DSM Performance Incentive to be recovered, as that would be based upon actual DSM program performance in the prior year.

Q. Are there any DSM costs that will not be recovered through the DSM Adjustor Mechanism?

A. It is the Company's intention to move all costs to implement energy efficiency and demand reduction from base rates into the DSM Adjustor Mechanism. However, to the extent that DSM related renewable energy program costs fall within the REST, 14-2-1801 *et seq.*, those costs will be recovered through the tariff TEP files with the Commission pursuant to the REST rules.

Q. Mr. Hansen, please provide additional detail regarding the dollar amounts that the Company proposes to transfer from base rates to the DSM Adjustor Mechanism?

A. At this time, the Company proposes an initial annual funding of $12.4 million for the proposed DSM programs, including $4 million in expenses removed from base rates. The Direct Testimony of Mr. Dallas Dukes contains an explanation of the specific DSM expenses and revenues removed from base rates. The allocation of the funding by program is as listed below:

Program	**1st full Year DSM Program Costs**
Residential New Construction program	$ 3,200,000
Shade Tree program	$ 160,000
Low Income Weatherization program	$ 381,000
Education and Outreach program	$ 651,000
Residential HVAC Replacement program	$ 500,000
Efficient Commercial Building Design program	$ 800,000
Non-residential Existing Facilities program	$ 700,000
Compact Fluorescent Lamp Buydown program	$ 700,000
Small Business DSM program	$ 1,300,000
Direct Load Control program	$ 3,970,500
Total of DSM Programs	**$ 12,362,500**

Q. Previously you referred to a portion of the DSM funding that was diverted to the EPS that the Company proposes to revert back to DSM and into the DSM Adjustor Mechanism. Can you please elaborate?

A. Yes. As part of the funding for the EPS in 2000, the Commission authorized TEP to use increasing amounts of base rate System Benefit Charge ("SBC") revenues originally allocated to

DSM program funding for renewable energy program funding. Those funds were $2.25 million in the test year. As a result of the implementation of the funding provisions of the REST for 2008, TEP will no longer need to use SBC revenues for renewable energy programs. Because the REST tariff will replace the EPS, and the REST tariff will provide all revenue recovery for the renewable energy programs as part of the REST, there will not be a need to continue funding the EPS through the SBC or EPS surcharge.

Q. When will the DSM Adjustor Mechanism begin operation and how does the Company propose to transition costs to the new DSM Adjustor Mechanism?

A. TEP is requesting that the DSM Adjustor Mechanism and the DSM Portfolio be effective simultaneously. At that time the removal of the DSM-related funds in the SBC portion of the base rates will occur, and expenses normally supported by such funds will thereafter be supported through the DSM Adjustor Mechanism as a line item on customer bills. Given the fixed estimated nature of the DSM Adjustor Mechanism, each subsequent annual review of the DSM Adjustor Mechanism will true-up actual expenses against estimated expenses.

Q. How will the DSM Adjustor Mechanism be reset?

A. After its first year in operation, the DSM Adjustor Mechanism will be modified based on: (1) historic and projected DSM funding and customer collections, (2) the Efficiency Enhanced Financial Incentive, and (3) the DSM Performance Incentives. No later than June 1 of each year, the Company will file a request with the Commission with supporting documentation to revise its DSM Adjustor Mechanism for the following year. Exhibits TNH-3 and TNH-4 to my testimony show the calculation of the proposed DSM Adjustor Mechanism for the first year after receiving an order in this proceeding and by this reference are incorporated herein.

Q. How does the Company propose to bill the new DSM Adjustor Mechanism to customers?

A. The DSM Adjustor Mechanism will appear as a separate line item on the customers' bills. Exhibit TNH-3 provides the proposed tariff rates for the DSM Adjustor Mechanism and by this reference is incorporated herein. Where a customer has a tiered rate, the DSM Adjustor Mechanism Rate will also be tiered, in that a zero DSM Adjustor Mechanism Rate is charged on the first tier of 500 kWh of monthly consumption. For second-tier monthly energy consumption (over 500 kWh but less than 3,500 kWh for residential – Rates 01, 21, 70, 201 – and less than 55,000 kWh for commercial – Rates 10, 76), the basic calculated DSM Adjustor Mechanism Rate would be charged. For third-tier monthly energy consumption (over 3,500 kWh for residential and over 55,000 kWh for commercial), three times the basic DSM Adjustor Mechanism Rate calculated would be charged. Where a customer has a flat energy consumption rate, the second-tier DSM Adjustor Mechanism Rate calculated will also be a flat amount per kWh of all energy consumed per month. The proposed second-tier DSM Adjustor Mechanism rate in the first year of implementation is $0.000625/kWh. As all customers benefit financially from reductions in energy consumption and demand through the DSM programs, all customer classes should be required to support those programs financially.

Q. What is the proposed DSM Adjustor Mechanism rate in the first year of implementation?

A. TEP proposes to collect, in the first year DSM Adjustor Mechanism, 100% of the existing program budgets and 25% of the new program budgets for a total of $6,384,625 (See the table below). Using adjusted test year energy consumption, the proposed tier two DSM Adjustor Mechanism rate in the first year of implementation is $0.000625/kWh and the third tier rate is $0.001875. See Exhibits TNH-3 and TNH-4 to my testimony for an explanation by this reference incorporated herein. As all customers benefit financially from reductions in energy consumption and demand through the DSM programs, all customer classes should be required to support those programs financially.

PROGRAM	1st full Year DSM Program Costs	Proposed 1st Year DSM AM collections
Residential New Construction (existing)	$ 3,200,000	$ 3,200,000
Shade Tree (existing)	$ 160,000	$ 160,000
Low Income Weatherization (existing)	$ 381,000	$ 381,000
Education and Outreach (existing)	$ 651,000	$ 651,000
Residential HVAC Replacement (new)	$ 500,000	$ 125,000
Efficient Commercial Building Design (new)	$ 800,000	$ 200,000
Non-residential Existing Facilities (new)	$ 700,000	$ 175,000
Compact Fluorescent Lamp Buydown (new)	$ 700,000	$ 175,000
Small Business DSM program (new)	$1,300,000	$ 325,000
Direct Load Control program (new)	$3,970,500	$ 992,625
Total Proposed 1st year collection		**$6,384,625**

Q. Is the Company proposing to have the DSM Adjustor Mechanism account accrue interest?

A. No, interest will not be accrued on the DSM accounts. The use of the annual true up should provide a balance between over recovery some years with under recovery some years.

Q. How will the DSM Adjustor Mechanism be recorded on TEP's books?

A. All labor and non-labor costs associated with each of the approved DSM programs will be recorded in specific Accounting Project Codes. These costs will be subject to balance sheet tracking and put into a deferral account on TEP's books. The DSM program cost will be recorded in accordance with Generally Accepted Accounting Principles and the Federal Energy Regulatory Commission's Uniform System of Accounts.

Q. Have you provided a proposed calculation methodology and example calculation for the DSM Adjustor Mechanism?

A. Yes. Exhibits TNH-1, TNH-2, TNH-3 and TNH-4 to my testimony show the proposed calculation methodology and example calculations for the DSM Adjustor Mechanism. By this reference, I am incorporating those exhibits into my Direct Testimony.

Q. When should the DSM Adjustor Mechanism be put in place?

A. The Company is requesting that the DSM Adjustor Mechanism be put in place prior to the effective date of any new DSM Portfolio programs. This is necessary so that TEP can be assured of timely recovery of costs associated with DSM Portfolio programs.

Q. Is TEP proposing that the DSM Adjustor Mechanism have a sunset date?

A. No. The DSM Adjustor Mechanism should be in effect as long as expenses of DSM programs are to be recovered. At this point the Company does not foresee a time when DSM programs would not be offered.

Q. Please explain the Company's proposed enhanced financial incentive for certain high energy-efficiency expenditures.

A. In order to provide economic incentives to the Company for certain high energy-efficient capital expenditures, the Company proposes an incentive mechanism that will allow TEP to earn an additional five-percent return, one percent for each of five consecutive years, on its capitalized DSM expenses above what it would claim on "normal" utility property. More specifically, the Company would be permitted to earn five percent more on the total dollar value of high efficiency equipment investment as compared to the total return on a non-high energy efficient investment.

Q. What type of energy efficiency expenditures would be eligible for the higher rate of return?

A. Expenditures eligible for this higher return would include:

- Equipment upgrades made to TEP-owned transmission or distribution system components, such as a line upgrade with a higher efficiency conductor, a transformer with high-efficiency windings, lighting upgrades in a power plant, high efficiency motor upgrade on pumps, or higher-efficiency capacitors in the distribution system; and
- Assets that TEP may not own but are: (1) installed at customer premises in TEP's service territory; (2) are financially supported by investments TEP makes outside of the DSM programs; and (3) are properly recovered through customer payments, such as an investment in the form of a financial incentive in a thermal storage system, a high-efficiency motor replacement, a lighting retrofit, or an internal transformer upgrade. The incentive would be applied to one-time agreements with customers for a specific equipment upgrade or replacement, or for internal equipment upgrades and replacements whose costs are recovered over a multiple-year period.

The high-efficiency equipment would have to provide at least 15 percent lower losses in the case of transmission or distribution equipment, or 15 percent better energy utilization in the case of energy conversion equipment, than similar equipment that would perform the same function in the most cost-effective manner without an enhanced financial incentive. The installed cost of the high efficiency equipment shall not exceed 120 percent of the installed cost of similar equipment that would perform the same function in the most cost-effective manner without an enhanced financial incentive.

For example, if the Company purchased a new high efficiency 500 kVA distribution transformer with 0.85 percent losses and a premium cost of 15 percent ($11,500) over a standard efficiency unit with 1.1 percent losses and a cost of $10,000, the investment in the transformer ($11,500) would be eligible for the five percent enhanced financial incentive. In this example, TEP would recover an additional $115 per year in the DSM Adjustor Mechanism for five consecutive years after the transformer is operational and in service.

Q. How would the proposed Efficiency Enhanced Financial Incentive rate operate?

A. No less than 30 days before making an expected expenditure or investment that the Company believes is appropriately recovered under the Efficiency Enhanced Financial Incentive rate, the Company will make a filing with the Commission. After Commission review and approval, the Company would proceed to purchase and install the equipment or make the investment with the expectation that it will be permitted to recover for that equipment or investment under the Efficiency Enhanced Financial Incentive rate through the DSM Adjustor Mechanism. The installed costs of the high-efficiency equipment would also be recorded in normal plant asset accounting records and applied to rate base at the next rate case, just as any other asset placed into service between rate cases. As an option, TEP proposes the Commission could grant authority for Staff to approve Efficiency Enhanced Financial Incentive filings of value below $100,000.

Q. Have you provided a proposed rate calculation for the Efficiency Enhanced Financial Incentive rate?

A. Yes. Attached as Exhibit TNH-5 is the proposed Efficiency Enhanced Financial Incentive rate calculation methodology and example calculation, which by this reference is incorporated herein.

Q. Are you aware of any jurisdictions that have approved an incentive mechanism similar to what you propose?

A. Yes. The State of Nevada has an incentive mechanism that allows for additional recovery above the authorized return on equity for the costs of conservation and DSM programs. This incentive mechanism includes utility purchases of energy efficient equipment for utility service purposes.

Q. Please explain the purpose of a DSM performance incentive.

A. The intended result of successful energy-efficiency programs is the reduction of electric energy consumption and/or electric demand. While this reduces the costs of producing electrical energy for an electric utility, it also reduces the revenue derived from energy consumption-based rates and thus reduces the opportunity for the utility to earn a fair rate of return on assets. These intended results are mitigated by the implementation of a performance incentive which allows the customers and the Company to share the overall net benefits of the DSM portfolio. To that end, TEP proposes the Performance Incentive that would allow customers to receive 90 percent and the Company to receive up to 10 percent of the net benefits of the DSM portfolio, excluding the Low-Income Weatherization ("LIW") program and the Educational and the Outreach Programs. In addition, the DSM Performance Incentive calculation would not include the Direct Load Control ("DLC") program benefits, as those are primarily capacity-related rather than consumption-related.

