ORIGINAL

NEW APPLICATION

0000137955

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
GARY PIERCE- CHAIRMAN
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

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-12-0291

Arizona Corporation Commission
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TUCSON ELECTRIC POWER COMPANY

APPLICATION
TESTIMONY AND EXHIBITS

VOLUME 1 of 4

July 2, 2012

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APPLICATION

E-01933A-12-0291

PART 1 OF 3

BARCODE # 0000137955

To review Part 2 please see:

BARCODE #0000137960

To review Part 3 please see:

BARCODE #0000137961

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Tucson Electric Power Company ("TEP" or "Company"), through undersigned counsel, and pursuant to A.R.S. §§ 40-250 and 40-251 and A.A.C. R14-2-103, hereby submits its Application for an increase in its non-fuel base rates of $127,760,000, or approximately 15.3% over adjusted test year retail revenues of $836,938,000, to be effective no later than August 1, 2013.

TEP is also seeking approval of: (i) an updated rate design; (ii) modifications to its Purchased Power and Fuel Adjustment Clause ("PPFAC"); (iii) a lost fixed cost recovery mechanism related to the Arizona Corporation Commission's ("Commission") Renewable Energy Standard ("REST") rules and Electric Energy Efficiency ("EE") rules; (iv) a new approach to funding cost-effective demand-side management and energy efficiency programs; (v) an environmental compliance cost recovery mechanism to smooth the rate impact of anticipated environmental mandates for TEP's generating facilities; and (vi) modifications to its Tariff, Rules and Regulations and certain existing compliance requirements.

The Company's request is fully supported by the testimony, exhibits, and schedules submitted concurrently with this Application.

I. SUMMARY.

TEP's current rates were established in Decision No. 70628 (December 1, 2008), based on a test year ending December 31, 2006, with rates effective on December 1, 2008. As part of the 2008 TEP Rate Case Settlement Agreement approved in Decision No. 70628 ("2008 Settlement Agreement"), TEP has been under a rate case moratorium that prevents the Company from filing a new rate case until June 30, 2012. As a result, the test year in this rate case ends December 31, 2011.

A. Impact of the Rate Case Moratorium. Since the previous test year, the Company has faced significant challenges from the economic downturn. Growth in TEP's service area has come to a virtual standstill and usage per customer has declined since the prior rate case. As a result, TEP's retail kWh sales have remained essentially flat on a year-to-year basis since 2006.

Other intervening events have exacerbated TEP's financial challenges. The Company is facing ever increasing distributed renewable energy and energy efficiency requirements, which result in further erosion of its retail kWh sales. Compliance with new environmental regulations creates further pressure on TEP's capital requirements and increases the Company's need to access the capital markets.

Over the same time, TEP has invested substantially in its utility plant in order to maintain safe and reliable electric service. Those capital investments have increased TEP's original cost rate base by approximately $500 million since the prior test year, from $1 billion to $1.5 billion. Moreover, despite its best efforts to control costs, TEP's operating and maintenance expenses ("O&M") also have increased over the past five years and are now approximately $29 million higher on annual basis than they were in 2006.

Given its current rate design, which relies heavily on volumetric energy charges, TEP is unable to fully cover its fixed costs of providing safe and reliable electric service. This factor, coupled with the increase in costs outlined above, does not provide TEP with an opportunity to earn a reasonable rate of return on its investment.

B. Need for Increased Revenue Requirement. Despite these challenges, TEP has faithfully adhered to its commitments in the 2008 Settlement Agreement while at the same time meeting the many new regulatory requirements impacting the Company. TEP has improved its ability to reliably serve customers through an increasingly diverse portfolio of energy resources, including renewable energy and EE. TEP has continued to make investments to improve its financial health. The Company also has succeeded in controlling its costs without compromising reliability or safety.

However, TEP has been unable to earn a reasonable rate of return on a retail jurisdictional basis, and, therefore, TEP's current rates are no longer just and reasonable. New and updated rates are needed to provide sufficient and predictable revenues in order to stabilize TEP's financial health, as well as provide TEP with access to the capital markets at reasonable rates, which is particularly important given TEP's upcoming capital requirements. The Company also needs a revenue increase to prevent TEP from losing the momentum it has gained in recent years with respect to its credit rating.

TEP is, therefore, filing this rate case to: (i) enable it to continue to provide safe and reliable service; (ii) recover its full cost of service, including an appropriate return on invested capital; and (iii) maintain or improve its credit rating, all of which will benefit TEP and its customers.

The Company remains, however, sensitive to the impact of increased rates on its customers. In its filing, TEP has proposed several measures to mitigate the rate increase. The Company estimates these mitigation measures have reduced the requested revenue requirement by approximately $37 million. TEP also has proposed several mechanisms to moderate the size of future rate increases as TEP continues to invest in its plant to maintain safe and reliable service and to fund infrastructure and programs necessary to meet governmental requirements.

In this case, the Company is requesting a $127,760,000 non-fuel base rate increase. Based on this increase, the current monthly bill[1] would increase from $85.17 to $98.58 (a 15.7% increase) for an average TEP residential customer.

C. Need for Updated Rate Design. TEP is proposing to update its rate design and reduce customer confusion by simplifying its rate offerings. The current rate design, which relies heavily on volumetric rate elements to recover the majority of the Company's fixed costs, creates difficulties for TEP in recovering its authorized revenue requirement. TEP is proposing rates that will provide the Company with a better opportunity to recover its fixed costs and earn a reasonable return on its investment.

Moreover, TEP's current rate design and related tariffs also are unduly complicated. For example, TEP currently has over 50 different basic residential and commercial rates, including 33 different residential rates that result in over 340 residential rate variations. Many of these different rates apply to only a handful of customers. TEP is requesting that numerous "frozen" rates be eliminated and that other rates be consolidated into more understandable options for customers. These updated rates will reduce customer confusion and decrease administrative costs.

In order to simplify customer bills and improve customer price signals, TEP is also requesting to recover all of its fuel and purchased power costs through the Company's PPFAC. Currently, TEP's fuel and purchased power costs are split and recovered through base rates and through the PPFAC. Additionally, TEP further proposes to modify the PPFAC to provide for different PPFAC rates for different customer classes in order to more accurately allocate fuel and purchased power costs.

D. Need for New and Updated Adjustor Mechanisms. TEP is seeking the approval of certain adjustor mechanisms which will allow it to meet current and upcoming regulatory mandates without jeopardizing the financial stability of the Company. Those adjustors include: (i) a lost fixed cost recovery mechanism to address kWh sales lost as a result of the REST and

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[1] The current monthly bill includes the PPFAC rate that went into effect on April 1, 2012.

EE rules and (ii) an environmental compliance cost recovery mechanism designed to mitigate large future rate increases stemming from changes in environmental regulations. TEP is also proposing a new method for determining the demand side management and energy efficiency program costs that will be recovered through its existing Demand Side Management Surcharge ("DSMS").

E. Need for Timely Relief. Given the significant amount of time that has passed since the prior rate case and the economic and regulatory realities presently facing the Company, it is critical to adopt new rates and related relief in a timely fashion. Under the 2008 Settlement Agreement approved by the Commission, TEP, Commission Staff and other parties agreed as follows:

> TEP shall not submit a rate application sooner than June 30, 2012. On or after June 30, 2012, TEP may not submit a rate application that uses a test year ending earlier than December 31, 2011. The Signatories agree to use their best efforts to have post-moratorium rates in place no later than thirteen months after TEP's rate application is filed with the Commission. For purposes of this paragraph, Staff will be deemed to have used its "best efforts" if it endeavors to process TEP's rate application within the time frames set forth in A.A.C. R14-2-103. The Signatories recognize that Staff cannot ensure that the Commission will act on a rate application by any date certain.[2]

Therefore, TEP requests that this Application be processed within thirteen months and that new rates and other related relief go into effect no later than August 1, 2013 consistent with the "best efforts" provision of the 2008 Settlement Agreement.

II. KEY ELEMENTS OF THE RATE CASE.

A. Revenue Requirement.

The Company is requesting a $127,760,000 million non-fuel base rate increase, which represents a 15.3% increase over adjusted test year revenues, including fuel and purchased power costs. As a result of this increase, the current monthly bill for an average TEP residential customer would increase from $85.17 to $98.58.

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[2] 2008 Settlement Agreement, Section 10.2.

TEP's revenue requirement increase is based on an Original Cost Rate Base ("OCRB") of $1.5 billion and a Replacement Cost New Less Depreciation ("RCND") rate base of $3.0 billion, resulting in Fair Value Rate Base ("FVRB") of $2.3 billion using a traditional 50/50 weighting of OCRB and RCND.

TEP proposes the continued use of a pro forma capital structure in determining the weighted average cost of capital ("WACC"), as approved by the Commission in TEP's last rate case. This proposed capital structure is comprised of 54% long-term debt and 46% common equity. TEP's actual test year capital structure is 56.5% debt and 43.5% equity, which contains a higher common equity weighting than the pro forma capital structure of 57.5% debt and 42.5% equity adopted in TEP's last rate case, thus reflecting TEP's ongoing commitment to improve its balance sheet and credit ratings.

TEP's cost of debt is 5.18%. The Company proposes a cost of equity of 10.75%, which is less than the level that TEP believes it can justify, but reflects TEP's efforts to mitigate the rate increase in this case. The Company's WACC, based on these cost rates and the test year capital structure, is 7.74%.

TEP is further proposing a fair value rate of return ("FVROR") of 5.68%. This FVROR is based on the methodology used by the Commission in several recent rate cases. The FVROR also reflects a return on the fair value increment of fair value rate base that is less than what TEP believes it can justify.

B. Rate Design.

TEP is proposing significant changes to its rate design. First, the Company is proposing rates that more accurately reflect the current cost of service for each customer class. These changes include increases in the monthly customer charge for all customer classes, which allows for recovery of a greater share of the Company's fixed costs through fixed charges. This approach will assist TEP in promoting conservation, will reduce the future magnitude of lost fixed cost recovery, and facilitate greater revenue stability.

Second, TEP also is requesting to simplify its tariffs through consolidation of multiple tariffs and elimination of tariffs that have been frozen. The Company currently has over 50 different basic rates and there are multiple options within many of those rates. TEP is now proposing to have fewer rates and has designed those rates to give customers accurate and timely price signals to help them better manage their energy expenses. Fewer rates also mean less confusion for customers and lower administrative burden on the Company.

Third, the Company is proposing to eliminate the recovery of any fuel or purchased power costs through base rates and to recover those costs solely through the PPFAC.

Finally, TEP is proposing to modify its low-income Lifeline program; again through consolidation and simplification of tariffs.

C. PPFAC.

TEP is proposing several modifications to its PPFAC. First, as noted above, the Company proposes to recover all of its fuel and purchased power costs through the PPFAC and to eliminate the current fuel component recovered through base rates. In order to offer rates that better match costs to revenues and to send more accurate price signals to customers, TEP has developed 16 different PPFAC rates based on the voltage at which a customer receives service, on-peak and off-peak usage and winter and summer periods. Although the Company currently has a single PPFAC rate applicable to all customers at all times, it also currently has 83 fuel component rates contained within base rates. Therefore, TEP's proposal will reduce the 83 fuel component rates to 16 PPFAC rates.

Second, the Company is requesting to recover some additional costs through the PPFAC, including credit support costs, wholesale energy broker fees, greenhouse gas costs and incremental lime costs above those included in base rates. The levels of these costs are tied directly to the acquisition of fuel and wholesale power and should be recovered through the PPFAC. The cost of obtaining and maintaining credit with trade counterparties is a real cost of doing business in the wholesale markets for fuel and purchased power. Moreover, although some broker fees are currently being recovered in base rates, it is more appropriate to recover those expenses through the PPFAC because these costs are associated with purchased power and vary with the amount of energy purchased. Further, lime costs are incurred when removing sulfur dioxide or SO2, and are directly linked to fuel consumption, specifically coal usage. Finally, any future greenhouse gas costs will likely be tied directly to fuel costs. In anticipation of potential federal regulatory or congressional (or state) action, TEP is requesting that such costs, if any, be recovered through the PPFAC. In connection with these additional costs, TEP is proposing that if the cost of lime incremental to the amount included in the test year is recovered through the PPFAC, it will credit 100% of the revenues from sales of SO2 emission allowance to the PPFAC (currently, TEP credits 50 percent of the SO2 sales revenues to customers).

Third, TEP is proposing several procedural changes to its Plan of Administration ("POA") for the PPFAC.

D. Lost Fixed Cost Recovery Mechanism ("LFCR").

The Company is proposing a lost fixed cost recovery mechanism that is very similar to the mechanism approved for UNS Gas, Inc. in Decision No. 73142 (May 1, 2012) and Arizona Public Service Company ("APS") in Decision No. 73183 (May 24, 2012). The LFCR is not a full decoupling mechanism; rather it is a mechanism narrowly tailored to provide TEP an opportunity to recover non-fuel costs, costs that would otherwise go unrecovered due to lost kWh sales from compliance with the REST rules and EE rules. The Company is also including a fixed rate, or "opt-out", option as part of its LFCR proposal.

The Company needs such a mechanism, or a similar alternative mechanism (such as a full decoupling mechanism), to mitigate the negative financial impacts to the Company of complying with the EE rules and the rising number of distributed generation ("DG") resources in TEP's service territory resulting from the REST rules, and to provide TEP a reasonable opportunity to recover its authorized revenue requirement while pursuing these Commission mandates.

E. Proposals to Moderate Future Rate Impacts.

A continuation of slow customer growth and flat energy sales experienced over the past few years, combined with an anticipated increase in regulatory and environmental compliance costs, could contribute to the need for a steep rate increase in TEP's next general rate case. Therefore, the Company is proposing several mechanisms in this rate case designed to "smooth out" rate increases over time and avoid potential rate shock to our customers. TEP believes that these mechanisms will help customers to better manage their energy expenses. Finally, these proposals can assist TEP to synchronize recovery of costs, improve its opportunity to earn the authorized rate of return, and manage its capital expenditures and related financing needs, thus reducing the borrowing costs ultimately borne by its customers.

1. Energy Efficiency Resource Plan ("EE Resource Plan").

TEP is proposing its EE Resource Plan as an innovative solution for funding the cost of meeting the EE rules requirements. Under this proposed pilot program, the Commission would approve a three-year EE program budget for TEP. The program costs would be treated as a regulatory asset that would be amortized over four years. This proposal will result in a gradually-inclining rate in the DSMS – also to be set by the Commission in this rate case - while increasing program offerings each year to meet the rising EE Standard. Because TEP would amortize its EE costs over a four-year period, the EE Resource Plan would allow DSMS surcharges to be significantly lower from 2014-2016 than they would be if those annual expenses were fully recovered each year under the current practice. Under TEP's proposal, the Company would determine the most cost-effective EE option appropriate for its particular system, invest its capital to procure that resource and recover the associated costs – including the amortization expense and an appropriate return on investment – through the DSMS surcharge. This capital investment and recovery model is similar to that used for any other supply-side resource. The specific mechanics for the EE Resource Plan are set forth in a POA.

As a result, the EE Resource Plan would reduce and stabilize the rate impacts to our customers, better synchronize the benefits of EE with their associated costs, provide a base level of certainty to program offerings, and eliminate the need to provide a performance incentive. This will result in DSM/EE contractors having more certainty regarding program funding levels, and will provide TEP with more certainty as to the amount and timing of energy savings it can rely on in its resource and system planning, while also reducing the burden on Commission Staff now tasked with annually reviewing implementation plans and the DSMS.

2. Environmental Compliance Adjustor ("ECA").

The Company is proposing a mechanism, the Environmental Compliance Adjustor, to provide more timely recovery of substantial upcoming capital expenditures necessary to meet several new government mandated environmental regulations. These costs will include investments in pollution control equipment and efficiency projects at the Company's power plants. Specifically, TEP will likely be required to invest significant capital at the following locations to comply with one or more of the federal rules:

- San Juan Generating Station –approximately $200 million in capital costs and $3-6 million in annual O&M costs to comply with the Regional Haze mandates;
- Navajo Generating Station – approximately $86 million in capital costs and $2-4 million in annual O&M costs to comply with the Regional Haze and the Environmental Protection Agency ("EPA") Mercury and Air Toxics Standard ("MATS") rule mandates;
- Four Corners Power Plant – approximately $36 million in capital costs and $2 - $4 million in annual O&M costs to comply with the Regional Haze and the MATS rule mandates; and
- Springerville Generating– approximately $5 million in capital costs and $3 million in annual O&M costs to comply with the MATS rule.

In the aggregate, TEP is likely to invest approximately $300 million over the next five years and incur annual O&M expenses in the tens of millions. Depending on the final outcome of certain proposed regulations, TEP's total capital outlays could approach $400 million. TEP is not able to stagger or control the timing of these costs, as the compliance deadlines are mandated exclusively by the EPA and judicial rulings. Given the magnitude of the costs relative to TEP's existing rate base and capitalization, TEP cannot afford to wait several years to recover these costs in the next general rate case. Moreover, accumulating such large capital investments until the next general rate case would contribute to a sharp spike in TEP's rate base and a correspondingly sharp increase in rates. Recovering these environmental costs as they are incurred through an adjustor moderates their impact on our customers.

The proposed ECA is similar to the APS Environmental Improvement Surcharge (EIS) recently approved by the Commission in Decision No. 73183. However, the ECA is tailored to meet the needs of TEP and its customers, as the amount of investment required to comply with environmental regulations is significantly higher relative to existing rate base for TEP than APS. Specifically, the ECA is tailored to recover narrowly-defined costs (defined as "Qualified Investments" in the ECA POA) to comply with environmental mandates from the federal government (amongst other entities) that are known and measurable and eligible for recovery in accordance with Arizona law. By providing timely recovery of such costs between full rate cases (that is, the "Qualified Investments" including carrying costs for construction work in progress), the ECA will allow TEP to secure the necessary capital at a reasonable cost, with TEP passing through savings from avoided carrying costs to its customers. This also mitigates future rate impacts to customers and reduces the frequency of and costs associated with a full rate case.

3. TEP Solar Ownership Plan (Bright Tucson Solar Buildout Plan).

The Company is requesting authorization to invest up to $30 million annually for the development of TEP-owned renewable energy resources and allow TEP to receive recovery of related expenses through the REST surcharge including: return on investment, depreciation, property taxes, and O&M expenses. This authorization is similar to the authority previously provided by the Commission in connection with the Company's currently approved REST Implementation Plans. The Company is requesting this recovery mechanism between 2014 and 2017 (four years) or until the next rate case, to provide it with a more balanced, comprehensive and efficient renewable energy procurement process, particularly because it is not practical to procure such resources on a year-to-year timeframe as contemplated under the current REST rules.

Moreover, the Company proposes to transfer into rate base its renewable generation assets previously approved under its REST Implementation Plan's Bright Tucson Solar Buildout Program. TEP has been recovering the carrying cost of this plant through the REST surcharge, but is now able to move those facilities into its rate base and treat them the same as other generation plant going forward.

4. Post-Test Year Plant.

The Company is proposing to adjust TEP's rate base to include approximately $40 million of used and useful solar projects and other plant additions as post-test year plant that will be in service by December 31, 2012. Not only will the addition of such plant reduce the level of future rate increases, it will also enable TEP to recover the cost of investing in renewable generation that will be in service when new rates are established for TEP and help mitigate increases of the REST surcharge. Further, it more closely aligns the recovery of costs with the benefits that are currently being provided to existing customers, while also lowering the cost to customers by limiting the amount of Allowance for Funds Used During Construction charged to the assets, thereby reducing the future depreciation and carrying costs associated with this plant.

F. Depreciation Rates.

TEP is submitting an updated depreciation study and is requesting approval of new depreciation rates in this case.

G. Rules and Regulations.

The Company is proposing modifications to its Rules and Regulations and to its Tariffs. These modifications are intended to modernize TEP's Rules and Regulations and to clarify areas in the Rules and Regulations that have caused undue customer confusion. The Company is also seeking to eliminate or modify various compliance requirements from previous Commission decisions.

III. APPLICATION.

In support of this Application, TEP respectfully states as follows:

A. 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 88 East Broadway Boulevard, Tucson, Arizona 85701

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

C. 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:

Bradley S. Carroll
Tucson Electric Power Company
88 East Broadway Blvd., MS HQE910
P. O. Box 711
Tucson, Arizona 85702
520-884-3679
bcarroll@tep.com

and

Michael W. Patten
Jason D. Gellman
Roshka, DeWulf & Patten, PLC
One Arizona Center
400 East Van Buren Street, Suite 800
Phoenix, Arizona 85004
602-256-6100
mpatten@rdp-law.com

D. The 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 prehearing and hearing matters.

E. Accompanying this Application are the standard filing requirements and rate design schedules described in A.A.C. R14-2-103. The Company also provides pre-filed direct testimonies and related exhibits from the following witnesses for TEP supporting the requests made within the Application and schedules:

Paul J. Bonavia	State of the Company; challenges facing TEP and proposed solutions to those challenges; and why approval of the rate application is critical to TEP's customers and shareholders.
David G. Hutchens	Overview of TEP's rate application and primary proposals, including the LFCR, the ECA, the EE Resource Plan and the Solar Buildout Plan; and modifications to the PPFAC.
Michael J. DeConcini	Overview of TEP operations, capital spending, customer service and environmental compliance requirements.
Kevin P. Larson	Overview of TEP's financial condition, including capital expenditures, anticipated capital needs, financings, credit rating and ratings agency concerns; and capital structure.
Kentton C. Grant	Cost of long-term debt; cost of credit support for fuel and purchased power procurement; acquisition of Sundt 4; and Springerville leases.
John J. Reed (consultant)	Cost of equity, fair value rate base and fair value rate of return.
Karen G. Kissinger	Adjustments to rate base and operating income and expense.
Dr. Ronald E. White (consultant)	Depreciation rates.
Mark C. Mansfield	Decommissioning of generating plants.
James I. Warren (consultant)	Tax issues related to Net Operating Losses.

Dallas J. Dukes	Revenue requirement; RCND; adjustments to rate base and operating income and expense; and rate base and income statement pro formas.
Lindy L. Sheehey	Revisions to TEP's Rules and Regulations.
Craig A. Jones	Cost of service study; proposed rate design; Plans of Administration for PPFAC, LFCR, ECA and EE Resource Plan; and revisions to tariffs.
David F. DesLauriers (consultant)	Rate design.

F. 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 no later than August 1, 2013. 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 that as a result, its current rates and charges are not just and reasonable;

(2) the requested revenue increase 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 on reasonable terms, and is in the public interest;

(3) the Company's request for a permanent base revenue increase of $127,760,000 based on annualized test period sales is reasonable and necessary in order for the Company to continue to provide adequate and reliable electric service to its customers as required by law, and is in the public interest;

(4) the proposed LFCR mechanism is in accordance with Commission policy, so that the Company can recover lost revenues associated with compliance with

Commission renewable energy DG and EE requirements, and is in the public interest;

(5) the proposed ECA addresses the need to timely recover significant investment in pollution control and other facilities to respond to government mandates for environment standards, and is in the public interest;

(6) the proposed EE Resource Plan provides a more cost effective and stable approach to implementing DSM and EE programs, and is in the public interest;

(7) transferring into base rates those costs of Company-owned renewable generation resources and approving its plan to more cost-effectively to comply with the REST is in the public interest;

(8) including post-test year plant that will be in service by December 31, 2012 in rate base is in the public interest;

(9) modifying the Company's PPFAC to allow for recovery of additional costs and for price differentiation by customer class is in the public interest;

(10) the proposed rate design will better align the fixed and variable costs of service with the rates paid by the customers causing those costs and is in the public interest; and

(11) the proposed revisions to the Company's Tariff, Rules and Regulations and certain compliance requirements are in the public interest.

G. In addition to setting a hearing date, TEP asks that the Commission issue a procedural order setting forth the prescribed public 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. Finally, TEP requests that a procedural schedule be established, including a settlement track option, so that a final order in this case can be rendered and new rates can be effective by August 1, 2013.

WHEREFORE, TEP respectfully requests that the Commission:

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

(2) issue a final order finding and concluding that the Company's rate application is just and reasonable and granting the Company the permanent rate increase of $127,760,000 million to allow it to recover its expenses and a reasonable opportunity to earn its authorized rate of return on its investment;

(3) issue a final order approving the new or modified rate and service schedules included with the Company's Application with an effective date no later than August 1, 2013;

(4) issue a final order approving the Company's proposed revisions to its Purchased Power and Fuel Adjustment Clause;

(5) issue a final order approving the Company's proposed Lost Fixed Cost Recovery Mechanism;

(6) issue a final order approving the Company's proposed Environmental Compliance Adjustor;

(7) issue a final order approving the Company's proposed Energy Efficiency Resource Plan;

(8) issue a final order approving the proposed rate design described in the testimony accompanying this Application;

(9) issue a final order approving the Company's proposed depreciation rates as set forth in Dr. White's testimony;

(10) issue a final order approving the Company's revised Rules and Regulations and modified compliance requirements; and

(11) grant the Company such additional relief as the Commission deems just and proper.

RESPECTFULLY SUBMITTED this 2nd day of July 2012.

TUCSON ELECTRIC POWER COMPANY

By ______________________
Bradley S. Carroll
Tucson Electric Power Company
88 East Broadway, MS HQE910
P.O. Box 711
Tucson, Arizona 85702

and

Michael W. Patten
Jason D. Gellman
Roshka DeWulf & Patten, PLC
One Arizona Center
400 East Van Buren Street, Suite 800
Phoenix, Arizona 85004

Attorneys for Tucson Electric Power Company

Original and 13 copies of the foregoing filed this 2nd day of July 2012, with:

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Copies of the foregoing hand-delivered/mailed this 2nd day of July 2012, to:

Lyn A. Farmer, Chief Administrative Law Judge
Hearing Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Janice M. Alward, Chief Counsel
Legal Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Steve Olea, Director
Utilities Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Jodi A. Jerich, Director
Residential Utility Consumer Office
1110 West Washington Street, Ste. 220
Phoenix, Arizona 85007

By Mary Ippolito

Direct Testimony of Paul J. Bonavia

BEFORE THE ARIZONA CORPORATION COMMISSION

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Direct Testimony of

Paul J. Bonavia

on Behalf of

Tucson Electric Power Company

July 2, 2012

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I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Paul J. Bonavia. My business address is 88 East Broadway Boulevard, Tucson, Arizona, 85701.

Q. By whom are you employed and what are your duties and responsibilities?

A. I am employed by Tucson Electric Power Company ("TEP" or the "Company") and I am Chairman and Chief Executive Officer of both TEP and UNS Energy Corporation ("UNS Energy"). UNS Energy was known as UniSource Energy Corporation before a name change that took effect in May 2012. For simplicity's sake, I will refer to that company as UNS Energy throughout my testimony, even when describing events that occurred under the company's previous name.

Q. Please describe your background, education and experience.

A. UNS Energy's Board of Directors appointed me as Chairman, President and CEO of TEP and UNS Energy effective Jan. 1, 2009. In December 2011, our Board named David G. Hutchens as President of TEP. I have retained my positions as Chairman and CEO, and Mr. Hutchens reports to me.

Before joining UNS Energy, I served five years as President of the Utilities Group of Xcel Energy. In that capacity, I oversaw four operating subsidiaries serving more than 3.3 million electric customers and 1.8 million natural gas customers in Colorado, Minnesota and six other states. I previously worked as president of Xcel Energy's Commercial Enterprises and Energy Markets Units. I also was Senior Vice President and General Counsel for Denver-based New Century Energies ("NCE"), an electric and gas utility that merged with Northern States Power in 2000 to form Xcel Energy. Before coming to NCE, I held several senior management positions with Dominion Resources in Richmond, Virginia, and I was an attorney with the law firm of LeBoeuf, Lamb, Green & MacRae. I hold a bachelor's degree from Drake University and a Juris Doctorate from the University of Miami in Coral Gables, Florida.

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

A. The purpose of my testimony is to (i) characterize the challenging conditions TEP has faced since current rates (which are based upon 2006 costs) took effect in December 2008, (ii) outline the strong performance the Company has achieved despite those challenges, and (iii) articulate the need to modernize the Company's rates in a way that benefits both the Company and its customers.

Q. Please summarize your testimony.

A. In my testimony, I describe the significant challenges faced by the Company since its current rates took effect in December 2008, including unprecedented sales declines driven by a lagging economy and the impact of the Renewable Energy and Energy Efficiency Standards approved by the Arizona Corporation Commission ("Commission"). I detail how, amid these and other challenges, the Company has tightly managed costs without compromising reliability or safety, made investments that improved TEP's financial health, and maintained the Company's positive presence in the community. Despite these successes, TEP needs prompt rate relief to maintain cost-effective access to capital markets and to earn a reasonable return on its investments in order to continue to provide safe, reliable service. Finally, I provide a broad overview of the Company's proposal for modernizing rates that reflect the changes taking place in the energy industry while providing customers with accurate, timely price signals that help them better manage their energy expenses.

Q. Could you please provide some context for this rate case?

A. This case arises from the regulatory compact that establishes clear responsibilities for both regulated companies and their regulators. As a regulated utility, TEP must take all prudent steps to provide safe and reliable service to customers. Our investments and operations are driven by our resolve to keep this commitment under conditions that are often beyond anyone's direct control – such as the weather or the economy – as well as those established by the Commission.

As I will discuss later, TEP has fulfilled this obligation to serve despite conditions that have grown significantly more challenging since the Company's current rates took effect. We have lived up to the terms of that 2008 Settlement Agreement and related rate order, while maintaining high service levels despite a slumping economy and regulatory mandates that have driven down energy sales. We have invested significant capital and shouldered increases in operating and maintenance expenses while laboring under a "stay out" provision that precludes any prospect of rate relief before 2013. We have faithfully adopted the policies and practices approved by this Commission, even when their implementation preceded any opportunity to address their associated costs. We have, in other words, kept up our end of the bargain.

This case represents an opportunity for the Commission to fulfill its obligations under the regulatory compact. TEP must be allowed to begin recovering the costs it has prudently incurred since 2006. We must be granted an opportunity to earn a fair return on our investments in safe, reliable and environmentally responsible service. The rates we have proposed in this matter will provide that opportunity, while allowing TEP to turn its attention to the challenges that await us in coming years.

II. RATE REQUEST.

Q. What level of rate increase is TEP requesting?

A. TEP is requesting a non-fuel base rate increase of approximately $127.8 million over adjusted test year revenues, to become effective on or before August 1, 2013. For an average residential customer, this would represent a monthly bill increase of about $13 over rates in effect at the time of our Application.

Q. This is a substantial increase over current rates. Why is the request so large?

A. Simply put, this rate request is the result of the significant passage of time without a base rate increase. As I mentioned above, our current rates are based on costs the Company incurred in 2006. Our costs have increased due to our capital investments that have increased TEP's rate base by approximately $500 million. In addition, the annual costs of operating and maintaining TEP's system have increased by $29 million between 2006 and 2011.

Q. What actions has the Company taken to control its O&M costs since its last rate increase?

A. Between 2006 and 2011, TEP's O&M expense increased at an average annual rate of just 1.6%. Despite various external pressures, such as commodity prices and compliance costs, our employees have done a tremendous job holding the line on the expenses they can directly control. In addition, TEP took advantage of favorable conditions in the capital markets to reduce its weighted average cost of debt by 120 basis points between

2006 and 2011. This reduction in TEP's cost of debt lowered the Company's proposed revenue requirement by nearly $10 million.

Q. Has the Company taken further steps to mitigate the size of the rate increase it is requesting?

A. Yes. TEP has taken several steps to moderate the requested rate increase for its customers including:

- Return on Equity ("ROE"). Witness John Reed's analysis demonstrates that an appropriate return on equity for TEP is 11.25%. However, we are proposing the use of a 10.75% ROE, which has the effect of lowering TEP's revenue requirement by approximately $6 million.
- Fair Value. As described in the testimony of Kevin Larson, we are proposing to apply a return on the fair value increment equal to just one-half of the real risk-free rate. This modification lowered TEP's rate request by approximately $19 million.
- Expenses. TEP has reduced or eliminated certain management compensation expenses from its revenue requirement, which has the effect of lowering TEP's revenue requirement by nearly $5 million.

III. CHALLENGES.

Q. How have the conditions facing TEP changed since its current rates were set?

A. The Commission approved the 2008 Settlement Agreement Order (Decision No. 70628 (December 1, 2008)), which led to the establishment of TEP's current rates, at a time when rising retail energy sales seemed as predictable as a hot Arizona summer. TEP's retail sales had increased at a greater than 3 percent annual rate for five successive years, including a 4.7 percent jump in 2007. That spring, when TEP initiated settlement discussions regarding its pending rate filing, even a very conservative growth rate was expected to generate enough revenue to sustain the Company through the five-year rate freeze contained in a proposed settlement agreement. The Commission issued its 2008 Settlement Agreement Order in November 2008, establishing new base rates that took effect the following month and could not be increased again until at least 2013. Less than four months later, the Dow Jones Industrial Average – which was holding above 12,500 when the proposed settlement agreement was first signed – culminated a historic slide by settling below 7,000 for the first time since 1997. That fall heralded a painful recession that dramatically altered the economic landscape that TEP would traverse over the next four years.

Q. How have TEP's retail sales fared during this recent economic downturn?

A. The Company's retail energy sales fell by 3.1 percent from 2007 to 2011 and are expected to drop another 0.7 percent in 2012. The downturn in Arizona's housing market and the increase in the unemployment rate combined to slow the traditional growth of TEP's retail customer base. After expanding at an average annual rate of 2.3 percent between 2000 and 2007, TEP's customer base grew by less than one percentage point in each of the last four years.

Our customers also are using less power than we once expected. Residential customers reduced their average annual energy usage by nearly 5 percent between 2007 and 2011. Average usage among our commercial customers fell by nearly 8 percent over the same period.

Q. What other factors have contributed to reduce TEP's retail energy sales?

A. TEP has been driven to significantly expand its energy efficiency programs by the ambitious goals in Arizona's Energy Efficiency Standard ("EES"), which was approved by the Commission in July 2010. The EES requires the Company to increase the savings it achieves through energy efficiency programs each year until the cumulative impact on usage reaches 22 percent in 2020. The programs TEP carried out in 2011 alone reduced that year's retail energy sales by at least 66 gigawatt-hours ("GWh"), or 0.7 percent. That figure understates the true losses since it does not include the impact of energy efficiency gains first realized in previous years through programs developed to satisfy either the EES or the Demand-Side Management ("DSM") Portfolio approved by the Commission. Most energy efficiency gains realized through such programs – savings from energy efficient homes, for example, or commercial equipment upgrades – are repeated year after year, long after the improvements are first implemented. Consequently, the escalating impact of the Company's historic and expanding energy efficiency efforts, combined with the absence of a decoupling mechanism or other, comparable relief, is increasingly hampering the Company's ability to recover its fixed costs through the usage-based rates established by the 2008 Settlement Agreement Order.

Q. How have renewable energy programs affected TEP's retail energy sales?

A. Arizona's Renewable Energy Standard and Tariff ("REST") has effectively mandated reductions in TEP's retail sales by requiring that the Company procure a share of its renewable power from distributed generation ("DG") resources. That share, which has risen from 10 percent in 2008 to 30 percent in 2012, is necessarily subtracted from the energy the Company would otherwise deliver to customers who install rooftop solar arrays or other DG systems. From 2008 through 2011, the DG systems installed through incentives authorized by the Commission through TEP's annual REST compliance plans generated a combined 88.8 GWh, directly reducing the Company's sales by an equivalent amount. In 2011 alone, the output of DG systems hosted by TEP customers reduced the Company's retail sales by 55 GWh, or 0.6 percent. These losses, like those linked to energy efficiency, limit the Company's ability to recover its fixed costs, including those associated with facilities that directly serve customers with installed DG systems. By contrast, renewable energy generated by TEP's utility-scale systems or procured through power purchase agreements does not reduce TEP's retail energy sales or compromise its ability to recover its fixed costs through usage-based rates.

Q. How has TEP's inability to file for new rates before June 30, 2012 compounded the impact of lower retail sales?

A. The "stay-out" provision of the 2008 Settlement Agreement Order has prevented the Company and the Commission from making timely adjustments to TEP's rates in response to the significant changes in our business and regulatory climate. While the EES has created a pressing need for TEP to recover the revenue lost to its successful DSM programs, the Commission has not approved the Company's requests to implement fixed cost recovery mechanisms outside of a rate case. At the January 10, 2012 Open Meeting discussion of TEP's EES implementation plan filing, Chairman Gary Pierce noted the difficulty of applying new Commission policies to utilities facing "stay-out" provisions: "I almost believe that what you do is, you say, okay, this applies to those who don't have the stay-out.... But those who have a stay-out – that's why one size does not fit all." In TEP's case, the imposition of the EES created additional pressure on a utility already struggling with reduced retail sales under base rates that remain capped at levels reflecting costs from 2006 – more than five years ago.

Q. How have TEP's costs increased since then?

A. The Company has invested nearly $1.3 billion in capital from 2007 through 2011 to allow TEP to continue providing safe, reliable, efficient and environmentally responsible service. We have expanded and upgraded our transmission and distribution systems, increased our renewable generating capacity, improved emissions controls at our power plants and made other long-term investments that will support our operations for years to come. TEP also has faced rising prices for materials, equipment and fuel; higher labor, pension and medical costs; and increased compliance expenses associated with new environmental and cyber security regulations. Despite these pressures, we have constrained the growth of TEP's O&M expense to an average of 1.6 percent per year through prudent management of our operations. While we might reasonably have anticipated such rising costs at the time our rates were established, it would have been difficult to foresee the extended downturn in economic conditions, or the evolving regulatory requirements which have compromised the Company's ability to recover its prudently incurred expenses.

IV. <u>BUILDING STRENGTH</u>.

Q. Has the Company weakened under the weight of these ongoing challenges?

A. No. TEP is, in many ways, a stronger, more efficient utility than it was five years ago. Our investments in new utility infrastructure have improved our ability to reliably serve customers through an increasingly diverse portfolio of energy resources, including new renewable power and energy efficiency options. Our power plants are running cleaner, our transmission system is stronger, and our substations are more robust. We are also working more effectively, thanks in part to a new, energy-efficient corporate headquarters building that promotes collaboration and operational efficiency. In the face of scarce revenue, we have embraced new, streamlined work processes that eliminate redundancies and reduce our workforce needs. Our efforts have generated estimated savings of more than $40 million from 2009 through 2011, mitigating the impact of lower sales levels while laying the groundwork for long-term savings.

Q. Has the Company compromised on the safety or reliability of its service?

A. No. TEP's service reliability remains as strong as ever, ranking in the first or second quartile in comparisons with other comparable utilities. We also have established a remarkable safety record through a vigorous awareness and training campaign that has reached employees in all areas of our operations.

Q. How has TEP's financial condition changed over the past five years?

A. Despite the challenges we have faced, the Company's financial health has gradually improved over the past five years. We have continued our efforts to improve our capital structure, increasing TEP's equity to total capital ratio from 39.9 percent in 2006 to 43.5 percent in 2011. This progress and other improvements in the Company's financial health and operating environment coupled with recent improvements in the Arizona regulatory environment are reflected in rising credit ratings. Moody's Investors Service, Standard & Poor's and Fitch Ratings each have increased their ratings on one or more aspect of TEP's debt since 2006. Since September 2011, both Moody's and Fitch have upgraded their grade of the Company's outlook from "Stable" to "Positive." The rate relief supported by this Application will strengthen TEP's underlying financial position and credit metrics, and could ultimately result in higher credit ratings. All of these factors will help TEP attract capital at reasonable terms, thereby reducing costs and helping to minimize future rate increases to our customers.

Without the rate relief supported by this Application, TEP will face significant barriers to raising the capital needed to invest in its utility infrastructure in order to provide safe and reliable service to customers, while abiding by the Commission's energy efficiency and renewable energy policies and complying with federal environmental mandates.

Q. Has TEP maintained its community service activities?

A. Yes. Our commitment to the community we serve is stronger than ever. TEP's employees joined their friends and family members in volunteering more than 31,000 hours to their chosen charitable causes in 2011, including many that provide critical support to the most vulnerable members of our community. The Company's shareholders bolstered these efforts by contributing more than $2.3 million in 2011 to nonprofit groups in communities served by TEP and its sister companies. With support from TEP's award-winning Community Action Team, our employees have embraced leadership positions in the local community through positions on 82 nonprofit boards. TEP also has maintained its position as a leader in the local business community with ongoing support for economic development efforts and active engagement in key regional issues.

Q. How does the Company plan to maintain such strong performance in future years?

A. The success we have achieved while living up to the terms of the 2008 Settlement Agreement Order will be compromised if the Commission does not take timely action to update TEP's rates. We have made remarkable progress with increasingly limited resources, but we cannot keep this pace for much longer. Our current rates do not provide us with an opportunity to earn a fair return on our investments. Moreover, we face significant capital needs in coming years from transmission and distribution system improvements and the looming prospect of costly environmental upgrades at our generating plants. To address these needs, we must maintain access to capital markets on reasonable terms, something that would not be possible without a significant increase to our current rates. To avoid losing the ground we have gained, the rising costs we have incurred in service to our customers since 2006 must be incorporated in new, modernized rates that provide customers with predictable, accurate price signals and reflect our new regulatory and economic climate.

V. MODERNIZED RATES.

Q. Aside from incorporating recent costs, what changes should be made to TEP's rates?

A. We should start by reducing the number of retail rates. While comparable regional utilities offer residential customers a choice of eight different rates, on average, TEP is currently maintaining 33 separate residential rates. A number of these rates are frozen for the benefit of a relative handful of customers who were not asked to adopt newer rates during previous rate adjustments, some of which occurred more than a decade ago. Thanks in part to these outdated tariffs and our renewable energy plans, budget billing programs and other offerings, TEP currently offers residential customers a staggering 341 rate variations. That complexity creates confusion for customers, imposes significant administrative burdens on the Company and stymies efforts to fairly allocate system costs. Therefore, we have proposed a streamlined rate structure that eliminates frozen tariffs, simplifies our time-of-use plans and makes our offerings much easier to understand. We also have proposed changes to our commercial and industrial rates that allocate costs more fairly and improve the Company's ability to fairly recover its fixed system costs.

Q. What changes have you proposed to reflect recent changes in the regulatory environment?

A. Our rates must be designed to accommodate rather than conflict with Commission policies promoting energy efficiency and distributed renewable generation. The Company is compelled by the EES to pursue ever deepening decreases in annual energy sales – the very sales that, under current rates, offer the only meaningful opportunity for the Company to recover fixed system costs. Meanwhile, the Company is required under the REST to promote the development of DG systems that further erode its ability to recover fixed costs through system usage. TEP must have an opportunity to reclaim the revenues lost to these programs to ensure that their success does not compromise our ability to maintain safe, reliable service or an opportunity to earn a reasonable return on our investment. To address that need, the Company is proposing a Lost Fixed Cost Recovery ("LFCR") mechanism in this proceeding that would help align our rates with the Commission's energy efficiency and renewable energy initiatives. Like similar mechanisms recently approved by the Commission for use by TEP's sister company UNS Gas, Inc. and Arizona Public Service Company ("APS"), the LFCR is designed to capture revenue lost to energy efficiency and distributed renewable generation without addressing revenues lost to weather or general economic conditions.

Q. Has the Company proposed any other changes to support its energy efficiency efforts?

A. We have proposed a new funding plan for TEP's DSM programs that reflects our emerging understanding of energy efficiency as a low-cost resource. Those who believe, as we do, in the value of energy efficiency often come to that conclusion by calculating the cost of the power it saves. For utilities, an energy efficiency program often represents the least expensive way to address a forecasted electric load – cheaper than buying power on the wholesale market or building a new power plant. TEP's 2012 Integrated Resource Plan outlines our expectation that DSM programs will reduce TEP's annual energy requirements by approximately 1,700 GWh in 2020, scaling back that year's system peak demand by 325 MW. But for those programs, TEP would be evaluating the need for another new power plant or finding another source for that energy.

In this context, we believe it makes more sense to fund TEP's energy efficiency programs in the same way we fund other energy resources. Rather than seeking Commission approval for annual stipends to support specific programs, we have proposed a three-year pilot program that allows TEP to invest and recover the capital spent on cost-effective energy efficiency measures in a way that more closely aligns costs with the programs' long-term benefits. Our proposed Energy Efficiency Resource Plan also would moderate the increase in the up-front costs of complying with the EES, helping ease customers into the program's long-term benefits.

Q. Has the Company proposed other rate changes that promote a gradual sharing of costs with customers?

A. We are requesting approval of an Environmental Compliance Adjustor ("ECA") mechanism that would pass along expenses associated with emissions control upgrades that will be required at several power plants in coming years. TEP is facing capital investments of approximately $300 million over the next five years to cover the costs associated with new environmental mandates affecting several power plants. Rather than allowing these costs to form the foundation of a large future rate increase, the ECA would pass them along as they are incurred. This would help the Company avoid interest costs associated with funding such improvements through debt, further reducing the future burden on customers.

Q. How do customers benefit from rates that force them to pay costs sooner rather than later?

A. The revenue increase we have requested in this filing was driven higher each year during the rate freeze provision of the 2008 Settlement Agreement. If TEP had the opportunity to recover some portion of those increases through mechanisms such as those we are now proposing, our customers would have had the opportunity to gradually adjust to those costs. Instead, we come now with a revenue request that simply cannot be delayed further without compromising our Company's financial health and our ability to provide safe, reliable service.

The benefits of gradualism and timely cost recovery were discussed earlier this year during the Commission's approval of TEP's Purchased Power and Fuel Adjustment Clause ("PPFAC") rate. As noted during that March 27, 2012 Open Meeting, the increase in the charge could have been mitigated if the Company had been authorized to pass along its energy costs in a more timely fashion. "If the Commission had maybe done just a little bit here the first year, a little bit here the second year, a little bit here the third year, would we see the impact that we're going to see, that we're seeing today?" Commissioner Kennedy asked. When TEP's outside counsel Michael Patten confirmed that the Commission could have smoothed out the impact by passing along costs sooner, Commissioner Kennedy responded: "So basically we kicked the can down the road. We're here at the end of that road today?" "Yes," Patten responded.

In this filing, we have proposed a different road, one that leads more directly through the challenges we face rather than trying to avoid them, only to double back to a place where they loom even larger. Our proposed rates provide customers with accurate and timely price signals based on the true cost of providing safe, reliable and environmentally responsible service in our current economic and regulatory environment. They also provide an opportunity for TEP to earn a reasonable return on its investments, something that is no longer possible under the Company's current rates.

Q. Does this conclude your testimony?

A. Yes, it does.

Direct Testimony of David G. Hutchens

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
GARY PIERCE- CHAIRMAN
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

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-12-____

Direct Testimony of

David G. Hutchens

on Behalf of

Tucson Electric Power Company

July 2, 2012

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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 88 East Broadway Blvd., Tucson, Arizona 85702.

Q. By whom are you employed and what are your duties and responsibilities?

A. I am employed by Tucson Electric Power Company ("TEP" or the "Company") and I am President of both TEP and UNS Energy Corporation ("UNS Energy"). UNS Energy was known as UniSource Energy Corporation before a name change that took effect on May 4, 2012. For simplicity's sake, I will refer to that company as UNS Energy throughout my testimony, even when describing actions taken under the company's previous name.

Q. Please describe your background and work 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.

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 Vice President of Wholesale Energy and of UNS Gas, Inc. ("UNS Gas") in 2007 and to Vice President of Energy Efficiency and Resource Planning in 2009. In 2011, I was promoted to Executive Vice President of

UNS Energy and TEP and in December I was promoted to my current position of President of UNS Energy and TEP.

Q. What is the purpose of your Direct Testimony?

A. First, I discuss the scope of TEP's rate request, the key issues in the case, and the central factors necessitating a base rate increase.

Second, I describe the Company's proposal to recover certain revenues that are lost as a result of our efforts to comply with the Arizona Corporation Commission ("ACC" or "Commission") Renewable Energy Standard and Tariff ("REST") and Energy Efficiency Standard ("EES") through the proposed Lost Fixed Cost Recovery ("LFCR") mechanism.

Third, I propose several methods to recover some ongoing and anticipated future costs, including costs associated with our compliance with the REST, EES and environmental regulations, in ways that will moderate the impact of those costs to our customers through future rates.

Over the past few years, the Commission has indicated its preference for gradually increasing customer bills through timely rate increases or adjustor mechanism charges, while criticizing proposals to "kick the can down the road" and subjecting customers to larger increases later. The proposals described in my testimony are consistent with this philosophy. They reflect a more realistic, forward-looking approach to setting rates that will provide more gradual rate increases while allowing the Company to obtain financing for capital projects on more favorable terms. For these reasons, as I will explain, these approaches are just and reasonable and in the public interest.

Finally, I will address the reasonable modifications that the Company is requesting to the Plan of Administration ("POA") for its Purchased Power and Fuel Adjustment Clause ("PPFAC").

II. SUMMARY.

Q. What level of base rate increase is TEP requesting?

A. TEP is requesting a non-fuel rate increase over adjusted test year revenues of $127.8 million, or 15.3 percent, to become effective on or before August 1, 2013. For an average residential customer, this would represent a monthly bill increase of approximately $13 over current rates.

Q. Why is TEP requesting that new base rates be effective on or before August 1, 2013?

A. As set forth in the 2008 Settlement Agreement approved in Decision No. 70628, (December 1, 2008) in TEP's last rate case: "The Signatories [to the Settlement] agree to use their best efforts to have post-moratorium rates in place no later than thirteen months after TEP's rate application is filed with the Commission." That commitment is an important element of the 2008 Settlement Agreement given the five-year rate case moratorium also negotiated in that Agreement.

Additionally, TEP's rate structure is based on costs incurred in 2006. By August 1, 2013, those costs will be almost seven years out of date. As the evidence will show in this rate case, the cost of supplying safe and reliable service has increased significantly since 2006. TEP has invested $1.3 billion in capital additions over the last five years, boosting its rate base from the $1.0 billion level approved in Decision No. 70628 to approximately $1.5 billion by the end of 2011. Moreover, the Company's ACC-jurisdictional operating and maintenance expenses ("O&M") were $29 million higher in 2011 than they were in 2006.

The financial burden imposed by these higher costs has been exacerbated by flat to declining sales levels that resulted from reduced per-customer energy usage and a decline in the traditional growth of TEP's customer base. As shown by the chart appearing later in my testimony, TEP expects to sell essentially the same amount of electricity in 2012 as it did six years ago in 2006.

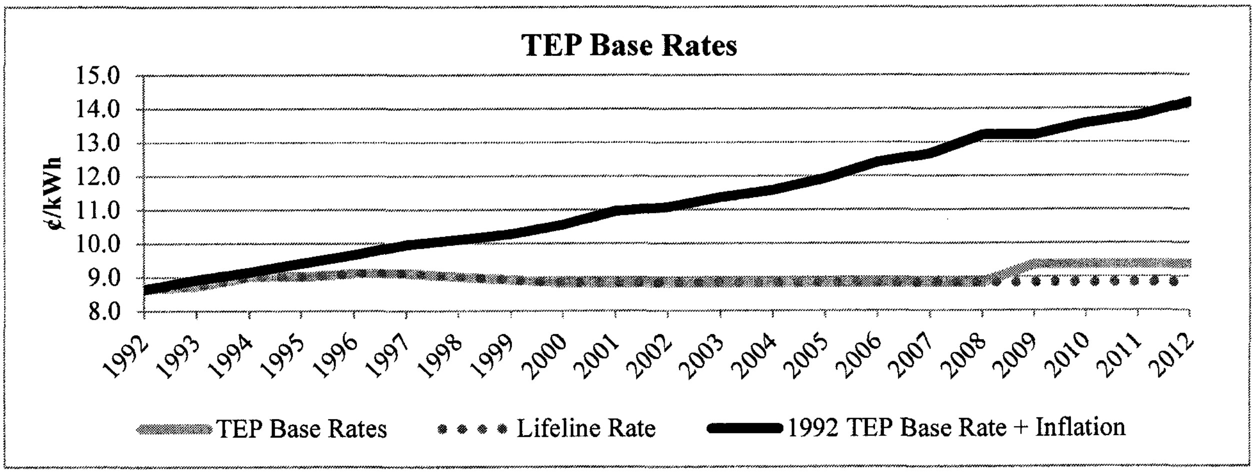
It is clear from the record that the prudently incurred cost increases TEP has endured during the rate freeze without the benefit of increased sales have rendered its current rates inadequate and do not afford the Company a reasonable opportunity to earn its authorized rate of return. TEP's rate increase request is necessary to: (i) maintain safe and reliable service throughout its service area; (ii) comply with new environmental regulations; (iii) build new transmission and distribution facilities; and (iv) invest in renewable energy resources and energy efficiency ("EE") measures to serve our customers' energy requirements.

Finally, in conjunction with the revenue increase, TEP is proposing an updated rate regime that is designed to address the need for TEP to recover its costs in a more timely manner that is not wholly dependent on increasing sales volumes. The rate design is consistent with policies set forth by the Commission and benefits our customers by providing more predictability and by moderating future rate increases.

Given the Company's circumstances and its innovative solutions in this case, I urge the Commission to grant TEP's requested rate increase as soon as possible to provide the Company a reasonable opportunity to earn its authorized rate of return.

Q. What has been the overall trend in base rates paid by TEP customers?

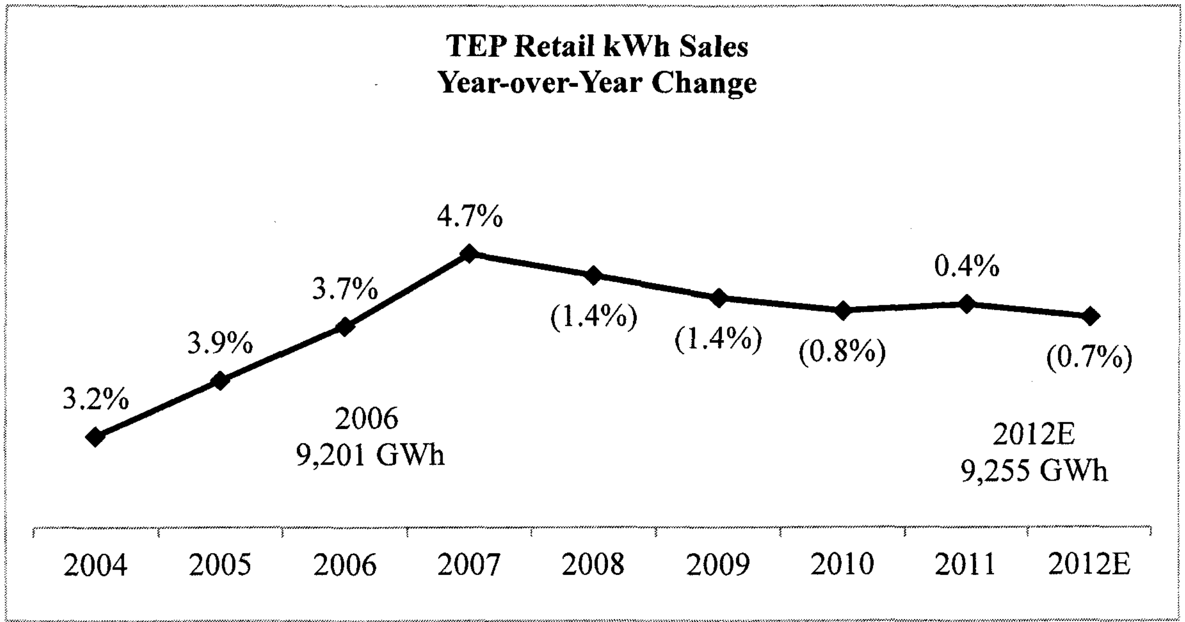
A. TEP's base rates have increased three times and decreased three times over the last 20 years. Despite the rising cost of goods and services, including those tracked by the Consumer Price Index ("CPI"), TEP's base rates, in real dollars, are lower than they were in 1992, as shown in the following chart.



In years past, the rising costs borne by TEP were mitigated by growing energy sales driven by an expanding customer base and increasing use per-customer. But that growth has since stalled due to weak economic conditions, increasing EE measures, and the rising number of distributed generation ("DG") resources installed in our service territory, greatly increasing the burden imposed on TEP, especially as service costs have escalated.

Q. Were slower sales anticipated when TEP's current rates were approved?

A. While we expected DG systems to limit sales to some degree, our sales forecast at the time assumed a more historical level of an annual growth rate. TEP certainly did not assume that the sales levels in 2012 would be essentially the same as in 2006. Additionally, it is highly unlikely that the Commission, or any other party, would have predicted the actual sales levels shown in the chart below. TEP also could not have predicted that the Commission would approve an EES containing such aggressive energy savings goals without providing any way for the Company to recover the revenue losses attributable to compliance efforts (since base rates were frozen until January 1, 2013). Those lost revenues have been significant even in the standard's early years. Finally, the penetration of DG reservations in TEP's service area is greater than predicted, further reducing sales in the absence of a fixed cost recovery mechanism.



Q. Has the lack of sales growth mitigated the costs TEP has incurred to maintain reliable service?

A. Although TEP has deferred some planned system expansion projects due to slower energy sales, TEP still made significant capital investments that were necessary to maintain its generating facilities, comply with environmental regulations, and continue providing the Company's customers with safe, reliable service. These investments have increased TEP's rate base by 50 percent over the rate base reflected in its current rates.

In addition, the Company's O&M costs have increased over the last five years due primarily to higher environmental and regulatory compliance costs; increased pension expense, and higher costs for most materials used in our business. As discussed further in TEP witness Michael DeConcini's Direct Testimony, controlling O&M costs is embedded in TEP's culture and we continue to focus our efforts on containing costs without compromising safety, reliability or service.

Q. Has TEP sought to moderate the level of its requested rate increase?

A. Yes. The Company recognizes that long rate freezes prevent the prompt recovery of prudently incurred costs, leading to much larger rate increases that make it more difficult for customers to manage their energy expenses. We also understand that our local community is trying to recover from a weak economy. The combination of those and other factors has compelled TEP to reduce its total revenue request in an effort to mitigate the rate impact on our customers. We have mitigated our proposed rate increase in a number of ways.

First, TEP is seeking a lower fair value rate of return ("FVROR") than the level supported in the Direct Testimony of TEP witness John J. Reed (the Chairman and Chief Executive Officer of Concentric Energy Advisors, Inc. and CE Capital, Inc.). While the Company could provide support justifying a higher FVROR on fair value rate base, TEP is recommending only 5.68%. Mr. Reed describes how that number was determined using Commission Staff's methodology.

Second, the Company is also seeking a lower return on equity ("ROE") of 10.75 percent rather than the 11.25 percent level that Mr. Reed identified as the mid-point of the appropriate range for TEP (11.00% to 11.50%).

Third, TEP has proposed passing onto its customers many of the ongoing financial benefits realized from the construction of two new units at TEP's Springerville

Generating Station ("Springerville"), as described in more detail in the Direct Testimony of Michael DeConcini.

Finally, TEP has lowered its request for certain employee compensation costs. The Company is not requesting recovery of its Supplemental Executive Retirement Benefits Plan ("SERP") or Long-Term Incentive compensation plan ("LTI") costs and is seeking recovery of just 50 percent of the short-term cash incentive compensation paid to employees at the officer and senior management levels.

While TEP has excluded these costs from its rate request for the reasons listed above, the Company believes these costs were prudently incurred and reserves the right to seek their recovery in future rate cases. TEP's request is based solely on current facts and circumstances and is not intended to establish a precedent for future filings.

Q. How have these changes affected TEP's proposed revenue requirement?

A. These changes reduced the Company's test year revenue requirement by approximately $37 million.

Q. In addition to higher base rates, is TEP proposing other modifications to its current rate structure?

A. Yes. TEP is proposing the following modifications to its rate structure:

- TEP has an unusually large number of rate options for customers and is proposing the consolidation and modification of those rates in order to reduce customer confusion, trim administrative burdens and better align costs with revenue recovery.
- We are proposing to eliminate the fuel component of base rates and recover all of those costs through the PPFAC.

- The Company is also proposing a LFCR that would align our rate structure with Commission policies and mitigate the adverse financial impact of sales revenue lost to Commission-mandated EE and DG requirements.
- The Company is further requesting approval of two new mechanisms that would allow TEP to recover the necessary and prudent ongoing costs of complying with the EES and environmental regulations in a way that moderates their impact on customers' future bills.
- Our proposal to include approximately $40 million of post-test year net plant additions in rate base also would serve to mitigate future rate requests.
- Finally, we have requested approval of a solar energy development plan that will allow TEP to expand its renewable energy portfolio in a cost-effective manner.

III. LOST FIXED COST RECOVERY MECHANISM.

Q. What is the LFCR?

A. The LFCR is a mechanism narrowly tailored to collect delivery service costs that would have been recovered through usage lost to EE programs and DG systems. It is not intended to recover lost fixed costs attributable to other factors, such as weather or general economic conditions. As such, it is not a full decoupling mechanism.

The LFCR would serve to align the interests of the Commission and our customers with the Company's need to mitigate the adverse financial impacts inherent in the Commission's EE and DG requirements. This mechanism would provide TEP with an opportunity to recover its prudently incurred system costs despite sales reductions that result from compliance with the REST and EES.

Q. Why are you proposing the Commission approve an LFCR mechanism for TEP?

A. TEP's current rate structure is designed to recover the Company's authorized revenue requirement primarily through usage-based kilowatt hour ("kWh") sales. The volumetric rate charged for those sales is calculated based on the system-wide usage, based largely on the sales volumes experienced during the rate case test year. A majority of the costs included in TEP's revenue requirement, however, do not vary with kWh sales, but are fixed in nature.

Given the current rate structure, when kWh sales decline as a result of EE programs and DG systems developed pursuant to the EES and REST, TEP is unable to recover the fixed costs that are embedded in its volumetric-based rates.

As a result, without a mechanism in place to capture and recover these lost revenues, TEP's rates are inadequate as they do not provide the Company with a reasonable opportunity to recover certain costs or achieve its Commission-authorized rate of return. The proposed LFCR mechanism would alleviate this inequity, while aligning the Company's financial well-being with the Commission's mandates and our customers' desire to participate in EE and DG programs. Adoption of this mechanism reduces the financial penalties resulting from compliance with the EES and REST and counterbalances the additional financial risk those Commission mandates have created for the Company.

Q. Has the Commission previously approved a similar mechanism?

A. The LFCR mechanism the Company is proposing is similar to the lost-fixed cost recovery mechanisms that the Commission approved for Arizona Public Service Company ("APS") in Decision No. 73183 (May 24, 2012) and UNS Gas in Decision No. 73142 (May 1, 2012).

Q. Will TEP's LFCR provide a variable and fixed rate (opt-out) option for residential customers?

A. Yes. Residential customers who do not want to be charged the standard LFCR variable rate charge based on kWh usage will have the option of choosing a fixed, monthly LFCR charge. TEP will implement an extensive customer education and outreach program to help customers understand the new LFCR and available options. TEP witness Craig Jones explains how the LFCR will operate and sponsors the LFCR's associated POA.

Q. If the Commission does not approve the LFCR as proposed, are you proposing an alternative?

A. If the LFCR is not approved, the Company recommends the Commission approve a full decoupling mechanism designed to recover all fixed cost revenues on a per customer basis.

IV. <u>PROPOSALS TO MODERATE FUTURE RATE IMPACTS.</u>

Q. Why is the Company proposing ways to moderate future rate impacts in this filing?

A. We believe our customers prefer moderate rate increases over time in comparison to the large bill impacts that result from delaying the recovery of all significant costs until the next general rate case. Revenue stabilization also helps the Company more effectively manage and time its external financing activities, thereby reducing the borrowing costs ultimately borne by TEP's customers.

Historically, TEP's rising costs were mitigated by the sales growth that resulted from customer additions and increasing per-capita usage. Such growth can serve to delay and moderate rate increase requests, even in jurisdictions that use historic test years. But our experience over the last five years has proven that TEP can no longer depend on such sales growth. Even if our economy regains some momentum, the increasing impact of the EES and DG requirements will limit TEP's ability to rely on growing sales to achieve its authorized rate of return.

The impact of slower sales is compounded by costs that are rising more rapidly due in part to increasing costs of materials and equipment in addition to environmental restrictions and other regulatory mandates. If these costs are allowed to accumulate between rate cases, our customers will most likely be subject to steep increases at the end of each general rate case. Our proposals to recover some of these costs before our next rate case filing will lead to more moderate, gradual increases in monthly electric bills, satisfying the Commission's oft-stated goal of smoothing rate impacts. Our proposals will help customers manage their energy expenses while improving TEP's opportunity to earn its authorized rate of return.

Q. What specific measures is TEP proposing to moderate future rate impacts on customers?

A. TEP is targeting four primary costs to moderate future rate impacts – energy efficiency, environmental compliance, the TEP-owned solar build out plan and post test-year plant additions. We are proposing the following specific measures:

Energy Efficiency

One of the rate-smoothing proposals is the Energy Efficiency Resource Plan ("EE Resource Plan"). This is a three-year pilot program that allows TEP to invest in and deliver cost-effective energy efficiency programs to our customers. The adoption of cost-effective energy efficiency measures plays an important role in the Company's ability to develop a diverse and least-cost resource portfolio. Our goal is to develop and deploy measures that provide the greatest operating efficiencies to TEP's generation, transmission and distribution system; reduce reliance on more costly traditional generating resources; and provide more rate stability and more program certainty to customers, contractors and the Company. Allowing TEP to invest and recover capital spent on energy efficiency measures in a timely manner, similar to investments in conventional and renewable resources, more closely aligns costs and benefits and eliminates the need for a performance incentive.

Further, the adoption of a three-year program provides our customers, the EE market and local contractors with some predictability, allows TEP to adequately plan and budget for EE programs, and affords TEP and Commission Staff easier administration of the Company's EE Implementation Plan. All of those benefits should ultimately reduce the costs of the EE program to TEP and Commission Staff, when compared to the current method for acquiring annual approval of an EE Implementation Plan, which should ultimately benefit our customers. The EE Resource Plan is the most cost-effective way to achieve the desired energy savings levels set forth in the EE Rules by establishing a moderate, gradually inclining rate for the Demand-Side Management Surcharge ("DSMS").

Environmental Regulation Compliance

Over the next five years, TEP expects to spend approximately $300 million in capital to comply with new environmental regulations that have been imposed by the Environmental Protection Agency ("EPA") and other governmental agencies. Other rulemakings that are pending at the EPA could further add to the level of capital investment TEP will be required to make for environmental compliance.

Recovering these environmental costs as they are incurred, through an adjustor, moderates their long-term impact on our customers, especially when compared to the more costly effect on our customers' rates when they are instituted through much larger rate increases in the future. Thus, the Company is also proposing to establish an Environmental Compliance Adjustor ("ECA") mechanism. This mechanism would allow TEP to recover the significant capital costs required to meet the environmental mandates mentioned above, including return of and on investments in pollution control equipment and related incremental O&M costs as they are incurred This mechanism is beneficial to our customers as it moderates the cost impact of compliance with those governmental regulations on our customers by reducing TEP's carrying costs and, most likely, lowering TEP's costs to finance those mandatory capital investments.

Solar Build Out

The Company is requesting Commission approval to allow TEP to continue investing in, and recovering its costs of, Company-owned solar projects. We are proposing to invest up to $30 million annually from 2014 through 2017 in locally-based solar projects. The revenue requirement associated with these investments would be recovered through the REST surcharge until the plant is included in base rates.

Post Test Year Plant Additions

The Company is proposing to adjust TEP's rate base to include post test-year plant additions that are in service by December 31, 2012. Not only will the addition of post test-year plant reduce the level of future rate increases, it will also enable TEP to recover the cost of investing in renewable generation that will be in service when new rates are established for TEP, and help mitigate increases in the REST surcharge.

The evidence in this case will show that each of these proposals is in the public interest as they gradually phase-in cost recovery and result in more moderate rates increases.

A. EE Resource Plan.

Q. What is the EE Resource Plan?

A. TEP's EE Resource Plan provides an alternate and improved approach to EES compliance. It is a three-year pilot program that allows TEP to invest in and deliver cost-effective EE programs to our customers. As a part of this proposal, the Company would recover the cost of its EE investments, including a return, through TEP's existing DSMS.

Q. Does TEP believe that DSM/EE can be a cost-effective supply-side resource?

A. Yes. Based on analysis performed in conjunction with TEP's Integrated Resource Plan ("IRP") efforts, the savings produced by certain EE measures will cost less than traditional supply-side resources, help reduce peak load requirements and, in the future, may reduce the need for investment in new generation resources. Further, the deployment of cost-effective EE also has less environmental (water, air, land) impact than other generation resources.

Q. What costs are to be included in the EE Resource Plan and recovered through the DSMS?

A. The EE Resource Plan will include the same type of program-related costs that are currently being recovered through the DSMS. This includes the costs of developing, implementing and administering DSM/EE measures and programs. A return on TEP's investments in DSM/EE will also be recovered through the DSMS. The EE Resource Plan POA included in the Direct Testimony of Mr. Jones describes in detail the costs TEP proposes to recover through the DSMS.

Q. Does the EE Resource Plan include a performance incentive?

A. No.

Q. Please describe the challenges TEP has faced in its efforts to comply with the EES.

A. The EES, which was approved two years after TEP's current frozen base rates took effect, compels utilities to pursue ambitious energy sales reductions through customer-oriented conservation programs. While TEP supports the underlying principles, the Company has continuously asserted that the EES goals may not be reasonably achievable and, as such, may create unintended consequences for utilities and customers. For instance, EES compliance costs increase significantly each year as utilities are required to meet ever increasing annual and cumulative savings goals. Costs will escalate further as utilities exhaust the potential of the simplest and most cost-effective measures and are forced to invest in less productive and more expensive programs.

Since filing TEP's EE Implementation Plan in 2011, concerns have been expressed to TEP regarding rising bill impacts and the value received by customers. While such concerns are certainly appropriate, those concerns have delayed TEP's EES compliance efforts. The extended debate also highlighted the need for a broadly accepted definition of cost-effectiveness that, once satisfied, would empirically determine the prudence of proposed EE programs.

Q. How would TEP's EE Resource Plan improve the current regulatory framework for complying with the EE Rules?

A. TEP's proposal provides an alternative solution for financing the cost of complying with the EE Rules that would reduce and stabilize the rate impacts to our customers, better synchronize the benefits of EE with their associated costs, provide a base level of certainty to program offerings and eliminate the need to provide a performance incentive.

The EE Resource Plan would establish a three-year planning horizon for the Company's EE programs and the associated DSMS. The DSMS rate would be established in advance and would include moderate, predictable year-over-year increases to ease customers into the increasing costs of EES compliance.

The proceeds of the DSMS would be used to recover the costs of TEP's investments in EE programs. I believe the most efficient way to provide cost-effective EE is to treat it like any other resource in our IRP process. Under TEP's proposal, the Company would determine the most cost-effective EE option appropriate for its particular system, invest its capital to procure that resource, and recover the associated costs – including the amortization expense and an appropriate return on investment – through the DSMS. This capital investment and recovery model is similar to that used for any other supply-side resource except that, due to the nature of EE measures, the capital invested in such programs will be considered a regulatory asset and amortized over a four-year term.

Q. Please describe the benefits of the EE Resource Plan's multi-year planning and investment cycle compared with the current annual DSMS approval process.

A. TEP's EE Resource Plan is a win-win proposition for all stakeholders. Customers would benefit from a predictable DSMS that allows them to plan for their energy expenses while gaining greater assurance that TEP's EE programs will be available over a multi-year timeframe. The local contractors who manage such programs will enjoy greater certainty regarding program funding levels. The Commission and its Staff would benefit from a reduction in the administrative burden associated with annual reviews of TEP's EE Implementation Plans. Finally, TEP will have more certainty about the energy savings to incorporate into its resource and system planning and will realize a reasonable return from its EE investments.

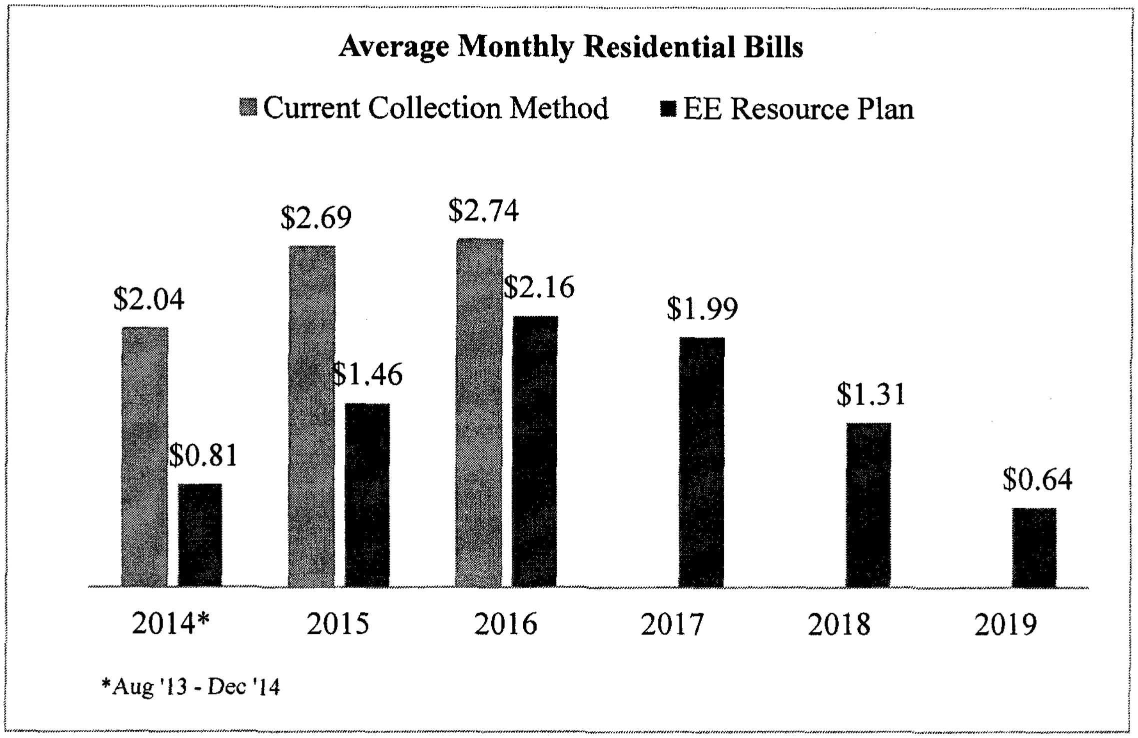
Q. What rate of return on EE investments is TEP requesting?

A. The Company believes the Weighted Average Cost of Capital used to calculate the return on TEP's EE investments should be based on the capital structure and cost of debt approved by the Commission in this proceeding. The ROE component, however, should be increased by 200 basis points to reflect the nature of the investment. Unlike its investments in power plants, buildings, computers and other assets with independent market value, TEP's EE expenditures produce only intangible assets with no value outside of the Commission's rules. That is why the creation of a regulatory asset – the value of which is derived solely from the Commission's authorization – is required to allow TEP to recover and earn a return on its EE investment. The nature of this investment justifies this higher rate of return, since intangible assets do not necessarily provide TEP with the same financial benefits as tangible, saleable assets.

Q. Would TEP's proposal reduce the EE costs reflected on customers' bills?

A. Yes. Because TEP would amortize its EE costs over a four-year period, the EE Resource Plan would allow DSM surcharges to be significantly lower from 2014 - 2016 than they would be compared to the status quo where the annual expenses are fully recovered each year. If the program is extended past its initial pilot period, those savings would be extended to future years.

This benefit remains even though the DSMS would moderately step up each year under TEP's proposal. The EE programs TEP intends to offer in 2014 through 2016 would be funded under the EE Resource Plan with a DSMS that would create an average monthly residential bill impact of $0.81 in 2014, $1.46 in 2015 and $2.16 in 2016. By comparison, TEP estimates that the average monthly residential bill impact of funding the same level of EE programs under the current pay-as-you-go system would be $2.04 in 2014, $2.69 in 2015 and $2.74 in 2016. The comparison of the two alternatives is shown in the chart below.



The calculation of the DSMS is included in the EE Resource Plan POA included in Mr. Jones's Direct Testimony.

Q. Is this type of DSM/EE cost recovery allowed under the EE Rules?

A. Yes. Alternative recovery mechanisms were discussed in the EE workshops and are specifically allowed in the rules. R14-2-2406 (A) (1) states:

> An affected utility's DSM tariff filing shall include the following:
> 1) A detailed <u>description of each method proposed</u> by the affected utility <u>to recover the reasonable and prudent costs</u> associated with implementing the affected utility's intended DSM programs (emphasis added)

TEP's alternative recovery method, as described in the proposed EE Resource Plan, provides the Commission an opportunity to implement a three-year pilot program to determine if this is a superior approach to meeting the EES. If the Commission determines that TEP's pilot program provides greater benefits for all stakeholders and is in the public interest, the Commission may consider continuing the program beyond the initial three-year term.

Q. What are the accounting implications of treating such amounts as regulatory assets?

A. Accounting rules governing alternative revenue programs (ASC 980-605-25-4) proscribe specific criteria permitting recognition of revenue–related regulatory asset associated with our EE Resource Plan. One such criterion is that "[t]he amount of additional revenues for the period is objectively determinable and is probable of recovery."

Q. Why is a four-year amortization period appropriate for recovering Company investments in EE programs and measures?

A. First, cost recovery as proposed by TEP's EE Resource Plan requires a balance between the need for timely cost recovery and customers' desire for more moderate rate increases. A four-year amortization provides an appropriate balance.

Second, accounting rules governing recognition of a regulatory asset provide criteria for deferring costs that would otherwise be immediately expensed. ASC 980-340-25-1 allows the deferral of costs as long as it is probable that those specific costs are subject to recovery in future revenues. The term *probable* is defined as "the future event or events are likely to occur." In addition, as acknowledged by rules that govern accounting for regulatory assets, the risk associated with full recovery of a regulatory asset increases as the corresponding recovery period expands. The Company believes that a four-year period is short enough to meet the probable recovery determination.

Third, TEP believes that a recovery period of four years is reasonable and appropriate in order to maintain a moderately sized regulatory asset over time. Longer amortization periods will produce larger regulatory assets.

Q. How will cost effectiveness of EE measures or programs be determined under the EE Resource Plan?

A. The Societal Cost Test ("SCT"), as defined in the TEP POA for the EE Resource Plan, will determine if a program or measure is cost-effective for recovery through the DSMS. This is set forth in more detail in the EE Resource Plan POA included in Mr. Jones' Direct Testimony.

Q. What standard industry cost-benefit methodology will be used to determine cost effectiveness?

A. The determination of cost effectiveness of TEP's DSM/EE programs will be the societal cost test based upon the methodology sanctioned by the EPA in 2008. The EPA's methodology is the most widely used approach by utilities and regulatory agencies to determine cost effectiveness.

Q. Why should the Societal Cost Test be used to determine the cost effectiveness of an EE measure or program?

A. In accordance with A.A.C. R14-2-2412(B), the Commission requires the SCT be used to determine cost effectiveness. The EE Rules define the SCT and the Total Resource Cost Test ("TRC") (which is contained within the SCT definition) as follows:

For the SCT:

> A cost-effectiveness test of the net benefits of DSM programs that starts with the Total Resource Cost Test, but includes non-market benefits and costs to society.

For the TRC:

> A cost-effectiveness test that measures the net benefits of a DSM/EE programs as a resource option, including incremental measure costs, incremental affected utility costs, and carrying costs as a component of avoided capacity cost, but excluding incentives paid by affected utilities and non-market benefits to society.

Q. Will TEP invest its capital as proposed in the EE Resource Plan without a definition of "cost effective" that is approved by the Commission in this case?

A. No. Unless TEP agrees with the definition of cost effectiveness and standardized measurements that are embedded in the calculation, we will withdraw our proposal to invest the Company's capital in EE programs and measures and will continue to fund these costs on an annual basis based on Commission approval of TEP's EE Implementation Plans. The most critical component included in the determination of cost effectiveness is agreement on inputs and methodology. If, however, the existing funding method is maintained, TEP will request a performance incentive and propose changes to the methodology currently in place for calculating the utility performance incentive as allowed under the EE Rules.

Q. Do you have any concluding comments regarding the proposed EE Resource Plan?

A. Yes. TEP is undertaking an innovative departure from the way in which we traditionally finance and implement EE programs and measures, because we believe that the adoption of cost-effective EE measures significantly enhances the Company's ability to develop a balanced and low cost resource portfolio, which is certainly in the best interest of our customers. Our goal is to develop and deploy measures that provide the greatest operating efficiencies to TEP's generation, transmission and distribution systems; reduce reliance on more costly generating resources; and provide customers with the most cost-effective DSM/EE programs.

By "putting our skin in the game" the Company is taking on additional risk by investing in a regulatory asset that derives value <u>only</u> as a result of an order of the Commission authorizing TEP to recover its costs from customers.

As discussed above, we believe that implementation of the EE Resource Plan will not only eliminate the need for a performance incentive, but will also result in:

- lower costs;
- more stable rates and more predictable program availability for customers;
- greater stability for local EE contractors; and
- less administrative burden on the Commission and its Staff.

B. <u>The Environmental Compliance Adjustor.</u>

Q. What is the ECA?

A. The ECA is a mechanism that will allow TEP to recover the significant costs required to meet environmental compliance standards imposed by federal or other governmental agencies. The availability of an adjustor to recover theses costs ***as they are incurred*** would moderate the impact on our customers, avoiding the large rate increases that would result from deferring these costs to a future rate filing. Mr. Jones is sponsoring the POA for the ECA, which details the specific types of costs that will be included for recovery through the ECA and a description of the annual adjustment process.

Q. Please describe the need for the ECA mechanism and why TEP is proposing that it be considered in this rate case.

A. TEP is proposing the implementation of the ECA in this rate case in response to an ever-increasing number of rules creating more stringent environmental standards that require the Company to invest an unprecedented amount of capital in its generation resource portfolio over the next five years. The EPA and other federal agencies (e.g. Office of Surface Mining) recently have mandated through various rulemakings that certain electric utility generating facilities install, upgrade, and revise environmental control measures and practices. These rules include, but are not limited to, the following EPA final rules and proposed rules that will likely become final in the foreseeable future:

Final rules:

- Regional Haze Best Available Retrofit Technology ("BART") mandates;
- Mercury and Air Toxics Standards rule ("MATS"); and
- Greenhouse Gas New Source Performance Standard ("GHG NSPS") for new sources.

Proposed rules:

- Coal Combustion Residuals ("CCR");
- GHG NSPS for existing sources;
- Greenhouse Gas Prevention of Significant Deterioration Permit ("Tailoring Rule");
- Ozone Standards; and
- 316(b) Cooling Water Intake Structure modification.

These rules will require increased capital spending for the installation of additional equipment with corresponding increases in O&M costs associated with the installation and operation of such equipment or implementation of new environmental protocols at TEP's facilities. For example:

- San Juan Generating Station –approximately $200 million in capital costs and $3-6 million in annual O&M costs to comply with the Regional Haze mandates;
- Navajo Generating Station – approximately $86 million in capital costs and $2-4 million in annual O&M costs to comply with the Regional Haze and the MATS rule mandates;

- Four Corners Power Plant – approximately $36 million in capital costs and $2 - $4 million in annual O&M costs to comply with the Regional Haze and the MATS rule mandates; and
- Springerville Generating– approximately $5 million in capital costs and $3 million in annual O&M costs to comply with the MATS rule.

Such additional capital investment will not create any additional generating capacity. In fact, the additional equipment will actually reduce available plant capacity as it requires station power to function.

Depending on the final outcome of certain proposed regulations, TEP's total capital outlays could approach $400 million, in addition to annual increases in O&M costs in the tens of millions of dollars. TEP will not be able to phase-in or control the timing of these costs, as the compliance deadlines are mandated exclusively by the EPA and judicial rulings.

Q. How will the cost of complying with these environmental mandates impact TEP and its customers?

A. It is likely that most of the expenditures discussed above will occur between rate cases. The inability to recover the significant environmental compliance costs as they are incurred, places TEP and its customers in an untenable position. With respect to TEP, these environmental mandates will result in reduced cash flow and increased capital and O&M expenditures without recovery of those costs through increased revenue because of the extended time between the adjudication of TEP rate cases. This will be detrimental to TEP's financial health and may adversely impact its access to capital on reasonable terms. TEP's customers will be negatively impacted by the extended timeframe between rate cases because the accumulated capital costs and increased O&M will result in larger rate increases.

The Company asserts that it is preferable to recover these mandatory compliance costs over time – between rate cases – which would lead to more moderate annual rate increases. *Otherwise, TEP's financial health will suffer and our customers will have to* absorb large rate increases following the adjudication of multiple, general rate cases.

The ECA solves these dilemmas as it will allow for the timely recovery of the large capital costs associated with environmental mandates and provide for more gradual rate increases over time. While TEP must receive timely recovery of such capital and the related O&M costs to ensure safe, reliable and cost-effective base load generation, it is even more imperative TEP receive this ECA treatment to enable it meet governmental mandates, especially environmental requirements given their significant impact on TEP and its generation resource portfolio.

Q. **Is TEP proposing an adjustor mechanism to recover costs associated with complying with environmental regulations?**

A. Yes.

Q. **Please describe the details of the ECA.**

A. TEP's proposed ECA, is similar to the APS Environmental Improvement Surcharge ("EIS") approved by the Commission in May 2012 (Decision No. 73183). However, because of significant differences in TEP's and APS's generation portfolio, TEP's relative cost to comply with environmental regulations is considerably higher than APS's cost. Accordingly, TEP has tailored the ECA to the needs of our Company and its customers. Specifically, the ECA would allow TEP to recover the incremental costs of its qualified environmental compliance investments, including return on investment, depreciation expense, taxes and associated O&M costs for plant placed in service by year-end. In addition, TEP would be allowed to recover on-going carrying costs on expenditures for assets not yet in-service by year end. Such costs are normally deferred as Allowance for Funds Used During Construction ("AFUDC") and recovered as a component of book depreciation over the service life of the respective asset (45-60 years for generation assets), but not before the asset is placed in service.

The ECA POA provides a detailed description of the type of investments ("Qualified Investments") allowed under the ECA recovery mechanism. Under the proposed ECA, TEP will calculate the ECA annual adjustment to include capital carrying costs incurred prior to the in-service date of Qualified Investments on an annual basis and any Qualified Investments that are anticipated to come online during a particular calendar year between general rate cases.

Q. Please describe the types of investments TEP proposes to include in the ECA.

A. The ECA POA describes in detail the Qualified Investments TEP proposes to recover through the ECA. Generally, TEP's proposal includes environmental improvement projects required to comply with current and future federal, state, tribal, and local environmental standards. In general, these environmental standards seek to reduce the emission of certain substances including: sulfur dioxide ("SO_2"), nitrogen oxide, carbon dioxide, ozone, particulate matter, volatile organic compounds, mercury and other toxics, coal ash and other combustion residuals. For example, under current EPA rules and the current EPA Federal Implementation Plan ("FIP") for the San Juan Generating Station ("San Juan"), TEP estimates it will be required to spend between $180 million and $200 million to install selective catalytic reduction ("SCR") technology at the San Juan by 2017 to reduce regional haze. As has been noted by various Commissioners, spreading the impact of cost increases incrementally on an annual basis, through a mechanism like the ECA, is preferable to larger rate impacts implemented through multiple rate cases.

Q. Why is TEP proposing to include a return on its investments in environmental compliance plant prior to the in-service date?

A. As noted above, current and future environmental mandates will require the investment of significant capital in projects whose construction will span several years. Absent an ECA recovery mechanism, TEP will be expending substantial funds to construct and install environmental improvements before those additions are in service, and long before such costs may begin to be recovered through determined in future TEP rate cases. By including such costs in the ECA, the Company will reduce the AFUDC that would otherwise be included in the final asset cost, thereby reducing future depreciation and returns on investment implicit in future service rates.

Q. Is TEP requesting recovery of carrying costs on Construction Work in Progress ("CWIP") that meets the definition of "Qualified Investment"?

A. Yes. This is a critical element of the ECA given the amount and nature of the investments related to environmental compliance. In fact, if CWIP is not included in the ECA, the ECA will fall far short of its intended purpose. Most major compliance projects take a significant time to design, permit and construct. For example, the SCR facilities at San Juan require investment over four or five years before the projects are complete. As a result, TEP would be investing hundreds of millions of dollars but would be precluded from any recovery on that investment for years if CWIP is not included as part of the ECA. The Company cannot carry approximately 30 percent of our rate base for several years without receiving any return on that investment. Moreover, these facilities are not constructed to meet anticipated growth. Rather, the facilities are needed to allow existing plant to continue to serve customers. On-going recovery of environmental compliance costs from existing customers matches the costs with those who are benefiting from such expenses.

The magnitude of the investment required for environmental compliance relative to TEP's rate base or its market capital requires a non-traditional solution. This dilemma is similar to that facing APS when it was building the Palo Verde nuclear plants. In that case, APS was investing enormous capital relative to its existing rate base but potentially would not see any return until the lengthy construction process was completed. Moreover, the sudden inclusion of such a large asset in rate base would result in rate shock. Therefore, the Commission allowed APS to include CWIP in rate base. See Decision No. 54247 (November 28, 1984) at 19-20.

I believe our circumstance is more compelling than the APS's Palo Verde situation. There, APS was constructing generation to serve future growth. APS anticipated having increased demand (and therefore increased revenues) to help mitigate the financial impact of the significant capital expenditure. Here, we are incurring the significant capital costs to be able to comply with environmental requirements to continue to use existing generation to serve existing customers – without the expectation of additional revenues resulting from the capital expenditures.

Q. How will TEP's customers benefit from adoption of the ECA?

A. By providing timely recovery of required environmental improvement projects and generation capacity acquisitions or additions between general rate cases, the ECA will provide necessary cash flow to help TEP finance capital additions and support credit quality. This can lower financing costs to the benefit of our customers. More importantly, the ECA will smooth the rate impact of complying with environmental mandates. This more gradual approach to cost recovery moderates the rate shock effect of deferring the costs of compliance until new rates are approved in subsequent general rate cases. Finally, implementation of the ECA may reduce the frequency of, and need to, file general rate cases, thereby reducing the impact on our customers and reducing the amount of Commission resources expended on TEP-related issues.

Q. Do you have any concluding remarks on the ECA?

A. Yes, with increasingly stringent environmental rules and the rate effect that they will have on our customers over the very foreseeable future (the next five to six years),the implementation of the ECA will provide for measured and timely recovery of the required environmental investments. The ECA will reduce the time lag between when costs are incurred for a particular project and when the Company begins to recover the costs associated with the project. The reduction in the lag should reduce the financing costs and the savings will be passed on to our customers. Importantly, the ECA will also promote rate gradualism for customers by providing modest annual increases to customer bills, as opposed to the less frequent, larger increases that will occur if the Qualified Investment costs are recovered only when a project is completed and incorporated into rates as part of a general rate case.

C. <u>TEP's Solar Ownership Plan (Bright Tucson Solar Build-Out Plan).</u>

Q. Would you describe TEP's proposal for additional investments in Company-owned solar projects?

A. The Company is requesting that the Commission allow it to continue to invest in TEP's very successful and cost-effective utility ownership of solar assets. TEP is requesting continued authority to invest in up to $30 million of capital annually in 2014 through 2017 to develop cost-effective, solar energy resources. The revenue requirement associated with these investments would include depreciation, property taxes, income taxes, O&M expense and carrying costs using TEP's authorized Weighted Average Cost of Capital and would be recovered through the REST surcharge until the investment is included in base rates. Specific projects and associated revenue requirement will be submitted as part of TEP's annual REST Implementation Plans.

Q. Has the Commission previously given TEP approval for solar investments with cost recovery through the REST surcharge?

A. Yes. In each of TEP's 2010, 2011 and 2012 REST Implementation Plans, the Commission allowed TEP to invest in solar projects and recover the associated revenue requirement through the REST surcharge. Decision Nos. 71465, 72033 and 72736.

Q. Why are solar projects important additions to TEP's resource portfolio?

A. Ownership of solar resources is an essential component of the Company's renewable resource strategy. Adding solar generation to TEP's generating resource portfolio provides much needed balance to TEP's renewable and overall resource portfolios and will help the Company meet the REST requirement in a more balanced, cost-effective manner. TEP's current solar portfolio is heavily skewed towards power purchase agreements ("PPA"). In fact, by 2014, we expect Company-owned solar projects to represent only 15 percent of TEP's total solar resource portfolio. In order to properly balance its portfolio, TEP should be allowed to continue to invest in these assets in the manner the Commission has previously approved, and one that has proven to be very successful for TEP and its customers. Utility ownership, particularly the local development model that TEP employs, provides a number of benefits to the community beyond those associated with the PPA model projects. PPA projects are not obligated to employ local products, and as a result as many of the project components come from outside the area. Often, PPA projects use additional services such as legal, engineering and environmental services from their own locale instead of using local resources. As the local utility and project owner developing inside in our service territory, we only use local resources and project components whenever possible. Utilizing and capitalizing on all of the local resources in our area results in those additional labor, business, and income taxes staying right here in our community, along with longer-term contract services such as operations and maintenance required to operate such facilities.

Q. Why is TEP requesting approval for four consecutive years of investments in solar projects?

A. Requiring annual approval of utility-owned investments through the REST process, which typically requires project to be operational within 12 months from the time they are approved, is proving too difficult to achieve as the Company pursues new technologies and a greater number of projects. The increase in the number of projects is directly associated with the significant increase in renewable production that the Commission mandates are placing on TEP in the later years of the REST rules.[1]

Due to the length of time required to plan, design, build and test some facilities, approval of a multi-year build-out plan would provide the Company and the developers the necessary certainty to move forward on projects, such as the concentrating solar thermal steam augmentation project approved by the Commission in Decision No. 72736.

Most solar projects require longer than 12 months to go from inception to completion, including siting, an RFP process, contract negotiations, permitting, interconnection design, financing, and construction. The Company is not requesting that prudence reviews be waived or any procurement requirements be superseded. In fact, TEP recognizes that each year's expenditures will be reviewed for prudency at the next general rate case. The Company is simply requesting that the Commission approve the

[1] Between 2009 and 2015, the Renewable Portfolio Standard ("RPS") increases at a rate of 0.5 % annually; beginning in 2016, the RPS increases at a rate of 1.0% each year.

recovery of investment and associated revenue requirement through the REST surcharge until that next rate case. This will enable the Company to have a more balanced and comprehensive renewable energy procurement process.

Q. **Is there any precedent for this request?**

A. Yes, both APS and UNS Electric, Inc. ("UNS Electric") received similar treatment in their previous rate cases, Decision No. 71502 (March 17, 2010) and Decision 71914 (September 10, 2010), respectively.

D. Post-Test Year Plant.

Q. **Please describe your proposal for including post-test year plant.**

A. TEP has adjusted its rate base to include approximately $40 million of used and useful solar projects and other plant additions that have been, or are expected to be, placed in service between December 31, 2011 (the end of the test year) and December 31, 2012. These projects will be benefiting customers by the time new rates are effective.

Q. **What are the benefits of including post test year plant in rate base?**

A. It more closely aligns the recovery of costs with the benefits that are currently being provided to existing customers. It also lowers the cost to customers by limiting the amount of AFUDC charged to the assets, thereby reducing the future depreciation and carrying costs associated with this plant. Additionally, the timely recovery of costs necessary to maintain a safe, reliable electric system is necessary to mitigate the large rate impacts that result from the use of historic test years combined with little to no increase in sales.

Q. Has the Commission allowed the use of Post-Test Year Plan before?

A. Yes. In APS's recent rate case settlement, the Commission approved the inclusion of Post-Test Year Plant, including renewable energy projects, in rate base for a period of fifteen months after the test year. See Decision No. 73183 (May 24, 2012). The Commission has also allowed Post-Test Year Plant in numerous other cases, including: *Rio Rico Utilities, Inc.*, Decision No. 67279 (October 5, 2004); *Arizona Water Co.*, Decision No. 66849 (March 19, 2004); and *Bella Vista Water Co., Inc.*, Decision No. 65350 (November 1, 2002).

V. PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE.

Q. Are you proposing any modifications to the PPFAC?

A. Yes, the Company is proposing necessary modifications to the PPFAC including: (i) eliminating the current base power supply rates and recovering those costs through the PPFAC; (ii) adopting PPFAC rates that are differentiated to reflect seasonal differences, on-peak and off-peak differences and the voltage at which a customer takes service; and (iii) revising the costs to be recovered through the PPFAC. We are also proposing changes to the administration process of the PPFAC POA.

A. Consolidation of Base Power Supply Rates into the PPFAC.

Q. Please describe the consolidation of the base fuel and purchased power rates into the PPFAC.

A. TEP's current unbundled rates include, among other things, a base power supply rate for each pricing plan. Each customer class has its own base power supply rate. The current PPFAC is calculated to recover the difference between revenues recovered through the base power supply rates and the actual fuel and purchased power costs. Thus, the PPFAC effectively adjusts the base power supply rate on an annual basis. Our proposal is to consolidate the two. After the consolidation, we will continue to have some differentiation in the fuel and purchased power rates based on the usage. The PPFAC rates will be differentiated to reflect the voltage level at which a customer takes service, on-peak vs. off-peak and summer vs. winter. The Direct Testimonies of David DesLauriers and Craig Jones provide further discussion on this rate design change.

B. <u>Additional Costs to be Recovered through the PPFAC</u>.

Q. In general, what costs are currently included in the PPFAC?

A. As described more completely in the existing TEP PPFAC POA, the PPFAC recovers costs associated with the following Federal Energy Regulatory Commission ("FERC") accounts:

- 501 Steam Power Generation – Fuel
- 547 Other Power Generation – Fuel
- 555 Purchased Power
- 565 Transmission of Electricity by Others

Q. What revenues are included in the PPFAC and offset the fuel and purchased power costs?

A. Pursuant to the Company's PPFAC POA, the following are credited back to TEP's customers through the PPFAC: (i) all short-term off-system wholesale revenue recorded in FERC account 447; (ii) 10 percent of annual positive wholesale trading profits; and (iii) 50 percent of the revenue from sales of SO_2 emission allowances.

Q. What additional costs are TEP proposing to recover through the PPFAC?

A. TEP is proposing to include any credit costs and broker fees associated with power supply and procurement. Additionally, the Company is proposing to recover lime costs incremental to the amount included in the test year through the PPFAC. Finally, TEP requests to recover future greenhouse gas costs through the PPFAC.

1. Credit Costs.

Q. Why is the Company proposing to recover costs associated with credit through the PPFAC?

A. The cost of obtaining and maintaining credit with trading counterparties is a real cost of doing business in the wholesale markets for fuel and purchased power. Prepayments, cash escrow accounts, standby letters of credit and parental guarantees are all common forms of credit support in these markets. As described in the Direct Testimony of TEP witness Kentton C. Grant, the amount of credit support required can vary significantly over time due to changes in wholesale market prices, changes in purchase volumes, and changes in the cost of credit generally. Since these credit costs are incurred in order to support TEP's procurement of fuel and purchased power, and those costs are out of TEP's control, these costs should be recovered by TEP. The most logical place for that to occur is through the PPFAC. Therefore, TEP is requesting that costs associated with obtaining the necessary credit to purchase fuel and power be recovered through the PPFAC.

Q. What level of credit support has TEP been required to provide?

A. The amount of credit support has varied significantly over the past three years. As discussed in Mr. Grant's testimony, the Company was required to provide as much as $12 million in credit support during the summer of 2009 due primarily to falling gas and wholesale power prices in the forward markets, as well as a seasonal increase in accounts payable to gas and wholesale power providers. During the test-year ending December 31, 2011, the amount of credit support provided by TEP in the form of letters of credit and cash collateral was much lower, averaging only $1 million. While Mr. Grant has calculated the cost of providing credit support during the test-year at only $21,000, it is a cost that is not within TEP's control and is a cost of providing that service to our customers that should be recovered through the PPFAC. For purposes of cost verification, the Company will continue to track the outstanding balance of letters of credit and cash collateral provided, and will continue to apply the actual cost rates for letters of credit and short-term borrowings as specified in the Company's revolving credit agreement.

Q. What other reasons justify recovery of credit costs through the PPFAC?

A. The Commission has long recognized the volatility of fuel and purchased power costs as justification for the PPFAC. The Commission has also recognized that a PPFAC allows utilities to respond to such volatility without incurring the cost and time of a rate case. Costs over which a utility has little or no control that are directly associated with the procurement of fuel and purchased power should be included in the PPFAC methodology.

Further, the fact that the necessary and prudent credit costs directly linked to procuring fuel and power on behalf of our customers varies makes the PPFAC the appropriate mechanism to recover these costs. In contract, setting a fixed amount for the recovery of those costs in base rates (which TEP does not profit from) is not reasonable because, as mentioned above, any changes in such costs would inappropriately benefit the Company or its customers depending on circumstances that are beyond the Company's control.

2. Broker Fees.

Q. Please describe how broker fees add to the efficiency of the procurement of purchased power.

A. Broker fees are assessed by the entity arranging the transaction between a buyer and seller. TEP often utilizes third-party brokers for the procurement of its day-ahead and forward power requirements. These brokers play an important role in facilitating an efficient wholesale energy market. Through brokers, TEP has access to a multitude of sellers that it would not ordinarily have a chance to access. This increase in the supply of sellers helps to lower the overall price TEP and ultimately our customers pay, as it helps ensure that those services are acquired at a competitive market price.

Q. How are broker fees currently recovered by the Company?

A. Broker fees are included in the recovery of operating expenses in an amount established in the 2008 Settlement Agreement. These costs are directly linked to power purchases, vary with the amount of energy purchased, are not within TEP's control, and should be recovered through the PPFAC.

Q. Is there precedent by the Commission to permit broker fee recovery through a fuel and purchased power adjustment mechanism?

A. Yes. The Commission now permits APS to recover broker fees recorded in FERC Account 557 through its Power Supply Adjustor Mechanism (Decision No. 73183).

3. Lime costs and SO_2 *Emission Credits.*

Q. What lime costs are you proposing to recover through the PPFAC?

A. The base rates include the test year level of lime costs. However, those costs can vary significantly. Therefore, TEP is proposing to recover (or refund) the incremental lime costs relative to the test year through the PPFAC.

Q. Why is it appropriate to recover incremental lime costs in the fuel adjustor?

A. Lime and coal are inextricably interdependent. All coal contains a certain amount of sulfur that must be removed as part of the combustion process in order to comply with government-mandated clean air regulations. TEP can accomplish this in one of two ways. First, it can purchase more expensive coal with a relatively low amount of sulfur and thereby use less lime to remove the SO_2 by-product. Second, it can purchase lower-cost coal with a higher sulfur content and use more lime to remove SO_2 from the flue gas stream. Inclusion of the coal and lime costs in the fuel adjustor allows us to make the most economical decision based on the current market conditions. In either case, the amount of lime needed for SO_2 removal is directly linked with the coal supply and is considered to be an integral part of the combustion process. In both scenarios the amount of SO_2 emitted after treatment remains the same, but the lime required to remove the SO_2 and the associated cost may vary.

Q. How is lime used to remove SO_2 during the generation process?

A. During the coal combustion process a number of constituents present in the coal are released as gasses. This includes sulfur, which combines with oxygen to form SO_2. In order to remove many of these constituents released as gasses, generating plants are equipped with emissions control equipment. To remove SO_2, many plants, such as Springerville, have installed a technology known as spray dry absorbers ("SDA") or "dry scrubbers". The flue gas stream enters the SDA module where it is mixed with a hydrated lime mist. The calcium in the hydrated lime reacts with the SO_2 molecules in the flue gas to form solid particles of calcium sulfate and calcium sulfite. These particles are captured and removed in a baghouse prior to the flue gas exiting the stack. This method eliminates approximately 90% of the SO_2 from stack emissions. The amount of lime required is a function of the desired removal rate and the amount of sulfur in the coal.

Q. How are lime costs and SO_2 emission credits related?

A. As mentioned above, lime is used to remove the SO_2 formed during the combustion process. In general, the more lime used in the scrubbing process, the more SO_2 is removed, thus creating the possibility for excess credits available for sale. However, as higher removal rates are achieved, exponentially more lime is needed per ton of SO_2 removed. The total amount or percentage of SO_2 removed is also limited by coal type and scrubber design.

Q. How do you propose recovering lime costs in the PPFAC?

A. As noted above, test year amounts of lime expense will be included in base rates. TEP proposes to pass incremental lime costs or savings through the PPFAC.

Q. If TEP is allowed to recover 100 percent of incremental lime costs through the PPFAC, are you proposing to increase the level of SO_2 emission credit revenues credited to the PPFAC?

A. Yes. If the cost of lime incremental to the amount included in the test year is recovered through the PPFAC, the Company would credit 100% of the revenues from sales of SO_2 emission allowance to the PPFAC. As I stated previously, TEP currently credits 50 percent of the SO_2 sales revenues to customers through the PPFAC.

Q. Please summarize why TEP is proposing that incremental lime costs be recovered through the PPFAC.

A. The Company is proposing to include these costs because lime is used to remove the sulfur that is present in the coal as it is brought to the plant, is emitted as SO_2 during coal combustion and is directly linked to production levels and amount of fuel consumed. Price changes in lime also contribute to variations in total lime cost and are beyond the Company's control. Given that lime is directly correlated to fuel consumption and can vary in annual volume and average price, the Company believes it is appropriate to recover costs through the PPFAC.

4. Greenhouse Gas Costs.

Q. Is the Company proposing any other costs associated with fuel and purchased power to be added to the list of PPFAC eligible costs?

A. Yes. TEP is proposing to include greenhouse gas ("GHG") costs in PPFAC recoverable costs. Although the Company does not currently incur GHG costs, the EPA has just approved GHG NSPS rules for new power plants and has indicated it is reviewing GHG rules for existing power plants. Therefore, TEP believes this rate case is the appropriate time to modify the PPFAC POA for its inclusion. Based upon EPA action, and the possibility of Congressional or State action, it is a very real possibility that TEP could incur GHG expenses prior to the filing of its next rate case and therefore GHG costs should be included in TEP's PPFAC. Recovering these costs through the PPFAC is reasonable because such costs will only be incurred by our customers pursuant to a mandate from the government and are fuel-related costs.

C. <u>Changes to the Plan of Administration.</u>

Q. Is the Company proposing any changes to the PPFAC POA?

A. Yes. TEP is proposing several changes to the PPFAC POA. These changes are included in POA included in Mr. Jones's Direct Testimony. I discuss several of those changes below.

Q. Please describe the proposed change to the compliance filing report due date in Section 8 of the POA.

A. Currently, the monthly reports are due within thirty days of the end of the reporting period. TEP proposes to change the due date to forty-five days.

Q. Why is TEP proposing to increase the filing due date from thirty days to forty-five days after the end of the reporting period?

A. The Company proposes this extension of time in the preparation of the monthly filing for three reasons:

1. Not all of the data included in the filing is always available in time to enable filing in 30 days. Extending the filing date will allow for more complete, accurate and timely PPFAC filings, and will eliminate the need for re-filing and/or revision, and additional footnotes explaining the changes;
2. The extended deadline will allow time for additional analytical review during the preparation and review process, which would be beneficial to the Commission, Commission Staff and TEP should questions arise; and
3. The extended deadline will allow more time for cross-training of TEP staff so that the filing can be prepared on a consistently timely basis.

Q. Please describe the proposed change to the effective date of the new PPFAC rate in Section 5.B of the PPFAC POA.

A. TEP proposes to change the last sentence in Section 5.B from "The new PPFAC rate will go into effect on April 1 upon Commission approval" to "The new PPFAC rate will go into effect on April 1 unless otherwise ordered by the Commission". This change will make the effective date consistent with the UNS Electric POA. Similarly, the APS POA approved by the Commission in Decision No. 73183 states, "Unless the Commission has otherwise acted on the APS calculation by February 1, the PSA rate proposed by APS shall go into effect with the first February billing cycle".

Q. Please explain the proposed change to the definition of Long-Term Energy Sales in Section 2 of the PPFAC POA.

A. The current definition lists sales to Salt River Project, the Tohono O'odham Utility Authority and the Navajo Tribal Utility Authority. The Navajo Tribal Utility Authority and the Salt River Project agreements terminate in 2015 and 2016, respectively. TEP believes the definition should be expanded to include other long-term energy sales agreements it may enter into in the future. TEP proposes to define long-term energy sales as sales other than short-term firm service using the FERC definitions of Sales for Resale (Account 447). The FERC defines short-term firm service as a sale where the period of commitment is one year or less. It defines intermediate-term service as longer than one year but less than five years; and long-term service as five years or longer. Therefore, TEP proposes to define Long-Term Energy Sales as sales where the duration is longer than one year.

Q. Is the Company proposing any other changes to the definition of Long-Term Energy Sales?

A. Yes. TEP proposes to include in the definition of Long-Term Energy Sales any sales that are not supplied out of its generation system, but rather through a long-term purchase. Such sale and purchase will be in like quantity and duration. All costs associated with the purchase in this arrangement will also be excluded from the PPFAC eligible costs in Purchased Power (Account 555).

Q. Do you have any concluding remarks?

A. The rates TEP has proposed in this filing reflect both the necessities created by five years of unrecovered costs and our commitment to avoid similar consequences in the future. Now that we understand TEP's historic sales growth is just that – history – we must find ways to recover our rising costs promptly and gradually, without the lengthy delays that lead to large rate requests. In addition to taking steps to reduce our request in this matter, we have offered proposals that would allow timely recovery of the Company's rising service and regulatory compliance costs in ways that generate smoother, more moderate rate increases. These changes will help our customers manage their energy expenses while providing TEP, for the first time in years, with a reasonable opportunity to earn its Commission-authorized return on its investment in safe and reliable service.

Q. Does this conclude your Direct Testimony?

A. Yes.

Direct Testimony of Michael J. DeConcini

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
GARY PIERCE- CHAIRMAN
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

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-12-____

Direct Testimony of

Michael J. DeConcini

on Behalf of

Tucson Electric Power Company

July 2, 2012

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I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Michael J. DeConcini. My business address is 88 East Broadway Boulevard, Tucson, Arizona, 85701.

Q. What is your employment position?

A. I am employed by UNS Energy Corporation ("UNS Energy") and Tucson Electric Power Company ("TEP" or the "Company") as Senior Vice President, Operations. UNS Energy was known as UniSource Energy Corporation before a name change that took effect on May 4, 2012. For simplicity's sake, I will refer to that company as UNS Energy throughout my testimony, even when describing events that occurred under that company's previous name.

Q. Please describe your background, education and experience.

A. I have been employed by TEP since 1988, serving in various management capacities since 1994. My previous positions have included Senior Vice President and Chief Operating Officer of the Energy Resources business unit of TEP and Senior Vice President and Chief Operating Officer, Transmission and Distribution ("T&D"). I hold a Master of Business Administration degree from Arizona State University and a Bachelor of Science degree in Finance from Moorhead State University.

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

A. My testimony describes TEP's: (i) operating areas; (ii) maintenance practices related to operations; (iii) safety; (iv) growth and its impact on the Company; (v) environmental compliance; (vi) capital spending; (vii) the benefits of TEP's purchase of Unit 4 at the H. Wilson Sundt Generating Station ("Sundt"); (viii) operating and maintenance ("O&M")

costs; and (ix) the benefits TEP has realized through its operation of Units 3 and 4 at the Springerville Generating Station ("SGS").

Q. Please summarize your testimony.

A. I describe TEP's business operations, including distribution of electricity within our service territory, transmission of power into our service territory, and the generation of power by both remote and local facilities. I outline our employees' exemplary safety record, as well as their continued commitment to providing safe, reliable and environmentally responsible service to our customers. I describe TEP's historical capital spending, including the justification for the Company's purchase of Sundt Unit 4 and projected capital investments, which are likely to include significant expenditures for compliance with environmental regulations. I will also describe how the Company has provided safe, reliable service to its customers while containing O&M expenses. I further describe the reduced O&M expenses and other benefits created through TEP's operation of SGS Units 3 and 4, the Sahuarita-Nogales transmission line project and pro-forma adjustments.

II. TEP'S OPERATIONS.

Q. Mr. DeConcini, please describe TEP's distribution operations.

A. TEP serves approximately 404,000 customers in Pima County. Its service territory spans 1,155 square miles, extending north to the Pinal County line and south to the Santa Cruz County line. TEP serves customers in Tucson, South Tucson, Oro Valley, Sahuarita, Marana, and unincorporated areas of Pima County. TEP also provides power to Fort Huachuca, a U.S. Army base located in Cochise County. As of December 31, 2011, TEP owned or participated in an overhead electrical T&D system consisting of:

- 512 circuit-miles of 500-kilovolt (kV) lines;

- 1,088 circuit-miles of 345-kV lines;
- 405 circuit-miles of 138-kV lines;
- 479 circuit-miles of 46-kV lines; and
- 2,615 circuit-miles of lower voltage primary lines.

TEP also operates 4,389 cable-miles of underground electric distribution lines. The Company's electric substation capacity operates 103 substations with a total installed transformer capacity of 13,266,850 kilovolt amperes.

Q. Please describe TEP's transmission system operations.

A. TEP's Extra-High Voltage ("EHV") transmission system links the Company's southern Arizona service territory to generation resources in New Mexico and northeastern and central Arizona via three links to our High Voltage ("HV") transmission system in the Tucson area. TEP's HV transmission system includes looped 138-kV lines and radial 46-kV lines serving substations that provide 13.8-kV and 4-kV distribution service. In accordance with prudent utility practice and mandatory electric reliability standards established and enforced by the North American Electric Reliability Corporation ("NERC"), as approved by the Federal Energy Regulatory Commission ("FERC"), TEP employs operating procedures and controlled load shedding schemes to mitigate overloads of the 345-kV and 138-kV systems. System reinforcement and expansion projects typically include the installation of new or upgraded HV line conductors and substation reliability and capacity additions.

Q. Please describe TEP's generation assets.

A. As of December 31, 2011, TEP owned or leased 2,262 megawatts ("MW") of net generating capability from 24 units, including 13 steam units, seven simple-cycle combustion turbine units, one gas-fired combined cycle unit and three solar-generating facilities. In addition, TEP utilizes landfill gas to produce approximately 6 MW of continuous output at the Sundt generating station and purchases 52 MW of wind and solar generating resources from third parties. The generating source, location, fuel type, size and ownership of these units 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
SGS Station[1]	1	Springerville, AZ	1985	Coal	401	TEP	100.0	401
SGS Station	2	Springerville, AZ	1990	Coal	403	TEP	100.0	403
San Juan Station	1	Farmington, NM	1976	Coal	340	PNM	50.0	170
San Juan Station	2	Farmington, NM	1973	Coal	340	PNM	50.0	170
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	555	PNM	33.0	185
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	4	Tucson, AZ	1988*	Coal/Gas	156	TEP	100.0	156
Internal Combustion Turbines		Tucson, AZ	1972	Gas/Oil	125	TEP	100.0	125
Internal Combustion Turbines		Tucson, AZ	2001	Gas	95	TEP	100.0	95
Solar Electric Generation		Springerville/ Tucson, AZ	2002-2011	Solar	13	TEP	100.0	13
Total TEP Generation Capacity								2,262
Renewable Energy Power Purchase Agreements								

Concentrating Solar PV		Tucson, AZ	2011	Solar	2	Amonix	100	2
Macho Springs Wind Farm		Deming, NM	2011	Wind	50	Element Power	100	50

(1) Leased assets.

* Prior to coal conversion – 1967; after coal conversion – 1988.

III. RELIABILITY.

Q. Please describe the Company's commitment to providing safe and reliable service.

A. Providing safe, reliable and economic electric service is the principal focus of TEP's business. We have earned a reputation for reliability that reflects our employees' commitment to effective, efficient operations in all areas of our Company. This commitment has been challenged in recent years by our need to tightly manage increasing O&M expenses in the face of lagging retail energy sales. I am proud to say that our employees are responding to this challenge by finding new, more efficient ways to operate in a cost-effective manner while leveraging their expertise and experience to provide top tier reliability without compromising on safety.

Q. How reliable is TEP's service, compared to other utilities?

A. TEP's system reliability compares favorably on two common industry benchmarks: System Average Interruption Duration Index ("SAIDI") and Customer Average Interruption Duration Index ("CAIDI"). These comparisons are made annually based on the Edison Electric Institute ("EEI") Distribution Reliability Survey, which aggregates data from utilities across the country. EEI survey data is formatted into quartiles to indicate how individual utilities compare to their peers. TEP's performance earned the Company a spot in EEI's first or second quartile in each year from 2008-2010; quartile data for 2011 is not yet available. Based on these figures, which are shown in the following table, TEP's distribution operations rank among the most reliable in the industry. This reliability provides customers with significant benefits, including safety, productivity, comfort and convenience.

2008-2011 SAIDI/CAIDI Comparison

Year	SAIDI	EEI Quartile	CAIDI	EEI Quartile
2008	80.1	2nd	75.7	1st
2009	71.9	1st	82.1	1st
2010	89.0	2nd	85.9	1st
2011	93.9	N/A	83.5	N/A

Q. How does TEP plan improvements to its T&D system to meet its customers' long-term energy needs?

A. TEP performs five-year and ten-year system assessment studies to identify potential overloads and voltage concerns. These studies are first performed on all transmission and generation facilities in service. Sensitivity studies are next performed for specific transmission facilities removed from service. If overloads or voltage concerns are discovered, transmission and/or substation facilities are added or existing facilities are upgraded to resolve potential issues. These studies are completed pursuant to planning standards issued by NERC. TEP invests significant time and resources to maintain and document its compliance with NERC reliability standards. Failure to comply with these standards could expose the Company to significant fines[1] and compromise the reliability of

[1] Under the Energy Policy Act of 2005 ("EPAct 2005"), FERC is responsible for overseeing mandatory electric reliability standards governing the bulk power system. This oversight function is accomplished through the designation of an electric reliability organization (which is the NERC), and through procedures implemented by the FERC for the establishment, approval and enforcement of mandatory electric reliability standards. Under EPAct 2005, FERC was also granted the authority to issue significant fines, which includes penalties of up to $1,000,000 per day per occurrence. This penalty authority extends to violations of the mandatory electric reliability standards (also referred to as the NERC reliability standards). NERC, as the designated electric reliability organization, has the legal

the regional electric grid. TEP underwent an audit of its compliance with the NERC reliability standards in 2011, which was conducted by the Western Electricity Coordinating Council ("WECC"), the regional entity tasked with monitoring and enforcing compliance with the NERC reliability standards. During the TEP audit, WECC determined that there were no findings of non-compliance. In fact, the managing director of compliance for WECC complimented TEP on the strength of its NERC compliance program.

Q. How does TEP assess the need for near-term improvements to its distribution systems?

A. TEP employees conduct a thorough performance analysis of the Company's distribution system each year to identify the circuits most critical to continued reliability. Those circuits are then inspected by TEP journeymen linemen to assess the condition of insulators, guy wires, poles, cross arms, ground wire attachments, static and neutral wires, conductors and other distribution equipment and to evaluate the threat posed by nearby vegetation. TEP crews also patrol assigned geographic areas to assess and report any significant changes in the condition of the T&D system. Any issues identified on these patrols or inspections are addressed as needed. TEP invested $11.7 million during the 2011 test year in the "like-for-like" replacement of T&D line assets.

Q. How does TEP identify necessary substation improvements?

A. To evaluate the performance of our substations, employees prepare and review monthly equipment outage reports comparing the periodic and year-to-date failure rates to the same data from the previous three years. The report identifies any substation equipment that fails to function as designed. Any failure that results in an unscheduled service interruption, momentary or otherwise, is classified as an outage. On a monthly basis, each equipment

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authority to enforce compliance with the mandatory electric reliability standards with all users, owners, and operators of the bulk power system, which it achieves through monitoring, audits and investigations, and the imposition of financial penalties and other enforcement actions for non-compliance, subject to the oversight and approval of FERC.

failure and outage is reviewed to ensure that the appropriate corrective maintenance was completed or has been scheduled to be addressed in a timely manner.

Q. Please describe TEP's efforts to maintain substation transformers.

A. TEP takes significant steps to protect substation transformers that play a critical role in the reliability of our service. Because new transformers can cost more than $1 million and can take nearly 18 months to build and install, TEP follows a well-defined and disciplined maintenance program. Twice a year, we complete an updated transformer fleet assessment that weighs numerous factors to generate an index number used for ranking the condition of each transformer. Some of these factors include: oil condition, maintenance history, fault history, paper condition, bushings, lightning arrestors, age, maintenance bulletins, infrared scans, and loading history. The resulting rankings are used to project equipment life cycles and they are helpful in planning and budgeting the capital costs for transformer replacements. We also seek to reduce risks to the operation our transformers through new engineering standards, including requirements for fire walls and oil retention basins in new substations as well as substations with capacity improvements. In preparation for potential transformer failures, we maintain emergency spare units for line voltages as high as 138-kV to facilitate timely replacements. We also operate two mobile transformers/substations and one portable transformer that can be used to stand in for failed units or to supplement our capabilities during periods of high energy usage.

Q. Please describe TEP's efforts to maintain the reliability of other key substation components.

A. TEP maintains its largest, most critical substation circuit breakers by scheduling and performing work based on the manufacturers' recommendations. For others, we employ a program of predictive maintenance based on the results of diagnostic tests rather than a predetermined schedule. We also make strategic decisions to perform across-the-board upgrades of certain key components, such as the older EHV oil circuit breakers in 345-kV substations.

TEP diligently performs maintenance on components that protect the bulk electric system as defined by the NERC. These include protective relays and their supporting subsystems, such as communications paths, voltage and current sensing devices, relays, power supplies (including batteries, battery chargers, and non-battery-based direct current ("DC") resources), and breaker trip-and-close circuitry.

Q. Please describe TEP's transmission line maintenance efforts.

A. TEP uses Transmission Line Asset Management Program software to manage inspections and maintenance of its 138-kV and 345-kV structures. The program calls for inspections and upgrades based on a schedule that varies by voltage class.

TEP's transmission line maintenance crews perform aerial inspections of our 345-kV transmission lines on a semiannual basis. Inspectors look for imminent dangers to the system, such as foreign objects caught in the lines or towers. They also observe the condition of anchors and guy wires and look for encroachment by trees or other vegetation. The same 345-kV lines and towers are subjected to a close inspection from the ground every five years. Crews also perform climb-and-shake tests on a sample of the Company's transmission structures in areas with limited access or exposure to high winds.

For TEP's 138-kV transmission system, ground patrols are performed annually. Crews inspect the condition of insulators, guy wires, wood poles, cross-arms, cross- and knee-braces, ground wire attachments, static wires, conductors and vegetation. In 2012, TEP began systematically replacing its older 138-kV wood structures with steel poles. The new steel structures will reduce the number of future service outages caused by pole failures, accident damage, fires, and storms.

Q. What role does vegetation management play in transmission line maintenance?

A. Maintaining adequate clearance around transmission lines is critical to TEP's efforts to provide safe and reliable service and comply with FERC's mandatory reliability standards as enforced by NERC. Our vegetation management efforts are intended to prevent plant material such as stray tree branches from blowing across conductors in a storm and to reduce the fuel available to any wildfire that may approach our transmission lines. Vegetation is cleared based on five-year growth cycles established through consultation with the U.S. Forest Service and other entities. Our clearance efforts are designed to maintain adequate clearances for at least five years, though more frequent trimming is sometimes necessary if line inspections reveal faster-than-expected vegetation growth.

Q. How does TEP assess the reliability of its generation plants?

A. TEP gauges the reliability of its coal-fired plants using NERC's Generating Availability Data System ("NERC-GADS") measure of Equivalent Availability Factor ("EAF"). EAF represents the percentage of time during a given period that a unit is available to provide power at its maximum continuous rating ("MCR"). Therefore, EAF reflects all scheduled and forced outages, as well as de-ratings periods when the unit is forced to run at less than its MCR.

TEP uses the NERC-GADS data to compare the reliability of our units to others throughout the industry. TEP has developed a weighted EAF average from the NERC-GADS database using plants that are similar in size and construction to our own units, allowing us to accurately compare our performance with other coal generation plants across the country. A five-year average is used to normalize the effects of unit overhaul cycles. From 2006 through 2010, TEP's EAF was 87.12 percent, which exceeds the industry average of 84.18 percent for the same time period. The superior reliability of TEP's generating plants provides significant service and cost benefits to our customers.

Q. What ongoing maintenance programs ensure the continued reliability of TEP's generation assets?

A. TEP employs a variety of maintenance programs for its generating units. Our preventative maintenance program combines the original equipment manufacturers' recommendations, industry experience, plant history and equipment history to create cyclic work orders for inspecting, adjusting, and maintaining equipment. A computerized maintenance management system creates orders on a weekly, monthly, quarterly or annual basis. Our maintenance crews then perform the required tasks and track the results. If problems are found, the frequency of preventive maintenance work is correspondingly increased to maintain reliability.

This schedule-based system is complemented by our predictive maintenance program, which assigns work based on specialized tests of our generation equipment. Through analysis of oils and motor electrical signatures, vibration measures, thermography and other tests, dedicated inspectors can identify deteriorating equipment and order repairs during planned outages, avoiding catastrophic failures that would compromise our reliability. Our plant operators also are tasked with the responsibility of monitoring unit performance during their shifts and initiating work orders to address any needs for corrective action they observe in a timely manner.

TEP also employs specialized maintenance programs for certain power plant components. These include our boiler tube failure reduction program, critical piping and pipe hanger inspection program, flow-accelerated corrosion inspections, cathodic protection surveys, and corrosion monitoring efforts in various systems through the plants.

TEP schedules plant outages during periods of reduced electric demand to accommodate inspections and repairs that can only be completed when units are off line. The need for such an outage is determined by manufacturers' maintenance schedules, insurance requirements, past reliability concerns and issues identified through other maintenance programs. This work is packaged into a tightly scheduled overhaul plan so that all necessary maintenance can be completed safely while minimizing the duration and cost of the outage. These efforts benefit customers by reducing outage expenses, improving reliability and increasing the amount of time customers have access to the Company's affordable generating resources.

Q. What steps has TEP taken to protect the reliability of its service from cyber attacks?

A. TEP employs virtual and physical security systems and processes to protect its critical assets from cyber attacks. TEP's efforts are designed to comply with the Critical Infrastructure Protection ("CIP") standards established by NERC and adopted by FERC to preserve the reliability of the bulk electric system. These standards became fully mandatory in 2009, creating compliance costs which have increased significantly since 2006 (the Company's previous test year).

The CIP standards require utilities to establish both physical and electronic security perimeters around key facilities and computer systems. A strict change control process enables these protections to be preserved as the underlying systems are expanded. TEP also performs annual vulnerability assessments in accordance of its energy management system ("EMS") and substation networks.

Q. How will future changes to cyber-security standards affect TEP?

A. Future versions of NERC's CIP standards are expected to apply to a broader range of assets. Although, a well-defined process is already in place to manage these assets, compliance with these new mandatory standards will continue to increase the Company's capital and O&M expenses and the amount of time and effort our employees must spend to document our compliance with NERC standards.

IV. SAFETY.

Q. How does TEP work to ensure the safety of its operations?

A. Safety is an essential element of TEP's operational philosophy. We strive to perform all of our work in a manner that prevents injury to ourselves, our co-workers, our customers or any other member of the community who may come in contact with us or our equipment.

This philosophy is supported by our overall "Target Zero" safety strategy, which includes three elements:

- active safety leadership;
- increased employee involvement in safety activities; and
- regulatory compliance.

I am proud that the focused implementation of this strategy throughout the Company has resulted in dramatic and continued improvement in our total recordable incident rate, which fell from 2.99 in 2007 to 0.99 in 2011. That 67-percent improvement lifted TEP's performance into the top third in the Bureau of Labor Statistics safety rankings among electric utilities of a similar size.

Our commitment to safety is conveyed through employee training initiatives, including behavior-based safety programs and a companywide effort to train all supervisors in "Leading in a Manner that Prevents Injury". We also employ continuous improvement tools to analyze current practices and look for opportunities to improve our safety performance.

To monitor the effectiveness of these efforts, we conduct a bi-annual Safety Process Analysis to review our safety leadership activities, employee involvement in safety and our compliance with Occupational Safety and Health Administration ("OSHA") regulations. This assessment is used to highlight and share outstanding processes and identify improvement opportunities that will help us continue to improve our safety performance.

Q. **What efforts does TEP undertake to maintain its safety record at its power plants?**

A. In addition to participating in companywide efforts, TEP's generation crews are focused on improving near-miss reporting and improving the effectiveness of their joint management/union safety committees. As a result of these activities and continued focus on compliance with all OSHA regulations, we have reduced the total recordable incident rate at our power plants from 2.95 in 2007 to 1.19 in 2011, a 60 percent improvement. Although industry statistics for 2011 have not yet been published, TEP's performance that year was clearly superior to the national average recordable incident rate of 2.9 recorded in 2010 by operators of coal-fired generating facilities.

Q. **Please describe TEP's efforts to increase electric safety awareness in the community.**

A. TEP has invested significant time and resources to promote public awareness of electric safety concerns. These efforts include:

- Electrical safety training lessons for fourth- and fifth-grade students;
- "Stay Away, Stay Alive" training for first responders;

- Substation fire drills conducted in conjunction with local police and fire agencies;
- Electrical safety training for local contractors;
- Bill inserts and paid advertising campaigns promoting electrical safety;
- Online electrical safety resources for contractors on tep.com; and
- Support for Arizona Blue Stake's outreach efforts.

These programs are an integral part of TEP's overall safety philosophy. To truly "work in a manner that prevents injury", we must do all we can to help protect the public from potential electrical hazards.

V. <u>GROWTH.</u>

Q. Please describe the growth in TEP's customer base since the last test year and the forecast for future customer growth.

A. The robust growth that once typified TEP's service territory has stalled in recent years during challenging economic conditions. After expanding at an average annual rate of 2.3 percent between 2000 and 2007, TEP's customer base grew by less than one percent in each of the last four years. During the 2011 test year, TEP added about 1,500 customers. This represents a decrease of 80 percent when compared with the number of customers added in 2006 – TEP's last test year. At year's end, TEP's customer base included approximately: 367,000 residential customers, 36,000 commercial customers, 636 industrial customers, 62 public authorities and two mining customers. TEP's annual customer growth rate is expected to slowly rebound as the economy recovers, potentially increasing to nearly one percent per-year in 2012, and to 1.5 percent per year in 2015. But it appears that the higher growth rates are a thing of the past and that a 1 percent growth rate represents what TEP can reasonably expect in the years to come.

Q. How have customers' energy demands changed in recent years, and what are your expectations for future retail energy sales?

A. Slower customer growth, sluggish economic conditions and the impact of energy efficiency and renewable energy distributed generation standards have combined to reduce our customers' energy usage in recent years. In 2011, TEP's retail energy sales were 3.1 percent below sales levels experienced in 2007. This compares with retail kWh sales growth averaging three percent per year from 2004 through 2007. Compared to TEP's last test year, 2006, retail sales volumes remain essentially flat. Average usage among our residential customers – who comprised 91 percent of our customer base and accounted for 42 percent of our retail sales in 2011 – has fallen by five percent between 2007 and 2011. While use per customer will continue to decline due to energy efficiency programs and distributed generation, increased customer growth and improved economic conditions potentially could produce modest annual energy sales increases of approximately one percent in future years.

Q. How have recent reductions in TEP's retail sales affected the company's plans to serve customers' future energy needs?

A. We have deferred planned transmission upgrades, substation expansions and other projects that would have been needed sooner if customer demand had continued to grow at its previous rate. Many of these projects remain part of our long-term plans, however, to address the prospect of future growth.

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

A. Our plans to address future growth are contained in the Integrated Resource Plan ("IRP") that TEP filed April 2, 2012, with the Arizona Corporation Commission ("Commission") (Docket No. E-01933A-11-0113). The IRP identifies the Company's future capacity requirements through 2027 and outlines a plan for addressing those needs safely, reliably and cost-effectively. The IRP's "Reference Case" is designed to manage costs to customers, mitigate environmental impacts and comply with regulatory requirements while effectively using TEP's generation and transmission infrastructure and protecting Arizona's local economies. It calls for new renewable energy resources, expanded energy efficiency efforts, new natural gas-fired generation and upgrades to TEP's transmission infrastructure. It also highlights decisions that must be made regarding the Company's existing coal generation fleet. The IRP offers a high-level guide to TEP's long-range plans and, as such, serves as the starting point for our reliability planning efforts.

Q. How does TEP plan to address its future energy needs?

A. The IRP's Reference Case anticipates that TEP will make increasing market purchases of power to complement its own generating resources. The Company also plans to expand its renewable energy resources and demand side management programs under the Renewable Energy and Energy Efficiency Standards. Finally, TEP is considering the addition of gas-fired simple-cycle and combined-cycle generation for intermediate and peaking needs.

Q. What transmission improvements are planned to address future reliability and energy needs?

A. To improve our access to economic market power resources, TEP is developing a new 500-kV transmission line that will link the Pinal Central Substation in central Arizona to TEP's Tortolita Substation northwest of Tucson. This line will increase the Company's cumulative import capacity by approximately 500 MW, or 21 percent, providing new access to available energy resources in other markets. The Arizona Power Plant and Transmission Line Siting Committee ("Line Siting Committee") granted a Certificate of Environmental Compatibility ("CEC") for the project on May 24, 2012, and we expect that the Commission will review the matter in the near future.

TEP also is planning several major transmission projects between 2012 and 2017 intended to maintain service reliability and satisfy customers' energy needs. These projects include:

- A new 138-kV line linking the DeMoss Petrie and Tucson Substations (the Commission approved the CEC in Decision No. 72231 (March 9, 2011));
- New 138-kV lines linking the Tucson and Irvington Substations to the planned Kino Substation;
- A new 138-kV line extending from the Canoa Ranch Substation to the planned Duval Clear Switchyard; and
- The installation of new conductors on the 138-kV line linking the 22nd Street and Irvington Substations.

Q. What substation improvements will be needed in coming years to maintain the reliability of TEP's service?

A. The distribution systems serving certain areas of our service territory have reached the capacity limits of existing substations. To continue reliable service in those areas and to serve future customer growth, TEP is planning several new substations and switchyards as well as upgrades to existing facilities. These projects include:

- New Marana Substation;
- New Orange Grove Substation;
- New Craycroft Substation;
- New Harrison Substation;
- New Kino Substation;
- New Corona Substation;
- New Duval Clear Switchyard; and
- Upgrades to the Rancho Vistoso, Tortolita, North Loop and Hartt Substations.

TEP's substation development efforts must overcome challenges associated with securing land and permits for such facilities. It typically takes about five years to permit, engineer, procure and build a standard distribution substation, with most of that time spent resolving land and permit related issues. TEP has modified its planning process and substation standards in an effort to reduce delays and optimize the overall economics of our distribution infrastructure.

VI. TEP'S WORKFORCE.

Q. What challenges does TEP face in ensuring the continued availability of trained personnel to address long-term infrastructure needs?

A. We are preparing for the impending retirement of many experienced employees in our T&D area. Approximately 40 percent of the 469 TEP employees engaged in various aspects of electric service delivery will be eligible to retire between 2012 and 2016. The majority of these retirement-eligible employees hold skilled craft positions, making their replacement much more difficult.

Q. Is TEP engaged in workforce development efforts to generate new prospects for critical T&D positions?

A. Yes. In addition to the training we make available to current employees, we have engaged in comprehensive efforts to attract new employees to skilled craft roles. Our "Building for Success" program exposes high school students to craft-based career opportunities in the electric utility industry. Through TEP's partnership with the Pima County Joint Technical Education District, program participants can pursue their industrial electrician certificate while receiving both high school and college credit. They also can earn one of a limited number of scholarships to pursue the next step of their career development at Pima Community College ("PCC").

TEP has partnered with PCC to develop pre-requisite classes that support entry into our Craft Internship or Craft Pre-Apprentice programs. Individuals that complete at least one year of pre-requisite training at PCC and maintain a minimum 3.0 GPA have the opportunity to apply for a one year, paid internship with Southwest Energy Solutions, Inc. ("SES"), a sister company that provides cost-effective electrical contracting services to TEP. This internship provides a rotation through the various craft areas to expose participants to potential career opportunities with SES, TEP and the Company's other affiliate, UNS Electric, Inc. ("UNS Electric").

The Company is also a member of the Arizona Energy Workforce Consortium ("AEWC"), whose mission is to build alliances, processes and tools to develop tomorrow's energy workforce. The AEWC's goals include implementing the Center for Energy Workforce Development's "Get Into Energy" and the "Troops to Energy Jobs" educational programs.

Q. How does the company use its Craft Pre-Apprentice and Apprentice Programs to develop skilled T&D employees?

A. New Craft workers are hired through the Craft Pre-Apprentice program. Job candidates accepted as Pre-Apprentices are hired as core TEP employees on a probationary basis for at least one year. These individuals are provided with classroom and field training, exposing them to different career paths while allowing the Company to assess their potential success as a Craft Apprentice.

TEP operates nine Craft Apprentice Programs in various T&D specialties, each lasting three to four years. Apprentices are chosen through testing and interviews from the ranks of the Craft Pre-Apprentices. Successful candidates are provided classroom education and on-the-job training under the direction of qualified and experienced "Journeyworkers" of their Craft. Apprentices are required to complete extensive on-the-job and class room training each year, with continuing evaluation of their attitude, aptitude and safety records.

Those who complete this intensive program are recognized by the Company and the State of Arizona as a Journeyworker of their specific craft. This accomplishment would not be possible without a shared commitment among the Company, its Journeyworkers and the community at large to endow a new generation with the skills to maintain TEP's safe, reliable service.

Q. How many employees have participated in these workforce development efforts?

A. Forty-eight new Journeyworkers have graduated from the Company's craft apprentice programs over the past four years. Another 44 apprentices are currently enrolled in these programs, along with three pre-apprentices and five active interns. We intend to hire additional apprentices based on our expected levels of future retirement and our expected needs in various craft areas.

VII. <u>ENVIRONMENTAL COMPLIANCE.</u>

Q. Please describe TEP's environmental stewardship and compliance programs.

A. TEP is committed to conducting business in an environmentally responsible manner. The Company has established an exemplary record of compliance with local, state and federal environmental standards. Environmental leadership has become increasingly important to all aspects of our operations, including our ongoing efforts to develop EHV transmission lines and associated substations. In such projects, we ensure responsible land use through an inclusive, detailed process that incorporates the following key concepts:

1. environmental education;
2. collaborative planning to identify sensitive areas;

3. avoidance of sensitive areas whenever possible; and

4. mitigation of impacts when unavoidable.

TEP has a number of policies, procedures and programs in place to protect and preserve biological and cultural resources during the construction and operation of facilities. For example, our Raptor Protection Program relies on formal partnerships with local wildlife protection experts and community members to reduce the potential for raptor electrocutions in our service territory and provide information to regulatory agencies as required by law. These partnerships promote surveys, notification and reporting that support our efforts to install safeguards on utility poles within 300 feet of active Harris hawk nests. Many of TEP's raptor protection processes have been adopted by the Industry and incorporated into nationally-distributed publications on the subject.

Q. **What efforts does TEP undertake to manage the wastes generated by utility operations?**

A. TEP has developed specific procedures and policies to safely dispose of hazardous waste, used oil and oil-contaminated debris and other non-hazardous solid wastes generated through its utility operations.

- **Hazardous waste** – Paint residue and spent solvents are the primary hazardous wastes generated at TEP facilities. TEP complies with all storage, labeling, transportation, recordkeeping and disposal requirements for such materials and has worked to reduce the generation of such waste to very low levels.

- **Used oil and oil-contaminated debris** – More than four million gallons of oil are in use at any given time in TEP's transmission, distribution, generation and support facilities. The majority of used oil is generated through maintenance of the Company's motorized fleet, power plant repairs, and the maintenance and decommissioning of electrical T&D equipment. A small percentage of this used oil may contain Polychlorinated Biphenyls ("PCB") and is managed appropriately. Thanks to our efforts to reduce the use of these chemicals, less than two percent of the equipment brought in for maintenance or repair is found to contain PCBs.

- **Non-hazardous solid wastes** – These include coal combustion residuals ("CCRs"), wastewater, solvents, wood, metal, paper, cardboard, vegetation waste, and general refuse. Most of these materials are disposed of in municipal solid waste landfills, discharged under permit to the sanitary sewer or recycled. Most CCRs are securely disposed of in the ash landfill facility at SGS.

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

A. TEP's power plants currently comply with the requirements of their respective facility permits and all applicable local, state, and federal environmental requirements. TEP is committed to maintaining compliance with emission standards and other environmental requirements through efforts that include:

- 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
- abiding by the general and specific conditions of facility permits.

In fact, TEP environmental compliance protocols have been used as a model for industry operations. Currently, TEP spends approximately $36 million per year to comply with all local, state and federal regulations at its generating facilities.

VIII. HISTORICAL CAPITAL SPENDING.

Q. Please describe the Company's capital spending over the last five years.

A. Although slower growth has allowed the Company to defer some system expansion projects to future years, TEP has nonetheless invested significant capital over the past five years to maintain safe, reliable and responsible service. Some infrastructure costs were made necessary by robust growth over the preceding five years, including new residential demand on the previously undeveloped fringes of the Company's service territory. Other investments were driven by environmental emission control restrictions and other regulatory mandates. Finally, the last five years presented the Company with unique opportunities to make significant long-term investments in two key assets – a new energy efficient corporate headquarters building and the purchase of Sundt Unit 4 (a reliability-must-run generation plant located in the Tucson load pocket) – that will generate significant benefits for customers for years to come.

Q. Please provide details regarding TEP's recent capital investments.

A. The following table outlines annual investment in capital projects for the five-year period ending December 2011.

($ Millions)	2007	2008	2009	2010	2011	Total Capital Investments
Capital Investments	$187	$263	$231	$279	$343	$1,303

TEP's cumulative capital investments for the five years prior to and including the test year (2007 - 2011) was approximately $1.3 billion. This total includes, for example: $336 million for generation projects, $250 million for transmission upgrades, $199 million for distribution system improvements, $102 million to accommodate new business demands and $118 million for environmental projects.

Generation-related capital spending increased in 2008 and 2009 due to environmental upgrades at the San Juan Generating Station ("San Juan") and a major upgrade at SGS Unit 2. As previously noted, in 2010, TEP purchased Sundt Unit 4. Additionally, generation spending over the last five years specific to SGS included significant spending to improve the water facilities and a drag chain project for SGS Unit 2 that improved the efficiency of the bottom ash removal process. We also made improvements at the Sundt facility during the last five years by replacing step-up transformers and improving our distributive control systems that operate the units.

The Company also invested substantial capital in T&D system improvements, including a new quad-circuit 500-kV transmission line in the northwest region of our service territory and a third transformer at the Tortolita Substation. Other significant projects included the installation of a static VAR compensator, which has provided improved reliability to our service territory, and the replacement of capacitor banks in the southeast region of TEP's service area to support the necessary voltage needed for reliable power. The Company's substation build-out continues throughout our service territory as discussed previously, although the rate of expansion has slowed given the decreasing number of new customers.

We have also completed significant information technology ("IT") projects to upgrade our systems and improve our business processes. Projects were completed in 2010 and 2011 to improve our customers' ability to complete certain transactions over the internet. We also installed a meter data management system and continue to install meters with communication capabilities. This will support improved information on customer usage patterns and automation of the billing process for major customers. TEP also seeks to keep its computer software systems up-to-date to ensure accuracy and continued vendor support. For these reasons, our financial systems, human resources systems, and EMS were all upgraded in the last five years. Lastly, we have increased the capacity of our data centers to better protect our important IT and data assets.

Q. Please describe recent improvements to the environmental controls at TEP's generating units.

A. TEP invested approximately $82 million between 2007 and 2010 for major emission control upgrades at San Juan, where the Company owns a 50 percent stake in Units 1 and 2. Both units received upgraded scrubbers to reduce sulfur dioxide ("SO_2") emissions, new baghouses to limit particulate matter ("PM") emissions, new burners to reduce nitrogen oxide ("NOx") emissions and an activated carbon injection system to reduce mercury emissions. The upgrades reduced emissions of SO_2 by 83 percent, PM by 72 percent, NOx by 41 percent and mercury by more than 90 percent.

TEP also invested $3.38 million to upgrade emission controls at the Navajo Generating Station ("Navajo"), where the Company owns a 7.5 percent stake in Units 1, 2 and 3. Low NO_x burners were installed on all three units between 2009 and 2011, resulting in a 35 percent reduction in NO_x emissions. The cost of emission control upgrades for all the plant owners totaled nearly $45 million. NOx, SO_2 and PM emissions have been shown to adversely impact visibility. Due to the proximity of TEP's remote generating facilities (San Juan, Four Corners and Navajo) to national parks and wilderness areas, TEP is committed, along with the operators of these facilities, to the preservation of the scenic views in a cost effective manner over a reasonable period of time.

Q. Please describe the Company's investment in a new headquarters building.

A. TEP invested approximately $92 million related to construction of a new headquarters building in downtown Tucson. The building has alleviated significant overcrowding at TEP's campus on East Irvington Road, where hundreds of employees were working in trailers separating them from other related workgroups. The new building also allowed us to bring more than 500 employees together in a dedicated work environment that was built for our specific business needs. Though the up-front cost associated with building a new corporate headquarters is significant, customers will realize significant and measurable benefits in the long term.

Q. What benefits does TEP expect to realize through its new headquarters?

A. The new building allows employees to work more efficiently and effectively on behalf of our customers. Departments that frequently work together have been assigned to offices in the same areas of the building. As a result, members of a project team who were once located miles away from each other now find themselves on the same floor, making it much easier to communicate and collaborate while saving travel time and other expenses. The building offers modern conference rooms and convenient amenities that help our employees work productively. It features up-to-date information technology systems and a data center with improved security features that reduce our Company's exposure to cyber threats. The building's many energy-efficient and environmentally sensitive features also help us communicate the value of conservation to our customers while cost-effectively reducing our own energy consumption. TEP has submitted an application to secure Leadership in energy and Environmental Design ("LEED") Gold Certification for the building from the U.S. Green Building Council.

Q. Has TEP proposed recovery of capital costs incurred after the 2011 test year was complete?

A. Yes. Our proposed revenue requirement reflects recovery of approximately $40 million of capital investments which are expected to be placed into service during 2012, and will be used and useful at the time new rates become effective. The plant costs requested for inclusion in the test-year rate base will adjusted to reflect the actual cost of plant placed in service. These projects include approximately $23 million of general plant investments and approximately $17 million for TEP's 5 MW solar photovoltaic array, which was previously approved by the Commission.

IX. PURCHASE OF SUNDT UNIT 4.

Q. The lease on Sundt 4 was due to expire in 2011. What is the status of Sundt 4?

A. TEP purchased the plant from the lessor in 2010. TEP witness Kentton C. Grant provides details on the purchase in his direct testimony.

Q. What is the operational significance of Sundt 4?

A. Throughout much of the year, TEP requires local generation to provide voltage and volt-ampere reactive support. The Company also requires the use of local generation to serve customers' energy needs during higher demand periods and when there are disturbances on the regional transmission system. Sundt 4 is TEP's most economic local generating unit, due in part to its ability to operate on either coal or natural gas. The unit also is equipped to burn methane gas piped from a local landfill, a renewable resource that reduces plant emissions and contributes toward the Company's compliance with Arizona's Renewable Energy Standard.

Q. How did the purchase price of Sundt 4 compare to other available alternatives?

A. TEP's purchase price for Sundt 4 was $52 million, or $333/MW of capacity for the 156-MW unit. That price compares favorably with the estimated $600/MW to $1,000/MW it would have cost the Company to site, permit and construct a similarly-sized new combustion turbine facility that could provide similar operational benefits in the Tucson metropolitan area. The unit's ability to burn coal, natural gas and landfill gas provides fuel flexibility that contributes to TEP's service reliability, particularly during periods when natural gas supplies may be limited by severe weather or other factors. The purchase also gives TEP full control over the operating permits and plant site, providing greater opportunity for the future development of additional energy resources or other projects that will help the Company better serve its customers. For example, a solar thermal generating system will be built in 2012 at the Sundt site that will boost the output of Unit 4 with no increase in fuel requirements and no incremental pollutants.

X. FUTURE CAPITAL SPENDING.

Q. Please describe TEP's plans for future capital expenditures.

A. The following table outlines planned capital expenditures for the five-year period ending December 2016.

($ Millions)	2012	2013	2014	2015	2016	Total Capital Spending
Capital Budget	$266	$342	$382	$612	$421	$2,024

TEP has planned significant future capital investments, including: (i) upgrade, reinforcement and expansion of its distribution and transmission systems; (ii) investments in generating resources; (iii) environmental upgrades for generating facilities; and (iv) IT improvements. Spending will increase in 2013-2016 primarily due to capital expenditures of approximately $300 million required for environmental upgrades mandated by federal regulations at our coal-fired generating plants; $195 million for new gas-fired generating units; $231 million for the anticipated purchase of TEP's leased interest in SGS Unit 1 and the plant's coal handling facilities; and $155 million for renewable energy projects.

Much of the increase in planned capital expenditures result from one-time costs, such as the SGS lease buyouts. The spending for new generation resources, currently a placeholder in our five-year capital plan, is dependent on the level of future sales growth. For many years, the Company did not invest significant amounts in transmission projects. However over the next five years, TEP expects to spend approximately $226 million upgrading its transmission system. These investments are necessary to improve reliability by allowing us to bring additional power into our service territory. Lastly, significant environmental spending is anticipated at our participant generation plants, as previously discussed. While these expenditures would not increase our generation output, they are mandatory to maintain compliance with an increasing number of environmental regulations.

Q. How much does TEP expect to spend for capital improvements to its distribution and transmission systems?

A. In order to continue to provide safe and reliable service to our customers, TEP expects to invest approximately $371 million in T&D system reinforcement projects from 2012-2016, including $145 million for distribution projects and $226 million for transmission upgrades. Of those expenses, the largest investment will be an anticipated $114 million for the 500-kV Pinal Central to Tortolita Transmission Line Project, which will benefit our customers by providing increased access to the wholesale power markets and the commensurate existing and new generating resources associated therewith. Additionally, we expect to spend $104 million to provide new infrastructure for businesses and residences over the next five years.

Q. Please describe anticipated environmental controls that will be required at TEP's generating units.

A. As described in Mr. Hutchens' direct testimony, TEP anticipates spending approximately $300 million over the next five years for capital expenses related to emission control upgrades at its Arizona and New Mexico generating stations. TEP is committed to finding the most cost-effective ways to protect the environment through regulatory compliance while also ensuring that we provide our customers with safe and reliable service at just and reasonable prices.

The largest share of those projected costs are expected to be incurred at San Juan. The Environmental Protection Agency ("EPA") has issued a final Federal Implementation Plan ("FIP") under the Regional Haze rule for San Juan that would require the installation of selective catalytic reduction ("SCR") technology by 2016. The total cost of satisfying that requirement is estimated between $900 million and $1 billion; TEP's share of that cost is estimated at $180 million to $200 million.

A similar issue faces the Four Corners Generating Station ("Four Corners"), where TEP owns a seven percent stake in Units 4 and 5. The EPA has issued a draft Best Available Retrofit Technology ("BART") assessment calling for the installation of SCR technology on the remaining units at Four Corners by 2018. If that requirement remains in the EPA's final BART ruling, SCRs will have to be installed at a total cost of $500 million. TEP's share of those costs would be $35 million.

The EPA is also is drafting a BART rule for Navajo that could be issued later this year or in 2013. The rule could require the installation of SCR and/or a baghouse within five years. TEP would be obligated to pay $42 million of the total estimated $544 million cost for SCR technology and/or $43 million of the estimated $587 million cost of a baghouse at the plant.

Q. What other generation-related environmental compliance costs might TEP face over the next five years?

A. The EPA is developing new rules for CCRs that could require TEP to treat coal ash as either solid waste or, more expensively, as hazardous waste. These rules, which are expected next year, could add significant capital and O&M costs at each coal plant.

Four Corners, Navajo, SGS and Sundt may also require the injection of carbon and/or bromine to satisfy the final Mercury Air Toxics Standards published by the EPA in February 2012. TEP would be obligated to pay approximately $7 million to install such equipment at those plants.

XI. OPERATING AND MAINTENANCE COSTS.

Q. Are the O&M costs incurred by TEP in the test year reasonable?

A. Yes. A focus on managing O&M expenses is embedded in TEP's culture. Since the late 1980's when the Company faced significant financial obstacles and continuing today through a series of rate moratoriums, it has been vital that TEP closely monitor its costs in order to maintain and improve its financial position. Our corporate goals include maintaining O&M at or below a predetermined level in addition to process improvement goals that help us to achieve the O&M targets. As our customers depend on us to provide safe and reliable service in addition to maintaining a reasonable price for electric service, we balance our O&M goal with goals associated with safety, reliability, regulatory compliance and customer service. As I have discussed previously in my testimony and other witness further support, our results in all of these areas support a balanced approach under which we are prudently managing costs while being successful in providing safe and reliable service as well.

In order to manage our O&M costs on an ongoing basis, we hold monthly reviews which involve management personnel from all areas of the organization to discuss and review the status of our expenditures that have already occurred and those that are expected during the remainder of a given time period. Decisions impacting future expenditures are made openly and discussed among all areas of the Company as we decide where reductions or additions to spending should occur. We also monitor the number of employees in the organization very closely in light of the personnel needed to maintain safe, reliable and economic service now and in the future. The number of employees at TEP is virtually unchanged since our last rate case other than the 90 additional employees at SGS who were hired primarily to operate the new units at that generating station (the cost of which is paid by the owners of SGS Units 3 and 4).

Despite our strong cost oversight, TEP's O&M costs have increased since our last rate case test year in 2006 due primarily to: increased environmental and regulatory compliance costs; increased pension expenses; and generally higher costs of material used in our business. Although the Company's costs have risen over the last five years, we have taken efforts to manage our O&M costs by closely monitoring labor costs, reducing the use of contract services, process improvements and other cost containment efforts.

Significant increases in the cost of many of the raw materials that are used in constructing our equipment (e.g. copper, steel, fuel, etc.) have increased the cost of the equipment that we purchase. This has impacted the cost of all of our system improvements and is particularly noticeable in the cost of power plant outages which tend to involve a high quantity of replacement material. The cost of lime and chemicals associated with pollution control efforts at most of the generating units that we operate and or own have increased in line with the general increase in commodity costs. Additionally, the pollution-control efforts have increased at many of our plants (particularly San Juan and SGS). NERC and

FERC regulations in the areas of reliability and CIP have also increased our costs of doing business. We have additional monitoring and audit requirements associated with these regulations and there has been a significant increase in the dues we are required to pay to those organizations so that they can manage the new programs. Pension costs, which we pay directly for TEP employees and indirectly for employees of the operators of the San Juan, Four Corners, Navajo and Luna power plants, have increased significantly since 2006 primarily due to the low returns in the stock market where pension funds are invested and the historically low interest rates that have persisted during the economic downturn.

XII. SPRINGERVILLE GENERATING STATION UNITS 3 AND 4.

Q. Please describe the developments that led to construction of SGS Units 3 and 4.

A. Although SGS was originally proposed as a site for four similar coal-fired units, TEP halted development after bringing Units 1 and 2 online in 1985 and 1990, respectively. Development rights for SGS Unit 3 were later transferred to Tri-State Generating and Transmission Association ("Tri-State"), while the rights to develop SGS Unit 4 were transferred to Salt River Project ("SRP"). Unit 3 was built first and entered commercial operation in July 2006, while Unit 4 was placed in operation in December 2009.

Development of the two new units was managed through TEP's sister company, UniSource Energy Development Company ("UED"). Over a three-year period, UED invested approximately $32.8 million in the development of SGS, costs that were borne by shareholders of UNS Energy, TEP's parent company. See Decision No. 65347 (November 1, 2002), Findings of Fact 62 and 65.

Q. How have TEP's customers benefited from the construction of SGS Units 3 and 4?

A. TEP's customers have realized significant and ongoing cost benefits from the project, including improved emission controls, avoided capital costs and reduced O&M expenses.

As part of the project, Tri-State invested approximately $65 million to upgrade the emission controls of SGS Units 1 and 2 with improved sulfur dioxide scrubbers, low-NOx burners and modifications to the coal handling system to allow the use of low-sulfur coal. Those improvements, combined with the advanced control technologies built into Units 3 and 4, have reduced total regulated emissions from the expanded plant below the levels previously emitted by the original two units. These improvements came at no cost to TEP's customers and likely spared them the burden of paying a higher cost to install similar controls at a later date. Tri-State and SRP also continue to cover the cost of the additional lime associated with those improved controls, saving more than $3 million in annual costs that would otherwise be absorbed by TEP's customers.

Tri-State also invested another $15 million to upgrade the plant's water supply system and other common facilities as part of the expansion project. These improvements included new water wells; a new booster pump station and raw water storage ponds; the addition of a redundant water supply line; resurfacing of a road; new rail spurs; additional maintenance buildings; and improvements to the existing warehouse. These upgrades improved the performance of TEP's plants and spared our customers the burden of paying for similar improvements.

The owners of Units 3 and 4 agreed to pay TEP for use of the common facilities and coal handling facilities that previously served only Units 1 and 2. TEP presently receives approximately $14 million per year from the owners of Units 3 and 4 for use of these common and coal handling facilities. Additionally, the owners of Units 3 and 4 have agreed to either purchase a share of these facilities or continue making periodic usage payments to TEP upon the expiration of the long-term lease agreements that TEP previously entered into for these facilities. As described in the direct testimony of TEP witness Kentton Grant, if the Company exercises its purchase option for the coal handling facilities in 2015 and the owners of Units 3 and 4 both pay their agreed-upon share of facility costs (discussed in additional detail below), the net cost of TEP's purchase option would be significantly reduced from $120 million to $73 million. Similarly, TEP's net cost to acquire the common facilities at the end of their respective lease agreements will be much lower due to the addition of SGS Units 3 and 4.

TEP has realized significant economies of scale at the SGS site by spreading O&M costs over four units instead of just two, and through lower property tax assessments on Units 1 and 2 due to the addition of other taxable property at the site. Additionally, the Company is also able to pass along a portion of TEP's administrative and general costs at SGS to the owners of Units 3 and 4 for support services such as human resources, information technology, materials purchasing, inventory management and accounting. A conservative estimate of these savings is $3 million per year in O&M costs, $4 million per year in administrative and general costs and $5 million per year in property taxes.

Q. **How has TEP reflected these benefits in this rate application?**

A. While it was the shareholders of TEP's parent company, not the customers of TEP, that initially took on significant risks associated with managing the development of Units 3 and 4, the Company is proposing what it considers to be a fair sharing of the benefits created through construction of SGS Units 3 and 4 with its customers. Savings realized by TEP totaling approximately $21 million are embedded in the Company's test-year revenue requirement.

Customers also continue to benefit from the avoided capital costs associated with the environmental upgrades and common facility improvements paid for by the owners of Units 3 and 4, as those costs were avoided by TEP and are therefore not included in rate base. As an additional benefit for customers, TEP has reduced its test-year revenue requirement by $7 million to reflect half of the approximately $14 million in annual payments TEP receives from the owners of Units 3 and 4 for the use of common and coal handling facilities. For its part, TEP would benefit from the remaining half of those payments while retaining the approximately $2 million to $2.5 million in annual fees and performance bonuses it receives from Tri-State and SRP for operating Units 3 and 4. Given the substantial benefits passed along to customers and the $32.8 million of capital that TEP's parent company had at risk during the project development phase, this proposed sharing of benefits is reasonable to both customers and shareholders.

Q. How long will the Company benefit from retaining half of the facility use payments?

A. While most of the benefits passed on to customers will endure through the useful life of Units 1 and 2, TEP's opportunity to retain its half of facility use fees will likely be temporary. As described by TEP witness Mr. Grant, TEP intends to exercise its fixed-price purchase option for the SGS coal handling facilities at the end of the lease term for those facilities in 2015. After completing that purchase, the owner of Unit 4 will be obligated to pay for an allocated share of those facilities, and the owner of Unit 3 will have the option of purchasing its share or continuing to make periodic facility use payments. A similar arrangement will apply in 2021, if TEP completes its planned purchase of the SGS common facilities currently under lease. Any payments received by TEP from the owners of Units 3 and 4 for the purchase of those facilities will serve to reduce the net investment by TEP in SGS common and coal handling facilities, thereby reducing future rate base and the ultimate cost to customers for Units 1 and 2.

XIII. SAHUARITA-NOGALES TRANSMISSION LINE PROJECT.

Q. TEP has requested recovery of costs related to a proposed 345-kV line from Tucson to Nogales. Can you please provide background on this project?

A. TEP began to consider the prospect of a new transmission link to Mexico after participating in the "United States – Mexico Electricity Trade Study," which was issued jointly by the U.S. Department of Energy ("DOE") and Mexico's Secretaría de Energía, Minas e Industria Paraestatal in 1991. The study identified potential economic and technical benefits from increased trade and cooperation between U.S. and Mexican utilities and expressed hope that the report would prompt utilities to begin studying specific projects. That push was consistent with then-President George H. W. Bush's National Energy Strategy, which called for expanding U.S. electric supply options and promoting system efficiency while streamlining regulatory and environmental review processes. Against this backdrop, TEP began studying potential opportunities for a transmission line between Mexico and TEP's system. At the time, TEP believed that an interconnection between Mexico's transmission system and the Southwestern power markets would benefit the region and TEP customers. The potential benefits to TEP customers would come primarily from more efficient power market (due to increase size and diversity) and from increased utilization of the TEP transmission system (which would likely reduce the average costs on the system). Other parties (most notably Public Service Company of New Mexico) also were attempting to develop an interconnection between the southwest and Mexico during this time frame.

In October 1998, the City of Nogales filed a formal complaint with the Commission against the city's electric service provider, Citizens Utilities. The complaint alleged that Citizens' failure to adequately maintain its transmission lines and back-up generation capacity led to numerous power outages, causing economic damages to Nogales and its residents and endangering the community's welfare. That complaint was resolved through a settlement approved by the Commission in November 1999 that required Citizens to build a second transmission line to serve customers in Santa Cruz County.

TEP was concerned that construction of the new Citizens line would preclude future transmission projects in the region, including a new link to Mexico. So the Company approached Citizens and proposed a joint transmission project that would avoid duplication of facilities in southern Arizona, provide the best technical solution for a second transmission source for Santa Cruz County, and establish Arizona's first significant transmission link to Mexico. In 2000, TEP and Citizens entered into a memorandum of understanding ("MOU") under which the parties would work together to design, site, and permit and build what became known as the Sahuarita-Nogales 345-kV Transmission Line Project.

Q. How did the parties proceed after signing the MOU?

A. In October 2000, TEP applied to the Department of Energy ("DOE") for a Presidential Permit to authorize the proposed cross-border transmission link. Pursuant to the review of that application, DOE and TEP enlisted a contractor to produce an Environmental Impact Statement ("EIS") for the project. The Company also began working with Citizens to develop an application for a CEC that, if approved by the Commission, would provide state authorization for construction of the proposed line along one of two proposed routes: the "western" or "central" corridor. After the Line Siting Committee held eight public hearings on the project from May to October 2001, the Commission approved a CEC for the western route in January 2002. Work continued on the EIS process until March 2005, when the DOE released a final EIS that indicated the "central" corridor was preferred by the U.S. Forest Service. Because that preference conflicted with the Commission's decision, TEP was left without authorization to build the line along a single route.

Q. What is the status of the Sahuarita-Nogales 345-kV Transmission Line Project?

A. After reviewing the reliability improvements to the system already achieved by UNS Electric in Santa Cruz County – as well as those that will be realized through completion of the 138-kV upgrade – and weighing the high cost of the proposed 345-kV line, in light of the limited progress on an interconnection agreement with Mexico and the difficulties in coming to agreement with the Forest Service on a path for the line, TEP and UNS Electric are leaning toward abandoning the project. The improvements to UNS Electric's system combined with the ongoing transmission line upgrade provide a more cost-effective solution for that company's customers, particularly since the significant growth anticipated at the time the Commission ordered construction of a second transmission line has not materialized.

Q. Can you provide some perspective on the charges that have been incurred for the project?

A. Although the 345-kV line is no longer necessary, TEP and UNS Electric prudently incurred more than $8 million pursuant to the Commission's directive to develop the project. Accordingly, TEP should be afforded a reasonable opportunity to seek their recovery in rates. These costs included expenses associated with the state and federal siting processes and other expenses incurred to site the line.

These expenditures have been charged to Account No. 183, Preliminary Survey and Investigation Charges, in accordance with the FERC Uniform System of Accounts ("USOA") Part 101 of Title 18 of the Code of Federal Regulations, adopted by the Commission for electric utilities under its jurisdiction in accordance with R14-2-212(G) of the Arizona Administrative Code. TEP witness Dallas J. Dukes provides additional details regarding the requested recovery of these costs.

XIV. PRO FORMA ADJUSTMENTS.

Q. Please describe the Power Supply Management adjustment.

A. The Company provides coordination of wholesale energy supplies, energy scheduling and management of ancillary services for wholesale customers. The adjustment included in Mr. Dukes' Direct Testimony is necessary to remove the revenues associated with these agreements as well as the proportional cost associated with providing these services. By providing these services TEP is reducing the cost of power supply management to its retail customers.