Q. How would TEP's proposed DSM Performance Incentive operate?

A. Each year TEP would file with the Commission the actual net DSM portfolio benefits (program benefits minus the program costs) as verified through the measurement and evaluation process. The net benefits will be calculated each reporting period and will be included in the next annual true-up of TEP's DSM Adjustor Mechanism. Ten percent of the sum of the program's net benefits will be calculated as the DSM Performance Incentive. The DLC, LIW and the Education and Outreach programs are outside of the scope of the DSM Performance Incentive and will not be considered with the net benefits or the incentive cap. After the total DSM portfolio's net benefits are summed, a ten-percent cap (of period spending) will be applied to determine the maximum amount of the DSM Performance Incentive. During the first year, DSM programs would most likely produce reduced or negative net benefits. Therefore, the DSM Performance Incentive would start after the first full year of implementation -- giving time for programs to ramp up and reach their potential.

Q. Are you aware of any precedent for such a Performance Incentive?

A. Yes, this Commission is considering a similar performance incentive mechanism for Arizona Public Service Company. In addition, TEP's DSM program consultants have provided information that similar mechanisms have been approved in Connecticut, Massachusetts, Minnesota, Ontario and Vermont. Several of these jurisdictions, including Connecticut, Ontario, Massachusetts and Vermont, allow for lost revenue recovery, and California allows for a mechanism to decouple profits from sales to address the inherent disincentive for a utility using consumption-based rates to offer energy-efficiency programs.

Q. Have you provided a proposed rate calculation for the DSM Performance Incentive?

A. Yes. Attached hereto as Exhibit TH-6 is a description and example of the DSM Performance Incentive, which by this reference is incorporated into my direct testimony.

Q. Mr. Hansen, are you aware if any party has recommended an Energy Efficiency Standard ("EES")?

A. Yes. In the 1999 Settlement Agreement Amendment Docket, Mr. Jeffrey Schlegel of the Southwest Energy Efficiency Project ("SWEEP") advocated an EES. The Company is responding to that suggestion in the DSM Program filing.

III. <u>RENEWABLE ENERGY STANDARD AND TARIFF COMPLIANCE.</u>

Q. Please explain Decision No. 69568's requirement that TEP file information regarding a REAP.

A. In Decision No. 69568, the Company was ordered to file its REAP Portfolio in a separate docket from this rate case filing by July 2, 2007. TEP understood that the REAP was to be a placeholder for the REST rules in the event that the rules were subsequently passed or a substitute if they were not eventually enacted.

Q. What do you understand to be the current status of the REST rules?

A. It is my understanding that the REST rules have been approved by the Commission and, as of June 15, 2007, certified by the Attorney General. I also understand that the REST rules must be on file with the Secretary of State for sixty (60) days before they will become effective. I believe that as of the date of this filing we are in that 60 day period. I anticipate that within the next two (2) months the REST rules will be effective.

Q. How does this change in the status of the REST rules impact the Company's REAP filing?

A. In light of this change in events since Decision No. 69568, TEP's REAP filing will merely acknowledge the status of the REST rules, re-affirm the Company's intent to abide by the procedures and provisions of the REST rules, and state TEP's intention to submit its compliance plan (along with a request for a cost recovery mechanism) to the Commission within the timeframe specified in the REST rules.

Q. Mr. Hansen will TEP be seeking a REST cost recovery mechanism in this rate case proceeding?

A. No. The Company's request for a REST cost recovery mechanism will be part of the plan compliance filing that I referenced above and will be made within sixty (60) days of the effective date of the REST rules, as noted in R14-2-1808.

IV. CONCLUSION.

Q. Mr. Hansen, do you have any concluding thoughts?

A. Yes, with respect to DSM, through this filing the Company has proposed cost recovery mechanisms that allow the Company to promote energy efficiency while recovering its costs and continuing to earn the return found appropriate in this proceeding. The Company believes that such cost recovery mechanisms are proper and seeks Commission approval in this proceeding.

In regard to renewable energy programs, it must be recognized that Arizona is beginning the transition from a fossil-fuel-based primary energy foundation to a sustainable primary energy foundation. The transition is needed to ensure that future generations of Arizona citizens have a long-term supply of safe, affordable, convenient energy on demand. As with all transitions, the first steps are the most expensive, difficult and uncertain. Currently, all Arizona sources of renewable energy come at a cost greater than any current fossil-fuel energy source. However, due to increased use of renewable energy, the cost differential is closing and in a decade or less, renewable energy may be at economic parity with fossil-fuel sources. Technical challenges to the seamless integration of time-variant renewable energy sources with dispatchable generation sources have been found. However, with proper planning, continuous data analysis and deliberate technology management, the challenges can be converted to opportunities and the path to sustainable energy integration can be smooth.

Q. Does this conclude your testimony?

A. Yes, it does.

EXHIBIT

TNH-1

DSM AM Calculation

DSM Tariff Calculation Spreadsheet

Customer Class	Customer Months	Annual Energy Consumption - KWH	1st Tier - KWH @ 0X	2nd Tier - KWH @ 1X	3rd Tier - KWH @ 3X	DSMAMTR Energy Equivalent
Residential						
Rate 01						
Single Phase Customer Months	4,102,937					
Poly Phase Customer Months	3,804					
Summer Monthly Energy 1st 500 kWh		157,191,445	157,191,445			0
Summer Monthly Energy Next 3000 kWh		1,944,859,708		1,944,859,708		1,944,859,708
Summer monthly Energy over 3500 kWh		140,610,250			140,610,250	421,830,751
Winter Monthly Energy 1st 500 kWh		280,753,681	280,753,681			0
Winter Monthly Energy Next 3000 kWh		1,095,328,529		1,095,328,529		1,095,328,529
Winter Monthly Energy over 3500 kWh		21,914,549			21,914,549	65,743,647
Subtotal	4,106,741	3,640,658,163	437,945,126	3,040,188,237	162,524,799	3,527,762,635
% of Annual Energy Per Category			12.03%	83.51%	4.46%	96.90%
Rate 21						
Single Phase Customer Months	34,512					
Poly Phase Customer Months						
Summer Monthly Energy 1st 500 kWh		291,925	291,925			0
Summer Monthly Energy Next 3000 kWh		26,169,378		26,169,378		26,169,378
Summer monthly Energy over 3500 kWh		4,405,393			4,405,393	13,216,180
Winter Monthly Energy 1st 500 kWh		636,300	636,300			0
Winter Monthly Energy Next 3000 kWh		20,392,657		20,392,657		20,392,657
Winter Monthly Energy over 3500 kWh		720,269			720,269	2,160,807
Subtotal	34,512	52,615,922	928,225	46,562,035	5,125,662	61,939,022
% of Annual Energy Per Category			1.76%	88.49%	9.74%	117.72%
Rate 70						
Single Phase Customer Months	50,748					
Poly Phase Customer Months						
Summer Monthly Energy 1st 500 kWh		838,733	838,733			0
Summer Monthly Energy Next 3000 kWh		34,156,925		34,156,925		34,156,925
Summer monthly Energy over 3500 kWh		3,846,009			3,846,009	11,538,027
Winter Monthly Energy 1st 500 kWh		2,116,434	2,116,434			0
Winter Monthly Energy Next 3000 kWh		22,582,213		22,582,213		22,582,213
Winter Monthly Energy over 3500 kWh		610,107			610,107	1,830,320
Subtotal	50,748	64,150,421	2,955,167	56,739,139	4,456,116	70,107,486
% of Annual Energy Per Category			4.61%	88.45%	6.95%	109.29%
Rate 201 A						
Single Phase Customer Months	86,138					
Poly Phase Customer Months						
Summer Monthly Energy 1st 500 kWh		1,698,038	1,698,038			0
Summer Monthly Energy Next 3000 kWh		48,260,469		48,260,469		48,260,469
Summer monthly Energy over 3500 kWh		3,086,079			3,086,079	9,258,236
Winter Monthly Energy 1st 500 kWh		3,035,325	3,035,325			0
Winter Monthly Energy Next 3000 kWh		34,712,462		34,712,462		34,712,462
Winter Monthly Energy over 3500 kWh		802,397			802,397	2,407,191
Subtotal	86,138	91,594,770	4,733,363	82,972,931	3,888,476	94,638,359
% of Annual Energy Per Category			5.17%	90.59%	4.25%	103.32%
Rate 201 B						
Single Phase Customer Months	6,353					
Poly Phase Customer Months						
Summer Monthly Energy 1st 500 kWh		124,686	124,686			0
Summer Monthly Energy Next 3000 kWh		3,485,102		3,485,102		3,485,102
Summer monthly Energy over 3500 kWh		451,491			451,491	1,354,473
Winter Monthly Energy 1st 500 kWh		155,813	155,813			0
Winter Monthly Energy Next 3000 kWh		2,882,298		2,882,298		2,882,298
Winter Monthly Energy over 3500 kWh		489,048			489,048	1,467,144
Subtotal	6,353	7,588,438	280,499	6,367,401	940,539	9,189,017
% of Annual Energy Per Category			3.70%	83.91%	12.39%	121.09%

Rate 201 C						
Single Phase Customer Months	2,560					
Poly Phase Customer Months						
Summer Monthly Energy 1st 500 kWh		77,688	77,688			0
Summer Monthly Energy Next 3000 kWh		1,213,451		1,213,451		1,213,451
Summer monthly Energy over 3500 kWh		83,921			83,921	251,764
Winter Monthly Energy 1st 500 kWh		109,123	109,123			0
Winter Monthly Energy Next 3000 kWh		811,362		811,362		811,362
Winter Monthly Energy over 3500 kWh		188,566			188,566	565,699
Subtotal	2,560	2,484,111	186,811	2,024,813	272,488	2,842,276
% of Annual Energy Per Category			7.52%	81.51%	10.97%	114.42%
Total Residential	4,287,053	3,859,091,826	447,029,190	3,234,854,556	177,208,079	3,766,478,794
Commercial						
Rate 10						
Single Phase Customer Months	200,229					
Poly Phase Customer Months	192,377					
Summer Monthly Energy 1st 500 kWh		9,543,561	9,543,561	0	0	0
Summer Monthly Energy Next 54,500 kWh		780,251,167	0	780,251,167	0	780,251,167
Summer monthly Energy over 55,000 kWh		233,743,492	0	0	233,743,492	701,230,477
Winter Monthly Energy 1st 500 kWh		11,972,322	11,972,322	0	0	0
Winter Monthly Energy Next 54,500 kWh		600,068,846	0	600,068,846	0	600,068,846
Winter Monthly Energy over 55,000 kWh		128,074,365	0	0	128,074,365	384,223,096
Subtotal	392,606	1,763,653,755	21,515,883	1,380,320,014	361,817,858	2,465,773,587
% of Annual Energy Per Category			1.22%	78.26%	20.52%	139.81%
Rate 76						
Single Phase Customer Months	4,203					
Poly Phase Customer Months	7,473					
Summer Monthly Energy 1st 500 kWh		275,230	275,230	0	0	0
Summer Monthly Energy Next 54,500 kWh		59,906,836	0	59,906,836	0	59,906,836
Summer monthly Energy over 55,000 kWh		15,467,659	0	0	15,467,659	46,402,976
Winter Monthly Energy 1st 500 kWh		263,000	263,000	0	0	0
Winter Monthly Energy Next 54,500 kWh		53,958,136	0	53,958,136	0	53,958,136
Winter Monthly Energy over 55,000 kWh		6,856,871	0	0	6,856,871	20,570,613
Subtotal	11,676	136,727,732	538,230	113,864,972	22,324,530	180,838,561
% of Annual Energy Per Category			0.39%	83.28%	16.33%	132.26%
Rate 11						
Single Phase Customer Months	3,948					
Poly Phase Customer Months	336					
Annual kWh		60,332,539	0	60,332,539	0	60,332,539
Rate 31						
Rate 31	499	16,196,892	0	16,196,892	0	16,196,892
Total Commercial	408,729	1,916,582,327	22,054,113	1,510,381,879	384,142,387	2,662,809,041
Industrial						
RT-13	7,200	1,204,228,137	0	1,204,228,137	0	1,204,228,137
RT-13PRS	24	4,088,075	0	4,088,075	0	4,088,075
RT-14	96	614,097,291	0	614,097,291	0	614,097,291
RT-14PRS	12	93,850,178	0	93,850,178	0	93,850,178
RT-85	612	128,481,410	0	128,481,410	0	128,481,410
RT-90	60	241,242,523	0	241,242,523	0	241,242,523
Subtotal	8,004	2,285,987,614	0	2,285,987,614	0	2,285,987,614
% of Annual Energy Per Category			0.00%	100.00%	0.00%	100.00%
Mining						
RT-15	24	926,300,900	0	926,300,900	0	926,300,900
% of Annual Energy Per Category			0.00%	100.00%	0.00%	100.00%
Public Streets and Highway Lighting						