Q. Does this conclude your testimony?

A. Yes.

Direct Testimony of Kevin P. Larson

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
GARY PIERCE- CHAIRMAN
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

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-12-____

Direct Testimony of

Kevin P. Larson

on Behalf of

Tucson Electric Power Company

July 2, 2012

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Exhibits

Exhibit KPL-1 Standard & Poor's report dated December 2, 2008
Exhibit KPL-2 Fitch report dated September 21, 2011
Exhibit KPL-3 Moody's report dated August 24, 2011
Exhibit KPL-4 Moody's report dated May 24, 2012
Exhibit KPL-5 Moody's report dated May 21, 2012
Exhibit KPL-6 Moody's press release dated May 23, 2012

I. INTRODUCTION.

Q. Please state your name and business address.

A. Kevin P. Larson. My business address is 88 E. Broadway, Tucson, Arizona, 85701.

Q. By whom are you employed and what are your duties and responsibilities?

A. I am employed by UNS Energy Corporation ("UNS Energy") as Senior Vice President, Chief Financial Officer and Treasurer. UNS Energy was known as UniSource Energy Corporation before a name change that took effect on May 4, 2012. For simplicity's sake, I will refer to that company as UNS Energy throughout my testimony, even when describing actions taken under the company's previous name. For Tucson Electric Power Company ("TEP" or the "Company"), I am Senior Vice President and Chief Financial Officer.

Q. Please describe your background and work experience.

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 UNS Energy and TEP in October 2000. I became Senior Vice President, Chief Financial Officer and Treasurer of UNS Energy and TEP in September 2005. I became Vice President and Treasurer of UNS Gas, Inc. ("UNS Gas") and UNS Electric, Inc. ("UNS Electric") 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.

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

A. The purpose of my testimony is to describe TEP's financial condition and the importance of TEP's rate request to the Company's long-term financial condition. My testimony also contains recommendations with respect to: (i) the proposed capital structure for TEP; and (ii) the proposed weighted average cost of capital ("WACC") for TEP. I also provide testimony on the Company's proposed methodology for determining fair value rate base ("FVRB") and the fair value rate of return ("FVROR").

Q. Please summarize your conclusions and recommendations.

A. I offer the following conclusions and recommendations:

- The rate relief requested by this application is critical to TEP's long-term financial health;
- TEP proposes the use of a pro forma capital structure of 54% debt and 46% equity;
- TEP's WACC as of the end of the test year is 7.74%; and
- TEP proposes a FVROR of 5.68% and FVRB of $2.3 billion.

Q. Please summarize your testimony.

A. TEP's rate request will enable the Company to continue the positive momentum created by the 2008 Settlement Agreement, approved in Decision No. 70628 on December 1, 2008 ("2008 Settlement Agreement"). The 2008 Settlement Agreement provided TEP with the ability to gradually improve the Company's financial condition through a base rate increase and the adoption of a rate mechanism that allows for the timely recovery of fuel and purchased power costs, thereby creating more stable operating cash flows. The stability of cash flows (i) resulted in the improvement in credit metrics and led to an increase in TEP's bond ratings, and (ii) provided flexibility that allowed TEP to continue to reduce its debt leverage. All of these financial improvements allowed TEP to compete for, and attract, capital on favorable terms. Between 2007 and 2011, TEP used a combination of internal cash, external debt financing and equity contributions from its parent company to fund capital expenditures of approximately $1.3 billion,[1] which resulted in retail rate base additions of approximately $500 million. TEP's cost of debt in its last rate case was 6.38%[2]; the Company's current rate request proposes a cost of debt of 5.18%. This reduction in TEP's cost of debt lowered the Company's proposed revenue requirement by nearly $10 million, which shows how TEP's access to and cost of capital impacts customer rates. In other words, because TEP was able to attract capital on more favorable terms, its proposed rate increase is significantly lower than it could have been.

As previously noted, TEP's original cost rate base ("OCRB") has grown by approximately $500 million or 50%, from $1.0 billion in 2006 to $1.5 billion[3] in 2011. These rate base additions by TEP represent investments necessary to maintain high levels of safety and service reliability. TEP and its customers realize tangible benefits from these infrastructure investments. Additionally, despite our focused efforts on cost containment, TEP's operations and maintenance ("O&M") in the 2011 test year was $382 million compared with $353 million in 2006 (the test year used in the 2008 Settlement Agreement). This level of spending was required in order to comply with regulatory mandates and to provide safe and reliable service to TEP's customers, as TEP witness Michael DeConcini explains in his direct testimony. TEP's reportable incident rate decreased by 67% between 2007 and 2011, and the electricity service TEP delivers to customers consistently ranks among the most reliable in the industry.

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[1] See Direct Testimony of Michael J. DeConcini.
[2] The test year used in the 2008 Settlement Agreement was the 12-month period ended December 31, 2006.
[3] See schedules B-2 and B-3.

TEP has made great strides in reducing costs by improving operational efficiencies and taking advantage of capital market conditions. Despite these efforts, lower-than-expected retail sales levels, coupled with the increase in rate base and other cost increases since 2006, are creating financial headwinds to the momentum created by the 2008 Settlement Agreement. The rates established in the 2008 Settlement Agreement, which were based on a 2006 test year, need to be updated to reflect TEP's cost of service. The under-recovery of TEP's full cost of service is reflected in the Company's 2011 test-year rate of return ("ROR") on rate base of only 3.45% on an original cost basis, and 2.30% on a fair value basis. These returns are far below TEP's WACC of 7.74% and the Company's proposed FVROR of 5.68%. Clearly, under existing service rates, TEP is unable to earn its authorized ROR.

The rate proposal supported by this application is designed to build upon the momentum created by the 2008 Settlement Agreement by providing the Company with the opportunity to earn a ROR that is sufficient to maintain and improve TEP's financial condition and to provide for additional infrastructure investments. TEP's financial condition will be tested over the next five years by a capital expenditure budget that will far exceed the Company's cash flow from operations.

TEP's current retail rate structure simply cannot support the 2011 test-year rate base of $1.5 billion, let alone provide the financial flexibility to attract capital to help fund up to an estimated $2 billion in utility infrastructure investments over the next five years. The rate relief supported by this application will strengthen TEP's underlying financial position and credit metrics, and could ultimately result in higher credit ratings. All of these factors will help TEP attract capital at reasonable terms, thereby reducing costs and helping to minimize future rate increases to our customers.

Without the rate relief supported by this filing, TEP will face significant barriers to raising the capital needed to invest in its utility infrastructure in order to provide safe and reliable service to customers, as well as to meet the Arizona Corporation Commission's ("Commission") energy efficiency ("EE") and renewable energy policies, and to comply with Federal environmental mandates.

II. FINANCIAL CONDITION.

A. Overview.

Q. Briefly describe TEP's financial condition.

A. TEP's financial profile is stable by most measures. Despite little to no retail sales growth over the past five years, TEP: (i) invested $1.3 billion in utility infrastructure, leading to an approximately $500 million increase in original cost retail rate base, while lowering its overall cost of debt by 120 basis points; (ii) reduced debt leverage through the retention of earnings and capital contributions from UNS Energy; (iii) enhanced its liquidity position by amending and extending its bank facility; (iv) attained investment grade credit ratings on its unsecured debt from all three major rating agencies; and (v) mitigated interest rate risk by lowering its exposure to variable rate debt to 15% of total long-term debt outstanding.

It is clear that TEP's financial condition will deteriorate without the rate relief supported by this filing. The Company's rate structure needs to be updated to: (i) reflect TEP's *current* full cost of service; (ii) provide TEP with the opportunity to earn its proposed return on common equity ("ROE") of 10.75% on a regulatory accounting basis; and (iii) strengthen the Company's financial profile as it enters a period when rate base growth could far outpace historical levels without the corresponding historical sales growth rates.

Q. You mentioned in the summary of your testimony that the 2008 Settlement Agreement resulted in positive momentum for TEP. Please provide an example.

A. The 2008 Settlement Agreement, among other things, supported and strengthened TEP's financial position through (i) the approval of the Purchased Power and Fuel Adjustor Clause ("PPFAC"), which provides for the timely recovery of fuel and purchase power costs, and (ii) an increase in non-fuel base rates designed to allow TEP to recover 2006 test-year costs and rate-base investments. Standard & Poor's ("S&P") upgraded TEP's unsecured credit ratings to investment grade in December 2008 (from BB+ to BBB-), shortly after the approval of the 2008 Settlement Agreement.

In their explanation of upgrading TEP's ratings, S&P stated in a December 2, 2008 report:[4]

> The upgrades reflect the Arizona Corporation Commission's ("ACC") approval of TEP's rate case settlement, with modifications. With this order, TEP's generation operations are re-regulated, which should allow the company to better match revenues with expenses. The order provides for an estimated 6% increase in retail base rates that should allow the company to stabilize cash flows at modestly stronger levels and, importantly, provides the company with a beneficial purchased power and fuel adjustment clause ("PPFAC") that will mitigate TEP's significant exposure to unplanned outages and unexpected increases in fuel and purchased power costs and reduce cash flow volatility. Under a rate freeze, in place since 1999, the Tucson-based utility was not able to defer these costs for future collection in rates.

Q. Briefly describe the importance of TEP's rate request.

A. The rate proposal supported by this application builds on the 2008 Settlement Agreement by:

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[4] See **Exhibit KPL-1**.

(i) allowing TEP the opportunity to continue to gradually improve its underlying financial condition;

(ii) positioning the Company to access the capital markets to finance future utility investments on reasonable terms; and

(iii) providing TEP with the financial flexibility to meet the Commission's goals for EE and renewable energy.

Most importantly, the sustainability of TEP's long-term financial health supports our primary goal of providing safe, reliable service to our customers.

B. <u>Operating Costs</u>.

Q. Briefly describe the increase in TEP's cost of service from 2006 to 2011 that necessitate rate relief.

A. TEP's 2011 test-year non-fuel revenue deficiency is $128 million, as described in the direct testimony of TEP witness Dallas Dukes. This represents the base-rate revenue increase necessary to provide TEP with the opportunity to earn its requested ROE of 10.75% on a regulatory accounting basis.

In order to deliver safe and reliable electric service, as well as meet numerous governmental mandates and the Commission's Renewable Energy Standard, TEP added approximately $500 million of retail rate base over the five-year period from 2007 through 2011. All of the costs associated with supporting this level of additional rate base have been borne by TEP during a period when the Company's retail sales volumes remained flat, and non-fuel base revenues declined.

Q. What other factors contributed to increases in the Company's cost of service?

A. In addition to the increase in TEP's rate base, the Company experienced cost pressures in other parts of the business between 2007 and 2011. Despite our best efforts to manage costs, TEP had $29 million of higher O&M expense in 2011 as compared to 2006 on a retail jurisdictional basis. Generation plant maintenance, distribution maintenance, commodity prices (including gasoline), compliance costs, wages and benefits, and other factors have contributed to this increase. Again, these costs increased without any corresponding change in non-fuel base revenues between 2007 and 2011.

Q. Please explain the steps TEP has taken to reduce operating costs since the approval of the 2008 Settlement Agreement.

A. Between 2009, the first full year of the rates approved in the 2008 Settlement Agreement, and 2011, TEP's retail sales volumes have declined by 0.4% and non-fuel retail revenues have declined by $5 million. These declines are primarily the result of the recession, the adoption of the Commission's EE Standard, and higher penetration rates of distributed solar generation. As a result, TEP has initiated company-wide efforts to improve operational efficiencies and reduce operating costs. Some examples include:

- Hiring restrictions and rigorous approval process for new hires;
- Contract renegotiation with several vendors and/or switching to new vendors;
- Generating plant maintenance optimization;
- Automation of customer service functions; and
- Thorough assessment of business risks, processes, and controls for improved productivity and efficiency.

Reports on these cost containment efforts have been filed annually with the Commission since 2009 in Docket No. E-01933A-07-0402.[5]

C. **Financing Activity.**

Q. Has TEP taken other steps to improve its financial condition since the approval of the 2008 Settlement Agreement?

A. Yes, the adoption of the PPFAC and the base-rate increase resulting from the 2008 Settlement Agreement provided TEP with the flexibility to continue to improve its financial position. Since 2006, the amortization of capital leases, capital contributions from UNS Energy, and retained earnings from operations have improved TEP's equity ratio, as calculated under Generally Accepted Account Principles ("GAAP"), from 29% to 35%. Excluding capital-lease obligations, the actual test-year equity ratio increased from 39.9% to 43.5%, as shown below:

	Balance (in millions) 12/31/2006	% Total 12/31/2006	Balance (in millions) 12/31/2011	% Total 12/31/2011
Equity	$ 554.7	39.9%	$824.9	43.5%
Debt	$ 835.6	60.1%	$1,071.4	56.5%
	$1,390.3	100.0%	$1,896.3	100.0%

The provisions of the 2008 Settlement Agreement and resulting bond rating upgrades also helped TEP take advantage of favorable conditions in the capital markets to improve its financial flexibility and reduce the level of interest expense passed on to customers.

[5] The requirement to file cost containment reports was originally ordered in Decision No. 59594 (March 29, 1996). That requirement had been waived, but the Commission, in Decision No. 71256 (September 3, 2009), reinstated the requirement.

Q. Please describe how TEP has taken advantage of favorable capital market conditions to improve its financial flexibility and reduce the level of interest expense passed on to customers.

A. Since the Commission's approval of the 2008 Settlement Agreement, TEP has been active in the capital markets:

- In 2009, TEP issued $95 million of fixed-rate tax-exempt bonds at an average coupon of approximately 5% and used the proceeds to retire a like amount of bonds with an average coupon of almost 7%.
- In 2010, TEP issued $100 million of fixed-rate tax-exempt bonds at 5.25% to help fund utility infrastructure investments. In addition, TEP issued $37 million of tax-exempt variable-rate bonds to redeem a like amount of bonds with a coupon over 7%.
- In 2011, TEP issued $250 million of fixed-rate taxable bonds at 5.15%, locking in historically low rates for 10 years. A portion of the proceeds were used to purchase $150 million of variable-rate debt and redeem $22 million of fixed-rate debt with a coupon of 6.1%. Variable-rate debt now represents only about 15% of TEP's total long-term debt outstanding. Reducing TEP's exposure to variable interest rate risk helps support long-term rate stability for customers. In a report on September 21, 2011, Fitch Ratings, Inc. ("Fitch")[6] revised their outlook on TEP from stable to positive, in part due to lower exposure to variable interest rates: *"The ratings affirmation and Positive Outlook reflect ...an improving debt leverage profile including lower levels of variable-rate debt".*
- In 2010 and 2011, TEP amended its credit agreement. TEP's credit agreement consists of: (i) a revolving credit facility under which the Company can make short-term borrowings to fund working capital needs; and (ii) a letter of credit facility that provides credit support for variable rate tax-exempt bonds. In 2010,

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[6] Report attached as **Exhibit KPL-2**.

TEP increased the size of the revolving credit facility from $150 million to $200 million, and extended the maturity of the entire credit agreement to 2014. The higher short-term borrowing capacity gives TEP much needed liquidity during periods when cash flows are inadequate to cover working capital requirements. When bank market conditions became more favorable in 2011, TEP refinanced the entire credit agreement, reducing the pricing by nearly 50% and extending the term by two more years to 2016.

Q. Can you quantify the impact of TEP's financing activities on customer rates?

A. Yes. TEP's cost of debt in 2006, the test year used in the 2008 Settlement Agreement, was 6.38%. The Company's proposed cost of debt in this rate application is 5.18%, or 120 basis points lower than the current authorized cost of debt. If TEP's cost of debt remained at the 2006 level, the Company's current rate request would increase by nearly $10 million as shown in the following table:

Original Cost Rate Base ($000)	Proposed Debt % of Capital Structure	Cost of Debt Authorized	Cost of Debt Proposed	Reduction in Revenue Requirement ($000)
$1,519,073	54%	6.38%	5.18%	$9,844

D. Credit Ratings.

Q. What are TEP's current credit ratings?

A. The table below summarizes TEP's current credit ratings from each credit rating agency.

	S&P	Moody's	Fitch
Senior Secured	BBB+	Baa1	BBB
Senior Unsecured	BBB-	Baa3	BBB-
Issuer Rating	BB+	Baa3	BB+

Q. Are TEP's credit ratings considered "investment grade?"

A. TEP senior secured and senior unsecured ratings are investment grade. The Company's senior unsecured ratings are one notch above non-investment grade. However, TEP's issuer rating from both S&P and Fitch is one notch below investment grade. The table below shows the ratings tiers for investment grade and non-investment grade ratings.

S&P and Fitch	Moody's
AAA	Aaa
AA+, AA, AA-	Aa1, Aa2, Aa3
A+, A, A-	A1, A2, A3
BBB+, BBB, BBB-	Baa1, Baa2, Baa3
Investment Grade Cut-Off	
BB+, BB, BB-	Ba1, Ba2, Ba3
B+, B, B-	B1, B2, B3
CCC, CC, C	Caa, Ca, C

Q. How important are TEP's credit ratings?

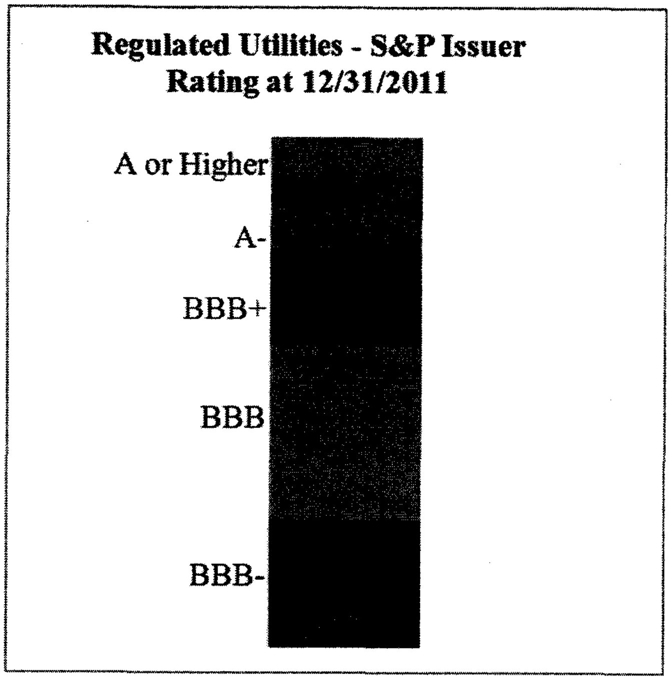
A. It is critical that the Company maintain, and hopefully improve, its credit ratings during this period when significant external financing is anticipated. Both the access to this anticipated new capital and the cost of new capital become more favorable with higher credit ratings, while also decreasing the Company's long-term cost of debt and reducing the interest costs passed on to customers. Based on current forecasts, TEP will need approximately $2 billion for capital investments and $476 million for mandatory capital lease payments over the next five years. Internal cash flows alone will not be able to fund all of these investments and payments. To fund the amount not covered by internally generated cash, TEP will need to enter the capital markets to raise debt capital, while UNS Energy may issue new equity in order to make equity contributions to TEP.

As reflected in TEP's pending financing application,[7] the Company is seeking authority to increase its permitted level of long-term debt capital by $400 million. TEP is also seeking the authority to increase the amount of equity capital it can receive from its parent company, UNS Energy, to $400 million over the next four years.

Q. How do TEP's credit ratings compare to other utilities?

A. As depicted in the chart below, 89% of regulated investor-owned utilities have a higher issuer rating than TEP's non-investment grade S&P issuer rating of BB+.

[7] Docket number E-01933A-12-0176.



Q. What factors are preventing TEP's credit ratings from being in the same range as the typical investor-owned utility?

A. The rating agencies look at multiple factors when determining a company's rating. Moody's Investor Services ("Moody's") bases their ratings on four factors: (1) regulatory framework; (2) ability to recover costs and earn returns; (3) diversification; and (4) financial strength, liquidity, and key financial metrics.

Historically, Arizona's challenging regulatory environment has held back TEP's ratings relative to its peers. A Moody's report, dated August 24, 2011,[8] states:

> TEP is regulated by the Arizona Corporation Commission (ACC), an elected body that we view as below average among U.S. state regulatory environments in terms of predictability and timeliness of rate decisions, the ability to recover costs, and overall supportiveness to credit quality. Rate cases before the ACC use historical test years and tend to be decided in 12-18 months, resulting in new rates reflecting a test year from almost two years

[8] See **Exhibit KPL-3**.

> prior. Should the timing for rate decisions and regulatory lag shorten, we would view the regulatory framework for Arizona utilities to be more in line with the U.S. average.

Q. **What credit rating is TEP seeking to attain?**

A. TEP is targeting an unsecured rating of at least BBB/Baa2 or BBB+/Baa1 (S&P/Moody's) to provide a cushion so that an unforeseen negative event would not lower TEP's credit ratings below investment grade. In addition, an improved credit rating will lower the cost of obtaining new debt, which helps support long-term rate stability for customers. TEP's credit ratings are critical given the amount of capital expenditures needed for the next five years.

Q. **How can TEP achieve a higher credit rating?**

A. TEP can achieve a higher credit rating by attaining regulatory outcomes that support credit metrics, and by making prudent financial decisions that support the long-term financial health of the Company. We believe the base rate increase requested and supported by this application will allow TEP the opportunity to meet these goals. The excerpt below is from Moody's most recent credit opinion of TEP published on May 24, 2012.[9]

> TEP's ratings could be upgraded in the next 12 – 18 months if the company receives a favorable outcome in its upcoming rate case. Upward pressure could also occur if there is an improvement in credit metrics, including CFO pre-WC/debt above 22%, on a sustainable basis.

[9] See **Exhibit KPL-4**.

Q. Please describe the key financial credit metrics that will help maintain or improve TEP's credit ratings.

A. From a financial perspective, the rating agencies tend to focus on cash flow metrics and capitalization. Moody's key financial metrics include: (i) the ratio of cash flows to interest paid; (ii) the ratio of cash flows to total debt; and (iii) the ratio of total debt to capitalization.

The cash flow metrics provide a good picture of whether a company, through its current operations, can support current and future debt levels. The ratings agencies like higher ratios and multiples from these cash flow metrics.

When looking at debt to total capitalization, ratings agencies prefer a lower ratio. A low debt to total capitalization ratio provides companies the leverage necessary to issue new debt and maintain the ability to pay back the new interest and new principal.

Strong operating cash flows will maintain or improve TEP's current cash flow metrics. Growth in retained earnings through cost recovery and return on investment will maintain or improve TEP's ratio of debt to total capitalization.

Q. Please comment on TEP's current credit metrics.

A. TEP's current cash flow metrics are within the investment grade rating range, but are trending downward and would significantly deteriorate without adequate rate relief. Despite gradual improvement since the 2008 Settlement Agreement, TEP's debt to capitalization ratio of 65% (including capital lease obligations) is still high and falls within in the below investment grade "Ba" range by Moody's.[10]

[10] See **Exhibit KPL-5**, Moody's Credit Opinion, May 24, 2012.

Q. Why does TEP want to maintain investment grade credit ratings?

A. As noted previously, with its current capital expenditure forecast, TEP will need access to the capital markets. Maintaining TEP's current investment grade ratings will allow the Company to access the new capital on favorable terms. I explained above how access to credit on more favorable terms benefits ratepayers. Further, banks and other debt investors are less willing to lend money to companies rated below investment grade. A rating below investment grade implies more risk of default on the debt. Banks and investors are compensated for this increased risk with higher interest expense on the debt. A company with credit ratings below investment grade has higher direct debt costs, which are then passed on to customers.

Low credit ratings also adversely impact TEP's working capital. As discussed in more detail in TEP witness Kentton Grant's direct testimony, TEP's procurement of fuel and wholesale power requires that it maintain adequate trade credit with other utilities, power marketers and natural gas providers. TEP frequently posts collateral with these counterparties in order to buy power and natural gas. The amount of collateral TEP posts with its counterparties is inversely related to TEP's credit ratings. If TEP has low credit ratings, TEP will have to provide more cash collateral or letters of credit to support its procurement function. We estimate that a one notch credit downgrade would reduce TEP's trade credit with our current counterparties by approximately $60 million. This would increase the amount of credit support required and thus increase the cost to TEP and its customers.

Q. Are the rating agencies changing their view on Arizona regulation in light of recent rate case outcomes?

A. Yes. Following the recent rate case decisions for Southwest Gas Corporation (Decision No. 72723, UNS Gas, Inc. ("UNS Gas") (Decision No. 73142), and Arizona Public

Service Company (Decision No. 73183), Moody's upgraded its rating of the Arizona regulatory environment. On May 21, 2012, Moody's issued a report[11] on Arizona regulation entitled, "Rate Case Decision Positive for Arizona Utilities." An excerpt is included below:

> ...the (APS) settlement points to an Arizona regulatory framework that is more credit supportive for electric and gas utilities...In the past six months, the ACC has sped up its decision-making process to about 12-13 months...As a result (of recent rate case outcomes) we expect the utilities to earn close to their allowed returns on equity and maintain or improve their credit metrics for several years.

Q. Have the rating agencies taken any recent action on UNS Energy, TEP, UNS Gas or UNS Electric?

A. Yes. On May 23, 2012, Moody's upgraded[12] the unsecured ratings of UNS Gas and UNS Electric, Inc. ("UNS Electric") by one notch from Baa3 to Baa2 (which is one notch above TEP). In addition, Moody's also changed their outlook for UNS Energy and TEP to positive from stable. In the report Moody's stated:

> The upgrade to the UNSG and UNSE ratings reflects recent improvements in the Arizona regulatory environment, including a favorable rate case settlement for UNSG, combined with strong credit metrics for both entities.

The report also stated:

> UNS and TEP could be upgraded in the next 12 to18 months if TEP also achieves a supportive outcome in its upcoming rate case.

[11] **See Exhibit KPL-5.**
[12] **See Exhibit KPL-6.**

E. Financial Outlook.

Q. What is the expected impact on TEP's financial condition if the proposed rate request is granted?

A. TEP's proposed rate request should provide for continued, gradual improvement of the Company's financial condition, and should provide a much-needed increase in cash flow to fund a portion of the Company's capital spending needs and to make mandatory capital lease payments. TEP will also be better positioned to compete for and attract capital at reasonable terms, allowing it to continue making the required investments to ensure that customers receive safe, reliable service, as well as long-term rate stability.

On May 24, 2012, Moody's published a credit opinion[13] on TEP and noted the following about the importance of the outcome of this rate case:

> TEP's positive outlook reflects the improvement in the Arizona regulatory environment including a credit supportive outcome in TEP's upcoming rate case, the expectation of continued stable cash flows, and reasonably timely recoveries of fuel and purchase power costs and credit metrics remaining strong for the rating...TEP's ratings could be upgraded in the next 12 to 18 months if the company receives a favorable outcome in its upcoming rate case...TEP's rating could be stabilized if the outcome of the upcoming rate case is not as credit supportive as the three recent Arizona rate case settlements. TEP could be downgraded if the regulatory framework were to become less supportive or predictable or its credit metrics declined to the low-end of the Baa range.

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[13] See **Exhibit KPL-4**.

Q. You mentioned that the rate relief supported by TEP's filing will provide much-needed cash flow to fund a *portion* of the Company's capital spending needs. Where will the rest of the funds come from to pay for capital investments?

A. As previously described, TEP expects to be very active in the capital markets over the next five years. The portion of the Company's capital expenditures not covered by internally generated cash flows will be financed by a combination of new debt issued by TEP and equity contributions from UNS Energy. TEP's ability to receive equity contributions from UNS Energy is critical to maintaining and improving the Company's capital structure and cost of capital. As reflected in a pending financing application,[14] TEP is seeking the authority to increase the amount of equity capital it can receive from UNS Energy by $400 million over the next four years.

Q. Does the rate relief supported by this filing help UNS Energy's ability to provide equity funding to TEP?

A. Yes. The rate relief supported by the Company's filing would improve the financial condition of both TEP and UNS Energy, since the majority of UNS Energy's earnings and cash flows come from TEP. Thus, an improvement in TEP's financial condition would enhance UNS Energy's ability to issue new equity on favorable terms. UNS Energy's and TEP's ability to attract capital on favorable terms supports long-term rate stability for customers.

III. CAPITAL STRUCTURE.

Q. What capital structure is TEP proposing in this case?

A. TEP proposes a pro forma capital structure of 54% debt and 46% common equity.

[14] Docket number E-01933A-12-0176.

Q. What is TEP's actual 2011 test-year capital structure?

A. As reflected in Schedule D-1, the Company's actual test-year capital structure, at December 31, 2011, consisted of 56.5% debt and 43.5% common equity.

Q. Why is TEP proposing a pro forma capital structure?

A. Since its last rate case, the Company has continued to focus on maintaining and improving its credit ratings. One of TEP's objectives is to, over time, improve its balance sheet and raise its unsecured credit rating above the lowest investment grade rating of BBB-/Baa3. The key metric preventing improvement of TEP's credit 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, the Company expects to continue to increase its equity to total capitalization ratio gradually over time.

TEP is entering a period when its financial condition will be even more important, as it will rely on the capital markets to help fund, in part, its substantial projected capital investments, previously described herein. TEP intends to use a mix of debt and equity financing in funding 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, reducing the amount of future interest costs passed along to customers.

Q. What is the current condition of TEP's capital structure?

A. Even though it faced significant economic headwinds, TEP has made great strides in improving its balance sheet and credit ratings since the 2008 Settlement Agreement, which was approved in November 2008. This improvement was accomplished through the retention of earnings and through capital contributions made by UNS Energy.

Despite an extended rate freeze with minimal sales growth, the Company managed to increase its equity ratio beyond the pro forma ratio that was authorized in the 2008 Settlement Agreement.

Q. Was a pro forma capital structure authorized in TEP's last rate decision?

A. Yes. The Commission approved a 42.5% pro forma equity ratio even though the actual equity ratio at December 31, 2006 was 39.9%.

Q. How does TEP's actual capital structure and proposed pro forma capital structure compare to other utilities?

A. As discussed by TEP witness John Reed in his Direct Testimony, the median equity ratio for the proxy group of companies used in his cost of equity analysis is 51%. Based upon a review of data published by S&P, the median equity ratio for regulated utility operating companies[15] with issuer ratings of "BBB" and "BBB+" ranges from 48% to 51%.

TEP's test-year equity ratio of 43.5% is significantly lower than Mr. Reed's findings and the median of S&P's data. Although TEP's proposed equity ratio of 46% is still below industry norms, it represents a more balanced capital structure that is more consistent with an investment grade credit rating. It also represents a reasonably attainable goal for TEP, assuming the Company receives all or substantially all of its requested rate relief.

[15] Regulated electric utilities, as defined by Edison Electric Institute, with investor-owned parent companies.

IV. WEIGHTED AVERAGE COST OF CAPITAL ("WACC").

Q. Please summarize your recommendations regarding the WACC for TEP.

A. In the context of this rate case, based on: (i) the pro forma capital structure discussed above; (ii) the 10.75% cost of equity capital proposed by TEP; and (iii) the 5.18% cost of debt found in the direct testimony of TEP witness Kentton Grant, I recommend the Commission approve an overall WACC of 7.74%. 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	46.00%	10.75%	4.94%
Long-Term Debt	54.00%	5.18%	2.80%
Total	100.00%		7.74%

TEP has a current authorized WACC of 8.02% based upon a capital structure of 42.5% common equity and 57.5% debt, as determined in TEP's last rate case. The proposed WACC in this rate application is 28 basis points lower than the WACC authorized in TEP's last rate case, despite the Company's request for an increase in the pro forma equity ratio from 42.5% to 46.0%.

Q. Why is the Company proposing a 10.75% cost of equity in this proceeding, when TEP witness John Reed has determined a higher cost of equity?

A. TEP has decided to reduce its requested ROE in order to mitigate the impact on customers. Therefore, although the Company could support a cost of equity in the range between 11.0 and 11.5% based on the direct testimony of TEP witness John Reed, we have decided for purposes of this rate case to seek a lower ROE that is still close to the cost range determined by Mr. Reed.

V. FAIR VALUE RATE BASE AND FAIR VALUE RATE OF RETURN.

Q. What does TEP propose as the FVROR on FVRB for the purposes of this filing?

A. As discussed in the Direct Testimony of TEP witness John Reed, the Company proposes a FVROR of 5.68% using the same methodology advocated by Staff and adopted by the Commission in several recent rate cases. Although a higher value for FVROR could be justified, as discussed in Mr. Reed's testimony, at the Company's request, Mr. Reed applied a ROR to the "fair value increment" (the difference between OCRB and FVRB) equal to only one-half of the real risk-free rate. Again, for purposes of this rate case, the Company is applying this ROR in order to better balance the financial need of the Company with the desire to mitigate the rate increase to customers.

Q. How does TEP calculate FVRB for the purposes of this filing?

A. TEP proposes to use the approach traditionally adopted by the Commission, using average of OCRB and reconstructed cost new less depreciation rate base ("RCND"), as those terms are defined in the Commission's rules, as the basis for calculating the Company's FVRB.

As discussed in Mr. Reed's testimony, this value for FVRB is also supported by a market-based approach to fair value.

VI. SUMMARY OF SCHEDULES.

Q. Please describe Schedules D-1, D-3 and D-4 in the Company's Application.

A. Schedules D-1, D-3 and D-4 contain the Company's actual and proposed capital structure and WACC for the test year ended December 31, 2011. These schedules also include projected capital structure and WACC for the period ended December 31, 2012.

Schedule D-2, which pertains to the Company's cost of debt, is sponsored by TEP witness Kentton Grant.

Q. Please describe Schedule F in the Company's Application.

A. Schedule F consists of four parts, Schedules F-1 through F-4.

Schedule F-1 contains a summary income statement and a ROE calculation for the test year ended December 31, 2011. This same information is presented on a projected basis for the year ending December 31, 2012. The projected year information is also presented assuming that the requested rate increase was implemented on January 1, 2012.

Schedule F-2 contains a summary cash flow statement for the test year ended December 31, 2011. This same information is presented on a projected basis for the year ending December 31, 2012. The projected year information is also presented assuming that the requested rate increase was implemented on January 1, 2012.

Schedule F-3 contains information on the Company's capital investments during the test year ended December 31, 2011. The same information is presented on a projected basis for calendar years 2012, 2013 and 2014.

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 2012 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 rate as of January 1, 2012. These additional projections are included for purposes of complying with the Commission's rate filing requirements. Since the Company cannot increase its non-fuel base rates until 2013 under the 2008 Rate Settlement, projections assuming that the requested rates were implemented in January 2012 are of limited analytical value.

Q. The projected ROE for 2012 assuming a full year of requested rate relief, as shown in Schedule F-1, is higher than the 10.75% requested by TEP this matter. 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. Additionally, as noted above, TEP will not actually be able to implement new rates until January 2013 at the earliest. Therefore, the projected ROE for 2012 assuming a full year of rate relief is of limited value for rate-making purposes.

Further, 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. The largest difference pertains to the accounting for TEP's capital lease obligations, which is discussed in Mr. Grant's Direct Testimony. 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 non-recurring gains or losses under GAAP that would ordinarily be eliminated for rate-making purposes. The point to be made is that a casual observation of reported returns should not be used to determine whether or not the Company has "over-earned" or "under-earned" on a retail jurisdictional basis.

Q. Does this conclude your testimony?

A. Yes.

EXHIBIT

KPL-1

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December 2, 2008

Research Update:

Tucson Electric Power Co. Corporate Credit Rating Raised To 'BB+'

Primary Credit Analyst:
Antonio Bettinelli, San Francisco (1) 415-371-5067;antonio_bettinelli@standardandpoors.com

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Research Update:

Tucson Electric Power Co. Corporate Credit Rating Raised To 'BB+'

Rationale

On Dec. 2, 2008, Standard & Poor's Ratings Services raised Tucson Electric Power Co.'s (TEP) corporate credit rating to 'BB+' from 'BB'. At the same time, the secured ratings were raised to 'BBB+' from 'BBB' and the unsecured notes were raised to 'BBB- from 'BB+'. The respective recovery ratings of '1+' and '2' remain unchanged. The outlook is stable.

The upgrades reflect the Arizona Corporation Commission's (ACC) approval of TEP's rate case settlement, with modifications. With this order, TEP's generation operations are re-regulated, which should allow the company to better match revenues with expenses. The order provides for an estimated 6% increase in retail base rates that should allow the company to stabilize cash flows at modestly stronger levels and, importantly, provides the company with a beneficial purchased power and fuel adjustment clause (PPFAC) that will mitigate TEP's significant exposure to unplanned outages and unexpected increases in fuel and purchased power costs and reduce cash flow volatility. Under a rate freeze, in place since 1999, the Tucson-based utility was not able to defer these costs for future collection in rates.

The order also determined that collections under the competition transition charge (CTC) that are subject to refund (estimated to be $59 million) will be credited to customers against the PPFAC until the balance is zero. Because of this netting, cash flow-based financial metrics are not expected improve until 2010, depending on power prices and how fast the credits are amortized. Additionally, the company also agreed to a base rate freeze through December 2012, except in emergency circumstances, including federal carbon regulation. The rate freeze could negatively impact the company if unforeseen costs arise that cannot be included in the PPFAC and are not considered an emergency by the ACC.

TEP is a vertically integrated, investor-owned utility in Arizona, serving 400,000 customers within Tucson and southeastern Arizona. The company is a wholly owned subsidiary of UniSource. TEP's credit ratings are based on the consolidated creditworthiness of UniSource and its subsidiaries, of which TEP is by far the largest, generating about 82% of UniSource's cash flows from operations in 2007. Other regulated operations consist of UNS Gas and UNS Electric, which provide retail natural gas service to 146,000 customers and electric services to about 90,000 mostly residential customers in six counties located in northern and southern Arizona. (UniSource Energy owns these operating companies through an intermediate company, UniSource Energy Services Inc.) UniSource's other holdings are small and not considered to be material to consolidated credit quality.

The consolidated business profile is 'strong', reflecting favorable factors that include: TEP's fully regulated utility operations, low-cost coal-fired generation sufficient to meet the majority of its retail loads, manageable growth in its service territory, and the absence of significant new generation investment. Weaknesses in the business profile include the management of regulatory relationships and the potential for carbon regulation, which could impose material costs given TEP's coal-dominated portfolio. TEP's wholesale sales are also significant due in part to its coal portfolio. The bulk of excess base load coal to sell is available in the first and fourth quarters. These sales revenues will now be netted against the PPFAC. Also underpinning the profile is the fact that UniSource's other operations, which consist of regulated UNS Gas and UNS Electric, also have gas and power supply adjusters that significantly insulate them from commodity cost increases.

The consolidated financial risk profile is 'highly leveraged' due to financial performance and debt balances. Leverage remains high for a regulated utility at 74% as of Sept. 30, 2008, but is related to legacy debt that management has made steady progress in addressing over the last five years. By year-end 2012, consolidated debt balances are expected to be progressively managed down to the range of 60%-62% of total capitalization. (This calculation excludes capital lease obligations that TEP has invested in and holds.) As of Sept. 30, 2008, consolidated trailing 12-month cash flow metrics were 15% for funds from operations (FFO) to total debt and 2.9x for FFO interest coverage.

Short-term rating factors

TEP's liquidity is adequate, supported by cash and credit available, no near-term maturities, and a capital program that can be significantly funded internally, if necessary. Consolidated cash and cash equivalent stood at $77 million as of Nov. 4, 2008, of which about $39 million is at TEP. TEP maintains a $491 million senior secured credit agreement, of which $341 million is committed as collateral that supports about $329 million in outstanding industrial development bonds. However, the remaining revolver capacity, $150 million, is available for general corporate purposes. There was $11 million in outstanding loans under the revolving credit facility as of Nov. 4, 2008.

TEP's parent, UniSource, has a $100 million credit agreement, of which $30 million is a term-loan facility and $70 million is a revolver available for general corporate purposes, of which $42 million was drawn as of Nov. 4, 2008. The agreement expires in 2011. A $60 million revolver, due in August 2011, is also available to support UNS Gas and UNS Electric; $30 million was utilized as of Aug. 5, 2008. Neither UniSource Energy nor any of its subsidiaries will experience any debt maturities until 2011 when $50 million of unsecured notes mature at UNS Gas.

Outlook

The stable outlook reflects our expectation that further improvements in credit metrics and a stronger balance sheet are likely to result from higher base rates and cost mechanisms and that the company will maintain liquidity sufficient to absorb any reasonable shock, including a major outage. A positive outlook would require a significant decrease in consolidated debt leverage, in addition to the progress that the company has already achieved. We would note that while modest improvements in cash flow metrics are expected that may help the company accelerate deleveraging, they are not likely to occur until after 2009 due to the crediting of CTC funds TEP collected in 2008. A weakening in cash flow coverage or a weaker liquidity profile, possibly resulting from the base rate freeze, may result in a negative outlook.

Ratings List

Upgraded; CreditWatch/Outlook Action; Ratings Affirmed

	To	From
Tucson Electric Power Co.		
Corporate Credit Rating	BB+/Stable/B-2	BB/Positive/B-2

Upgraded

	To	From
Tucson Electric Power Co.		
Senior Secured		
US$150 mil revolv credit fac bank ln due 2011	BBB+	BBB
Recovery Rating	1+	1+
US$341 mil term bank ln due 2011	BBB+	BBB
Recovery Rating	1+	1+
Senior Unsecured (8 issues)	BBB-	BB+
Recovery Ratings	2	2

Complete ratings information is available to subscribers of RatingsDirect, the real-time Web-based source for Standard & Poor's credit ratings, research, and risk analysis, at www.ratingsdirect.com. All ratings affected by this rating action can be found on Standard & Poor's public Web site at www.standardandpoors.com; select your preferred country or region, then Ratings in the left navigation bar, followed by Credit Ratings Search.

The McGraw-Hill Companies

EXHIBIT

KPL-2

FitchRatings

Tagging Info

Fitch Affirms Tucson Electric IDR at 'BB+'; Outlook Revised to Positive Ratings

21 Sep 2011 5:42 PM (EDT)

Fitch Ratings-New York-21 September 2011: Fitch Ratings has affirmed the Issuer Default Rating (IDR) of Tucson Electric Power Company (TEP) at 'BB+' and revised the Rating Outlook to Positive from Stable. Approximately $1 billion of debt securities are affected by the rating actions. The full list of ratings is included below.

Key rating drivers include TEP's:
--Stable earnings and cash flows;
--Continued management focus on debt reduction and regulatory process;
--High but improving debt leverage;
--Exposure to changes in environmental rules and regulations;
--Interest rate risk exposure on variable-rate debt securities.

The ratings affirmation and Positive Outlook reflect TEP's stable earnings and cash flows, competitive electric rates, an improving debt leverage profile including lower levels of variable-rate debt, and successful renegotiation of its bank agreement in November 2010. Specifically, TEP's new four-year secured credit facility replaced the maximum debt-to-EBITDA leverage covenant in its previous bank agreement with a 70% maximum debt-to-total capitalization covenant. Debt to capital is expected to be a more stable measure than debt-to-EBITDA.

Commodity price risk is mitigated by TEP's purchase power and fuel adjustment clause (PPFAC) that provides for 100% recovery of fuel and purchase power cost variation from amounts reflected in rates.

Rating concerns include high debt leverage, limited room under debt-to-capitalization leverage restrictions in TEP's bank agreements and frozen non-fuel base rates through 2012. TEP is precluded from filing a new rate case before June 30, 2012. Management of costs will be key to maintaining credit metrics. For the last 12-month (LTM) period ending June 30, 2011 TEP's EBITDA and funds from operations coverage ratios were consistent with the rating category at 4.2 times (x) and 3.7x, respectively.

Going forward, Fitch expects TEP's energy sales growth to approximate 1% from its historical 2% to 3% annual rate during 2011-2014, reflecting a slowly recovering economy in Arizona and energy efficiency initiatives.

The ratings and Positive Outlook assume a reasonable outcome in TEP's next rate case. In the intermediate term, TEP is forecasted by Fitch to be modestly free cash flow negative due to increased capital spending needs associated with emissions compliance and transmission investments. Going forward, leverage ratios are also expected to show improvement over the same time period as TEP amortizes its capital lease obligations. Debt-to-total capitalization is expected to decline to 63% in 2014 from 67% at year-end 2010.

Debt maturities at TEP are manageable through 2014, with $331 million of $441 million of TEP's long-term capital lease obligations amortizing through 2015. There are no other scheduled long-term debt maturities.

TEP had total available liquidity of $183 million including $34 million of cash and cash equivalents and $149 million of borrowing capacity available under its secured revolving credit facility as of June 30, 2011.

TEP had $365 million in tax-exempt variable-rate debt outstanding as of June 30, 2011, which corresponds to a 26.7% ratio of variable-rate debt to total long-term debt, including capital lease obligations. As such, TEP faces interest rate risk on the outstanding variable-rate debt, whose rates are reset weekly by its remarketing agents. In an effort to mitigate interest rate risk TEP hedged $50 million of variable-rate debt through a fixed-for-floating interest rate swap.

Fitch also takes into account the credit implications of TEP's status as a subsidiary utility operating company within the UniSource Energy (UNS) corporate complex. Fitch notes that the amount of dividends TEP is permitted to upstream to UNS is limited to 100% of net income per annum under the Federal Power Act. UNS also owns the much smaller, UniSource Energy Services, Inc. (UES), an intermediate holding company which owns two Arizona-based operating utility

subsidiaries,
TEP serves more than 400,000 electric customers in Tucson, Arizona.

The full list of ratings affirmed is as follows:

--Long-term IDR at 'BB+';
--First mortgage bonds at 'BBB';
--Secured bank facility at 'BBB';
--Unsecured industrial revenue bonds at 'BBB-';
--Unsecured pollution control revenue bonds at 'BBB-';
--Short-term IDR at 'B'.

Contact:

Primary Analyst:
Daniel Neama
Associate Director
+1-212-908-0561
Fitch, Inc.
One State Street Plaza
New York, NY 10004

Secondary Analyst:
Philip W. Smyth, CFA
Senior Director
+1-212-908-0531

Committee Chairperson
Glen Grabelsky
Managing Director
+1-212-908-0577

Media Relations: Brian Bertsch, New York, Tel: +1 212-908-0549, Email: brian.bertsch@fitchratings.com.

Additional information is available at 'www.fitchratings.com'.

Applicable Criteria and Related Research:
--'Corporate Rating Methodology' (Aug. 12, 2011);
--' Recovery Ratings and Notching Criteria for Utilities' (Aug. 12, 2011).

EXHIBIT

KPL-3

MOODY'S
INVESTORS SERVICE

Credit Opinion: Tucson Electric Power Company

Global Credit Research - 24 Aug 2011

United States

Ratings

Category	Moody's Rating
Outlook	Stable
Issuer Rating	Baa3
Sr Sec Bank Credit Facility	Baa1
Parent: UniSource Energy Corporation	
Outlook	Stable
Sr Sec Bank Credit Facility	Ba1

Contacts

Analyst	Phone
Mitchell Moss/New York	212.553.4478
William L. Hess/New York	212.553.3837

Key Indicators

[1]**Tucson Electric Power Company** **ACTUALS**	2Q11 LTM	2010	2009	2008
(CFO Pre-W/C + Interest) / Interest Expense	3.9x	4.1x	4.7x	3.5x
(CFO Pre-W/C) / Debt	16.4%	17.7%	20.5%	16.2%
(CFO Pre-W/C - Dividends) / Debt	12.5%	13.6%	16.3%	16.0%
Debt / Book Capitalization	61.0%	61.6%	62.5%	65.8%

[1] All ratios are calculated in accordance with the Regulated Electric and Gas Utilities Rating Methodology using Moody's standard adjustments

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

Regulatory environment remains challenging

Credit supportive cost recovery mechanisms

Metrics help offset weaker regulatory environment

Corporate Profile

Tucson Electric Power Company (TEP: Baa3 senior unsecured, stable) is an integrated electric utility that provides regulated electricity service to approximately 403,000 retail customers in southeastern Arizona. TEP is the principal operating subsidiary of UniSource Energy Corporation (UNS: Ba1 senior secured bank credit facility (security limited to stock of subsidiaries excluding TEP), stable), a holding company whose subsidiaries provide electricity and natural gas to customers across Arizona.

SUMMARY RATING RATIONALE

Based on factors in Moody's August 2009 Rating Methodology for Regulated Electric and Gas Utilities (the Methodology), TEP's Baa3 senior unsecured rating is driven by the challenging regulatory environment in Arizona, credit metrics at the upper end of the range for U.S. electric utilities rated Baa and TEP's relatively concentrated service territory.

DETAILED RATING CONSIDERATIONS

Regulatory environment is challenging; however rate agreement in place through 2012

TEP is regulated by the Arizona Corporation Commission (ACC), an elected body that we view as below average among U.S. state regulatory environments in terms of predictability and timeliness of rate decisions, the ability to recover costs, and overall supportiveness to credit quality. Rate cases before the ACC use historical test years and tend to be decided in 12-18 months, resulting in new rates reflecting a test year from almost two years prior. Should the timing for rate decisions and regulatory lag shorten, we would view the regulatory framework for Arizona utilities to be more in line with the U.S. average. TEP is expected to file a rate case in the second half of 2012 and we expect new rates to be in place by year-end 2013.

Power cost recovery is credit supportive

TEP's Purchased Power and Fuel Adjustment Clause (PPFAC) allows the utility to adjust rates to reflect changes in power costs. The PPFAC is adjusted every April and it includes a forward component based on projected costs and a true-up component reflecting actual costs over the prior calendar year. However, PPFAC recoveries are currently being offset by competitive transition charge (CTC) refunds to customers. As of June 30, 2011, the net CTC liability to be refunded to customers by year-end was approximately $21 million. Once the refunds are completed and a new PPFAC is set in April 2012, TEP's cash flow should improve modestly due to PPFAC recoveries.

In July 2011, the ACC reopened TEP's 2008 rate decision and discontinued TEP's surcharge to recover line extension fees. TEP did not object to this change but is expected to spend $2 million in 2011 for line extension costs. Although the line extension spending is relatively modest, we viewed the line extension surcharge as supportive to credit quality.

Within the framework of the Methodology, for Factor 1: Regulatory Framework, TEP maps to a rating factor in the Ba range reflecting a regulatory environment with significant uncertainty and regulatory lag. For Factor 2: Ability to Recover Costs and Earn Returns, considering the PPFAC, TEP maps to a rating factor in the Baa range.

Coverage metrics offset regulatory weakness

TEP's cash flow credit metrics are moderately strong for TEP's rating and provide an offset to its below average regulatory environment. Credit metrics have remained relatively stable due to TEP's reasonable multi-year rate settlement. Assuming adequate regulatory relief, cash flow to debt is expected to remain above 18% and cash flow interest coverage is expected to remain above 4x over the medium-term, which map to the upper end of the Baa-rating category. Debt to capitalization has historically mapped to weaker rating level within the mid-Ba rating range though it should improve as well with continued capital lease paydowns and reasonable rate relief.

Liquidity

TEP's liquidity position adequately supports its planned capital expenditures and dividends. Over the next several years, we anticipate TEP's capital expenditures will be approximately $270-370 million annually. This includes a total of approximately $270 million through 2015 for environmental spending. Most of the environmental expenditures are related to SCR installation at TEP's San Juan coal plant. The EPA is currently determining if SCR technology also needs to be installed at the Navajo and Four Corners coal plants where TEP's proportionate share of costs would be about $80 million.

We expect forecasted cash from operations to modestly exceed capital expenditures going forward. In 2010, UNS made a $15 million capital contribution to TEP to fund capital expenditures and we anticipate future funding shortfalls will be financed primarily via long and short term debt issuances. Neither TEP nor its parent have any long-term debt maturities until 2018; however, TEP has scheduled capital lease payments of $118 million in 2011 and $122 million in 2013.

TEP has a $200 million revolving credit facility and a $341 million letter of credit facility supporting $329 million of tax-exempt variable rate bonds; both facilities expire November 2014. TEP's credit facilities are secured by $541 million of first mortgage bonds. As of July 25, 2011, TEP had $46 million in borrowings and letters of credit under its revolving credit facility and $12 million of cash. The credit facility's financial covenant requires a maximum debt to capital ratio of 70%. As of June 30, 2011, the ratio, as calculated in accordance with the credit agreements, was approximately 66%.

Within the framework of the Methodology, given TEP's adequate internal cash generation and appropriately sized credit facility, for Factor 4: Liquidity, TEP maps to a rating factor in Baa range.

Rating Outlook

TEP's stable outlook reflects our expectation of continued stable cash flows, reasonably timely recoveries of fuel and purchased power costs, credit metrics remaining supportive for its rating and that future capital expenditures will be funded in a manner intended to maintain TEP's current financial position and flexibility. The stable outlook recognizes the challenging regulatory environment in Arizona and the company's limited rate relief available until its next rate case filing.

What Could Change the Rating - Up

TEP' rating is not likely to be revised upward in the near-term. An upgrade could be possible if TEP receives consistent supportive regulatory treatment resulting in material, timely rate increases, or if there are material reductions in costs or leverage such that Moody's could anticipate key financial ratios improving moderately from their current levels, if for example, cash flow to debt could be maintained above 22%, there could be upward pressure on the rating.

What Could Change the Rating - Down

TEP's rating could be downgraded if the regulatory framework were to be less supportive or less predictable, and rate case outcomes, cost recovery disallowances or cost increases were to result in cash flow and credit metrics materially below the levels currently expected. If for example, credit metrics declined to the low-end of the Baa range, including cash flow to debt at or below 16%.

Rating Factors

Tucson Electric Power Company

Regulated Electric and Gas Utilities Industry [1][2]	FYE 2010		Moody's 12-18 Month Forward View As of August 23, 2011	
Factor 1: Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Regulatory Framework		Ba		Ba
Factor 2: Ability To Recover Costs And Earn Returns (25%)				
a) Ability To Recover Costs And Earn Returns		Baa		Baa
Factor 3: Diversification (10%)				
a) Market Position (5%)		Ba		Ba
b) Generation and Fuel Diversity (5%)		Ba		Ba
Factor 4: Financial Strength, Liquidity And Key Financial Metrics (40%)				
a) Liquidity (10%)		Baa		Baa
b) CFO pre-WC + Interest/ Interest (3 Year Avg) (7.5%)	4.1x	Baa	4.2x-4.6x	Baa
c) CFO pre-WC / Debt (3 Year Avg) (7.5%)	18%	Baa	19-22%	Baa
d) CFO pre-WC - Dividends / Debt (3 Year Avg) (7.5%)	15%	Baa	16-19%	Baa
e) Debt/Capitalization (3 Year Avg) (7.5%)	63%	Ba	56-60%	Ba
Rating:				
a) Indicated Rating from Grid		Ba1		Baa3
b) Actual Rating Assigned		Baa3		Baa3

* THIS REPRESENTS MOODY'S FORWARD VIEW; NOT THE VIEW OF THE ISSUER; AND UNLESS NOTED IN THE TEXT DOES NOT INCORPORATE SIGNIFICANT ACQUISITIONS OR DIVESTITURES

[1] All ratios are calculated using Moody's Standard Adjustments. [2] As of 12/31/2010; Source: Moody's Financial Metrics

MOODY'S
INVESTORS SERVICE

EXHIBIT

KPL-4

MOODY'S
INVESTORS SERVICE

Credit Opinion: Tucson Electric Power Company

Global Credit Research - 24 May 2012

United States

Ratings

Category	**Moody's Rating**
Outlook	Positive
Issuer Rating	Baa3
Sr Sec Bank Credit Facility	Baa1
Senior Unsecured	Baa3
Parent: UNS Energy Corporation	
Outlook	Positive
Sr Sec Bank Credit Facility	Ba1

Contacts

Analyst	**Phone**
Mitchell Moss/New York City	212.553.4478
William L. Hess/New York City	212.553.3837

Key Indicators

[1]**Tucson Electric Power Company**

ACTUALS	**1Q12 LTM**	**2011**	**2010**	**2009**
(CFO Pre-W/C + Interest) / Interest Expense	**3.9x**	**4.1x**	**4.2x**	**4.7x**
(CFO Pre-W/C) / Debt	**16.6%**	**17.2%**	**17.8%**	**20.5%**
(CFO Pre-W/C - Dividends) / Debt	**16.6%**	**17.2%**	**13.8%**	**16.3%**
Debt / Book Capitalization	**59.4%**	**59.1%**	**61.4%**	**62.5%**

[1] All ratios are calculated in accordance with the Regulated Electric and Gas Utilities Rating Methodology using Moody's standard adjustments

Note: For definitions of Moody's most common ratio terms please see the accompanying <u>*User's Guide*</u>.

Opinion

Rating Drivers

Improved regulatory environment in Arizona

Recovery mechanisms supportive of credit quality

Relatively strong credit metrics

Potential recovery concerns for significant environmental capital expenditures

Corporate Profile

Tucson Electric Power Company (TEP) is an integrated electric utility that provides regulated electricity service to approximately 404,000 retail customers in southeastern Arizona. TEP is the principal operating subsidiary of UNS

Energy Corporation (UNS), a holding company whose subsidiaries operate electric and natural gas utilities in Arizona.

SUMMARY RATING RATIONALE

TEP's Baa3 senior unsecured rating is driven by the credit metrics at the upper end of the range for U.S. electric utilities rated Baa and TEP's relatively concentrated service territory and large coal exposure. The positive outlook reflects the improved regulatory environment in Arizona and the expectation for a reasonable outcome in TEP's upcoming rate case.

DETAILED RATING CONSIDERATIONS

Improved regulatory environment in Arizona

The evaluation of the ratings for UNS and its subsidiaries was driven by the recent credit positive rate decisions for UNS Gas, Southwest Gas and Arizona Public Service which indicate an improvement in the Arizona regulatory environment.

All three rate cases were decided in 11 to 13 months. This time frame is a considerable improvement over the 17 to 18 month average that had previously existed in Arizona. Historically, Moody's has considered the regulatory framework for TEP to be below average among U.S. utilities due to the lengthy decision process and use of a historical test period. As a result, new rates were determined on a rate base that was typically more than two years old leading to significant regulatory lag. In addition to the shorter decision timeframe, the three cases included decoupling mechanisms which followed the announcement of the new ACC policy in December 2010 to encourage utilities to apply for decoupling in rate cases.

We view these recent rate cases as evidence that the Arizona Corporation Commission (ACC) is now committed to finalizing cases within 13 months, following its earlier public statements supporting an accelerated decision timeline. Moreover, the ACC recently received a substantial increase to its budget from the governor of Arizona specifically for the purpose of improving the infrastructure and staff available to facilitate rate cases.

TEP's last rate case was settled in 2008, and it currently plans to file for a new rate case in early July 2012. If the ACC continues to hold to its 13 month decision timeframe, a decision should be expected around mid 2013. TEP has indicated it will request a decoupling mechanism, an environmental cost recovery mechanism, and a continuation of the renewable energy recovery mechanism.

Depending on the size of TEP's requested increase, there is some risk the rate case could potentially receive more significant consumer or regulatory pushback to an increase in customer bills. In the UNS Gas case, despite the rate increase, customer bills declined by 2% due to lower fuel costs. The increase in base rates in the Southwest Gas case was also moderated by lower gas prices. With the APS case, there was no initial change in customer rates due to a decrease in base fuel rates.

Recovery mechanisms supportive of credit quality

TEP utilizes a Purchased Power and Fuel Adjustment Clause to adjust rates to reflect changes in power costs. This mechanism incorporates forward and true-up components and is intended to allow the utilities to recover fuel, purchased power and gas costs in a timely manner.

In addition, TEP is allowed to include a surcharge to recover its renewable investments and above-market cost of PPAs through the Renewable Energy Standard and Tariff. In addition, it is authorized to apply a surcharge to recover its investments in Demand Side Management to meet efficiency standards. The revenues from this charge will increase substantially for TEP in 2012 to support the company in its efforts to meet the energy efficiency standards, which calls for a 3% reduction in kWh sales from 2011.

Given the awarding of decoupling mechanisms in all three of the recent rate settlements, we believe there is a reasonable likelihood that TEP will also be authorized such a mechanism. Moody's views decoupling mechanisms as credit supportive as they reduce uncertainty and volatility of cash flows. The Lost Fixed Cost Recovery (LFCR) mechanism authorized in the UNSG and APS rate cases is credit supportive, but its impact is limited to recovery of lost revenues that result from energy efficiency investments versus Southwest Gas' full decoupling which also provides for the recovery of weather-related losses.

Relatively strong credit metrics

TEP's credit metrics are relatively strong for the rating, with interest and debt coverage in the mid Baa range. Over the period from 2009-2011, CFO pre-WC+interest/interest was in the low 4 times range and CFO pre-WC/debt was in the high teens. In 2011, CFO pre-WC+interest/interest at TEP was 4.1x and CFO pre-WC/debt was 17.2%. The interest and debt coverage at TEP is expected to improve following a supportive rate decision in 2013.

TEP's Debt/Capitalization ratio fell to 59% in 2011 primarily due to the continued amortization ofthe lease obligations for the Springerville plant unit 1 and coal handling facilities. The Springerville unit 1 and coal handling facilities leases will expire in 2015.

High capital expenditures including environmental

TEP expects to spend $1.8 billion on capital expenditures over the next 5 years. Given its large exposure to coal, which accounts for over 90% of energy consumed in the TEP system, the company is facing considerable environmental capital expenditures, which under current mandates would be over $320 million over the next five years. The ACC awarded APS a rider for environmental compliance spending, which indicates that TEP should also be granted a similar mechanism in its upcoming rate case. Moody's views environmental riders as credit supportive since they reduce regulatory lag in recovering mandated capital expenditures.

Liquidity

TEP's credit facility provides adequate liquidity support. However, TEP is expected to operate with negative free cash flow over the next several years. Capital expenditures in 2011 were $352 million versus CFO pre-WC of $270 million. In 2011, TEP did not pay a dividend and UNS made a $30 million capital contribution to TEP to partially fund capital expenditures. We anticipate future funding shortfalls will be financed primarily via long and short term debt issuances with occasional capital contributions from UNS. Neither TEP nor its parent have any long-term debt maturities until 2018; however, TEP has scheduled capital lease payments of $118 million, $112 million, and $195 million in 2012, 2013, and 2014, respectively, and then these drop to $23 million after the expiration of the Springerville unit 1 and coal handling facilities leases in 2015.

TEP has two credit agreements. The TEP Credit Agreement, expiring in 2016, is secured by $386 million in Mortgage Bonds and includes a $200 million revolving credit facility and a $186 million letter of credit (LOC) facility supporting $178.6 million of tax-exempt variable rate bonds. The TEP Reimbursement Agreement, expiring in 2014, is a $37 million LOC facility supporting $37 million in variable rate tax-exempt bonds. As of May 21, 2012, TEP had $140 million in borrowings under its revolving credit facility and $22 million of cash. Both credit agreements have essentially the same financial covenant requiring a maximum debt to capital ratio of 70%. As of March 31, 2012, the ratio, as calculated in accordance with the credit agreements, was approximately 65%.

Rating Outlook

TEP's positive outlook reflects the improvement in the Arizona regulatory environment including a credit supportive outcome in TEP's upcoming rate case, the expectation of continued stable cash flows , reasonably timely recoveries of fuel and purchased power costs and credit metrics remaining strong for its rating. The outlook assumes that planned capital expenditures will be financed in a manner that is consistent with TEP's current financial position.

What Could Change the Rating - Up

TEP's ratings could be upgraded in the next 12 to 18 months if the company receives a favorable outcome in its upcoming rate case. Upward pressure could also occur if there is an improvement in credit metrics, including CFO pre-WC/debt above 22%, on a sustainable basis.

What Could Change the Rating - Down

TEP's rating could be stabilized if the outcome of the outcome of its upcoming rate case is not as credit supportive as the three recent Arizona rate case settlements. TEP could downgraded if the regulatory framework were to become less supportive or predictable or if its credit metrics declined to the low-end of the Baa range, including CFO pre-WC/debt at or below 13%.

Rating Factors

Tucson Electric Power Company

Regulated Electric and Gas Utilities Industry [1][2]	FYE 2011			Moody's 12-18 Month Forward View As of May 24, 2012	
Factor 1: Regulatory Framework (25%)	**Measure**	**Score**		**Measure**	**Score**
a) Regulatory Framework		Ba			Baa
Factor 2: Ability To Recover Costs And Earn Returns (25%)					
a) Ability To Recover Costs And Earn Returns		Baa			Baa
Factor 3: Diversification (10%)					
a) Market Position (5%)		Ba			Ba
b) Generation and Fuel Diversity (5%)		Ba			Ba
Factor 4: Financial Strength, Liquidity And Key Financial Metrics (40%)					
a) Liquidity (10%)		Baa			Baa
b) CFO pre-WC + Interest/ Interest (3 Year Avg) (7.5%)	4.3x	Baa		4.3x-5.5x	A
c) CFO pre-WC / Debt (3 Year Avg) (7.5%)	19%	Baa		18-21%	Baa
d) CFO pre-WC - Dividends / Debt (3 Year Avg) (7.5%)	16%	Baa		15%-19%	Baa
e) Debt/Capitalization (3 Year Avg) (7.5%)	61%	Ba		55-59%	Ba
Rating:					
a) Indicated Rating from Grid		Baa3			Baa2
b) Actual Rating Assigned		Baa3			Baa3

* THIS REPRESENTS MOODY'S FORWARD VIEW; NOT THE VIEW OF THE ISSUER; AND UNLESS NOTED IN THE TEXT DOES NOT INCORPORATE SIGNIFICANT ACQUISITIONS OR DIVESTITURES

[1] All ratios are calculated using Moody's Standard Adjustments. [2] As of 12/31/2011; Source: Moody's Financial Metrics

MOODY'S
INVESTORS SERVICE

credit rating agency subsidiary of Moody's Group Japan G.K., which is wholly owned by Moody's Overseas Holdings Inc., a wholly-owned subsidiary of MCO.

This credit rating is an opinion as to the creditworthiness of a debt obligation of the issuer, not on the equity securities of the issuer or any form of security that is available to retail investors. It would be dangerous for retail investors to make any investment decision based on this credit rating. If in doubt you should contact your financial or other professional adviser.

EXHIBIT

KPL-5

MOODY'S
INVESTORS SERVICE

ISSUER COMMENT

Rate Case Decision Is Credit Positive for Arizona Utilities

From Weekly Credit Outlook

Analyst Contacts:

NEW YORK +1.212.553.1653

Mitchell Moss +1.212.553.4478
Analyst
mitchell.moss@moodys.com

Last Tuesday, the Arizona Corporation Commission (ACC) adopted a settlement that provides Arizona Public Service Company (APS, Baa2 stable) a $116.3 million non-fuel base rate increase to recover increased operating costs and to earn a return on capital invested in its plants. The settlement also lowered fuel rates so that there will be no net change to customer bills. The settlement is credit positive for APS and its parent, Pinnacle West Capital Corporation (PNW, Baa3 stable), because we expect the base rate increase to improve APS' and PNW's credit metrics and because the settlement points to an Arizona regulatory framework that is more credit supportive for electric and gas utilities.

Arizona has historically been a regulatory jurisdiction that we consider to be below average in terms of credit supportiveness. In the past, utilities in the state have experienced significant delays in cost recovery and earning returns on their rate bases. Owing to rate cases taking 18 months to complete, this regulatory lag resulted in rates derived from a cost basis that was more than two years old.

However, in the past six months, the ACC has sped up its decision-making process to about 12-13 months, as reflected in its rate-case orders for APS last Tuesday, UNS Gas, Inc. (Baa3 stable) in April, and Southwest Gas Corporation (Baa1 stable) in December 2011. In addition to the quicker rate case turnaround time, all three utilities received reasonable rate increases and will be allowed to adjust rates via a mechanism to recover lost revenues owing to reductions in sales load. The ACC will also allow APS to implement an environmental cost tracker that adjusts rates on a timely basis to recover carrying costs for environmental compliance capital expenditures.

As a result, we expect the utilities to earn close to their allowed returns on equity and maintain or improve their credit metrics for several years. For instance, we expect APS' cash flow pre-working capital interest coverage to improve to 5.3x from 4.7x in 2011 and cash flow pre-working capital to debt to improve to 26% from 23.5% in 2011.

The negotiated settlements among ratepayer advocates, regulatory staff, and the utilities are credit positive for the utilities since the settlements avoided longer rate proceedings with more uncertain ACC decisions and allowed the utilities to increase base rates and implement new cost recovery mechanisms. The settlements indicate an improved communication of priorities among the parties since the utilities, ACC staff, and other advocates have conflicting priorities regarding rate increases.

What is Moody's Weekly Credit Outlook?

Moody's Weekly Credit Outlook provides our research clients with timely opinions on breaking credit market developments and trends. Published every Monday morning, the newsletter will help you start your week informed of Moody's latest opinions from across the organization.

We expect Tucson Electric Power Company (TEP, Baa3 stable) to file a rate case with the ACC to request an increase in its base rates in July. Although we do not expect a decision until early to mid-2013, a settlement seems possible since we expect TEP to request similar recovery mechanisms as APS did. A favorable result would further indicate an improvement in Arizona's regulatory framework.

Report Number: 142184

Author
Mitchell Moss

Production Specialist
Wing Chan

MOODY'S
INVESTORS SERVICE

EXHIBIT

KPL-6

MOODY'S
INVESTORS SERVICE

Rating Action: Moody's upgrades UNS Gas and UNS Electric; changes UNS Energy Corporation and Tucson Electric Power outlook to positive

Global Credit Research - 23 May 2012

New York, May 23, 2012 -- Moody's upgrades UNS Gas and UNS Electric; changes UNS Energy Corporation and Tucson Electric Power outlook to positive

Moody's Investors Service today upgraded the senior unsecured ratings of UNS Gas, Inc. (UNSG) and UNS Electric, Inc. (UNSE) to Baa2 from Baa3 and assigned a stable outlook. In addition, Moody's affirmed the ratings of UNS Energy Corporation (UNS), the ultimate parent of UNSG and UNSE, and Tucson Electric Power Company (TEP) and changed their outlooks to positive from stable.

RATINGS RATIONALE

"The upgrade to the UNSG and UNSE ratings reflects recent improvements in the Arizona regulatory environment, including a favorable rate case settlement for UNSG, combined with strong credit metrics for both entities" said Moody's Analyst Mitchell Moss. "UNS and TEP could be upgraded in the next 12 to18 months if TEP also achieves a supportive outcome in its upcoming rate case."

On April 24, 2012, the Arizona Corporation Commission (ACC) awarded UNSG a $2.7 million base rate increase (1.8% of revenues) based upon a 9.75% ROE and 50.82% equity ratio; in addition, the ACC allowed UNSG to implement a Lost Fixed Cost Recovery decoupling mechanism. UNS Gas filed its rate case in April 2011 requesting a $5.6 million base rate increase (3.8% of revenues) based on a 10.5% ROE and 51% equity ratio. In February 2012, UNS Gas filed testimony that it agreed with ACC Staff's recommendations for a $2.7 million rate increase. Although base revenues are increasing, overall customer bills are expected to decline by approximately 2% due to reductions in the price of purchased gas and refunds of previously over-collected gas costs.

In addition to the recent UNSG's rate case resolution, Arizona Public Service and Southwest Gas also received recent rate case decisions. The Southwest Gas settlement, finalized in December 2011, was also determined in 13 months while the Arizona Public Service settlement announced May 15, 2012 was determined in 11 months. This 11 to13 month time frame for resolving rate cases is a considerable improvement over the 17 to 18 month average that had previously existed in Arizona. Historically, Moody's has considered the regulatory framework for UNS and its subsidiaries to be below average among U.S. utilities due to the lengthy decision process and corresponding regulatory lag, which along with a historical test period, meant that new rates were determined on a rate base that was typically more than two years old.

Moody's views these recent rate cases as evidence that the ACC is now committed to finalizing settlements within 13 months, following its earlier public statements supporting an accelerated decision timeline. Moreover, the ACC recently received a substantial increase to its budget from the governor of Arizona specifically for the purpose of improving the infrastructure and staff available to facilitate rate settlements. With regard to decoupling, the favorable settlements follow the announcement of the new ACC policy in December 2010 to encourage utilities to apply for decoupling in rate cases.

All of these factors point to a clear improvement in the regulatory supportiveness for UNS and its subsidiaries. Whereas previously, Factor 1: Regulatory Framework, was rated Ba according Moody's Regulated Electric and Gas Utilities Methodology (Methodology), we are now upgrading the rating of this factor to Baa for UNS and its subsidiaries.

In addition to the improved regulatory framework, UNSG and UNSE have demonstrated strong credit metrics relative to their prior Baa3 rating, which had been primarily held back from an upgrade due to the previous Ba rating of the regulatory framework factor in the Methodology. Over the 2009-2011 period, UNSG averaged cash flow from operations pre working capital changes (CFO pre-WC) interest coverage of 4.5 times and CFO pre-WC/debt of 22%. Over the same period, UNSE averaged CFO pre-WC interest coverage of 5.9 times and CFO pre-WC/debt of

31%. These metrics range in the high Baa to A range within the Methodology. This strength in the credit metrics, combined with the improve regulatory framework, supported the upgrade of the ratings of these two utilities to Baa2 from Baa3. The level of interconnectedness including a shared credit facility and guarantees on their debt by their intermediate parent, Unisource Energy Services, Inc., keeps the credit ratings of the two entities the same.

Since over 85% UNS' operating cash flows are generated by TEP, UNS' credit profile and rating is largely driven by TEP whose last rate case was settled in December 2008. TEP currently plans to file for a new rate in early July 2012. If the ACC continues to hold to its 12 to 13 month decision timeframe, a settlement should be expected around mid 2013, with rates going into effect later that year. TEP has indicated it will request a decoupling mechanism, an environmental cost recovery mechanism, and a continuation of the renewable recovery mechanism. Moody's view is that UNS and TEP could potentially be upgraded in 12 to 18 months if there is a favorable outcome in the anticipated TEP rate case.

One of TEP's challenges in its rate case is the potential regulatory pushback to an increase in customer bills. In the UNS Gas case, despite the rate increase, customer bills are expected to decrease by 2% due to lower fuel costs. The increase in base rates in the Southwest Gas case was also moderated by lower gas prices. With the APS case, there was no net initial rate increase in electric rates due to a decrease in base fuel rates. Depending on the size of TEP's requested increase, the rate case could potentially receive more significant consumer or regulatory pushback.

With respect to the credit metrics, both UNS and TEP have metrics in the mid to high Baa category for interest and debt coverage, with CFO pre-WC+interest/interest averaging from 2009-2011 in the low 4 times range and CFO pre-WC/debt in the high teens. Over the same period, the debt/capitalization metrics have been in the Ba range with levels above 60%. However, debt/capitalization has been declining due to reducing lease obligations at TEP for the Springerville plant unit 1 lease which is set to expire in 2015. UNS' and TEP's credit metrics would be expected to improve with a supportive rate settlement.

The Ba1 rating assigned to UNS' secured credit facility predominantly reflects normal notching relative to the Baa3 unsecured rating of TEP, UNS's largest subsidiary. It also considers that the security is limited to the stock of certain subsidiaries (excluding TEP); as a result, its credit quality is assessed as akin to an unsecured claim.

The principal methodology used in this rating was Regulated Electric and Gas Utilities published in August 2009. Please see the Credit Policy page on www.moodys.com for a copy of this methodology.

Headquartered in Tucson, Arizona, UNS Energy Corporation is a holding company that provides electricity and natural gas to customers across Arizona through its regulated utility subsidiaries, Tucson Electric Power Corporation, UNS Electric, Inc. and UNS Gas, Inc. UNS Energy Services, Inc. is an intermediate parent of UNS Energy Corporation which serves as a holding company for UNS Electric, Inc. and UNS Gas, Inc.

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Mitchell Moss
Analyst
Infrastructure Finance Group
Moody's Investors Service, Inc.
250 Greenwich Street
New York, NY 10007
U.S.A.
JOURNALISTS: 212-553-0376
SUBSCRIBERS: 212-553-1653

William L. Hess
MD - Utilities
Infrastructure Finance Group
JOURNALISTS: 212-553-0376
SUBSCRIBERS: 212-553-1653

Releasing Office:
Moody's Investors Service, Inc.
250 Greenwich Street
New York, NY 10007
U.S.A.
JOURNALISTS: 212-553-0376
SUBSCRIBERS: 212-553-1653

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Direct Testimony of Kentton C. Grant

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
GARY PIERCE- CHAIRMAN
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

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-12-____

Direct Testimony of

Kentton C. Grant

on Behalf of

Tucson Electric Power Company

July 2, 2012

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Exhibit KCG-4 Scheduled Lease Payments for Springerville Common Facilities

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Kentton C. Grant. My business address is 88 E. Broadway Blvd., Tucson, Arizona, 85701.

Q. By whom are you employed and what are your duties and responsibilities?

A. I am Vice President and Treasurer of Tucson Electric Power Company ("TEP" or the "Company"). I also serve as Vice President of Finance and Rates for TEP's parent company, UNS Energy Corporation ("UNS Energy"). UNS Energy was known as UniSource Energy Corporation before a name change that took effect on May 4, 2012. For simplicity's sake, I will refer to that company as UNS Energy throughout my testimony, even when describing actions taken under the company's previous name.

Q. Please describe your background and work experience.

A. I have been employed by TEP since 1995. I was originally hired as a senior financial analyst and was subsequently promoted in 1997 to Director of Capital Resources and elected Assistant Treasurer of the Company. Shortly after that I was promoted to Manager of Financial Planning, and in 2003 I became a General Manager in TEP's Shared Services Unit. In 2007, I was elected Vice President of Finance and Rates for both TEP and UniSource Energy Corporation (before the name was changed to UNS Energy). In 2010, I was elected Treasurer for both TEP and UniSource Energy Services, a sister company to TEP. In these roles I have gained extensive experience in financial forecasting, financial analysis, the structuring of financing transactions and other related activities.

From 1984 to 1995, I was employed as a staff member at the Public Utility Commission of Texas. During this period I worked in several different capacities, including Director of the Financial Review Division. In that role, I directed staff responsible for performing financial analyses, accounting reviews and management audits of electric and telecommunications utilities. As a staff member, I also 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 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 also a member of the Chartered Financial Analyst ("CFA") Institute, and in 1995, I was awarded the professional designation of CFA.

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to quantify the cost of long-term debt for TEP, to recommend an appropriate cost recovery method for credit support costs TEP incurs when procuring fuel and purchased power on behalf of its customers, and to recommend an appropriate period for amortizing leasehold improvements at the Springerville Generating Station ("SGS"). I also provide an overview of the long-term lease obligations related to SGS and describe the process TEP went through in acquiring Unit 4 at the H. Wilson Sundt Generating Station ("Sundt Unit 4") in 2010.

Q. Please summarize your conclusions and recommendations.

A. I offer the following conclusions and recommendations:

- TEP's cost of long-term debt as of the end of the test year was 5.18%;

- The cost of providing credit support for TEP's fuel and purchased power procurement is significant and should be recovered through the Company's Purchased Power and Fuel Adjustment Clause ("PPFAC");
- The $52 million paid by TEP in 2010 to acquire the lease equity interest in Sundt Unit 4 was reasonable and prudent, especially in light of the expected useful life of the facility and the substantial benefit it provides as a must-run generating unit;
- The amount of lease expense included in the Arizona Corporation Commission's ("Commission") last rate decision for TEP for the SGS Unit 1 lease and the SGS coal handling lease continues to be just and reasonable as the terms of those leases have not been altered;
- The only change required in calculating lease expense for the SGS common facilities, relative to the amount included in the Commission's last rate decision for TEP, is to reflect the changes in interest rates that have occurred and are projected to occur on variable-rate lease debt;
- The appropriate amortization period for leasehold improvements is 10 years for SGS Unit 1 and SGS coal-handling facilities; and
- The end of the current lease term for the SGS common facilities (January 2021) is a reasonable date for purposes of calculating an amortization period for SGS common facility leasehold improvements.

II. COST OF DEBT CAPITAL.

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 5.18% as of the end of the test year. This cost reflects the weighted average interest rate on all of the Company's long-term debt outstanding as of December 31, 2011. It also reflects the cost of providing credit enhancement (letters of credit) in support of TEP's variable rate bonds, annual commitment fees on TEP's revolving credit facility, and the amortization of debt issuance costs, debt discounts to par value and losses on reacquired debt.

Q. Please provide an overview of TEP's long-term debt structure.

A. As of the end of the test year, TEP had $1.08 billion of long-term debt obligations, of which $865.9 million were fixed-rate obligations and $215.3 million were variable-rate obligations. All of TEP's long-term debt obligations, with the exception of $250 million of taxable fixed-rate notes, are tax-exempt obligations that were issued to finance local furnishing facilities and pollution control facilities. As a local furnishing utility, whose retail service area is confined to a contiguous two-county area, the Company has been able to finance a substantial portion of its utility plant assets with tax-exempt revenue bonds issued by governmental entities on TEP's behalf. This access to tax-exempt financing has helped the Company to maintain a relatively low cost of debt compared to many other investor-owned utilities, a benefit that is passed on to TEP's customers through cost-of-service rate-making.

Q. How does TEP's cost of debt compare with the cost approved by the Commission in the Company's last rate case?

A. It is significantly lower. The cost of debt approved in TEP's last general rate case was 6.38%. That cost was based on the Company's embedded cost of debt as of December 31, 2006. Since that time, TEP has taken advantage of lower long-term interest rates, as well as improved credit ratings, by refinancing a substantial portion of the Company's long-term debt. In 2006, the Company had eight different series of fixed rate debt obligations with interest rates ranging from 5.85% to 7.50%. As of the end of the test year in this case (December 31, 2011), TEP had nine different series of fixed rate debt obligations with interest rates ranging from 4.95% to 6.375%. Importantly, the weighted average maturity date of TEP's fixed rate debt was also extended, thereby locking in lower long-term rates for an extended period of time. The Company has also reduced its exposure to variable interest rate risk by refinancing variable-rate obligations on a fixed-rate basis and by hedging a portion of its variable rate debt with a fixed-for-floating interest rate swap. In 2006, 40% of TEP's long-term debt was exposed to changes in variable interest rates. As of December 2011, only 15% of the Company's long-term debt was similarly exposed.

Q. Have changes in short-term interest rates helped to reduce TEP's cost of debt?

A. Yes. The average interest rate on TEP's variable rate long-term debt, excluding letter of credit and re-marketing fees, was 3.9% in 2006. For the test year ended December 31, 2011, the average interest rate on TEP's variable rate long-term debt was 0.2%. Clearly, the recent reduction in short-term interest rates has served to reduce, at least temporarily, the Company's weighted average cost of long-term debt.

Q. Are variable interest rates expected to increase over time?

A. Yes. After the collapse of Lehman Brothers in 2008 and the severe economic recession that followed, floating rates on U.S. Treasury securities and other high quality investments fell to all-time lows, and have remained extraordinarily low due in part to investor risk aversion and the accommodative monetary policy of the Federal Reserve. However, forward interest rate markets, as well as the upward slope of the U.S. Treasury yield curve, indicate an expected rise in interest rates over the next several years.

Q. How has TEP protected itself from the risk of rising variable interest rates?

A. As discussed above, the Company has refinanced a substantial portion of its variable rate debt on a fixed-rate basis. Additionally, in August 2009, the Company entered into a five-year fixed-for-floating interest rate swap agreement in order to hedge the interest rate risk on a portion of its variable rate bonds. Under that agreement, TEP pays a 2.40% fixed rate on a $50 million notional amount of bonds, and receives a floating rate tied to a weekly tax-exempt index that is highly correlated with the rates paid by TEP on its variable rate bonds. From an economic perspective, this hedging transaction had the effect of fixing the rate on $50 million of variable rate bonds at 2.40% through September 2014. At the time this hedge was entered into in 2009, TEP had a much higher exposure to variable rate risk, with approximately 50% of its long-term debt comprised of tax-exempt variable rate bonds. Subsequent refinancing activity in the fixed-rate market has since reduced that exposure even further.

Q. How did you calculate the interest rate on TEP's variable rate debt for the test year ended December 31, 2011?

A. For the $165.3 million of variable rate bonds that were not hedged, I calculated the simple average of the rates paid by TEP over the year, which was approximately 0.2%. For the $50 million of principal amount hedged as described above, I used the 2.40% swap rate paid by TEP during the test year.

Q. What other costs need to be considered in calculating TEP's cost of variable rate debt?

A. The cost of providing credit enhancement for these bonds, in the form of stand-by letters of credit issued by banks, is necessary if the bonds are to be successfully marketed in the short-term money markets. At the end of the test year, the average annual cost of a letter of credit equaled approximately 1.4% of the principal amount of bonds supported. Additionally, the cost of re-marketing these bonds, which presently is conducted on a weekly basis by TEP's re-marketing agents, needs to be included. At the end of the test year, the average annual re-marketing fee was approximately 0.1% of the principal amount of bonds being re-marketed. As reflected in Schedule D-2, the weighted average cost of TEP's variable rate bonds, including the fees and hedging costs described above, was 2.21% for the test year ending December 31, 2011, considerably lower than the cost of variable rate debt in TEP's last general rate case.

Q. You stated earlier that the annual commitment fees on TEP's revolving credit facility are included in the cost of long-term debt. Why is it important to include these costs in the weighted average cost of long-term debt?

A. Although TEP had only a $10 million balance of revolving credit loans outstanding at the end of the test year, maintenance of this credit facility is critical for purposes of funding seasonal working capital needs, financing temporary balances of under-recovered fuel and purchased power costs under the Company's PPFAC, providing required credit support to wholesale natural gas and power suppliers, and funding a portion of capital expenditures from time to time. The commitment fees paid to maintain this facility, which provides $200 million in revolving credit to the Company, accrue at a rate of 0.175% of the unused balance of the facility. Since these fees are charged to interest expense on the Company's income statement, and not to operating expense, recovery of these fees is properly included in the cost of long-term debt for TEP. This is the same treatment of revolving credit commitment fees as was adopted and approved in TEP's last general rate case.

Q. What cost of long-term debt is TEP proposing in this case?

A. I recommend a cost of 5.18%, which represents TEP's weighted average cost of long-term debt outstanding as of the end of the test year.

III. COST OF CREDIT SUPPORT FOR FUEL AND POWER PROCUREMENT.

Q. Does TEP incur credit-related costs to support the procurement of natural gas and wholesale power for retail customers?

A. Yes. In addition to financing temporary under-collections of fuel and purchased power costs under the Company's PPFAC mechanism, TEP must also provide credit support to wholesale suppliers from whom these purchases are made. This credit support may either take the form of a letter of credit issued by a creditworthy bank, a deposit of cash collateral in an escrow account, or under some circumstances a pre-payment of amounts owed to the supplier. Credit support is often required to provide assurance to a wholesale counter-party that TEP will perform its obligation to purchase natural gas or wholesale power as specified by contract.

Q. Under what situations may wholesale credit support be required?

A. It is customary for participants in the wholesale gas and power markets to set a credit limit for each counter-party with whom it conducts business. Larger credit lines are typically extended to large and highly-rated market participants, while credit lines are typically much lower for small and mid-sized companies or those having weaker credit ratings. When the credit exposure to a counter-party exceeds the specified credit limit, a request for credit support is made. From the standpoint of a seller of natural gas or wholesale power, credit exposure to a contracted buyer is typically defined as the sum of: (i) the receivable balance due from the buyer; and (ii) the mark-to-market value (positive or negative) of future sales specified under the contract.

In the case of TEP, requests for credit support are received from sellers of natural gas and wholesale power whenever their credit exposure to the Company exceeds the credit limit they have assigned to TEP. Although credit limits may be negotiated when a new business relationship is being established or when a change in credit ratings occurs, the decision to extend credit is solely at the discretion of the seller.

Q. Is wholesale credit support needed to facilitate TEP's energy hedging program?

A. Yes. TEP's energy hedging program involves the purchase of natural gas and wholesale power in the forward energy markets in order to stabilize the cost of energy provided to TEP's customers. As discussed above, changes in the market value of forward energy contracts can create a need for wholesale credit support.

Q. What level of credit support has TEP been required to provide?

A. **Exhibit KCG-1** shows the historical level of credit support provided by TEP since January 2009. As may be seen, the Company was required to provide as much as $12 million in credit support during the summer of 2009 due primarily to falling gas and wholesale power prices in the forward markets, as well as a seasonal increase in accounts payable to gas and wholesale power providers. Credit support during that summer took the form of cash collateral deposited with suppliers, letters of credit issued for the benefit of suppliers, and pre-payments of amounts owed to certain other suppliers. Since 2009, the amount of credit support required from TEP has been much less, averaging only $991,000 during the test year ended December 31, 2011. This lower level of credit support is due in part to more stable forward prices in the natural gas and wholesale power markets, improvement in TEP's credit ratings and greater diversification of suppliers by TEP.

Q. What is the cost to TEP when it provides credit support to a wholesale natural gas supplier?

A. These costs include the cost of obtaining letters of credit under TEP's revolving credit facility, as well as the cost of borrowing under the Company's credit facility to fund cash collateral deposits and pre-payments to suppliers. Due to the relatively small amount of credit support required in 2011, total credit support costs for the test year were only $21,000. However, credit support costs were higher in previous years, totaling $56,000 in 2009 and $30,000 in 2010.

The cost of obtaining a letter of credit under TEP's revolving credit facility is presently equal to 1.125% of the face value of the letter of credit, prorated for the number of days outstanding using a 30/360 day pricing convention. An additional 0.25% is paid by TEP as a fronting fee to the issuing bank, again prorated for the number of days outstanding. The cost of obtaining a loan under TEP's revolving credit facility is presently 1.125% over the applicable 1-month or 3-month London Interbank Offered Rate ("LIBOR") benchmark rate. Since interest income on cash collateral deposits accrues to the benefit of TEP, and can be earned at a rate comparable to LIBOR, the net cost of making a cash collateral deposit is equal to the bank margin rate of 1.125%. The dollar cost of a cash collateral deposit can therefore be calculated by applying the bank margin rate to the balance of the cash deposit, and prorating that amount for the number of days outstanding using a 30/360 day pricing convention. Under TEP's current credit facility, the net cost of credit support is very similar whether a letter of credit is obtained or cash collateral is provided.

Q. Are TEP's credit support costs expected to increase over time?

A. Yes, relative to the level of costs incurred during the test year. As greater amounts of natural gas and wholesale power are purchased to meet customer energy demands, the amount of credit support required will tend to increase over time. Additionally, the cost of short-term bank credit is presently quite low by historical standards, and may very well increase, causing upward pressure on credit support costs. Other factors affecting the amount of credit support required include the Company's credit ratings, the number of natural gas and wholesale power suppliers with whom TEP does business, and future changes in the market value of TEP's portfolio of forward natural gas and wholesale power purchases. Since natural gas and wholesale power prices can be fairly volatile in both the spot and forward markets, it is difficult to predict how the mark-to-market value of TEP's forward purchase portfolio will change, and by extension, how much credit support will be required. However, if the Company's credit ratings were to improve, this would help to reduce the amount of credit support required, resulting in savings to TEP and its customers.

Q. What is your recommendation concerning the recovery of wholesale credit support costs by TEP?

A. Since wholesale credit support costs are incurred as a result of TEP's fuel and purchased power procurement, and since these costs are highly variable, I recommend that these costs be recovered through the Company's PPFAC. These costs may be readily quantified using the pricing defined in TEP's revolving credit facility for letters of credit and short-term borrowings, and are easy to track, verify and reconcile for purposes of recovery through the PPFAC. Only those costs that have been fully documented would be eligible for recovery through the PPFAC.

IV. <u>ACQUISITION COST OF SUNDT UNIT 4.</u>

Q. What is Sundt Unit 4 and when was it acquired by TEP?

A. Sundt Unit 4 is a 156 megawatt dual-fuel generating unit located in Tucson that is capable of burning either natural gas or coal.[1] As described in the Direct Testimony of TEP witness Michael DeConcini, Sundt Unit 4 is a must-run unit that is needed for voltage support in the Tucson load pocket and for meeting peak customer demand in

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[1] In addition to natural gas and coal, Sundt Unit 4 also uses landfill gas as a fuel source.

Tucson. TEP purchased the unit in 2010. Prior to that purchase, TEP operated the unit under the terms of a long-term lease agreement that was scheduled to expire in January 2011.

Q. Please describe the purchase transaction that TEP entered into in 2010.

A. Because the lease covering Sundt Unit 4 had both equity and debt investors, each of whom received a share of the rental payments received from TEP, the Company had to complete the purchase in two stages. First, the Company had to negotiate and close on the purchase of the lease equity interest from the owner participant in the lease. This was accomplished in March 2010 after receiving approval of the purchase from the Federal Energy Regulatory Commission ("FERC"). Following that purchase, the Company then exercised its right to redeem the remaining balance of lease debt at par. Upon retirement of the lease debt in April 2010, the Company then caused the lease to be terminated and assumed direct ownership of the facility.

Q. Please describe the negotiation process leading up to the purchase of the lease equity from the owner participant.

A. In late 2008, TEP was contacted by the owner participant with a verbal offer to sell their lease equity interest in Sundt Unit 4. Following that initial discussion, a written offer was received by TEP specifying a modestly lower sales price. That offer was premised on a closing date of June 30, 2009 or earlier. In response to that offer, and in recognition of the deadline for exercising its purchase option under the lease agreement, TEP hired an independent appraiser to assess the value of Sundt Unit 4. In October 2009, after the appraisal was completed, the Company contacted the owner participant to begin discussions on a possible purchase of the unit. After two months of negotiation, during which the parties exchanged offers and reassessed their positions, a verbal agreement on price was finally reached and memorialized in a letter of understanding in December

2009. This was followed by the execution of a purchase agreement on January 13, 2010, two days before the deadline for exercising TEP's purchase option under the lease.

Q. Please describe the purchase option that was available to TEP under the lease agreement.

A. The purchase option specified in the Sundt 4 lease agreement was a fair market sales value ("FMSV") purchase option, the value of which was to be determined either through agreement of the parties or through a formal appraisal process. In order for TEP to exercise this purchase option, the Company was required to submit an irrevocable notice to the owner participant by January 15, 2010. Upon receipt of that notice, a 45-day negotiation period would have been triggered, to be followed by a formal appraisal procedure if an agreement on price could not be reached. The appraisal procedure specified that the FMSV was to be determined either by an appraiser mutually agreed upon by the owner participant and TEP, or by a three-member panel of appraisers with one being selected by the owner participant, one by TEP, and the third by mutual agreement of the other two appraisers. Under the three-member panel approach, the two closest appraisals would be averaged for purposes of determining the FMSV of Sundt Unit 4. The lease agreement also specified a purchase price cap of $109.6 million. Therefore, the price TEP would have paid under the purchase option would have been the lower of FMSV or $109.6 million. The purchase date specified under the lease agreement was the lease termination date of January 15, 2011.

Q. Why did TEP decide to negotiate a purchase of the lease equity instead of simply exercising the purchase option available under the lease agreement?

A. Exercising the purchase option under the Sundt Unit 4 lease agreement would have exposed TEP and its customers to significant price risk. Under the terms of the lease agreement, TEP was required to exercise its purchase option by sending an irrevocable notice to the owner participant at least one year before the scheduled termination date of the lease. Since the lease was scheduled to terminate on January 15, 2011, TEP had until January 15, 2010 to send such a notice to the owner participant. However, the purchase price specified under the lease agreement was not a fixed price. Instead, the purchase price was to be determined based on the FMSV of the unit, and such determination was to be made only after TEP submitted its irrevocable notice to purchase the unit. In other words, TEP would have been required to commit to the purchase of Sundt Unit 4 without knowing the ultimate purchase price. Absent an agreement on price with the owner participant, the Company would have been required to pay whatever value was determined through the appraisal procedure described in the lease agreement.

Q. **In the context of a formal appraisal process, can there be a wide divergence of opinion as to the FMSV of a power plant?**

A. Yes. Unless there have been recent sale transactions involving similar assets in the same regional or local market, it can be very difficult to predict the outcome of a formal appraisal procedure. For example, in the appraisal process recently completed for SGS Unit 1, which is discussed later in my testimony, the highest appraised value was over two and one-half times the appraised value submitted by another appraiser appointed to a three-member panel of appraisers. For Sundt Unit 4, additional uncertainty regarding its FMSV existed due to its unique status as both a dual-fuel unit and a must-run unit located within the Tucson load pocket.

Q. **Did TEP have an appraisal prepared prior to engaging in negotiations with the owner participant?**

A. Yes. TEP retained a nationally recognized appraisal firm with extensive experience conducting power plant valuations in both the regulated and competitive sectors of the power industry.

Q. Was the appraisal obtained by TEP significantly lower than the price initially offered by the owner participant?

A. Yes. The price initially offered by the owner participant was 90% higher than the high end of the range of appraised values obtained by TEP. Consequently, there was a wide divergence of opinion between the owner participant and TEP as to the FMSV of Sundt Unit 4.

Q. Was the final agreed-upon price close to the appraised value obtained by TEP?

A. Yes. The negotiated purchase price of $52 million was very close to the high end of the range of appraised values obtained by TEP. Due to the wide divergence of opinion on value between the owner participant and TEP, and the significant price risk associated with the formal appraisal procedure specified in the lease agreement, the Company chose to accept a negotiated outcome that was only slightly higher than the confidential independent appraisal obtained by TEP.

Q. Do you believe the purchase price paid by TEP for Sundt Unit 4 was reasonable?

A. Yes. This conclusion is based on a number of factors including:

- the substantial price concession obtained from the owner participant through a lengthy and rigorous negotiation process;
- the proximity of the negotiated purchase price to the value obtained from an independent and highly qualified appraiser;
- the avoidance of price risk associated with the Company's FMSV purchase option under the lease agreement;
- the importance of this facility to TEP and its customers from an operational standpoint; and
- the higher value that TEP and its customers should be able to realize from Sundt Unit 4 relative to the independently appraised value.

Q. Please elaborate on this last point.

A. Certainly. Under the terms of the lease agreement, FMSV was to be determined under the assumption that a willing buyer would only have rights to Sundt Unit 4 through the remaining term of the easement agreement for the unit, which was scheduled to expire in 2020. Hence, the range of values obtained from the independent appraiser, referenced above, was based on a limited operational life for Sundt Unit 4. However, as owner of the unit, TEP will be able to operate the unit through its remaining useful life, which is expected to extend well beyond 2020. Recognizing this, the same independent appraiser estimated the fair value to TEP, outside of the lease agreement, to be much higher than the previously referenced range of values. In fact, the independent estimate of fair value to TEP was significantly higher than the $52 million purchase price ultimately agreed upon by the Company and the owner participant.

Q. After the ownership interest was purchased by TEP in March 2010, and the remaining lease debt was redeemed in April 2010, did TEP make accounting entries to reclassify certain Sundt Unit 4 costs as plant in-service?

A. Yes. Those accounting entries are described in TEP witness Karen Kissinger's Direct Testimony and were subsequently approved by the FERC. As discussed by Ms. Kissinger, the accounting entries associated with the purchase of the lease equity interest and the termination of the lease agreement resulted in a beginning balance of net plant in-service of $69.9 million for Sundt Unit 4. This balance included a re-classification of $11.6 million of net leasehold improvements to plant in-service, as well as other costs related to the early termination of the lease agreement. The re-classified leasehold improvements represented capital improvements that were required in order to keep the facility in good operating condition, and were included in rate base by the Commission in prior TEP rate cases during the term of the Sundt Unit 4 lease agreement, including TEP's last general rate case.

V. OVERVIEW OF LEASE OBLIGATIONS AT SGS.

A. SGS Unit 1 Lease.

Q. Please describe the long-term lease arrangement for SGS Unit 1.

A. TEP leases SGS Unit 1 and 50% of the SGS common facilities under seven separate lease agreements that expire in January 2015. The seven lease agreements are nearly identical to one another, except that each lease covers a different ownership share and has different scheduled rent payments. In my testimony, I will refer to these seven lease agreements collectively as the SGS Unit 1 lease. Under the terms of the SGS Unit 1 lease, rent is paid semi-annually by TEP to a trustee. This trustee then applies the rent proceeds to principal and interest on lease obligation bonds that were issued in connection with the original sale and leaseback transaction, and then distributes any remainder to the owner participants who have equity interests in the lease. While the scheduled lease payments vary from period to period, they are fixed by contract and are not tied to any market-based index or variable rate of interest.

Q. How is the SGS Unit 1 lease accounted for?

A. Under Generally Accepted Accounting Principles ("GAAP"), which TEP must apply for financial reporting purposes, the lease is accounted for using the interest method of capital lease accounting. This requires TEP to record a lease obligation on its balance sheet equal to the net present value of scheduled rent payments and to record interest expense on the liability in each reporting period. This method of accounting also requires TEP to record a capital lease asset equal to the initial lease obligation on its balance sheet and to amortize the asset on a straight-line basis over the term of the lease. As the lease nears the expiration date of January 2015, the lease obligation and related interest expense will decline over time, while the amount of amortization expense recorded each period remains unchanged. Consequently, for financial reporting purposes, the overall level of expense reported by the Company declines over time as the lease obligation is reduced. However, for retail rate-making purposes, the SGS Unit 1 lease is accounted for as an operating lease and included in TEP's revenue requirement as an operating expense. The amount of SGS Unit 1 rent expense included in the Company's last rate case was based on the average of remaining lease payments through the scheduled lease termination date.

Q. Does TEP own an equity interest in one of the seven separate leases comprising the SGS Unit 1 lease?

A. Yes. In 2006, TEP paid $48 million to a third-party investor to acquire the lease equity covering a 14.1% undivided interest in SGS Unit 1 and related common facilities. Shortly thereafter, TEP caused the lease to be amended to eliminate the equity portion of rent payments. Since there still remain lease obligation bonds outstanding, TEP continues to make rent payments to the indenture trustee for purposes of paying the principal and interest on those bonds. After the bonds have been paid in full, TEP will then have the right to terminate the lease agreement and take direct ownership of the 14.1% undivided interest in SGS Unit 1 and related common facilities. Assuming TEP retains ownership of this interest, the Company would then seek rate-base treatment of its investment in a future TEP rate case.

Q. Was the reduction in rent payments that resulted from this lease equity purchase reflected in the Company's last rate case?

A. Yes. TEP's acquisition of the 14.1% interest took place during the test year for the last rate case and the reduction in scheduled rent payments was fully reflected in calculating the average remaining lease payment for SGS Unit 1 in that rate case. The resulting average annual lease payment for the remaining term of the lease (January 2009 to

January 2015) was determined to be $81.1 million, a value that was included in the non-fuel cost recovery of $25.67 per kW per month approved by the Commission for SGS Unit 1.

Q. Have the scheduled rent payments under the SGS Unit 1 lease changed since TEP's last rate case?

A. No. As discussed above, the reduction in lease payments resulting from the 2006 purchase of a lease interest was already taken into account in the last rate case. The schedule of rent payments under the SGS Unit 1 lease have not changed since that time. Consequently, the same level of lease expense included in TEP's last rate case for SGS Unit 1 should be reflected in this rate case. **Exhibit KCG-2** shows the scheduled rent payments for SGS Unit 1 over the lease term considered in TEP's last rate case. As may be seen in that exhibit, TEP's remaining rent payments over the period 2012 through 2014 are considerably higher than the average annual rent payment of $81.1 million for the period 2009 through 2014. No rent payments are scheduled for the final month of the lease in January 2015.

Q. What options are available to TEP for retaining an interest in SGS Unit 1 beyond the current lease term?

A. Each of the seven separate lease agreements contains identical purchase and lease renewal options, except that each lease covers a different percentage ownership in the facilities. For a purchase, the option price is based on the FMSV of the facilities. For a lease renewal, payments are to be based on the fair market rental value of the facilities. For each separate lease interest TEP can elect to purchase the facilities, renew the lease, or forego the right to purchase or lease the facilities. Under this last alternative, TEP would still operate SGS Unit 1 for third-party owners and provide those owners with a share of output from SGS Unit 1 equal to their ownership percentage.

Q. Has TEP taken any steps to retain an interest in SGS Unit 1 beyond the current lease term?

A. Yes. As previously described, in 2006, TEP purchased a lease equity interest in SGS Unit 1, a step that will allow the Company to take direct ownership of a 14.1% undivided interest in the facilities after the lease obligations bonds have been retired. Additionally, in December 2011, the Company and the owners of the other six lease interests completed a formal appraisal process as specified in the lease agreements that established the FMSV for SGS Unit 1 under TEP's purchase options. The appraised value was determined to be $159 million for the 85.9% of SGS Unit 1 not already owned by TEP, which equates to $478 per kW of generating capacity. TEP has until September 1, 2013, to exercise this purchase option, which stipulates a financial closing in January 2015.[2]

Q. Does TEP intend to exercise its purchase option for SGS Unit 1?

A. Assuming appropriate regulatory approvals and acknowledgements are received in a timely manner, the Company does intend to exercise its purchase option for SGS Unit 1. As described in the Integrated Resource Plan ("IRP") that TEP filed April 2, 2012 (in Docket No. E-00000A-11-0113), the purchase of SGS Unit 1 at this price would result in significant long-term economic benefits to the Company and its customers relative to the construction of a new gas-fired generating facility. Unless the value of SGS Unit 1 drops substantially between now and September 2013, or the Company is unable to raise the capital required to purchase the facilities, TEP intends to exercise this purchase option for all six lease interests by September 1, 2013.

Q. What regulatory approvals and acknowledgements will TEP need before exercising this option?

A. The Company will need approval of the purchase from the FERC before the September

[2] In April 2012, TEP filed a petition in Federal Court seeking to confirm the results of the appraisal. As of July 2012, this matter was still pending.

2013 deadline for exercising the purchase option. TEP will also need a new financing order from the Commission that provides the Company with sufficient financing capacity to complete the purchase. TEP recently filed such an application in May 2012 (in Docket No. E-01933A-12-0176). Finally, TEP requested in its IRP that the Commission find the planned purchase of SGS Unit 1 to be prudent, or in the alternative, acknowledge the long-term economic benefits that the purchase would provide to TEP and its customers.

Q. Assuming the Company purchases SGS Unit 1 in 2015, when would TEP seek rate-base treatment for that investment?

A. The Company would seek rate-base treatment for SGS Unit 1 in a future rate case.

B. <u>SGS Coal Handling Facilities ("CHF") Lease.</u>

Q. Please describe the long-term lease arrangement for the SGS CHF.

A. TEP leases the CHF through two separate lease agreements that expire in April 2015. The Company also owns a 13.3% undivided interest in the facilities, an ownership interest it acquired in 2002, and which had been leased to TEP under a third CHF lease. The SGS CHF include a rail spur, a rotary rail car dumper, a coal conveyor system and other facilities needed for the supply of coal to SGS Units 1 & 2. A portion of these facilities are also used by the owners of SGS Units 3 & 4. As described in the Direct Testimony of TEP witness Michael DeConcini, TEP receives periodic payments from the owners of SGS Units 3 & 4 for the use of those facilities.

The two CHF lease agreements are nearly identical, except that each lease covers a different ownership share and has different scheduled rent payments. In my testimony I refer to these two lease agreements collectively as the SGS CHF lease. Under the terms of the lease, rent is paid semi-annually by TEP to the owner trustee who then distributes the rent proceeds to the owner participants who have equity interests in the lease. While the scheduled lease payments vary from period to period, they are fixed by contract and are not tied to any market-based index or variable rate of interest.

Q. How is the SGS CHF lease accounted for?

A. For financial reporting purposes it is accounted for as a capital lease obligation. For the portion of the lease obligation allocable to SGS Unit 1 non-fuel costs, the Company applies the same method of expense recognition previously described for the SGS Unit 1 lease. For the remaining 75% of the CHF lease, a modified interest method of expense recognition is used. Under this method, capital lease amortization expense is increased over time to offset reductions in capital lease interest expense, resulting in a levelized amount of total lease expense. For rate-making purposes, the SGS CHF lease is accounted for as an operating lease and included in TEP's revenue requirement as an operating expense. The amount of SGS CHF rent expense included in the Company's last rate case was based on the average lease payment over the primary term of the lease. TEP is proposing this same method of cost recovery in this rate case.

Q. Does TEP own a portion of the SGS CHF?

A. Yes. In December 2001, the Company paid a third-party investor $13.0 million for a lease equity interest covering a 13.3% undivided interest in the SGS CHF, which had been leased to TEP under a third CHF lease. In January 2002, TEP also purchased $13.0 million principal amount of lease obligation bonds associated with this lease interest for $13.8 million. Following the purchase of the lease debt, TEP then caused the lease to be terminated and the Company took direct ownership of this 13.3% undivided interest in the CHF. As described above, the remaining 86.7% of the SGS CHF are still under lease.

Q. Why did TEP decide to purchase an interest in the SGS CHF?

A. First, it was recognized that the facilities represent core assets needed for the continued operation of SGS Units 1 & 2. By purchasing the lease equity, the Company would avoid having to purchase the facilities or renew the lease at the end of the primary lease term in 2015. Second, by purchasing both the lease equity and related lease debt, the Company was able to collapse the lease and reduce the amount of lease obligations on its balance sheet. Since the credit rating agencies view lease obligations as being similar to long-term debt obligations, the purchase was helpful in terms of de-leveraging TEP's balance sheet and supporting the Company's credit ratings. Finally, the Company realized a modest earnings benefit due to a reduction in reported interest expense on its capital lease obligations.

Q. How was this 13.3% interest in the SGS CHF treated in the Company's last rate case?

A. It was treated the same as the two CHF leases that are still in effect. In other words, the originally scheduled lease payments associated with this 13.3% interest were included in the calculation of the average annual rent payment all of the SGS CHF. This was done in part because, for financial reporting purposes, TEP's investment in this 13.3% interest is still accounted for as a capital lease asset and not as plant in-service. This rate treatment was also justified since the price paid by TEP to acquire this interest was based on the net present value of the originally scheduled lease payments as well as the residual value of the facilities at the end of the lease. From an economic standpoint, TEP pre-funded the lease payments that were scheduled to occur over the remaining term of the lease. Since cost recovery for the SGS CHF lease is based on the average rent payment over the life of the lease, TEP's pre-funding of a portion of those lease payments should not affect the levelized amount of lease expense included in rates.

Q. Have the scheduled rent payments under the SGS CHF lease changed since TEP's last rate case?

A. No. Consequently, the same level of lease expense for the SGS CHF adopted in the last rate case should continue to be reflected in the new service rates granted in this proceeding. **Exhibit KCG-3** shows the scheduled rent payments for SGS CHF over the lease term considered in TEP's last rate case. As shown in that exhibit, the average annual lease payment was determined to be $22.6 million. Consistent with TEP's last rate case, one-half of that amount is subject to recovery through TEP's PPFAC, while the other half is included in TEP's non-fuel revenue requirement. Of the $11.3 million in non-fuel lease expense, 50% is allocated to SGS Unit 1 and included in the $25.67/kW/month levelized cost recovery for that unit, while the other 50% is allocated to SGS Unit 2.

Q. What options are available to TEP for retaining an interest in the SGS CHF beyond the current lease term?

A. The two remaining lease agreements contain identical purchase and lease renewal options, except that they cover a different facilities ownership percentage. Under each lease, the Company has the option of purchasing the facilities for a fixed price at the end of the lease term, or it can elect a fixed-rate renewal of the lease for a six-year term if TEP has a senior long-term debt rating of at least BBB+ from Standard & Poor's and Baa1 from Moody's. At the end of the six-year renewal term the Company could then choose to either purchase the facilities at a lower fixed price or renew the lease based on the fair market rental value of the facilities.

Q. Does TEP intend to exercise its purchase option for the SGS CHF at the end of the current lease term?

A. Yes. The Company currently cannot predict whether it will be able to meet the minimum credit rating required for the lease renewal option. Additionally, if the Company purchases the facilities, the owner of SGS Unit 4 will be contractually obligated to purchase a portion of the facilities from TEP, thereby offsetting the cost to the Company and its customers. Under a similar agreement, the owner of SGS Unit 3 will have the option of either purchasing its share of the facilities from TEP or continuing to make periodic payments to the Company for use of the facilities. Under the fixed purchase price option, the total cost of acquiring the 86.7% of the CHF not already owned by TEP is contractually set at $120.3 million before consideration of any offsetting payments to be received from the owners of SGS Units 3 & 4. Assuming the owners of SGS Units 3 & 4 purchase their share of the CHF, the net cost to TEP of acquiring this 86.7% interest would be $73 million, resulting in savings of $47 million to TEP and its customers. TEP has until April 2014 to elect either the fixed purchase price option or the fixed-rate lease renewal option.

Q. Assuming the Company purchases the SGS CHF in 2015, when would TEP seek rate-base treatment for that investment?

A. The Company would seek rate-base treatment for the SGS CHF in a future rate case.

C. <u>SGS Common Facilities Lease.</u>

Q. Please describe the long-term lease arrangement for the SGS Common Facilities.

A. TEP leases a 50% undivided interest in the common facilities under three separate lease agreements that expire in 2017 and 2021. The three lease agreements are nearly identical, except that each lease covers a different ownership share and has different scheduled rent payments. In my testimony, I will refer to these three lease agreements collectively as the Common Facilities lease. As described earlier, the other 50% undivided interest in common facilities is leased by TEP pursuant to the SGS Unit 1 lease.

Under the terms of the Common Facilities lease, rent is paid semi-annually by TEP to a trustee. This trustee then uses the rent proceeds to pay principal and interest on lease debt that was issued in connection with the original sale and leaseback transaction, and then distributes any remainder to the owner participants who have an equity interest in the lease agreement. Since the lease debt issued in connection with this lease is variable rate, the lease payments vary based on changes in the underlying variable interest rate.

Q. How is the Common Facilities lease accounted for?

A. For financial reporting purposes, it is accounted for as a capital lease obligation. The same method of expense recognition described earlier for a 75% share of the SGS CHF lease is also applied to this lease obligation. For rate-making purposes, the Common Facilities lease is accounted for as an operating lease and included in TEP's revenue requirement as an operating expense. The amount of SGS Common Facilities rent expense included in the Company's last rate case was based on the average lease payment over the primary term of the lease. TEP is proposing a continuation of that same cost recovery method in this rate case.

Q. Does TEP own an equity interest in any of the three separate leases comprising the Common Facilities lease?

A. No, the Company has not purchased any ownership interest from the owner participants in these leases.

Q. Have the scheduled rent payments under the Common Facilities lease changed since TEP's last rate case?

A. Yes. This is due to the variable rate of interest applied to the underlying lease debt. Additionally, since TEP's last rate case, the Company has hedged additional amounts of lease debt for the purpose of limiting TEP's exposure to variable interest rate risk.

Q. Please describe the interest rate hedging agreements that TEP has entered into for the Common Facilities lease debt.

A. In 2006, TEP entered into a fixed-for-floating interest rate swap on $36.8 million principal amount of lease debt. This hedge was required by lenders as a condition to the refinancing of the Common Facilities lease debt that TEP completed that same year. The notional amount of debt hedged declines over time as the underlying lease debt is paid down, with a final maturity of January 2020. Under the swap agreement, TEP pays a 5.77% fixed rate on the specified notional amount and receives an interest rate equal to six month LIBOR, a published benchmark interest rate. Since the Common Facilities lease debt has a variable interest rate tied to six month LIBOR, this swap agreement has the effect of fixing the interest rate paid by TEP on this tranche of lease debt through January 2020.

In May 2009, TEP entered into two additional interest rate swap agreements covering an additional $29.9 million of Common Facilities lease debt. Like the 2006 swap agreement, the notional amount of debt hedged declines over time as the underlying lease debt is paid down. However, the terms of these agreements extend only to mid-2014. Under these agreements, TEP pays 3.32% on one notional amount and 3.18% on the other notional amount, and receives an interest rate equal to six month LIBOR on both notional amounts. Like the 2006 hedging arrangement, these swap agreements have the effect of fixing the interest rate paid by TEP on these tranches of lease debt, albeit only through mid-2014.

Q. Have these additional hedging arrangements been reflected in the lease expense that TEP is requesting in this proceeding?

A. Yes. While the 2006 hedging arrangements were already reflected in TEP's last rate case, the impact of the new swap agreements is also incorporated in the calculation of average lease expense. **Exhibit KCG-4** shows the actual and projected rent payments for the Common Facilities lease over the lease term considered in TEP's last rate case.

Q. How does TEP's requested lease expense differ relative to the amount included in the Company's last rate case?

A. The requested lease expense for the Common Facilities lease is $1.2 million lower. This is the result of lower interest rates on the Common Facilities lease debt, both on an historical and projected basis, relative to the interest rates assumed in TEP's last rate case. As a result, the average lease payment as calculated over the primary term of the lease is now $10.6 million versus the $11.8 million calculated in TEP's last rate case. This reduction is reflected in the lease expense adjustment discussed in Ms. Kissinger's Direct Testimony.

Q. What options are available to TEP for retaining an interest in the Springerville Common Facilities beyond the current lease terms?

A. The Company has a fair market value lease renewal option and a fixed price purchase option under each of the three separate lease agreements. In aggregate, the fixed price to acquire the leased facilities is contractually set at $38 million in 2017 and $68 million in 2021. As with the SGS CHF, the owner of SGS Unit 4 will be contractually obligated to purchase an allocated share of the Common Facilities from TEP if the Company exercises this purchase option. Under a similar agreement, the owner of SGS Unit 3 will have the option of either purchasing its share of the facilities from TEP or continuing to make periodic payments to the Company for use of the facilities. The end result of these contractual arrangements will be a lower net cost of acquiring the Common Facilities for TEP and its customers.

D. Comparison of Operating Lease Expense and Cash Rental Payments.

Q. Please summarize the amount of operating lease expense calculated for the SGS lease obligations.

A. The amount of lease expense calculated for rate-making purposes, which treats each of TEP's long-term lease obligations as operating leases, is summarized as follows:

Operating Lease Expense ($ million)	
SGS Unit 1	$81.1
SGS CHF – Fuel	$11.3
SGS CHF – Non-Fuel	$11.3
SGS Common Facilities	$10.6
Total Expense for Rate-making	$114.3

As previously discussed, the $11.3 million of SGS CHF lease expense allocated to fuel expense is subject to recovery through TEP's PPFAC.

Q. How does the $114 million of total operating lease expense compare with the cash rental payments TEP must make over the next several years?

A. In the aggregate, TEP will pay out cash rent averaging $147 million per year for these three leases over the period 2012-2014.[3] Thus, TEP will be paying out much more each year relative to the $114 million in operating lease expense. As may be seen in **Exhibit KCG-2**, cash rental payments for the SGS Unit 1 lease are approximately the same as the $81.1 million of operating lease expense in 2012 and 2013, but are scheduled to increase to $151 million in the final full year of the lease in 2014. As shown in **Exhibit KCG-3**, cash rental payments for the SGS CHF lease exceed the $22.6 million of operating lease expense in each of the final three years of that lease agreement. Finally, as may be seen in **Exhibit KCG-4**, the projected rent payments for the Common Facilities lease are expected to exceed the $10.6 million of operating lease expense by a wide margin over the remaining term of that lease which expires in 2021.

E. Comparison of Operating Lease Expense and Capital Lease Expense.

Q. Mr. Grant, earlier you described the two different methods for lease accounting that TEP must apply for financial reporting purposes and for rate-making purposes. What is the difference in reported lease expense using these two different methods of accounting?

A. As discussed in the section above, the total amount of operating lease expense for rate-making purposes is $114.3 million. By contrast, the total amount of lease expense under capital lease accounting, which TEP must use for financial reporting purposes, is much lower. The amount of capital lease expense is summarized as follows for 2011 (actual) and 2012 (projected):

[3] Includes $6.0 million to be paid in January 2015 under the CHF lease, which is scheduled to expire in April 2015. Excludes $14.8 million of payments that TEP prefunded through its prior purchase of a $13.3% undivided interest in the CHF.

Capital Lease Expense ($ million)	2011	2012
Interest Expense		
SGS Unit 1	$30.5	$24.6
SGS CHF – Fuel	3.5	2.7
SGS CHF – Non-Fuel	3.5	2.7
SGS Common Facilities	6.4	6.3
Total	$43.8	$36.2
Amortization Expense		
SGS Unit 1	$7.2	$7.2
SGS CHF – Fuel	3.4	4.2
SGS CHF – Non-Fuel	3.7	4.2
SGS Common Facilities	2.4	2.4
Total	$16.7	$18.0
Total Lease Expense per GAAP	$60.5	$54.2

Q. Why is there such a large difference in lease expense under these two different accounting methods?

A. As I discussed previously, the interest method of capital lease accounting that is applied to the SGS Unit 1 lease and a portion of the SGS CHF lease results in a lower amount of lease interest expense over time as the lease obligation is reduced through continued rent payments. Consequently, with straight-line amortization of the capital lease asset, the total amount of lease expense reported under this method of capital lease accounting will be higher in the early years of a lease and much lower as the lease approaches its termination date. By contrast, the operating lease method of accounting used for rate-making purposes results in a levelized amount of lease expense, which is equal to the average rent payment over the life of the lease, or in the case of SGS Unit 1, over the period 2009 – 2014 used in TEP's last rate case. Since all of TEP's long-term lease obligations are nearing their expiration dates, the difference in lease expense under these two different accounting methods is much more pronounced than it was in previous years.

Q. Why is this difference in reported lease expense important to consider?

A. The use of different accounting methods for rate-making purposes and financial reporting purposes causes significant timing differences in expense recognition. During the later years of a long-term lease obligation, the amount of operating lease expense used for rate-making purposes will exceed the amount of capital lease expense reported under GAAP. As shown in the table above, total capital lease expense reported by TEP during 2011 for the SGS lease obligations was $60.5 million. By contrast, the amount of operating lease expense calculated in a manner consistent with TEP's last rate case totals $114.3 million. As a result, this additional $53.8 million of lease expense caused TEP's net income to be much lower on a regulated basis relative to the Company's reported net income under GAAP.

VI. <u>AMORTIZATION OF LEASEHOLD IMPROVEMENTS AT SGS.</u>

Q. How much does TEP have invested in leasehold improvements at SGS?

A. At the end of the test year, TEP had accumulated a $122 million balance of leasehold improvements at SGS, net of accumulated amortization expense. Over the years, TEP has made numerous capital improvements to SGS Unit 1, the SGS CHF and the SGS common facilities. These improvements have been made in order to keep the facilities in good operating condition and to improve operating efficiencies at SGS.

Q. How were SGS leasehold improvements treated in TEP's last rate case?

A. These improvements were included in rate base at their original cost, net of accumulated amortization. Amortization of the leasehold improvements was also included in the Company's non-fuel revenue requirement using a time period that approximated the remaining number of years under each respective lease agreement.

Q. Is it reasonable to use a "remaining life of lease" approach in calculating amortization expense in this rate case?

A. That approach still seems reasonable for leasehold improvements made to the SGS common facilities, since the current lease term for those facilities does not expire until 2021. However, for SGS Unit 1 and the CHF, the rate impact of using amortization periods equal to the remaining lives of the leases would be too great since both leases expire in early 2015.

Q. What amortization period is TEP recommending for leasehold improvements made to SGS Unit 1 and the SGS CHF?

A. TEP is recommending a 10-year amortization period for these leasehold improvements. This time period represents a reasonable balance between TEP's need for timely cost recovery and the Company's desire to limit the near-term rate increase on customers. Additionally, if cost recovery were pushed beyond ten years, this could have adverse consequences for TEP from a financial accounting perspective.

VII. <u>SUMMARY OF SCHEDULE D-2.</u>

Q. Please describe Schedule D-2 in the Company's Application.

A. 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, 2011. Schedule D-2, page 2, contains a projection of the Company's cost of debt as of December 31, 2012. Schedule D-2 contains detailed information on TEP's cost of long-term debt.

Q. Does this conclude your direct testimony?

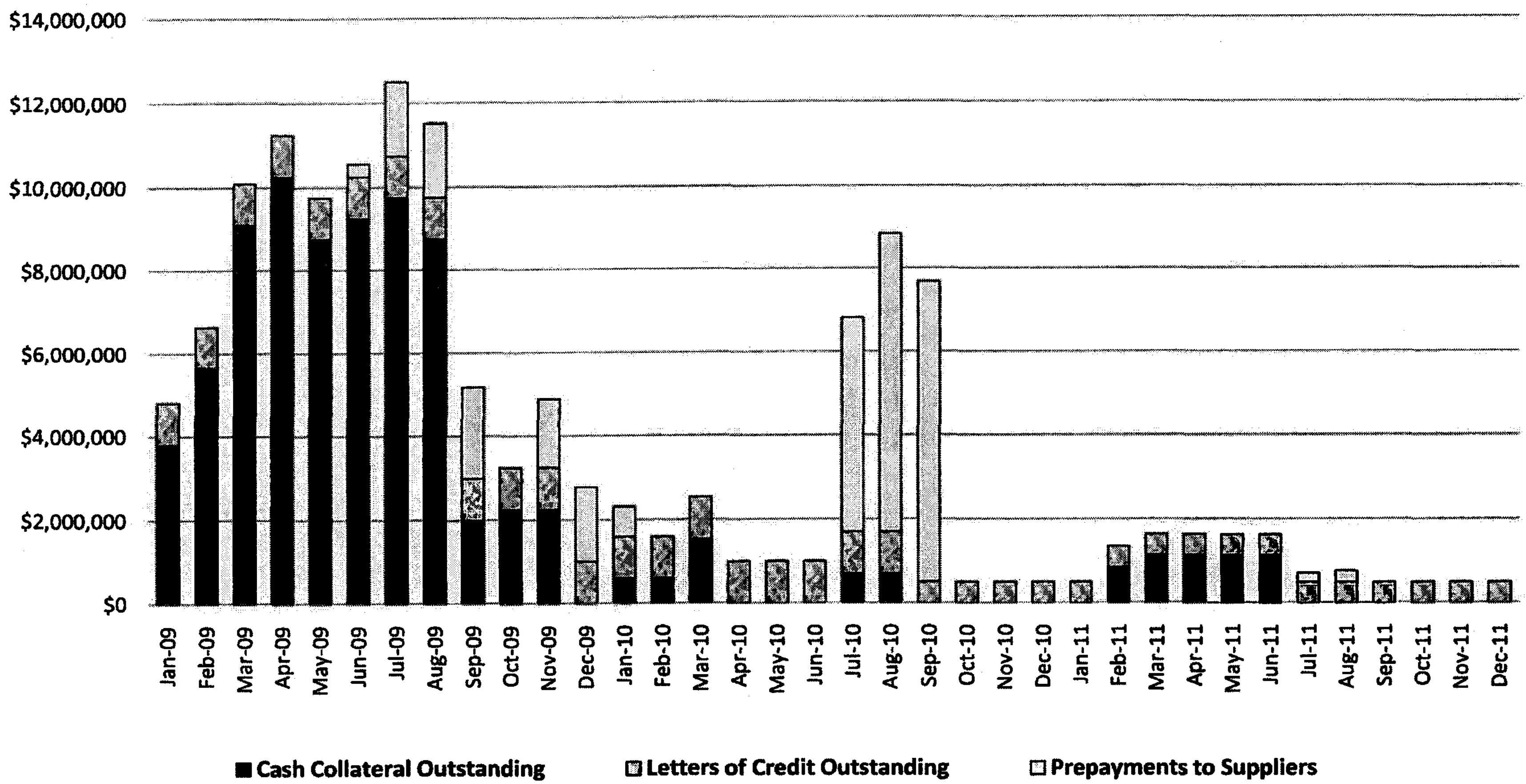
A. Yes, it does.

EXHIBIT

KCG-1

Exhibit KCG-1

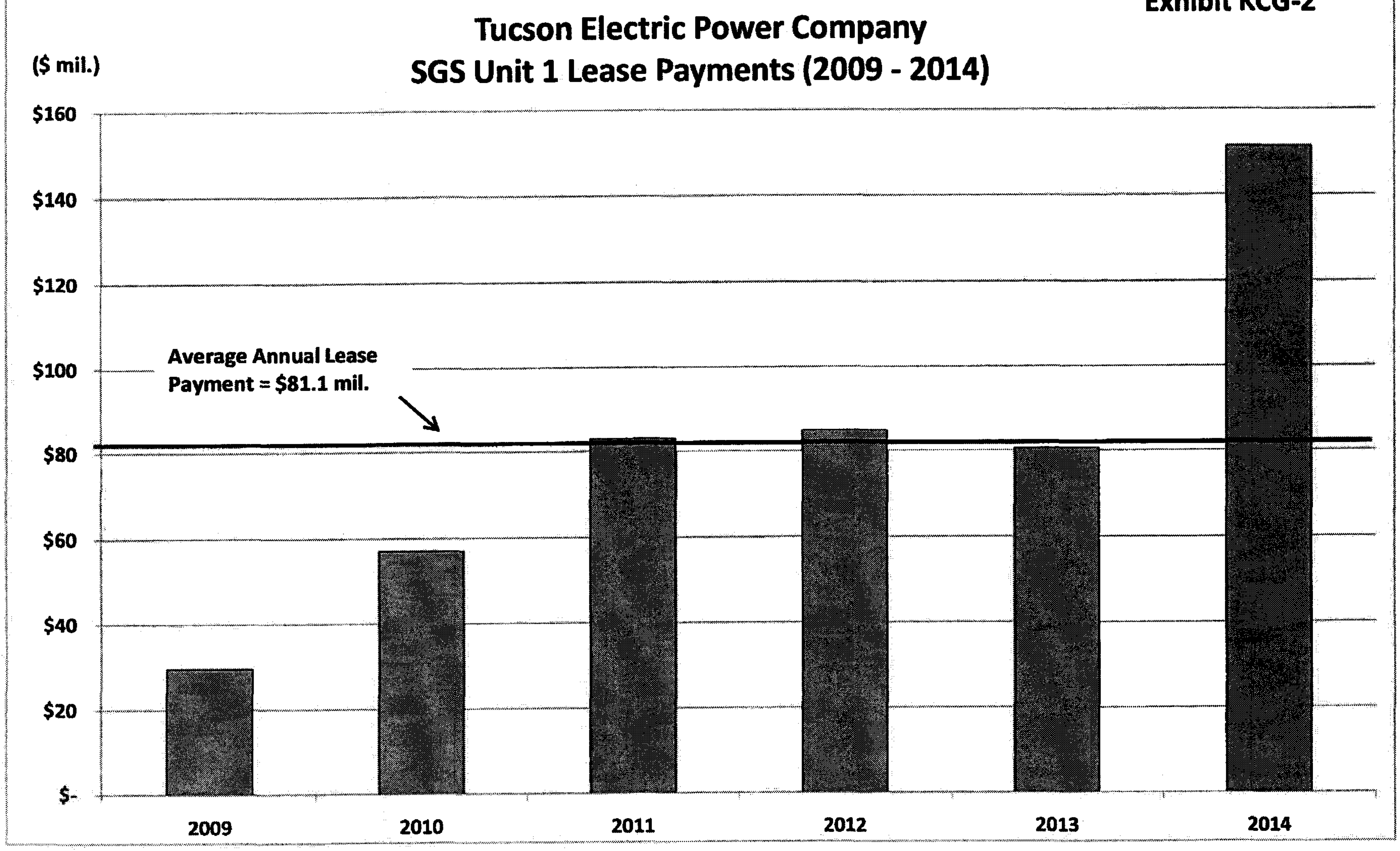
Tucson Electric Power Company
Credit Support Required for Fuel & Power Procurement



EXHIBIT

KCG-2

Exhibit KCG-2

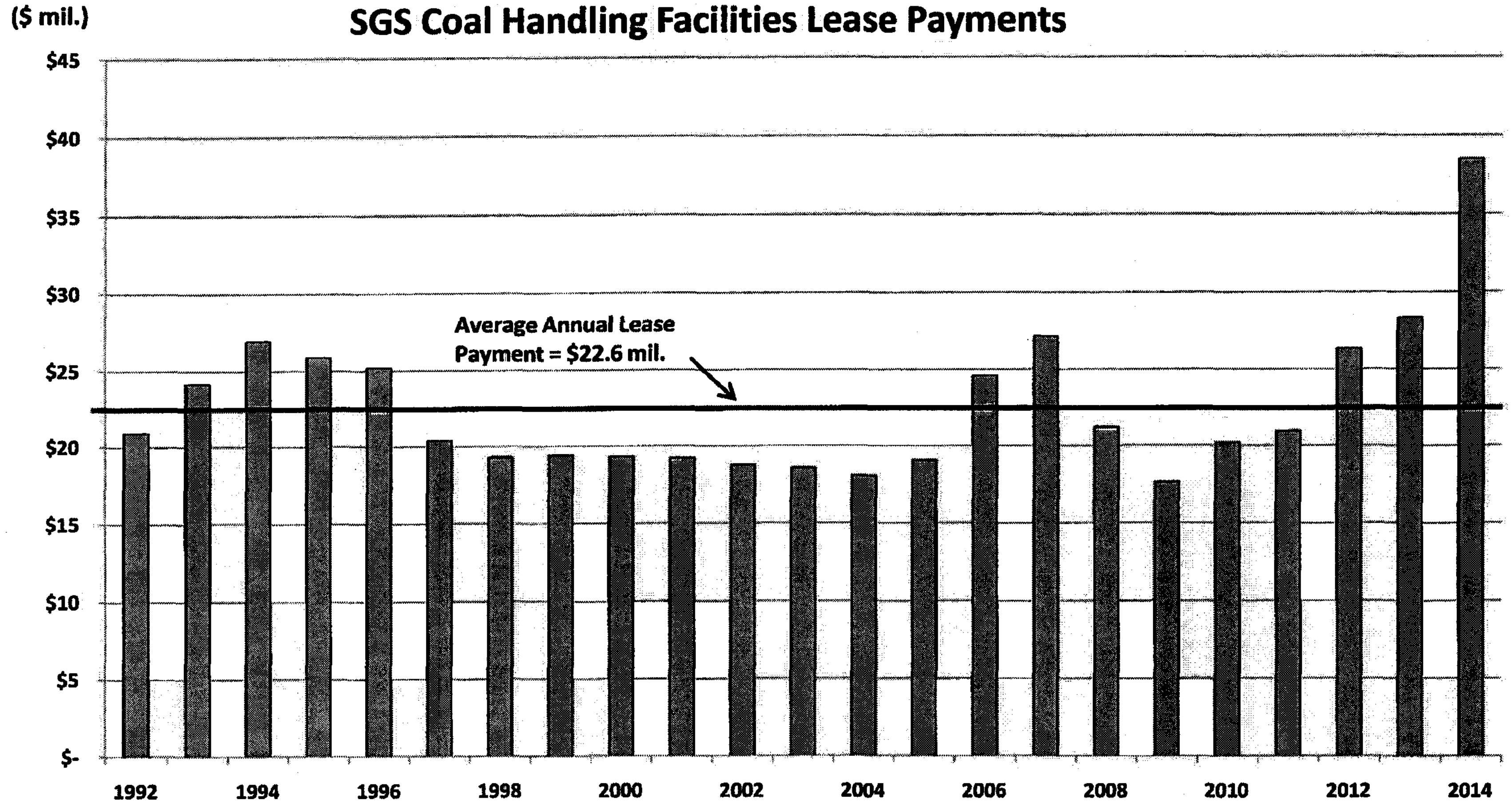


EXHIBIT

KCG-3

Exhibit KCG-3

Tucson Electric Power Company
SGS Coal Handling Facilities Lease Payments

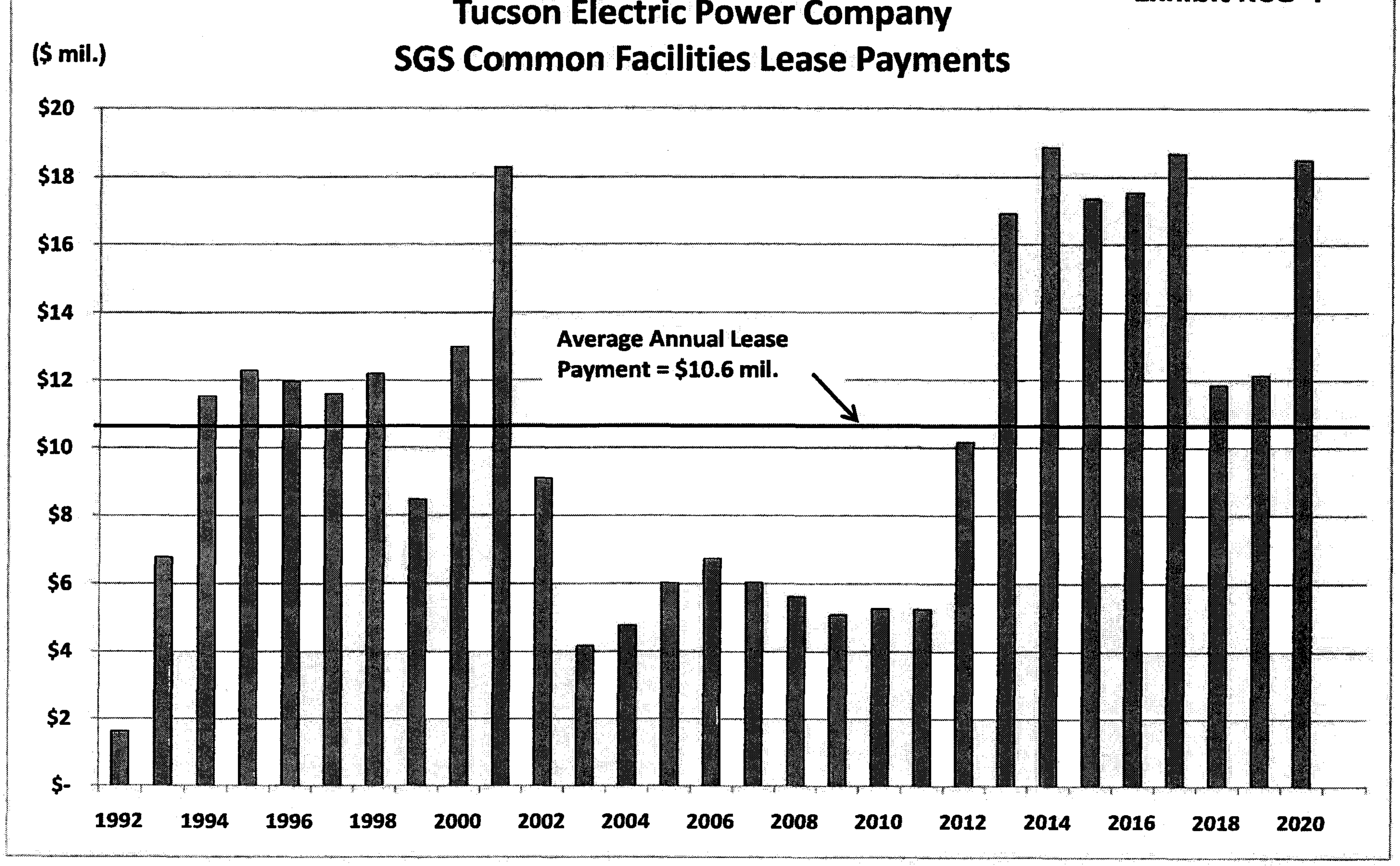


Notes: Payments include scheduled lease payments on 13.3% lease interest purchased by TEP in 2002.
Lease payment scheduled for January 2015 is shown paid in 2014, consistent with calculation in TEP's last rate case.

EXHIBIT

KCG-4

Exhibit KCG-4



Direct Testimony of John J. Reed

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
GARY PIERCE- CHAIRMAN
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

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-12-____

Direct Testimony of

John J. Reed

on Behalf of

Tucson Electric Power Company

July 2, 2012

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Of
Direct Testimony
Of
John J. Reed

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BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
Of
John J. Reed

I. INTRODUCTION.

Q. 1 Please state your name, affiliation, and business address.

A. 1 My name is John J. Reed. I am Chairman and Chief Executive Officer ("CEO") of Concentric Energy Advisors, Inc. ("Concentric") and CE Capital, Inc. located at 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. 2 On whose behalf are you submitting this testimony?

A. 2 I am submitting this testimony on behalf of Tucson Electric Power Company ("TEP" or the "Company").

Q. 3 Please describe your educational background and professional experience in the energy and utility industries.

A. 3 I have more than 35 years of experience in the energy industry, and have worked as an executive in, and consultant and economist to, the energy industry for the past 30 years. Over the past 23 years, I have directed the energy consulting services of Concentric, Navigant Consulting and Reed Consulting Group. I have served as Vice Chairman and Co-CEO of the nation's largest publicly-traded consulting firm and as Chief Economist for the nation's largest gas utility. I have provided regulatory policy and regulatory economics support to more than 100 energy and utility clients and have provided expert testimony on regulatory, economic and financial matters on more than 150 occasions before the Federal Energy Regulatory Commission ("FERC"), Canadian regulatory agencies, state utility regulatory agencies, various state and federal courts, and before arbitration panels in the United States and Canada. My background is presented in more detail in **Attachment A.**

Q. 4 Please describe Concentric's and CE Capital's activities in energy and utility engagements.

A. 4 Concentric provides financial and economic advisory services to many and various energy and utility clients across North America. Our regulatory economic and market analysis services include utility rate-making and regulatory advisory services, energy market assessments; market entry and exit analysis, corporate and business unit strategy development, demand forecasting, resource planning, and energy contract negotiations. Our financial advisory activities include both buy and sell side merger, acquisition and divestiture assignments, due diligence and valuation assignments, project and corporate finance services, and transaction support services. In addition, we provide litigation support services on a wide range of financial and economic issues on behalf of clients throughout North America. CE Capital is a fully registered broker-dealer securities firm specializing in merger and acquisition activities. As CEO of CE Capital, I hold several securities licenses that cover all forms of securities and investment banking activities.

II. PURPOSE AND OVERVIEW OF TESTIMONY.

Q. 5 What is the purpose of your testimony?

A. 5 The purpose of my testimony is to present evidence and provide a recommendation regarding the Company's return on equity ("ROE").[1] My analyses and recommendations are supported by the data presented in **Exhibit JJR-1 through Exhibit JJR-12**, which have been prepared by me or under my supervision.

Q. 6 What are your conclusions regarding the appropriate cost of equity for the Company?

A. 6 My analyses indicate that the Company's cost of equity is currently within the range of 11.00%to 11.50%. I agree with the Arizona Corporation Commission's ("Commission") position as noted in its 2007 decision in an Arizona Public Service Company ("APS") case that considering the Discounted Cash Flow ("DCF") results

[1] Throughout my testimony, I interchangeably use the terms "ROE" and "cost of equity."

alone would not result in an appropriate cost of equity under current circumstances.[2] Therefore, I base my recommendation on the results of several quantitative methodologies and qualitative analyses discussed throughout my testimony. Considering the results of those analyses, I believe that a reasonable ROE for TEP is 11.25%. The Company, seeking to moderate the effect of the rate increase on its customers, has elected to request a ROE of 10.75%.

Q. 7 Please provide a brief overview of the analysis that led to your ROE recommendation.

A. 7 As discussed in more detail in Section VI, in developing my ROE recommendation, I applied the Constant Growth and Multi-Stage forms of the DCF model, the Capital Asset Pricing Model ("CAPM"), and the Risk Premium approach.

In addition to the analyses discussed above, my recommendation also takes into consideration: (1) the regulatory environment in which the Company operates; (2) the Company's capital expenditure plan; and (3) the Lost Fixed Cost Recovery ("LFCR") mechanism proposed by TEP. Finally, I considered the Company's proposed capital structure as compared with the capital structures of the proxy companies. While I did not make any specific adjustments to my ROE estimates for each of those factors, I did take them into consideration in aggregate when determining where the Company's ROE falls within the range of analytical results.

Q. 8 How is the remainder of your testimony organized?

A. 8 The remainder of my testimony is organized in eleven sections. Section III provides a summary of my results and conclusions. Section IV reviews the regulatory guidelines and financial considerations pertinent to the development of the cost of capital. Section V discusses the current capital market conditions and the effect of those conditions on the Company's cost of equity. Section VI explains my selection of a proxy group of electric utilities. Section VII describes my analyses and the analytical basis for the recommendation of the appropriate ROE for TEP. Section VIII provides a discussion of specific regulatory and financial risks that have a direct bearing on the ROE to be

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[2] Arizona Corporation Commission, Decision No. 69663, Docket No. E-01345A-05-0816, June 28, 2007, at 49.

authorized for the Company in this case. Section IX discusses the capital structure of the Company as compared with the proxy group. Section X discusses the effect of the Company's proposed LFCR on the ROE. Section XI presents my conclusions and recommendation for the market cost of equity. Section XII discusses my analysis of the Company's proposed fair value rate base ("FVRB"), and Section XIII discusses the estimation of the fair value rate of return ("FVROR").

III. SUMMARY OF ANALYSIS AND CONCLUSIONS.

Q. 9 Please summarize the key factors considered in your analyses and upon which you base your recommended ROE.

A. 9 My analyses and recommendations considered the following:

- The *Hope* and *Bluefield* decisions[3] that established the standards for determining a fair and reasonable allowed ROE including consistency of the allowed return with other businesses having similar risk, adequacy of the return to provide access to capital and support credit quality, and that the end result must lead to just and reasonable rates.
- The effect of current capital market conditions on investors' return requirements.
- The Company's financial profile as compared with the proxy group, including its credit rating and capital structure.
- The Company's business risks relative to the proxy group of comparable companies and the implications of those risks in arriving at the appropriate ROE.

Q. 10 Please explain how you considered those factors.

A. 10 As discussed in the remainder of my testimony, I have relied on several analytical approaches to estimate the Company's cost of equity based on a proxy group of publicly traded companies. As shown in Table 1, below, there is a range of returns that results from those ROE estimation approaches.

[3] *Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia,* 262 U.S. 679 (1923); *Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S. 591 (1944).

My conclusion as to where within that range of results TEP's ROE should be placed is based on TEP's business and financial risk relative to a proxy group of companies. While my proxy group is generally comparable to TEP in several important ways, TEP faces significantly greater risk than that group in certain areas. In particular, TEP's below-average credit rating and lower equity ratio create greater financial risk for TEP than the proxy companies. In order to be able to compete with the proxy companies for capital, those additional risk factors must be acknowledged and reflected in a higher ROE for TEP than the average for the proxy group.

Other factors also create greater risk for TEP than the proxy companies, specifically regulatory risk, regulatory lag and the Company's capital investment plan. Investors place significant emphasis on regulatory conditions and the ability of the regulatory process to provide companies the opportunity to earn the equity return that is authorized. In Section VIII of my testimony, I apply the Standard & Poor's regulatory ranking system to TEP and the proxy companies. From that analysis, I conclude that TEP faces significantly higher regulatory risk than the average of the proxy companies, which must also be considered in establishing the appropriate ROE for TEP.

Furthermore, I considered the additional financial risk related to the Company's capital investment plan as compared to the proxy group. The Company's capital spending plan through 2016 includes approximately $2.02 billion of investment, including upgrades, reinforcements, and expansion of the distribution and transmission systems, additional generation, environmental upgrades to generation assets and information technology improvements.[4] As discussed in Section VIII of my testimony, the Company's capital investment plan is 1.64 times the median investment level of the proxy companies.[5] In addition to the investment being substantially larger than the median of the proxy companies, TEP has indicated that it will need to access capital to finance the plan. The Company's substantial capital investment program could adversely affect the Company's risk profile in two related ways: (1) the heightened level of investment increases the risk of under recovery, or delayed recovery of the invested capital; and (2)

[4] The Company's capital investment plan is discussed in greater detail in the testimony of Mr. Michael J. DeConcini.

[5] The relative investment is measured as a percentage of total net plant.

an inadequate return would put downward pressure on key credit metrics, at a time when the Company has a below average rating and is expected to raise significant amounts of new capital.

Q. 11 Please summarize the ROE estimation models that you considered to establish the range of ROEs for TEP.

A. 11 I considered the results of two forms of the DCF model; the Constant Growth and the Multi-Stage DCF model. In addition, I considered two risk premium approaches, the CAPM and a Bond Yield Risk Premium methodology. Finally, I considered the effect of the difference between the Company's capital structure and the proxy companies. The results of my analyses are summarized in Table 1.

Table 1: Summary of Analytical Results

	Mean Low	**Mean**	**Mean High**
Constant Growth DCF			
30-Day Average	9.70%	10.81%	12.00%
90-Day Average	9.66%	10.77%	11.95%
180-Day Average	9.76%	10.87%	12.06%
Multi-Stage DCF			
30-Day Average	9.65%	10.59%	12.15%
90-Day Average	9.65%	10.55%	11.93%
180-Day Average	9.77%	10.67%	12.02%
CAPM			
	Current Risk Free Rate (3.24%)	**2012-2013 Projected Risk Free Rate (3.58%)**	**2013-2017 Projected Risk Free Rate (5.10%)**
Bloomberg	10.33%	10.42%	10.83%
Value Line	10.35%	10.44%	10.85%
Bond Yield Plus Risk Premium			
	Low	**Mean**	**High**
Risk Premium	10.16%	10.44%	10.87%

Q. 12 What is your recommended ROE for TEP?

A. 12 The analytical results presented in Table 1 provide the range of results for the proxy group companies. However, TEP has much higher risk than the proxy companies based on the following four criteria (1) capital structure, (2) credit rating, (3) regulatory risk and (4) capital investments. In light of that fact, it is my view that the Company's return should be above the mean result for the proxy group. Based on the analytical results presented in Table 1, I believe a reasonable range of estimates is from 11.00% to 11.50%, and within that range, an ROE of 11.25% is reasonable and appropriate. The Company, seeking to moderate the effect of the rate increase on its customers, is proposing a ROE of 10.75%.

Q. 13 Did you consider the effect of the Company's proposed LFCR on the ROE?

A. 13 Yes. As with each of the other business and financial risks discussed above, I considered the Company's proposed LFCR as compared with the revenue stabilization mechanisms that have been implemented by the proxy companies. I concluded that to the extent that investors attribute a specific increment of the required ROE to revenue stabilization, because each of the proxy companies has some form of stabilization mechanism, the effects of revenue stabilization were already included in the results of the ROE estimation models. Therefore, I have not made any reduction in the ROE for TEP as a result of the Company's proposed LFCR.

Q. 14 Please summarize the analysis that you conducted to validate the FVRB for TEP.

A. 14 Consistent with Commission precedent, the Company has estimated the FVRB by weighting equally its Original Cost Rate Base ("OCRB") and an estimate of the Replacement Cost New Depreciated ("RCND") of those assets. In my testimony I relied on two market comparable approaches to test the FVRB that is being relied on in the FVROR analysis; a Comparable Transactions analysis, and a market value of the proxy group.

I estimated the market value of TEP's assets by comparing the Company's FVRB estimate to the market value of comparable companies in recent arms-length transactions. To create a consistent basis of comparison among the transactions (which took place amid different market conditions), I normalized the transaction values using the corporate value of the acquired company, which incorporates the book value of debt and equity, resulting in a premium to corporate value resulting from the transactions. I estimated the market value of TEP's assets by applying the median premium of 49.46% to the Company's OCRB. That analysis resulted in an estimated market value for TEP's assets of $2.270 billion.

I also considered a Market Multiples analysis based on the value of the proxy companies. In that analysis, I estimated the Implied Market Value of the proxy companies and normalized that value by the proxy companies' Net Plant, resulting in a multiple of Implied Market Value to Net Plant ("IMP/NP"). The Implied Market Value was estimated by calculating the transaction premium over enterprise value for the transactions discussed above and applying that premium to the 30-day average of the proxy companies' enterprise value as of April 30, 2012. I estimated the market value of TEP's assets by applying the IMV/Net Plant multiple for the proxy companies to TEP's net plant. That analysis results in a range of value from $1.886 billion to $3.018 billion with a median of $2.171 billion. The Company's FVRB estimate of $2.280 billion falls within that range.

Q. 15 What do you conclude from those analyses?

A. 15 Based on the results of those analyses, I conclude that the Company's estimated FVRB of $2.280 billion is reasonable.

Q. 16 How did you estimate the FVROR?

A. 16 I estimated the FVROR using the approach relied on by the Commission in several recent rate cases. In applying that method, I also conclude that the minimum rate of return ("ROR") that should be applied to the fair value "increment" of rate base is the real risk-free ROR, which I estimate to be 3.12%. Notwithstanding the market expectation that the risk-free rate should represent the floor on investments that are not risk-free, in an attempt to moderate the effect of a rate increase on customers, the Company has proposed the use of 50.00% of the risk-free rate in the estimate of the

FVROR calculation to moderate the effect of the rate increase on its customers. As shown in Table 2 below, the result of that analysis is a FVROR of 5.68%.

Table 2- Estimation of the FVROR

Capital	($ Million)	Percent	Cost Rate	Weighted Cost Rate
FVRB	$2,280			
OCRB	$1,519			
RCND	$3,041			
Long-Term Debt	$820	35.97%	5.18%	1.86%
Common Equity	$699	30.65%	10.75%	3.29%
Fair Value Increment	$761	33.38%	1.56%	0.52%
Total	$2,280	100.00%		5.68%

IV. REGULATORY GUIDELINES AND FINANCIAL CONSIDERATIONS.

Q. 17 Please describe the guiding principles to be considered in establishing the cost of capital for a regulated utility.

A. 17 The United States Supreme Court's precedent-setting *Hope* and *Bluefield* cases established the standards for determining the fairness or reasonableness of a utility's allowed ROE. Among the standards established by the Court in those cases are: (1) consistency with other businesses having similar or comparable risks; (2) adequacy of the return to support credit quality and access to capital; and (3) the principle that the specific means of arriving at a fair return are not important, only that the end result leads to just and reasonable rates.[6]

Q. 18 Has the Commission provided similar guidance in establishing the appropriate return on common equity?

A. 18 Yes. The Commission has noted that under the Arizona Constitution, a public utility is entitled to a fair return on the fair value of its property devoted to public uses. The Commission is required to find the fair value of the utility's property and to use that value to establish just and reasonable rates.[7]

6 *Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia,* 262 U.S. 679 (1923); *Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S. 591 (1944).

7 Arizona Corporation Commission, Decision No. W-02113A-04-0616, *Chaparral City Water Company,* February 13, 2007, at 11. References Ariz. Water co., 85 Ariz. at 203, 335, P.2d at 415.

Q. 19 Why is it important for a utility to be allowed the opportunity to earn a return that is adequate to attract equity capital at reasonable terms?

A. 19 There is a long history of precedent regarding the allowed ROE, the role of capital structure, and the resulting cost of capital in establishing just and reasonable rates for utility services. Among the themes common to many such decisions is the principle that a utility's cost of capital (including its capital structure and allowed return on common equity) must reflect other enterprises having comparable risks, and acting independently in the financial markets. As noted elsewhere in my testimony, a return that is adequate to attract capital at reasonable terms enables the Company to provide safe, reliable electric service while maintaining its financial integrity. That return should be commensurate with the returns expected elsewhere in the market for investments of equivalent risk. If it is not, debt and equity investors will seek alternative investment opportunities for which the expected return reflects the perceived risks, thereby impairing the Company's ability to attract capital at reasonable cost rates.

The consequence of the Commission's order in this case, therefore, should be rates that provide the Company with the opportunity to earn a ROE that is: (1) adequate to attract capital at reasonable terms, thereby enabling it to continue to provide safe and reliable electric service; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments in enterprises having corresponding risks. To the extent TEP is provided the opportunity to earn its market-based cost of capital, neither customers nor shareholders are disadvantaged.

V. <u>CAPITAL MARKET ENVIRONMENT.</u>

Q. 20 How do economic conditions influence the required cost of capital and required ROE?

A. 20 The required cost of capital, including the ROE, is a function of prevailing and expected economic and capital market conditions. During times of capital market instability, risk aversion increases, which causes investors to seek the relative safety of U.S. Treasury debt, resulting in lower Treasury yields.

To the extent that observable measures of market instability and risk aversion remain elevated relative to historical norms, it would be incorrect to conclude that the cost of equity has materially decreased. While there is little question that the capital market dislocation that began in late 2008 has moderated, market instability and investor risk aversion remain at comparatively high levels, especially relative to the conditions that existed prior to the 2008-09 financial market dislocation.

Q. 21 What analysis have you conducted to assess current capital market conditions?

A. 21 As discussed in more detail in **Appendix A**, I considered two widely-recognized measures of investor risk sentiment, including: (1) incremental credit spreads; and (2) the relationship between the dividend yields of the proxy group companies and Treasury yields. I compared current market conditions to the two-year period prior to the 2007-2009 recession (*i.e.*, January 2006 through November 2007), and to the capital market contraction period of 2002-2003. As shown in Table 3, those metrics indicate that current levels of instability and risk aversion are significantly higher than the levels observed prior to the recent recession, and the levels experienced during the 2002-2003 capital market contraction.

Table 3: Risk Sentiment Indicators[8]

	April 30, 2012[9]	**Pre-recession (Jan-2006 through Nov-2007)**	**Jan-2002 through Dec-2003**
Credit Spreads (Moody's Utility Bond Index) Baa-rated bond to A-rated bond	0.69%	0.25%	0.46%
Dividend Yield Spreads 10-year Treasury to Proxy Group Dividend Yield	-2.07%	0.51%	-1.47%

Q. 22 What conclusions do you draw from those analyses?

A. 22 Those analyses clearly demonstrate that current market conditions are similar to the 2002-2003 market dislocation that affected all market segments, including utilities. One outcome of the 2002-2003 market dislocation was a renewed emphasis on capital market access and the importance of maintaining a strong financial profile, both of

8 Source: Bloomberg Professional Service.

9 90-trading day average as of April 30, 2012, except as noted otherwise.

which are equally important in the current market environment. The result of market instability and risk aversion, of course, is an increased, not a decreased equity risk premium and cost of capital. The extent of that uncertainty manifested, at least in part, in the significant decrease in long-term Treasury yields since Standard and Poor's ("S&P") downgraded U.S. sovereign debt on August 5, 2011. Even though that ratings action would call into question the meaning and application of the "Risk Free Rate", investors still have sought safety in Treasury securities. In summary, market instability and measures of risk aversion remain above historical norms.

Q. 23 How should current economic conditions be taken into consideration in determining the appropriate ROE for the Company?

A. 23 First, based on the continuing capital market instability, it is important to assess the reasonableness of any financial model's results in the context of observable market data. To the extent that certain ROE estimates are incompatible with such metrics or inconsistent with basic financial principles, it is appropriate to consider whether alternative estimation techniques are likely to provide more meaningful and reliable results.

Second, in my view, the authorized ROR in this proceeding will provide a signal to the financial community concerning the ability of the Company to meet its capital needs during a period in which its capital investments are increasing. If investors perceive a supportive regulatory environment, as evidenced by an allowed ROR that compensates the Company at a level commensurate with its risk, the Company should be able to attract equity capital at a reasonable cost. Conversely, if investors perceive a lack of connection between the allowed ROR and current economic conditions, the regulatory environment would be seen as less supportive.

VI. PROXY GROUP SELECTION.

Q. 24 Why have you used a group of proxy companies to determine the cost of equity for TEP?

A. 24 First, it is important to bear in mind that the cost of equity for a given enterprise depends on the risks of the business in which the company is engaged. According to financial theory, the aggregate value of a given company is equal to the weighted average market value of the constituent business units. The value of the individual business units reflects the risks and opportunities inherent in the business sectors in which those units operate. In this proceeding, I am estimating the cost of equity for TEP, which is a rate-regulated subsidiary of UNS Energy Corporation ("UNS Energy"). Since the ROE is a market-based concept, and given the fact that TEP's operations do not make up the entirety of the publicly traded entity, it is necessary to establish a group of companies that are both publicly traded and comparable to TEP in certain fundamental business and financial respects to serve as its "proxy" for purposes of the ROE estimation process.

Even if TEP's regulated electric operations made up the entirety of the publicly traded entity, it is possible that transitory events could bias its market value in one way or another over a given period of time. A significant benefit of using a proxy group, therefore, is its ability to mitigate the effects of anomalous events that may be associated with any one company. As discussed later in my testimony, the proxy companies used in my analyses all possess a set of operating and risk characteristics that are substantially comparable to TEP's regulated electric operations, and thus provide a reasonable basis for the derivation and assessment of ROE estimates.

The importance of selecting a proxy group that is similar in overall financial and business risk to the subject company was endorsed by the United States Court of Appeals for the District of Columbia (the "Court of Appeals") in the *Petal Gas Storage* decision. The Court of Appeals acknowledged that the goal of a proxy group is to rely on companies that possess similar risk to the subject company for the determination of the cost of equity:

> That proxy group arrangements must be risk-appropriate is the common theme in each argument. The principle is well-established. *See Hope Natural Gas Co.*, 320 U.S. at 603 ("[T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."); *CAPP I*, 254 F.3d at 293 ("[A] utility must offer a risk-adjusted expected rate of return sufficient to attract investors."). The principle captures what proxy groups do, namely, provide market-determined stock and dividend figures from public companies comparable to a target company for which those figures are unavailable. *CAPP I*, 254 F.3d at 293–94. Market determined stock figures reflect a company's risk level and, when combined with dividend values, permit calculation of the "risk-adjusted expected rate of return sufficient to attract investors."[10]
>
> ***
>
> What matters is that the overall proxy group arrangement makes sense in terms of relative risk and, even more importantly, in terms of the statutory command to set "just and reasonable" rates, 15 U.S.C. § 717c, that are "commensurate with returns on investments in other enterprises having corresponding risks" and "sufficient to assure confidence in the financial integrity of the enterprise . . . [and] maintain its credit and . . . attract capital," *Hope Natural Gas Co.*, 320 U.S. at 603.[11]

Thus, both regulatory commissions and financial analysts recognize the importance of developing a proxy group that adequately represents the ongoing risks and prospects of the subject company.

Q. 25 Please provide a brief profile of TEP.

A. 25 TEP generates, transmits and distributes electric service to approximately 404,000 retail customers in southeastern Arizona.[12] As of December 31, 2011, TEP represented approximately 82% of UNS Energy's assets. TEP currently has speculative-grade Long Term Issuer credit ratings of BB+ from both S&P and Fitch Ratings, and a low investment-grade Issuer credit rating of Baa3 from Moody's Investment Services ("Moody's"). TEP has senior unsecured credit ratings from S&P and Fitch Ratings of

[10] *Petal Gas Storage v. FERC*, 496 F.3d 695, 699 (D.C. Cir. 2007).
[11] *Ibid.*, at 7.
[12] Source: SNL Financial.

BBB- and from Moody's of Baa3, the lowest investment-grade ratings assigned by each of these credit rating agencies.[13]

Q. 26 How did you select the companies included in your proxy group?

A. 26 The proxy group was selected based on the following criteria:

- I began with the group of 53 domestic U.S. utilities that Value Line classifies as Electric Utilities;
- I excluded companies that did not have long-term growth forecasts from at least two utility industry equity analysts;
- I excluded companies that had senior unsecured bond and/or corporate ratings below BB;
- I excluded companies that do not pay cash dividends, because such companies cannot be analyzed using the Constant Growth DCF model, which is the primary model that has been relied on by the Commission;
- I excluded companies that do not own regulated generation assets;
- To ensure a focus on companies that are primarily regulated utilities, I excluded companies whose revenue and net operating income derived from regulated operations both are less than 60% of total reported revenue and net operating income;
- To ensure a focus on companies that are primarily electric utilities, I excluded companies whose regulated electric revenue and net operating income both are less than 90% of total regulated revenue and net operating income; and
- Finally, I excluded any companies that were party to a merger or transformative transaction during the analytical periods considered.

Q. 27 Why did you include below investment grade companies in your proxy group?

A. 27 As noted earlier in my testimony, the fundamental purpose of a proxy group is to select those companies that are most comparable in terms of business and financial risk to the subject company. Since TEP has a speculative grade Long Term Issuer rating from

[13] Source: SNL Financial.

both S&P and Fitch Ratings, I determined that it was appropriate for the proxy group to include companies that have investment grade or below investment grade credit ratings.

Q. 28 Based on those criteria, what was the composition of your proxy group?

A. 28 The criteria discussed above resulted in a proxy group consisting of the thirteen companies provided in Table 4 (below).