RT-41	48	24,132,797	0	24,132,797	0	24,132,797
RT-47	48	9,397,676	0	9,397,676	0	9,397,676
Subtotal	96	33,530,473	0	33,530,473	0	33,530,473
% of Annual Energy Per Category			0.00%	100.00%	0.00%	100.00%
Other Sales - Public Authorities						
RT-40	36	101,171,460	0	101,171,460	0	101,171,460
RT-43	3,212	123,574,584	0	123,574,584	0	123,574,584
Subtotal	3,248	224,746,044	0	224,746,044	0	224,746,044
% of Annual Energy Per Category			0.00%	100.00%	0.00%	100.00%
Lighting						
RT-50	216		0	0	0	0
RT-51	14,628		0	0	0	0
RT-52	39,276		0	0	0	0
Subtotal	53,904	7,287,604	0	7,287,604	0	7,287,604
% of Annual Energy Per Category			0.00%	0.00%	0.00%	100.00%
						Estimated Total DSM Qualifying Adjusted Retail Sales
Total	**4,707,154**	**9,246,239,184**	**469,083,303**	**8,215,801,466**	**561,350,467**	**9,899,852,866**
% of Annual Energy Per Category =			5.29%	92.61%	6.33%	111.58%
% of Annual DSM Revenue Per Category =			0.00%	82.99%	17.01%	

Energy consumption Growth Rate for Next Year without DSM	3.59%
DSM Program Energy Consumption Reduction Expected in kWh next year:	34,700,000
Expected Cost DSM Programs for Next Year (TDSMENY) =	$12,500,000
Operating cost from the previous year (ADSMEPY) =	$10,450,252
The proposed TEP Efficiency Incentive from the previous year (ADSMIPY) =	$214,000
The proposed TEP Performance Incentive from the previous year (ADSMPPY) =	$520,000
The Actual Revenue produced by the previous years Adjustor mechanism (ADSMRPY) =	$11,217,936
The DSM Basic Program Dollars =	$12,466,316

Basic DSM Adjustor Mechanism Tariff Rate Second Tier per KWH =	$0.00121973
DSM Performance Incentive Adjustor Rate	$0.00061635
DSM TEP Efficiency Incentive Adjustor Rate	$0.00002314
DSM Adjustor Mechanism Tariff Rate First Tier per KWH =	$0.00000000
DSM Adjustor Mechanism Tariff Rate Second Tier per KWH =	$0.00185922
DSM Adjustor Mechanism Tariff Rate Third Tier per KWH =	$0.00557767

Residential RD

TUCSON ELECTRIC POWER COMPANY
FOR PERIOD ENDING DECEMBER 31, 2006
PROOF OF REVENUE - RESIDENTIAL

Line No.	Pricing Plan		Adjusted Booked Billing Determinants A
	RESIDENTIAL- R01 - FROZEN		
1	Customers (Single-Phase)		4,102,937
2	Customer (Three-Phase)		3,804
	Summer		
4	1st 500 kWhs		157,191,445
5	3,000 kWhs		1,944,859,708
6	3,501 kWhs and above		140,610,250
	Winter		
7	1st 500 kWhs		280,753,681
8	3,000 kWhs		1,095,328,529
9	3,501 kWhs and above		21,914,549
10	Revenue		
11	**TOTAL R01 - FROZEN**	kWh	3,640,658,163
12		Cust	342,228
	RESIDENTIAL WATER HEATING - R02		
13	Customers		28,728
14	1st 100 kWhs - is a customer charge		2,472,456
15	All Additional kWhs		2,788,089
16	Revenue		
17	**TOTAL R02**	kWh	5,260,545
18		Cust	

TUCSON ELECTRIC POWER COMPANY
FOR PERIOD ENDING DECEMBER 31, 2006
PROOF OF REVENUE - RESIDENTIAL

Line No.	Pricing Plan		Adjusted Booked Billing Determinants
			A
	RESIDENTIAL TIME OF USE - R21 - ELIMINATED - REPLACED BY NEW TIME OF USE - R70N		
1	Customer Charge		34,512
	Summer On Peak		
2	1st 500 kWhs		117,504
3	3,000 kWhs		10,533,594
4	3,501 kWhs and above		1,773,241
	Summer Off Peak		
5	1st 500 kWhs		174,420
6	3,000 kWhs		15,635,784
7	3,501 kWhs and above		2,632,152
	Summer Shoulder Peak		
8	1st 500 kWhs		0
9	3,000 kWhs		0
10	3,501 kWhs and above		0
	Winter On Peak		
11	1st 500 kWhs		149,837
12	3,000 kWhs		4,802,085
13	3,501 kWhs and above		169,610
	Winter Off Peak		
14	1st 500 kWhs		486,463
15	3,000 kWhs		15,590,572
16	3,501 kWhs and above		550,659
17	Revenue		
18	**TOTAL R21**	kWh	52,615,922
		Cust	2,876

TUCSON ELECTRIC POWER COMPANY
FOR PERIOD ENDING DECEMBER 31, 2006
PROOF OF REVENUE - RESIDENTIAL

Line No.	Pricing Plan		Adjusted Booked Billing Determinants A
	RESIDENTIAL TIME OF USE - R70 - ELIMINATED - REPLACED BY NEW TIME OF USE - R70N		
1	Customers		50,748
	Summer On Peak		
2	1st 500 kWhs		150,911
3	3,000 kWhs		6,145,782
4	3,501 kWhs and above		692,004
	Summer Off Peak		
5	1st 500 kWhs		628,225
6	3,000 kWhs		25,584,092
7	3,501 kWhs and above		2,880,723
	Summer Shoulder Peak		
8	1st 500 kWhs		59,597
9	3,000 kWhs		2,427,051
10	3,501 kWhs and above		273,282
	Winter On Peak		
11	1st 500 kWhs		465,283
12	3,000 kWhs		4,964,541
13	3,501 kWhs and above		134,128
	Winter Off Peak		
14	1st 500 kWhs		1,651,151
15	3,000 kWhs		17,617,672
16	3,501 kWhs and above		475,979
17	Revenue		
18	**TOTAL R70**	kWh	64,150,421
		Cust	4,229

TUCSON ELECTRIC POWER COMPANY
FOR PERIOD ENDING DECEMBER 31, 2006
PROOF OF REVENUE - RESIDENTIAL

Line No.	Pricing Plan		Adjusted Booked Billing Determinants
			A
	SPECIAL RESIDENTIAL ELECTRIC SERVICE - R201A - FROZEN		
1	Customers (Single-Phase)		86,138
	Mid-Summer		
2	1st 500 kWhs		777,880
3	3,000 kWhs		27,076,790
4	3,501 kWhs and above		2,295,440
	Remaining Summer		
5	1st 500 kWhs		920,158
6	3,000 kWhs		21,183,679
7	3,501 kWhs and above		790,638
	Winter		
8	1st 500 kWhs		3,035,325
9	3,000 kWhs		34,712,462
10	3,501 kWhs and above		802,397
11	Revenue		
12	**TOTAL R201A**	kWh	91,594,770
		Cust	7,178

TUCSON ELECTRIC POWER COMPANY
FOR PERIOD ENDING DECEMBER 31, 2006
PROOF OF REVENUE - RESIDENTIAL

Line No.	Pricing Plan		Adjusted Booked Billing Determinants
			A
	SPECIAL RESIDENTIAL ELECTRIC SERVICE TIME OF USE - R201B - ELIMINATED - REPLACED BY NEW ELECTRIC SERVICE TIME OF USE - R201BN		
1	Customers		6,353
	Mid-Summer On Peak		
2	1st 500 kWhs		8,987
3	3,000 kWhs		390,920
4	3,501 kWhs and above		55,298
	Mid-Summer Off Peak		
5	1st 500 kWhs		36,423
6	3,000 kWhs		1,584,414
7	3,501 kWhs and above		224,124
	Mid-Summer Shoulder Peak		
8	1st 500 kWhs		3,696
9	3,000 kWhs		160,791
10	3,501 kWhs and above		22,745
	Remaining Summer On Peak		
11	1st 500 kWhs		13,871
12	3,000 kWhs		247,584
13	3,501 kWhs and above		27,406
	Remaining Summer Off Peak		
14	1st 500 kWhs		56,428
15	3,000 kWhs		1,007,149
16	3,501 kWhs and above		111,486
	Remaining Summer Shoulder Peak		
17	1st 500 kWhs		5,280
18	3,000 kWhs		94,245
19	3,501 kWhs and above		10,432
	Winter On Peak		
20	1st 500 kWhs		37,240
21	3,000 kWhs		688,879
22	3,501 kWhs and above		116,884
	Winter Off Peak		
23	1st 500 kWhs		118,573
24	3,000 kWhs		2,193,419
25	3,501 kWhs and above		372,164
26	Revenue		
27	**TOTAL R201B**	kWh	7,588,438
		Cust	529

TUCSON ELECTRIC POWER COMPANY
FOR PERIOD ENDING DECEMBER 31, 2006
PROOF OF REVENUE - RESIDENTIAL

Line No.	Pricing Plan		Adjusted Booked Billing Determinants
			A
	SPECIAL RESIDENTIAL ELECTRIC SERVICE TIME OF USE - R201C - ELIMINATED - REPLACED BY NEW ELECTRIC SERVICE TIME OF USE - R201CN		
1	Customers		2,560
	Mid-Summer On Peak		
2	1st 500 kWhs		2,595
3	3,000 kWhs		123,116
4	3,501 kWhs and above		8,996
	Mid-Summer Off Peak		
5	1st 500 kWhs		11,459
6	3,000 kWhs		543,590
7	3,501 kWhs and above		39,721
	Mid-Summer Shoulder Peak		
8	1st 500 kWhs		1,164
9	3,000 kWhs		55,194
10	3,501 kWhs and above		4,033
	Remaining Summer On Peak		
11	1st 500 kWhs		10,149
12	3,000 kWhs		79,858
13	3,501 kWhs and above		5,064
	Remaining Summer Off Peak		
14	1st 500 kWhs		47,618
15	3,000 kWhs		374,688
16	3,501 kWhs and above		23,760
	Remaining Summer Shoulder Peak		
17	1st 500 kWhs		4,703
18	3,000 kWhs		37,005
19	3,501 kWhs and above		2,347
	Winter On Peak		
20	1st 500 kWhs		26,194
21	3,000 kWhs		194,760
22	3,501 kWhs and above		45,264
	Winter Off Peak		
23	1st 500 kWhs		82,929
24	3,000 kWhs		616,601
25	3,501 kWhs and above		143,303
26	Revenue		
27	**TOTAL R201C**	kWh	2,484,111
		Cust	213
28	**TOTAL 201**		
29	Revenue		
30		kWh	101,667,319
31		Cust	7,921