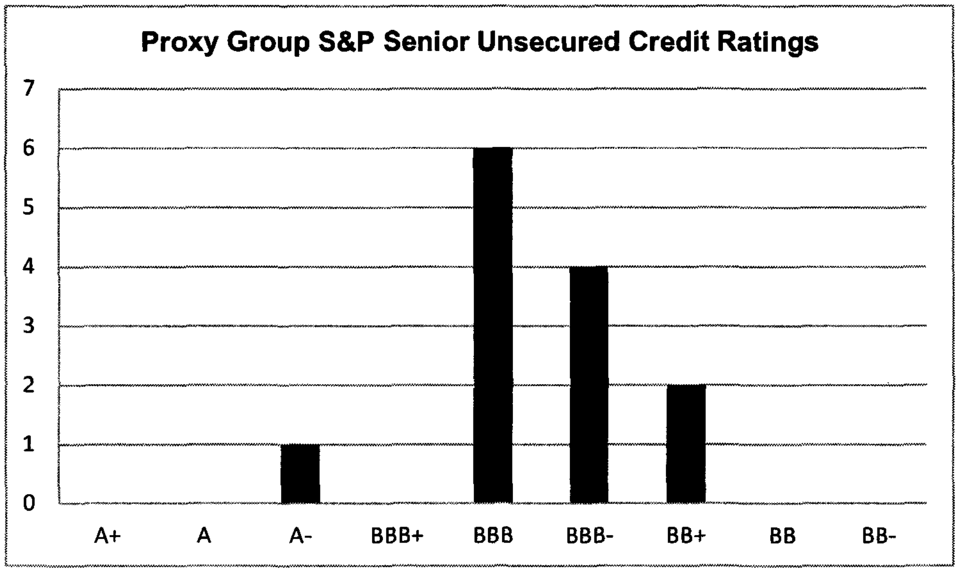
Table 4: Proxy Group

Company	Ticker
American Electric Power	AEP
Cleco Corp.	CNL
Empire District Electric	EDE
Entergy Corp.	ETR
Great Plains Energy Inc.	GXP
Hawaiian Electric	HE
IDACORP, Inc.	IDA
NV Energy, Inc.	NVE
Pinnacle West Capital	PNW
PNM Resources, Inc.	PNM
Portland General	POR
Southern Co.	SO
Westar Energy	WR

As shown in Chart 1 below, the majority of the proxy group companies are rated BBB or above by S&P's. Only NV Energy and PNM Resources have below investment grade senior unsecured credit ratings.[14]

[14] While I recognize that S&P recently upgraded the long-term issuer rating of PNM Resources to BBB-, that company's senior unsecured credit rating is still BB+.

Chart 1- Distribution of Proxy Group Credit Ratings



VII. <u>COST OF EQUITY ESTIMATION.</u>

Q. 29 Please briefly discuss the ROE in the context of the regulated ROR.

A. 29 Regulated utilities primarily use common stock and long-term debt to finance their permanent property, plant, and equipment. The overall ROR for a regulated utility is based on its weighted average cost of capital, in which the cost rates of the individual sources of capital are weighted by their respective book values. While the costs of debt and preferred stock can be directly observed, the cost of equity is market-based and, therefore, must be estimated based on observable market information.

Q. 30 How is the required ROE determined?

A. 30 The required ROE is estimated by using one or more analytical techniques that rely on market-based data to quantify investor expectations regarding required equity returns, adjusted for certain incremental costs and risks. Quantitative models produce a range of reasonable results from which the market required ROE is selected. As discussed throughout my testimony, that selection must be based on a comprehensive review of relevant data and information, and does not necessarily lend itself to a strict mathematical solution. As a general proposition, the key consideration in determining the cost of equity is to ensure that the methodologies employed reasonably reflect investors' view of the financial markets in general, and the subject company (in the context of the proxy group) in particular.

Q. 31 Why do you believe it is important to use more than one analytical approach?

A. 31 When faced with the task of estimating the cost of equity, analysts are inclined to gather and evaluate as much relevant data (both quantitative and qualitative) as can be reasonably analyzed. For that reason, Concentric employs multiple approaches to estimate the cost of equity used in performing valuation analyses in the context of our financial advisory and transaction practices. Furthermore, analysts and academics understand that ROE models are tools to be used in the ROE estimation process and that strict adherence to any single approach, or the specific results of any single approach, can lead to flawed and irrelevant conclusions. That position is consistent with the *Hope* finding that it is the analytical result, as opposed to the methodology, that is controlling in arriving at ROE determinations. Therefore, I have considered the results of the Constant Growth and Multi-Stage form of the DCF model, the CAPM, and the Risk Premium approach.

A. Constant Growth DCF Model

Q. 32 Are DCF models widely used to determine the ROE for regulated utilities?

A. 32 Yes. DCF models are widely used in regulatory proceedings and have sound theoretical bases, although neither the DCF model nor any other model can be applied without considerable judgment in the selection of data and the interpretation of results. In a prior rate order, the Commission stated that the:

> [u]se of the DCF as the primary basis for determining the Company's reasonable estimated cost of equity capital is a methodology that has been used for many years by this Commission, as well as other regulatory commissions across the country.[15]

[15] *In the Matter of the Application of Southwest Gas Corporation for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return of the Fair Value of its Properties of Southwest Gas Corporation Devoted to its Operations throughout Arizona,* Opinion and Order, Arizona Corporation Commission, Docket No. G-01551A-04-0876. February 23, 2006 at 29.

The DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its simplest form, the DCF model expresses the cost of equity as the sum of:

(a) the expected dividend yield and

(b) the long-term growth rate in dividends per share.[16]

The formula for the DCF approach is provided in Appendix A.

Q. 33 What assumptions are required for the Constant Growth DCF model?

A. 33 The Constant Growth DCF model is predicated on the following assumptions: (1) a constant growth rate for dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings multiple; and (4) a discount rate greater than the expected growth rate. To the extent that any of these assumptions is violated, the need to apply considered judgment and/or specific adjustments to the model's results is increased.

B. Dividend Yield for the Constant Growth DCF Model

Q. 34 What market data did you use to calculate the dividend yield in your Constant Growth DCF model?

A. 34 The dividend yield in my Constant Growth DCF model is based on the proxy companies' current annual dividend and average closing stock prices over the 30-, 90- and 180-trading days ended April 30, 2012.

Q. 35 Why did you use three averaging periods for stock prices?

A. 35 I believe it is important to use an average of trading days to calculate the price term in the DCF model to ensure that the calculated ROE is not skewed by anomalous events that may affect stock prices on any given trading day. In that regard, the averaging period should be reasonably representative of expected capital market conditions over the long term. At the same time, it is important to reflect the volatile conditions present in the financial markets over the recent past. In my view, the use of the 30, 90, and 180-day averaging periods reasonably balances those concerns.

16 This form of the DCF model is referred to as the Constant Growth DCF model.

Q. 36 Putting aside the issue of the averaging period, did you make any adjustments to the dividend yield to account for periodic growth in dividends?

A. 36 Yes. Since utility companies tend to increase their quarterly dividends at different times throughout the year, it is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. Given that assumption, it is reasonable to apply one-half of the expected annual dividend growth rate for purposes of calculating the expected dividend yield component of the DCF model. This adjustment ensures that the expected first year dividend yield is, on average, representative of the coming twelve-month period.

C. Growth Rates for the Constant Growth DCF Model

Q. 37 What growth rates have you relied on in applying the Constant Growth DCF model?

A. 37 In its Constant Growth form, the DCF model assumes a single growth estimate in dividends per share in perpetuity. In order to reduce the long-term growth rate to a single measure, one must assume a constant payout ratio, and that earnings per share, dividends per share and book value per share all grow at the same constant rate. This can be accomplished by averaging those measures of long-term growth that tend to be least influenced by capital allocation decisions that companies may make in response to near-term changes in the business environment. Since such decisions may directly affect near-term dividend payout ratios, estimates of earnings growth are more indicative of long-term investor expectations than are dividend or book value growth estimates. Furthermore, earnings are the fundamental driver of a company's ability to pay dividends. Therefore, for the purposes of the Constant Growth form of the DCF model, growth in earnings per share represents the appropriate measure of long-term growth.

Q. 38 Please summarize your inputs to the Constant Growth DCF model.

A. 38 I applied the Constant Growth DCF model to the proxy group of thirteen electric utilities using the following inputs for the price and dividend terms:

1. The average daily closing prices for the 30-, 90-, and 180-trading days ended April 30, 2012 for the stock price; and
2. The annualized dividend per share as of April 30, 2012.

I then calculated the DCF results using a range of growth rates from the following:

1. The Zacks consensus long-term earnings growth estimates;
2. The First Call consensus long-term earnings growth estimates; and
3. The Value Line long-term earnings growth estimates.

D. Multi-Stage DCF Model

Q. 39 What other forms of the DCF model have you considered?

A. 39 In order to address some of the limiting assumptions underlying the Constant Growth form of the DCF model, I also considered the results of a multi-stage DCF model. The multi-stage model, which is an extension of the Constant Growth form, enables the analyst to specify growth rates over multiple stages. As with the Constant Growth form of the DCF model, the multi-period form defines the cost of equity as the discount rate that sets the current price equal to the discounted value of future cash flows. The specific form of the model is presented in Appendix A.

Q. 40 Please generally describe the structure of your multi-stage DCF model.

A. 40 My multi-stage model sets the subject company's stock price equal to the present value of future cash flows received over three "stages." In the first two stages, cash flows are defined as projected dividends. In the third stage, cash flows equal the sum of the dividend and the expected price at which the stock will be sold at the end of the period. I estimated the expected terminal stock price based on the Gordon model, which defines the price as the expected dividend divided by the difference between the cost of equity (*i.e.*, the discount rate) and the long-term expected growth rate. In each of the three stages, the dividend is estimated as the product of the projected earnings per share and the expected dividend payout ratio.

Q. 41 What are the benefits of a three-stage model?

A. 41 The three-stage model allows for a transition from the first stage growth rate to the long-term growth rate, thereby avoiding the often unrealistic assumption that growth will change immediately between the first and final stages. In addition, the three stage model projects dividends as the product of earnings per share and the payout ratio, which recognizes that payout ratios may change over time.

Q. 42 Please summarize the EPS growth rates used in your multi-stage DCF model.

A. 42 I began with the 2011 EPS for the proxy companies as reported by Value Line. In the first stage of the model, EPS is escalated based on the average of the long-term earnings growth estimates reported by Value Line, Zacks and First Call. For the third or terminal stage of the model, I relied on the long-term projected growth in GDP. The second stage growth rate is a transition to the long-term growth rate on a geometric average basis.

Q. 43 Please summarize the payout ratios used in your multi-stage DCF model.

A. 43 I relied on the short term projected payout ratios for the proxy companies as reported by Value Line and assumed that the payout ratios of the proxy companies would converge to the industry average in the third stage of the DCF model.[17]

Q. 44 How did you calculate the long-term GDP growth rate?

A. 44 The long-term growth rate of 5.45% is based on the real GDP growth rate of 3.24% from 1929 through 2011,[18] and a projected inflation rate of 2.14%. The rate of inflation of 2.14% is based on three measures: (1) the average of the long-term projected growth rate in the Consumer Price Index ("CPI") for all urban consumers of 2.30%, as reported by Blue Chip Financial Forecasts;[19] (2) the compound annual CPI growth rate of 2.19% as projected by the Energy Information Administration ("EIA") in the 2011 Annual

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17 The multi-stage DCF model relies on 2012 and 2015 payout ratios and the industry average payout ratio, which begins in 2022 and is held constant for the remainder of the third stage of the DCF model. For 2013 and 2014 and the 2016 through 2021 period, I have escalated the payout ratios on a geometric average basis.

18 Bureau of Economic Analysis, National Economic accounts, December 20, 2011 update.

19 Blue Chip Financial Forecast, Vol. 30 No. 12, December 1, 2011, at 14.

Energy Outlook; and (3) the GDP price index for 2022-2035 of 1.94%, also projected by the EIA.[20]

E. Discounted Cash Flow Model Results

Q. 45 Please summarize the results of your DCF analyses.

A. 45 Table 5 (below), (*see* also **Exhibit JJR-2** and **Exhibit JJR-3**), presents the results of the Constant Growth and Multi-Stage DCF analyses. Based on the company's above average risk profile, which is discussed in Section VIII of my testimony, the Constant Growth DCF model produces a range of results for firms of average to above average risk of between 10.77% to 12.06%. The multi-stage DCF analysis produces a range of results for similar firms from 10.55% to 12.15%.

Table 5: Discounted Cash Flow Analyses Results

	Mean Low	**Mean**	**Mean High**
Constant Growth DCF			
30-Day Average	9.70%	10.81%	12.00%
90-Day Average	9.66%	10.77%	11.95%
180-Day Average	9.76%	10.87%	12.06%
Multi-Stage DCF			
	Low	**Mean**	**High**
30-Day Average	9.65%	10.59%	12.15%
90-Day Average	9.65%	10.55%	11.93%
180-Day Average	9.77%	10.67%	12.02%

Q. 46 Referring to your Constant Growth DCF model, how did you calculate the range of results?

A. 46 I calculated the mean high result for my Constant Growth DCF model using the maximum growth rate (*i.e.*, the maximum of the Zacks, First Call, and Value Line EPS growth rates) in combination with the dividend yield for each of the proxy group companies. Thus, the mean high result reflects the maximum DCF result for the proxy group. I used a similar approach to calculate the mean low results, using the minimum

[20] Energy Information Administration, 2012 Annual Energy Outlook, Table A20 Early Release 2012, Macroeconomic Indicators.

growth rate for each proxy group company. The mean results were calculated using the average of all three sources' growth rates.

Q. 47 Did you undertake any additional analyses to support your DCF model results?

A. 47 Yes. As noted earlier, I also used the CAPM and the Risk Premium approach as a means of assessing the reasonableness of my Constant Growth and Multi-Stage DCF results.

F. CAPM Analysis

Q. 48 Please briefly describe the CAPM.

A. 48 The CAPM is a risk premium approach that estimates the cost of equity for a given security as a function of a risk-free return plus a risk premium (to compensate investors for the non-diversifiable or "systematic" risk of that security).[21] This second component is the product of the market risk premium times the "Beta" term, which measures the relative riskiness of the security being evaluated.

Q. 49 What risk-free rate did you use in your CAPM analysis?

A. 49 Since both the DCF and CAPM models assume long-term investment horizons, I relied on three estimates of the yield on treasury bonds: (1) the current 30-day average yield on 30-year Treasury bonds (*i.e.*, 3.24%); (2) the projected 30-year Treasury yield for 2012 through 2013 of 3.58%; and (3) the projected 30-year Treasury yield for the period from 2013 through 2017 of 5.10% as my estimates of the risk-free rate[22].

Q. 50 How did you estimate the market risk premium in the CAPM?

A. 50 I estimated the Market Risk Premium based on the expected return on the S&P 500 Index, less the 30-year Treasury bond yield. The expected return on the S&P 500 is calculated using the Constant Growth DCF model discussed earlier in my testimony for the companies in the S&P 500 index for which long-term earnings projections are available. Based on an estimated weighted-index dividend yield of 2.13% and a weighted-index long-term growth rate of 10.72%, the estimated required market return

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21 The specific equation of the CAPM is provided in Appendix A.

22 Blue Chip Financial Forecast, Vol. 30, No. 12, December 1, 2011, at 14.

for the S&P 500 index is approximately 12.97%. The implied Market Risk Premium over the current 30-day average of the 30-year Treasury yield, and the short and near term projected yields on the 30-year Treasury bonds range from 7.87% to 9.73%.

Q. 51 What is the next step in the CAPM analysis?

A. 51 I considered the average Beta estimates for the proxy group companies as reported by Bloomberg and Value Line. Value Line calculates Beta coefficients over a five-year period. Bloomberg's calculation is based on two years of data, which more closely reflects current market conditions than the five-year historical period relied on by Value Line.

Q. 52 How did you apply the CAPM?

A. 52 I relied on the forward looking risk premium and both the Bloomberg and Value Line Beta estimates to calculate the CAPM result using both the current 30-day average yield on the 30-year Treasury bond and projections of the 30-year Treasury bond yield as the risk-free rate. As shown in **Exhibit JJR-4**, the use of a projected market risk premium and risk-free rates produces a range of results that is generally consistent with the range of results produced by the other ROE estimation methodologies.

Q. 53 What are the results of your CAPM analyses?

A. 53 As shown in Table 6 (below), (*see* also **Exhibit JJR-4**), the results of my CAPM analysis, using the Bloomberg Beta coefficient estimate, suggest a mean ROE of 10.53% based on a range of returns from 10.33% to 10.83%. My CAPM analysis using the average Value Line Beta coefficient produces a range of returns from 10.35% to 10.85% and a mean of 10.55%.

Table 6: Forward-Looking CAPM Results

	Current 30-Year Treasury (3.24%)	**Near Term Projected 30-Year Treasury (3.58%)**	**Projected 30-Year Treasury (5.10%)**	**Mean Result**
Bloomberg Beta	10.33%	10.42%	10.83%	10.53%
Value Line Beta	10.35%	10.44%	10.85%	10.55%

G. Bond Yield Plus Risk Premium Analysis

Q. 54 Please describe the bond yield plus risk premium approach you employed.

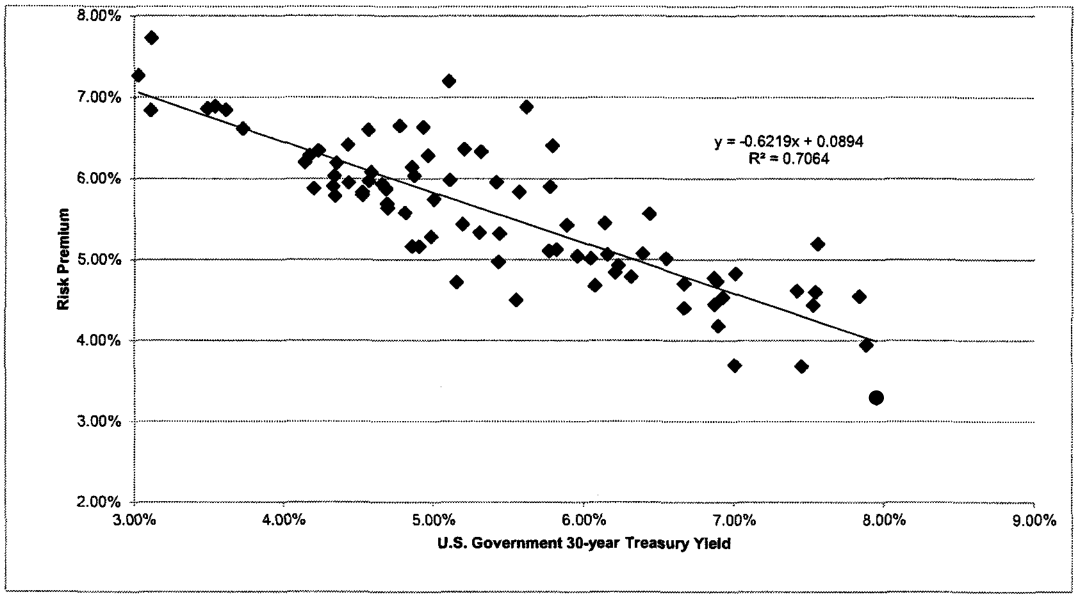
A. 54 In general terms, this approach is based on the fundamental principle that equity investors bear the residual risk associated with ownership and therefore require a premium over the return they would have earned as a bondholder. Risk premium approaches, therefore, estimate the cost of equity as the sum of the equity risk premium and the yield on a particular class of bonds. Since the equity risk premium is not directly observable, it typically is estimated using a variety of approaches, some of which incorporate forward-looking estimates of the cost of equity, and others that consider historical estimates. In the case of the CAPM, those estimates are with respect to the return on the broad market. An alternative approach is to use authorized returns over a long-term period for electric utilities as the measure of the cost of equity to determine the Equity Risk Premium, which will be added to the yield on long-term government bonds.

Q. 55 What did your bond yield plus risk premium analysis reveal?

A. 55 As shown on **Exhibit JJR-5**, from January 1, 1992 through April 30, 2012, there was, in fact, a significant statistical relationship between risk premiums and interest rates, which I examined through a linear regression model.

Data regarding allowed ROEs were derived from 537 electric utility rate decisions from 1992 through April 30, 2012 as reported by Regulatory Research Associates. As shown in Chart 2 (below), the regression equation explains approximately 70% of the deviation from the regression line. Based upon the equation shown in Chart 2 (below), and projected yields on 30-year U.S. Treasury bonds, the derived ROE ranges between 10.16% and 10.87%. These results are presented in Exhibit JJR-5.

Chart 2: Risk Premium Results



VIII. <u>REGULATORY AND BUSINESS RISKS</u>

Q. 56 Do the mean DCF, CAPM, and Risk Premium results for the proxy group provide an appropriate estimate of the cost of equity for TEP?

A. 56 These results provide only a range of the appropriate estimate of the Company's cost of equity. In my view, there are several additional factors that must be taken into consideration when determining where the Company's cost of equity falls within the range of results. These risk factors, which are discussed below, should be considered with respect to their overall effect on the Company's risk profile.

A. Regulatory Risk

Q. 57 Please explain how the regulatory environment affects investors' risk assessments.

A. 57 The ratemaking process is premised on the principle that, in order for investors and companies to commit the capital needed to provide safe and reliable utility services, the subject utility must have the opportunity to recover the return of, and the market-required return on, invested capital. Regulatory commissions recognize that because utility operations are capital intensive, regulatory decisions should enable the utility to attract capital at reasonable terms; doing so balances the long-term interests of investors and customers. In that respect, the regulatory environment is one of the most important factors considered in both debt and equity investors' risk assessments.

From the perspective of debt investors, the authorized return should enable the Company to generate the cash flow needed to meet its near-term financial obligations, make the capital investments needed to maintain and expand its system, and maintain sufficient levels of liquidity to fund unexpected events. This financial liquidity must be derived not only from internally generated funds, but also by efficient access to capital markets. Moreover, because fixed income investors have many investment alternatives, even within a given market sector, the Company's financial profile must be adequate on a relative basis to ensure its ability to attract capital under a variety of economic and financial market conditions.

From the perspective of equity investors, the authorized return must be adequate to provide a risk-comparable return on the equity portion of the Company's capital investments. Because equity investors are the residual claimants on the Company's cash flows (which is to say that the equity return is subordinate to interest payments), they are particularly concerned with the strength of regulatory support and its effect on future cash flows.

The financial community monitors not only the regulatory environment in which utility companies operate, but also the current and expected conditions of the capital markets from which utilities must attract long-term capital. As such, it is important for the ROE authorized in this proceeding to consider the capital market conditions with which TEP must contend, as well as investors' expectations and requirements relating to both risks and returns. Therefore, it is important that TEP be afforded the opportunity to maintain (or enhance) their financial integrity and to earn a reasonable return taking into consideration the current market conditions and the Company's specific business risk profile.

Q. 58 Please explain how credit rating agencies consider regulatory risk in establishing a company's credit rating.

A. 58 While both S&P and Moody's consider regulatory risk in establishing credit ratings, Moody's has published a report quantifying the importance of this metric. Moody's establishes credit ratings based on four key factors: (1) regulatory framework; (2) the ability to recover costs and earn returns; (3) diversification; and (4) financial strength, liquidity, and key financial metrics. Of these criteria, regulatory framework and the ability to recover costs and earn returns are each given a broad rating factor of 25%. Therefore, Moody's assigns regulatory risk a 50% weighting in the overall assessment of business and financial risk for regulated utilities.[23]

Standard & Poor's has also identified regulatory risk as an important factor. In its assessment of U.S. utility regulatory environments, S&P stated, "we believe the fundamental regulatory environment in the jurisdictions in which a utility operates often influence credit quality the most."[24]

Q. 59 How does the regulatory environment in which a utility operates affect its access to and cost of capital?

A. 59 The regulatory environment can significantly affect both the access to, and cost of capital in several ways. First, the proportion and cost of debt capital available to utility companies are influenced by the rating agencies' assessment of the regulatory environment. As noted by Moody's, "the predictability and supportiveness of the regulatory framework in which a regulated utility operates is a key credit consideration and the one that differentiates the industry from most other corporate sectors."[25] Moody's further noted that:

> For a regulated utility company, we consider the characteristics of the regulatory environment in which it operates. These include how developed the regulatory framework is; its track record for predictability and stability in terms of decision making; and the strength of the regulator's authority over utility regulatory issues. A utility operating in a stable, reliable, and highly predictable

[23] Moody's Investors Service, *Rating Methodology: Regulated Electric and Gas Utilities*, August 2009, at 4.
[24] Standard & Poor's, *Assessing U.S. Utility Regulatory Environments*, March 11, 2010, at 2.
[25] Moody's Global Infrastructure Finance, *Regulated Electric and Gas Utilities*, August 2009, at 6.

> regulatory environment will be scored higher on this factor than a utility operating in a regulatory environment that exhibits a high degree of uncertainty or unpredictability. Those utilities operating in a less developed regulatory framework or one that is characterized by a high degree of political intervention in the regulatory process will receive the lowest scores on this factor.[26]

Q. 60 Is regulatory risk an important consideration for TEP?

A. 60 Yes. In a recent report, S&P noted that its stable outlook for TEP was dependent on the expectation that the Company's credit metrics would not weaken under the current rate freeze.[27] Furthermore, in a recent credit opinion Moody's noted that it changed its outlook for Tucson Electric Power from stable to positive reflecting "the improved regulatory environment in Arizona and the expectation for a reasonable outcome in TEP's upcoming rate case".[28] Moody's also stated that its conclusion regarding improvement in the Arizona regulatory environment is based on the Commission finalizing cases within 13 months and its more supportive rate treatment, approving decoupling mechanisms in three recent cases. Moody's stated that "[g]iven the awarding of decoupling mechanisms in all three of the recent rate settlements, we believe there is a reasonable likelihood that TEP will also be authorized such a mechanism".[29] Therefore, supportive regulatory treatment in this case will be an important factor in Moody's rating of TEP.

Q. 61 Have you conducted any analysis of investors' perceptions of the regulatory environment in which TEP operates relative to the proxy group companies?

A. 61 Yes, I have. In order to assess investors' view as to the Company's regulatory environment, I considered the jurisdictional rankings developed by S&P, which ranks regulatory jurisdictions on a five tier scale from least credit supportive ("1") to most credit supportive ("5").[30] I applied that ranking system to the proxy group companies

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26 *Ibid.*

27 Standard & Poor's, Ratings Direct, Tucson Electric Power Company, October 31, 2011, p. 4.

28 Moody's Investors Service, Credit Opinion: Tucson Electric Power, May 24, 2012.

29 *Ibid.*

30 Standard and Poor's, *Assessing U.S. Utility Regulatory Environments*, updated March 12, 2010, at 1-2. For the purposes of this analysis, Concentric assigned numeric rankings to the Standard and Poor's criteria ranging from "1", which was assigned to the Standard and Poor's ranking "Least Credit Supportive" to "5" which was assigned to the Standard and Poor's ranking "Most Credit Supportive"..

by regulatory jurisdiction. For each proxy group company that operates in multiple jurisdictions, I considered the ranking for each regulatory jurisdiction in which they operate. As shown in **Exhibit JJR-6**, S&P's average ranking of the proxy group companies, using the simple average of the jurisdictions in which they operate, is 2.68 (*i.e.*, generally credit supportive) whereas Arizona's ranking is 1 (*i.e.,* least credit supportive).

Q. 62 What are your conclusions regarding the regulatory risk faced by TEP?

A. 62 As noted earlier, both Moody's and S&P have identified the regulatory environment in Arizona as an important factor, and have noted the credit considerations attendant to that risk. Furthermore, the S&P jurisdictional rankings suggest that the Company is subject to greater regulatory risk than the proxy group. Therefore, while the Commission may be making improvements in the regulatory process and rate treatments, as noted by Moody's, the regulatory environment remains an important factor to consider for TEP relative to the proxy group.

B. Risks Associated with TEP's Capital Expenditure Plan

Q. 63 Please summarize the Company's capital expenditure plan.

A. 63 The Company's current projections include approximately $2.02 billion in capital investments for the period from 2012 through 2016 Mr. DeConcini describes the specific capital investments in his Direct Testimony.

Q. 64 How is the Company's risk profile affected by the substantial increase in its planned capital expenditures?

A. 64 As with any utility faced with the need for a substantial capital expenditure plan, the Company's risk profile is adversely affected in two significant and related ways: (1) the heightened level of investment increases the risk of under recovery, or delayed recovery of the invested capital; and (2) an inadequate return would put downward pressure on key credit metrics, at a time when the Company is expected to raise significant amounts of new capital.

Q. 65 Do credit rating agencies recognize the risks associated with increased capital expenditures?

A. 65 Yes, they do. From a credit perspective, the additional pressure on cash flows associated with high levels of capital expenditures exerts corresponding pressure on credit metrics and, therefore, credit ratings. As discussed above, S&P identified this as a specific concern for TEP. Therefore, to the extent that the Company's rates do not permit it to recover its full cost of doing business, the Company will face increased recovery risk and thus increased pressure on its credit metrics.

Q. 66 Will the Company need continued access to the capital markets in order to finance its capital expenditure plan?

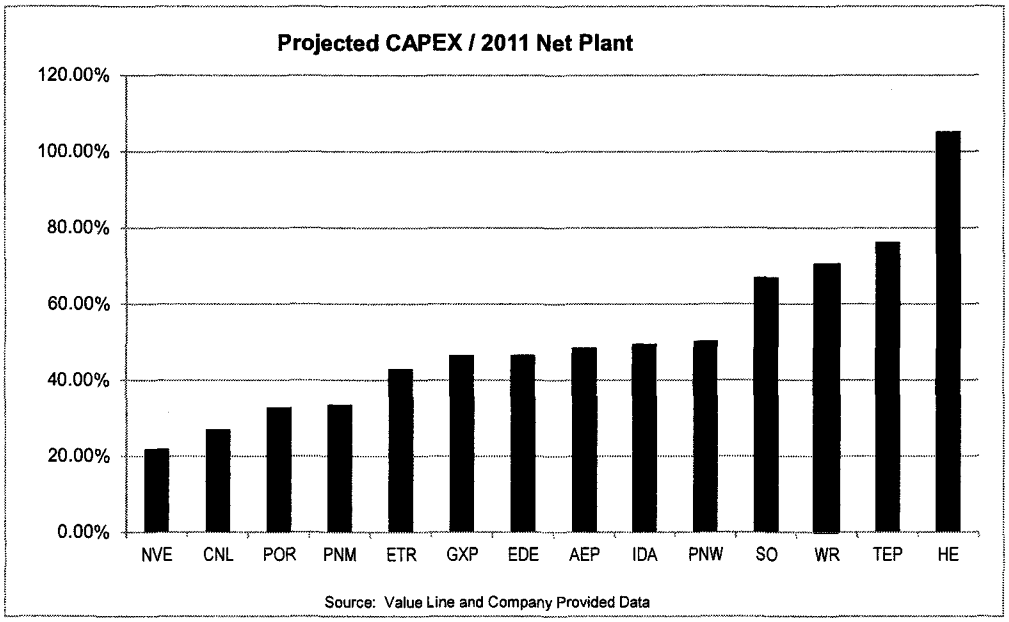
A. 66 Yes. When the level of capital expenditures outpaces the growth in internally generated cash, there is increasing pressure to access external capital markets. Given the size and long-term nature of TEP's anticipated capital expenditures, the Company will require continued access to external capital, at reasonable terms, in order to finance its capital expenditure plan. As noted throughout my testimony, the Company's ability to generate internal cash flow and access the capital markets will be directly affected by the Commission's order in this proceeding.

Q. 67 Have you conducted any analysis of the Company's projected capital expenditures relative to the proxy companies?

A. 67 Yes. I compared the ratio of projected capital expenditures from 2012 through 2016 to net utility plant as of December 31, 2011, for TEP and each of the proxy group companies have. As shown on Exhibit JJR-7, the Company's percentage of projected capital expenditures to net utility plant is approximately 1.64 times the median ratio of the proxy group companies. Chart 3, below, demonstrates that TEP's projected capital spending as a percentage of net utility plant is higher than the majority of the proxy group companies over this time period.

Chart 3: Comparison of Capital Expenditures

2012 -2016



Q. 68 What are your conclusions regarding the effect of the Company's capital spending plans on its risk profile?

A. 68 It is clear that on a relative basis, the Company's capital expenditure program is significant and could materially dilute the Company's current earnings and cash flows. It also is clear that the financial community recognizes the additional risks associated with substantial capital expenditures and that those risks are reflected in market valuation multiples. Further, taking into consideration the Company's below average bond rating[31] and the fact that TEP will need to access capital markets to finance its capital expenditure plan, it is very important that the authorized ROE in this proceeding provide the Company with the opportunity to maintain its financial integrity. In my view, those factors support an ROE above the proxy group mean.

[31] As noted earlier, TEP has a speculative grade Long Term Issuer rating of BB+ from Standard and Poor's and Fitch Ratings, and a low investment grade Issuer rating of Baa3 from Moody's.

IX. CAPITAL STRUCTURE.

Q. 69 What is the Company's proposed capital structure?

A. 69 The Company's proposal is to establish a capital structure comprised of 46.00% common equity and 54.00% long-term debt. Those proportions incorporate a pro-forma adjustment to the Company's actual capital structure as of the test year ended December 31, 2011, which was comprised of 43.50% common equity and 56.50% long-term debt. As discussed below, the proposed equity ratio for TEP is lower than the mean and median equity ratios at the operating utilities held within the proxy group. The Company's actual capital structure has a level of equity that is far below the average of the proxy group.

Q. 70 Please discuss your analysis of the capital structures of the proxy group companies.

A. 70 My analysis of the actual proxy group capital structures is provided in **Exhibit JJR–8**. As shown in that Exhibit, I calculated the mean and median proportions of common equity and long-term debt over the most recent eight quarters[32] for each of the proxy group companies at the operating company level. The Company's proposed equity ratio of 46.00% is well below the mean and median equity ratios for the proxy companies, of 51.08% and 51.32% respectively.

Q. 71 Is there a relationship between a company's equity ratio and its ROE?

A. 71 Yes. The cost of common equity capital and the fair ROR depend in part on the company's capital structure. Other factors being equal, firms with lower common equity ratios have higher costs of common equity and require higher rates of return to compensate for the additional financial risks to which their shareholders are exposed. Consequently, when a regulator selects a capital structure, that decision affects the required ROR on common equity.[33]

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[32] The source data for this analysis is the operating company data provided in the FERC Form 1 reports. Due to the timing of those filings, my average capital structure analysis uses the quarterly capital structures reported for the proxy group companies for the period from January 2010 through December 2011, which is the most recent eight quarters of data available at the operating company level.

[33] Please see Appendix A for a discussion of the Modigliani-Miller Theory regarding the relationship between the capital structure and the return on equity.

Q. 72 Will the capital structure and ROE authorized in this proceeding affect the Company's ability to complete its capital expenditure plan?

A. 72 Yes, I believe so. The level of earnings authorized by the Commission directly affects the Company's ability to fund capital investments with internally generated funds. Both lenders and equity investors expect a significant portion of on-going capital investments to be financed with internally generated funds; this is particularly important in light of the Company's below average credit rating. It also is important to realize that investors weigh a given utility's authorized ROE in the context of the nature of its expected capital investments. Because a utility's investment horizon is very long, investors require the assurance of a sufficiently high return to satisfy the long-run financing requirements of the assets it puts into service. Those assurances, which often are measured by the relationship between internally generated cash flows and debt (or interest expense), depend quite heavily on the capital structure. As a consequence, both the ROE and capital structure are very important to debt and equity investors. Given the capital market conditions and the Company's significant financing requirements, the authorized ROE and capital structure are extremely important considerations in this proceeding.

Q. 73 Are you proposing a specific adjustment to the Company's authorized ROE to reflect differences in its proposed equity ratio relative to the proxy group average?

A. 73 No, I am not. I did, however, take TEP's lower equity ratio into consideration when determining where within the range of results the Company's authorized ROE rightly falls.

X. <u>EFFECT OF THE COMPANY'S PROPOSED LOST FIXED COST RECOVERY ("LFCR") MECHANISM ON COST OF EQUITY.</u>

Q. 74 Please summarize the Company's proposed LFCR.

A. 74 As discussed in greater detail in the testimony of Mr. Craig A. Jones, the Company is proposing an LFCR that would recover lost revenue that is the direct result of the Commission's Energy Efficiency Standard ("EES") and Renewable Energy Standard

("REST") rules.[34] As discussed by Mr. Jones, the Company's proposal is not a full decoupling mechanism. The program is designed to recover only the losses attributable to quantifiable results through the Company's energy efficiency efforts and the promotion of distributed generation. Because the LFCR is only recovering a portion of the lost revenue related to these programs, it would be considered a partial decoupling mechanism.

Q. 75 If the Commission were to adopt the Company's proposed LFCR, what is the appropriate standard to consider in establishing the Company's ROE?

A. 75 Under the comparable earnings standard, the allowed ROE should represent a return commensurate with the returns on investments of similar risk. In this case, the proxy group companies would constitute the comparable earnings standard for TEP. Therefore, the issue is not whether the Company's revenues would be less volatile with the LFCR than without it; rather the relevant question is whether the Company would be more or less risky with its LFCR as compared to the proxy group. Exhibit JJR-9 provides a summary of the methods used by the proxy group companies to address revenue stability. As shown in that exhibit, the issue of revenue stability has been addressed by each of the proxy group companies through the implementation of various revenue stabilization adjustment mechanisms and favorable rate structures.

Q. 76 How do rating agencies view the implementation of revenue stabilization mechanisms?

A. 76 S&P recently commented on revenue stabilization mechanisms:

> Regulatory jurisdictions apply a host of other rate mechanisms or special tariffs to allow timely recovery of costs, including...legislatively mandated energy efficiency and renewable resource projects...,the greater the percentage of a utility's rates that they recover through fixed charges rather than volume-based charges, the greater the support for credit quality.[35]

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[34] *See* Direct Testimony of Mr. Craig A. Jones, at 53.

[35] Standard & Poor's, *How Utilities Weather a Slow Economy,* May 15, 2012.

Q. 77 What do you conclude about TEP's risk relative to the proxy group if the Company's LFCR is approved?

A. 77 It is important to note that while TEP does not currently have any revenue stabilization mechanisms in its rate structure, the majority of the proxy companies have some form of revenue stabilization in most jurisdictions. Therefore, implementation of the proposed LFCR would not make TEP less risky than the proxy group companies, but rather would make the Company more comparable to the proxy group in that the proposed LFCR provides for similar revenue stability to the structures that have been implemented by the proxy group companies.

Q. 78 Is it your view that the implementation of the Company's proposed LFCR should have no effect on the Company's ROE?

A. 78 Not exactly. My viewpoint is that the required ROE derived from proxy group analysis already reflects the risk of a utility with significant revenue stabilization. As noted previously, the Company's proposed LFCR is designed to eliminate disincentives to achieving the Commission's EES and REST. As noted earlier, a comparison of the proxy group rate structures and the Company's LFCR demonstrates that the proposed LFCR provides similar revenue stabilization as the mechanisms that have been implemented by the proxy group companies, in that they are designed to address revenue deficiencies that result from weather normalization, declining demand/volume, and other demand related risks. Therefore, the Company would have a risk profile that is more like the proxy group if the LFCR were to be implemented. Furthermore, there is no conclusive evidence of which I am aware indicating that companies that have implemented such structures either have lower required ROEs or have significantly different market valuations. Based on the comparability of the company's proposed LFCR to the rate structures implemented by the proxy group companies, and the market's valuation of companies with decoupling mechanisms, I conclude that approval of the Company's LFCR should not cause any adjustment to my required ROE analysis, which was derived from data for proxy companies that already have such mechanisms in place.

Q. 79 What would be the effect on your recommended ROE if the Company were not proposing an LFCR or if the Commission does not approve the proposed LFCR?

A. 79 As a preliminary matter, it is important to recall that the estimation of the cost of equity is a comparative analysis. It also is important to keep in mind that for several years, rating agencies (Moody's in particular) have identified revenue stabilization mechanisms as an increasingly common rate-making mechanism. Absent such a structure, TEP would be susceptible to incrementally greater risks than the proxy group. Consequently, while the Commission's acceptance of the Company's proposed LFCR would not result in a reduced cost of equity relative to TEP's peer group, the denial of such a structure would render the Company more risky than its peers, resulting in a cost of equity toward the upper end of the range. As previously discussed, approval of the proposed LFCR by the Commission in this proceeding should make the Company more comparable to the proxy group companies.

XI. CONCLUSIONS AND RECOMMENDATION FOR THE ORIGINAL COST RATE BASE ROE.

Q. 80 What is your conclusion regarding a fair ROE for TEP?

A. 80 Based on the various quantitative and qualitative analyses presented in my testimony, I believe that a reasonable range of results for TEP is from approximately 11.00% to 11.50%.

In light of the regulatory, business and financial risks of TEP compared to the proxy group, it is my view that an ROE of 11.25% is reasonable, if not somewhat conservative. My recommended ROE is above the midpoint of my range of results and reflects the Company's regulatory risks relative to the proxy group, its projected capital expenditures relative to the proxy group, its lower proposed equity ratio compared to the proxy group companies, and other business risks. It is my view, that an 11.25% ROE would reasonably balance the interests of customers and shareholders by enabling the Company to maintain its financial integrity and therefore its ability to attract capital at reasonable rates under a variety of different economic and financial market conditions. However, in an effort to moderate the effect of this case on customers, the Company is requesting an ROE of 10.75%.

Table 7: Summary of Analytical Results

	Mean Low	Mean	Mean High
Constant Growth DCF			
30-Day Average	9.70%	10.81%	12.00%
90-Day Average	9.66%	10.77%	11.95%
180-Day Average	9.76%	10.87%	12.06%
Multi-Stage DCF			
30-Day Average	9.65%	10.59%	12.15%
90-Day Average	9.65%	10.55%	11.93%
180-Day Average	9.77%	10.67%	12.02%
CAPM			
	Current Risk Free Rate (3.24%)	**2012-2013 Projected Risk Free Rate (3.58%)**	**2013-2017 Projected Risk Free rate (5.10%)**
Bloomberg	10.33%	10.42%	10.83%
Value Line	10.35%	10.44%	10.85%
Bond Yield Plus Risk Premium			
	Low	**Mean**	**High**
Risk Premium	10.16%	10.44%	10.87%

XII. FAIR VALUE RATE BASE.

Q. 81 What is the fair value standard in Arizona?

A. 81 As noted in *Chapparal*,[36] the Arizona Constitution requires the use of a FVRB in establishing rates. Article 15 para. 14 of the Arizona Constitution states:

> The corporation commission shall, to aid it in the proper discharge of its duties, ascertain the fair value of the property within the state of every public service corporation doing business therein; and every public service corporation doing

36 *In the Matter of the Application of Chapparal City Water Company, an Arizona Corporation, for a Determination of the Current Fair Value of its Utility Plant and Property and for Increases in its Rates and Charges for Utility Service Based Thereon,* Docket No. W-02113A-04-0616, Arizona Corporation Commission, Decision No. 70441, July 28, 2008, at 20-21.

> business within the state shall furnish to the commission all evidence in its possession, and all assistance in its power, requested by the commission in aid of the determination of the value of the property within the state of such public service corporation.

As interpreted by the Arizona Court of Appeals, this paragraph requires the Commission to find the fair value of a public service corporation's property and to use that value to set just and reasonable rates.[37]

Q. 82 How has the Commission applied the fair value standard in prior cases?

A. 82 The Fair Value Standard, as applied by the Commission in recent rate cases, includes the estimation of two components: (1) FVRB; and (2) the FVROR on the FVRB.[38]

Q. 83 How has the Commission estimated the FVRB?

A. 83 In several recent cases, the Commission has determined that it was appropriate to estimate the FVRB by weighing equally the OCRB and the RCND. The RCND estimates the current replacement cost value of the utility system by escalating the original investments in the utility rate base assets by inflation, since the installation year of the asset. In order to recognize physical and functional depreciation of the assets, the replacement cost is then adjusted for the accounting depreciation of the assets based on the expected useful life of the asset, as determined through the company's depreciation study.

Q. 84 How do you define "fair value"?

A. 84 Used in this context, "fair value" is the price at which a property would change hands between a willing buyer and a willing seller, when neither party is under any compulsion to enter into a transaction, and both parties have reasonable knowledge of relevant facts.[39] That definition is consistent with the Internal Revenue Code and Revenue Ruling 59-60 ("Ruling 59-60"), which notes that court decisions regarding Fair Value further assume that the buyer and seller are "able, as well as willing, to trade

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[37] *Ibid.*

[38] Arizona Corporation Commission, Decision No. 71914 at 51.

[39] *See* Shannon P. Pratt, Valuing a Business, 5th Ed. McGraw Hill, 2008, at 41-42.

and to be well informed about the property and concerning the market for such property."[40]

Q. 85 Do you have any concerns with the methodology that the Commission has used to estimate the FVRB?

A. 85 Yes, I do. Applying a 50% weight to the OCRB to estimate the FVRB is inconsistent with valuation theory that is relied upon by investors. Valuation theory identifies three traditional approaches that are used to estimate the value of an asset: (1) the Income Approach; (2) the Cost Approach; and (3) the Comparable Transactions Approach. The Income Approach establishes the value of the asset based on the present discounted value of the expected income from the asset. Using the Cost Approach an investor estimates the value of the asset based on the current cost of a reasonably comparable replacement asset, adjusted to reflect all forms of depreciation that are presented in the subject asset. Finally, using the Comparable Transactions or Market Multiples Approach the investor relies on the use of market data on the sale of comparable assets, or the trading multiples for similar companies to estimate the value of the assets.

While different circumstances of the asset or the investor can affect whether or not all three approaches are considered or how much emphasis should be placed on any given approach, the objective of each approach is to use available market data to derive a market-based value of an asset. An approach which places a 50% weight on the depreciated original cost of the assets at the time those assets were installed suggests that the accounting value of an investment has a relationship to the current market value of the asset. This is not the case, as is recognized both in the market place and in academia.[41]

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40 IRS Revenue Ruling 59-60, 1959-1 CB 237-IRC Sec. 2031.

41 *Pratt, Reilly, Schweihs, Valuing a Business* (Irwin 4th ed. 2000) at 308, which states: Under any standard of value, the true economic value of a business enterprise equals the company's accounting book value only by coincidence. More likely than not, the true economic value of a company will be either higher or lower than its accounting book value. There is no theoretical support, conceptual reasoning, or empirical data to suggest that the value of a business enterprise (under any standard of value) will necessarily equal the company's accounting book value. From a valuation perspective, the terms *book value* or *net book value* are merely accounting jargon. This is because book value is not related to economic value, or to the valuation process, at all… In any event, accounting book value is not a recommended business valuation method.

Q. 86 Have you conducted any analysis to assess the reasonableness of using the RCND as the FVRB for TEP?

A. 86 Yes, I have. As noted above, there are three main approaches to valuation typically relied upon by investors and analysts: the Income Approach; the Cost Approach; and the Comparables Approach. The Income Approach is not appropriate in circumstances such as these where the value of the assets is used to determine the income of the assets. The RCND is the Company's estimate of the current value of the assets using the Cost Approach. As shown in Exhibit JJR-10, page 1, the FVRB of $2.280 billion is calculated by weighting equally the Company's OCRB of $1.519 billion and the Company's estimated RCND of $3.041 billion.

In order to determine the reasonableness of the Company's estimate of the FVRB, which includes a 50% weight on OCRB, I relied on two approaches to estimate the market value of the Company's OCRB, the Comparables Approach, specifically Transaction Comparables, and a proxy group market multiples approach.

Q. 87 Please explain how you applied the Transaction Comparables Methodology to determine the reasonableness of the Company's FVRB.

A. 87 I compared the Company's FVRB estimate to the market value of comparable companies in recent arms-length transactions. I normalized the transaction values using the percentage premium over the corporate value of the acquired company, which incorporates the book value of debt and equity, resulting in a premium to corporate value resulting from the transactions to create a consistent basis of comparison among the transactions (which took place amid different market conditions). I estimated the market value of TEP's assets by applying the median premium of 49.46% to the Company's OCRB. That analysis resulted in an estimated market value for TEP's assets of $2.270 billion.

Q. 88 How did you establish the universe of transactions that were analyzed for comparability to the TEP system?

A. 88 I began by developing a database of announced and executed transactions involving the sale of utility companies and assets. Those data were compiled using the SNL

Financial utility merger screening tool. I also reviewed publicly available information such as press releases, investor presentations, SEC filings, and regulatory commission filings. Once that preliminary list of transactions was developed, I then applied the following screening criteria to establish a final group of transactions for which I calculated the transaction premium.

1. I included transactions that involved the sale of state-regulated investor-owned utilities;
2. I included transactions that resulted in the sale of the entire company, excluding partial system or asset sales;
3. I included transactions with a value of between $100 million and $10 billion.

While there were 28 transactions that met my screening criteria, there was sufficient data available for 21 of those transactions to be used in my analysis.

Q. 89 What period of time did you consider in developing your list of comparable transactions?

A. 89 My Comparable Transactions analysis was performed on utility transmission and distribution asset transactions that were announced within the past fifteen years (*i.e.*, from January 1, 1997 through April 30, 2012). In my view, that period is sufficiently long to avoid the bias that could result from limiting the analysis to a shorter period, yet produces a sufficient number of observations.

Q. 90 Please summarize the result of that analysis.

A. 90 Table 8 (below) summarizes the range of acquisition premiums for the comparable transactions. As shown in Table 8, and in Exhibit JJR-11, the median acquisition premium was 49.46%. Applying that premium to TEP's OCRB of $1.519 billion indicates an implied market value for TEP's assets of $2.270 billion.

Table 8: Comparable Transaction Multiples

	Transaction Premium	TEP Implied Valuation
Maximum	116.9%	$3.295 billion
Minimum	5.1%	$1.596 billion
Mean	52.1%	$2.310 billion
Standard Deviation	31.5%	*n/a*
Median	**49.5%**	**$2.270 billion**

Q. 91 Please explain how you applied the Market Multiples Approach to assess the reasonableness of the Company's estimate of FVRB.

A. 91 I relied on market multiples for the proxy group companies and an acquisition premium estimated from the transactions analysis discussed above to estimate the market value of the Company's assets. In the analysis I estimated an IMV/NP multiple for each of the proxy companies and applied that multiple to TEP's net plant to derive a range of market values for TEP.

To calculate Implied Market Values for the proxy group companies, I first calculated the premium over enterprise value paid in the transactions from the Comparable Transactions analysis discussed above. As shown on page 2 of **Exhibit JJR-11**, the median Transaction Value to Enterprise Value (TV/EV) premium is 11.42%. As shown on **Exhibit JJR-12**, the median TV/EV premium was applied to the Enterprise Value of each member of the proxy group, yielding a range of Implied Market Values for the proxy companies. The Implied Market Value was normalized by each proxy company's net plant to estimate an IMV/NP multiple. As shown in Exhibit JJR-12, the range of IMV/NP multiples for the proxy companies was 1.05 to 1.69 with a median value of 1.21. As shown in Table 9 below, applying that range of multiples to TEP's net distribution plant of $1.788 billion results in an estimated range of market value of $1.886 billion to $3.018 billion, with a median value of $2.171 billion. The Company's estimate of the FVRB of $2.280 billion falls within that range.

Table 9: Proxy Group Market Multiples

	Adjusted Enterprise Value /Net Plant Multiple	TEP Implied Valuation
Maximum	1.69	$3,018
Minimum	1.05	$1,886
Mean	1.26	$2,255
Standard Deviation	0.20	$358
Median	1.21	$2,171

Q. 92 What do you conclude from the comparables analyses discussed above?

A. 92 The results of the comparable analyses demonstrate that the Company's estimated FVRB is a reasonable estimate of the fair market value of the Company's distribution assets.

XIII. FAIR VALUE RATE OF RETURN.

Q. 93 Does the Fair Value Standard also require consideration of the fair return on the fair value of the Company's assets?

A. 93 Yes. As noted above, the Arizona Constitution requires that the Commission establish just and reasonable rates using the fair value of the Company's property. In establishing the revenue requirement, the Commission would also need to establish the appropriate ROE to apply to the equity component of the FVRB.

Q. 94 How has the Commission estimated the FVROR on the FVRB?

A. 94 In prior cases, the Commission has determined the FVROR by applying the market ROE and the cost of debt to the Company's OCRB based on the percent of equity and debt in the Company's proposed capital structure. The Commission then applies a different rate, traditionally one half of the risk free rate, to what has been commonly referred to as the "fair value increment."[42] The fair value increment is the difference between the OCRB and the Company's proposed FVRB. The FVROR is then the sum of the returns on each of the three components: equity capital, debt capital and the fair value increment weighted by the percentage of each in the FVRB.

[42] Arizona Corporation Commission, Decision No. 70665, at 32.

Q. 95 What does the fair value increment represent?

A. 95 As is described in the Commission's Decision No. 70665, the fair value increment represents the appreciation in the value of the assets to their current value from the value at which they entered service. Therefore, the sum of the OCRB and the fair value increment is meant to represent the total fair value of the utility's property.[43]

Q. 96 What ROR should be applied to the fair value increment?

A. 96 Based on the risk differential between equity and debt investments, equity holders will require a greater return than the risk free rate. There is no basis whatsoever for reducing this return component to one-half of the risk-free rate. The range of returns on the fair value increment should be between the risk free rate and the cost of equity established by the results of the proxy group analysis.

Q. 97 How does your recommended range compare with the range of returns considered by the Commission in prior cases?

A. 97 In the recent UNS Electric case, (Docket No. 71914) the staff witness proposed a range that could be applied to the fair value increment that was between zero and the real risk-free rate.[44]

Q. 98 Do you agree with this methodology of determining the ROR to be applied to the fair value increment?

A. 98 No. Since equity investors are the residual claimants after bond holders and preferred stock holders, it is inconceivable to me that an investor would accept a ROR that is less than the cost of debt for an equity position in any investment. Furthermore, the application of 50% of the risk free rate as a measure of the cost of equity on the fair value increment is subjective and has no basis in financial theory. The risk free rate, which was used by the staff to establish the range of returns applied to the fair value increment sets the low end of the range of returns that I believe would be appropriate to apply to the fair value increment.

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43 Arizona Corporation Commission, Decision No. 70665, at 32.

44 Arizona Corporation Commission, Decision No. 71914, at 47.

Q. 99 How have you estimated the FVROR in this case?

A. 99 While I do not agree with all aspects of the Commission's approach, as shown on page 1 of Exhibit JJR-10, I have estimated the FVROR using the methodology that has traditionally been relied on by the Commission.

Q. 100 How did you estimate the risk free ROR?

A. 100 As shown on page 3 of Exhibit JJR-10, my estimate of the nominal risk free ROR is the average of the short-term (2013-2017) projected yield on 30-year Treasury bonds of 5.08% and the long-term (2018-2022) projected yield on the 30-year Treasury bonds of 5.50% as reported in the Blue Chip Financial Forecast. I then adjusted the nominal risk free rate of 5.29% by the rate of inflation, which I estimated to be 2.10% over the period from 2012-2022 (see, page 2 of Exhibit JJR-10). The resulting real risk free rate is then 3.12%.[45]

Q. 101 Please explain how you estimated the rate of inflation?

A. 101 I calculated the rate of inflation based on the average of two measures of inflation, the Blue Chip Financial Forecast estimate of the long term change in CPI for 2018 through 2022, which is 2.30%[46] and the EIA Annual Energy Outlook estimate of the change in CPI and GDP for the period from 2012 through 2022, of 2.15%[47] and 1.85% respectively, all of which were averaged to arrive at an inflation rate of 2.10%.

Q. 102 Please explain how you applied the Commission's methodology to estimate the FVROR.

A. 102 As shown on page 1 of Exhibit JJR-10 and in Table 10 below, I calculated the difference between the Company's OCRB and the Company's proposed FVRB, which included a 50% weight on original cost. That difference represents the appreciation in the value of the assets based on the "market value" of the OCRB, and has been commonly referred to as the "fair value increment."[48] The market cost of debt and cost of equity were applied to the OCRB.

[45] The real risk free rate = ((1+ nominal Treasury rate)/(inflation rate+1))-1.

[46] Blue Chip Financial Forecasts, Vol. 30, No. 12, December 1, 2011, p. 14.

[47] Energy Information Administration, 2012 Annual Energy Outlook, Assumptions, Table 20.

[48] Arizona Corporation Commission, Decision No. 70665, at 32.

Q. 103 Please explain how you estimated the ROR that you applied to the fair value increment.

A. 103 As discussed above, I believe that the appropriate range of returns that could be applied to the fair value increment is bounded on the low end by the risk-free rate and on the high end by the results of the returns on rate base for the proxy group discussed in Section VII of my testimony. While I believe it would be appropriate to select a return from within that range, in order to mitigate the effects of this case on its customers, the Company has requested that I estimate the FVROR by applying 50.00% of the risk free rate or approximately 1.56%, to the fair value increment.

Table 10: Estimated FVROR

Capital	($ Million)	Percent	Cost Rate	Weighted Cost Rate
FVRB	$2,280			
OCRB	$1,519			
RCND	$3,041			
Long-Term Debt	$820	35.97%	5.18%	1.86%
Common Equity	$699	30.65%	10.75%	3.29%
Fair Value Increment	$761	33.38%	1.56%	0.52%
Total	$2,280	100.00%		5.68%

Q. 104 What is the resulting FVROR?

A. 104 As shown in Table 10 above, (*see also* Exhibit JJR-10, based on the calculation discussed previously, the FVROR that would be applied to the FVRB is 5.68%.

Q. 105 Does this conclude your pre-filed testimony?

A. 105 Yes.

ATTACHMENT
"A"

John J. Reed
Chairman and Chief Executive Officer

John J. Reed is a financial and economic consultant with more than 35 years of experience in the energy industry. Mr. Reed has also been the CEO of an NASD member securities firm, and Co-CEO of the nation's largest publicly traded management consulting firm (NYSE: NCI). He has provided advisory services in the areas of mergers and acquisitions, asset divestitures and purchases, strategic planning, project finance, corporate valuation, energy market analysis, rate and regulatory matters and energy contract negotiations to clients across North and Central America. Mr. Reed's comprehensive experience includes the development and implementation of nuclear, fossil, and hydroelectric generation divestiture programs with an aggregate valuation in excess of $20 billion. Mr. Reed has also provided expert testimony on financial and economic matters on more than 150 occasions before the FERC, Canadian regulatory agencies, state utility regulatory agencies, various state and federal courts, and before arbitration panels in the United States and Canada. After graduation from the Wharton School of the University of Pennsylvania, Mr. Reed joined Southern California Gas Company, where he worked in the regulatory and financial groups, leaving the firm as Chief Economist in 1981. He served as executive and consultant with Stone & Webster Management Consulting and R.J. Rudden Associates prior to forming REED Consulting Group (RCG) in 1988. RCG was acquired by Navigant Consulting in 1997, where Mr. Reed served as an executive until leaving Navigant to join Concentric as Chairman and Chief Executive Officer.

REPRESENTATIVE PROJECT EXPERIENCE

Executive Management

As an executive-level consultant, worked with CEOs, CFOs, other senior officers, and Boards of Directors of many of North America's top electric and gas utilities, as well as with senior political leaders of the U.S. and Canada on numerous engagements over the past 25 years. Directed merger, acquisition, divestiture, and project development engagements for utilities, pipelines and electric generation companies, repositioned several electric and gas utilities as pure distributors through a series of regulatory, financial, and legislative initiatives, and helped to develop and execute several "roll-up" or market aggregation strategies for companies seeking to achieve substantial scale in energy distribution, generation, transmission, and marketing.

Financial and Economic Advisory Services

Retained by many of the nation's leading energy companies and financial institutions for services relating to the purchase, sale or development of new enterprises. These projects included major new gas pipeline projects, gas storage projects, several non-utility generation projects, the purchase and sale of project development and gas marketing firms, and utility acquisitions. Specific services provided include the development of corporate expansion plans, review of acquisition candidates, establishment of divestiture standards, due diligence on acquisitions or financing, market entry or expansion studies, competitive assessments, project financing studies, and negotiations relating to these transactions.

Litigation Support and Expert Testimony

Provided expert testimony on more than 150 occasions in administrative and civil proceedings on a wide range of energy and economic issues. Clients in these matters have included gas distribution utilities, gas pipelines, gas producers, oil producers, electric utilities, large energy consumers, governmental and regulatory agencies, trade associations, independent energy project developers, engineering firms, and gas and power marketers. Testimony has focused on issues ranging from broad regulatory and economic policy to virtually all elements of the utility ratemaking process. Also frequently testified regarding energy contract interpretation, accepted energy industry practices, horizontal and vertical market power, quantification of damages, and management prudence. Has been active in regulatory contract and litigation matters on virtually all interstate pipeline systems serving the U.S. Northeast, Mid-Atlantic, Midwest, and Pacific regions.

Also served on FERC Commissioner Terzic's Task Force on Competition, which conducted an industry-wide investigation into the levels of and means of encouraging competition in U.S. natural gas markets and served on a "Blue Ribbon" panel established by the Province of New Brunswick regarding the future of natural gas distribution service in that province.

Resource Procurement, Contracting and Analysis

On behalf of gas distributors, gas pipelines, gas producers, electric utilities, and independent energy project developers, personally managed or participated in the negotiation, drafting, and regulatory support of hundreds of energy contracts, including the largest gas contracts in North America, electric contracts representing billions of dollars, pipeline and storage contracts, and facility leases.

These efforts have resulted in bringing large new energy projects to market across North America, the creation of hundreds of millions of dollars in savings through contract renegotiation, and the regulatory approval of a number of highly contested energy contracts.

Strategic Planning and Utility Restructuring

Acted as a leading participant in the restructuring of the natural gas and electric utility industries over the past fifteen years, as an adviser to local distribution companies, pipelines, electric utilities, and independent energy project developers. In the recent past, provided services to most of the top 50 utilities and energy marketers across North America. Managed projects that frequently included the redevelopment of strategic plans, corporate reorganizations, the development of multi-year regulatory and legislative agendas, merger, acquisition and divestiture strategies, and the development of market entry strategies. Developed and supported merchant function exit strategies, marketing affiliate strategies, and detailed plans for the functional business units of many of North America's leading utilities.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2002 – Present)
Chairman and Chief Executive Officer

CE Capital Advisors (2004 – Present)
Chairman, President, and Chief Executive Officer

Navigant Consulting, Inc. (1997 – 2002)
President, Navigant Energy Capital (2000 – 2002)
Executive Director (2000 – 2002)
Co-Chief Executive Officer, Vice Chairman (1999 – 2000)
Executive Managing Director (1998 – 1999)
President, REED Consulting Group, Inc. (1997 – 1998)

REED Consulting Group (1988 – 1997)
Chairman, President and Chief Executive Officer

R.J. Rudden Associates, Inc. (1983 – 1988)
Vice President

Stone & Webster Management Consultants, Inc. (1981 – 1983)
Senior Consultant
Consultant

Southern California Gas Company (1976 – 1981)
Corporate Economist
Financial Analyst
Treasury Analyst

EDUCATION AND CERTIFICATION

B.S., Economics and Finance, Wharton School, University of Pennsylvania, 1976
Licensed Securities Professional: NASD Series 7, 63, 24, 79 and 99 Licenses

BOARDS OF DIRECTORS (PAST AND PRESENT)

Concentric Energy Advisors, Inc.
Navigant Consulting, Inc.
Navigant Energy Capital
Nukem, Inc.
New England Gas Association
R. J. Rudden Associates
REED Consulting Group

AFFILIATIONS

American Gas Association
Energy Bar Association
Guild of Gas Managers
International Association of Energy Economists
National Association of Business Economists
New England Gas Association
Society of Gas Lighters

ARTICLES AND PUBLICATIONS

"Maximizing U.S. federal loan guarantees for new nuclear energy," *Bulletin of the Atomic Scientists* (with John C. Slocum), July 29, 2009
"Smart Decoupling – Dealing with unfunded mandates in performance-based ratemaking," *Public Utilities Fortnightly*, May 2012

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Alaska Public Utilities Commission				
Chugach Electric	12/86	Chugach Electric	Docket No. U-86-11	Cost Allocation
Chugach Electric	6/87	Enstar Natural Gas Company	Docket No. U-87-2	Tariff Design
Chugach Electric	12/87	Enstar Natural Gas Company	Docket No. U-87-42	Gas Transportation
Chugach Electric	11/87, 2/88	Chugach Electric	Docket No. U-87-35	Cost of Capital
California Energy Commission				
Southern California Gas Co.	8/80	Southern California Gas Co.	Docket No. 80-BR-3	Gas Price Forecasting
California Public Utility Commission				
Southern California Gas Co.	3/80	Southern California Gas Co.	TY 1981 G.R.C.	Cost of Service, Inflation
Pacific Gas Transmission Co.	10/91, 11/91	Pacific Gas & Electric Co.	App. 89-04-033	Rate Design
Pacific Gas Transmission Co.	7/92	Southern California Gas Co.	A. 92-04-031	Rate Design
Colorado Public Utilities Commission				
AMAX Molybdenum	2/90	Commission Rulemaking	Docket No. 89R-702G	Gas Transportation
AMAX Molybdenum	11/90	Commission Rulemaking	Docket No. 90R-508G	Gas Transportation
Xcel Energy	8/04	Xcel Energy	Docket No. 031-134E	Cost of Debt
CT Dept. of Public Utilities Control				
Connecticut Natural Gas	12/88	Connecticut Natural Gas	Docket No. 88-08-15	Gas Purchasing Practices
United Illuminating	3/99	United Illuminating	Docket No. 99-03-04	Nuclear Plant Valuation
Southern Connecticut Gas	2/04	Southern Connecticut Gas	Docket No. 00-12-08	Gas Purchasing Practices
Southern Connecticut Gas	4/05	Southern Connecticut Gas	Docket No. 05-03-17	LNG/Trunkline
Southern Connecticut Gas	5/06	Southern Connecticut Gas	Docket No. 05-03-17PH01	LNG/Trunkline

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Southern Connecticut Gas	8/08	Southern Connecticut Gas	Docket No. 06-05-04	Peaking Service Agreement
District Of Columbia PSC				
Potomac Electric Power Company	3/99, 5/99, 7/99	Potomac Electric Power Company	Docket No. 945	Divestiture of Gen. Assets & Purchase Power Contracts
Fed'l Energy Regulatory Commission				
Safe Harbor Water Power Corp.	8/82	Safe Harbor Water Power Corp.		Wholesale Electric Rate Increase
Western Gas Interstate Company	5/84	Western Gas Interstate Company	Docket No. RP84-77	Load Fcst. Working Capital
Southern Union Gas	4/87, 5/87	El Paso Natural Gas Company	Docket No. RP87-16-000	Take-or-Pay Costs
Connecticut Natural Gas	11/87	Penn-York Energy Corporation	Docket No. RP87-78-000	Cost Alloc./Rate Design
AMAX Magnesium	12/88, 1/89	Questar Pipeline Company	Docket No. RP88-93-000	Cost Alloc./Rate Design
Western Gas Interstate Company	6/89	Western Gas Interstate Company	Docket No. RP89-179-000	Cost Alloc./Rate Design, Open-Access Transportation
Associated CD Customers	12/89	CNG Transmission	Docket No. RP88-211-000	Cost Alloc./Rate Design
Utah Industrial Group	9/90	Questar Pipeline Company	Docket No. RP88-93-000, Phase II	Cost Alloc./Rate Design
Iroquois Gas Trans. System	8/90	Iroquois Gas Transmission System	Docket No. CP89-634-000/001; CP89-815-000	Gas Markets, Rate Design, Cost of Capital, Capital Structure

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Boston Edison Company	1/91	Boston Edison Company	Docket No. ER91-243-000	Electric Generation Markets
Cincinnati Gas and Electric Co., Union Light, Heat and Power Company, Lawrenceburg Gas Company	7/91	Texas Gas Transmission Corp.	Docket No. RP90-104-000, RP88-115-000, RP90-192-000	Cost Alloc./Rate Design Comparability of Svc.
Ocean State Power II	7/91	Ocean State Power II	ER89-563-000	Competitive Market Analysis, Self-dealing
Brooklyn Union/PSE&G	7/91	Texas Eastern	RP88-67, et al	Market Power, Comparability of Service
Northern Distributor Group	9/92, 11/92	Northern Natural Gas Company	RP92-1-000, et al	Cost of Service
Canadian Association of Petroleum Producers and Alberta Pet. Marketing Comm.	10/92. 7/97	Lakehead Pipe Line Co. L.P.	IS92-27-000	Cost Allocation, Rate Design
Colonial Gas, Providence Gas	7/93, 8/93	Algonquin Gas Transmission	RP93-14	Cost Allocation, Rate Design
Iroquois Gas Transmission	94	Iroquois Gas Transmission	RP94-72-000	Cost of Service and Rate Design
Transco Customer Group	1/94	Transcontinental Gas Pipeline Corporation	Docket No. RP92-137-000	Rate Design, Firm to Wellhead
Pacific Gas Transmission	2/94, 3/95	Pacific Gas Transmission	Docket No. RP94-149-000	Rolled-In vs. Incremental Rates; rate design
Tennessee GSR Group	1/95, 3/95, 1/96	Tennessee Gas Pipeline Company	Docket Nos. RP93-151-000, RP94-39-000, RP94-197-000, RP94-309-000	GSR Costs
PG&E and SoCal Gas	8/96, 9/96	El Paso Natural Gas Company	RP92-18-000	Stranded Costs

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Iroquois Gas Transmission System, L.P.	97	Iroquois Gas Transmission System, L.P.	RP97-126-000	Cost of Service, Rate Design
BEC Energy - Commonwealth Energy System	2/99	Boston Edison Company/ Commonwealth Energy System	EC99-___-000	Market Power Analysis – Merger
Central Hudson Gas & Electric, Consolidated Co. of New York, Niagara Mohawk Power Corporation, Dynegy Power Inc.	10/00	Central Hudson Gas & Electric, Consolidated Co. of New York, Niagara Mohawk Power Corporation, Dynegy Power Inc.	Docket No. EC00-___	Market Power 203/205 Filing
Wyckoff Gas Storage	12/02	Wyckoff Gas Storage	CP03-33-000	Need for Storage Project
Indicated Shippers/Producers	10/03	Northern Natural Gas	Docket No. RP98-39-029	Ad Valorem Tax Treatment
Maritimes & Northeast Pipeline	6/04	Maritimes & Northeast Pipeline	Docket No. RP04-360-000	Rolled-In Rates
ISO New England	8/04 2/05	ISO New England	Docket No. ER03-563-030	Cost of New Entry
Transwestern Pipeline Company, LLC	9/06	Transwestern Pipeline Company, LLC	Docket No. RP06-614-000	
Portland Natural Gas Transmission System	6/08	Portland Natural Gas Transmission System	Docket No. RP08-306-000	Market Assessment, natural gas transportation; rate setting
Portland Natural Gas Transmission System	5/10, 3/11, 4/11	Portland Natural Gas Transmission System	Docket No. RP10-729-000	Business risks; extraordinary and non-recurring events pertaining to discretionary revenues
Morris Energy	7/10	Morris Energy	Docket No. RP10-79-000	Affidavit re: Impact of Preferential Rate

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Florida Public Service Commission				
Florida Power and Light Co.	10/07	Florida Power & Light Co.	Docket No. 070650-EI	Need for new nuclear plant
Florida Power and Light Co.	5/08	Florida Power & Light Co.	Docket No. 080009-EI	New Nuclear cost recovery, prudence
Florida Power and Light Co.	3/09	Florida Power & Light Co.	Docket No. 080677-EI	Benchmarking in support of ROE
Florida Power and Light Co.	3/09, 5/09, 8/09	Florida Power & Light Co.	Docket No. 090009-EI	New Nuclear cost recovery, prudence
Florida Power and Light Co.	3/10; 5/10, 8/10	Florida Power & Light Co.	Docket No. 100009-EI	New Nuclear cost recovery, prudence
Florida Power and Light Co.	3/11, 7/11	Florida Power & Light Co.	Docket No. 110009-EI	New Nuclear cost recovery, prudence
Florida Power and Light Co.	3/12	Florida Power & Light Co.	Docket No. 120009-EI	New Nuclear cost recovery , prudence
Florida Power and Light Co.	3/12	Florida Power & Light Co.	Docket No. 120015-EI	Benchmarking in support of ROE
Florida Senate Committee on Communication, Energy and Utilities				
Florida Power and Light Co.	2/09	Florida Power & Light Co.		Securitization
Hawaii Public Utility Commission				
Hawaiian Electric Light Company, Inc. (HELCO)	6/00	Hawaiian Electric Light Company, Inc.	Docket No. 99-0207	Standby Charge

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Indiana Utility Regulatory Commission				
Northern Indiana Public Service Company	10/01	Northern Indiana Public Service Company	Cause No. 41746	Valuation of Electric Generating Facilities
Northern Indiana Public Service Company	01/08, 03/08	Northern Indiana Public Service Company	Cause No. 43396	Asset Valuation
Northern Indiana Public Service Company	08/08	Northern Indiana Public Service Company	Cause No. 43526	Fair Market Value Assessment
Iowa Utilities Board				
Interstate Power and Light	7/05	Interstate Power and Light and FPL Energy Duane Arnold, LLC	Docket No. SPU-05-15	Sale of Nuclear Plant
Interstate Power and Light	5/07	City of Everly, Iowa	Docket No. SPU-06-5	Municipalization
Interstate Power and Light	5/07	City of Kalona, Iowa	Docket No. SPU-06-6	Municipalization
Interstate Power and Light	5/07	City of Wellman, Iowa	Docket No. SPU-06-10	Municipalization
Interstate Power and Light	5/07	City of Terril, Iowa	Docket No. SPU-06-8	Municipalization
Interstate Power and Light	5/07	City of Rolfe, Iowa	Docket No. SPU-06-7	Municipalization
Maine Public Utility Commission				
Northern Utilities	5/96	Granite State and PNGTS	Docket No. 95-480, 95-481	Transportation Service and PBR
Maryland Public Service Commission				
Eastalco Aluminum	3/82	Potomac Edison	Docket No. 7604	Cost Allocation
Potomac Electric Power Company	8/99	Potomac Electric Power Company	Docket No. 8796	Stranded Cost & Price Protection

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Mass. Department of Public Utilities				
Haverhill Gas	5/82	Haverhill Gas	Docket No. DPU #1115	Cost of Capital
New England Energy Group	1/87	Commission Investigation		Gas Transportation Rates
Energy Consortium of Mass.	9/87	Commonwealth Gas Company	Docket No. DPU-87-122	Cost Alloc./Rate Design
Mass. Institute of Technology	12/88	Middleton Municipal Light	DPU #88-91	Cost Alloc./Rate Design
Energy Consortium of Mass.	3/89	Boston Gas	DPU #88-67	Rate Design
PG&E Bechtel Generating Co./ Constellation Holdings	10/91	Commission Investigation	DPU #91-131	Valuation of Environmental Externalities
Coalition of Non-Utility Generators		Cambridge Electric Light Co. & Commonwealth Electric Co.	DPU 91-234 EFSC 91-4	Integrated Resource Management
The Berkshire Gas Company Essex County Gas Company Fitchburg Gas and Elec. Light Co.	5/92	The Berkshire Gas Company Essex County Gas Company Fitchburg Gas & Elec. Light Co.	DPU #92-154	Gas Purchase Contract Approval
Boston Edison Company	7/92	Boston Edison	DPU #92-130	Least Cost Planning
Boston Edison Company	7/92	The Williams/Newcorp Generating Co.	DPU #92-146	RFP Evaluation
Boston Edison Company	7/92	West Lynn Cogeneration	DPU #92-142	RFP Evaluation
Boston Edison Company	7/92	L'Energia Corp.	DPU #92-167	RFP Evaluation
Boston Edison Company	7/92	DLS Energy, Inc.	DPU #92-153	RFP Evaluation
Boston Edison Company	7/92	CMS Generation Co.	DPU #92-166	RFP Evaluation
Boston Edison Company	7/92	Concord Energy	DPU #92-144	RFP Evaluation

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
The Berkshire Gas Company Colonial Gas Company Essex County Gas Company Fitchburg Gas and Electric Company	11/93	The Berkshire Gas Company Colonial Gas Company Essex County Gas Company Fitchburg Gas and Electric Co.	DPU #93-187	Gas Purchase Contract Approval
Bay State Gas Company	10/93	Bay State Gas Company	Docket No. 93-129	Integrated Resource Planning
Boston Edison Company	94	Boston Edison	DPU #94-49	Surplus Capacity
Hudson Light & Power Department	4/95	Hudson Light & Power Dept.	DPU #94-176	Stranded Costs
Essex County Gas Company	5/96	Essex County Gas Company	Docket No. 96-70	Unbundled Rates
Boston Edison Company	8/97	Boston Edison Company	D.P.U. No. 97-63	Holding Company Corporate Structure
Berkshire Gas Company	6/98	Berkshire Gas Mergeco Gas Co.	D.T.E. 98-87	Merge approval
Eastern Edison Company	8/98	Montaup Electric Company	D.T.E. 98-83	Marketing for divestiture of its generation business.
Boston Edison Company	98	Boston Edison Company	D.T.E. 97-113	Fossil Generation Divestiture
Boston Edison Company	2/99	Boston Edison Company	D.T.E. 98-119	Nuclear Generation Divestiture
Eastern Edison Company	12/98	Montaup Electric Company	D.T.E. 99-9	Sale of Nuclear Plant
NStar	9/07, 12/07	NStar, Bay State Gas, Fitchburg G&E, NE Gas, W. MA Electric	DPU 07-50	Decoupling, risk
NStar	6/11	NStar, Northeast Utilities	DPU 10-170	Merger approval
Mass. Energy Facilities Siting Council				
Mass. Institute of Technology	1/89	M.M.W.E.C.	EFSC-88-1	Least-Cost Planning
Boston Edison Company	9/90	Boston Edison	EFSC-90-12	Electric Generation Mkts

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Silver City Energy Ltd. Partnership	11/91	Silver City Energy	D.P.U. 91-100	State Policies; Need for Facility
Michigan Public Service Commission				
Detroit Edison Company	9/98	Detroit Edison Company	Case No. U-11726	Market Value of Generation Assets
Consumers Energy Company	8/06, 1/07	Consumers Energy Company	Case No. U-14992	Sale of Nuclear Plant
WE Energies	12/11	Wisconsin Electric Power Co	Case No. U-16830	Economic Benefits/Prudence
Minnesota Public Utilities Commission				
Xcel Energy/No. States Power	9/04	Xcel Energy/No. States Power	Docket No. G002/GR-04-1511	NRG Impacts
Interstate Power and Light	8/05	Interstate Power and Light and FPL Energy Duane Arnold, LLC	Docket No. E001/PA-05-1272	Sale of Nuclear Plant
Northern States Power Company d/b/a Xcel Energy	11/05	Northern States Power Company	Docket No. E002/GR-05-1428	NRG Impacts on Debt Costs
Northern States Power Company d/b/a Xcel Energy	09/06	NSP v. Excelsior	Docket No. E6472/M-05-1993	PPA, Financial Impacts
Northern States Power Company d/b/a Xcel Energy	11/06	Northern States Power Company	Docket No. G002/GR-06-1429	Return on Equity
Northern States Power	11/08, 05/09	Northern States Power Company	Docket No. E002/GR-08-1065	Return on Equity
Northern States Power	11/09 6/10	Northern States Power Company	Docket No. G002/GR-09-1153	Return on Equity
Northern States Power	11/10, 5/11	Northern States Power Company	Docket No. E002/GR-10-971	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Missouri Public Service Commission				
Missouri Gas Energy	1/03 04/03	Missouri Gas Energy	Case No. GR-2001-382	Gas Purchasing Practices; Prudence
Aquila Networks	2/04	Aquila-MPS, Aquila_L&P	Case Nos. ER-2004-0034 HR-2004-0024	Cost of Capital, Capital Structure
Aquila Networks	2/04	Aquila-MPS, Aquila_L&P	Case No. GR-2004-0072	Cost of Capital, Capital Structure
Missouri Gas Energy	11/05	Missouri Gas Energy	Case Nos. GR-2002-348 GR-2003-0330	Capacity Planning
Missouri Gas Energy	11/10, 1/11	KCP&L	Case No. ER-2010-0355	Natural Gas DSM
Missouri Gas Energy	11/10, 1/11	KCP&L GMO	Case No. ER-2010-0356	Natural Gas DSM
Laclede Gas Company	5/11	Laclede Gas Company	Case No. CG-2011-0098	Affiliate Pricing Standards
Union Electric Company d/b/a Ameren Missouri	2/12	Union Electric Company	Case. No. ER-2012-0166	ROE/earnings attrition/regulatory lag
Montana Public Service Commission				
Great Falls Gas Company	10/82	Great Falls Gas Company	Docket No. 82-4-25	Gas Rate Adjust. Clause
Nat. Energy Board of Canada				
Alberta-Northeast	2/87	Alberta Northeast Gas Export Project	Docket No. GH-1-87	Gas Export Markets
Alberta-Northeast	11/87	TransCanada Pipeline	Docket No. GH-2-87	Gas Export Markets
Alberta-Northeast	1/90	TransCanada Pipeline	Docket No. GH-5-89	Gas Export Markets

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Indep. Petroleum Association of Canada	1/92	Interprovincial Pipe Line, Inc.	RH-2-91	Pipeline Valuation, Toll
The Canadian Association of Petroleum Producers	11/93	Transmountain Pipe Line	RH-1-93	Cost of Capital
Alliance Pipeline L.P.	6/97	Alliance Pipeline L.P.	GH-3-97	Market Study
Maritimes & Northeast Pipeline	97	Sable Offshore Energy Project	GH-6-96	Market Study
Maritimes & Northeast Pipeline	2/02	Maritimes & Northeast Pipeline	GH-3-2002	Natural Gas Demand Analysis
TransCanada Pipelines	8/04	TransCanada Pipelines	RH-3-2004	Toll Design
Brunswick Pipeline	5/06	Brunswick Pipeline	GH-1-2006	Market Study
TransCanada Pipelines Ltd.	3/07, 04/07	TransCanada Pipelines Ltd.: Gros Cacouna Receipt Point Application	RH-1-2007	Toll Design
Repsol Energy Canada Ltd	3/08	Repsol Energy Canada Ltd	GH-1-2008	Market Study
Maritimes & Northeast Pipeline	7/10	Maritimes & Northeast Pipeline	RH-4-2010	Regulatory policy, toll development
TransCanada Pipelines Ltd	9/11, 5/12	TransCanada Pipelines Ltd.	RH-3-2011	Business Services and Tolls Application
New Brunswick Energy and Utilities Board				
Atlantic Wallboard/JD Irving Co	1/08	Enbridge Gas New Brunswick	MCTN #298600	Rate Setting for EGNB
Atlantic Wallboard/Flakeboard	09/09, 6/10, 7/10	Enbridge Gas New Brunswick	NBEUB 2009-017	Rate Setting for EGNB
NH Public Utilities Commission				
Bus & Industry Association	6/89	P.S. Co. of New Hampshire	Docket No. DR89-091	Fuel Costs

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Bus & Industry Association	5/90	Northeast Utilities	Docket No. DR89-244	Merger & Acq. Issues
Eastern Utilities Associates	6/90	Eastern Utilities Associates	Docket No. DF89-085	Merger & Acq. Issues
EnergyNorth Natural Gas	12/90	EnergyNorth Natural Gas	Docket No. DE90-166	Gas Purchasing Practices
EnergyNorth Natural Gas	7/90	EnergyNorth Natural Gas	Docket No. DR90-187	Special Contracts, Discounted Rates
Northern Utilities, Inc.	12/91	Commission Investigation	Docket No. DR91-172	Generic Discounted Rates
New Jersey Board of Public Utilities				
Hilton/Golden Nugget	12/83	Atlantic Electric	B.P.U. 832-154	Line Extension Policies
Golden Nugget	3/87	Atlantic Electric	B.P.U. No. 837-658	Line Extension Policies
New Jersey Natural Gas	2/89	New Jersey Natural Gas	B.P.U. GR89030335J	Cost Alloc./Rate Design
New Jersey Natural Gas	1/91	New Jersey Natural Gas	B.P.U. GR90080786J	Cost Alloc./Rate Design
New Jersey Natural Gas	8/91	New Jersey Natural Gas	B.P.U. GR91081393J	Rate Design; Weather Norm. Clause
New Jersey Natural Gas	4/93	New Jersey Natural Gas	B.P.U. GR93040114J	Cost Alloc./Rate Design
South Jersey Gas	4/94	South Jersey Gas	BRC Dock No. GR080334	Revised levelized gas adjustment
New Jersey Utilities Association	9/96	Commission Investigation	BPU AX96070530	PBOP Cost Recovery
Morris Energy Group	11/09	Public Service Electric & Gas	BPU GR 09050422	Discriminatory Rates
New Jersey American Water Co.	4/10	New Jersey American Water Co.	BPU WR 1040260	Tariff Rates and Revisions
Electric Customer Group	01/11	Generic Stakeholder Proceeding	BPU GR10100761 and ER10100762	Natural gas ratemaking standards and pricing

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
New Mexico Public Service Commission				
Gas Company of New Mexico	11/83	Public Service Co. of New Mexico	Docket No. 1835	Cost Alloc./Rate Design
New York Public Service Commission				
Iroquois Gas. Transmission	12/86	Iroquois Gas Transmission System	Case No. 70363	Gas Markets
Brooklyn Union Gas Company	8/95	Brooklyn Union Gas Company	Case No. 95-6-0761	Panel on Industry Directions
Central Hudson, ConEdison and Niagara Mohawk	9/00	Central Hudson, ConEdison and Niagara Mohawk	Case No. 96-E-0909 Case No. 96-E-0897 Case No. 94-E-0098 Case No. 94-E-0099	Section 70, Approval of New Facilities
Central Hudson, New York State Electric & Gas, Rochester Gas & Electric	5/01	Joint Petition of NiMo, NYSEG, RG&E, Central Hudson, Constellation and Nine Mile Point	Case No. 01-E-0011	Section 70, Rebuttal Testimony
Rochester Gas & Electric	12/03	Rochester Gas & Electric	Case No. 03-E-1231	Sale of Nuclear Plant
Rochester Gas & Electric	01/04	Rochester Gas & Electric	Case No. 03-E-0765 Case No. 02-E-0198 Case No. 03-E-0766	Sale of Nuclear Plant; Ratemaking Treatment of Sale
Rochester Gas and Electric and NY State Electric & Gas Corp	2/10	Rochester Gas & Electric NY State Electric & Gas Corp	Case No. 09-E-0715 Case No. 09-E-0716 Case No. 09-E-0717 Case No. 09-E-0718	Depreciation policy
Oklahoma Corporation Commission				
Oklahoma Natural Gas Company	6/98	Oklahoma Natural Gas Company	Case PUD No. 980000177	Storage issues

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Oklahoma Gas & Electric Company	9/05	Oklahoma Gas & Electric Company	Cause No. PUD 200500151	Prudence of McLain Acquisition
Oklahoma Gas & Electric Company	03/08	Oklahoma Gas & Electric Company	Cause No. PUD 200800086	Acquisition of Redbud generating facility
Ontario Energy Board				
Market Hub Partners Canada, L.P.	5/06	Natural Gas Electric Interface Roundtable	File No. EB-2005-0551	Market-based Rates For Storage
Pennsylvania Public Utility Commission				
ATOC	4/95	Equitrans	Docket No. R-00943272	Rate Design, unbundling
ATOC	3/96	Equitrans	Docket No. P-00940886	Rate Design, unbundling
Rhode Island Public Utilities Commission				
Newport Electric	7/81	Newport Electric	Docket No. 1599	Rate Attrition
South County Gas	9/82	South County Gas	Docket No. 1671	Cost of Capital
New England Energy Group	7/86	Providence Gas Company	Docket No. 1844	Cost Alloc./Rate Design
Providence Gas	8/88	Providence Gas Company	Docket No. 1914	Load Forecast., Least-Cost Planning
Providence Gas Company and The Valley Gas Company	1/01	Providence Gas Company and The Valley Gas Company	Docket No. 1673 and 1736	Gas Cost Mitigation Strategy
The New England Gas Company	3/03	New England Gas Company	Docket No. 3459	Cost of Capital
Texas Public Utility Commission				
Southwestern Electric	5/83	Southwestern Electric		Cost of Capital, CWIP

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
P.U.C. General Counsel	11/90	Texas Utilities Electric Company	Docket No. 9300	Gas Purchasing Practices, Prudence
Oncor Electric Delivery Company	8/07	Oncor Electric Delivery Company	Docket No. 34040	Regulatory Policy, Rate of Return, Return of Capital and Consolidated Tax Adjustment
Oncor Electric Delivery Company	6/08	Oncor Electric Delivery Company	Docket No.35717	Regulatory policy
Oncor Electric Delivery Company	10/08, 11/08	Oncor, TCC, TNC, ETT, LCRA TSC, Sharyland, STEC, TNMP	Docket No. 35665	Competitive Renewable Energy Zone
CenterPoint Energy	6/10 10/10	CenterPoint Energy/Houston Electric	Docket No. 38339	Regulatory policy, risk, consolidated taxes
Oncor Electric Delivery Company	1/11	Oncor Electric Delivery Company	Docket No. 38929	Regulatory policy, risk
Texas Railroad Commission				
Western Gas Interstate Company	1/85	Southern Union Gas Company	Docket 5238	Cost of Service
Atmos Pipeline Texas	9/10; 1/11	Atmos Pipeline Texas	GUD 10000	Ratemaking Policy, risk
Utah Public Service Commission				
AMAX Magnesium	1/88	Mountain Fuel Supply Company	Case No. 86-057-07	Cost Alloc./Rate Design
AMAX Magnesium	4/88	Utah P&L/Pacific P&L	Case No. 87-035-27	Merger & Acquisition
Utah Industrial Group	7/90	Mountain Fuel Supply	Case No. 89-057-15	Gas Transportation Rates
AMAX Magnesium	9/90	Utah Power & Light	Case No. 89-035-06	Energy Balancing Account
AMAX Magnesium	8/90	Utah Power & Light	Case No. 90-035-06	Electric Service Priorities

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Questar Gas Company	12/07	Questar Gas Company	Docket No. 07-057-13	Benchmarking in support of ROE
Vermont Public Service Board				
Green Mountain Power	8/82	Green Mountain Power	Docket No. 4570	Rate Attrition
Green Mountain Power	12/97	Green Mountain Power	Docket No. 5983	Cost of Service
Green Mountain Power	7/98, 9/00	Green Mountain Power	Docket No. 6107	Rate development
Wisconsin Public Service Commission				
WEC & WICOR	11/99	WEC	Docket No. 9401-YO-100 Docket No. 9402-YO-101	Approval to Acquire the Stock of WICOR
Wisconsin Electric Power Company	1/07	Wisconsin Electric Power Co.	Docket No. 6630-EI-113	Sale of Nuclear Plant
Wisconsin Electric Power Company	10/09	Wisconsin Electric Power Co.	Docket No. 6630-CE-302	CPCN Application for wind project

SPONSOR	Date	CASE/APPLICANT	DOCKET NO.	SUBJECT
American Arbitration Association				
Michael Polsky	3/91	M. Polsky vs. Indeck Energy		Corporate Valuation, Damages
ProGas Limited	7/92	ProGas Limited v. Texas Eastern		Gas Contract Arbitration
Attala Generating Company	12/03	Attala Generating Co v. Attala Energy Co.	Case No. 16-Y-198-00228-03	Power Project Valuation; Breach of Contract; Damages
Nevada Power Company	4/08	Nevada Power v. Nevada Cogeneration Assoc. #2		Power Purchase Agreement
Sensata Technologies, Inc./EMS Engineered Materials Solutions, LLC	1/11	Sensata Technologies, Inc./EMS Engineered Materials Solutions, LLC v. Pepco Energy Services	Case No. 11-198-Y-00848-10	Change in usage dispute/damages
Commonwealth of Massachusetts, Suffolk Superior Court				
John Hancock	1/84	Trinity Church v. John Hancock	C.A. No. 4452	Damages Quantification
State of Colorado District Court, County of Garfield				
Questar Corporation, et al	11/00	Questar Corporation, et al.	Case No. 00CV129-A	Partnership Fiduciary Duties
State of Delaware, Court of Chancery, New Castle County				
Wilmington Trust Company	11/05	Calpine Corporation vs. Bank Of New York and Wilmington Trust Company	C.A. No. 1669-N	Bond Indenture Covenants

SPONSOR	Date	CASE/APPLICANT	DOCKET NO.	SUBJECT
Illinois Appellate Court, Fifth Division				
Norweb, plc	8/02	Indeck No. America v. Norweb	Docket No. 97 CH 07291	Breach of Contract; Power Plant Valuation
Independent Arbitration Panel				
Alberta Northeast Gas Limited	2/98	ProGas Ltd., Canadian Forest Oil Ltd., AEC Oil & Gas		
Ocean State Power	9/02	Ocean State Power vs. ProGas Ltd.	2001/2002 Arbitration	Gas Price Arbitration
Ocean State Power	2/03	Ocean State Power vs. ProGas Ltd.	2002/2003 Arbitration	Gas Price Arbitration
Ocean State Power	6/04	Ocean State Power vs. ProGas Ltd.	2003/2004 Arbitration	Gas Price Arbitration
Shell Canada Limited	7/05	Shell Canada Limited and Nova Scotia Power Inc.		Gas Contract Price Arbitration
International Court of Arbitration				
Wisconsin Gas Company, Inc.	2/97	Wisconsin Gas Co. vs. Pan-Alberta	Case No. 9322/CK	Contract Arbitration
Minnegasco, A Division of NorAm Energy Corp.	3/97	Minnegasco vs. Pan-Alberta	Case No. 9357/CK	Contract Arbitration
Utilicorp United Inc.	4/97	Utilicorp vs. Pan-Alberta	Case No. 9373/CK	Contract Arbitration
IES Utilities	97	IES vs. Pan-Alberta	Case No. 9374/CK	Contract Arbitration

SPONSOR	Date	CASE/APPLICANT	DOCKET NO.	SUBJECT
State of New Jersey, Mercer County Superior Court				
Transamerica Corp., et. al.	7/07, 10/07	IMO Industries Inc. vs. Transamerica Corp., et. al.	Docket No. L-2140-03	Breach-Related Damages, Enterprise Value
State of New York, Nassau County Supreme Court				
Steel Los III, LP	6/08	Steel Los II, LP & Associated Brook, Corp v. Power Authority of State of NY	Index No. 5662/05	Property seizure
Province of Alberta, Court of Queen's Bench				
Alberta Northeast Gas Limited	5/07	Cargill Gas Marketing Ltd. vs. Alberta Northeast Gas Limited	Action No. 0501-03291	Gas Contracting Practices
State of Rhode Island, Providence City Court				
Aquidneck Energy	5/87	Laroche vs. Newport		Least-Cost Planning
State of Texas Hutchinson County Court				
Western Gas Interstate	5/85	State of Texas vs. Western Gas Interstate Co.	Case No. 14,843	Cost of Service
State of Texas District Court of Nueces County				
Northwestern National Insurance Company	11/11	ASARCO LLC	No. 01-2680-D	Damages

SPONSOR	Date	CASE/APPLICANT	DOCKET NO.	SUBJECT
State of Utah Third District Court				
PacifiCorp & Holme, Roberts & Owen, LLP	1/07	USA Power & Spring Canyon Energy vs. PacifiCorp. et. al.	Civil No. 050903412	Breach-Related Damages
U.S. Bankruptcy Court, District of New Hampshire				
EUA Power Corporation	7/92	EUA Power Corporation	Case No. BK-91-10525-JEY	Pre-Petition Solvency
U.S. Bankruptcy Court, District Of New Jersey				
Ponderosa Pine Energy Partners, Ltd.	7/05	Ponderosa Pine Energy Partners, Ltd.	Case No. 05-21444	Forward Contract Bankruptcy Treatment
U.S. Bankruptcy Court, No. District of New York				
Cayuga Energy, NYSEG Solutions, The Energy Network	09/09	Cayuga Energy, NYSEG Solutions, The Energy Network	Case No. 06-60073-6-sdg	Going concern
U.S. Bankruptcy Court, So. District Of New York				
Johns Manville	5/04	Enron Energy Mktg. v. Johns Manville; Enron No. America v. Johns Manville	Case No. 01-16034 (AJG)	Breach of Contract; Damages

SPONSOR	Date	CASE/APPLICANT	DOCKET NO.	SUBJECT
U.S. Bankruptcy Court, Northern District Of Texas				
Southern Maryland Electric Cooperative, Inc. and Potomac Electric Power Company	11/04	Mirant Corporation, et al. v. SMECO	Case No. 03-4659; Adversary No. 04-4073	PPA Interpretation; Leasing
U. S. Court of Federal Claims				
Boston Edison Company	7/06, 11/06	Boston Edison v. Department of Energy	No. 99-447C No. 03-2626C	Spent Nuclear Fuel Litigation
Consolidated Edison of New York	08/07	Consolidated Edison of New York, Inc. and subsidiaries v. United States	No. 06-305T	Leasing, tax dispute
Consolidated Edison Company	2/08, 6/08	Consolidated Edison Company v. United States	No. 04-0033C	SNF Expert Report
Vermont Yankee Nuclear Power Corporation	6/08	Vermont Yankee Nuclear Power Corporation	No. 03-2663C	SNF Expert Report
U. S. District Court, Boulder County, Colorado				
KN Energy, Inc.	3/93	KN Energy vs. Colorado GasMark, Inc.	Case No. 92 CV 1474	Gas Contract Interpretation
U. S. District Court, Northern California				
Pacific Gas & Electric Co./PGT PG&E/PGT Pipeline Exp. Project	4/97	Norcen Energy Resources Limited	Case No. C94-0911 VRW	Fraud Claim

SPONSOR	Date	CASE/APPLICANT	DOCKET NO.	SUBJECT
U. S. District Court, District of Connecticut				
Constellation Power Source, Inc.	12/04	Constellation Power Source, Inc. v. Select Energy, Inc.	Civil Action 304 CV 983 (RNC)	ISO Structure, Breach of Contract
U.S. District Court, Northern District of Illinois, Eastern Division				
U.S. Securities and Exchange Commission	4/12	U.S. Securities and Exchange Commission v. Thomas Fisher, Kathleen Halloran, and George Behrens	Case No. 07 C 4483	Prudence, PBR
U. S. District Court, Massachusetts				
Eastern Utilities Associates & Donald F. Pardus	3/94	NECO Enterprises Inc. vs. Eastern Utilities Associates	Civil Action No. 92-10355-RCL	Seabrook Power Sales
U. S. District Court, Montana				
KN Energy, Inc.	9/92	KN Energy v. Freeport MacMoRan	Docket No. CV 91-40-BLG-RWA	Gas Contract Settlement
U.S. District Court, New Hampshire				
Portland Natural Gas Transmission and Maritimes & Northeast Pipeline	9/03	Public Service Company of New Hampshire vs. PNGTS and M&NE Pipeline	Docket No. C-02-105-B	Impairment of Electric Transmission Right-of-Way

SPONSOR	Date	CASE/APPLICANT	DOCKET NO.	SUBJECT
U. S. District Court, Southern District of New York				
Central Hudson Gas & Electric	11/99, 8/00	Central Hudson v. Riverkeeper, Inc., Robert H. Boyle, John J. Cronin	Civil Action 99 Civ 2536 (BDP)	Electric restructuring, environmental impacts
Consolidated Edison	3/02	Consolidated Edison v. Northeast Utilities	Case No. 01 Civ. 1893 (JGK) (HP)	Industry Standards for Due Diligence
Merrill Lynch & Company	1/05	Merrill Lynch v. Allegheny Energy, Inc.	Civil Action 02 CV 7689 (HB)	Due Diligence, Breach of Contract, Damages
U. S. District Court, Eastern District of Virginia				
Aquila, Inc.	1/05, 2/05	VPEM v. Aquila, Inc.	Civil Action 304 CV 411	Breach of Contract, Damages
U. S. District Court, Portland Maine				
ACEC Maine, Inc. et al.	10/91	CIT Financial vs. ACEC Maine	Docket No. 90-0304-B	Project Valuation
Combustion Engineering	1/92	Combustion Eng. vs. Miller Hydro	Docket No. 89-0168P	Output Modeling; Project Valuation
U.S. Securities and Exchange Commission				
Eastern Utilities Association	10/92	EUA Power Corporation	File No. 70-8034	Value of EUA Power
Council of the District of Columbia Committee on Consumer and Regulatory Affairs				
Potomac Electric Power Co.	7/99	Potomac Electric Power Co.	Bill 13-284	Utility restructuring

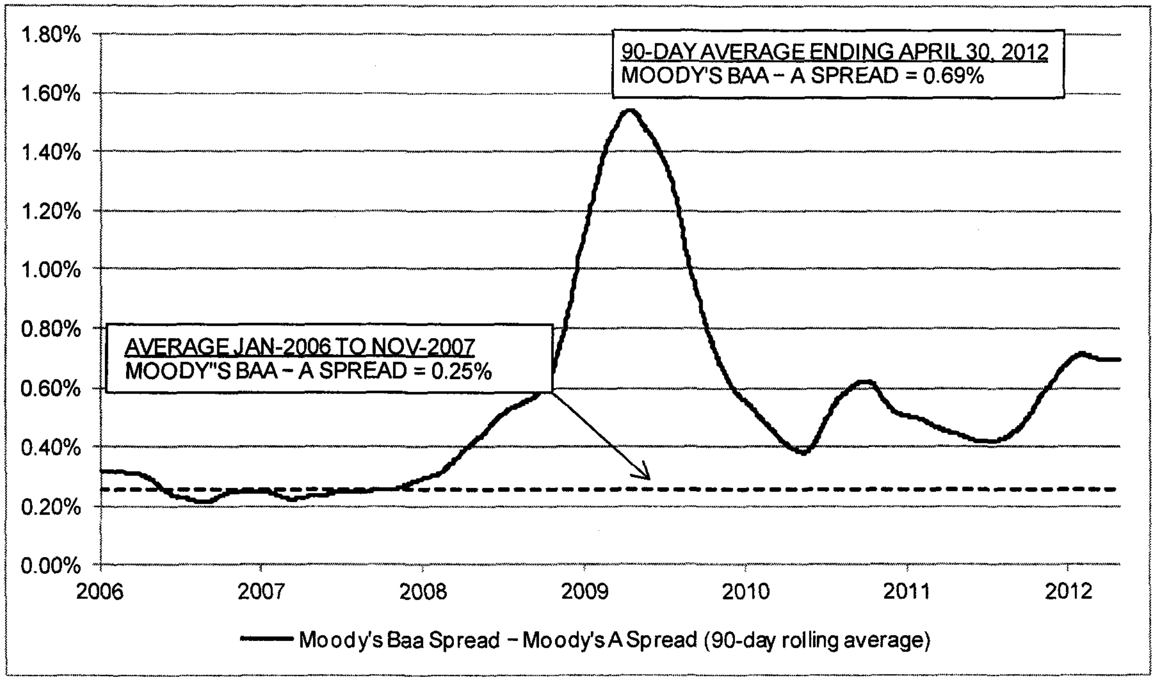
APPENDIX
"A"

I. Capital Market Conditions

Credit Spreads

As a preliminary matter, the "credit spread" is the incremental return required by debt investors to take on the default risk associated with securities of differing credit quality. As Chart 1 demonstrates, the 90-day moving average spread as of April 30, 2012 between the Moody's Baa-rated utility bond index and the Moody's A-rated utility bond index is 44 basis points (or 176 percent) above the comparable average credit spread immediately prior to the onset of the recent recession. As such, investors currently require a substantially higher return to compensate for the perceived risk of holding lower-rated debt securities than was the case prior to the onset of the recent recession.

Chart 1: Moody's Utility Bond Index Baa-A Credit Spread



To the extent that credit spreads have increased, it is an observable measure of the capital markets' increased risk aversion; increased risk aversion clearly is associated with a relatively higher Cost of Equity. Although increased credit spreads have recently coincided with a reduction in the absolute level of utility bond and Treasury yields, that fact does not necessarily imply a correspondingly lower Cost of Equity; to the contrary, there is a clear and well-established inverse relationship between the level of interest rates and the equity risk premium.[1] Consequently, lower utility bond yields, which are a function of lower Treasury yields, do not imply a correspondingly lower Cost of Equity, particularly considering that the current level of credit spreads is higher than the long-term average.

Yield Spreads

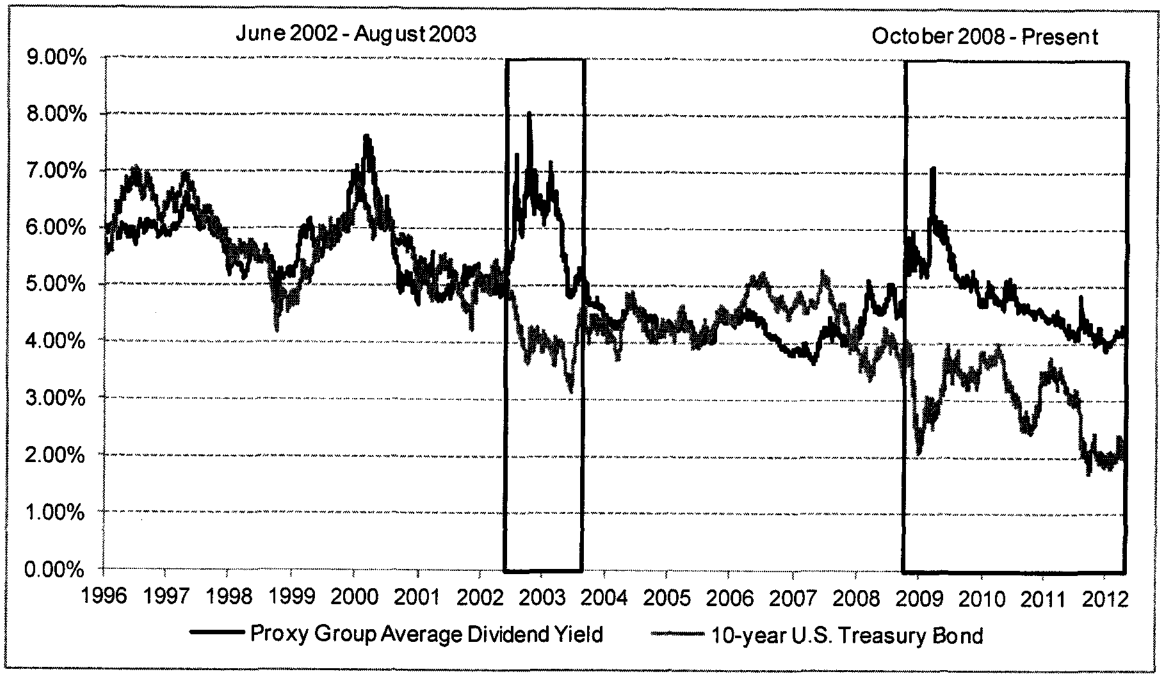
As a preliminary matter, the "yield spread" is the difference between long-term Treasury yields and dividend yields.[2] Investors often consider yield spreads in their assessment of security valuation and capital market conditions. As shown in Chart 2, the 2008 – 2009 financial market dislocation created the first significant inversion of the yield spread (*i.e.,* the average dividend yield for the proxy group was significantly higher than the 90-day average Treasury yield) in five years. Prior to that time, the most recent period during which dividend yields for the proxy group were significantly higher than Treasury yields was from mid-2002 through mid-2003, which itself was a period of credit and equity valuation contraction.

1 Robert S. Harris and Felicia C. Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts,* Financial Management, Summer 1992, at 69; Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, Financial Management, Spring 1985, at 33-45; and Farris M. Maddox, Donna T. Pippert, and Rodney N. Sullivan, *An Empirical Study of Ex Ante Risk Premiums for the Electric Utility Industry*, Financial Management, Autumn 1995, at 89-95.

2 The analysis presented in Chart 2 is based on yield spreads calculated using 10-year Treasury Bond Yields.

Chart 2: Treasury Yield/Dividend Yield Divergence

(January 1, 1996 – April 30, 2012)



An article in *The Wall Street Journal* during this period noted this same relationship between utility dividend yields and the ten-year Treasury yield, observing that, "Dividend yields have tended to track the yield on 10-year Treasurys closely."[3]

As suggested by *The Wall Street Journal*, investors often look to the relationships among financial metrics to assess current and expected levels of market stability. To the extent that such relationships materially and persistently deviate from long-term norms, it may be an indication of continuing or expected instability. In the case of the yield spread, the fact that continued Federal intervention in the capital markets has been required to maintain relatively low Treasury yields introduces yet another significant element of capital market uncertainty. For example, in its second round of "Quantitative Easing", the Federal Reserve Board ("Fed") purchased $600 billion of Treasury securities between November 2010 and June 2011, thereby injecting additional liquidity into capital markets. In an effort to reduce interest rates on longer-term government bonds, on

3 Denning, Liam, "A Short Circuit in the Stock Market," *The Wall Street Journal*, October 23, 2009, at C10.

September 21, 2011, the Fed announced plans to purchase by June 2012 $400 billion in Treasury securities with remaining maturities of six to 30 years and to sell an equal amount of Treasury securities with remaining maturities of three years or less. More recently, in a press release in March 2012, the Federal Open Market Committee ("FOMC") announced its intention to keep the federal funds rate at 0.00 to 0.25 percent possibly through late 2014. In addition, the FOMC announced plans to continue its policy that was announced in September 2011 to extend the average maturity of its holdings and to roll over maturing Treasury securities at auction, thereby maintaining low interest rates on longer-term government bonds.[4]

The widened yield spread, which began in 2008, has continued. From January 2000 through September 15, 2008 (*i.e.*, the time of the Lehman Brothers bankruptcy filing), the average yield spread between ten-year Treasury securities and the proxy group average dividend yield was negative 25 basis points. During the two-year period[5] prior to the recession, the average yield on ten-year Treasury securities exceeded the proxy group average dividend yield by approximately 62 basis points. As Chart 3 indicates, the 90-day average yield spread as of April 30, 2012 was negative 207 basis points.

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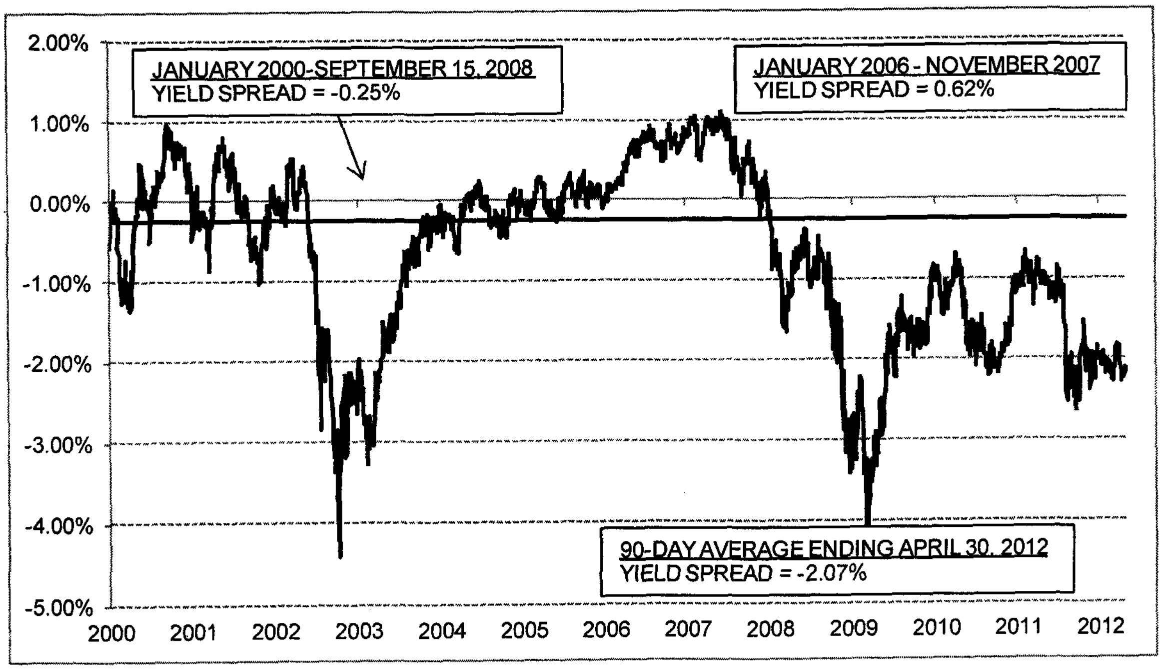
4 Press Release from the Federal Open Market Committee, March 13, 2012.

5 This analysis includes the 23 months beginning January 2006 and ending November 30, 2007, just prior to the start of the recent recession, as defined by the National Bureau of Economic Research.

Chart 3: Proxy Company Yield Spread



Constant Growth DCF Model

The DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its most general form, the DCF model is expressed as follows:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \ldots + \frac{D_\infty}{(1+k)^\infty} \quad [1]$$

where:

P_0 = the current stock price;

$D_1 \ldots D_\infty$ = all expected future dividends; and

k = the discount rate or required ROE.

Equation [1] is a standard present value calculation that can be simplified and rearranged into the familiar form:

$$k = \frac{D(1+g)}{P_0} + g \quad [2]$$

Equation [2] is often referred to as the "Constant Growth DCF" model in which the first term is the expected dividend yield and the second term is the expected long-term growth rate.

Multi-Stage DCF Model

The model sets the subject company's stock price equal to the present value of future cash flows received over three "stages." In the first two stages, cash flows are defined as projected dividends. In the third stage, cash flows equal both dividends and the expected price at which the stock will be sold at the end of the period. I estimated the expected terminal stock price based on the Gordon model, which defines the price as the expected dividend divided by the difference between the cost of equity (*i.e.*, the discount rate) and the long-term expected growth rate. In each of the three stages, the dividend is the product of the projected earnings per share and the expected dividend payout ratio. A summary description of the model is provided in Table 1 (below).

Table 1: Multi-Stage DCF Structure

Stage	0	1	2	3
Cash Flow Component	Initial Stock Price	Expected Dividend	Expected Dividend	Expected Dividend + Terminal Value
Inputs	Stock Price Earnings Per Share ("EPS") Dividends Per Share ("DPS")	Expected EPS Expected DPS	Expected EPS Expected DPS	Expected EPS Expected DPS Terminal Value
Assumptions	30, 90, and 180-day average stock price	EPS growth rate Payout ratio		Long-term growth rate

Assumptions to the Multi-Stage DCF model

Table 2 (below) summarizes the assumptions that are used in the multi-stage DCF model.

Table 2: Assumptions to the Multi-Stage DCF model

Stage	0	1	2	3
Stock Price	30, 90, and 180-day average stock price as of March 16, 2012			
Earnings Growth	EPS as reported by Value Line	EPS growth as average of (1) Value Line, (2) Zacks, and (3) First Call projected growth rates	Transition to Long-term GDP growth on geometric average basis	Long-term GDP Growth
Payout Ratio		Value Line company-specific	Transition to industry average payout ratio (Value Line) on a geometric average Basis	Industry average (Value Line)
Terminal Value				Expected dividend in final year calculated using the Gordon Growth model

It is important to note that while the model calculates the cost of equity based on expected dividends, it does not rely solely on Value Line for dividend growth rate projections. A common and legitimate criticism of DCF models that rely on projected dividend growth rates (especially in the Constant Growth form of the model) is that Value Line is the sole source of such projections.[6] The model also enables the analyst to assess the reasonableness of the inputs and results by reference to certain market-based metrics. For example, using the Gordon model to estimate the terminal price, the stock price estimate can be divided by the expected earnings per share in the final year to calculate an average P/E ratio. To the extent that the projected P/E ratio is inconsistent with either historical or expected levels, it may indicate incorrect or inconsistent assumptions within the balance of the model.

Capital Asset Pricing Model

The CAPM is defined by four components, each of which must theoretically be a forward-looking estimate:

$$K_e = r_f + \beta(r_m - r_f) \quad [3]$$

where:

K_e = the required market ROE;

β = Beta of an individual security;

r_f = the risk-free rate of return; and

r_m = the required return on the market as a whole.

In this specification, the term $(r_m - r_f)$ represents the market risk premium. According to the theory underlying the CAPM, since unsystematic risk can be diversified away, investors should be concerned only with systematic or non-diversifiable risk. Non-diversifiable risk is measured by Beta, which is defined as:

$$\beta = \frac{Covariance(r_e, r_m)}{Variance(r_m)} \quad [4]$$

The variance of the market return, noted in Equation [5], is a measure of the uncertainty of the general market, and the covariance between the return on a specific security and the market reflects the extent to which the return on that security will respond to a given change in the market return. Thus, Beta represents the risk of the security relative to the market.

Modigliani and Miller Theorem

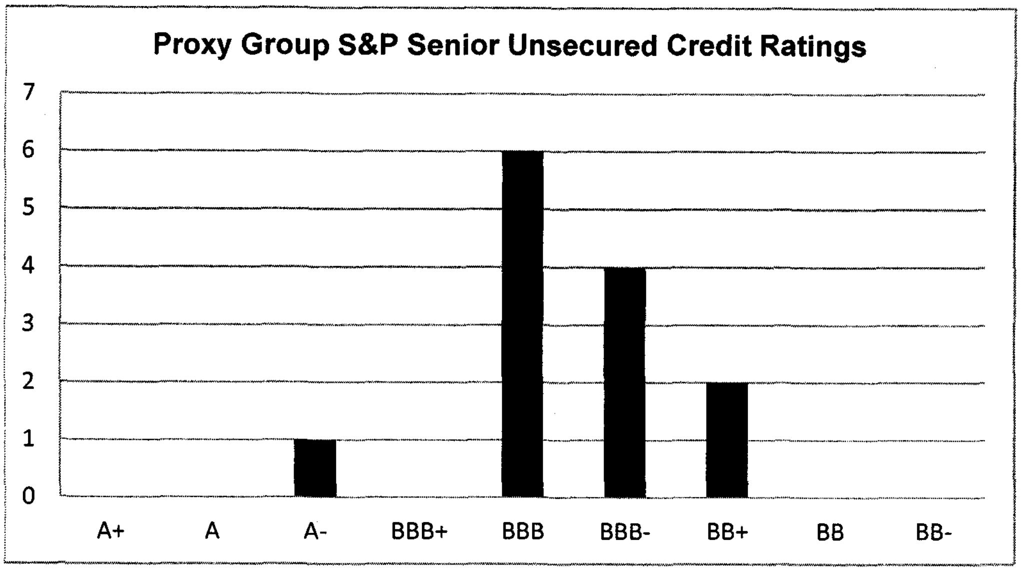
The cost of capital for a company depends upon both its business and financial risks, the latter of which are evaluated primarily by reference to the amount of debt leverage in its capital structure. In developing the theory of capital structure, Professors Modigliani and Miller (1958) questioned why the mix of debt and equity in the capital structure should have any effect upon the overall weighted cost of capital of the firm. They argued that the risks and operating income of a company should be the same regardless of how the company is financed. They reasoned that any change in capital structure would merely shift the risks and rights to operating income between lenders and shareholders without changing the overall risks or income of the company and therefore should have no effect upon the overall cost of capital. The position that capital structure theoretically should not affect the overall cost of capital of a company is known as the Modigliani-Miller Theory.

The Modigliani-Miller Theory set off a great deal of research in finance, and it is now widely agreed that the theory failed to recognize several important effects of capital structure decisions. First, the theory incorrectly assumed that operating income is split only between lenders and shareholders. However, the government, through corporate income taxes, typically is a third claimant on a portion of the company's operating income. Because interest payments are tax deductible, but dividend payments generally are not, as a company takes on more debt it increases the amount of its tax deductions and reduces the share of operating income claimed by the government. Thus, the size of the government's share of income depends upon the capital structure of the firm.

EXHIBIT

JJR-1

Company	Ticker	S&P Senior Unsecured Rating	Notes
American Electric Power	AEP	BBB	
Cleco Corp.	CNL	BBB	[1]
Empire District Electric	EDE	BBB-	
Entergy Corp.	ETR	BBB-	
Great Plains Energy Inc.	GXP	BBB-	
Hawaiian Electric	HE	BBB-	
IDACORP, Inc.	IDA	BBB	[1]
NV Energy	NVE	BB+	
Pinnacle West Capital	PNW	BBB	[1]
PNM Resources	PNM	BB+	
Portland General	POR	BBB	
Southern Co.	SO	A-	
Westar Energy	WR	BBB	[1]



Notes:
[1] For companies that did not have a senior unsecured rating available from S&P, we relied on the long-term issuer rating. Ratings are as of 5-11-12.

EXHIBIT

JJR-2

30-DAY CONSTANT GROWTH DCF RESULTS

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Zacks EPS Growth	Value Line EPS Growth	First Call	Average Growth Rate	Low DCF ROE	Mean DCF ROE	High DCF ROE
American Electric Power	AEP	$1.88	$38.21	4.92%	5.02%	4.30%	4.00%	3.54%	3.95%	8.55%	8.96%	9.33%
Cleco Corp.	CNL	$1.25	$39.52	3.16%	3.25%	NA	8.00%	3.00%	5.50%	6.21%	8.75%	11.29%
Empire District Electric	EDE	$1.00	$20.13	4.97%	5.17%	NA	6.00%	10.20%	8.10%	11.12%	13.27%	15.42%
Entergy Corp.	ETR	$3.32	$66.37	5.00%	5.05%	2.00%	NA	NA	2.00%	7.05%	7.05%	7.05%
Great Plains Energy Inc.	GXP	$0.85	$20.04	4.24%	4.37%	7.00%	5.50%	4.97%	5.82%	9.32%	10.19%	11.39%
Hawaiian Electric	HE	$1.24	$25.45	4.87%	5.09%	6.50%	9.00%	11.37%	8.96%	11.53%	14.05%	16.52%
IDACORP, Inc.	IDA	$1.32	$40.37	3.27%	3.34%	5.00%	3.00%	4.00%	4.00%	6.32%	7.34%	8.35%
NV Energy	NVE	$0.52	$15.95	3.26%	3.44%	10.20%	11.00%	12.63%	11.28%	13.63%	14.72%	16.10%
Pinnacle West Capital	PNW	$2.10	$47.38	4.43%	4.55%	5.30%	5.00%	5.88%	5.39%	9.54%	9.95%	10.44%
PNM Resources	PNM	$0.58	$18.41	3.15%	3.36%	12.60%	15.50%	10.95%	13.02%	14.27%	16.37%	18.90%
Portland General	POR	$1.06	$25.01	4.24%	4.34%	5.20%	5.50%	4.27%	4.99%	8.60%	9.33%	9.85%
Southern Co.	SO	$1.89	$44.99	4.20%	4.31%	5.10%	5.00%	5.58%	5.23%	9.31%	9.54%	9.90%
Westar Energy	WR	$1.32	$27.80	4.75%	4.89%	5.80%	6.50%	6.13%	6.14%	10.69%	11.04%	11.40%
			MEAN	4.19%	4.32%	6.27%	7.00%	6.88%	6.49%	9.70%	10.81%	12.00%

Notes
[1] Source: Bloomberg
[2] Source: Bloomberg. Based on 30 days historical average.
[3] Equals Col. [1]/Col. [2]
[4] Equals (Col. [3] x (1+(.5 x Col. [8]))
[5] Source: Zacks
[6] Source: Value Line.
[7] Source: Yahoo! Finance
[8] Equals average of Cols [5], [6], [7]
[9] Equals Col [3] x (1+(0.5 x (Min (Cols [5], [6], [7])) + Min (Cols [5], [6], [7])
[10] Equals Col. [4] + Col. [8]
[11] Equals Col [3] x (1+(0.5 x (Max (Cols [5], [6], [7])) + Max (Cols [5], [6], [7])

90-DAY CONSTANT GROWTH DCF RESULTS

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Zacks EPS Growth	Value Line EPS Growth	First Call	Average Growth Rate	Low DCF ROE	Mean DCF ROE	High DCF ROE
American Electric Power	AEP	$1.88	$39.30	4.78%	4.88%	4.30%	4.00%	3.54%	3.95%	8.41%	8.82%	9.19%
Cleco Corp.	CNL	$1.25	$38.73	3.23%	3.32%	NA	8.00%	3.00%	5.50%	6.28%	8.82%	11.36%
Empire District Electric	EDE	$1.00	$20.45	4.89%	5.09%	NA	6.00%	10.20%	8.10%	11.04%	13.19%	15.34%
Entergy Corp.	ETR	$3.32	$68.50	4.85%	4.90%	2.00%	NA	NA	2.00%	6.90%	6.90%	6.90%
Great Plains Energy Inc.	GXP	$0.85	$20.55	4.14%	4.26%	7.00%	5.50%	4.97%	5.82%	9.21%	10.08%	11.28%
Hawaiian Electric	HE	$1.24	$25.66	4.83%	5.05%	6.50%	9.00%	11.37%	8.96%	11.49%	14.01%	16.48%
IDACORP, Inc.	IDA	$1.32	$41.15	3.21%	3.27%	5.00%	3.00%	4.00%	4.00%	6.26%	7.27%	8.29%
NV Energy	NVE	$0.52	$16.00	3.25%	3.43%	10.20%	11.00%	12.63%	11.28%	13.62%	14.71%	16.09%
Pinnacle West Capital	PNW	$2.10	$47.51	4.42%	4.54%	5.30%	5.00%	5.88%	5.39%	9.53%	9.93%	10.43%
PNM Resources	PNM	$0.58	$18.17	3.19%	3.40%	12.60%	15.50%	10.95%	13.02%	14.32%	16.42%	18.94%
Portland General	POR	$1.06	$24.97	4.25%	4.35%	5.20%	5.50%	4.27%	4.99%	8.61%	9.34%	9.86%
Southern Co.	SO	$1.89	$44.95	4.20%	4.31%	5.10%	5.00%	5.58%	5.23%	9.31%	9.54%	9.90%
Westar Energy	WR	$1.32	$28.08	4.70%	4.85%	5.80%	6.50%	6.13%	6.14%	10.64%	10.99%	11.35%
			MEAN	4.15%	4.28%	6.27%	7.00%	6.88%	6.49%	9.66%	10.77%	11.95%

Notes
[1] Source: Bloomberg
[2] Source: Bloomberg. Based on 90 days historical average.
[3] Equals Col. [1]/Col. [2]
[4] Equals (Col. [3] x (1+(.5 x Col. [8]))
[5] Source: Zacks
[6] Source: Value Line.
[7] Source: Yahoo! Finance
[8] Equals average of Cols [5], [6], [7]
[9] Equals Col [3] x (1+(0.5 x (Min (Cols [5], [6], [7])) + Min (Cols [5], [6], [7])
[10] Equals Col. [4] + Col. [8]
[11] Equals Col [3] x (1+(0.5 x (Max (Cols [5], [6], [7])) + Max (Cols [5], [6], [7])

180-DAY CONSTANT GROWTH DCF RESULTS

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Zacks EPS Growth	Value Line EPS Growth	First Call	Average Growth Rate	Low DCF ROE	Mean DCF ROE	High DCF ROE
American Electric Power	AEP	$1.88	$38.82	4.84%	4.94%	4.30%	4.00%	3.54%	3.95%	8.47%	8.89%	9.25%
Cleco Corp.	CNL	$1.25	$36.98	3.38%	3.47%	NA	8.00%	3.00%	5.50%	6.43%	8.97%	11.52%
Empire District Electric	EDE	$1.00	$20.20	4.95%	5.15%	NA	6.00%	10.20%	8.10%	11.10%	13.25%	15.40%
Entergy Corp.	ETR	$3.32	$67.66	4.91%	4.96%	2.00%	NA	NA	2.00%	6.96%	6.96%	6.96%
Great Plains Energy Inc.	GXP	$0.85	$20.27	4.19%	4.32%	7.00%	5.50%	4.97%	5.82%	9.27%	10.14%	11.34%
Hawaiian Electric	HE	$1.24	$25.19	4.92%	5.14%	6.50%	9.00%	11.37%	8.96%	11.58%	14.10%	16.57%
IDACORP, Inc.	IDA	$1.32	$40.06	3.29%	3.36%	5.00%	3.00%	4.00%	4.00%	6.34%	7.36%	8.38%
NV Energy	NVE	$0.52	$15.47	3.36%	3.55%	10.20%	11.00%	12.63%	11.28%	13.73%	14.83%	16.20%
Pinnacle West Capital	PNW	$2.10	$46.02	4.56%	4.69%	5.30%	5.00%	5.88%	5.39%	9.68%	10.08%	10.58%
PNM Resources	PNM	$0.58	$17.46	3.32%	3.54%	12.60%	15.50%	10.95%	13.02%	14.45%	16.56%	19.08%
Portland General	POR	$1.06	$24.51	4.32%	4.43%	5.20%	5.50%	4.27%	4.99%	8.69%	9.42%	9.94%
Southern Co.	SO	$1.89	$43.76	4.32%	4.43%	5.10%	5.00%	5.58%	5.23%	9.43%	9.66%	10.02%
Westar Energy	WR	$1.32	$27.31	4.83%	4.98%	5.80%	6.50%	6.13%	6.14%	10.77%	11.13%	11.49%
			MEAN	4.25%	4.38%	6.27%	7.00%	6.88%	6.49%	9.76%	10.87%	12.06%

Notes
[1] Source: Bloomberg
[2] Source: Bloomberg. Based on 180 days historical average.
[3] Equals Col. [1]/Col. [2]
[4] Equals (Col. [3] x (1+(.5 x Col. [8]))
[5] Source: Zacks
[6] Source: Value Line.
[7] Source: Yahoo! Finance
[8] Equals average of Cols [5], [6], [7]
[9] Equals Col [3] x (1+(0.5 x (Min (Cols [5], [6], [7])) + Min (Cols [5], [6], [7])
[10] Equals Col. [4] + Col. [8]
[11] Equals Col [3] x (1+(0.5 x (Max (Cols [5], [6], [7])) + Max (Cols [5], [6], [7])

EXHIBIT

JJR-3

MULTI-STAGE DCF MODEL - 30-DAY AVERAGE PRICE
TERMINAL VALUE - GORDON MODEL

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
		Stock	EPS	GDP		Payout Ratio		Solver Cells		Near-Term	Intermediate	Long-Term
Company	Ticker	Price	Growth	Growth	2012	2016	2026	Delta	Solution	Growth	Growth	Growth
American Electric Power	AEP	$38.21	3.95%	5.45%	60.00%	58.00%	66.57%	$0.00	10.77%	3.95%	4.70%	5.45%
Cleco Corp.	CNL	$39.52	5.50%	5.45%	52.00%	52.00%	66.57%	$0.00	10.00%	5.50%	5.48%	5.45%
Empire District Electric	EDE	$20.13	8.10%	5.45%	80.00%	68.00%	66.57%	$0.00	11.24%	8.10%	6.77%	5.45%
Entergy Corp.	ETR	$66.37	2.00%	5.45%	62.00%	61.00%	66.57%	$0.00	12.15%	2.00%	3.72%	5.45%
Great Plains Energy Inc.	GXP	$20.04	5.82%	5.45%	66.00%	60.00%	66.57%	$0.00	10.06%	5.82%	5.64%	5.45%
Hawaiian Electric	HE	$25.45	8.96%	5.45%	77.00%	65.00%	66.57%	$0.00	10.67%	8.96%	7.20%	5.45%
IDACORP, Inc.	IDA	$40.37	4.00%	5.45%	43.00%	54.00%	66.57%	$0.00	10.63%	4.00%	4.72%	5.45%
NV Energy	NVE	$15.95	11.28%	5.45%	49.00%	64.00%	66.57%	$0.00	9.88%	11.28%	8.35%	5.45%
Pinnacle West Capital	PNW	$47.38	5.39%	5.45%	63.00%	64.00%	66.57%	$0.00	10.02%	5.39%	5.42%	5.45%
PNM Resources	PNM	$18.41	13.02%	5.45%	42.00%	44.00%	66.57%	$0.00	11.54%	13.02%	9.22%	5.45%
Portland General	POR	$25.01	4.99%	5.45%	55.00%	54.00%	66.57%	$0.00	10.73%	4.99%	5.22%	5.45%
Southern Co.	SO	$44.99	5.23%	5.45%	73.00%	69.00%	66.57%	$0.00	9.65%	5.23%	5.34%	5.45%
Westar Energy	WR	$27.80	6.14%	5.45%	70.00%	63.00%	66.57%	$0.00	10.38%	6.14%	5.80%	5.45%
MEAN:		$33.05	6.49%	5.45%	60.92%	59.69%	66.57%		10.59%	6.49%	5.97%	5.45%

Earnings per Share		[12]	[13]	[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]
Company	Ticker	**2011**	2012	2013	2014	2015	2016	**2017**	2018	2019	2020	2021	**2022**	2023	2024	2025	2026
American Electric Power	AEP	$3.13	$3.25	$3.38	$3.52	$3.65	$3.80	$3.96	$4.13	$4.33	$4.54	$4.78	$5.04	$5.31	$5.60	$5.91	$6.23
Cleco Corp.	CNL	$2.59	$2.73	$2.88	$3.04	$3.21	$3.39	$3.57	$3.77	$3.97	$4.19	$4.42	$4.66	$4.91	$5.18	$5.46	$5.76
Empire District Electric	*EDE*	*$1.31*	*$1.42*	*$1.53*	*$1.65*	*$1.79*	*$1.93*	$2.08	*$2.23*	$2.38	$2.53	$2.68	$2.83	$2.98	$3.15	$3.32	$3.50
Entergy Corp.	ETR	$7.55	$7.70	$7.86	$8.01	$8.17	$8.34	$8.55	$8.82	$9.15	$9.54	$10.01	$10.55	$11.13	$11.73	$12.37	$13.05
Great Plains Energy Inc.	GXP	$1.25	$1.32	$1.40	$1.48	$1.57	$1.66	$1.75	$1.85	$1.96	$2.07	$2.18	$2.30	$2.43	$2.56	$2.70	$2.85
Hawaiian Electric	HE	$1.44	$1.57	$1.71	$1.86	$2.03	$2.21	$2.40	$2.58	$2.77	$2.95	$3.13	$3.30	$3.48	$3.67	$3.87	$4.08
IDACORP, Inc.	IDA	$3.36	$3.49	$3.63	$3.78	$3.93	$4.09	$4.26	$4.45	$4.66	$4.89	$5.15	$5.43	$5.73	$6.04	$6.37	$6.71
NV Energy	NVE	$0.69	$0.77	$0.85	$0.95	$1.06	$1.18	$1.30	$1.42	$1.54	$1.65	$1.76	$1.85	$1.96	$2.06	$2.17	$2.29
Pinnacle West Capital	PNW	$2.99	$3.15	$3.32	$3.50	$3.69	$3.89	$4.10	$4.32	$4.55	$4.80	$5.06	$5.34	$5.63	$5.94	$6.26	$6.60
PNM Resources	PNM	$1.08	$1.22	$1.38	$1.56	$1.76	$1.99	$2.23	$2.46	$2.69	$2.90	$3.09	$3.26	$3.44	$3.63	$3.83	$4.04
Portland General	POR	$1.95	$2.05	$2.15	$2.26	$2.37	$2.49	$2.61	$2.75	$2.89	$3.04	$3.21	$3.38	$3.57	$3.76	$3.97	$4.18
Southern Co.	SO	$2.57	$2.70	$2.85	$2.99	$3.15	$3.32	$3.49	$3.68	$3.87	$4.08	$4.30	$4.53	$4.78	$5.04	$5.32	$5.61
Westar Energy	WR	$1.79	$1.90	$2.02	$2.14	$2.27	$2.41	$2.56	$2.71	$2.87	$3.03	$3.20	$3.37	$3.55	$3.75	$3.95	$4.17

Projected Annual Data Dividend Payout Ratio		[28]	[29]	[30]	[31]	[32]	[33]	[34]	[35]	[36]	[37]	[38]	[39]	[40]	[41]	[42]
Company	Ticker	**2012**	2013	2014	2015	2016	**2017**	2018	2019	2020	2021	**2022**	2023	2024	2025	2026
American Electric Power	AEP	60.00%	59.50%	59.00%	58.50%	58.00%	59.43%	60.86%	62.28%	63.71%	65.14%	66.57%	66.57%	66.57%	66.57%	66.57%
Cleco Corp.	CNL	52.00%	52.00%	52.00%	52.00%	52.00%	54.43%	56.86%	59.28%	61.71%	64.14%	66.57%	66.57%	66.57%	66.57%	66.57%
Empire District Electric	EDE	80.00%	77.00%	74.00%	71.00%	68.00%	67.76%	67.52%	67.28%	67.04%	66.81%	66.57%	66.57%	66.57%	66.57%	66.57%
Entergy Corp.	ETR	62.00%	61.75%	61.50%	61.25%	61.00%	61.93%	62.86%	63.78%	64.71%	65.64%	66.57%	66.57%	66.57%	66.57%	66.57%
Great Plains Energy Inc.	GXP	66.00%	64.50%	63.00%	61.50%	60.00%	61.09%	62.19%	63.28%	64.38%	65.47%	66.57%	66.57%	66.57%	66.57%	66.57%
Hawaiian Electric	HE	77.00%	74.00%	71.00%	68.00%	65.00%	65.26%	65.52%	65.78%	66.04%	66.31%	66.57%	66.57%	66.57%	66.57%	66.57%
IDACORP, Inc.	IDA	43.00%	45.75%	48.50%	51.25%	54.00%	56.09%	58.19%	60.28%	62.38%	64.47%	66.57%	66.57%	66.57%	66.57%	66.57%
NV Energy	NVE	49.00%	52.75%	56.50%	60.25%	64.00%	64.43%	64.86%	65.28%	65.71%	66.14%	66.57%	66.57%	66.57%	66.57%	66.57%
Pinnacle West Capital	PNW	63.00%	63.25%	63.50%	63.75%	64.00%	64.43%	64.86%	65.28%	65.71%	66.14%	66.57%	66.57%	66.57%	66.57%	66.57%
PNM Resources	PNM	42.00%	42.50%	43.00%	43.50%	44.00%	47.76%	51.52%	55.28%	59.04%	62.81%	66.57%	66.57%	66.57%	66.57%	66.57%
Portland General	POR	55.00%	54.75%	54.50%	54.25%	54.00%	56.09%	58.19%	60.28%	62.38%	64.47%	66.57%	66.57%	66.57%	66.57%	66.57%
Southern Co.	SO	73.00%	72.00%	71.00%	70.00%	69.00%	68.59%	68.19%	67.78%	67.38%	66.97%	66.57%	66.57%	66.57%	66.57%	66.57%
Westar Energy	WR	70.00%	68.25%	66.50%	64.75%	63.00%	63.59%	64.19%	64.78%	65.38%	65.97%	66.57%	66.57%	66.57%	66.57%	66.57%

Projected Annual Data Dividends per Share & Terminal Market Value		[43]	[44]	[45]	[46]	[47]	[48]	[49]	[50]	[51]	[52]	[53]	[54]	[55]	[56]	[57]	[58]	[59]
Company	Ticker	**2012**	2013	2014	2015	2016	**2017**	2018	2019	2020	2021	**2022**	2023	2024	2025	2026	Terminal Price	Terminal P/E Ratio
American Electric Power	AEP	$1.95	$2.01	$2.07	$2.14	$2.20	$2.35	$2.52	$2.70	$2.89	$3.11	$3.35	$3.54	$3.73	$3.93	$4.15	$82.27	13.20
Cleco Corp.	CNL	$1.42	$1.50	$1.58	$1.67	$1.76	$1.94	$2.14	$2.36	$2.59	$2.83	$3.10	$3.27	$3.45	$3.64	$3.84	$88.88	15.42
Empire District Electric	EDE	$1.13	$1.18	$1.22	$1.27	$1.31	$1.41	$1.51	$1.60	$1.70	$1.79	$1.88	$1.99	$2.09	$2.21	$2.33	$42.44	12.13
Entergy Corp.	ETR	$4.77	$4.85	$4.93	$5.01	$5.08	$5.30	$5.54	$5.84	$6.17	$6.57	$7.02	$7.41	$7.81	$8.24	$8.69	$136.74	10.48
Great Plains Energy Inc.	GXP	$0.87	$0.90	$0.93	$0.96	$1.00	$1.07	$1.15	$1.24	$1.33	$1.43	$1.53	$1.62	$1.70	$1.80	$1.89	$43.29	15.21
Hawaiian Electric	HE	$1.21	$1.27	$1.32	$1.38	$1.44	$1.56	$1.69	$1.82	$1.95	$2.08	$2.20	$2.32	$2.44	$2.58	$2.72	$54.95	13.46
IDACORP, Inc.	IDA	$1.50	$1.66	$1.83	$2.01	$2.21	$2.39	$2.59	$2.81	$3.05	$3.32	$3.61	$3.81	$4.02	$4.24	$4.47	$90.94	13.54
NV Energy	NVE	$0.38	$0.45	$0.54	$0.64	$0.75	$0.84	$0.92	$1.00	$1.09	$1.16	$1.23	$1.30	$1.37	$1.45	$1.53	$36.32	15.84
Pinnacle West Capital	PNW	$1.99	$2.10	$2.22	$2.35	$2.49	$2.64	$2.80	$2.97	$3.16	$3.35	$3.55	$3.75	$3.95	$4.17	$4.39	$101.37	15.36
PNM Resources	PNM	$0.51	$0.59	$0.67	$0.77	$0.88	$1.06	$1.27	$1.48	$1.71	$1.94	$2.17	$2.29	$2.42	$2.55	$2.69	$46.53	11.53
Portland General	POR	$1.13	$1.18	$1.23	$1.29	$1.34	$1.47	$1.60	$1.74	$1.90	$2.07	$2.25	$2.37	$2.50	$2.64	$2.78	$55.60	13.29
Southern Co.	SO	$1.97	$2.05	$2.13	$2.21	$2.29	$2.39	$2.51	$2.62	$2.75	$2.88	$3.02	$3.18	$3.36	$3.54	$3.73	$93.72	16.71
Westar Energy	WR	$1.33	$1.38	$1.42	$1.47	$1.52	$1.63	$1.74	$1.86	$1.98	$2.11	$2.24	$2.37	$2.50	$2.63	$2.77	$59.37	14.24
																		13.88
																		13.54

Projected Annual Data Investor Cash Flows		[60]	[61]	[62]	[63]	[64]	[65]	[66]	[67]	[68]	[69]	[70]	[71]	[72]	[73]	[74]	[75]	[76]
Company	Ticker	Initial Outflow	4/30/12	**10/30/12**	10/30/13	10/30/14	10/30/15	10/30/16	**10/30/17**	10/30/18	10/30/19	10/30/20	10/30/21	**10/30/22**	10/30/23	10/30/24	10/30/25	10/30/26
American Electric Power	AEP	($38.21)	$0.00	$1.95	$2.01	$2.07	$2.14	$2.20	$2.35	$2.52	$2.70	$2.89	$3.11	$3.35	$3.54	$3.73	$3.93	$86.42
Cleco Corp.	CNL	($39.52)	$0.00	$1.42	$1.50	$1.58	$1.67	$1.76	$1.94	$2.14	$2.36	$2.59	$2.83	$3.10	$3.27	$3.45	$3.64	$92.71
Empire District Electric	EDE	($20.12)	$0.00	$1.13	$1.18	$1.22	$1.27	$1.31	$1.41	$1.51	$1.60	$1.70	$1.79	$1.88	$1.99	$2.09	$2.21	$44.77
Entergy Corp.	ETR	($66.37)	$0.00	$4.77	$4.85	$4.93	$5.01	$5.08	$5.30	$5.54	$5.84	$6.17	$6.57	$7.02	$7.41	$7.81	$8.24	$145.43
Great Plains Energy Inc.	GXP	($20.04)	$0.00	$0.87	$0.90	$0.93	$0.96	$1.00	$1.07	$1.15	$1.24	$1.33	$1.43	$1.53	$1.62	$1.70	$1.80	$45.18
Hawaiian Electric	HE	($25.45)	$0.00	$1.21	$1.27	$1.32	$1.38	$1.44	$1.56	$1.69	$1.82	$1.95	$2.08	$2.20	$2.32	$2.44	$2.58	$57.67
IDACORP, Inc.	IDA	($40.37)	$0.00	$1.50	$1.66	$1.83	$2.01	$2.21	$2.39	$2.59	$2.81	$3.05	$3.32	$3.61	$3.81	$4.02	$4.24	$95.41
NV Energy	NVE	($15.95)	$0.00	$0.38	$0.45	$0.54	$0.64	$0.75	$0.84	$0.92	$1.00	$1.09	$1.16	$1.23	$1.30	$1.37	$1.45	$37.85
Pinnacle West Capital	PNW	($47.38)	$0.00	$1.99	$2.10	$2.22	$2.35	$2.49	$2.64	$2.80	$2.97	$3.16	$3.35	$3.55	$3.75	$3.95	$4.17	$105.76
PNM Resources	PNM	($18.41)	$0.00	$0.51	$0.59	$0.67	$0.77	$0.88	$1.06	$1.27	$1.48	$1.71	$1.94	$2.17	$2.29	$2.42	$2.55	$49.21
Portland General	POR	($25.01)	$0.00	$1.13	$1.18	$1.23	$1.29	$1.34	$1.47	$1.60	$1.74	$1.90	$2.07	$2.25	$2.37	$2.50	$2.64	$58.39
Southern Co.	SO	($44.99)	$0.00	$1.97	$2.05	$2.13	$2.21	$2.29	$2.39	$2.51	$2.62	$2.75	$2.88	$3.02	$3.18	$3.36	$3.54	$97.46
Westar Energy	WR	($27.80)	$0.00	$1.33	$1.38	$1.42	$1.47	$1.52	$1.63	$1.74	$1.86	$1.98	$2.11	$2.24	$2.37	$2.50	$2.63	$62.14

MULTI-STAGE DCF MODEL - 90-DAY AVERAGE PRICE
TERMINAL VALUE - GORDON MODEL

Inputs

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
		Stock	EPS	GDP	Payout Ratio			Solver Cells		Near-Term	Intermediate	Long-Term
Company	Ticker	Price	Growth	Growth	2012	2016	2026	Delta	Solution	Growth	Growth	Growth
American Electric Power	AEP	$39.30	3.95%	5.45%	60.00%	58.00%	66.57%	$0.00	10.62%	3.95%	4.70%	5.45%
Cleco Corp.	CNL	$38.73	5.50%	5.45%	52.00%	52.00%	66.57%	($0.00)	10.09%	5.50%	5.48%	5.45%
Empire District Electric	EDE	$20.45	8.10%	5.45%	80.00%	68.00%	66.57%	$0.00	11.14%	8.10%	6.77%	5.45%
Entergy Corp.	ETR	$68.50	2.00%	5.45%	62.00%	61.00%	66.57%	$0.00	11.93%	2.00%	3.72%	5.45%
Great Plains Energy Inc.	GXP	$20.55	5.82%	5.45%	66.00%	60.00%	66.57%	$0.00	9.95%	5.82%	5.64%	5.45%
Hawaiian Electric	HE	$25.66	8.96%	5.45%	77.00%	65.00%	66.57%	$0.00	10.62%	8.96%	7.20%	5.45%
IDACORP, Inc.	IDA	$41.15	4.00%	5.45%	43.00%	54.00%	66.57%	$0.00	10.54%	4.00%	4.72%	5.45%
NV Energy	NVE	$16.00	11.28%	5.45%	49.00%	64.00%	66.57%	$0.00	9.87%	11.28%	8.35%	5.45%
Pinnacle West Capital	PNW	$47.51	5.39%	5.45%	63.00%	64.00%	66.57%	$0.00	10.01%	5.39%	5.42%	5.45%
PNM Resources	PNM	$18.17	13.02%	5.45%	42.00%	44.00%	66.57%	($0.00)	11.61%	13.02%	9.22%	5.45%
Portland General	POR	$24.97	4.99%	5.45%	55.00%	54.00%	66.57%	$0.00	10.74%	4.99%	5.22%	5.45%
Southern Co.	SO	$44.95	5.23%	5.45%	73.00%	69.00%	66.57%	$0.00	9.65%	5.23%	5.34%	5.45%
Westar Energy	WR	$28.08	6.14%	5.45%	70.00%	63.00%	66.57%	$0.00	10.33%	6.14%	5.80%	5.45%
MEAN:		$33.39	6.49%	5.45%	60.92%	59.69%	66.57%		10.55%	6.49%	5.97%	5.45%

Projected Annual Data
Earnings per Share

		[12]	[13]	[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]
Company	Ticker	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
American Electric Power	AEP	$3.13	$3.25	$3.38	$3.52	$3.65	$3.80	$3.96	$4.13	$4.33	$4.54	$4.78	$5.04	$5.31	$5.60	$5.91	$6.23
Cleco Corp.	CNL	$2.59	$2.73	$2.88	$3.04	$3.21	$3.39	$3.57	$3.77	$3.97	$4.19	$4.42	$4.66	$4.91	$5.18	$5.46	$5.76
Empire District Electric	EDE	$1.31	$1.42	$1.53	$1.65	$1.79	$1.93	$2.08	$2.23	$2.38	$2.53	$2.68	$2.83	$2.98	$3.15	$3.32	$3.50
Entergy Corp.	ETR	$7.55	$7.70	$7.86	$8.01	$8.17	$8.34	$8.55	$8.82	$9.15	$9.54	$10.01	$10.55	$11.13	$11.73	$12.37	$13.05
Great Plains Energy Inc.	GXP	$1.25	$1.32	$1.40	$1.48	$1.57	$1.66	$1.75	$1.85	$1.96	$2.07	$2.18	$2.30	$2.43	$2.56	$2.70	$2.85
Hawaiian Electric	HE	$1.44	$1.57	$1.71	$1.86	$2.03	$2.21	$2.40	$2.58	$2.77	$2.95	$3.13	$3.30	$3.48	$3.67	$3.87	$4.08
IDACORP, Inc.	IDA	$3.36	$3.49	$3.63	$3.78	$3.93	$4.09	$4.26	$4.45	$4.66	$4.89	$5.15	$5.43	$5.73	$6.04	$6.37	$6.71
NV Energy	NVE	$0.69	$0.77	$0.85	$0.95	$1.06	$1.18	$1.30	$1.42	$1.54	$1.65	$1.76	$1.85	$1.96	$2.06	$2.17	$2.29
Pinnacle West Capital	PNW	$2.99	$3.15	$3.32	$3.50	$3.69	$3.89	$4.10	$4.32	$4.55	$4.80	$5.06	$5.34	$5.63	$5.94	$6.26	$6.60
PNM Resources	PNM	$1.08	$1.22	$1.38	$1.56	$1.76	$1.99	$2.23	$2.46	$2.69	$2.90	$3.09	$3.26	$3.44	$3.63	$3.83	$4.04
Portland General	POR	$1.95	$2.05	$2.15	$2.26	$2.37	$2.49	$2.61	$2.75	$2.89	$3.04	$3.21	$3.38	$3.57	$3.76	$3.97	$4.18
Southern Co.	SO	$2.57	$2.70	$2.85	$2.99	$3.15	$3.32	$3.49	$3.68	$3.87	$4.08	$4.30	$4.53	$4.78	$5.04	$5.32	$5.61
Westar Energy	WR	$1.79	$1.90	$2.02	$2.14	$2.27	$2.41	$2.56	$2.71	$2.87	$3.03	$3.20	$3.37	$3.55	$3.75	$3.95	$4.17

Projected Annual Data
Dividend Payout Ratio

		[28]	[29]	[30]	[31]	[32]	[33]	[34]	[35]	[36]	[37]	[38]	[39]	[40]	[41]	[42]
Company	Ticker	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
American Electric Power	AEP	60.00%	59.50%	59.00%	58.50%	58.00%	59.43%	60.86%	62.28%	63.71%	65.14%	66.57%	66.57%	66.57%	66.57%	66.57%
Cleco Corp.	CNL	52.00%	52.00%	52.00%	52.00%	52.00%	54.43%	56.86%	59.28%	61.71%	64.14%	66.57%	66.57%	66.57%	66.57%	66.57%
Empire District Electric	EDE	80.00%	77.00%	74.00%	71.00%	68.00%	67.76%	67.52%	67.28%	67.04%	66.81%	66.57%	66.57%	66.57%	66.57%	66.57%
Entergy Corp.	ETR	62.00%	61.75%	61.50%	61.25%	61.00%	61.93%	62.86%	63.78%	64.71%	65.64%	66.57%	66.57%	66.57%	66.57%	66.57%
Great Plains Energy Inc.	GXP	66.00%	64.50%	63.00%	61.50%	60.00%	61.09%	62.19%	63.28%	64.38%	65.47%	66.57%	66.57%	66.57%	66.57%	66.57%
Hawaiian Electric	HE	77.00%	74.00%	71.00%	68.00%	65.00%	65.26%	65.52%	65.78%	66.04%	66.31%	66.57%	66.57%	66.57%	66.57%	66.57%
IDACORP, Inc.	IDA	43.00%	45.75%	48.50%	51.25%	54.00%	56.09%	58.19%	60.28%	62.38%	64.47%	66.57%	66.57%	66.57%	66.57%	66.57%
NV Energy	NVE	49.00%	52.75%	56.50%	60.25%	64.00%	64.43%	64.86%	65.28%	65.71%	66.14%	66.57%	66.57%	66.57%	66.57%	66.57%
Pinnacle West Capital	PNW	63.00%	63.25%	63.50%	63.75%	64.00%	64.43%	64.86%	65.28%	65.71%	66.14%	66.57%	66.57%	66.57%	66.57%	66.57%
PNM Resources	PNM	42.00%	42.50%	43.00%	43.50%	44.00%	47.76%	51.52%	55.28%	59.04%	62.81%	66.57%	66.57%	66.57%	66.57%	66.57%
Portland General	POR	55.00%	54.75%	54.50%	54.25%	54.00%	56.09%	58.19%	60.28%	62.38%	64.47%	66.57%	66.57%	66.57%	66.57%	66.57%
Southern Co.	SO	73.00%	72.00%	71.00%	70.00%	69.00%	68.59%	68.19%	67.78%	67.38%	66.97%	66.57%	66.57%	66.57%	66.57%	66.57%
Westar Energy	WR	70.00%	68.25%	66.50%	64.75%	63.00%	63.59%	64.19%	64.78%	65.38%	65.97%	66.57%	66.57%	66.57%	66.57%	66.57%

Projected Annual Data
Dividends per Share & Terminal Market Value

		[43]	[44]	[45]	[46]	[47]	[48]	[49]	[50]	[51]	[52]	[53]	[54]	[55]	[56]	[57]	[58]	[59]
Company	Ticker	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Terminal Price	Terminal P/E Ratio
American Electric Power	AEP	$1.95	$2.01	$2.07	$2.14	$2.20	$2.35	$2.52	$2.70	$2.89	$3.11	$3.35	$3.54	$3.73	$3.93	$4.15	$84.65	13.59
Cleco Corp.	CNL	$1.42	$1.50	$1.58	$1.67	$1.76	$1.94	$2.14	$2.36	$2.59	$2.83	$3.10	$3.27	$3.45	$3.64	$3.84	$87.16	15.13
Empire District Electric	EDE	$1.13	$1.18	$1.22	$1.27	$1.31	$1.41	$1.51	$1.60	$1.70	$1.79	$1.88	$1.99	$2.09	$2.21	$2.33	$43.15	12.33
Entergy Corp.	ETR	$4.77	$4.85	$4.93	$5.01	$5.08	$5.30	$5.54	$5.84	$6.17	$6.57	$7.02	$7.41	$7.81	$8.24	$8.69	$141.32	10.83
Great Plains Energy Inc.	GXP	$0.87	$0.90	$0.93	$0.96	$1.00	$1.07	$1.15	$1.24	$1.33	$1.43	$1.53	$1.62	$1.70	$1.80	$1.89	$44.40	15.60
Hawaiian Electric	HE	$1.21	$1.27	$1.32	$1.38	$1.44	$1.56	$1.69	$1.82	$1.95	$2.08	$2.20	$2.32	$2.44	$2.58	$2.72	$55.40	13.57
IDACORP, Inc.	IDA	$1.50	$1.66	$1.83	$2.01	$2.21	$2.39	$2.59	$2.81	$3.05	$3.32	$3.61	$3.81	$4.02	$4.24	$4.47	$92.66	13.80
NV Energy	NVE	$0.38	$0.45	$0.54	$0.64	$0.75	$0.84	$0.92	$1.00	$1.09	$1.16	$1.23	$1.30	$1.37	$1.45	$1.53	$36.42	15.89
Pinnacle West Capital	PNW	$1.99	$2.10	$2.22	$2.35	$2.49	$2.64	$2.80	$2.97	$3.16	$3.35	$3.55	$3.75	$3.95	$4.17	$4.39	$101.65	15.40
PNM Resources	PNM	$0.51	$0.59	$0.67	$0.77	$0.88	$1.06	$1.27	$1.48	$1.71	$1.94	$2.17	$2.29	$2.42	$2.55	$2.69	$46.00	11.40
Portland General	POR	$1.13	$1.18	$1.23	$1.29	$1.34	$1.47	$1.60	$1.74	$1.90	$2.07	$2.25	$2.37	$2.50	$2.64	$2.78	$55.51	13.27
Southern Co.	SO	$1.97	$2.05	$2.13	$2.21	$2.29	$2.39	$2.51	$2.62	$2.75	$2.88	$3.02	$3.18	$3.36	$3.54	$3.73	$93.65	16.70
Westar Energy	WR	$1.33	$1.38	$1.42	$1.47	$1.52	$1.63	$1.74	$1.86	$1.98	$2.11	$2.24	$2.37	$2.50	$2.63	$2.77	$59.96	14.39
																		13.99
																		13.80

Projected Annual Data
Investor Cash Flows

		[60]	[61]	[62]	[63]	[64]	[65]	[66]	[67]	[68]	[69]	[70]	[71]	[72]	[73]	[74]	[75]	[76]
Company	Ticker	Initial Outflow	4/30/12	10/30/12	10/30/13	10/30/14	10/30/15	10/30/16	10/30/17	10/30/18	10/30/19	10/30/20	10/30/21	10/30/22	10/30/23	10/30/24	10/30/25	10/30/26
American Electric Power	AEP	($39.30)	$0.00	$1.95	$2.01	$2.07	$2.14	$2.20	$2.35	$2.52	$2.70	$2.89	$3.11	$3.35	$3.54	$3.73	$3.93	$88.80
Cleco Corp.	CNL	($38.73)	$0.00	$1.42	$1.50	$1.58	$1.67	$1.76	$1.94	$2.14	$2.36	$2.59	$2.83	$3.10	$3.27	$3.45	$3.64	$90.99
Empire District Electric	EDE	($20.45)	$0.00	$1.13	$1.18	$1.22	$1.27	$1.31	$1.41	$1.51	$1.60	$1.70	$1.79	$1.88	$1.99	$2.09	$2.21	$45.48
Entergy Corp.	ETR	($68.50)	$0.00	$4.77	$4.85	$4.93	$5.01	$5.08	$5.30	$5.54	$5.84	$6.17	$6.57	$7.02	$7.41	$7.81	$8.24	$150.01
Great Plains Energy Inc.	GXP	($20.55)	$0.00	$0.87	$0.90	$0.93	$0.96	$1.00	$1.07	$1.15	$1.24	$1.33	$1.43	$1.53	$1.62	$1.70	$1.80	$46.29
Hawaiian Electric	HE	($25.66)	$0.00	$1.21	$1.27	$1.32	$1.38	$1.44	$1.56	$1.69	$1.82	$1.95	$2.08	$2.20	$2.32	$2.44	$2.58	$58.11
IDACORP, Inc.	IDA	($41.15)	$0.00	$1.50	$1.66	$1.83	$2.01	$2.21	$2.39	$2.59	$2.81	$3.05	$3.32	$3.61	$3.81	$4.02	$4.24	$97.13
NV Energy	NVE	($15.99)	$0.00	$0.38	$0.45	$0.54	$0.64	$0.75	$0.84	$0.92	$1.00	$1.09	$1.16	$1.23	$1.30	$1.37	$1.45	$37.95
Pinnacle West Capital	PNW	($47.51)	$0.00	$1.99	$2.10	$2.22	$2.35	$2.49	$2.64	$2.80	$2.97	$3.16	$3.35	$3.55	$3.75	$3.95	$4.17	$106.04
PNM Resources	PNM	($18.17)	$0.00	$0.51	$0.59	$0.67	$0.77	$0.88	$1.06	$1.27	$1.48	$1.71	$1.94	$2.17	$2.29	$2.42	$2.55	$48.68
Portland General	POR	($24.97)	$0.00	$1.13	$1.18	$1.23	$1.29	$1.34	$1.47	$1.60	$1.74	$1.90	$2.07	$2.25	$2.37	$2.50	$2.64	$58.29
Southern Co.	SO	($44.95)	$0.00	$1.97	$2.05	$2.13	$2.21	$2.29	$2.39	$2.51	$2.62	$2.75	$2.88	$3.02	$3.18	$3.36	$3.54	$97.38
Westar Energy	WR	($28.08)	$0.00	$1.33	$1.38	$1.42	$1.47	$1.52	$1.63	$1.74	$1.86	$1.98	$2.11	$2.24	$2.37	$2.50	$2.63	$62.73

MULTI-STAGE DCF MODEL – 180-DAY AVERAGE PRICE
TERMINAL VALUE - GORDON MODEL

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
		Stock	EPS	GDP		Payout Ratio		Solver Cells		Near-Term	Intermediate	Long-Term
Company	Ticker	Price	Growth	Growth	2012	2016	2026	Delta	Solution	Growth	Growth	Growth
American Electric Power	AEP	$38.82	3.95%	5.45%	60.00%	58.00%	66.57%	$0.00	10.68%	3.95%	4.70%	5.45%
Cleco Corp.	CNL	$36.98	5.50%	5.45%	52.00%	52.00%	66.57%	$0.00	10.30%	5.50%	5.48%	5.45%
Empire District Electric	EDE	$20.20	8.10%	5.45%	80.00%	68.00%	66.57%	$0.00	11.22%	8.10%	6.77%	5.45%
Entergy Corp.	ETR	$67.66	2.00%	5.45%	62.00%	61.00%	66.57%	$0.00	12.02%	2.00%	3.72%	5.45%
Great Plains Energy Inc.	GXP	$20.27	5.82%	5.45%	66.00%	60.00%	66.57%	$0.00	10.01%	5.82%	5.64%	5.45%
Hawaiian Electric	HE	$25.19	8.96%	5.45%	77.00%	65.00%	66.57%	$0.00	10.72%	8.96%	7.20%	5.45%
IDACORP, Inc.	IDA	$40.06	4.00%	5.45%	43.00%	54.00%	66.57%	$0.00	10.67%	4.00%	4.72%	5.45%
NV Energy	NVE	$15.47	11.28%	5.45%	49.00%	64.00%	66.57%	$0.00	10.01%	11.28%	8.35%	5.45%
Pinnacle West Capital	PNW	$46.02	5.39%	5.45%	63.00%	64.00%	66.57%	$0.00	10.16%	5.39%	5.42%	5.45%
PNM Resources	PNM	$17.46	13.02%	5.45%	42.00%	44.00%	66.57%	$0.00	11.83%	13.02%	9.22%	5.45%
Portland General	POR	$24.51	4.99%	5.45%	55.00%	54.00%	66.57%	$0.00	10.84%	4.99%	5.22%	5.45%
Southern Co.	SO	$43.76	5.23%	5.45%	73.00%	69.00%	66.57%	$0.00	9.77%	5.23%	5.34%	5.45%
Westar Energy	WR	$27.31	6.14%	5.45%	70.00%	63.00%	66.57%	$0.00	10.47%	6.14%	5.80%	5.45%
MEAN:		$32.59	6.49%	5.45%	60.92%	59.69%	66.57%		10.67%	6.49%	5.97%	5.45%

Projected Annual Data
Earnings per Share

Company	Ticker	[12] 2011	[13] 2012	[14] 2013	[15] 2014	[16] 2015	[17] 2016	[18] 2017	[19] 2018	[20] 2019	[21] 2020	[22] 2021	[23] 2022	[24] 2023	[25] 2024	[26] 2025	[27] 2026
American Electric Power	AEP	$3.13	$3.25	$3.38	$3.52	$3.65	$3.80	$3.96	$4.13	$4.33	$4.54	$4.78	$5.04	$5.31	$5.60	$5.91	$6.23
Cleco Corp.	CNL	$2.59	$2.73	$2.88	$3.04	$3.21	$3.39	$3.57	$3.77	$3.97	$4.19	$4.42	$4.66	$4.91	$5.18	$5.46	$5.76
Empire District Electric	EDE	$1.31	$1.42	$1.53	$1.65	$1.79	$1.93	$2.08	$2.23	$2.38	$2.53	$2.68	$2.83	$2.98	$3.15	$3.32	$3.50
Entergy Corp.	ETR	$7.55	$7.70	$7.86	$8.01	$8.17	$8.34	$8.55	$8.82	$9.15	$9.54	$10.01	$10.55	$11.13	$11.73	$12.37	$13.05
Great Plains Energy Inc.	GXP	$1.25	$1.32	$1.40	$1.48	$1.57	$1.66	$1.75	$1.85	$1.96	$2.07	$2.18	$2.30	$2.43	$2.56	$2.70	$2.85
Hawaiian Electric	HE	$1.44	$1.57	$1.71	$1.86	$2.03	$2.21	$2.40	$2.58	$2.77	$2.95	$3.13	$3.30	$3.48	$3.67	$3.87	$4.08
IDACORP, Inc.	IDA	$3.36	$3.49	$3.63	$3.78	$3.93	$4.09	$4.26	$4.45	$4.66	$4.89	$5.15	$5.43	$5.73	$6.04	$6.37	$6.71
NV Energy	NVE	$0.69	$0.77	$0.85	$0.95	$1.06	$1.18	$1.30	$1.42	$1.54	$1.65	$1.76	$1.85	$1.96	$2.06	$2.17	$2.29
Pinnacle West Capital	PNW	$2.99	$3.15	$3.32	$3.50	$3.69	$3.89	$4.10	$4.32	$4.55	$4.80	$5.06	$5.34	$5.63	$5.94	$6.26	$6.60
PNM Resources	PNM	$1.08	$1.22	$1.38	$1.56	$1.76	$1.99	$2.23	$2.46	$2.69	$2.90	$3.09	$3.26	$3.44	$3.63	$3.83	$4.04
Portland General	POR	$1.95	$2.05	$2.15	$2.26	$2.37	$2.49	$2.61	$2.75	$2.89	$3.04	$3.21	$3.38	$3.57	$3.76	$3.97	$4.18
Southern Co.	SO	$2.57	$2.70	$2.85	$2.99	$3.15	$3.32	$3.49	$3.68	$3.87	$4.08	$4.30	$4.53	$4.78	$5.04	$5.32	$5.61
Westar Energy	WR	$1.79	$1.90	$2.02	$2.14	$2.27	$2.41	$2.56	$2.71	$2.87	$3.03	$3.20	$3.37	$3.55	$3.75	$3.95	$4.17