TUCSON ELECTRIC POWER COMPANY
FOR PERIOD ENDING DECEMBER 31, 2006
PROOF OF REVENUE - RESIDENTIAL

Line No.	Pricing Plan	Adjusted Booked Billing Determinants
		A
	RESIDENTIAL SUMMARY	
1	TOTAL RESIDENTIAL REVENUE	
2	TOTAL RESIDENTIAL KWHS	3,864,352,371
3	TOTAL RESIDENTIAL CUSTOMERS	357,254

General Service RD

TUCSON ELECTRIC POWER COMPANY
FOR PERIOD ENDING DECEMBER 31, 2006
PROOF OF REVENUE - GENERAL SERVICE

Line No.	Pricing Plan	Total	Adjusted Booked Billing Determinants
			A
	SMALL GENERAL SERVICE - C10 - FROZEN		
1	Customers (Single-Phase)		200,229
2	Customer (Three-Phase)		192,377
3	Energy First 3400 kWh per month		287,747,871
	Summer		
4	1st 500 kWhs		9,543,061
5	next 54,500 kWhs		780,196,667
6	all remaining kWhs		233,692,602
	Winter		
7	1st 500 kWhs		11,971,822
8	next 54,500 kWhs		600,014,346
9	all remaining kWhs		128,023,475
10	Revenue		
11	**TOTAL C10**	kWh	1,763,441,975
		Cust	32,717
	SMALL GENERAL SERVICE - PRS 10 - CONTRACT		
12	Revenue		
		kWh	211,780
		Cust	1
	Summer		
	1st 500 kWhs		500
	next 54,500 kWhs		54,500
	all remaining kWhs		50,890
	Winter		
	1st 500 kWhs		500
	next 54,500 kWhs		54,500
	all remaining kWhs		50,890
	C11		
13	Customers (Single-Phase)		3,948
14	Customer (Three-Phase)		336
15	Energy Summer		33,529,195
16	Energy Winter		26,803,344
17	Revenue		
18	**TOTAL C11**	kWh	60,332,539
		Cust	357

TUCSON ELECTRIC POWER COMPANY
FOR PERIOD ENDING DECEMBER 31, 2006
PROOF OF REVENUE - GENERAL SERVICE

Line No.	Pricing Plan	Total	Adjusted Booked Billing Determinants
			A
	GENERAL SERVICE TIME OF USE - C76 - ELIMINATED - REPLACED BY NEW GENERAL SERVICE TIME OF USE - R76N		
1	Customers (Single-Phase)		4,203
2	Customer (Three-Phase)		7,473
	Summer On-Peak		
4	1st 500 kWhs		43,611
5	next 54,500 kWhs		9,492,367
6	all remaining kWhs		2,450,884
	Summer Off-Peak		
7	1st 500 kWhs		216,249
8	next 54,500 kWhs		47,069,001
9	all remaining kWhs		12,152,991
	Summer Shoulder Peak		
10	1st 500 kWhs		15,370
11	next 54,500 kWhs		3,345,468
12	all remaining kWhs		863,784
	Winter On Peak		
13	1st 500 kWhs		56,268
14	next 54,500 kWhs		11,544,100
15	all remaining kWhs		1,466,997
	Winter Off Peak		
16	1st 500 kWhs		206,732
17	next 54,500 kWhs		42,414,036
18	all remaining kWhs		5,389,874
19	Revenue		
20	**TOTAL C76**	kWh	136,727,732
		Cust	973
	C31		
21	Summer - all Kwhs		11,457,973
22	Winter - all kWhs		4,738,919
23	Revenue		
24	**TOTAL C31**	kWh	16,196,892
		Cust	42

TUCSON ELECTRIC POWER COMPANY
FOR PERIOD ENDING DECEMBER 31, 2006
PROOF OF REVENUE - GENERAL SERVICE

Line No.	Pricing Plan	Total	Adjusted Booked Billing Determinants
			A
	LARGE GENERAL SERVICE - I13 - ELIMINATED - REPLACED BY NEW LARGE GENERAL SERVICE TIME OF USE - I85N		
1	Customer Charge		7,200
	Summer Demand		
2	On Peak kW		720,000
3	Off Peak kW		720,000
	Winter Demand		
4	On Peak kW		720,000
5	Off Peak kW		720,000
	Summer Demand All Additional kW		
6	On Peak kW		916,524
7	Off Peak kW		916,524
	Winter Demand All Additional kW		
8	On Peak kW		916,524
9	Off Peak kW		916,524
	Summer		
10	On Peak kWhs		130,802,332
11	Off Peak kWhs		515,570,740
12	Shoulder Peak kWhs		46,711,075
	Winter		
13	On Peak kWhs		119,944,726
14	Off Peak kWhs		391,199,264
15	Revenue		
16	**TOTAL I13**	kWh	1,204,228,137
		Cust	600
17	**PRS 13 - CONTRACT**		
18		Revenue	
19		kWh	4,088,075
20		Cust	2

TUCSON ELECTRIC POWER COMPANY
FOR PERIOD ENDING DECEMBER 31, 2006
PROOF OF REVENUE - GENERAL SERVICE

Line No.	Pricing Plan	Total	Adjusted Booked Billing Determinants
			A
	LARGE GENERAL SERVICE TIME OF USE - I85A - ELIMINATED - REPLACED BY NEW LARGE GENERAL SERVICE TIME OF USE - I85N		
1	Customers		372
	Summer Demand		
2	On Peak kW		36,000
3	Off Peak kW		36,000
	Winter Demand		
4	On Peak kW		36,000
5	Off Peak kW		36,000
	Summer Demand All Additional kW		
6	On Peak kW		21,140
7	Off Peak kW		21,140
	Winter Demand All Additional kW		
8	On Peak kW		11,970
9	Off Peak kW		11,970
	Summer		
10	On Peak kWhs		6,151,695
11	Off Peak kWhs		29,592,895
12	Shoulder Peak kWhs		2,126,538
	Winter		
13	On Peak kWhs		5,802,304
14	Off Peak kWhs		22,212,312
15	Revenue		
16	**TOTAL I85A**	kWh	65,885,743
		Cust	31

TUCSON ELECTRIC POWER COMPANY
FOR PERIOD ENDING DECEMBER 31, 2006
PROOF OF REVENUE - GENERAL SERVICE

Line No.	Pricing Plan	Total	Adjusted Booked Billing Determinants
			A
	LARGE GENERAL SERVICE TIME OF USE FROZEN - I85F - ELIMINATED - REPLACED BY NEW LARGE GENERAL SERVICE TIME OF USE - I85N		
1	Customers		240
	Summer Demand		
2	On Peak kW		24,000
3	Off Peak kW		24,000
	Winter Demand		
4	On Peak kW		24,000
5	Off Peak kW		24,000
	Summer Demand All Additional kW		
6	On Peak kW		36,047
7	Off Peak kW		36,047
	Winter Demand All Additional kW		
8	On Peak kW		23,889
9	Off Peak kW		23,889
	Summer		
10	On Peak kWhs		5,748,531
11	Off Peak kWhs		27,935,990
12	Shoulder Peak kWhs		1,956,514
	Winter		
13	On Peak kWhs		5,677,051
14	Off Peak kWhs		21,277,580
15	Revenue		
16	**TOTAL I85F**	kWh	62,595,666
		Cust	20

	SMALL AND LARGE GENERAL SERVICE SUMMARY	
1	**TOTAL GENERAL SERVICE REVENUE**	
2	**TOTAL GENERAL SERVICE KWHS**	**3,313,708,541**
3	**TOTAL GENERAL SERVICE CUSTOMERS**	**34,743**

Industrial RD

TUCSON ELECTRIC POWER COMPANY
FOR PERIOD ENDING DECEMBER 31, 2006
PROOF OF REVENUE - LARGE LIGHT AND POWER SERVICE

Line No.	Pricing Plan	Total	Adjusted Booked Billing Determinants
			A
	LARGE LIGHT AND POWER - I14 - ELIMINATED - REPLACED BY NEW LARGE LIGHT AND POWER TIME OF USE - I90N		
1	**Customer Charge**		96
	Summer Demand		
2	On Peak kW		781,110
3	Off Peak kW		764,707
	Winter Demand		
4	On Peak kW		542,806
5	Off Peak kW		536,292
	Summer		
6	On Peak kWhs	17.7%	58,465,957
7	Off Peak kWhs	76.1%	251,749,604
8	Shoulder Peak kWhs	6.3%	20,711,872
	Winter		
9	On Peak kWhs	22.8%	64,495,493
10	Off Peak kWhs	77.2%	218,674,365
11	Revenue		
12	**TOTAL I14**	kWh	614,097,291
13		Cust	8
	PRS 14 - CONTRACT		
14	Revenue		
15		kWh	93,850,178
16		Cust	1

TUCSON ELECTRIC POWER COMPANY
FOR PERIOD ENDING DECEMBER 31, 2006
PROOF OF REVENUE - LARGE LIGHT AND POWER SERVICE

Line No.	Pricing Plan	Total	Adjusted Booked Billing Determinants
			A
	LARGE LIGHT AND POWER TIME OF USE - I90A - ELIMINATED - REPLACED BY NEW LARGE LIGHT AND POWER TIME OF USE - I90N		
1	**Customer Charge**		12
	Summer Demand		
2	On Peak kW		41,051
3	Off Peak kW		41,718
	Winter Demand		
4	On Peak kW		41,204
5	Off Peak kW		41,369
	Summer		
6	On Peak kWhs	13.9%	4,368,214
7	Off Peak kWhs	80.6%	25,419,192
8	Shoulder Peak kWhs	5.5%	1,744,779
	Winter		
9	On Peak kWhs	19.0%	5,896,039
10	Off Peak kWhs	81.0%	25,100,381
11	Revenue		
12	**TOTAL I90A**	kWh	62,528,605
13		Cust	1
			165,342

Line No.	Pricing Plan	Total	Adjusted Booked Billing Determinants
	LARGE LIGHT AND POWER TIME OF USE FROZEN I90F - ELIMINATED - REPLACED BY NEW LARGE LIGHT AND POWER TIME OF USE - I90N		
1	**Customer Charge**		48
	Summer Demand		
2	On Peak kW		148,098
3	Off Peak kW		150,506
	Winter Demand		
4	On Peak kW		132,674
5	Off Peak kW		133,207
	Summer		
6	On Peak kWhs	15.4%	15,169,458
7	Off Peak kWhs	78.8%	77,504,261
8	Shoulder Peak kWhs	5.8%	5,686,028
	Winter		
9	On Peak kWhs	21.1%	16,976,026
10	Off Peak kWhs	78.9%	63,378,144
11	Revenue		
12	**TOTAL I90F**	kWh	178,713,918
13		Cust	4

TUCSON ELECTRIC POWER COMPANY
FOR PERIOD ENDING DECEMBER 31, 2006
PROOF OF REVENUE - LARGE LIGHT AND POWER SERVICE

Line No.	Pricing Plan	Total	Adjusted Booked Billing Determinants
			A
	INDUSTRIAL SERVICE SUMMARY		
1	TOTAL LARGE LIGHT AND POWER SERVICE REVENUE		
2	TOTAL LARGE LIGHT AND POWER KWHS		949,189,992
3	TOTAL LARGE LIGHT AND POWER CUSTOMERS		14

Public Authority RD

TUCSON ELECTRIC POWER COMPANY
FOR PERIOD ENDING DECEMBER 31, 2006
PROOF OF REVENUE - PUBLIC AUTHORITY

Line No.	Pricing Plan	Total	Adjusted Booked Billing Determinants A
	O40		
1	Energy kWh Summer		58,667,833
2	Energy kWh Winter		42,694,636
3	Revenue		
4	**TOTAL P40**	kWh	101,362,469
		Cust	3
	P43		
5	Energy kWh Summer		33,365,680
6	Energy kWh Winter		25,062,900
	P45&46 Interruptible Service		
7	Energy kWh Summer		35,724,522
8	Energy kWh Winter		29,743,473
9	Revenue		
10	**TOTAL P43**	kWh	123,896,575
		Cust	32

	PUBLIC AUTHORITY SERVICE SUMMARY	
11	**TOTAL PA SERVICE REVENUE**	
12	**TOTAL PA SERVICE KWHS**	**225,259,044**
13	**TOTAL PA SERVICE CUSTOMERS**	**35**

Lighting RD

TUCSON ELECTRIC POWER COMPANY
FOR PERIOD ENDING DECEMBER 31, 2006
PROOF OF REVENUE - LIGHTING

Line No.	Pricing Plan	Total	Adjusted Booked Billing Determinants A
	P41&47		
1			33,727,523
2	Revenue		
3		kWh	33,727,523
4		Cust	8
	P50, P51, P52		
5	Per 100 Watt		120,300
6	Per 250 Watt		19,380
7	Per 400 Watt		17,568
8	Per One Pole		3,960
9	Underground Service		47,892
10	55OH - new		504
11	55P -new		1,104
12	55UG -new		1,512
13	70UG -new		2,472
14	Revenue		
15	**TOTAL P50**	kWh	7,287,604
16		Cust	

	LIGHTING SERVICE SUMMARY	
17	**TOTAL LIGHTING SERVICE REVENUE**	
18	**TOTAL LIGHTING SERVICE REVENUE KWHS**	**41,015,127**
19	**TOTAL LIGHTING SERVICE CUSTOMERS**	**8**

EXHIBIT

TNH-2

DSM Adjustor Mechanism Calculation

Annually TEP shall file support for modification to its DSM Adjustor Rate for the following year. The DSM Adjustor Mechanism will provide revenue recovery for: 1) expenses incurred by TEP for all DSM program implementation; 2) the TEP performance incentive; and 3) enhanced financial incentives for energy efficient equipment installed by TEP or its customers and approved for such incentives in advance by the Commission Staff.

The filing for modification of the DSM Adjustor Mechanism Rate for example year 2009 will include the following information:

(1) A list of the expected costs of each DSM program for the next year, in this example 2009. The expected expenses will be itemized into the cost categories of: (1) Planning and Administration, (2) Program Incentives, (3) Program Management, (4) Consumer Outreach and Education, (5) Program Implementation, (6) Training and Technical Assistance, and (7) Evaluation of Program Results. The total of these expected costs is the total DSM expenses of the next year ("TDSMENY").

(2) A list of the actual expenses of each DSM program provided in the previous year, in this example 2007, in the cost categories of: (1) Planning and Administration, (2) Program Incentives, (3) Program Management, (4) Consumer Outreach and Education, (5) Program Implementation, (6) Training and Technical Assistance, and (7) Evaluation of Program Results. The total of these actual expenses is the total DSM expenses of the previous year ("ADSMEPY").

(3) The actual revenue produced by the DSM Adjustor Mechanism the previous year ("ADSMRPY") calculated by multiplying the DSM Adjustor Mechanism Rate in the previous year, in this example 2008, by the retail energy kWh sold in the previous year.

(4) The TEP DSM Performance Incentive Revenue Requirement expected to be recovered in the previous year, in this example 2007, ("ADSMPPY").

(5) The TEP DSM Efficiency Incentive Mechanism Revenue Requirement expected to be recovered in the previous year, in this example 2007, ("ADSMIPY").

(6) Estimated total DSM qualifying adjusted retail sales of electrical energy in kWh for the next year, in this example 2009, ("TRSOEE"), before expected DSM program-created energy consumption reductions are included.

(7) The estimated DSM program-created energy consumption reductions in the next year, in this example 2009. ("DSMECRCY")

The DSM Basic Program Rate ("DSMBPR") would then be calculated as:

DSMBPR ($/kWh) = ((TDSMENY (1) +ADSMEPY (2) +ADSMPPY (4) +ADSMIPY (5) –ADSMRPY (3)) / (TRSOEE (6) – DSMECRCY (7)))

The DSM Adjustor Mechanism Rate ("DSMAMR") would then be calculated as the sum of the DSM Basic Program Rate, the projected DSM Efficiency Incentive Rate ("DSMEIR") and the projected DSM Performance Incentive Adjustor Rate ("DSMPAR"):

DSMAMR in $/kWh = (DSMBPR + DSMEIR + DSMDAR)

A hypothetical example calculating the DSMAMR for this example in year 2009:

- In 2007, the ADSMEPY (2) from operating the DSM program was $10,450,252.
- In 2007, the ADSMPPY (4) was to have been $520,000.00.
- In 2007, the ADSMIPY (5) was to have been $214,000.00.
- In 2007, the ADSMRPY (3) billed and received was $11,217,936.
- The calculated DSMEIR is $0.00000085 / kWh for 2009.
- The calculated DSMDAR is $0.00061635 / kWh for 2009.
- For 2009, TEP proposes a DSM program with expected TDSMENY (1) cost of $12,500,000.
- The 2009 estimated TRSOEE (6) before DSM measures are expected to be 10,076,379,461 kWh.
- DSMECRCY (7) in 2009 are expected to be 34,700,000 kWh.

The DSM Basic Program Rate for example year 2009 would be:

((12,500,000+10,450,252+520,000+214,000-11,217,936) / (10,076,379,461 – 34,700,000)) = $0.001241 / kWh

This would then be added to the DSMPAR and DSMEIR to build the DSM Adjustor Mechanism Tariff Rate for example year 2009:

$0.00124146 + $0.00061635 + $0.00000085 = $0.001859 per kWh

Thus completing the rate schedule for the DSM Tiers:

Tier 1 DSM Rate = $0.000000 per kWh.
Tier 2 DSM Rate = $0.001859 per kWh.
Tier 3 DSM Rate = $0.005576 per kWh.

EXHIBIT

TNH-3

DSM Adjustor Mechanism Rate Description

Example 2008

Concept:

- All customers will be billed for DSM on a per kWh of energy consumed per monthly billing period basis. However, different customer classes will be billed in different manners as follows:
    - **Residential Class (Rates 1, 21, 70, 201):** Residential customers will not be billed any DSM charges on the first 500 kWh of monthly energy consumption. For monthly energy consumption above 500 kWh but less than 3,500 kWh, the customer will be billed at the Second Tier DSM rate. For monthly energy consumption above 3,500 kWh, the customer will be billed at the Third Tier DSM rate.
    - **Small General Service Class (Rates 10, 76):** Commercial customers will not be billed any DSM charges on the first 500 kWh of monthly energy consumption. For monthly energy consumption above 500 kWh but less than 55,000 kWh, the customer will be billed at the Second Tier DSM rate. For monthly energy consumption above 55,000 kWh, the customer will be billed at the Third Tier DSM rate.
    - All other customers billed on a monthly energy consumption basis will be billed at the Second Tier DSM rate for all kWh of energy consumed per month.
- The Third Tier DSM rate will be three times the Second Tier DSM rate.

Rate Structure for First Year (2008):

- First Tier DSM rate = \$0.0000 per kWh of applicable monthly consumption
- Second Tier DSM rate = \$0.000625 per kWh of applicable monthly consumption
- Third Tier DSM rate = \$0.001875 per kWh of applicable monthly consumption

Sample Bill Example Calculations:

- Example #1: Residential customer consumes 450 kWh in the month. The first 500 kWh are exempt from the DSM charge. Therefore the DSM charge = \$0.00 for the month. This represents an average consumption of 0.6 kW for all hours of the month, a bit less than average.

(Average year round TEP residential customer monthly consumption is about 960 kWh which represents average consumption of 1.33 kW for all hours of the month.)

- Example #2: Residential customer consumes 1,250 kWh in the month. The first 500 kWh are exempt from the DSM charge. The remaining (1,250 - 500=) 750 kWh are billed at the Second Tier DSM rate of $0.000625/kWh = $0.47 for the month. This represents an average consumption of 1.7 kW for all hours of the month, a bit more than average.

- Example #3: Residential customer consumes 5,250 kWh in the month. The first 500 kWh are exempt from the DSM charge. The next (3,500 - 500=) 3,000 kWh are billed at the Second Tier DSM rate of $0.000625/kWh = $1.88 for the month. $1.88 is then added to the Third Tier DSM billed energy of (5,250 – 3,500 =) 1,750 kWh times $0.001875 = $3.28, for a total DSM charge of $5.16 for the month. This represents an average consumption of 7.3 kW for all hours of the month, a lot more than average.

- Example #4: A small Commercial customer consumes 3,250 kWh in the month. The first 500 kWh are exempt from the DSM charge. The remaining (3,250 - 500=) 2,750 kWh are billed at the Second Tier DSM rate of $0.000625/kWh = $1.72 for the month. This represents an average consumption of 4.5 kW for all hours of the month.

- Example #5: A larger Commercial customer consumes 75,250 kWh in the month. The first 500 kWh are exempt from the DSM charge. The next (55,000 - 500=) 54,500 kWh are billed at the Second Tier DSM rate of $0. 000625/kWh = $34.06 for the month. $34.06 is then added to the Third Tier DSM billed energy of (75,250 – 55,000 =) 20,250 kWh times $0. 001875 = $37.97, for a total DSM charge of $72.03 for the month. This represents an average consumption of 104.5 kW for all hours of the month.

- Example #6: A medium size Industrial customer consumes 3,275,000 kWh in the month. All kWhs are billed at the Second Tier DSM rate of $0. 000625 per kWh which results in a DSM charge of $2046.88 for the month. This represents an average consumption of 4,549 kW for all hours of the month.

EXHIBIT

TNH-4

DSM AM Calculation

DSM Tariff 2008 Specific Calculation Spreadsheet

Customer Class	Customer Months	Annual Energy Consumption - KWH	1st Tier - KWH @ 0X	2nd Tier - KWH @ 1X	3rd Tier - KWH @ 3X	DSMAMTR Energy Equivalent
Residential						
Rate 01						
Single Phase Customer Months	4,102,937					
Poly Phase Customer Months	3,804					
Summer Monthly Energy 1st 500 kWh		157,191,445	157,191,445			0
Summer Monthly Energy Next 3000 kWh		1,944,859,708		1,944,859,708		1,944,859,708
Summer monthly Energy over 3500 kWh		140,610,250			140,610,250	421,830,751
Winter Monthly Energy 1st 500 kWh		280,753,681	280,753,681			0
Winter Monthly Energy Next 3000 kWh		1,095,328,529		1,095,328,529		1,095,328,529
Winter Monthly Energy over 3500 kWh		21,914,549			21,914,549	65,743,647
Subtotal	4,106,741	3,640,658,163	437,945,126	3,040,188,237	162,524,799	3,527,762,635
% of Annual Energy Per Category			12.03%	83.51%	4.46%	96.90%
Rate 21						
Single Phase Customer Months	34,512					
Poly Phase Customer Months						
Summer Monthly Energy 1st 500 kWh		291,925	291,925			0
Summer Monthly Energy Next 3000 kWh		26,169,378		26,169,378		26,169,378
Summer monthly Energy over 3500 kWh		4,405,393			4,405,393	13,216,180
Winter Monthly Energy 1st 500 kWh		636,300	636,300			0
Winter Monthly Energy Next 3000 kWh		20,392,657		20,392,657		20,392,657
Winter Monthly Energy over 3500 kWh		720,269			720,269	2,160,807
Subtotal	34,512	52,615,922	928,225	46,562,035	5,125,662	61,939,022
% of Annual Energy Per Category			1.76%	88.49%	9.74%	117.72%
Rate 70						
Single Phase Customer Months	50,748					
Poly Phase Customer Months						
Summer Monthly Energy 1st 500 kWh		838,733	838,733			0
Summer Monthly Energy Next 3000 kWh		34,156,925		34,156,925		34,156,925
Summer monthly Energy over 3500 kWh		3,846,009			3,846,009	11,538,027
Winter Monthly Energy 1st 500 kWh		2,116,434	2,116,434			0
Winter Monthly Energy Next 3000 kWh		22,582,213		22,582,213		22,582,213
Winter Monthly Energy over 3500 kWh		610,107			610,107	1,830,320
Subtotal	50,748	64,150,421	2,955,167	56,739,139	4,456,116	70,107,486
% of Annual Energy Per Category			4.61%	88.45%	6.95%	109.29%
Rate 201 A						
Single Phase Customer Months	86,138					
Poly Phase Customer Months						
Summer Monthly Energy 1st 500 kWh		1,698,038	1,698,038			0
Summer Monthly Energy Next 3000 kWh		48,260,469		48,260,469		48,260,469
Summer monthly Energy over 3500 kWh		3,086,079			3,086,079	9,258,236
Winter Monthly Energy 1st 500 kWh		3,035,325	3,035,325			0
Winter Monthly Energy Next 3000 kWh		34,712,462		34,712,462		34,712,462
Winter Monthly Energy over 3500 kWh		802,397			802,397	2,407,191
Subtotal	86,138	91,594,770	4,733,363	82,972,931	3,888,476	94,638,359
% of Annual Energy Per Category			5.17%	90.59%	4.25%	103.32%
Rate 201 B						
Single Phase Customer Months	6,353					
Poly Phase Customer Months						
Summer Monthly Energy 1st 500 kWh		124,686	124,686			0
Summer Monthly Energy Next 3000 kWh		3,485,102		3,485,102		3,485,102
Summer monthly Energy over 3500 kWh		451,491			451,491	1,354,473
Winter Monthly Energy 1st 500 kWh		155,813	155,813			0
Winter Monthly Energy Next 3000 kWh		2,882,298		2,882,298		2,882,298
Winter Monthly Energy over 3500 kWh		489,048			489,048	1,467,144
Subtotal	6,353	7,588,438	280,499	6,367,401	940,539	9,189,017
% of Annual Energy Per Category			3.70%	83.91%	12.39%	121.09%