Projected Annual Data
Dividend Payout Ratio

Company	Ticker	[28] 2012	[29] 2013	[30] 2014	[31] 2015	[32] 2016	[33] 2017	[34] 2018	[35] 2019	[36] 2020	[37] 2021	[38] 2022	[39] 2023	[40] 2024	[41] 2025	[42] 2026
American Electric Power	AEP	60.00%	59.50%	59.00%	58.50%	58.00%	59.43%	60.86%	62.28%	63.71%	65.14%	66.57%	66.57%	66.57%	66.57%	66.57%
Cleco Corp.	CNL	52.00%	52.00%	52.00%	52.00%	52.00%	54.43%	56.86%	59.28%	61.71%	64.14%	66.57%	66.57%	66.57%	66.57%	66.57%
Empire District Electric	EDE	80.00%	77.00%	74.00%	71.00%	68.00%	67.76%	67.52%	67.28%	67.04%	66.81%	66.57%	66.57%	66.57%	66.57%	66.57%
Entergy Corp.	ETR	62.00%	61.75%	61.50%	61.25%	61.00%	61.93%	62.86%	63.78%	64.71%	65.64%	66.57%	66.57%	66.57%	66.57%	66.57%
Great Plains Energy Inc.	GXP	66.00%	64.50%	63.00%	61.50%	60.00%	61.09%	62.19%	63.28%	64.38%	65.47%	66.57%	66.57%	66.57%	66.57%	66.57%
Hawaiian Electric	HE	77.00%	74.00%	71.00%	68.00%	65.00%	65.26%	65.52%	65.78%	66.04%	66.31%	66.57%	66.57%	66.57%	66.57%	66.57%
IDACORP, Inc.	IDA	43.00%	45.75%	48.50%	51.25%	54.00%	56.09%	58.19%	60.28%	62.38%	64.47%	66.57%	66.57%	66.57%	66.57%	66.57%
NV Energy	NVE	49.00%	52.75%	56.50%	60.25%	64.00%	64.43%	64.86%	65.28%	65.71%	66.14%	66.57%	66.57%	66.57%	66.57%	66.57%
Pinnacle West Capital	PNW	63.00%	63.25%	63.50%	63.75%	64.00%	64.43%	64.86%	65.28%	65.71%	66.14%	66.57%	66.57%	66.57%	66.57%	66.57%
PNM Resources	PNM	42.00%	42.50%	43.00%	43.50%	44.00%	47.76%	51.52%	55.28%	59.04%	62.81%	66.57%	66.57%	66.57%	66.57%	66.57%
Portland General	POR	55.00%	54.75%	54.50%	54.25%	54.00%	56.09%	58.19%	60.28%	62.38%	64.47%	66.57%	66.57%	66.57%	66.57%	66.57%
Southern Co.	SO	73.00%	72.00%	71.00%	70.00%	69.00%	68.59%	68.19%	67.78%	67.38%	66.97%	66.57%	66.57%	66.57%	66.57%	66.57%
Westar Energy	WR	70.00%	68.25%	66.50%	64.75%	63.00%	63.59%	64.19%	64.78%	65.38%	65.97%	66.57%	66.57%	66.57%	66.57%	66.57%

Projected Annual Data
Dividends per Share & Terminal Market Value

Company	Ticker	[43] 2012	[44] 2013	[45] 2014	[46] 2015	[47] 2016	[48] 2017	[49] 2018	[50] 2019	[51] 2020	[52] 2021	[53] 2022	[54] 2023	[55] 2024	[56] 2025	[57] 2026	[58] Terminal Price	[59] Terminal P/E Ratio
American Electric Power	AEP	$1.95	$2.01	$2.07	$2.14	$2.20	$2.35	$2.52	$2.70	$2.89	$3.11	$3.35	$3.54	$3.73	$3.93	$4.15	$83.60	13.42
Cleco Corp.	CNL	$1.42	$1.50	$1.58	$1.67	$1.76	$1.94	$2.14	$2.36	$2.59	$2.83	$3.10	$3.27	$3.45	$3.64	$3.84	$83.32	14.46
Empire District Electric	EDE	$1.13	$1.18	$1.22	$1.27	$1.31	$1.41	$1.51	$1.60	$1.70	$1.79	$1.88	$1.99	$2.09	$2.21	$2.33	$42.60	12.17
Entergy Corp.	ETR	$4.77	$4.85	$4.93	$5.01	$5.08	$5.30	$5.54	$5.84	$6.17	$6.57	$7.02	$7.41	$7.81	$8.24	$8.69	$139.53	10.69
Great Plains Energy Inc.	GXP	$0.87	$0.90	$0.93	$0.96	$1.00	$1.07	$1.15	$1.24	$1.33	$1.43	$1.53	$1.62	$1.70	$1.80	$1.89	$43.78	15.39
Hawaiian Electric	HE	$1.21	$1.27	$1.32	$1.38	$1.44	$1.56	$1.69	$1.82	$1.95	$2.08	$2.20	$2.32	$2.44	$2.58	$2.72	$54.37	13.32
IDACORP, Inc.	IDA	$1.50	$1.66	$1.83	$2.01	$2.21	$2.39	$2.59	$2.81	$3.05	$3.32	$3.61	$3.81	$4.02	$4.24	$4.47	$90.27	13.45
NV Energy	NVE	$0.38	$0.45	$0.54	$0.64	$0.75	$0.84	$0.92	$1.00	$1.09	$1.16	$1.23	$1.30	$1.37	$1.45	$1.53	$35.28	15.39
Pinnacle West Capital	PNW	$1.99	$2.10	$2.22	$2.35	$2.49	$2.64	$2.80	$2.97	$3.16	$3.35	$3.55	$3.75	$3.95	$4.17	$4.39	$98.42	14.91
PNM Resources	PNM	$0.51	$0.59	$0.67	$0.77	$0.88	$1.06	$1.27	$1.48	$1.71	$1.94	$2.17	$2.29	$2.42	$2.55	$2.69	$44.40	11.00
Portland General	POR	$1.13	$1.18	$1.23	$1.29	$1.34	$1.47	$1.60	$1.74	$1.90	$2.07	$2.25	$2.37	$2.50	$2.64	$2.78	$54.51	13.03
Southern Co.	SO	$1.97	$2.05	$2.13	$2.21	$2.29	$2.39	$2.51	$2.62	$2.75	$2.88	$3.02	$3.18	$3.36	$3.54	$3.73	$91.08	16.24
Westar Energy	WR	$1.33	$1.38	$1.42	$1.47	$1.52	$1.63	$1.74	$1.86	$1.98	$2.11	$2.24	$2.37	$2.50	$2.63	$2.77	$58.30	13.99
																		13.65
																		13.45

Projected Annual Data
Investor Cash Flows

Company	Ticker	[60] Initial Outflow	[61] 4/30/12	[62] 10/30/12	[63] 10/30/13	[64] 10/30/14	[65] 10/30/15	[66] 10/30/16	[67] 10/30/17	[68] 10/30/18	[69] 10/30/19	[70] 10/30/20	[71] 10/30/21	[72] 10/30/22	[73] 10/30/23	[74] 10/30/24	[75] 10/30/25	[76] 10/30/26
American Electric Power	AEP	($38.82)	$0.00	$1.95	$2.01	$2.07	$2.14	$2.20	$2.35	$2.52	$2.70	$2.89	$3.11	$3.35	$3.54	$3.73	$3.93	$87.75
Cleco Corp.	CNL	($36.98)	$0.00	$1.42	$1.50	$1.58	$1.67	$1.76	$1.94	$2.14	$2.36	$2.59	$2.83	$3.10	$3.27	$3.45	$3.64	$87.16
Empire District Electric	EDE	($20.20)	$0.00	$1.13	$1.18	$1.22	$1.27	$1.31	$1.41	$1.51	$1.60	$1.70	$1.79	$1.88	$1.99	$2.09	$2.21	$44.93
Entergy Corp.	ETR	($67.66)	$0.00	$4.77	$4.85	$4.93	$5.01	$5.08	$5.30	$5.54	$5.84	$6.17	$6.57	$7.02	$7.41	$7.81	$8.24	$148.21
Great Plains Energy Inc.	GXP	($20.27)	$0.00	$0.87	$0.90	$0.93	$0.96	$1.00	$1.07	$1.15	$1.24	$1.33	$1.43	$1.53	$1.62	$1.70	$1.80	$45.68
Hawaiian Electric	HE	($25.19)	$0.00	$1.21	$1.27	$1.32	$1.38	$1.44	$1.56	$1.69	$1.82	$1.95	$2.08	$2.20	$2.32	$2.44	$2.58	$57.09
IDACORP, Inc.	IDA	($40.06)	$0.00	$1.50	$1.66	$1.83	$2.01	$2.21	$2.39	$2.59	$2.81	$3.05	$3.32	$3.61	$3.81	$4.02	$4.24	$94.74
NV Energy	NVE	($15.47)	$0.00	$0.38	$0.45	$0.54	$0.64	$0.75	$0.84	$0.92	$1.00	$1.09	$1.16	$1.23	$1.30	$1.37	$1.45	$36.81
Pinnacle West Capital	PNW	($46.02)	$0.00	$1.99	$2.10	$2.22	$2.35	$2.49	$2.64	$2.80	$2.97	$3.16	$3.35	$3.55	$3.75	$3.95	$4.17	$102.81
PNM Resources	PNM	($17.46)	$0.00	$0.51	$0.59	$0.67	$0.77	$0.88	$1.06	$1.27	$1.48	$1.71	$1.94	$2.17	$2.29	$2.42	$2.55	$47.09
Portland General	POR	($24.51)	$0.00	$1.13	$1.18	$1.23	$1.29	$1.34	$1.47	$1.60	$1.74	$1.90	$2.07	$2.25	$2.37	$2.50	$2.64	$57.30
Southern Co.	SO	($43.76)	$0.00	$1.97	$2.05	$2.13	$2.21	$2.29	$2.39	$2.51	$2.62	$2.75	$2.88	$3.02	$3.18	$3.36	$3.54	$94.81
Westar Energy	WR	($27.31)	$0.00	$1.33	$1.38	$1.42	$1.47	$1.52	$1.63	$1.74	$1.86	$1.98	$2.11	$2.24	$2.37	$2.50	$2.63	$61.07

MULTI-STAGE DCF NOTES

[1] Source: Exhibit JJR-2; Bloomberg Professional; based on 30, 90, or 180-day averaging period
[2] Source: Exhibit JJR-2; Yahoo! Finance, Zacks & Value Line; equals average earnings growth estimate
[3] Source: EIA Annual Energy Outlook 2012, Bloomberg Professional, Bureau of Economic Analysis
[4] Source: Value Line
[5] Source: Value Line
[6] Equals industry average historical payout ratio (1990-present)
[7] Equals Column [1] + Column [60]
[8] Equals result of Excel Solver function; goal: Column [7] equals $0.00
[9] Equals (Column [17] / Column [12]) ^ (1/(2016-2011)) - 1
[10] Equals (Column [22] / Column [17]) ^ (1/(2021-2016)) - 1
[11] Equals (Column [27] / Column [22]) ^ (1/(2026-2021)) - 1
[12] Source: Value Line
[13] Equals Column [12] x (1 + Column [2])
[14] Equals Column [13] x (1 + Column [2])
[15] Equals Column [14] x (1 + Column [2])
[16] Equals Column [15] x (1 + Column [2])
[17] Equals Column [16] x (1 + Column [2])
[18] Equals (1 + (Column [2] + (((Column [3] − Column [2]) / (2021 − 2016 + 1)) x (2017 − 2016)))) x Column [17]
[19] Equals (1 + (Column [2] + (((Column [3] − Column [2]) / (2021 − 2016 + 1)) x (2018 − 2016)))) x Column [18]
[20] Equals (1 + (Column [2] + (((Column [3] − Column [2]) / (2021 − 2016 + 1)) x (2019 − 2016)))) x Column [19]
[21] Equals (1 + (Column [2] + (((Column [3] − Column [2]) / (2021 − 2016 + 1)) x (2020 − 2016)))) x Column [20]
[22] Equals (1 + (Column [2] + (((Column [3] − Column [2]) / (2021 − 2016 + 1)) x (2021 − 2016)))) x Column [21]
[23] Equals Column [22] x (1 + Column [3])
[24] Equals Column [23] x (1 + Column [3])
[25] Equals Column [24] x (1 + Column [3])
[26] Equals Column [25] x (1 + Column [3])
[27] Equals Column [26] x (1 + Column [3])
[28] Equals Column [4]
[29] Equals Column [28] + ((Column [32] − Column [28]) / 4)
[30] Equals Column [29] + ((Column [32] − Column [28]) / 4)
[31] Equals Column [30] + ((Column [32] − Column [28]) / 4)
[32] Equals Column [5]
[33] Equals Column [32] + ((Column [38] − Column [32]) / 6)
[34] Equals Column [33] + ((Column [38] − Column [32]) / 6)
[35] Equals Column [34] + ((Column [38] − Column [32]) / 6)
[36] Equals Column [35] + ((Column [38] − Column [32]) / 6)
[37] Equals Column [36] + ((Column [38] − Column [32]) / 6)
[38] Equals Column [6]
[39] Equals Column [6]
[40] Equals Column [6]
[41] Equals Column [6]
[42] Equals Column [6]
[43] Equals Column [13] x Column [28]
[44] Equals Column [14] x Column [29]
[45] Equals Column [15] x Column [30]
[46] Equals Column [16] x Column [31]
[47] Equals Column [17] x Column [32]
[48] Equals Column [18] x Column [33]
[49] Equals Column [19] x Column [34]
[50] Equals Column [20] x Column [35]
[51] Equals Column [21] x Column [36]
[52] Equals Column [22] x Column [37]
[53] Equals Column [23] x Column [38]
[54] Equals Column [24] x Column [39]
[55] Equals Column [25] x Column [40]
[56] Equals Column [26] x Column [41]
[57] Equals Column [27] x Column [42]
[58] Equals (Column [57] x (1 + Column [3])) / (Column [8] − Column [3])
[59] Equals Column [58] / Column [27]
[60] Equals negative net present value; discount rate equals Column [8], cash flows equal Column [61] through Column [76]
[61] Equals $0.00
[62] Equals Column [43]
[63] Equals Column [44]
[64] Equals Column [45]
[65] Equals Column [46]
[66] Equals Column [47]
[67] Equals Column [48]
[68] Equals Column [49]
[69] Equals Column [50]
[70] Equals Column [51]
[71] Equals Column [52]
[72] Equals Column [53]
[73] Equals Column [54]
[74] Equals Column [55]
[75] Equals Column [56]
[76] Equals Column [57] + Column [58]

EXHIBIT

JJR-4

CAPITAL ASSET PRICING MODEL

	[4] Risk-Free Rate	[5] Average Beta	[6] Market Risk Premium	[7] Return on Equity
PROXY GROUP AVERAGE BLOOMBERG BETA				
[1] Current 30-day average Treasury Yield	3.24%	0.729	9.73%	10.33%
[2] Near-Term Projected 30-Year Treasury (Q1 2012-Q2 2013)	3.58%	0.729	9.38%	10.42%
[3] Projected 30-Year Treasury (2013-2017)	5.10%	0.729	7.87%	10.83%
			Average	10.53%
PROXY GROUP AVERAGE VALUE LINE BETA				
[1] Current 30-day average Treasury Yield	3.24%	0.731	9.73%	10.35%
[2] Near-Term Projected 30-Year Treasury (Q1 2012-Q2 2013)	3.58%	0.731	9.38%	10.44%
[3] Projected 30-Year Treasury (2013-2017)	5.10%	0.731	7.87%	10.85%
			Average	10.55%

Notes:
[1] 30-day average of 30-year Treasury yield as of April 30, 2012.
[2] Source: Blue Chip Financial Forecasts, Vol. 31, No. 5, May 1, 2012, at 2.
[3] Source: Blue Chip Financial Forecasts, Vol. 30, No. 12, December 1, 2011, at 14.
[4] *see Notes [1] and [2]*
[5] Sources: Bloomberg and Value Line.
[6] Source: Exhibit JJR-4, p. 2.
[7] Equals Col. [4] + (Col. [5] x Col. [6])

MARKET RISK PREMIUM DERIVED FROM ANALYSTS' LONG-TERM GROWTH ESTIMATES

[1] Estimated Weighted Index Dividend Yield	[2] Weighted Index Long-Term Growth Rate	[3] S&P 500 Est. Required Market Return
2.13%	10.72%	12.97%

	Risk-Free Rate [4]	Implied Market Risk Premium [5]
[6] Current 30-day average Treasury Yield	3.24%	9.73%
[7] Near-Term Projected 30-Year Treasury (Q1 2012-Q2 201	3.58%	9.38%
[8] Projected 30-Year Treasury (2013-2017)	5.10%	7.87%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[9] Weight in Index	[10] Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.	[12] Estimated Dividend Yield	[13] Cap-Weighted Dividend Yield
3M CO	MMM	0.48%	11.67%	0.06%	2.64%	0.01%
ABBOTT LABORATORIES	ABT	0.75%	9.46%	0.07%	3.30%	0.02%
ABERCROMBIE & FITCH CO-CL A	ANF	0.03%	21.89%	0.01%	1.26%	0.00%
ACCENTURE PLC-CL A	ACN	0.32%	14.67%	0.05%	2.10%	0.01%
ACE LTD	ACE	0.20%	9.65%	0.02%	2.39%	0.00%
ADOBE SYSTEMS INC	ADBE	0.13%	10.00%	0.01%	0.00%	0.00%
ADVANCED MICRO DEVICES	AMD	0.04%	9.78%	0.00%	0.00%	0.00%
AES CORP	AES	0.07%	8.00%	0.01%	0.64%	0.00%
AETNA INC	AET	0.12%	10.60%	0.01%	1.54%	0.00%
AFLAC INC	AFL	0.16%	12.00%	0.02%	2.96%	0.00%
AGILENT TECHNOLOGIES INC	A	0.11%	14.58%	0.02%	0.64%	0.00%
AGL RESOURCES INC	GAS	0.04%	4.00%	0.00%	4.82%	0.00%
AIR PRODUCTS & CHEMICALS INC	APD	0.14%	10.09%	0.01%	2.85%	0.00%
AIRGAS INC	ARG	0.05%	12.18%	0.01%	1.48%	0.00%
AKAMAI TECHNOLOGIES INC	AKAM	0.05%	14.71%	0.01%	0.00%	0.00%
ALCOA INC	AA	0.08%	10.00%	0.01%	1.33%	0.00%
ALLEGHENY TECHNOLOGIES INC	ATI	0.04%	15.00%	0.01%	1.69%	0.00%
ALLERGAN INC	AGN	0.23%	13.65%	0.03%	0.21%	0.00%
ALLSTATE CORP	ALL	0.13%	9.00%	0.01%	2.60%	0.00%
ALPHA NATURAL RESOURCES INC	ANR	0.03%	5.00%	0.00%	0.00%	0.00%
ALTERA CORP	ALTR	0.09%	14.75%	0.01%	0.90%	0.00%
ALTRIA GROUP INC	MO	0.51%	7.44%	0.04%	5.32%	0.03%
AMAZON.COM INC	AMZN	0.81%	22.30%	0.18%	0.00%	0.00%
AMEREN CORPORATION	AEE	0.06%	-4.00%	0.00%	4.87%	0.00%
AMERICAN ELECTRIC POWER	AEP	0.15%	4.33%	0.01%	4.86%	0.01%
AMERICAN EXPRESS CO	AXP	0.54%	11.67%	0.06%	1.31%	0.01%
AMERICAN INTERNATIONAL GROUP	AIG	0.47%	12.33%	0.06%	0.00%	0.00%
AMERICAN TOWER CORP	AMT	0.20%	20.60%	0.04%	1.32%	0.00%
AMERIPRISE FINANCIAL INC	AMP	0.09%	12.00%	0.01%	2.30%	0.00%
AMERISOURCEBERGEN CORP	ABC	0.07%	13.00%	0.01%	1.14%	0.00%
AMGEN INC	AMGN	0.43%	8.89%	0.04%	2.05%	0.01%
AMPHENOL CORP-CL A	APH	0.07%	14.00%	0.01%	0.68%	0.00%
ANADARKO PETROLEUM CORP	APC	0.28%	13.29%	0.04%	0.50%	0.00%
ANALOG DEVICES INC	ADI	0.09%	11.75%	0.01%	2.95%	0.00%
AON PLC	AON	0.13%	8.33%	0.01%	1.18%	0.00%
APACHE CORP	APA	0.29%	6.41%	0.02%	0.69%	0.00%
APARTMENT INVT & MGMT CO -A	AIV	0.03%	8.90%	0.00%	2.67%	0.00%
APOLLO GROUP INC-CL A	APOL	0.03%	8.74%	0.00%	0.00%	0.00%
APPLE INC	AAPL	4.22%	21.00%	0.89%	0.45%	0.02%
APPLIED MATERIALS INC	AMAT	0.12%	14.00%	0.02%	2.71%	0.00%
ARCHER-DANIELS-MIDLAND CO	ADM	0.16%	10.00%	0.02%	2.22%	0.00%
ASSURANT INC	AIZ	0.03%	10.33%	0.00%	1.93%	0.00%
AT&T INC	T	1.49%	6.51%	0.10%	5.37%	0.08%
AUTODESK INC	ADSK	0.07%	17.00%	0.01%	0.00%	0.00%
AUTOMATIC DATA PROCESSING	ADP	0.21%	10.17%	0.02%	2.78%	0.01%
AUTONATION INC	AN	0.03%	20.33%	0.01%	n/a	n/a
AUTOZONE INC	AZO	0.12%	16.00%	0.02%	0.00%	0.00%
AVALONBAY COMMUNITIES INC	AVB	0.11%	10.00%	0.01%	2.67%	0.00%
AVERY DENNISON CORP	AVY	0.03%	7.00%	0.00%	3.38%	0.00%
AVON PRODUCTS INC	AVP	0.07%	6.48%	0.00%	4.30%	0.00%
BAKER HUGHES INC	BHI	0.15%	20.67%	0.03%	1.37%	0.00%
BALL CORP	BLL	0.05%	10.00%	0.01%	0.95%	0.00%
BANK OF AMERICA CORP	BAC	0.68%	8.67%	0.06%	0.52%	0.00%
BANK OF NEW YORK MELLON CORP	BK	0.22%	10.10%	0.02%	2.22%	0.00%

BAXTER INTERNATIONAL INC	BAX	0.24%	8.96%	0.02%	2.48%	0.01%
BB&T CORP	BBT	0.17%	7.00%	0.01%	2.42%	0.00%
BEAM INC	BEAM	0.07%	11.76%	0.01%	1.44%	0.00%
BECTON DICKINSON AND CO	BDX	0.13%	8.00%	0.01%	2.27%	0.00%
BED BATH & BEYOND INC	BBBY	0.13%	14.27%	0.02%	0.00%	0.00%
BEMIS COMPANY	BMS	0.03%	6.00%	0.00%	3.14%	0.00%
BERKSHIRE HATHAWAY INC-CL B	BRK/B	0.67%	n/a	n/a	n/a	n/a
BEST BUY CO INC	BBY	0.06%	6.17%	0.00%	2.36%	0.00%
BIG LOTS INC	BIG	0.02%	12.40%	0.00%	n/a	n/a
BIOGEN IDEC INC	BIIB	0.25%	13.81%	0.03%	0.00%	0.00%
BLACKROCK INC	BLK	0.21%	12.50%	0.03%	3.11%	0.01%
BMC SOFTWARE INC	BMC	0.05%	9.65%	0.01%	0.00%	0.00%
BOEING CO/THE	BA	0.44%	12.87%	0.06%	2.29%	0.01%
BORGWARNER INC	BWA	0.07%	17.47%	0.01%	0.03%	0.00%
BOSTON PROPERTIES INC	BXP	0.12%	6.01%	0.01%	2.02%	0.00%
BOSTON SCIENTIFIC CORP	BSX	0.07%	5.13%	0.00%	0.00%	0.00%
BRISTOL-MYERS SQUIBB CO	BMY	0.44%	5.12%	0.02%	4.09%	0.02%
BROADCOM CORP-CL A	BRCM	0.14%	15.29%	0.02%	1.08%	0.00%
BROWN-FORMAN CORP-CLASS B	BF/B	0.06%	13.00%	0.01%	1.56%	0.00%
CA INC	CA	0.10%	10.67%	0.01%	3.80%	0.00%
CABLEVISION SYSTEMS-NY GRP-A	CVC	0.03%	19.05%	0.00%	4.05%	0.00%
CABOT OIL & GAS CORP	COG	0.06%	n/a	n/a	0.25%	0.00%
CAMERON INTERNATIONAL CORP	CAM	0.10%	17.00%	0.02%	0.00%	0.00%
CAMPBELL SOUP CO	CPB	0.08%	6.00%	0.00%	3.51%	0.00%
CAPITAL ONE FINANCIAL CORP	COF	0.25%	9.60%	0.02%	0.39%	0.00%
CARDINAL HEALTH INC	CAH	0.11%	12.25%	0.01%	1.76%	0.00%
CAREFUSION CORP	CFN	0.05%	9.59%	0.00%	0.00%	0.00%
CARMAX INC	KMX	0.05%	13.99%	0.01%	n/a	n/a
CARNIVAL CORP	CCL	0.15%	16.21%	0.02%	3.23%	0.00%
CATERPILLAR INC	CAT	0.52%	13.33%	0.07%	1.82%	0.01%
CBRE GROUP INC - A	CBG	0.05%	13.33%	0.01%	3.51%	0.00%
CBS CORP-CLASS B NON VOTING	CBS	0.16%	10.75%	0.02%	1.24%	0.00%
CELGENE CORP	CELG	0.25%	24.87%	0.06%	0.00%	0.00%
CENTERPOINT ENERGY INC	CNP	0.07%	5.33%	0.00%	4.01%	0.00%
CENTURYLINK INC	CTL	0.18%	2.07%	0.00%	7.52%	0.01%
CERNER CORP	CERN	0.11%	18.40%	0.02%	0.00%	0.00%
CF INDUSTRIES HOLDINGS INC	CF	0.10%	12.00%	0.01%	0.83%	0.00%
C.H. ROBINSON WORLDWIDE INC	CHRW	0.08%	14.26%	0.01%	2.20%	0.00%
SCHWAB (CHARLES) CORP	SCHW	0.14%	16.00%	0.02%	1.68%	0.00%
CHESAPEAKE ENERGY CORP	CHK	0.09%	3.70%	0.00%	1.38%	0.00%
CHEVRON CORP	CVX	1.62%	-0.98%	-0.02%	3.20%	0.05%
CHIPOTLE MEXICAN GRILL INC	CMG	0.10%	20.00%	0.02%	0.00%	0.00%
CHUBB CORP	CB	0.15%	9.75%	0.01%	2.22%	0.00%
CIGNA CORP	CI	0.10%	10.18%	0.01%	0.07%	0.00%
CINCINNATI FINANCIAL CORP	CINF	0.04%	5.00%	0.00%	4.55%	0.00%
CINTAS CORP	CTAS	0.04%	11.50%	0.00%	1.38%	0.00%
CISCO SYSTEMS INC	CSCO	0.84%	9.22%	0.08%	1.29%	0.01%
CITIGROUP INC	C	0.75%	8.33%	0.06%	0.24%	0.00%
CITRIX SYSTEMS INC	CTXS	0.12%	15.71%	0.02%	0.00%	0.00%
CLIFFS NATURAL RESOURCES INC	CLF	0.07%	11.00%	0.01%	3.41%	0.00%
CLOROX COMPANY	CLX	0.07%	10.00%	0.01%	3.41%	0.00%
CME GROUP INC	CME	0.14%	12.67%	0.02%	4.48%	0.01%
CMS ENERGY CORP	CMS	0.05%	5.67%	0.00%	4.18%	0.00%
COACH INC	COH	0.16%	15.29%	0.02%	1.26%	0.00%
COCA-COLA CO/THE	KO	1.33%	8.57%	0.11%	2.68%	0.04%
COCA-COLA ENTERPRISES	CCE	0.07%	7.86%	0.01%	2.22%	0.00%
COGNIZANT TECH SOLUTIONS-A	CTSH	0.17%	19.00%	0.03%	0.00%	0.00%
COLGATE-PALMOLIVE CO	CL	0.36%	8.69%	0.03%	2.40%	0.01%
COMCAST CORP-CLASS A	CMCSA	0.49%	17.96%	0.09%	2.09%	0.01%
COMERICA INC	CMA	0.05%	13.04%	0.01%	1.72%	0.00%
COMPUTER SCIENCES CORP	CSC	0.03%	8.00%	0.00%	2.85%	0.00%
CONAGRA FOODS INC	CAG	0.08%	9.00%	0.01%	3.68%	0.00%
CONOCOPHILLIPS	COP	0.70%	-1.36%	-0.01%	3.84%	0.03%
CONSOL ENERGY INC	CNX	0.06%	12.00%	0.01%	1.50%	0.00%
CONSOLIDATED EDISON INC	ED	0.13%	3.87%	0.01%	4.07%	0.01%
CONSTELLATION BRANDS INC-A	STZ	0.03%	9.01%	0.00%	0.00%	0.00%
COOPER INDUSTRIES PLC	CBE	0.08%	12.50%	0.01%	1.97%	0.00%
CORNING INC	GLW	0.17%	9.67%	0.02%	2.03%	0.00%
COSTCO WHOLESALE CORP	COST	0.30%	14.26%	0.04%	1.05%	0.00%
COVENTRY HEALTH CARE INC	CVH	0.03%	12.33%	0.00%	1.38%	0.00%
COVIDIEN PLC	COV	0.21%	11.43%	0.02%	1.54%	0.00%
CR BARD INC	BCR	0.06%	9.57%	0.01%	0.81%	0.00%
CROWN CASTLE INTL CORP	CCI	0.13%	29.63%	0.04%	0.00%	0.00%
CSX CORP	CSX	0.18%	16.13%	0.03%	2.32%	0.00%
CUMMINS INC	CMI	0.17%	10.67%	0.02%	1.38%	0.00%
CVS CAREMARK CORP	CVS	0.45%	13.50%	0.06%	1.44%	0.01%
DANAHER CORP	DHR	0.29%	15.00%	0.04%	0.19%	0.00%
DARDEN RESTAURANTS INC	DRI	0.05%	12.47%	0.01%	3.34%	0.00%
DAVITA INC	DVA	0.06%	12.57%	0.01%	0.00%	0.00%
DEAN FOODS CO	DF	0.02%	10.00%	0.00%	0.00%	0.00%

DEERE & CO	DE	0.26%	14.67%	0.04%	2.04%	0.01%
DELL INC	DELL	0.22%	5.50%	0.01%	0.00%	0.00%
DENBURY RESOURCES INC	DNR	0.06%	40.50%	0.02%	0.00%	0.00%
DENTSPLY INTERNATIONAL INC	XRAY	0.05%	10.80%	0.00%	0.51%	0.00%
DEVON ENERGY CORPORATION	DVN	0.22%	8.35%	0.02%	1.12%	0.00%
DEVRY INC	DV	0.02%	8.09%	0.00%	0.95%	0.00%
DIAMOND OFFSHORE DRILLING	DO	0.07%	17.33%	0.01%	5.15%	0.00%
DIRECTV-CLASS A	DTV	0.26%	22.30%	0.06%	0.00%	0.00%
DISCOVER FINANCIAL SERVICES	DFS	0.14%	10.50%	0.01%	1.26%	0.00%
DISCOVERY COMMUNICATIONS-A	DISCA	0.06%	20.34%	0.01%	0.00%	0.00%
DOLLAR TREE INC	DLTR	0.09%	17.05%	0.02%	n/a	n/a
DOMINION RESOURCES INC/VA	D	0.23%	6.00%	0.01%	3.99%	0.01%
DOVER CORP	DOV	0.09%	13.67%	0.01%	2.08%	0.00%
DOW CHEMICAL CO/THE	DOW	0.31%	5.33%	0.02%	3.37%	0.01%
DR HORTON INC	DHI	0.04%	7.67%	0.00%	0.92%	0.00%
DR PEPPER SNAPPLE GROUP INC	DPS	0.07%	7.20%	0.00%	3.34%	0.00%
DTE ENERGY COMPANY	DTE	0.07%	5.00%	0.00%	4.31%	0.00%
DUKE ENERGY CORP	DUK	0.22%	4.50%	0.01%	4.75%	0.01%
DUN & BRADSTREET CORP	DNB	0.03%	10.00%	0.00%	1.95%	0.00%
E*TRADE FINANCIAL CORP	ETFC	0.02%	26.00%	0.01%	0.00%	0.00%
EASTMAN CHEMICAL CO	EMN	0.06%	7.50%	0.00%	1.89%	0.00%
EATON CORP	ETN	0.13%	10.25%	0.01%	3.17%	0.00%
EBAY INC	EBAY	0.41%	12.58%	0.05%	0.00%	0.00%
ECOLAB INC	ECL	0.14%	12.80%	0.02%	1.25%	0.00%
EDISON INTERNATIONAL	EIX	0.11%	2.40%	0.00%	2.99%	0.00%
EDWARDS LIFESCIENCES CORP	EW	0.07%	21.90%	0.02%	0.00%	0.00%
DU PONT (E.I.) DE NEMOURS	DD	0.39%	8.30%	0.03%	3.08%	0.01%
EL PASO CORP	EP	0.16%	n/a	n/a	1.11%	0.00%
ELECTRONIC ARTS INC	EA	0.04%	17.42%	0.01%	0.00%	0.00%
ELI LILLY & CO	LLY	0.37%	-1.83%	-0.01%	4.73%	0.02%
EMC CORP/MA	EMC	0.46%	15.00%	0.07%	0.00%	0.00%
EMERSON ELECTRIC CO	EMR	0.30%	13.00%	0.04%	2.99%	0.01%
ENTERGY CORP	ETR	0.09%	-1.70%	0.00%	5.10%	0.00%
EOG RESOURCES INC	EOG	0.23%	12.58%	0.03%	0.60%	0.00%
EQT CORP	EQT	0.06%	30.00%	0.02%	1.77%	0.00%
EQUIFAX INC	EFX	0.04%	11.00%	0.00%	1.54%	0.00%
EQUITY RESIDENTIAL	EQR	0.14%	8.05%	0.01%	2.83%	0.00%
ESTEE LAUDER COMPANIES-CL A	EL	0.12%	13.25%	0.02%	0.88%	0.00%
EXELON CORP	EXC	0.26%	-3.32%	-0.01%	5.38%	0.01%
EXPEDIA INC	EXPE	0.04%	10.19%	0.00%	0.82%	0.00%
EXPEDITORS INTL WASH INC	EXPD	0.07%	10.18%	0.01%	1.41%	0.00%
EXPRESS SCRIPTS HOLDING CO	ESRX	0.35%	15.50%	0.05%	0.00%	0.00%
EXXON MOBIL CORP	XOM	3.14%	4.96%	0.16%	2.44%	0.08%
F5 NETWORKS INC	FFIV	0.08%	20.00%	0.02%	0.00%	0.00%
FAMILY DOLLAR STORES	FDO	0.06%	14.24%	0.01%	1.19%	0.00%
FASTENAL CO	FAST	0.11%	19.37%	0.02%	1.46%	0.00%
FEDERATED INVESTORS INC-CL B	FII	0.02%	8.00%	0.00%	4.49%	0.00%
FEDEX CORP	FDX	0.22%	13.60%	0.03%	0.59%	0.00%
FIDELITY NATIONAL INFORMATIO	FIS	0.08%	12.63%	0.01%	1.78%	0.00%
FIFTH THIRD BANCORP	FITB	0.10%	5.00%	0.01%	2.45%	0.00%
FIRST HORIZON NATIONAL CORP	FHN	0.02%	8.33%	0.00%	0.81%	0.00%
FIRST SOLAR INC	FSLR	0.01%	0.00%	0.00%	0.00%	0.00%
FIRSTENERGY CORP	FE	0.15%	2.50%	0.00%	4.70%	0.01%
FISERV INC	FISV	0.07%	12.43%	0.01%	0.00%	0.00%
FLIR SYSTEMS INC	FLIR	0.03%	12.80%	0.00%	1.25%	0.00%
FLOWSERVE CORP	FLS	0.05%	6.00%	0.00%	1.24%	0.00%
FLUOR CORP	FLR	0.08%	13.30%	0.01%	1.06%	0.00%
FMC CORP	FMC	0.06%	10.14%	0.01%	0.58%	0.00%
FMC TECHNOLOGIES INC	FTI	0.09%	13.00%	0.01%	0.00%	0.00%
FORD MOTOR CO	F	0.33%	11.29%	0.04%	1.77%	0.01%
FOREST LABORATORIES INC	FRX	0.07%	3.63%	0.00%	0.00%	0.00%
FOSSIL INC	FOSL	0.06%	18.90%	0.01%	0.00%	0.00%
FRANKLIN RESOURCES INC	BEN	0.21%	9.00%	0.02%	2.18%	0.00%
FREEPORT-MCMORAN COPPER	FCX	0.28%	n/a	n/a	3.53%	0.01%
FRONTIER COMMUNICATIONS CORP	FTR	0.03%	3.00%	0.00%	9.93%	0.00%
GAMESTOP CORP-CLASS A	GME	0.02%	9.48%	0.00%	0.88%	0.00%
GANNETT CO	GCI	0.03%	6.00%	0.00%	5.35%	0.00%
GAP INC/THE	GPS	0.11%	9.88%	0.01%	1.69%	0.00%
GENERAL DYNAMICS CORP	GD	0.19%	8.40%	0.02%	2.92%	0.01%
GENERAL ELECTRIC CO	GE	1.60%	13.33%	0.21%	3.40%	0.05%
GENERAL MILLS INC	GIS	0.19%	8.00%	0.02%	3.13%	0.01%
GENUINE PARTS CO	GPC	0.08%	8.23%	0.01%	3.06%	0.00%
GENWORTH FINANCIAL INC-CL A	GNW	0.02%	5.00%	0.00%	0.06%	0.00%
GILEAD SCIENCES INC	GILD	0.30%	15.57%	0.05%	0.00%	0.00%
GOLDMAN SACHS GROUP INC	GS	0.44%	11.51%	0.05%	1.50%	0.01%
GOODRICH CORP	GR	0.12%	10.73%	0.01%	0.94%	0.00%
GOODYEAR TIRE & RUBBER CO	GT	0.02%	43.64%	0.01%	0.00%	0.00%
GOOGLE INC-CL A	GOOG	1.22%	18.56%	0.23%	0.00%	0.00%
H&R BLOCK INC	HRB	0.03%	12.00%	0.00%	4.56%	0.00%
HALLIBURTON CO	HAL	0.24%	20.50%	0.05%	1.06%	0.00%

HARLEY-DAVIDSON INC	HOG	0.09%	13.00%	0.01%	1.18%	0.00%
HARMAN INTERNATIONAL	HAR	0.03%	20.00%	0.01%	0.58%	0.00%
HARRIS CORP	HRS	0.04%	6.50%	0.00%	2.56%	0.00%
HARTFORD FINANCIAL SVCS GRP	HIG	0.07%	9.50%	0.01%	2.10%	0.00%
HASBRO INC	HAS	0.04%	10.00%	0.00%	3.81%	0.00%
HCP INC	HCP	0.13%	4.92%	0.01%	4.83%	0.01%
HEALTH CARE REIT INC	HCN	0.09%	6.68%	0.01%	5.22%	0.00%
HELMERICH & PAYNE	HP	0.04%	8.00%	0.00%	0.54%	0.00%
HERSHEY CO/THE	HSY	0.08%	7.90%	0.01%	2.22%	0.00%
HESS CORP	HES	0.14%	3.71%	0.01%	0.77%	0.00%
HEWLETT-PACKARD CO	HPQ	0.38%	10.00%	0.04%	1.75%	0.01%
HJ HEINZ CO	HNZ	0.13%	8.00%	0.01%	3.60%	0.00%
HOME DEPOT INC	HD	0.61%	14.54%	0.09%	2.35%	0.01%
HONEYWELL INTERNATIONAL INC	HON	0.37%	15.00%	0.05%	2.40%	0.01%
HORMEL FOODS CORP	HRL	0.06%	11.00%	0.01%	2.07%	0.00%
HOSPIRA INC	HSP	0.04%	7.00%	0.00%	0.00%	0.00%
HOST HOTELS & RESORTS INC	HST	0.09%	12.18%	0.01%	1.49%	0.00%
HUDSON CITY BANCORP INC	HCBK	0.03%	0.50%	0.00%	4.51%	0.00%
HUMANA INC	HUM	0.10%	9.00%	0.01%	1.25%	0.00%
HUNTINGTON BANCSHARES INC	HBAN	0.04%	5.33%	0.00%	2.43%	0.00%
ILLINOIS TOOL WORKS	ITW	0.21%	10.88%	0.02%	2.50%	0.01%
INGERSOLL-RAND PLC	IR	0.10%	10.60%	0.01%	1.52%	0.00%
INTEGRYS ENERGY GROUP INC	TEG	0.03%	4.50%	0.00%	4.98%	0.00%
INTEL CORP	INTC	1.10%	10.66%	0.12%	2.98%	0.03%
INTERCONTINENTALEXCHANGE INC	ICE	0.07%	14.00%	0.01%	0.00%	0.00%
INTL BUSINESS MACHINES CORP	IBM	1.85%	10.00%	0.18%	1.55%	0.03%
INTL FLAVORS & FRAGRANCES	IFF	0.04%	3.00%	0.00%	2.09%	0.00%
INTL GAME TECHNOLOGY	IGT	0.04%	14.75%	0.01%	1.54%	0.00%
INTERNATIONAL PAPER CO	IP	0.11%	5.00%	0.01%	3.15%	0.00%
INTERPUBLIC GROUP OF COS INC	IPG	0.04%	9.33%	0.00%	2.10%	0.00%
INTUIT INC	INTU	0.13%	15.14%	0.02%	0.64%	0.00%
INTUITIVE SURGICAL INC	ISRG	0.18%	21.17%	0.04%	n/a	n/a
INVESCO LTD	IVZ	0.09%	11.33%	0.01%	2.70%	0.00%
IRON MOUNTAIN INC	IRM	0.04%	13.67%	0.01%	3.13%	0.00%
JABIL CIRCUIT INC	JBL	0.04%	12.00%	0.00%	1.33%	0.00%
JACOBS ENGINEERING GROUP INC	JEC	0.04%	13.65%	0.01%	0.00%	0.00%
J.C. PENNEY CO INC	JCP	0.06%	17.80%	0.01%	2.24%	0.00%
JDS UNIPHASE CORP	JDSU	0.02%	14.00%	0.00%	0.00%	0.00%
JM SMUCKER CO/THE	SJM	0.07%	8.00%	0.01%	2.40%	0.00%
JOHNSON & JOHNSON	JNJ	1.38%	6.66%	0.09%	3.68%	0.05%
JOHNSON CONTROLS INC	JCI	0.17%	19.90%	0.03%	2.11%	0.00%
JOY GLOBAL INC	JOY	0.06%	20.15%	0.01%	1.01%	0.00%
JPMORGAN CHASE & CO	JPM	1.27%	7.50%	0.10%	2.74%	0.03%
JUNIPER NETWORKS INC	JNPR	0.09%	14.88%	0.01%	0.00%	0.00%
KELLOGG CO	K	0.14%	8.06%	0.01%	3.45%	0.00%
KEYCORP	KEY	0.06%	7.02%	0.00%	2.26%	0.00%
KIMBERLY-CLARK CORP	KMB	0.24%	8.20%	0.02%	3.76%	0.01%
KIMCO REALTY CORP	KIM	0.06%	10.71%	0.01%	3.97%	0.00%
KLA-TENCOR CORPORATION	KLAC	0.07%	9.67%	0.01%	2.67%	0.00%
KOHLS CORP	KSS	0.09%	12.25%	0.01%	2.40%	0.00%
KRAFT FOODS INC-CLASS A	KFT	0.55%	8.85%	0.05%	2.96%	0.02%
KROGER CO	KR	0.10%	10.44%	0.01%	2.04%	0.00%
L-3 COMMUNICATIONS HOLDINGS	LLL	0.06%	2.42%	0.00%	2.65%	0.00%
LABORATORY CRP OF AMER HLDGS	LH	0.07%	12.25%	0.01%	0.00%	0.00%
LEGG MASON INC	LM	0.03%	11.00%	0.00%	1.39%	0.00%
LEGGETT & PLATT INC	LEG	0.02%	15.00%	0.00%	5.14%	0.00%
LENNAR CORP-A	LEN	0.03%	8.00%	0.00%	0.63%	0.00%
LEUCADIA NATIONAL CORP	LUK	0.05%	n/a	n/a	n/a	n/a
LEXMARK INTERNATIONAL INC-A	LXK	0.02%	-9.00%	0.00%	3.32%	0.00%
LIFE TECHNOLOGIES CORP	LIFE	0.06%	8.71%	0.01%	0.00%	0.00%
LINCOLN NATIONAL CORP	LNC	0.06%	9.50%	0.01%	1.36%	0.00%
LINEAR TECHNOLOGY CORP	LLTC	0.06%	10.00%	0.01%	3.01%	0.00%
LOCKHEED MARTIN CORP	LMT	0.23%	6.88%	0.02%	4.50%	0.01%
LOEWS CORP	L	0.13%	n/a	n/a	0.61%	0.00%
LORILLARD INC	LO	0.14%	11.18%	0.02%	4.57%	0.01%
LOWE'S COS INC	LOW	0.29%	14.17%	0.04%	1.97%	0.01%
LSI CORP	LSI	0.04%	15.00%	0.01%	n/a	n/a
LIMITED BRANDS INC	LTD	0.11%	14.53%	0.02%	2.55%	0.00%
M & T BANK CORP	MTB	0.08%	13.69%	0.01%	3.25%	0.00%
MACY'S INC	M	0.13%	10.90%	0.01%	1.96%	0.00%
MARATHON OIL CORP	MRO	0.16%	2.53%	0.00%	2.25%	0.00%
MARATHON PETROLEUM CORP	MPC	0.11%	12.00%	0.01%	2.73%	0.00%
MARRIOTT INTERNATIONAL-CL A	MAR	0.10%	17.12%	0.02%	1.07%	0.00%
MARSH & MCLENNAN COS	MMC	0.14%	10.67%	0.02%	2.64%	0.00%
MASCO CORP	MAS	0.04%	15.00%	0.01%	2.29%	0.00%
MASTERCARD INC-CLASS A	MA	0.42%	17.90%	0.08%	0.13%	0.00%
MATTEL INC	MAT	0.09%	10.00%	0.01%	3.70%	0.00%
MCCORMICK & CO-NON VTG SHRS	MKC	0.05%	9.50%	0.00%	2.18%	0.00%
MCDONALD'S CORP	MCD	0.77%	9.63%	0.07%	2.94%	0.02%
MCGRAW-HILL COMPANIES INC	MHP	0.11%	10.50%	0.01%	2.03%	0.00%

MCKESSON CORP	MCK	0.17%	n/a	n/a	0.68%	0.00%
MEAD JOHNSON NUTRITION CO	MJN	0.13%	10.33%	0.01%	1.40%	0.00%
MEADWESTVACO CORP	MWV	0.04%	10.00%	0.00%	3.14%	0.00%
MEDTRONIC INC	MDT	0.31%	7.46%	0.02%	2.58%	0.01%
MERCK & CO. INC.	MRK	0.92%	4.55%	0.04%	4.30%	0.04%
METLIFE INC	MET	0.30%	9.50%	0.03%	2.68%	0.01%
METROPCS COMMUNICATIONS INC	PCS	0.02%	18.84%	0.00%	0.00%	0.00%
MICROCHIP TECHNOLOGY INC	MCHP	0.05%	10.00%	0.01%	4.02%	0.00%
MICRON TECHNOLOGY INC	MU	0.05%	12.28%	0.01%	0.00%	0.00%
MICROSOFT CORP	MSFT	2.08%	9.33%	0.19%	2.42%	0.05%
MOLEX INC	MOLX	0.02%	11.67%	0.00%	2.94%	0.00%
MOLSON COORS BREWING CO -B	TAP	0.05%	8.00%	0.00%	3.30%	0.00%
MONSANTO CO	MON	0.31%	9.05%	0.03%	1.57%	0.00%
MOODY'S CORP	MCO	0.07%	12.00%	0.01%	1.56%	0.00%
MORGAN STANLEY	MS	0.26%	10.67%	0.03%	1.16%	0.00%
MOSAIC CO/THE	MOS	0.12%	21.42%	0.03%	0.49%	0.00%
MOTOROLA MOBILITY HOLDINGS I	MMI	0.09%	20.00%	0.02%	0.00%	0.00%
MOTOROLA SOLUTIONS INC	MSI	0.12%	n/a	n/a	1.83%	0.00%
MURPHY OIL CORP	MUR	0.08%	10.00%	0.01%	2.11%	0.00%
MYLAN INC	MYL	0.07%	10.70%	0.01%	0.00%	0.00%
NABORS INDUSTRIES LTD	NBR	0.04%	8.00%	0.00%	0.00%	0.00%
NASDAQ OMX GROUP/THE	NDAQ	0.03%	10.33%	0.00%	1.28%	0.00%
NATIONAL OILWELL VARCO INC	NOV	0.25%	18.00%	0.04%	0.60%	0.00%
NETAPP INC	NTAP	0.11%	15.86%	0.02%	0.00%	0.00%
NETFLIX INC	NFLX	0.03%	12.11%	0.00%	0.00%	0.00%
NEWELL RUBBERMAID INC	NWL	0.04%	9.01%	0.00%	1.97%	0.00%
NEWFIELD EXPLORATION CO	NFX	0.04%	11.50%	0.00%	0.00%	0.00%
NEWMONT MINING CORP	NEM	0.18%	-3.00%	-0.01%	3.35%	0.01%
NEWS CORP-CL A	NWSA	0.25%	17.68%	0.04%	0.92%	0.00%
NEXTERA ENERGY INC	NEE	0.21%	5.00%	0.01%	3.70%	0.01%
NIKE INC -CL B	NKE	0.32%	13.65%	0.04%	1.20%	0.00%
NISOURCE INC	NI	0.05%	n/a	n/a	3.79%	0.00%
NOBLE CORP	NE	0.07%	13.00%	0.01%	1.48%	0.00%
NOBLE ENERGY INC	NBL	0.14%	21.90%	0.03%	0.87%	0.00%
NORDSTROM INC	JWN	0.09%	13.20%	0.01%	1.69%	0.00%
NORFOLK SOUTHERN CORP	NSC	0.18%	12.33%	0.02%	2.57%	0.00%
NORTHEAST UTILITIES	NU	0.09%	8.19%	0.01%	3.15%	0.00%
NORTHERN TRUST CORP	NTRS	0.09%	10.13%	0.01%	2.57%	0.00%
NORTHROP GRUMMAN CORP	NOC	0.12%	3.75%	0.00%	3.34%	0.00%
NOVELLUS SYSTEMS INC	NVLS	0.03%	10.00%	0.00%	0.00%	0.00%
NRG ENERGY INC	NRG	0.03%	0.02%	0.00%	0.66%	0.00%
NUCOR CORP	NUE	0.10%	8.50%	0.01%	3.71%	0.00%
NVIDIA CORP	NVDA	0.06%	13.67%	0.01%	0.00%	0.00%
NYSE EURONEXT	NYX	0.05%	10.00%	0.01%	4.68%	0.00%
O'REILLY AUTOMOTIVE INC	ORLY	0.10%	17.94%	0.02%	0.00%	0.00%
OCCIDENTAL PETROLEUM CORP	OXY	0.57%	-0.28%	0.00%	2.25%	0.01%
OMNICOM GROUP	OMC	0.11%	8.00%	0.01%	2.32%	0.00%
ONEOK INC	OKE	0.07%	16.00%	0.01%	3.02%	0.00%
ORACLE CORP	ORCL	1.13%	14.11%	0.16%	0.80%	0.01%
OWENS-ILLINOIS INC	OI	0.03%	8.67%	0.00%	0.00%	0.00%
PACCAR INC	PCAR	0.12%	11.00%	0.01%	3.09%	0.00%
PALL CORP	PLL	0.05%	12.00%	0.01%	1.21%	0.00%
PARKER HANNIFIN CORP	PH	0.10%	6.00%	0.01%	1.76%	0.00%
PATTERSON COS INC	PDCO	0.03%	11.75%	0.00%	0.77%	0.00%
PAYCHEX INC	PAYX	0.09%	10.00%	0.01%	4.08%	0.00%
PEABODY ENERGY CORP	BTU	0.07%	12.00%	0.01%	1.09%	0.00%
PEOPLE'S UNITED FINANCIAL	PBCT	0.03%	7.67%	0.00%	5.17%	0.00%
PEPCO HOLDINGS INC	POM	0.03%	6.50%	0.00%	5.71%	0.00%
PEPSICO INC	PEP	0.80%	4.64%	0.04%	3.21%	0.03%
PERKINELMER INC	PKI	0.02%	11.16%	0.00%	1.01%	0.00%
PERRIGO CO	PRGO	0.08%	12.00%	0.01%	0.25%	0.00%
PFIZER INC	PFE	1.34%	4.21%	0.06%	3.85%	0.05%
P G & E CORP	PCG	0.14%	1.65%	0.00%	4.14%	0.01%
PHILIP MORRIS INTERNATIONAL	PM	1.19%	10.87%	0.13%	3.65%	0.04%
PINNACLE WEST CAPITAL	PNW	0.04%	6.25%	0.00%	4.43%	0.00%
PIONEER NATURAL RESOURCES CO	PXD	0.11%	79.60%	0.09%	0.10%	0.00%
PITNEY BOWES INC	PBI	0.03%	n/a	n/a	8.68%	0.00%
PLUM CREEK TIMBER CO	PCL	0.05%	5.00%	0.00%	4.00%	0.00%
PNC FINANCIAL SERVICES GROUP	PNC	0.27%	9.47%	0.03%	2.36%	0.01%
PPG INDUSTRIES INC	PPG	0.12%	7.00%	0.01%	2.20%	0.00%
PPL CORPORATION	PPL	0.12%	-8.00%	-0.01%	5.26%	0.01%
PRAXAIR INC	PX	0.27%	10.75%	0.03%	1.89%	0.01%
PRECISION CASTPARTS CORP	PCP	0.20%	13.70%	0.03%	0.07%	0.00%
PRICELINE.COM INC	PCLN	0.29%	20.65%	0.06%	0.00%	0.00%
PRINCIPAL FINANCIAL GROUP	PFG	0.06%	11.50%	0.01%	2.64%	0.00%
PROCTER & GAMBLE CO/THE	PG	1.35%	8.44%	0.11%	3.32%	0.04%
PROGRESS ENERGY INC	PGN	0.12%	3.10%	0.00%	4.67%	0.01%
PROGRESSIVE CORP	PGR	0.10%	7.75%	0.01%	1.87%	0.00%
PROLOGIS INC	PLD	0.13%	6.41%	0.01%	3.13%	0.00%
PRUDENTIAL FINANCIAL INC	PRU	0.22%	11.00%	0.02%	2.66%	0.01%

PUBLIC SERVICE ENTERPRISE GP	PEG	0.12%	0.30%	0.00%	4.54%	0.01%
PUBLIC STORAGE	PSA	0.19%	5.04%	0.01%	3.07%	0.01%
PULTEGROUP INC	PHM	0.03%	10.00%	0.00%	0.00%	0.00%
QEP RESOURCES INC	QEP	0.04%	19.50%	0.01%	0.19%	0.00%
QUALCOMM INC	QCOM	0.85%	15.50%	0.13%	1.38%	0.01%
QUANTA SERVICES INC	PWR	0.04%	15.83%	0.01%	n/a	n/a
QUEST DIAGNOSTICS INC	DGX	0.07%	11.71%	0.01%	1.16%	0.00%
RALPH LAUREN CORP	RL	0.08%	13.00%	0.01%	0.48%	0.00%
RANGE RESOURCES CORP	RRC	0.08%	10.00%	0.01%	0.24%	0.00%
RAYTHEON COMPANY	RTN	0.14%	7.75%	0.01%	3.62%	0.01%
RED HAT INC	RHT	0.09%	18.43%	0.02%	0.00%	0.00%
REGIONS FINANCIAL CORP	RF	0.07%	8.55%	0.01%	0.63%	0.00%
REPUBLIC SERVICES INC	RSG	0.08%	10.00%	0.01%	3.24%	0.00%
REYNOLDS AMERICAN INC	RAI	0.18%	7.41%	0.01%	5.70%	0.01%
ROBERT HALF INTL INC	RHI	0.03%	12.67%	0.00%	2.00%	0.00%
ROCKWELL AUTOMATION INC	ROK	0.09%	14.67%	0.01%	2.24%	0.00%
ROCKWELL COLLINS INC	COL	0.06%	8.03%	0.01%	1.91%	0.00%
ROPER INDUSTRIES INC	ROP	0.08%	14.00%	0.01%	0.52%	0.00%
ROSS STORES INC	ROST	0.11%	9.33%	0.01%	0.96%	0.00%
ROWAN COMPANIES INC	RDC	0.03%	18.33%	0.01%	0.00%	0.00%
RR DONNELLEY & SONS CO	RRD	0.02%	5.00%	0.00%	8.32%	0.00%
RYDER SYSTEM INC	R	0.02%	10.27%	0.00%	2.53%	0.00%
SAFEWAY INC	SWY	0.04%	10.77%	0.00%	2.89%	0.00%
SAIC INC	SAI	0.03%	4.33%	0.00%	3.95%	0.00%
SALESFORCE.COM INC	CRM	0.16%	26.89%	0.04%	0.00%	0.00%
SANDISK CORP	SNDK	0.07%	13.42%	0.01%	0.00%	0.00%
SARA LEE CORP	SLE	0.10%	6.00%	0.01%	2.04%	0.00%
SCANA CORP	SCG	0.05%	4.46%	0.00%	4.29%	0.00%
SCHLUMBERGER LTD	SLB	0.76%	19.33%	0.15%	1.46%	0.01%
SCRIPPS NETWORKS INTER-CL A	SNI	0.05%	13.94%	0.01%	0.88%	0.00%
SEALED AIR CORP	SEE	0.03%	5.50%	0.00%	2.71%	0.00%
SEARS HOLDINGS CORP	SHLD	0.04%	n/a	n/a	n/a	n/a
SEMPRA ENERGY	SRE	0.12%	7.00%	0.01%	3.43%	0.00%
SHERWIN-WILLIAMS CO/THE	SHW	0.10%	17.00%	0.02%	1.28%	0.00%
SIGMA-ALDRICH	SIAL	0.07%	8.04%	0.01%	1.12%	0.00%
SIMON PROPERTY GROUP INC	SPG	0.37%	5.92%	0.02%	2.53%	0.01%
SLM CORP	SLM	0.06%	n/a	n/a	3.37%	0.00%
SNAP-ON INC	SNA	0.03%	10.00%	0.00%	2.25%	0.00%
SOUTHERN CO/THE	SO	0.31%	5.95%	0.02%	4.24%	0.01%
SOUTHWEST AIRLINES CO	LUV	0.05%	6.00%	0.00%	0.24%	0.00%
SOUTHWESTERN ENERGY CO	SWN	0.09%	13.70%	0.01%	0.00%	0.00%
SPECTRA ENERGY CORP	SE	0.15%	5.00%	0.01%	3.69%	0.01%
SPRINT NEXTEL CORP	S	0.06%	-21.30%	-0.01%	0.00%	0.00%
ST JUDE MEDICAL INC	STJ	0.10%	9.86%	0.01%	2.30%	0.00%
STANLEY BLACK & DECKER INC	SWK	0.10%	13.00%	0.01%	2.35%	0.00%
STAPLES INC	SPLS	0.08%	9.37%	0.01%	2.67%	0.00%
STARBUCKS CORP	SBUX	0.33%	17.65%	0.06%	1.22%	0.00%
STARWOOD HOTELS & RESORTS	HOT	0.09%	19.98%	0.02%	0.89%	0.00%
STATE STREET CORP	STT	0.18%	7.78%	0.01%	2.01%	0.00%
STERICYCLE INC	SRCL	0.06%	16.67%	0.01%	n/a	n/a
STRYKER CORP	SYK	0.16%	10.53%	0.02%	1.14%	0.00%
SUNOCO INC	SUN	0.04%	-2.09%	0.00%	1.60%	0.00%
SUNTRUST BANKS INC	STI	0.10%	23.44%	0.02%	0.97%	0.00%
SUPERVALU INC	SVU	0.01%	6.10%	0.00%	5.94%	0.00%
SYMANTEC CORP	SYMC	0.09%	8.11%	0.01%	0.00%	0.00%
SYSCO CORP	SYY	0.13%	10.00%	0.01%	3.83%	0.01%
T ROWE PRICE GROUP INC	TROW	0.12%	12.50%	0.02%	2.15%	0.00%
TARGET CORP	TGT	0.30%	12.16%	0.04%	2.09%	0.01%
TE CONNECTIVITY LTD	TEL	0.12%	15.00%	0.02%	2.12%	0.00%
TECO ENERGY INC	TE	0.03%	3.50%	0.00%	4.88%	0.00%
TENET HEALTHCARE CORP	THC	0.02%	11.20%	0.00%	0.00%	0.00%
TERADATA CORP	TDC	0.09%	14.40%	0.01%	n/a	n/a
TERADYNE INC	TER	0.02%	11.75%	0.00%	0.00%	0.00%
TESORO CORP	TSO	0.03%	1.91%	0.00%	0.00%	0.00%
TEXAS INSTRUMENTS INC	TXN	0.28%	9.20%	0.03%	2.08%	0.01%
TEXTRON INC	TXT	0.06%	33.94%	0.02%	0.30%	0.00%
THERMO FISHER SCIENTIFIC INC	TMO	0.16%	12.10%	0.02%	0.60%	0.00%
TIFFANY & CO	TIF	0.07%	14.67%	0.01%	1.78%	0.00%
TIME WARNER CABLE	TWC	0.19%	17.81%	0.03%	2.75%	0.01%
TIME WARNER INC	TWX	0.28%	13.16%	0.04%	2.74%	0.01%
TITANIUM METALS CORP	TIE	0.02%	15.00%	0.00%	1.52%	0.00%
TJX COMPANIES INC	TJX	0.24%	11.83%	0.03%	1.12%	0.00%
TORCHMARK CORP	TMK	0.04%	9.00%	0.00%	1.01%	0.00%
TOTAL SYSTEM SERVICES INC	TSS	0.03%	9.43%	0.00%	1.66%	0.00%
TRAVELERS COS INC/THE	TRV	0.19%	8.67%	0.02%	2.81%	0.01%
TRIPADVISOR INC	TRIP	0.04%	15.25%	0.01%	n/a	n/a
TYCO INTERNATIONAL LTD	TYC	0.20%	13.00%	0.03%	1.89%	0.00%
TYSON FOODS INC-CL A	TSN	0.04%	6.00%	0.00%	0.90%	0.00%
UNION PACIFIC CORP	UNP	0.41%	13.00%	0.05%	2.13%	0.01%
UNITED PARCEL SERVICE-CL B	UPS	0.44%	11.86%	0.05%	2.91%	0.01%

UNITED STATES STEEL CORP	X	0.03%	6.50%	0.00%	0.71%	0.00%
UNITED TECHNOLOGIES CORP	UTX	0.57%	11.07%	0.06%	2.44%	0.01%
UNITEDHEALTH GROUP INC	UNH	0.45%	11.00%	0.05%	1.14%	0.01%
UNUM GROUP	UNM	0.05%	9.50%	0.00%	1.82%	0.00%
URBAN OUTFITTERS INC	URBN	0.03%	18.30%	0.01%	0.00%	0.00%
US BANCORP	USB	0.47%	14.24%	0.07%	2.35%	0.01%
VALERO ENERGY CORP	VLO	0.11%	2.01%	0.00%	2.43%	0.00%
VARIAN MEDICAL SYSTEMS INC	VAR	0.06%	12.33%	0.01%	0.00%	0.00%
VENTAS INC	VTR	0.13%	5.28%	0.01%	4.20%	0.01%
VERISIGN INC	VRSN	0.05%	13.00%	0.01%	0.00%	0.00%
VERIZON COMMUNICATIONS INC	VZ	0.89%	8.09%	0.07%	4.99%	0.04%
VF CORP	VFC	0.13%	12.13%	0.02%	1.92%	0.00%
VIACOM INC-CLASS B	VIAB	0.18%	16.12%	0.03%	2.16%	0.00%
VISA INC-CLASS A SHARES	V	0.50%	18.71%	0.09%	0.72%	0.00%
VORNADO REALTY TRUST	VNO	0.12%	1.91%	0.00%	3.30%	0.00%
VULCAN MATERIALS CO	VMC	0.04%	9.67%	0.00%	0.09%	0.00%
WAL-MART STORES INC	WMT	1.55%	9.70%	0.15%	2.72%	0.04%
WALGREEN CO	WAG	0.23%	12.83%	0.03%	2.56%	0.01%
WALT DISNEY CO/THE	DIS	0.60%	12.43%	0.07%	1.39%	0.01%
WASHINGTON POST-CLASS B	WPO	0.02%	n/a	n/a	n/a	n/a
WASTE MANAGEMENT INC	WM	0.12%	10.00%	0.01%	4.12%	0.01%
WATERS CORP	WAT	0.06%	11.37%	0.01%	0.00%	0.00%
WATSON PHARMACEUTICALS INC	WPI	0.07%	10.68%	0.01%	0.00%	0.00%
WELLPOINT INC	WLP	0.17%	10.50%	0.02%	1.67%	0.00%
WELLS FARGO & CO	WFC	1.37%	11.64%	0.16%	2.55%	0.03%
WESTERN DIGITAL CORP	WDC	0.07%	16.45%	0.01%	0.00%	0.00%
WESTERN UNION CO	WU	0.09%	11.21%	0.01%	2.18%	0.00%
WEYERHAEUSER CO	WY	0.08%	5.00%	0.00%	2.95%	0.00%
WHIRLPOOL CORP	WHR	0.04%	n/a	n/a	3.09%	0.00%
WHOLE FOODS MARKET INC	WFM	0.12%	17.66%	0.02%	0.65%	0.00%
WILLIAMS COS INC	WMB	0.16%	23.00%	0.04%	3.38%	0.01%
WINDSTREAM CORP	WIN	0.05%	0.00%	0.00%	8.90%	0.00%
WISCONSIN ENERGY CORP	WEC	0.07%	6.33%	0.00%	3.25%	0.00%
WPX ENERGY INC	WPX	0.03%	n/a	n/a	n/a	n/a
WW GRAINGER INC	GWW	0.11%	13.18%	0.01%	1.42%	0.00%
WYNDHAM WORLDWIDE CORP	WYN	0.06%	18.25%	0.01%	1.83%	0.00%
WYNN RESORTS LTD	WYNN	0.10%	9.00%	0.01%	1.54%	0.00%
XCEL ENERGY INC	XEL	0.10%	4.67%	0.00%	3.93%	0.00%
XEROX CORP	XRX	0.08%	n/a	n/a	2.19%	0.00%
XILINX INC	XLNX	0.07%	14.14%	0.01%	2.33%	0.00%
XL GROUP PLC	XL	0.05%	8.33%	0.00%	2.12%	0.00%
XYLEM INC	XYL	0.04%	n/a	n/a	1.45%	0.00%
YAHOO! INC	YHOO	0.15%	12.51%	0.02%	0.00%	0.00%
YUM! BRANDS INC	YUM	0.26%	11.50%	0.03%	1.65%	0.00%
ZIMMER HOLDINGS INC	ZMH	0.09%	10.25%	0.01%	0.49%	0.00%
ZIONS BANCORPORATION	ZION	0.03%	7.75%	0.00%	0.20%	0.00%

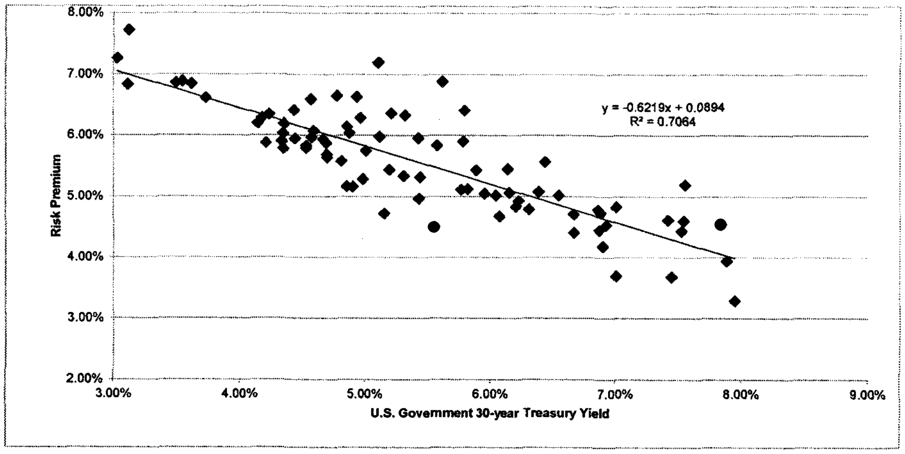
Notes:
[1] Equals sum of Col. [13]
[2] Equals sum of Col. [11]
[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]
[4] *See Notes [6], [7], and [8]*
[5] Equals [3] – [4]
[6] 30-day average of 30-year Treasury yield as of April 30, 2012
[7] Source: Blue Chip Financial Forecasts, Vol. 31, No. 5, May 1, 2012, at 2
[8] Source: Blue Chip Financial Forecasts, Vol. 30, No. 12, December 1, 2011, at 14
[9] Equals weight in S&P 500 based on market capitalization
[10] Source: Bloomberg Professional
[11] Equals Col. [6] x Col. [7]
[12] Source: Bloomberg Professional
[13] Equals Col. [9] x Col. [12]

EXHIBIT

JJR-5

Bond Yield Risk Premium

	[1] Average Authorized Electric ROE	[2] U.S. Govt. 30-year Treasury	[3] Risk Premium
1992.1	12.38%	7.84%	4.55%
1992.2	11.83%	7.88%	3.94%
1992.3	12.03%	7.42%	4.62%
1992.4	12.14%	7.54%	4.60%
1993.1	11.84%	7.01%	4.83%
1993.2	11.64%	6.86%	4.78%
1993.3	11.15%	6.23%	4.92%
1993.4	11.04%	6.21%	4.84%
1994.1	11.07%	6.66%	4.40%
1994.2	11.13%	7.45%	3.68%
1994.3	12.75%	7.55%	5.20%
1994.4	11.24%	7.95%	3.29%
1995.1	11.96%	7.52%	4.44%
1995.2	11.32%	6.87%	4.45%
1995.3	11.37%	6.66%	4.71%
1995.4	11.58%	6.14%	5.45%
1996.1	11.46%	6.39%	5.07%
1996.2	11.46%	6.92%	4.54%
1996.3	10.70%	7.00%	3.70%
1996.4	11.56%	6.54%	5.02%
1997.1	11.08%	6.90%	4.18%
1997.2	11.62%	6.88%	4.73%
1997.3	12.00%	6.44%	5.56%
1997.4	11.06%	6.04%	5.02%
1998.1	11.31%	5.89%	5.43%
1998.2	12.20%	5.79%	6.41%
1998.3	11.65%	5.32%	6.33%
1998.4	12.30%	5.11%	7.20%
1999.1	10.40%	5.43%	4.97%
1999.2	10.94%	5.82%	5.12%
1999.3	10.75%	6.07%	4.68%
1999.4	11.10%	6.31%	4.79%
2000.1	11.21%	6.15%	5.06%
2000.2	11.00%	5.95%	5.05%
2000.3	11.68%	5.78%	5.90%
2000.4	12.50%	5.62%	6.88%
2001.1	11.38%	5.42%	5.96%
2001.2	10.88%	5.77%	5.11%
2001.3	10.76%	5.44%	5.32%
2001.4	11.57%	5.21%	6.36%
2002.1	10.05%	5.55%	4.50%
2002.2	11.41%	5.57%	5.83%
2002.3	11.25%	4.96%	6.29%
2002.4	11.57%	4.93%	6.63%
2003.1	11.43%	4.78%	6.65%
2003.2	11.16%	4.57%	6.60%
2003.3	9.88%	5.15%	4.72%
2003.4	11.09%	5.11%	5.98%
2004.1	11.00%	4.86%	6.14%
2004.2	10.64%	5.31%	5.33%
2004.3	10.75%	5.01%	5.74%
2004.4	10.91%	4.87%	6.04%
2005.1	10.56%	4.69%	5.87%
2005.2	10.13%	4.34%	5.78%
2005.3	10.85%	4.43%	6.41%
2005.4	10.59%	4.66%	5.93%
2006.1	10.38%	4.69%	5.69%
2006.2	10.63%	5.19%	5.44%
2006.3	10.06%	4.90%	5.16%
2006.4	10.33%	4.70%	5.64%
2007.1	10.39%	4.81%	5.58%
2007.2	10.27%	4.98%	5.28%
2007.3	10.02%	4.85%	5.16%
2007.4	10.36%	4.53%	5.83%
2008.1	10.37%	4.34%	6.03%
2008.2	10.54%	4.57%	5.97%
2008.3	10.38%	4.44%	5.95%
2008.4	10.36%	3.49%	6.86%
2009.1	10.46%	3.62%	6.85%
2009.2	10.58%	4.23%	6.34%
2009.3	10.46%	4.18%	6.28%
2009.4	10.54%	4.35%	6.19%
2010.1	10.66%	4.59%	6.08%
2010.2	10.08%	4.20%	5.87%
2010.3	10.34%	3.73%	6.61%
2010.4	10.34%	4.14%	6.20%
2011.1	10.32%	4.53%	5.80%
2011.2	10.23%	4.33%	5.90%
2011.3	10.43%	3.54%	6.89%
2011.4	10.29%	3.03%	7.26%
2012.1	10.84%	3.12%	7.72%
2012.2	9.95%	3.11%	6.84%
MEAN	11.00%	5.45%	5.55%



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.84048118
R Square	0.70640862
Adjusted R Square	0.70273873
Standard Error	0.00487797
Observations	82

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.004580162	0.004580162	192.4875633	5.39594E-23
Residual	80	0.001903567	2.37946E-05		
Total	81	0.006483728			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.089375	0.002501647	35.72645942	6.16954E-51	0.084396568	0.09435344	0.08439657	0.09435344
X Variable 1	-0.62185524	0.044821662	-13.87398873	5.39594E-23	-0.71105319	-0.53265729	-0.71105319	-0.53265729

	[7] U.S. Govt. 30-year Treasury	[8] Risk Premium	[9] Authorized ROE
Current 30-Day Average [4]	3.24%	6.92%	10.16%
Blue Chip Consensus Forecast (Q2 2012-Q3 2013) [5]	3.58%	6.71%	10.29%
Blue Chip Consensus Forecast (2013-2017) [6]	5.10%	5.77%	10.87%
AVERAGE			10.44%

Notes:
[1] Source: Regulatory Research Associates, accessed May 15, 2012.
[2] Source: Bloomberg Professional, quarterly bond yields are the average of the last trading day of each month in the quarter.
[3] Equals Column [1] – Column [2]
[4] Source: Bloomberg Professional
[5] Source: Blue Chip Financial Forecasts, Vol. 31, No. 5, May 1, 2012, at 2.
[6] Source: Blue Chip Financial Forecasts, Vol. 30, No. 12, December 1, 2011, at 14.
[7] *See notes [4], [5] & [6]*
[8] Equals 0.089375 + (-0.621855 x Column [7])
[9] Equals Column [7] + Column [8]

EXHIBIT

JJR-6

Standard & Poor's Jurisdictional Rankings
for the Proxy Group Companies

		[1]	[2]
		S&P	
		Rank	Numeric Rank
American Electric Power Company, Inc.	Arkansas	Credit supportive	3
	Indiana	More credit supportive	4
	Kentucky	Credit supportive	3
	Louisiana	Less credit supportive	2
	Michigan	Credit supportive	3
	Ohio	Credit supportive	3
	Oklahoma	Credit supportive	3
	Tennessee		
	Texas	Less credit supportive	2
	Virginia	Credit supportive	3
	West Virginia	Less credit supportive	2
Cleco Corp.	Louisiana	Less credit supportive	2
Empire District Electric Company	Arkansas	Credit supportive	3
	Kansas	Credit supportive	3
	Oklahoma	Credit supportive	3
	Missouri	Less credit supportive	2
Entergy	Arkansas	Credit supportive	3
	Louisiana	Less credit supportive	2
	Mississippi	Credit supportive	3
	Texas	Less credit supportive	2
Great Plains Energy, Inc.	Kansas	Credit supportive	3
	Missouri	Less credit supportive	2
Hawaiian Electric	Hawaii	Less credit supportive	2
IDACORP, Inc.	Idaho	Credit supportive	3
	Oregon	Credit supportive	3
NV Energy	Nevada	Credit supportive	3
Pinnacle West Capital Corp.	Arizona	Least credit supportive	1
PNM Resources	New Mexico	Least credit supportive	1
	Texas	Less credit supportive	2
Portland General Electric Company	Oregon	Credit supportive	3
Southern Company	Alabama	More credit supportive	4
	Florida	Credit supportive	3
	Georgia	More credit supportive	4
	Mississippi	Credit supportive	3
Westar Energy, Inc.	Kansas	Credit supportive	3
Proxy Group Average		Less Credit Supportive / Credit Supportive	2.68
TEP	Arizona	Least credit supportive	1

Notes

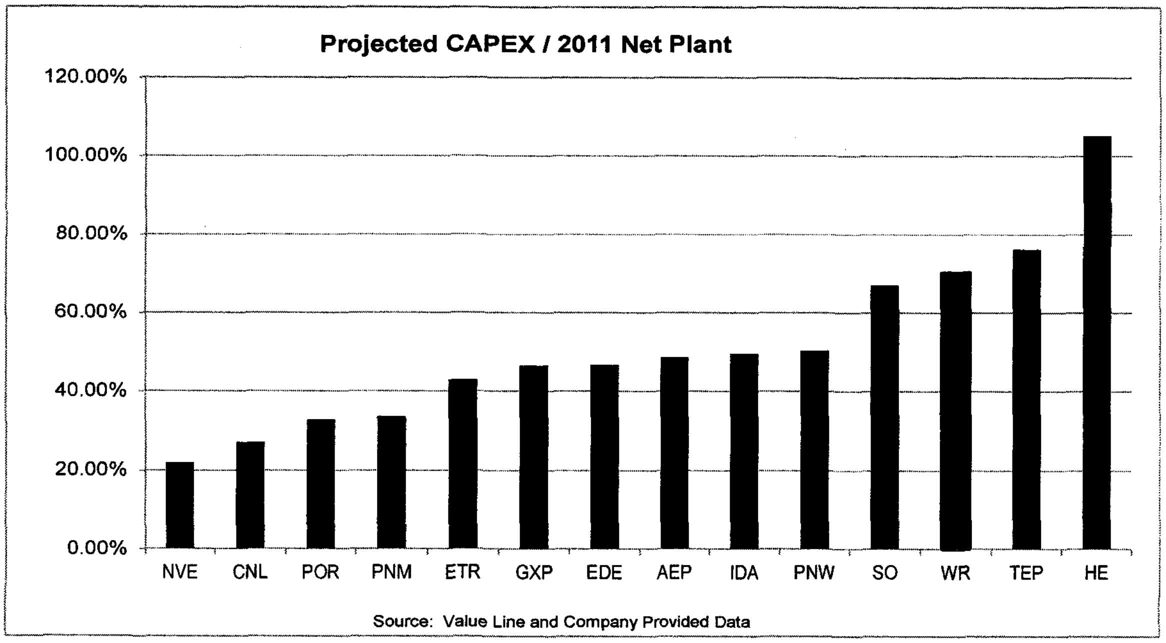
[1] Source: Assessing U.S. Utility Regulatory Environments, Standard and Poor's Ratings Services, Updated March 12, 2010.

[2] Least Credit Supportive = 1, Less Credit Supportive = 2, Credit Supportive = 3, More Credit Supportive = 4, Most Credit Supportive = 5.

EXHIBIT

JJR-7

Comparison of TEP's Capital Expenditures to the Proxy Companies



Projected CAPEX / 2011 Net Plant

Company	**Calc.** [1]
NV Energy	21.87%
Cleco Corporation	27.06%
Portland General Electric Company	32.88%
PNM Resources	33.61%
Entergy Corporation	42.91%
Great Plains Energy Inc.	46.50%
Empire District Electric Company	46.62%
American Electric Power Company, Inc.	48.50%
IDACORP, Inc.	49.49%
Pinnacle West Capital Corporation	50.35%
Southern Company	66.98%
Westar Energy, Inc.	70.34%
Tucson Electric Power Company	76.32%
Hawaiian Electric Industries, Inc.	105.25%
Proxy Group Median	46.62%
TEP percent/ Proxy Group Median	1.64

Notes:

[1] TEP Capital expenditures are projected for 2012-2016. However, Value Line projects capital expenditures for 2012, 2013, and 2015-17.

Sources: Value Line, Company projections, TEP 2011 SEC 10-K.