Subtotal	6,353	7,588,438	280,499	6,367,401	940,539	9,189,017
% of Annual Energy Per Category			3.70%	83.91%	12.39%	121.09%
Rate 201 C						
Single Phase Customer Months	2,560					
Poly Phase Customer Months						
Summer Monthly Energy 1st 500 kWh		77,688	77,688			0
Summer Monthly Energy Next 3000 kWh		1,213,451		1,213,451		1,213,451
Summer monthly Energy over 3500 kWh		83,921			83,921	251,764
Winter Monthly Energy 1st 500 kWh		109,123	109,123			0
Winter Monthly Energy Next 3000 kWh		811,362		811,362		811,362
Winter Monthly Energy over 3500 kWh		188,566			188,566	565,699
Subtotal	2,560	2,484,111	186,811	2,024,813	272,488	2,842,276
% of Annual Energy Per Category			7.52%	81.51%	10.97%	114.42%
Total Residential	4,287,053	3,859,091,826	447,029,190	3,234,854,556	177,208,079	3,766,478,794
Commercial						
Rate 10						
Single Phase Customer Months	200,229					
Poly Phase Customer Months	192,377					
Summer Monthly Energy 1st 500 kWh		9,543,561	9,543,561	0	0	0
Summer Monthly Energy Next 54,500 kWh		780,251,167	0	780,251,167	0	780,251,167
Summer monthly Energy over 55,000 kWh		233,743,492	0	0	233,743,492	701,230,477
Winter Monthly Energy 1st 500 kWh		11,972,322	11,972,322	0	0	0
Winter Monthly Energy Next 54,500 kWh		600,068,846	0	600,068,846	0	600,068,846
Winter Monthly Energy over 55,000 kWh		128,074,365	0	0	128,074,365	384,223,096
Subtotal	392,606	1,763,653,755	21,515,883	1,380,320,014	361,817,858	2,465,773,587
% of Annual Energy Per Category			1.22%	78.26%	20.52%	139.81%
Rate 76						
Single Phase Customer Months	4,203					
Poly Phase Customer Months	7,473					
Summer Monthly Energy 1st 500 kWh		275,230	275,230	0	0	0
Summer Monthly Energy Next 54,500 kWh		59,906,836	0	59,906,836	0	59,906,836
Summer monthly Energy over 55,000 kWh		15,467,659	0	0	15,467,659	46,402,976
Winter Monthly Energy 1st 500 kWh		263,000	263,000	0	0	0
Winter Monthly Energy Next 54,500 kWh		53,958,136	0	53,958,136	0	53,958,136
Winter Monthly Energy over 55,000 kWh		6,856,871	0	0	6,856,871	20,570,613
Subtotal	11,676	136,727,732	538,230	113,864,972	22,324,530	180,838,561
% of Annual Energy Per Category			0.39%	83.28%	16.33%	132.26%
Rate 11						
Single Phase Customer Months	3,948					
Poly Phase Customer Months	336					
Annual kWh		60,332,539	0	60,332,539	0	60,332,539
Rate 31						
Rate 31	499	16,196,892	0	16,196,892	0	16,196,892
Total Commercial	408,729	1,916,582,327	22,054,113	1,510,381,879	384,142,387	2,662,809,041
Industrial						
RT-13	7,200	1,204,228,137	0	1,204,228,137	0	1,204,228,137
RT-13PRS	24	4,088,075	0	4,088,075	0	4,088,075
RT-14	96	614,097,291	0	614,097,291	0	614,097,291
RT-14PRS	12	93,850,178	0	93,850,178	0	93,850,178
RT-85	612	128,481,410	0	128,481,410	0	128,481,410
RT-90	60	241,242,523	0	241,242,523	0	241,242,523
Subtotal	8,004	2,285,987,614	0	2,285,987,614	0	2,285,987,614
% of Annual Energy Per Category			0.00%	100.00%	0.00%	100.00%
Mining						

RT-15	24	926,300,900	0	926,300,900	0	926,300,900
% of Annual Energy Per Category			0.00%	100.00%	0.00%	100.00%
Public Streets and Highway Lighting						
RT-41	48	24,132,797	0	24,132,797	0	24,132,797
RT-47	48	9,397,676	0	9,397,676	0	9,397,676
Subtotal	96	33,530,473	0	33,530,473	0	33,530,473
% of Annual Energy Per Category			0.00%	100.00%	0.00%	100.00%
Other Sales - Public Authorities						
RT-40	36	101,171,460	0	101,171,460	0	101,171,460
RT-43	3,212	123,574,584	0	123,574,584	0	123,574,584
Subtotal	3,248	224,746,044	0	224,746,044	0	224,746,044
% of Annual Energy Per Category			0.00%	100.00%	0.00%	100.00%
Lighting						
RT-50	216		0	0	0	0
RT-51	14,628		0	0	0	0
RT-52	39,276		0	0	0	0
Subtotal	53,904	7,287,604	0	7,287,604	0	7,287,604
% of Annual Energy Per Category			0.00%	0.00%	0.00%	100.00%
						Estimated Total DSM Qualifying Adjusted Retail Sales
Total	4,707,154	9,246,239,184	469,083,303	8,215,801,466	561,350,467	9,899,852,866
% of Annual Energy Per Category =			5.29%	92.61%	6.33%	111.58%
% of Annual DSM Revenue Per Category =			0.00%	82.99%	17.01%	
		0				
Energy consumption Growth Rate for Next Year without DSM	3.59%					
DSM Program Energy Consumption Reduction Expected in kWh next year:	34,700,000					
DSM Basic Program Balance and Expenses - Next Year =	$6,384,625					
DSM Adjustor Mechanism Tariff Rate First Tier per KWH =			$0.000000			
DSM Adjustor Mechanism Tariff Rate Second Tier per KWH =			$0.000625			
DSM Adjustor Mechanism Tariff Rate Third Tier per KWH =			$0.001875			

Residential - RD

TUCSON ELECTRIC POWER COMPANY
FOR PERIOD ENDING DECEMBER 31, 2006
PROOF OF REVENUE - RESIDENTIAL

Line No.	Pricing Plan		Adjusted Booked Billing Determinants A
	RESIDENTIAL- R01 - FROZEN		
1	Customers (Single-Phase)		4,102,937
2	Customer (Three-Phase)		3,804
	Summer		
4	1st 500 kWhs		157,191,445
5	3,000 kWhs		1,944,859,708
6	3,501 kWhs and above		140,610,250
	Winter		
7	1st 500 kWhs		280,753,681
8	3,000 kWhs		1,095,328,529
9	3,501 kWhs and above		21,914,549
10	Revenue		
11	**TOTAL R01 - FROZE**	kWh	3,640,658,163
12		Cust	342,228
	RESIDENTIAL WATER HEATING - R02		
13	Customers		28,728
14	1st 100 kWhs - is a customer charge		2,472,456
15	All Additional kWhs		2,788,089
16	Revenue		
17	**TOTAL R02**	kWh	5,260,545
18		Cust	

TUCSON ELECTRIC POWER COMPANY
FOR PERIOD ENDING DECEMBER 31, 2006
PROOF OF REVENUE - RESIDENTIAL

Line No.	Pricing Plan		Adjusted Booked Billing Determinants
			A
	RESIDENTIAL TIME OF USE - R21 - ELIMINATED - REPLACED BY NEW TIME OF USE - R70N		
1	Customer Charge		34,512
	Summer On Peak		
2	1st 500 kWhs		117,504
3	3,000 kWhs		10,533,594
4	3,501 kWhs and above		1,773,241
	Summer Off Peak		
5	1st 500 kWhs		174,420
6	3,000 kWhs		15,635,784
7	3,501 kWhs and above		2,632,152
	Summer Shoulder Peak		
8	1st 500 kWhs		0
9	3,000 kWhs		0
10	3,501 kWhs and above		0
	Winter On Peak		
11	1st 500 kWhs		149,837
12	3,000 kWhs		4,802,085
13	3,501 kWhs and above		169,610
	Winter Off Peak		
14	1st 500 kWhs		486,463
15	3,000 kWhs		15,590,572
16	3,501 kWhs and above		550,659
17	Revenue		
18	**TOTAL R21**	kWh	52,615,922
		Cust	2,876

TUCSON ELECTRIC POWER COMPANY
FOR PERIOD ENDING DECEMBER 31, 2006
PROOF OF REVENUE - RESIDENTIAL

Line No.	Pricing Plan		Adjusted Booked Billing Determinants
			A
	RESIDENTIAL TIME OF USE - R70 - ELIMINATED - REPLACED BY NEW TIME OF USE - R70N		
1	Customers		50,748
	Summer On Peak		
2	1st 500 kWhs		150,911
3	3,000 kWhs		6,145,782
4	3,501 kWhs and above		692,004
	Summer Off Peak		
5	1st 500 kWhs		628,225
6	3,000 kWhs		25,584,092
7	3,501 kWhs and above		2,880,723
	Summer Shoulder Peak		
8	1st 500 kWhs		59,597
9	3,000 kWhs		2,427,051
10	3,501 kWhs and above		273,282
	Winter On Peak		
11	1st 500 kWhs		465,283
12	3,000 kWhs		4,964,541
13	3,501 kWhs and above		134,128
	Winter Off Peak		
14	1st 500 kWhs		1,651,151
15	3,000 kWhs		17,617,672
16	3,501 kWhs and above		475,979
17	Revenue		
18	**TOTAL R70**	kWh	64,150,421
		Cust	4,229

TUCSON ELECTRIC POWER COMPANY
FOR PERIOD ENDING DECEMBER 31, 2006
PROOF OF REVENUE - RESIDENTIAL

Line No.	Pricing Plan		Adjusted Booked Billing Determinants
			A
	SPECIAL RESIDENTIAL ELECTRIC SERVICE - R201A - FROZEN		
1	Customers (Single-Phase)		86,138
	Mid-Summer		
2	1st 500 kWhs		777,880
3	3,000 kWhs		27,076,790
4	3,501 kWhs and above		2,295,440
	Remaining Summer		
5	1st 500 kWhs		920,158
6	3,000 kWhs		21,183,679
7	3,501 kWhs and above		790,638
	Winter		
8	1st 500 kWhs		3,035,325
9	3,000 kWhs		34,712,462
10	3,501 kWhs and above		802,397
11	Revenue		
12	**TOTAL R201A**	kWh	91,594,770
		Cust	7,178

TUCSON ELECTRIC POWER COMPANY
FOR PERIOD ENDING DECEMBER 31, 2006
PROOF OF REVENUE - RESIDENTIAL

Line No.	Pricing Plan		Adjusted Booked Billing Determinants
			A
	SPECIAL RESIDENTIAL ELECTRIC SERVICE TIME OF USE - R201B - ELIMINATED - REPLACED BY NEW ELECTRIC SERVICE TIME OF USE - R201BN		
1	Customers		6,353
	Mid-Summer On Peak		
2	1st 500 kWhs		8,987
3	3,000 kWhs		390,920
4	3,501 kWhs and above		55,298
	Mid-Summer Off Peak		
5	1st 500 kWhs		36,423
6	3,000 kWhs		1,584,414
7	3,501 kWhs and above		224,124
	Mid-Summer Shoulder Peak		
8	1st 500 kWhs		3,696
9	3,000 kWhs		160,791
10	3,501 kWhs and above		22,745
	Remaining Summer On Peak		
11	1st 500 kWhs		13,871
12	3,000 kWhs		247,584
13	3,501 kWhs and above		27,406
	Remaining Summer Off Peak		
14	1st 500 kWhs		56,428
15	3,000 kWhs		1,007,149
16	3,501 kWhs and above		111,486
	Remaining Summer Shoulder Peak		
17	1st 500 kWhs		5,280
18	3,000 kWhs		94,245
19	3,501 kWhs and above		10,432
	Winter On Peak		
20	1st 500 kWhs		37,240
21	3,000 kWhs		688,879
22	3,501 kWhs and above		116,884
	Winter Off Peak		
23	1st 500 kWhs		118,573
24	3,000 kWhs		2,193,419
25	3,501 kWhs and above		372,164
26	Revenue		
27	**TOTAL R201B**	kWh	7,588,438
		Cust	529

TUCSON ELECTRIC POWER COMPANY
FOR PERIOD ENDING DECEMBER 31, 2006
PROOF OF REVENUE - RESIDENTIAL

Line No.	Pricing Plan		Adjusted Booked Billing Determinants
			A
	SPECIAL RESIDENTIAL ELECTRIC SERVICE TIME OF USE - R201C - ELIMINATED - REPLACED BY NEW ELECTRIC SERVICE TIME OF USE - R201CN		
1	Customers		2,560
	Mid-Summer On Peak		
2	1st 500 kWhs		2,595
3	3,000 kWhs		123,116
4	3,501 kWhs and above		8,996
	Mid-Summer Off Peak		
5	1st 500 kWhs		11,459
6	3,000 kWhs		543,590
7	3,501 kWhs and above		39,721
	Mid-Summer Shoulder Peak		
8	1st 500 kWhs		1,164
9	3,000 kWhs		55,194
10	3,501 kWhs and above		4,033
	Remaining Summer On Peak		
11	1st 500 kWhs		10,149
12	3,000 kWhs		79,858
13	3,501 kWhs and above		5,064
	Remaining Summer Off Peak		
14	1st 500 kWhs		47,618
15	3,000 kWhs		374,688
16	3,501 kWhs and above		23,760
	Remaining Summer Shoulder Peak		
17	1st 500 kWhs		4,703
18	3,000 kWhs		37,005
19	3,501 kWhs and above		2,347
	Winter On Peak		
20	1st 500 kWhs		26,194
21	3,000 kWhs		194,760
22	3,501 kWhs and above		45,264
	Winter Off Peak		
23	1st 500 kWhs		82,929
24	3,000 kWhs		616,601
25	3,501 kWhs and above		143,303
26	Revenue		
27	**TOTAL R201C**	kWh	2,484,111
		Cust	213
28	**TOTAL 201**		
29	Revenue		
30		kWh	101,667,319
31		Cust	7,921

TUCSON ELECTRIC POWER COMPANY
FOR PERIOD ENDING DECEMBER 31, 2006
PROOF OF REVENUE - RESIDENTIAL

Line No.	Pricing Plan	Adjusted Booked Billing Determinants A
	RESIDENTIAL SUMMARY	
1	TOTAL RESIDENTIAL REVENUE	
2	TOTAL RESIDENTIAL KWHS	3,864,352,371
3	TOTAL RESIDENTIAL CUSTOMERS	357,254

General Service - RD

TUCSON ELECTRIC POWER COMPANY
FOR PERIOD ENDING DECEMBER 31, 2006
PROOF OF REVENUE - GENERAL SERVICE

Line No.	Pricing Plan	Total	Adjusted Booked Billing Determinants A
	SMALL GENERAL SERVICE - C10 - FROZEN		
1	Customers (Single-Phase)		200,229
2	Customer (Three-Phase)		192,377
3	Energy First 3400 kWh per month		287,747,871
	Summer		
4	1st 500 kWhs		9,543,061
5	next 54,500 kWhs		780,196,667
6	all remaining kWhs		233,692,602
	Winter		
7	1st 500 kWhs		11,971,822
8	next 54,500 kWhs		600,014,346
9	all remaining kWhs		128,023,475
10	Revenue		
11	**TOTAL C10**	kWh	1,763,441,975
		Cust	32,717
	SMALL GENERAL SERVICE - PRS 10 - CONTRACT		
12	Revenue		
		kWh	211,780
		Cust	1
	Summer		
	1st 500 kWhs		500
	next 54,500 kWhs		54,500
	all remaining kWhs		50,890
	Winter		
	1st 500 kWhs		500
	next 54,500 kWhs		54,500
	all remaining kWhs		50,890
	C11		
13	Customers (Single-Phase)		3,948
14	Customer (Three-Phase)		336
15	Energy Summer		33,529,195
16	Energy Winter		26,803,344
17	Revenue		
18	**TOTAL C11**	kWh	60,332,539
		Cust	357

TUCSON ELECTRIC POWER COMPANY
FOR PERIOD ENDING DECEMBER 31, 2006
PROOF OF REVENUE - GENERAL SERVICE

Line No.	Pricing Plan	Total	Adjusted Booked Billing Determinants
			A
	GENERAL SERVICE TIME OF USE - C76 - ELIMINATED - REPLACED BY NEW GENERAL SERVICE TIME OF USE - R76N		
1	Customers (Single-Phase)		4,203
2	Customer (Three-Phase)		7,473
	Summer On-Peak		
4	1st 500 kWhs		43,611
5	next 54,500 kWhs		9,492,367
6	all remaining kWhs		2,450,884
	Summer Off-Peak		
7	1st 500 kWhs		216,249
8	next 54,500 kWhs		47,069,001
9	all remaining kWhs		12,152,991
	Summer Shoulder Peak		
10	1st 500 kWhs		15,370
11	next 54,500 kWhs		3,345,468
12	all remaining kWhs		863,784
	Winter On Peak		
13	1st 500 kWhs		56,268
14	next 54,500 kWhs		11,544,100
15	all remaining kWhs		1,466,997
	Winter Off Peak		
16	1st 500 kWhs		206,732
17	next 54,500 kWhs		42,414,036
18	all remaining kWhs		5,389,874
19	Revenue		
20	**TOTAL C76**	kWh	136,727,732
		Cust	973
	C31		
21	Summer - all Kwhs		11,457,973
22	Winter - all kWhs		4,738,919
23	Revenue		
24	**TOTAL C31**	kWh	16,196,892
		Cust	42

TUCSON ELECTRIC POWER COMPANY
FOR PERIOD ENDING DECEMBER 31, 2006
PROOF OF REVENUE - GENERAL SERVICE

Line No.	Pricing Plan	Total	Adjusted Booked Billing Determinants
			A
	LARGE GENERAL SERVICE - I13 - ELIMINATED - REPLACED BY NEW LARGE GENERAL SERVICE TIME OF USE - I85N		
1	Customer Charge		7,200
	Summer Demand		
2	On Peak kW		720,000
3	Off Peak kW		720,000
	Winter Demand		
4	On Peak kW		720,000
5	Off Peak kW		720,000
	Summer Demand All Additional kW		
6	On Peak kW		916,524
7	Off Peak kW		916,524
	Winter Demand All Additional kW		
8	On Peak kW		916,524
9	Off Peak kW		916,524
	Summer		
10	On Peak kWhs		130,802,332
11	Off Peak kWhs		515,570,740
12	Shoulder Peak kWhs		46,711,075
	Winter		
13	On Peak kWhs		119,944,726
14	Off Peak kWhs		391,199,264
15	Revenue		
16	**TOTAL I13**	kWh	1,204,228,137
		Cust	600
17	**PRS 13 - CONTRACT**		
18		Revenue	
19		kWh	4,088,075
20		Cust	2

TUCSON ELECTRIC POWER COMPANY
FOR PERIOD ENDING DECEMBER 31, 2006
PROOF OF REVENUE - GENERAL SERVICE

Line No.	Pricing Plan	Total	Adjusted Booked Billing Determinants
			A
	LARGE GENERAL SERVICE TIME OF USE - I85A - ELIMINATED - REPLACED BY NEW LARGE GENERAL SERVICE TIME OF USE - I85N		
1	Customers		372
	Summer Demand		
2	On Peak kW		36,000
3	Off Peak kW		36,000
	Winter Demand		
4	On Peak kW		36,000
5	Off Peak kW		36,000
	Summer Demand All Additional kW		
6	On Peak kW		21,140
7	Off Peak kW		21,140
	Winter Demand All Additional kW		
8	On Peak kW		11,970
9	Off Peak kW		11,970
	Summer		
10	On Peak kWhs		6,151,695
11	Off Peak kWhs		29,592,895
12	Shoulder Peak kWhs		2,126,538
	Winter		
13	On Peak kWhs		5,802,304
14	Off Peak kWhs		22,212,312
15	Revenue		
16	**TOTAL I85A**	kWh	65,885,743
		Cust	31

TUCSON ELECTRIC POWER COMPANY
FOR PERIOD ENDING DECEMBER 31, 2006
PROOF OF REVENUE - GENERAL SERVICE

Line No.	Pricing Plan	Total	Adjusted Booked Billing Determinants
			A
	LARGE GENERAL SERVICE TIME OF USE FROZEN - I85F - ELIMINATED - REPLACED BY NEW LARGE GENERAL SERVICE TIME OF USE - I85N		
1	Customers		240
	Summer Demand		
2	On Peak kW		24,000
3	Off Peak kW		24,000
	Winter Demand		
4	On Peak kW		24,000
5	Off Peak kW		24,000
	Summer Demand All Additional kW		
6	On Peak kW		36,047
7	Off Peak kW		36,047
	Winter Demand All Additional kW		
8	On Peak kW		23,889
9	Off Peak kW		23,889
	Summer		
10	On Peak kWhs		5,748,531
11	Off Peak kWhs		27,935,990
12	Shoulder Peak kWhs		1,956,514
	Winter		
13	On Peak kWhs		5,677,051
14	Off Peak kWhs		21,277,580
15	Revenue		
16	**TOTAL I85F**	kWh	62,595,666
		Cust	20

SMALL AND LARGE GENERAL SERVICE SUMMARY

1	**TOTAL GENERAL SERVICE REVENUE**	
2	**TOTAL GENERAL SERVICE KWHS**	**3,313,708,541**
3	**TOTAL GENERAL SERVICE CUSTOMERS**	**34,743**

Industrial - RD

TUCSON ELECTRIC POWER COMPANY
FOR PERIOD ENDING DECEMBER 31, 2006
PROOF OF REVENUE - LARGE LIGHT AND POWER SERVICE

Line No.	Pricing Plan	Total		Adjusted Booked Billing Determinants A
	LARGE LIGHT AND POWER - I14 - ELIMINATED - REPLACED BY NEW LARGE LIGHT AND POWER TIME OF USE - I90N			
1	**Customer Charge**			96
	Summer Demand			
2	On Peak kW			781,110
3	Off Peak kW			764,707
	Winter Demand			
4	On Peak kW			542,806
5	Off Peak kW			536,292
	Summer			
6	On Peak kWhs		17.7%	58,465,957
7	Off Peak kWhs		76.1%	251,749,604
8	Shoulder Peak kWhs		6.3%	20,711,872
	Winter			
9	On Peak kWhs		22.8%	64,495,493
10	Off Peak kWhs		77.2%	218,674,365
11	Revenue			
12	**TOTAL I14**	kWh		614,097,291
13		Cust		8
	PRS 14 - CONTRACT			
14	Revenue			
15		kWh		93,850,178
16		Cust		1

TUCSON ELECTRIC POWER COMPANY
FOR PERIOD ENDING DECEMBER 31, 2006
PROOF OF REVENUE - LARGE LIGHT AND POWER SERVICE

Line No.	Pricing Plan	Total		Adjusted Booked Billing Determinants A
	LARGE LIGHT AND POWER TIME OF USE - I90A - ELIMINATED - REPLACED BY NEW LARGE LIGHT AND POWER TIME OF USE - I90N			
1	**Customer Charge**			12
	Summer Demand			
2	On Peak kW			41,051
3	Off Peak kW			41,718
	Winter Demand			
4	On Peak kW			41,204
5	Off Peak kW			41,369
	Summer			
6	On Peak kWhs		13.9%	4,368,214
7	Off Peak kWhs		80.6%	25,419,192
8	Shoulder Peak kWhs		5.5%	1,744,779
	Winter			
9	On Peak kWhs		19.0%	5,896,039
10	Off Peak kWhs		81.0%	25,100,381
11	Revenue			
12	**TOTAL I90A**	kWh		62,528,605
13		Cust		1
				165,342

	LARGE LIGHT AND POWER TIME OF USE FROZEN I90F - ELIMINATED - REPLACED BY NEW LARGE LIGHT AND POWER TIME OF USE - I90N			
1	**Customer Charge**			48
	Summer Demand			
2	On Peak kW			148,098
3	Off Peak kW			150,506
	Winter Demand			
4	On Peak kW			132,674
5	Off Peak kW			133,207
	Summer			
6	On Peak kWhs		15.4%	15,169,458
7	Off Peak kWhs		78.8%	77,504,261
8	Shoulder Peak kWhs		5.8%	5,686,028
	Winter			
9	On Peak kWhs		21.1%	16,976,026
10	Off Peak kWhs		78.9%	63,378,144
11	Revenue			
12	**TOTAL I90F**	kWh		178,713,918
13		Cust		4

TUCSON ELECTRIC POWER COMPANY
FOR PERIOD ENDING DECEMBER 31, 2006
PROOF OF REVENUE - LARGE LIGHT AND POWER SERVICE

Line No.	Pricing Plan	Total	Adjusted Booked Billing Determinants
			A
	INDUSTRIAL SERVICE SUMMARY		
1	TOTAL LARGE LIGHT AND POWER SERVICE REVENUE		
2	TOTAL LARGE LIGHT AND POWER KWHS		949,189,992
3	TOTAL LARGE LIGHT AND POWER CUSTOMERS		14

Public Authority - RD

TUCSON ELECTRIC POWER COMPANY
FOR PERIOD ENDING DECEMBER 31, 2006
PROOF OF REVENUE - PUBLIC AUTHORITY

Line No.	Pricing Plan	Total	Adjusted Booked Billing Determinants A
	O40		
1	Energy kWh Summer		58,667,833
2	Energy kWh Winter		42,694,636
3	Revenue		
4	**TOTAL P40**	kWh	101,362,469
		Cust	3
	P43		
5	Energy kWh Summer		33,365,680
6	Energy kWh Winter		25,062,900
	P45&46 Interruptible Service		
7	Energy kWh Summer		35,724,522
8	Energy kWh Winter		29,743,473
9	Revenue		
10	**TOTAL P43**	kWh	123,896,575
		Cust	32

	PUBLIC AUTHORITY SERVICE SUMMARY	
11	TOTAL PA SERVICE REVENUE	
12	TOTAL PA SERVICE KWHS	**225,259,044**
13	TOTAL PA SERVICE CUSTOMERS	**35**

Lighting RD

TUCSON ELECTRIC POWER COMPANY
FOR PERIOD ENDING DECEMBER 31, 2006
PROOF OF REVENUE - LIGHTING

Line No.	Pricing Plan	Total	Adjusted Booked Billing Determinants A
	P41&47		
1			33,727,523
2	Revenue		
3		kWh	33,727,523
4		Cust	8
	P50, P51, P52		
5	Per 100 Watt		120,300
6	Per 250 Watt		19,380
7	Per 400 Watt		17,568
8	Per One Pole		3,960
9	Underground Service		47,892
10	55OH - new		504
11	55P -new		1,104
12	55UG -new		1,512
13	70UG -new		2,472
14	Revenue		
15	**TOTAL P50**	kWh	7,287,604
16		Cust	

LIGHTING SERVICE SUMMARY

17	TOTAL LIGHTING SERVICE REVENUE	
18	TOTAL LIGHTING SERVICE REVENUE KWHS	41,015,127
19	TOTAL LIGHTING SERVICE CUSTOMERS	8

1st Yr Portfolio Plan - Budget

Budgets

2008 Portfolio Budgets - Used in Portfolio Plan

Program
Education and Outreach
Direct Load Control
Residential Efficiency Programs
Low Income Weatherization
New Home Construction
Residential HVAC Retrofit
Shade Tree Program
CFL Buydown Program
Residential Subtotal
Non-Residential Efficiency Programs
Existing Facilities Program
Small Business Program
Existing Facilities Program
Non-Residential Subtotal
Total

EXHIBIT

TNH-5

DSM Efficiency Incentive Calculation

Calculation Description:

The DSM Efficiency Incentive Mechanism is intended to provide a financial incentive to install otherwise more expensive energy efficient equipment as part of the electric grid or in partnership with customers. In order for equipment to qualify for enhanced financial recovery, it must provide at least 15% lower losses in the case of transmission or distribution equipment or 15% better energy utilization in the case of energy conversion equipment, than similarly functioning cost effective equipment. The energy efficient asset can not cost more than 20% more than the similarly functioning asset that would most cost effectively serve TEP's purpose without any extra financial incentives.

The extra financial incentive would be provided by including the value of the energy efficiency asset in the utility rate base at the next rate case for full revenue recovery in the same manner as all other similar utility assets and, in addition, including 1% of the original value of the energy efficiency asset to be recovered each year for the first five years in the DSM Adjustor Mechanism after the energy efficiency asset is operational and in service.

Prior to the purchase of an energy efficient asset TEP will submit to the Commission Staff who then shall review and recommend Commission approval for each energy efficiency asset to be afforded enhanced financial recovery. TEP shall submit sufficient evidence as is needed to demonstrate that the energy efficient asset meets the qualification criterion established above.

Use of the DSM Efficiency Incentive Mechanism would require TEP to annually file in the DSM filing the following information:

- A statement of the original value of each energy efficient asset and the year it first was claimed for enhanced financial incentive.
- The total value of the aggregate of all energy efficient assets claimed for enhanced financial incentive in the next year ("TVAEEA").
- The estimated total retail sales of electrical energy in kWh for the next year ("TRSOEE") before expected DSM program-created energy consumption reductions are included.
- The estimated DSM program-created energy consumption reductions in the next year ("DSMECRCY").

The DSM Efficiency Incentive Rate ("DSMEIR") would then be calculated as:

$$\text{DSMEIR in \$/kWh} = ((\text{TVAEEA} * 0.01) / (\text{TRSOEE} - \text{DSMECRCY}))$$

Example:

A hypothetical example calculating the DSMEIR for 2009: In February 2008, a line reconductor project is completed, operational and in service using a 4/0 copper conductor resulting in a line segment with 22% lower lifetime losses than the 1/0 copper conductor that was otherwise the most cost effective. The total project cost was $850,000 which was 118% of the cost of the 1/0 copper conductor. The 4/0 copper conductor was approved for enhanced financial incentive treatment by the ACC in December 2007. It was the only asset approved at the time the 2009 DSM Adjustor Mechanism Rate filing was submitted.

The 2009 TRSOEE before DSM measures is expected to be 10,200,000,000 kWh. DSMECRCY in 2009 are expected to be 145,000,000 kWh. The DSM Efficiency Incentive Rate for 2009 would be:

$$((850{,}000 * 0.01) / (10{,}200{,}000{,}000 - 145{,}000{,}000)) = \$0.00000085 / \text{kWh}$$

This would then be added to the other components to build the DSM Adjustor Mechanism Tariff Rate for 2009, plus for an additional four years.

EXHIBIT

TNH-6

TEP's DSM Performance Incentive Mechanism Calculation Description and Example

The intended result of successful energy efficiency programs is the reduction of electric energy consumption and/or electric demand. While this reduces the variable and/or fixed costs of producing electrical energy for an electric utility, it also reduces the revenue derived from energy consumption based rates and reduces the opportunity for the utility to earn a return on assets. These intended results are mitigated by the implementation of a performance incentive by providing customers with a 90% share and TEP with 10% share of the overall net benefits of the DSM Portfolio excluding the Direct Load Control program, the Low-Income Weatherization program and the Educational and the Outreach Programs. During the first year of DSM programs would most likely produce reduced or negative net benefits. Therefore, the performance incentive would start after the first full year of implementation – giving time for programs to ramp up and reach their savings potential.

Use of the DSM Performance Incentive Mechanism would require TEP to annually file the following information:

- TEP will report actual net DSM Portfolio benefits (Program Benefits minus the Program costs). The net benefits will be verified through the Measurement and Evaluation process.
- The net benefits will be calculated each reporting period and will be included in the next annual true up in TEP's DSM adjustor mechanism.
- The total of each program's net benefits (or net costs) will be calculated and summed.
- The Direct Load Control ("DLC"), Low-Income Weatherization ("LIW") and the Education and Outreach Programs are outside of the scope of the performance incentive and will not be considered with the net benefits or the spending cap. The Education and Outreach Program will not have savings assigned to it and the LIW Program is expected to produce a negative net cost to society. The DLC Program results primarily in capacity reductions, not energy savings, and is thus not appropriate for being included in the DSM Performance Incentive. (The program descriptions have been filed in the separate DSM Docket as attachments 1, 2 and 3 to TEP's DSM Portfolio.)
- After the Portfolio's net benefits are summed then a 10% cap (of period spending) will be applied to determine the maximum amount of the performance incentive.
- The lesser of the 10% cap or the sum of the net benefits will be the total DSM performance incentive and added to the DSM Adjustor Mechanism.

See the attached example below.

Example of an Estimated DSM Performance Incentive
2008 Program Portfolio

Program	Total Benefits	Total Costs	Net Benefits	TEP – @ 100%
Residential Efficiency Programs				
New Home Construction	$12,487,377	$4,765,342	$7,722,035	$7,722,035
Residential HVAC Retrofit	$1,086,090	$641,333	$444,757	$444,757
Shade Tree Program	$451,828	$267,514	$184,315	$184,315
CFL Buydown Program	$3,602,232	$1,270,206	$2,332,026	$2,332,026
Non-Residential Efficiency Programs				
Existing Facilities Program	$7,162,266	$1,797,368	$5,364,898	$5,364,898
Small Business Program	$2,879,203	$1,063,992	$1,815,211	$1,815,211
Efficient Commercial Building Design	$2,763,623	$1,319,383	$1,444,240	$1,444,240
Performance Incentive				
Total Program Saving – Net Benefits @ 10% total program Cap				$2,077,730
Cap – 10% of spending (assuming a $12.4 M Budget)				$1,236,294
Total DSM Performance Incentive				$1,236,294
Outside the Scope of the Performance Incentive				
Direct Load Control	$5,440,427	$3,970,500	$1,469,927	$146,993
Education and Outreach	NA	NA	NA	NA
Low Income Weatherization	$251,584	$373,663	-$122,079	NA