EXHIBIT

JJR-8

CAPITAL STRUCTURE ANALYSIS

COMMON EQUITY RATIOS OF THE PROXY COMPANIES

Electric Proxy Group Company	Ticker	2011 Q4	2011 Q3	2011 Q2	2011 Q1	2010 Q4	2010 Q3	2010 Q2	2010 Q1	Average
American Electric Power Company, Inc.	AEP	52.94%	52.71%	50.85%	50.07%	49.98%	53.56%	53.10%	53.11%	52.04%
Cleco Corporation	CNL	48.29%	47.52%	47.75%	46.98%	47.33%	51.14%	50.52%	50.69%	48.78%
Empire District Electric Company	EDE	52.29%	51.95%	50.96%	51.03%	50.93%	50.99%	50.50%	51.88%	51.32%
Entergy Corporation	ETR	49.80%	50.54%	49.28%	49.42%	49.70%	49.64%	49.28%	47.93%	49.45%
Great Plains Energy Inc.	GXP	51.93%	51.13%	53.00%	53.59%	52.23%	52.34%	54.19%	53.82%	52.78%
Hawaiian Electric Industries, Inc.	HE	58.42%	57.59%	57.22%	55.86%	55.83%	55.62%	55.42%	55.31%	56.41%
IDACORP, Inc.	IDA	50.59%	50.44%	48.95%	48.84%	46.61%	46.22%	48.20%	47.56%	48.43%
NV Energy, Inc.	NVE	45.39%	45.39%	44.29%	44.52%	44.41%	43.02%	42.54%	42.67%	44.03%
Pinnacle West Capital Corporation	PNW	54.46%	52.06%	52.44%	52.57%	52.97%	52.98%	51.49%	49.78%	52.34%
Portland General Electric Company	POR	48.94%	47.90%	47.78%	47.74%	46.83%	46.73%	46.26%	46.47%	47.33%
PNM Resources, Inc.	PNM	49.93%	52.15%	51.38%	51.55%	51.55%	52.51%	52.26%	52.22%	51.69%
Southern Company	SO	47.43%	51.14%	50.22%	50.59%	49.27%	48.75%	50.45%	50.71%	49.82%
Westar Energy, Inc.	WR	61.36%	60.66%	59.62%	59.24%	59.37%	59.48%	58.67%	58.41%	59.60%
MEAN		51.68%	51.63%	51.06%	50.92%	50.54%	51.00%	50.99%	50.81%	51.08%
MEDIAN		50.59%	51.14%	50.85%	50.59%	49.98%	51.14%	50.52%	50.71%	51.32%

COMMON EQUITY RATIO - ELECTRIC UTILITY OPERATING COMPANIES

Company Name	Ticker	2011 Q4	2011 Q3	2011 Q2	2011 Q1	2010 Q4	2010 Q3	2010 Q2	2010 Q1	Average
AEP Texas Central Company	AEP	63.77%	60.84%	47.26%	44.99%	44.85%	44.76%	43.79%	43.89%	49.27%
AEP Texas North Company	AEP	46.93%	46.35%	46.08%	45.88%	45.52%	45.18%	45.09%	45.73%	45.85%
Alabama Power Company	SO	46.53%	47.29%	46.71%	46.46%	46.54%	47.06%	46.45%	46.16%	46.65%
Appalachian Power Company	AEP	44.07%	44.19%	43.14%	41.53%	44.21%	43.87%	43.52%	45.05%	43.70%
Arizona Public Service Company	PNW	54.46%	52.06%	52.44%	52.57%	52.97%	52.98%	51.49%	49.78%	52.34%
Cleco Power LLC	CNL	48.29%	47.52%	47.75%	46.98%	47.33%	51.14%	50.52%	50.69%	48.78%
Empire District Electric Company	EDE	52.29%	51.95%	50.96%	51.03%	50.93%	50.99%	50.50%	51.88%	51.32%
Entergy Arkansas, Inc.	ETR	47.33%	47.23%	47.42%	46.85%	46.66%	47.91%	48.41%	46.59%	47.30%
Entergy Gulf States Louisiana, L.L.C.	ETR	47.17%	46.94%	47.67%	47.45%	48.62%	47.95%	47.65%	45.09%	47.32%
Entergy Louisiana, LLC	ETR	55.49%	59.18%	51.09%	51.69%	53.66%	50.55%	52.77%	49.14%	52.94%
Entergy Mississippi, Inc.	ETR	47.46%	46.22%	45.19%	47.12%	46.67%	46.68%	46.34%	44.92%	46.32%
Entergy New Orleans, Inc.	ETR	52.10%	54.46%	53.99%	53.79%	53.40%	55.57%	51.59%	50.87%	53.22%
Entergy Texas, Inc.	ETR	49.23%	49.20%	50.31%	49.64%	49.17%	49.16%	48.90%	50.98%	49.57%
Georgia Power Company	SO	51.73%	51.94%	50.73%	51.17%	51.32%	50.22%	50.69%	50.99%	51.10%
Gulf Power Company	SO	47.61%	47.79%	47.45%	47.52%	46.71%	45.40%	47.46%	48.46%	47.30%
Hawaii Electric Light Company, Inc.	HE									
Hawaiian Electric Company, Inc.	HE									
Hawaiian Electric Company	HE	58.42%	57.59%	57.22%	55.86%	55.83%	55.62%	55.42%	55.31%	56.41%
Idaho Power Co.	IDA	50.59%	50.44%	48.95%	48.84%	46.61%	46.22%	48.20%	47.56%	48.43%
Indiana Michigan Power Company	AEP	49.13%	49.10%	49.06%	48.86%	48.47%	46.80%	46.29%	46.44%	48.02%
Kansas City Power & Light Company	GXP	51.59%	49.84%	54.41%	52.66%	52.90%	53.16%	52.29%	51.98%	52.35%
Kansas Gas and Electric Company	WR	57.55%	57.70%	56.77%	56.52%	57.00%	57.24%	56.49%	56.24%	56.94%
KCP&L Greater Missouri Operations Company	GXP	52.28%	52.42%	51.59%	54.52%	51.55%	51.52%	56.09%	55.66%	53.20%
Kentucky Power Company	AEP	45.61%	45.62%	45.42%	45.50%	44.84%	44.21%	43.59%	44.27%	44.88%
Kingsport Power Company	AEP	59.56%	58.67%	59.00%	59.12%	57.96%	100.00%	100.00%	100.00%	74.29%
Maui Electric Company, Limited	HE									
Mississippi Power Company	SO	43.83%	57.54%	55.99%	57.21%	52.51%	52.30%	57.20%	57.23%	54.23%
Nevada Power Company	NVE	45.53%	45.87%	44.10%	44.35%	43.95%	41.85%	40.93%	41.19%	43.47%
Ohio Power Company	AEP	52.12%	53.92%	54.34%	54.52%	53.43%	52.37%	52.33%	49.41%	52.80%
Portland General Electric Company	POR	48.94%	47.90%	47.78%	47.74%	46.83%	46.73%	46.26%	46.47%	47.33%
Public Service Company of New Mexico	PNM	49.93%	52.15%	51.38%	51.55%	51.55%	52.51%	52.26%	52.22%	51.69%
Public Service Company of Oklahoma	AEP	48.52%	48.56%	47.51%	45.21%	46.45%	46.65%	45.41%	45.33%	46.71%
Sierra Pacific Power Company	NVE	45.25%	44.90%	44.49%	44.69%	44.87%	44.18%	44.14%	44.15%	44.59%
Southwestern Electric Power Company	AEP	51.85%	51.99%	50.32%	49.58%	49.15%	49.07%	47.81%	47.41%	49.65%
Texas-New Mexico Power Company	PNM									
Westar Energy (KPL)	WR	65.18%	63.63%	62.47%	61.96%	61.74%	61.72%	60.84%	60.58%	62.26%
Wheeling Power Company	AEP	67.87%	67.88%	66.34%	65.53%	64.89%	62.73%	63.16%	63.54%	65.24%

Source: FERC Form 1 data as reported by SNL Financial

CAPITAL STRUCTURE ANALYSIS
LONG-TERM DEBT RATIOS OF THE PROXY COMPANIES

Electric Proxy Group Company	Ticker	2011 Q4	2011 Q3	2011 Q2	2011 Q1	2010 Q4	2010 Q3	2010 Q2	2010 Q1	Average
American Electric Power Company, Inc.	AEP	47.06%	47.29%	49.15%	49.93%	50.02%	46.44%	46.90%	46.89%	47.96%
Cleco Corporation	CNL	51.71%	52.48%	52.25%	53.02%	52.67%	48.86%	49.48%	49.31%	51.22%
Empire District Electric Company	EDE	47.71%	48.05%	49.04%	48.97%	49.07%	49.01%	49.50%	48.12%	48.68%
Entergy Corporation	ETR	50.20%	49.46%	50.72%	50.58%	50.30%	50.36%	50.72%	52.07%	50.55%
Great Plains Energy Inc.	GXP	48.07%	48.87%	47.00%	46.41%	47.77%	47.66%	45.81%	46.18%	47.22%
Hawaiian Electric Industries, Inc.	HE	41.58%	42.41%	42.78%	44.14%	44.17%	44.38%	44.58%	44.69%	43.59%
IDACORP, Inc.	IDA	49.41%	49.56%	51.05%	51.16%	53.39%	53.78%	51.80%	52.44%	51.57%
NV Energy, Inc.	NVE	54.61%	54.61%	55.71%	55.48%	55.59%	56.98%	57.46%	57.33%	55.97%
Pinnacle West Capital Corporation	PNW	45.54%	47.94%	47.56%	47.43%	47.03%	47.02%	48.51%	50.22%	47.66%
Portland General Electric Company	POR	51.06%	52.10%	52.22%	52.26%	53.17%	53.27%	53.74%	53.53%	52.67%
PNM Resources, Inc.	PNM	50.07%	47.85%	48.62%	48.45%	48.45%	47.49%	47.74%	47.78%	48.31%
Southern Company	SO	52.57%	48.86%	49.78%	49.41%	50.73%	51.25%	49.55%	49.29%	50.18%
Westar Energy, Inc.	WR	38.64%	39.34%	40.38%	40.76%	40.63%	40.52%	41.33%	41.59%	40.40%
MEAN		48.32%	48.37%	48.94%	49.08%	49.46%	49.00%	49.01%	49.19%	48.92%
MEDIAN		49.41%	48.86%	49.15%	49.41%	50.02%	48.86%	49.48%	49.29%	48.68%

LONG-TERM DEBT RATIO - ELECTRIC UTILITY OPERATING COMPANIES

Company Name	Ticker	2011 Q4	2011 Q3	2011 Q2	2011 Q1	2010 Q4	2010 Q3	2010 Q2	2010 Q1	Average
AEP Texas Central Company	AEP	36.23%	39.16%	52.74%	55.01%	55.15%	55.24%	56.21%	56.11%	50.73%
AEP Texas North Company	AEP	53.07%	53.65%	53.92%	54.12%	54.48%	54.82%	54.91%	54.27%	54.15%
Alabama Power Company	SO	53.47%	52.71%	53.29%	53.54%	53.46%	52.94%	53.55%	53.84%	53.35%
Appalachian Power Company	AEP	55.93%	55.81%	56.86%	58.47%	55.79%	56.13%	56.48%	54.95%	56.30%
Arizona Public Service Company	PNW	45.54%	47.94%	47.56%	47.43%	47.03%	47.02%	48.51%	50.22%	47.66%
Cleco Power LLC	CNL	51.71%	52.48%	52.25%	53.02%	52.67%	48.86%	49.48%	49.31%	51.22%
Empire District Electric Company	EDE	47.71%	48.05%	49.04%	48.97%	49.07%	49.01%	49.50%	48.12%	48.68%
Entergy Arkansas, Inc.	ETR	52.67%	52.77%	52.58%	53.15%	53.34%	52.09%	51.59%	53.41%	52.70%
Entergy Gulf States Louisiana, L.L.C.	ETR	52.83%	53.06%	52.33%	52.55%	51.38%	52.05%	52.35%	54.91%	52.68%
Entergy Louisiana, LLC	ETR	44.51%	40.82%	48.91%	48.31%	46.34%	49.45%	47.23%	50.86%	47.06%
Entergy Mississippi, Inc.	ETR	52.54%	53.78%	54.81%	52.88%	53.33%	53.32%	53.66%	55.08%	53.68%
Entergy New Orleans, Inc.	ETR	47.90%	45.54%	46.01%	46.21%	46.60%	44.43%	48.41%	49.13%	46.78%
Entergy Texas, Inc.	ETR	50.77%	50.80%	49.69%	50.36%	50.83%	50.84%	51.10%	49.02%	50.43%
Georgia Power Company	SO	48.27%	48.06%	49.27%	48.83%	48.68%	49.78%	49.31%	49.01%	48.90%
Gulf Power Company	SO	52.39%	52.21%	52.55%	52.48%	53.29%	54.60%	52.54%	51.54%	52.70%
Hawaii Electric Light Company, Inc.	HE									
Hawaiian Electric Company, Inc.	HE									
Hawaiian Electric Company	HE	41.58%	42.41%	42.78%	44.14%	44.17%	44.38%	44.58%	44.69%	43.59%
Idaho Power Co.	IDA	49.41%	49.56%	51.05%	51.16%	53.39%	53.78%	51.80%	52.44%	51.57%
Indiana Michigan Power Company	AEP	50.87%	50.90%	50.94%	51.14%	51.53%	53.20%	53.71%	53.56%	51.98%
Kansas City Power & Light Company	GXP	48.41%	50.16%	45.59%	47.34%	47.10%	46.84%	47.71%	48.02%	47.65%
Kansas Gas and Electric Company	WR	42.45%	42.30%	43.23%	43.48%	43.00%	42.76%	43.51%	43.76%	43.06%
KCP&L Greater Missouri Operations Company	GXP	47.72%	47.58%	48.41%	45.48%	48.45%	48.48%	43.91%	44.34%	46.80%
Kentucky Power Company	AEP	54.39%	54.38%	54.58%	54.50%	55.16%	55.79%	56.41%	55.73%	55.12%
Kingsport Power Company	AEP	40.44%	41.33%	41.00%	40.88%	42.04%	0.00%	0.00%	0.00%	25.71%
Maui Electric Company, Limited	HE									
Mississippi Power Company	SO	56.17%	42.46%	44.01%	42.79%	47.49%	47.70%	42.80%	42.77%	45.77%
Nevada Power Company	NVE	54.47%	54.13%	55.90%	55.65%	56.05%	58.15%	59.07%	58.81%	56.53%
Ohio Power Company	AEP	47.88%	46.08%	45.66%	45.48%	46.57%	47.63%	47.67%	50.59%	47.20%
Portland General Electric Company	POR	51.06%	52.10%	52.22%	52.26%	53.17%	53.27%	53.74%	53.53%	52.67%
Public Service Company of New Mexico	PNM	50.07%	47.85%	48.62%	48.45%	48.45%	47.49%	47.74%	47.78%	48.31%
Public Service Company of Oklahoma	AEP	51.48%	51.44%	52.49%	54.79%	53.55%	53.35%	54.59%	54.67%	53.29%
Sierra Pacific Power Company	NVE	54.75%	55.10%	55.51%	55.31%	55.13%	55.82%	55.86%	55.85%	55.41%
Southwestern Electric Power Company	AEP	48.15%	48.01%	49.68%	50.42%	50.85%	50.93%	52.19%	52.59%	50.35%
Texas-New Mexico Power Company	PNM									
Westar Energy (KPL)	WR	34.82%	36.37%	37.53%	38.04%	38.26%	38.28%	39.16%	39.42%	37.74%
Wheeling Power Company	AEP	32.13%	32.12%	33.66%	34.47%	35.11%	37.27%	36.84%	36.46%	34.76%

EXHIBIT

JJR-9

Electric Revenue Stabilization Mechanisms

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American Electric Power (AEP)

AEP Texas Central Company	
Rider NDC- Nuclear Decommissioning Collections	The Nuclear Decommissioning Charges collected under this rider are transferred to a trust that will hold the funds for future nuclear plant decommissioning. [Tariff Sheets 177-180]
Schedule TCRF- Transmission Cost Recovery Factor	Each retail customer connected to the Company's transmission or distribution system will be assessed a non-by-passable transmission service charge adjustment pursuant to this rider. [Tariff Sheet 182]
Rider EECRF- Energy Efficiency Cost Recovery Factors	Recovers the cost of energy efficiency programs not already included in base distribution service rates and is applicable to the kWh sales of retail customers taking retail electric delivery service from the Company. [Tariff Sheet 184-1]
Rider AMSCRF- Advanced Metering System Cost Recovery Fee	Applicable to retail customers receiving metered service for which the Company will install an advanced metering system during the recovery period approved by the PUCT. [Tariff Sheet 189]
AEP Texas North Company	
Schedule TCRF- Transmission Cost Recovery Factor- ERCOT System	Each retail customer connected to the Company's transmission or distribution system will be assessed a non-by-passable transmission service charge adjustment. [Tariff Sheet 137]
Rider AMSCRF- Advanced Metering System Cost Recovery Fee	Applicable to retail customers receiving metered service for which the Company will install an Advanced Metering Infrastructure system during the recovery period approved by the PUCT. [Tariff Sheet 141-1]
Rider EECRF- Energy Efficiency Cost Recovery Factors	Recovers the cost of energy efficiency programs not already included in base distribution service rates and is applicable to the kWh sales of retail customers taking retail electric delivery service from the Company. [Tariff Sheet 141-1]
Kingsport Power Company – Tennessee	
Purchased Power Adjustment Rider	Rider to apply a surcharge to all customer bills to allow for changes in the non-fuel cost of purchased power from the Company's wholesale power supplier. [Tariff Sheet 2-8]
Fuel Clause Rider	Adjusts customers' bills each month when the unit cost of fuel purchased under FERC Rate Schedule No. 23 from Appalachian Power Company is above or below a set value. [Tariff Sheet 2-11]
Appalachian Power Company- Virginia	
Sale and Use Tax Surcharge	A sales and use tax surcharge shall be applied to all customer bills to reflect the estimated sales and tax the company expects to pay in the coming year. [Tariff Sheet 25]

Fuel Factor Rider	Allows the Company to recover its cost of fuel used in generation of electricity. [Tariff Sheet 29]
Transmission Rate Adjustment Clause Rider	Applied to all standard customer bills rendered under the applicable standard schedules or special contract to recover transmission related investment. [Tariff Sheet 33]
Wheeling Power Company - West Virginia	
Construction / 765 kV Surcharge	A construction surcharge is applied to customers' bills (effective July 2011 to June 2012), including both the energy and demand component of rates, to recover costs associated with the construction of new transmission lines. [Tariff Sheet 27]
Schedule L.E.- Line Extensions	Customers are charged for line extensions based on installed extensions on a monthly basis. [Tariff Sheet 32-1]
Energy Efficiency / Demand Response Cost Recovery Rider	Collects energy efficiency and demand response costs through a bill adjustment, by rate schedule, using a specified adjustment factor per kWh. [Tariff Sheet 33]
Southwestern Electric Power Company- Arkansas Jurisdiction	
Energy Cost Recovery Rider (ECR)	Recovers the Company's net fuel and purchased energy cost. [Tariff Sheet R-27.1]
Charges for Special or Additional Facilities	In the event facilities in excess of a normal installation are found to be required to serve the Customer's load, or are requested by the Customer and approved by the Company, the Company is required to furnish, install, and maintain such facilities with a monthly charge to the Customer. [Tariff Sheet R-29.1]
Redundant Service Policy for Municipal Accounts	Certain customers are charged additional fees for redundant service. Additional charges are based on consumption. [Tariff Sheet R-34.1]
Extension of Facilities Agreement	Provides for cost recovery of Company investment in the extension of facilities when the revenue generated from such investment will not cover the entire cost. [Tariff Sheet R-35.1]
Radio Frequency Meter Installation Rider	A customer may request (or elect upon request by the Company) to have a radio frequency meter installed under the terms of this Rider as a mutually agreeable solution to Company personnel's lack of meter reading access to Company metering equipment on a customer's premises, due to a locked gate, animal concern, safety concern or other reason. This Rider lays out the one-time, non-refundable installation fee from the customer to the Company. [Tariff Sheet 42-1]
Energy Efficiency Cost Rate Rider (EECR)	The purpose of this Rider is to establish the EECR rate(s) by which the Company will recover the incremental costs of energy efficiency programs approved by the Commission. [Tariff Sheet R-45.1]

Federal Litigation Consulting Fee Rider	Enables the Company to recover the fees and expenses paid by the Company to contract attorneys and consultants retained by the Arkansas PSC, as authorized by the General Assembly, when it participates in litigation before a federal agency or federal court in proceedings that affect the Company. [Tariff Sheet R-46.1]
Alternative Generation Recovery Rider	Designed to adjust monthly billings to recover costs associated with the Stall Generating Facility. The Rider is designed to recover return on and of the generation facility and operation and maintenance expenditures after the facility commences commercial operation. [Tariff Sheet 47.1]
Southwestern Electric Power Company- Louisiana Jurisdiction	
Off-Peak Service Rider to the Lighting and Power Service Schedule and Metal Melting Service Schedule	Available to customers receiving electric service under either the Lighting and Power Service or the Metal Melting Service schedule when prearrangement has been made by contract for the installation of adequate facilities, including appropriate metering. Customers who contract for service under this rider will be billed a Customer Charge of $70.00 per month to help defray the additional costs incurred by the Company in providing service hereunder. [Tariff Section B, Sheet 2]
Fuel Adjustment Rider	All kilowatt-hours sold will be adjusted to reflect the current cost of fuel. This Rider recovers the net cost of fuel consumed in the Company's generating plants, plus the net cost of purchased economy and emergency energy, as well as energy purchased from qualifying small production or cogeneration facilities. [Tariff Section B, Sheet 8]
Charges for Special or Additional Facilities	In the event facilities in excess of a normal installation are found to be required to serve the Customer's load, or are requested by the Customer and approved by the Company, the Company is required to furnish, install, and maintain such facilities with a monthly charge to the Customer. [Tariff Section B, Sheet 10]
Rider for Radio Frequency Meter Installation	A customer may request (or elect upon request by the Company) to have a radio frequency meter installed under the terms of this Rider as a mutually agreeable solution to Company personnel's lack of meter reading access to Company metering equipment on a customer's premises, due to a locked gate, animal concern, safety concern or other reason. This Rider lays out the one-time, non-refundable installation fee from the customer to the Company. [Tariff Section B, Sheet 13]
Formula Rate Plan Rider Schedule (FRP)	The Formula Rate Plan Rider defines the procedure by which the rates contained in the Company rate schedules may be periodically adjusted. The FRP stipulates an authorized rate of return with a bandwidth. [Tariff Section B, Sheet 14]

Southwestern Electric Power Company- East Texas Jurisdiction	
Fixed Fuel Factor Tariff	Provides for the recovery of the net costs of fuel used to procure electricity for retail customers. [Tariff Section IV, Sheet IV-34]
Energy Efficiency Cost Recovery Rider	Recovers the cost of energy efficiency programs not included in base rates. [Tariff Section IV, Sheet IV-35]
Purchased Power and Conservation Factor (PPCF)	Recovers the costs of demand-side management resources and renewable energy resources that are approved for PPCF cost recovery by the Commission but are not recovered in base rates. [Tariff Section IV, Sheet IV-36]
Southwestern Electric Power Company- North Texas Jurisdiction	
Fixed Fuel Factor Rider	Allows for the recovery of the fixed costs related to fuel procurement for power production. [Tariff Section IV, Sheet IV-34]
Energy Efficiency Cost Recovery Rider	Rrecovers the cost of energy efficiency programs not included in base rates. [Tariff Section IV, Sheet IV-35]
Columbus Southern Power Company – Ohio	
Universal Service Fund Rider	All electric utility customers pay into a universal service fund to help balance the difference between what PIPP (Percentage of Income Payment Plan) customers pay and the charges for their actual use. [Tariff Sheet 60-1 and Regulatory Research Associates]
Provider of Last Resort Charge Rider	Allows the Company to recoup the costs related to the obligation to customers to be the provider of last resort. [Tariff Sheet 69-1]
Monongahela Power Litigation Termination Rider	This temporary Rider shall remain in effect until the amounts authorized by the Commission in Case No. 05-765-EL-UNC have been collected. [Tariff Sheet 73-1]
Transmission Cost Recovery Rider	Allows the Company to recover the costs associated with transmission investment that are not recovered in base rates. [Tariff Sheet 75-1 and Regulatory Research Associates]
Fuel Adjustment Clause Rider	Permits the Company to pass along to customers the net actual cost of fuel used in power procurement. [Tariff Sheet 80-1 and Regulatory Research Associates]
Energy Efficiency and Peak Demand Reduction Cost Recovery Rider	Provides for the recovery of costs related to energy efficiency programs and demand side management programs used to attenuate peak demand. [Tariff Sheet 81-1]
Enhanced Service Reliability Rider	Allows for the recovery of costs associated with improvements made to the reliability and integrity of the distribution system. [Tariff Sheet 83-1]
gridSMART Rider	Recovers the cost of purchasing and installing SMART technology. [Tariff Sheet 84-1]
Economic Development Cost Recovery Rider	Recovs economic development costs authorized by the Commission. [Tariff Sheet 82-1]

Environmental Investment Carrying Cost Rider	Recovers Commission approved costs through a set percentage charge applied to the customer's Non-Fuel generation charges, excluding charges under other applicable Riders. [Tariff Sheet 85-1]
Ohio Power Company	
Universal Service Fund Rider	All electric utility customers pay into a universal service fund to help balance the difference between what PIPP (Percentage of Income Payment Plan) customers pay and the charges for their actual use. [Tariff Sheet 60-1 and Regulatory Research Associates]
Provider of Last Resort Charge Rider	Allows the Company to recoup the costs related to the obligation to customers to be the provider of last resort. [Tariff Sheet 69-1]
Transmission Cost Recovery Rider	Allows the Company to recover the costs associated with transmission investment that are not recovered in base rates. [Tariff Sheet 75-1]
Fuel Adjustment Clause Rider	Permits the Company to pass along to customers the net actual cost of fuel used in power procurement. [Tariff Sheet 80-1 and Regulatory Research Associates]
Energy Efficiency and Peak Demand Reduction Cost Recovery Rider	Provides for the recovery of costs related to energy efficiency programs and demand side management programs used to reduce peak demand. [Tariff Sheet 81-1]
Enhanced Service Reliability Rider	Allows for the recovery of costs associated with improvements made to the reliability and integrity of the distribution system. [Tariff Sheet 83-1]
Economic Development Cost Recovery Rider	Recovers economic development costs authorized by the Commission. [Tariff Sheet 82-1]
Environmental Investment Carrying Cost Rider	Recovers Commission approved costs through a set percentage charge applied to the customer's Non-Fuel generation charges, excluding charges under other applicable Riders. [Tariff Sheet 85-1]
Indiana Michigan Power Company- Indiana Jurisdiction	
Fuel Cost Adjustment Rider	Permits the Company to pass along to customers the net actual cost of fuel used in power procurement. The costs eligible for recovery include the average cost of fossil and nuclear fuel consumed at the Company's own plants, plus net purchased power costs, and nuclear fuel disposal costs. [Tariff Sheet 50]
Demand-Side Management/ Energy Efficiency Program Cost Rider	Allows for cost recovery associated with demand-side management and energy efficiency programs. [Tariff Sheet 51]
PJM Cost Rider	Allows for the recovery of demand-related and energy-related costs related to PJM. [Tariff Sheet 53]

Environmental Compliance Cost Rider	Allows for the recovery of environmental compliance costs not included in base rates. [Tariff Sheet 54]
Clean Coal Technology Rider	Provides for cost recovery of the revenue requirement associated with CCTR investment, depreciation expense on in-service CCTR property, operation and maintenance expenses on CCTR property, and costs of consumables and chemical agents. [Tariff Sheet 55]
Off-System Sales Margin Sharing Rider	Provides for the sharing of off-system sales margins through a per kWh adjustment to applicable customer bills. The adjustment for each tariff class is based upon a specified cost sharing factor calculation. [Tariff Sheet 52]
Indiana Michigan Power Company – Michigan Jurisdiction	
NDS- Nuclear Decommissioning Surcharge Rider	Provides for cost recovery of future nuclear decommissioning costs. The charge is a per kWh charge by rate class. [Tariff Sheet 108]
CC- Customer Choice Cost Recovery	Recovers costs incurred to implement Customer Choice in Michigan. [Tariff Sheet 109]
EO- Energy Optimization Surcharge Rider	Funds energy optimization programs conducted by a Commission-approved energy optimization program administrator. [Tariff Sheet 107]
Power Supply Cost Recovery	Permits the monthly adjustment of rates to recover the booked costs, including transportation costs, reclamation costs, and disposal and reprocessing costs, of fuel burned for electric generation, the booked costs of purchased and net interchange power transactions and the cost of transmission service incurred under reasonable and prudent policies and practices. [Tariff Sheet 104]
Net Lost Revenue Recovery Surcharge	The Commission approved settlement of Case No. U-16180 authorized the creation of a regulatory asset for the Net Lost Revenue associated with lost sales that are caused by the Company's energy optimization program. The lost revenue is to be recovered through this rider. [Order approving settlement]
Kentucky Power Company	
Fuel Adjustment Clause	Allows for the recovery of fossil fuel and nuclear fuel consumed in the utility's own plants and the net costs of purchased power. This periodic adjustment allows for the recovery of the difference between actual fuel costs and sales. [Tariff Sheet 5-1]
Demand-Side Management Adjustment Clause	Allows for the recovery of demand-side management programs, net lost revenues, incentives, and any over/under recovery balances. [Tariff Sheet 22-1]
Environmental Surcharge	Provides for monthly adjustments based on the difference between the environmental compliance costs in a base period and the current period. [Tariff Sheet 29-1]

Capacity Charge	Kentucky Power Company is to recover from retail ratepayers the supplemental annual payments tied to the 18-year extension of the Rockpower Unit Power Agreement. The Company will apply surcharges under this Rider designed to enable the recovery from each tariff class of customers. [Tariff Sheet 28-1]
System Sales Clause	When the monthly net revenues from system sales are above or below the monthly base net revenues from system sales, as specified, an additional charge or credit is implemented based on a kWh system sales adjustment factor. [Tariff Sheet 19-1]
Public Service Company of Oklahoma	
Fuel Cost Adjustment Rider	Allows for the recovery of the cost of fuel used in generation of electric services plus net purchased power costs. [Tariff Sheet 70-1A]
Regulatory Assessment Rider	Allows for the recovery of an annual assessment as billed by the Commission, and applies to all retail monthly customer billings. [Tariff Sheet 73]
Reliability Vegetation/ Undergrounding Rider	The RVU Factor is determined on a quarterly basis for each major rate class to incorporate the previous quarter's Eligible Reliability Costs expended and adjusted by any over or under recovery of costs from the previous three month billing period and applied to the billings for the next quarter. This rider allows for the recovery of reliability costs associated with vegetation management not included in base rates. [Tariff Sheet 80-1A]
Purchased Power Capacity Rider	Allows for recovery of purchased power capacity costs. [Tariff Sheet 87]
Demand-Side Management Cost Recovery Rider	Designed to recover costs associated with Energy Efficiency and Demand-side Management programs. [Tariff Sheet 85-1A]
Regulatory Asset Recovery Rider	Designed to recover costs associated with extraordinary operation and maintenance expenses resulting from the January and December 2007 ice storms. [Tariff Sheet 86-1]
Long-Term Base Load Purchased Power Rider	Designed to recover all costs associated with a particular contract, and with recovery of the one-time RFP costs. [Tariff Sheet 88-1]

Cleco Corporation (CNL)

Cleco Power (Louisiana)	
Fuel Cost Adjustment (FAC)	Monthly adjustment to recover the actual cost of fuel and purchased power (energy only). The demand component of purchased power costs related to "economy" purchases (entered into when the price of purchased power is less than the cost of the Company's own generation) may also be recovered through the FAC. Any off-system sales of power are credited through this mechanism. [Regulatory Research Associates]
Storm Recovery Charge Adjustment	Recovers applicable storm restoration costs approved by the Louisiana PSC. This adjustment is reconciled semi-annually. [Cleco Power tariff]
Formula Rate Plan (FRP)	The Formula Rate Plan, which was approved in 2010 for an initial four-year term, has a target ROE and capital structure. The FRP also allows for recovery of certain purchased power capacity costs and the costs associated with certain infrastructure projects. The FRP also includes an "exceptional changes mechanism", whereby certain rate changes could be made for circumstances beyond the Company's control. [Regulatory Research Associates]
Environmental Cost Adjustment	Provides for the recovery of certain costs of environmental compliance as an adder to customers' bills. The costs eligible for recovery are prudently incurred air emissions credits associated with complying with federal, state, and local air emission regulations and variable emission mitigation costs. [Regulatory Research Associates]

Empire District Electric Company (EDE)

Empire District Electric Company (Arkansas)	
Energy Cost Recovery Rider	Recovers the Company's net fuel and purchased energy cost. The energy cost rate is subject to annual redetermination and reflects the projected energy cost for the 12-month period commencing April 1 of each year together with a true-up adjustment reflecting the over-recovery or under-recovery of the energy cost for the 12-month period ended December 31 of the prior calendar year. Interim adjustments are permitted if Arkansas PSC General Staff or the Company becomes aware of an event that is reasonably expected to occur and/or has occurred which will materially impact the Company's energy cost. In addition, Staff or the Company may propose an interim revision to the then currently effective energy cost rate if a cumulative over-recovery or under-recovery balance arises during any rider cycle which exceeds 10 percent of the energy cost determined for the period. [Sheet Nos. 34 – 35.3]
Energy Efficiency Cost Recovery Tariff	Recovers the incremental costs of energy efficiency programs approved by the Commission. Recovery is limited to the incremental costs which represent the direct program costs that are not already included in then current rates. The energy efficiency cost recovery rate is subject to annual redetermination based on the projected recoverable costs for the 12-month period commencing January 1 of each year together with a true-up adjustment reflecting the over-recovery or under-recovery of recoverable costs for the 12-month period ended December 31 of the prior calendar year. APSC General Staff or the Company may propose an interim adjustment if the cumulative over-recovery or under-recovery balance exceeds 10 percent of the approved energy efficiency cost. [Sheet Nos. 32 – 32.2]
Transmission Cost Recovery Rider	Recovers the Company's net transmission costs. Subject to annual redetermination and true-up reflecting the over-recovery or under-recovery of the transmission cost for the 12-month period ended December 31 of the prior calendar year. Interim adjustments are permitted if APSC General Staff or the Company becomes aware of an event that is reasonably expected to occur and/or has occurred which will materially impact the Company's transmission cost. [Sheet Nos. 33 – 33.4]

Excess Facilities Rider	1) If the Company, for the service of the Customer, is required to install and maintain distribution transformers having a total kVA rating numerically greater than 150 percent of the Customer's highest demand during the year ended with the current month, in accordance with the Customer's request, or if necessitated by the operating characteristics of Customer's equipment, the Customer will pay an added monthly charge of 1.5 percent of such excess investment by the Company. 2) If the Company, for the service of the Customer, is required to install and maintain multiple transformers or transformer banks on a single primary metered service, the Customer will pay an added monthly charge of 1.5 percent of the investment in the multiple transformers or transformer banks and primary distribution to same, starting with the first pole after the meter pole and including metering costs in excess of those provided for in the rate. 3) If the Company, for the service of the Customer, is required to install and maintain other special or additional facilities not normally provided by the Company for the Customer's rate or service classification, the Customer will pay an added monthly charge of 1.5 percent of such excess investment by the Company. [Sheet No. 31]
Tax Adjustment Rider	Bills to customers located within the municipal limits of a municipality imposing a franchise tax or fee upon the Company will be increased by an amount sufficient to compensate the Company for any charges (including, but not limited to, licenses, fees, charges, impositions or taxes of any kind other than special mileage taxes or general taxes applicable to all citizens and taxpayers) levied or imposed by any municipality on or against the Company as provided in the standard Franchise Agreement between Company and said municipality or in special ordinances passed by said municipality. [Sheet Nos. 49.1 – 49.2]
Empire District Electric Company (Kansas)	
Energy Cost Adjustment	Recovers the Company's cost of nuclear fuel, fossil fuel, purchased power, emission allowances, and air quality control system consumables (e.g. ammonia, limestone, charcoal). Includes annual settlement factor to adjust for prior period over-recovery or under-recovery. Offset by off system sales profits. [Sheet No. 9]
Energy Efficiency Rider	Recovers costs associated with Commission approved pilot energy efficiency and demand response programs deferred but not recovered from the inception of the individual programs through June 30, 2011. The Company will file a new energy efficiency rider for Commission approval in September 2012 and annually thereafter until all associated costs with the pilot energy efficiency and demand response programs are recovered, plus any over or under collection from the prior period rider. [Sheet No. 10]

Excess Facilities Rider	1) If the Company, for the service of the Customer, is required to install and maintain distribution transformers having a total kVA rating numerically greater than 150 percent of the Customer's highest reserved capacity during the year ended with the current month, in accordance with the Customer's request, or if necessitated by the operating characteristics of Customer's equipment, the Customer will pay an added monthly charge of 1.5 percent of such excess investment by the Company. 2) If the Company, for the service of the Customer, is required to install and maintain multiple transformers or transformer banks on a single primary metered service, the Customer will pay an added monthly charge of 1.5 percent of the investment in the multiple transformers or transformer banks and primary distribution to same, starting with the first pole after the meter pole and including metering costs in excess of those provided for in the rate. 3) If the Company, for the service of the Customer, is required to install and maintain other special or additional facilities not normally provided by the Company for the Customer's rate or service classification, the Customer will pay an added monthly charge of 1.5 percent of such excess investment by the Company. [Sheet No. XC]
Gross Receipts, Occupation or Franchise Taxes	There will be added to the Customer's bill, as a separate item, an amount equal to the proportionate part of any license, occupation, franchise, or other similar fee or tax imposed upon the Company by any municipality or any other governmental authority, whether imposed by ordinance, franchise, or otherwise, in which the fee or tax is based upon a percentage of gross receipts, net receipts, or revenues from the sale of electric service rendered by the Company to the Customer. Bills will be increased the proportionate amount only in service areas where such tax is applicable. [See, for example, Sheet No. RG]
Empire District Electric Company (Missouri)	
Fuel Adjustment Clause	Recovers the Company's costs for fuel consumed in Company generating units, including costs associated with the Company's fuel hedging program; purchased power energy charges, including applicable transmission fees; Southwest Power Pool variable costs; and emission allowance costs. Eligible costs do not include purchased power demand costs. These costs are offset by off-system sales margin and any emission allowance revenues. Costs are accumulated over a six-month period and recovered in the subsequent six-month period. The Fuel Adjustment Clause is adjusted to only reflect 95 percent of accumulated costs either above or below base costs. Includes true-up of under/over recovery of Fuel Adjustment Clause balance from prior recovery period. [Sheet Nos. 17 – 17k]

Excess Facilities Rider	1) If the Company, for the service of the Customer, is required to install and maintain distribution transformers having a total kVA rating numerically greater than 150 percent of the Customer's highest demand during the year ended with the current month, in accordance with the Customer's request, or if necessitated by the operating characteristics of Customer's equipment, the Customer will pay an added monthly charge of 1.25 percent of such excess investment by the Company. 2) If the Company, for the service of the Customer, is required to install and maintain multiple transformers or transformer banks on a single primary metered service, the Customer will pay an added monthly charge of 1.25 percent of the investment in the multiple transformers or transformer banks and primary distribution to same, starting with the first pole after the meter pole and including metering costs in excess of those provided for in the rate. 3) If the Company, for the service of the Customer, is required to install and maintain other special or additional facilities not normally provided by the Company for the Customer's rate or service classification, the Customer will pay an added monthly charge of 1.25 percent of such excess investment by the Company. [Section 4 Sheet No. 1]
Gross Receipts, Occupation, or Franchise Taxes	There will be added to the Customer's bill, as a separate item, an amount equal to the proportionate part of any license, occupation, franchise, gross or other similar fee or tax now or hereafter imposed upon the Company by any municipality or any other governmental authority, whether imposed by ordinance, franchise, or otherwise, in which the fee or tax is based upon a flat sum payment, a percentage of gross receipts, net receipts, or revenues from the sale of electric service rendered by the Company to the Customer. [See, for example, Section 1 Sheet No. 1]
Tracker Mechanism	The settlement agreement reached in the Company's 2010 rate case allowed for a tracker mechanism related to Plum Point, Iatan 2, and Iatan common plant operating expenses. The Company will record a regulatory asset or liability for the difference between actual expenses (excluding fuel and fuel-related expenses) and the amount of expense included in base rates. [2011 Form 10-K, pgs. 89-90]
Tornado Recovery	A joint settlement agreement allows the Company to defer actual incremental operating and maintenance expenses associated with the repair, restoration and rebuilding activities resulting from the tornado. In addition, depreciation related to the capital expenditures will be deferred and a carrying charge will be accrued. The settlement does not include deferral of the fixed cost component associated with the reduction in customers served by the Company as a result of the tornado. [2011 Form 10-K, pg. 91]

Miscellaneous	1) The Company is permitted to track, as a regulatory asset/liability, incremental variations in pension-related costs 2) The Company is permitted to record regulatory assets for costs related to energy efficiency programs 3) The Company utilizes vegetation management and infrastructure inspection tracking mechanisms, whereby costs associated with these activities that vary from a base level are to be deferred for future recovery/refund. [Regulatory Research Associates]
Empire District Electric Company (Oklahoma)	
Fuel Adjustment Rider	Compensates for changes in the cost of purchased power and fuel burned at the Company's thermal generating plants as well as air quality control system costs (e.g. limestone, activated carbon, and ammonia) and the net cost of emission allowances. Offset by off system sales and revenue from the sale of renewable energy credits. Includes true-up of prior period over-recovery or under-recovery. [Sheet No. 15]
Demand Side Management Cost Recovery Rider	Recovers the incremental costs of demand programs approved by the Commission. Recovery is limited to: the incremental costs which represent the direct program costs that are not already included in the then current rates of the utility; associated lost revenues; true-up amounts; and earned program incentives. The DSM rate is subject to annual re-determination and reflects projected DSM recoverable costs for the 12-month period commencing on January 1 of the following year, projected lost revenues, projected incentives earned, and a true-up adjustment reflecting the over-recovery or under-recovery of recoverable costs. Interim adjustments are permitted should a cumulative over-recovery or under-recovery balance arise which exceeds 10 percent of the DSM recoverable costs for the period. [Sheet Nos. 19 – 19d]
Storm Recovery Rider	Recovers Commission-approved storm recovery expenses over a five-year period. Including adjustment for over-recovery or under-recovery. [Sheet No. 18]
Transmission Cost Recovery	Energy charges are adjusted by the amount provided by the terms and provisions of the Southwest Power Pool Transmission Tariff. [See, for example, Sheet No. 1]

Excess Facilities Rider	1) If the Company, for the service of the Customer, is required to install and maintain distribution transformers having a total kVA rating numerically greater than 150 percent of the Customer's highest demand during the year ended with the current month, in accordance with the Customer's request, or if necessitated by the operating characteristics of Customer's equipment, the Customer will pay an added monthly charge of 1.5 percent of such excess investment by the Company. 2) If the Company, for the service of the Customer, is required to install and maintain multiple transformers or transformer banks on a single primary metered service, the Customer will pay an added distribution to same, starting with the first pole after the meter pole and including metering costs in excess of those provided for in the rate. 3) If the Company, for the service of the Customer, is required to install and maintain other special or additional facilities not normally provided by the Company for the Customer's rate or service classification, the Customer will pay an added monthly charge of 1.5 percent of such excess investment by the Company. [Sheet No. 12]
Gross Receipts, Occupation or Franchise Taxes	There will be added to the customer's bill, as a separate item, an amount equal to the proportionate part of any license, occupation, franchise, or other similar fee or tax now or hereafter imposed upon the Company by any municipality or any other governmental authority, whether imposed by ordinance, franchise, or otherwise, in which the fee or tax is based upon a percentage of gross receipts, net receipts, or revenues from the sale of electric service rendered by the Company to the Customer. Bills will be increased the proportionate amount only in service areas where such tax is applicable. [See, for example, Sheet No. 1]
Capital Reliability Rider	Recovers the carrying costs of capital investment for generation, transmission, and distribution assets that have been added to the system since the Company's last Oklahoma general rate case (May 2003), as well as investment made on an ongoing basis. The Company was granted a two-phase CRR by the Commission on August 30, 2010. The first phase of the rider was put into place for Oklahoma customers for usage on and after September 1, 2010. On January 28, 2011 the Company requested the approval by the Commission of the phase 2 rates of the CRR. On June 30, 2011, the Company filed a request with the Commission for an annual increase in base rates for its Oklahoma electric customers over the base rate and CRR revenues that were currently in effect. A stipulation and agreement, reached by all parties participating in the case, was filed on November 16, 2011. This agreement, which was approved by the Commission on January 4, 2012, made rates previously collected under the CRR permanent. [2011 Form 10-K, pg. 92]

Entergy Corporation (ETR)

Entergy Mississippi	
New Plant Investment	Since 2005, Entergy Mississippi (EM) has been recovering the costs of its 480-MW, gas-fired Attala power plant through a temporary rate rider. The rider is to remain in place until the company files for a general rate case. [Regulatory Research Associates]
Formula Rate Plan	Entergy Mississippi (EM) has been operating under a formula rate plan (FRP) since 1994. The company calculates: (1) its earned Rate of Return on Rate Base (ERORB), defined as net utility operating income divided by rate base; (2) the Performance-Adjusted Evaluation Period Cost Rate for Common Equity (PCOE)--the PCOE is derived by adding a Performance Rating Adjustment (PADJ) and a 12.5-basis-point flotation cost premium to the average of a discounted cash flow analysis and a regression analysis; (3) the PADJ may fall in a range of zero to 100 basis points, with price performance weighted 40%, customer satisfaction weighted 20%, and reliability weighted 40%; (4) a benchmark RORB (BRORB), essentially the company's cost of capital incorporating the PCOE; and, (5) a BRORB bandwidth, equivalent to the BRORB plus or minus 50 basis points. If the ERORB is within the BRORB bandwidth, no change in rates is made. If the ERORB is outside the BRORB bandwidth, rates are adjusted based upon a graduated formula that incorporates EM's PADJ. Annual rate adjustments under the FRP are capped at 4% of retail revenues, but the company may initiate a base rate case if it deems it necessary. [Regulatory Research Associates, Tariff Schedule FRP-5]
Fuel Adjustment	The company uses a levelized fuel adjustment clause based upon projected fuel use and costs, with a provision for the reconciliation of over- and under-recoveries. [Regulatory Research Associates]
Storm Damage Rider	Allows for the recovery of costs related to storm damage [Tariff Schedule SD-5]
Rate Deferral Plan Rider	Allows for the recovery of allocated costs associated with the Grand Gulf Generating Station [Tariff Schedule RDP]
Power Management Rider Schedule	Allows for the recovery of costs associated with power management, such as hedging, power purchases and options contracts [Tariff Schedule PMR-6]
Energy Efficiency Rider	Allows for the recovery of costs incurred by the Company in performing and carrying out any pilot program that has as one of its purposes a goal of directly or indirectly promoting efficient use of energy. [Tariff Schedule EE-1]
Energy Cost Recovery Rider	Allows for the recovery of net fuel and purchased energy costs [Tariff Schedule ECR-2]
System Restoration Charge Rider	Allows for the recovery of costs related to system restoration [Tariff Schedule SRC]
Entergy Arkansas	
Production Cost Allocation Rider	Recovers from retail customers the retail allocation of the Company's annual payments/receipts to/from the other Entergy Operating Companies, excluding any possible refunds that the FERC may order. Provides for timely recovery of the costs associated with "rough equalization" of electric generation production costs among the Entergy operating companies, as required by the FERC. [Regulatory Research Associates, Tariff Schedule 48]
Storm Recovery Charge Rider	Collects from ratepayers the amounts required to service its related securitization bonds related to storm cost recovery. [Regulatory Research Associates]
ANO Decommissioning Cost Rider	Allows for the collection of decommissioning costs associated with Arkansas Nuclear One nuclear generating station [Tariff Schedule 37]

Grand Gulf Rider	Allows for the recovery of allocated costs associated with the Grand Gulf Generating Station [Tariff Schedule 42]
Capacity Acquisition Rider	Allows the company to recover changes in costs associated with the Ouachita Plant Interim Tolling Agreement, the EAI-acquired capacity costs, along with the reserve equalization effects, if any, associated with the acquired capability and purchased capacity [Tariff Schedule 49]
Federal Litigation Consulting Fee Rider	Allows for the recovery of fees and/or expenses paid by Entergy Arkansas, Inc. ("Company") to contract attorneys and/or consultants retained by the Arkansas Public Service Commission ("Commission"), as authorized by the General Assembly, when it is a party in litigation before a federal agency and/or the federal courts in proceedings which affect the Company [Tariff Schedule 43]
Energy Cost Recovery Rider	Allows for the recovery of net fuel and purchased energy cost [Tariff Schedule 38]
Municipal Franchise Adjustment Rider	Billings under said rate schedules to customers located within the municipal limits of a municipality imposing a franchise tax or fee upon the Company will be increased by an amount sufficient to compensate Company for any charges (including, but not limited to, licenses, fees, charges, impositions or taxes of any kind other than special millage taxes or general taxes applicable to all citizens and taxpayers) levied or imposed by any municipality on or against the Company as provided in the standard Franchise Agreement between Company and said municipality or in special ordinances passed by said municipality [Tariff Schedule 39]
Charges Related to Customer Activity	Allows for the recovery of costs related to customers who have been released to EAI by other electric distribution utilities [Tariff Schedule 29]
Energy Efficiency Cost Rate Raider	Allows the company to recover its energy efficiency costs approved by the Commission in Docket No. 07-085-TF including: (1) the incremental Energy Efficiency Program costs ("Incremental Program Costs"); (2) Lost Contribution to Fixed Cost ("LCFC") as described and approved by the Commission in Order No. 14 issued in Docket No. 08-137-U; and (3) an incentive as described and approved by the Commission in Order No. 15, issued in Docket No. 08-137-U, (collectively, the "Recoverable Costs") [Tariff Schedule 40]
Storm Recovery Charges Rider	Allows for the recovery of costs related to storm recovery bonds [Tariff Schedule 50]
Entergy Louisiana	
Formula Rate Plan	Since 2005, the company has operated under an FRP which includes a 160-basis-point dead-band around a 10.25% ROE mid-point. If EL's earned ROE falls below the lower end of the dead-band (9.45%), the company is permitted to increase rates prospectively to recover 60% of the shortfall up to the lower end of the dead-band from ratepayers. If EL's earned ROE exceeds the upper end of the dead-band (11.05%), the company is to allocate 60% of the excess earnings to ratepayers. Under the FRP, certain transmission, capacity, environmental compliance, and efficiency costs and "extraordinary cost changes" are accorded different treatment. [Regulatory Research Associates]
Environmental Adjustment Clause (EAC)	Allows for the collection of .0001 cent per kWh for each .0001 cent of all qualifying environmental costs, adjusted for any over or under collection [Tariff page 86]
Rough Production Cost Equalization Adjustment Rider	Adjusts for over or under distribution of the incremental 2007 Rough Production Cost Equalization Remedy Receipts, including carrying costs [Tariff pg 82]

Financed Storm Cost Rider	Allows for the recovery of system restoration costs, storm damage reserve costs and system restoration bond financing costs [Tariff pg 80]
Securitized Little Gypsy Recovery Rider	Allows for the recovery of costs related to the financing of Little Gypsy investment recovery and up front financing [Tariff pg 91]
Entergy Gulf States (Louisiana)	
Formula Rate Plan	Since 2005, EGS has been subject to an electric formula rate plan (FRP), which incorporates a 150-basis-point dead-band around a 10.65% return on equity (ROE) mid-point. If EGS' earned ROE falls below the lower end of the dead-band (9.9%), the company is permitted to prospectively increase rates to recover 60% of the shortfall up to the lower end of the dead-band from ratepayers. If EGS' earned ROE exceeds the upper end of the dead-band (11.4%), the company is to allocate 60% of the excess to customers. Under the FRP, certain transmission, capacity, environmental compliance, and efficiency costs and "extraordinary cost changes" are accorded different treatment. [Regulatory Research Associates]
Environmental Adjustment Clause (EAC)	Allows for the collection of .0001 cent per kWh for each .0001 cent of all qualifying environmental costs, adjusted for any over or under collection [Tariff page 80]
Rough Production Cost Equalization Rider	Adjusts for over or under distribution of the incremental 2007 Rough Production Cost Equalization Remedy Receipts, including carrying costs [Tariff pg 71]
Financed Storm Cost Rider	Allows for the recovery of system restoration costs, storm damage reserve costs and system restoration bond financing costs [Tariff pg 68]
Fuel Adjustment Rider	The fuel adjustment factor for the current month for all rate schedules shall be calculated in accordance with the standard practice prescribed by the Louisiana Public Service Commission [Tariff pg 51]
Entergy New Orleans	
Formula Rate Plan	Established as part of a settlement adopted by the New Orleans City Council (NOCC) in 2009, ENO is to operate under FRPs for its electric and gas operations through 2012. The electric FRP incorporates an 80-basis-point dead-band around an 11.1% ROE mid-point. If ENO's actual electric ROE exceeds 11.5%, rates are to be reduced prospectively to reflect the 11.1% mid-point ROE, and if ENO's actual ROE falls below 10.7%, rates are to be increased prospectively to reflect the 11.1% mid-point ROE. In addition, ENO is permitted to earn up to an incremental 30-basis-point return for meeting certain customer usage reduction targets associated with its demand-side management programs. This incentive is determined outside of the FRP calculation. The FRPs permit ENO to seek recovery of "extraordinary cost changes" in certain circumstances. [Regulatory Research Associates]
Fuel Adjustment Clause (FAC)	Allows the company to recover its net fuel, purchased energy and capacity costs [Tariff pg 26]

Environmental Adjustment Clause (EAC)	Allows the company to charge .0001 cent per kWh used during the month for each .0001 cent of all qualifying environmental costs associated with the purchase and utilization of NOX Allowances and SO2 Allowances in compliance with the Clean Air Interstate Rule charged in the second preceding billing month, adjusted for any over or under collection [Tariff pg 35]
Storm Reserve Rider	Allows for the recovery of costs related to system restoration [Tariff pg 12]
Rough Production Cost Equalization Adjustment Rider	Adjusts for over or under distribution of the incremental 2007 Rough Production Cost Equalization Remedy Receipts, including carrying costs [Tariff pg 38]
Entergy Texas	
Storm Cost Recovery	Allows for the recovery of costs related to system restoration [Tariff pg 38.3]
Rough Production Cost Equalization	Adjusts for over or under distribution of the incremental 2007 Rough Production Cost Equalization Remedy Receipts, including carrying costs [Tariff pg 42]
Municipal Franchise Fee Adjustment	Allows for the recovery of incremental Franchise Fee costs not included in the Company's last general rate case proceeding [Tariff pgs 101-119]
Transition to Competition Rider	Allows for the recovery of costs incurred by the Company resulting from the transition to retail open access [Tariff pg 32]
Hurricane Reconstruction Costs Rider	Allows for the billing and collection of Hurricane Reconstruction Costs Charges [Tariff pg 33]
Energy Efficiency Cost Recovery Factor Rider	Allows for the recovery of costs associated with the Company's energy efficiency programs [Tariff pg 35]
Rate Case Expense Rider	Allows for the recovery of costs incurred by the Company resulting from the rate case filing in PUCT Docket No. 34800 [Tariff pg 37]

Great Plains Energy, Inc. (GXP)

KCP&L (Kansas)	
Energy Cost Adjustment (ECA)	Volumetric rate that recovers variations between actual costs and those reflected in base rates for generation costs including fuel, purchased power, emission allowances, and transmission costs. Rate is established monthly. [KCP&L tariff and Regulatory Research Associates]
Energy Efficiency Rider	Recovers the costs associated with Commission-approved affordability, energy efficiency and demand response programs. Rider and the cost estimates are filed annually with the Commission. [KCP&L tariff]
KCP&L (Missouri)	
None Found	
KCP&L Greater Missouri Operations (Missouri)	
Fuel Adjustment Clause	Through this mechanism, the Company recovers 95% of "prudently incurred" fuel and purchased power costs, net emissions allowance costs, and OSS margins that vary from the levels included in base rates. The mechanism is adjusted semi-annually. [Regulatory Research Associates]

Hawaiian Electric Industries, Inc. (HE)

Hawaiian Electric (HECO), Hawaii Electric Light (HELCO) and Maui Electric (ME)	
Energy Cost Adjustment Clause	Adjusted monthly for changes in fuel costs and the fuel cost component of purchased energy, and for variations from the forecasted generation mix On December 29, 2010, the PUC issued an order permitting HECO.to recover purchased power capacity costs and the O&M expense component of purchased power energy costs via a monthly adjustment clause. [Regulatory Research Associates]
Revenue Balancing Account Provision (Revenue Decoupling)	Utilities in Hawaii have committed to aggressive clean energy goals, and have gained some certainty in cost recovery through the Hawaii PUC's initial approval of revenue decoupling. Under the new decoupling regime, the PUC will approve a revenue level for HECO based on services authorized. Rates will be adjusted based on sales levels, allowing the utility to continue recovering the cost of providing services, but not to earn additional profit from higher sales. Rate increases or decreases between formal rate cases will occur largely based on independent cost indices and will enable recovery of PUC-approved capital additions. The Rate Adjustment Mechanism ('RAM') provision of the RBA will determine whether there is an increase or decrease in annual utility base revenue. The RAM is designed to determine the change in annual utility base revenue levels, recognizing certain estimated changes in the utility's cost to provide service. The RAM considers changes in labor costs, non-labor costs, major capital costs, and productivity offsets. [Tariff Sheets 93 – 93H]
Integrated Resource Planning Cost Recovery Adjustment	The PUC has approved recovery of certain demand side management program costs (to the extent they are not recovered through base rates) through an annual integrated resource planning cost recovery surcharge, subject to review. [Regulatory Research Associates]
Demand-Side Management (DSM) Adjustment Clauses	Adjustments are made to Residential, Commercial, and Industrial customer bills in order to recover the respective costs associated with the electric utilities' DSM programs for each customer class. Utilities recover certain load management and demand response costs associated with the companies' demand side management programs via a surcharge. Labor costs are recovered through base rates, while non-labor costs are recovered through the DSM surcharge. [Regulatory Research Associates]
Pension Tracking Mechanism	All three companies utilize tracking mechanisms for pension and other than pension benefit (OPEB) costs. [Regulatory Research Associates]
Purchased Power Adjustment Clause	Adjustments are made to various rate schedules in order to recover purchased power expenses that are not recovered in base rates or through the Energy Cost Adjustment Clause. [Tariff Sheet 94]
Renewable Energy Infrastructure Program Surcharge	Facilitates the recovery of renewable energy infrastructure investments. Recovery is to be capped at 100% of Commission-approved eligible project costs; recovery of any cost overruns may be examined in subsequent rate proceedings. This surcharge is intended to recover the revenue requirement of a renewable energy project until such a revenue requirement is included in rate base. The surcharge is subject to annual adjustments. [Regulatory Research Associates]

IDACORP, Inc. (IDA)

Idaho Power (Idaho)	
Power Cost Adjustment	Monthly adjustment mechanism allowing the Company to recover 95% of the difference between projected power costs and normal power costs included in base rates. Cost variations are associated with water supply for hydro-electric production, wholesale energy prices, and retail load charges. [Idaho Power tariff, Sheet 55]
Energy Efficiency Rider	Recovers the cost of analysis and implementation of energy conservation and demand response programs. [Idaho Power tariff, Sheet 91]
Fixed Cost Adjustment (FCA) - Decoupling	The Company establishes the costs charged to customers based on a fixed cost per customer that is then allocated based on units of consumption. The Fixed Cost Adjustment is the difference between the allowed fixed cost recovery and the actual fixed cost recovery, adjusted for normal weather. Actual sales are adjusted for weather, and there is a 3% cap on annual rate increases. The current FCA is calculated monthly and will expire on May 31, 2012 unless renewed by the Idaho Commission. [Idaho Power tariff, Sheet 54, and Regulatory Research Associates]
Accelerated Depreciation of Metering Infrastructure	On May 29, 2009, the Idaho Public Utility Commission allowed IPC to begin three-year accelerated depreciation of the existing metering equipment on June 1, 2009. The order reflects annualized depreciation expense relating to Advanced Metering Infrastructure. [Commission Order No. 30829]
Idaho Power (Oregon)	
Power Cost Adjustment Mechanism (PCAM)	Annual adjustment allowing the Company to recover 90% of the difference between actual power costs and normal power costs included in base rates. The PCA is subject to an earnings test with a deadband of 100 basis points. If the company earns less than its ROE by 100 basis points or more, the PCA true up is a charge to customers. If the Company has earned in excess of 100 basis points more than its allowed ROE, the company is required to include the PCA in a true-up balancing account as a credit to customers (back to a threshold of the authorized ROE plus 100 basis points). [Idaho Power tariff, Sheet 56]
Annual Power Cost Update (APCU)	Allows Idaho Power to reestablish its Oregon base net power supply costs annually, separate from a general rate case, and to forecast net power supply costs for the upcoming water year. [Idaho Power tariff, Sheet 55]
Depreciation Adjustment Rider	Recovers accelerated depreciation of the existing metering infrastructure that is replaced by AMI metering, less the revenue requirement impact of the revised depreciation rates. [Idaho Power tariff, Sheet 92]
Energy Efficiency Rider	Allows the company to recover the analysis and implementation of energy conservation and demand response programs. [Idaho Power tariff, Sheet 91]

NV Energy (NVE)

Nevada Power Company	
Schedule SST – Special Supplementary Tariff	In the event that a political subdivision imposes or exacts a business license fee or gross receipts tax, the utility shall be allowed to implement a tax adjustment in an amount sufficient to recover the amount of the tax in its applicable service rates. [Tariff Sheet 31]
Schedule REPR – Renewable Energy Program Rate	NPC's monthly energy charges for services otherwise included in rate schedules are increased or decreased by approved Renewable Energy Program Rates. [Tariff Sheet 9C]
Schedule EE – Energy Efficiency Rider	Provides a recovery mechanism for costs 'reasonably' incurred as a result of energy efficiency and conservation programs. The recovered amount is based on the measurable and verifiable effects of the programs' implementation, which is outlined in the utility's DSM plan. Lost revenues are to be recovered using a balancing account. [Tariff Sheet 9C]
Schedule DEAA – Deferred Energy Accounting Adjustment	Allows for recovery of (or return to) customers' deferred balances. These balances represent the difference between actual fuel and purchased power costs and the amounts reflected in rates. Commission approval is required prior to NPC's implementation of changes in the recovery of fuel and purchased power costs. [Tariff Sheet 6]
Sierra Pacific Power	
Schedule SSE – Shared Savings Electric	Recovers SPP's installation and financing costs of customers' energy-saving equipment costing over $10,000. The monthly rate varies five, seven, or ten years depending on the length of the agreement. The offering of this tariff is subject to SPP's determination of capital limitations and customers' ability to repay. [Tariff Sheet 81Q]
Schedule REPR – Renewable Energy Program Rate	A monthly charge for services otherwise included in rate schedules are increased or decreased by the approved Renewable Energy Program Rates. [Tariff Sheet 63B]
Schedule EE – Energy Efficiency Rider	Recovers costs 'reasonably' incurred due to energy efficiency and conservation programs. The recovered amount is based on the measurable and verifiable effects of the programs' implementation, which is included in the utility's DSM plan. Lost revenues are to be recovered using a balancing account. [Tariff Sheet 9C]
Schedule DEAA – Deferred Cost Accounting Adjustment	Allows for recovery of (or return to) customers' deferred balances. These balances represent the difference between actual fuel and purchased power costs and the amounts reflected in rates. Commission approval is required prior to SPP's implementation of changes in the recovery of fuel and purchased power costs. [Tariff Sheet 63]

Schedule TAR – Tax Adjustment Rider	In the event that a political subdivision imposes or exacts a business license fee or gross receipts tax, the utility shall be allowed to implement a tax adjustment in an amount sufficient to recover the amount of the tax in its applicable service rates. [Tariff Sheet 63E]

Pinnacle West Capital (PNW)

Arizona Public Service	
Renewable Energy Standard (RES) Adjustment Charge	Component of the Environmental Benefits Surcharge that collects costs associated with compliance to state renewable energy standards. Related charges and caps may be modified periodically by the Commission. [APS tariff, ACC No. 5780]
Environmental Improvement Surcharge	Recovers costs associated with investment and expenses for environmental improvements at Company generation facilities that the ACC has approved for recovery. Improvements must have been implemented on or after January 1, 2004, and include ongoing environmental improvement projects and environmental improvement projects designed to comply with prospective required environmental standards. [APS tariff, ACC No. 5760]
Demand Side Management Adjustment Charge	Component of the Environmental Benefits Charge that recovers costs related to Commission approved demand side management programs above those costs included in base rates. The Charge is collected on a monthly basis. [APS tariff, ACC No. 5785]
Power Supply Adjustment (PSA)	Recovers cost associated with fuel and purchased power, and applies to most retail electric rate schedules in accordance with their terms. The Company absorbs 10% of fuel and purchased power costs in excess of the amount that is reflected in base rates. [APS tariff, ACC No. 5783, and Regulatory Research Associates]
Transmission Cost Adjustment (TCA)	Applies to most retail electric rate schedules in accordance with their terms to recover costs associated with FERC approved transmission rate changes. [APS tariff, ACC No. 5787, and Regulatory Research Associates]

Public Service of New Mexico (PNM)

Public Service of New Mexico	
Rider 16 – Energy Efficiency Rider	Provides a mechanism for cost recovery associated with energy efficiency programs. This charge includes the costs associated with incentives (and removal of disincentives) for expenditures on energy efficiency and load management measures. [Tariff Sheet 16]
Rider 23 – Fuel and Purchased Power Cost Adjustment Clause (FPPRAC)	This monthly charge applies only to PNM's retail customers. It recovers increases (or refunds decreases) for fuel and purchased power costs above or below a base fuel cost per kWh. The FPPCAC fuel factor –the difference between the current base fuel rate and the new projected base fuel cost – is calculated annually. [Tariff Sheet 23].
Rider 26 – Sante Fe County Underground Project Rider (2007, 2009)	Provides for the recovery of total excess costs incurred by PNM as a result of underground construction on the Camel Tracks 13 project in Sante Fe County that PNM would normally install as overhead. [Tariff Sheet 26].
Rider 31 – City of Rio Rancho Underground Project	Provides for the recovery of total excess costs incurred by PNM as a result of underground construction on the Veranda 24 project in Rio Rancho that PNM would normally install as overhead. [Tariff Sheet 31].
Rider 32 – City of Albuquerque Underground Project Rider	Provides for the recovery of total excess costs incurred by PNM as a result of underground construction on the Black Ranch 12 project in the City of Albuquerque that PNM would normally install as overhead. [Tariff Sheet 32].

Portland General (POR)

Portland General	
Regulatory Adjustments	Reflects the effects of regulatory adjustments such as net gains from nonrecurring property transactions, and costs associated with implementation of SB 1149 as well as miscellaneous nonrecurring items. [Portland General tariff, Sheet 105-1]
Public Purpose Charge	Designed to collect funds associated with activities mandated for the benefit of the general public, such as energy conservation, new market transformation, new renewable energy resources and new low-income weatherization. [Portland General tariff, Sheet 108-1]
Energy Efficiency Customer Service	Designed to fund Company activities associated with enabling customers to achieve energy efficiency, including but not limited to project facilitation, technical assistance, education and assistance to support programs administered by the Energy Trust of Oregon. [Portland General tariff, Sheet 110-1]
Energy Efficiency Funding Adjustment	Designed to fund the acquisition of additional Energy Efficiency Measures for the benefit of the Company's customers, pursuant to the Oregon Renewable Energy Act, through programs administered by the Energy Trust of Oregon. [Portland General tariff, Sheet 109-1]
Renewable Resources Adjustment Clause	Recovers the revenue requirements of qualifying Company-owned or contracted new renewable energy resource projects (including associated transmission) not otherwise included in rates. Additional new renewable projects may be incorporated into this schedule as they are placed in service. [Portland General tariff, Sheet 122-1]
Decoupling Adjustment	Establishes balancing accounts and rate adjustment mechanisms to track and mitigate a portion of the transmission, distribution and fixed generation revenue variations caused by variations in applicable Customer Energy usage. The SNA reconciles on a monthly basis, differences between a) The monthly revenues resulting from applying distribution, transmission and fixed generation charges (Fixed Charge Energy Rate) to weather-normalized kWh Energy sales, and b) The Fixed Charge Revenues that would be collected by applying the Monthly Fixed Charge per Customer and to the numbers of active Customers, respectively, for each month. [Portland General tariff, Sheet 123-1]
Annual Power Cost Update	Rates are adjusted annually to account for changes in the Company's projected Net Variable Power Costs. The rate adjustment will be based on the Adjusted NVPC less the NVPC revenues that would occur at the NVPC prices determined in the Company's most recent general rate case applied to forecast loads used to determine changes in Net Variable Power Costs. [Portland General tariff, Sheet 125-1]

Annual Power Cost Variance Mechanism	Recognizes in rates part of the difference between actual and forecasted Net Variable Power Costs for a given year. The Company recovers 90% of the Annual Power Cost Variance, subject to the earnings test. [Portland General tariff, Sheet 126-1]
Demand Response Cost Recovery Mechanism	Recovers expenses associated with the implementation and operation (on a pilot basis) of an automated demand response program not otherwise included in rates. Rate adjustments will commence on January 1, 2012. [Portland General tariff, Sheet 135-1]
Short-Term Transition Adjustment	Calculates the Short-Term Transition Adjustment to reflect the results of an ongoing valuation. The Short-Term Transition Adjustment will reflect the difference between the Energy Charge(s) under the Cost of Service option and the market price of power for the period of the adjustment applied to the load shape of the applicable schedule. [Portland General tariff, Sheet 128-1]
Long-Term Transition Cost Adjustment	Calculates the Long-Term Transition Cost Adjustment applicable to large non-residential customers. Annually, changes in fixed generation revenues resulting from either return to or departure from cost of service pricing relative to the Company's most recent general rate case will be incorporated into the System Usage Charges of the large non-residential rate schedules. [Portland General tariff, Sheet 129-1]
Underground Conversion Cost Recovery	Recovers costs incurred by the Company to convert electric facilities from overhead to underground from customers within the boundaries of the local government requiring such conversion at the Company's expense. [Portland General tariff, Sheet 142-1]

Southern Company (SO)

Alabama Power Company	
Rate Adjustment for Certificated New Plant (Rate CNP)	Designed to recover costs associated with: • A generating facility that has been granted a certificate of convenience and necessity by the Alabama Public Service Commission (AL PSC), • A power purchase arrangement that has been granted a certificate of convenience and necessity by the AL PSC, or • Compliance with environmental laws, regulations, or other such mandates. [Alabama Power tariff]
Energy Cost Recovery (ECR) Rate	Provides the Company with a means to recover defined energy (i.e., fuel) costs. It also establishes a procedure for the recovery of defined energy costs through base rates. [Alabama Power tariff]
Differential Factors Rate Rider	Captures the effects of energy losses along the service chain, as well as the effect of seasonal differentials associated with costs recovered under ECR (above). [Alabama Power tariff]
Natural Disaster Reserve Rate Rider (NDR)	Designed to adjust monthly billings to address the financial impact of operating and maintenance (O&M) expenses attributable to certain natural disasters. [Alabama Power tariff]
Rate Stabilization and Equalization Factor (RSE)	Lessens the impact, frequency and size of retail rate increase requests by permitting the Company to adjust its charges more readily to achieve the rate of return authorized by the AL PSC. Charges are increased if projections for the upcoming year show that the designated rate of return range will not be met, and are decreased if projections show that the designated rate of return range will be exceeded. [Alabama Power tariff]
Georgia Power Company	
Fuel Cost Recovery Rider	Georgia Power Company has established fuel cost recovery rates that are approved by the Georgia PSC. Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. [Tariff Sheet 10.10]
Environmental Compliance Cost Recovery Rider	Recovers capital costs and O&M costs associated with government mandated environmental costs. [Tariff Sheet 10.00]
Demand Side Management Residential (DSM-R) Rider	Collects the projected program costs for approved and certified residential DSM programs, as well as an additional sum amount for certified residential DSM programs. [Tariff Sheet 10.20]
Demand Side Management Commercial (DSM-C) Rider	Collects the projected program costs for approved and certified commercial DSM programs, as well as an additional sum amount for certified commercial DSM programs. [Tariff sheet 10.30]

Nuclear Construction Cost Recovery	Recovers the cost of financing associated with the construction of a nuclear generating plant which has been certified by the Commission. The Georgia Nuclear Financing Act and the Georgia PSC certification of Plant Vogtle Units 3 and 4 allows Georgia Power to recover financing costs for construction of the new nuclear units during the construction period beginning in 2011. [Tariff Sheet 10.10 and Regulatory Research Associates]
Alternative Rate Plan	On December 21, 2010, the Georgia PSC approved the 2010 ARP. Under the terms of the 2010 ARP, Georgia Power will amortize approximately $92 million of its remaining regulatory liability related to other cost of removal obligations over the three years ending December 31, 2013. Also under the terms of the 2010 ARP, effective January 1, 2011, Georgia Power increased its (1) traditional base tariff rates by approximately $347 million; (2) Demand-Side Management (DSM) tariff rates by approximately $31 million; (3) ECCR tariff rate by approximately $168 million; and (4) Municipal Franchise Fee (MFF) tariff rate by approximately $16 million, for a total increase in base revenues of approximately $562 million. Additional base rate adjustments will be made to Georgia Power's tariffs in 2012 and 2013. [Order approving 2010 ARP] Under the 2010 ARP, Georgia Power's retail ROE is set at 11.15% and earnings will be evaluated against a retail ROE range of 10.25% to 12.25%. Two-thirds of any earnings above 12.25% will be directly refunded to customers, with the remaining one-third retained by Georgia Power. If at any time during the term of the 2010 ARP, Georgia Power projects that retail earnings will be below 10.25% for any calendar year, it may petition the Georgia PSC for the implementation of an Interim Cost Recovery (ICR) tariff to adjust Georgia Power's earnings back to a 10.25% retail ROE. In lieu of requesting implementation of an ICR tariff, or if the Georgia PSC chooses not to implement the ICR, Georgia Power may file a full rate case. [Regulatory Research Associates]
Gulf Power Company	
Cost Recovery Clause – Fossil Fuel and Purchased Power	Gulf Power files a rate clause request annually to recover costs associated with changing efficiency, cost of fossil fuel, and cost of purchased power. Revenues are adjusted for differences between recoverable costs and amounts actually recovered in current rates. [Tariff Sheet 6.34]
Purchased Power Capacity Cost Recovery Clause	Recovery of payments made by the Company for capacity, net of revenues received by the Company for capacity sales. [Tariff Sheet 6.35]
Energy Conservation Cost Recovery	Gulf Power files a rate clause request annually to recover costs associated with energy conservation. Revenues are adjusted for differences between recoverable costs and amounts actually recovered in rates. [Tariff Sheet 6.38]
Environmental Cost Recovery Clause	Recovers certain environmental investments and expenses that are not being recovered through base rates. [Tariff Sheet 6.36]

Mississippi Power Company	
Fuel Cost Recovery Clause	Mississippi Power's fuel cost recovery provisions are adjusted annually to reflect increases or decreases in such costs. Includes a true-up adjustment for any over/under collection in the twelve month period immediately preceding the calculation month. [Tariff Schedule No. 16]
Energy Cost Management Clause	Recovers budgeted transaction costs for entering forward or financial contracts such as option premiums for both gas and electricity futures contracts and budgeted gas transportation and electricity transmission necessary to meet futures contract obligations for a twelve month period. Includes a true-up adjustment for any over/under collection in the twelve month period immediately preceding the calculation month. [Tariff Schedule No. 49]
Performance Evaluation Plan	Annually on or before November 15, a determination will be made as to whether or not the Company's revenues should be increased, decreased, or remain the same. Based on a twelve month ending Projected Retail Return on Investment as well as the Company's Performance Rating and a Range of No Change. No annual revenue adjustment may exceed 4.00%. [Tariff Schedule No. 28.1]
Environmental Compliance Overview Plan	Approved environmental compliance costs are recovered through cost recovery provisions. Within limits, these rates are adjusted to reflect increases or decreases in such costs as required. [Tariff Schedule No. 39]
System Restoration Rider (SRR)	The Company is allowed to recover costs associated with property damage caused by severe storms. Under a revised SRR calculation method (January 2009), the Mississippi PSC is no longer required to set a cap on a property damage reserve, or to authorize the calculation of an annual property damage accrual. [Tariff Schedule No. 53]

Westar Energy (WR)

Northern and Southern Region	
Fuel Charge	The fuel charge includes costs incurred in production of electricity, as well as the Off-system Sales Adjustment, which credits profits from wholesale sales to retail customers. Wholesale sales are transactions in which the Company sells energy to other wholesale entities such as neighboring utilities, municipalities and power marketers. (See the Retail Energy Cost Adjustment below)
Environmental Cost Recovery Rider	This adjustment is designed to recover annual capital investment-related revenue requirements that are associated with Westar's Environmental Improvements Projects. The ECRC is collected on a monthly basis and includes an annual true-up. [Westar tariff]
Retail Energy Cost Adjustment	This quarterly adjustment recovers costs associated with the fuel costs to produce electricity, purchased power cost, emission allowance costs, and the off-system sales adjustment, which credits profits from wholesale sales to retail customers. [Westar tariff and Regulatory Research Associates]
Transmission Delivery Charge	Includes costs related to the construction and maintenance of Westar Energy's transmission system and the unbundling of FERC-regulated transmission charges. [Westar tariff and Regulatory Research Associates]
Property Tax Surcharge	The Company shall collect or refund the difference between the actual property tax and the amount approved in its most recent rate case in 2010, subject to annual true-up. [Westar tariff]
Storm Costs	The Company accumulated and deferred for future recovery costs related to restoring its electric transmission and distribution systems from damages sustained during unusually damaging storms. The Company amortizes these costs over periods ranging from three to five years and earns a return on a majority of this asset. [Westar 2010 Form 10-K, at 81]
Energy Efficiency Rider	The Company accumulates and defers for future recovery costs related to its various energy efficiency programs. The Company will amortize such costs over a one-year period. The Company does not earn a return on this asset. Westar is also allowed to recover lost revenues associated with its participation in the "Efficiency Kansas" conservation program. [Regulatory Research Associates and Westar tariff]

EXHIBIT

JJR-10

TUCSON ELECTRIC POWER
FAIR VALUE RATE OF RETURN
ARIZONA STAFF METHODOLOGY

	Amount	Weighting	Weighted Amount	
Original Cost Rate Base (OCRB)	$1,519	50.000%	$ 759.54	[1]
RCND Rate Base	$3,041	50.000%	$ 1,520.68	[2]
Fair Value Rate Base (FVRB)			$ 2,280	[3]
Appreciation above OCRB			$ 761	[4]
FV/OCRB Multiple	1.50			

Line No	Capital	Amount	Percent	Cost Rate		Weighted Cost Rate	
1	Long-Term Debt	$ 820	35.97%	5.18%	[5]	1.86%	
2	Common Equity	$ 699	30.65%	10.75%	[6]	3.29%	
3	Capital Financing OCRB	$ 1,519	66.62%			5.16%	
	Appreciation above OCRB						
4	not recognized on utility's books	$ 761	33.38%	1.56%		0.52%	
5	Total	$ 2,280	100.00%			5.68%	[7]

[1] Direct Testimony of Dallas J. Dukes, Schedule A-1
[2] Direct Testimony of Dallas J. Dukes, Schedule A-1
[3]=[1] +[2]
[4]=[3]-OCRB (Fair Value Incrmenet)
[5] Schedule D-1
[6]= Recommended ROE on OCRB
[7] Capital Financing OCRB +Return on the Fair Value Increment

TUCSON ELECTRIC POWER
LONG-TERM INFLATION RATE ESTIMATE

Line No.	Description (a)	Value (b)	Line No.
1	Blue Chip Finanical Forecast - Change in CPI 2018-2022 [1]	2.30%	1
2	2012 Energy Information Administration ("EIA") Annual Energy Outlook rate of change in CPI 2012 through 2022 [2]	2.15%	2
3	2012 EIA Annual Energy Outlook rate of change in GDP 2012 through 2022 [2]	1.85%	
4	Long-Term Expected Inflation Rate	2.10%	3

[1] Source: Blue Chip Financial Forecast Vol. 30, No. 12, December 1, 2011.
[2] Energy Information Administration, 2012 Annual Energy Outlook Early Release, Assumptions Table 20.

TUCSON ELECTRIC POWER
RISK FREE RATE CALCULATION

Line No.	Description	Value	
1	Near Term Projected Nominal 30-Year Treasury Rate (2013-2017)	5.08%	[1]
2	Long Term Projected Nominal 30-year Treasury Rate (2018-2022)	5.50%	[1]
3	Projected Nominal 30-year Treasury Rate	5.29%	
	Inflation	2.10%	[2]
	Real Risk Free Rate	3.12%	[3]

Notes:
[1] *Source*: Aspen Publishers *Blue Chip Financial Forecast*, Vol 30, No. 12, December 1, 2011, *p.* 14.
[2] Average of Energy Information Administration Annual Energy Outlook
Rate of Change in CPI from 2012-2022 and Blue Chip Financial Forecast, Vol.30, No. 12.
[3] Real Risk Free Rate = ((1+Nominal Treasury Rate)/(Inflation +1)-1

EXHIBIT

JJR-11

Comparable Transactions Analysis

Calculation of Transaction Premium over Enterprise Value

Comparable Transactions Analysis

Calculation of Transaction Premium over Corporate Value

M&A Target Company	Acquired By	*Date* Announced	*Target Book* Value Per Share	*Target Transaction* Value Per Share	*Premium to* Equity	*Target Equity* Ratio	*Transaction Premium* to Corporate Value	Implied TEP *Valuation* [1]
NSTAR	Northeast Utilities	10/18/10	$18.60	$40.28	116.5%	51.3%	59.8%	$2,427
Duquesne Light Holdings Inc	MacQuarie	7/5/06	$8.41	$20.00	137.8%	46.8%	64.5%	$2,500
CILCORP Inc	Ameren	11/23/98	$26.24	$65.00	147.7%	62.9%	92.9%	$2,931
Allegheny Energy	First Energy	2/11/10	$18.36	$27.34	48.9%	42.5%	20.8%	$1,835
Conectiv	Pepco	2/12/01	$13.10	$25.00	90.9%	54.4%	49.5%	$2,270
Florida Progress Corp	Carolina Power and Light	8/22/99	$19.70	$54.00	174.1%	51.4%	89.4%	$2,877
Eastern Utilities Associates	National Grid	2/1/99	$18.29	$31.46	72.0%	61.4%	44.3%	$2,191
EnergyNorth, Inc.	Eastern Enterprises	7/15/99	$16.89	$47.00	178.2%	57.1%	101.8%	$3,065
DPL, Inc.	AES	4/19/11	$10.52	$30.00	185.2%	63.1%	116.9%	$3,295
Florida Public Utilities Company	Chesapeake	4/17/09	$8.14	$12.47	53.2%	53.4%	28.4%	$1,951
TNP Enterprises, Inc.	an Investor Group	5/24/99	$23.21	$44.00	89.6%	40.0%	35.8%	$2,063
Montana Power Company	NorthWestern Corporation	9/28/00	$9.86	$10.50	6.5%	77.6%	5.1%	$1,596
Niagara Mohawk Holdings, Inc.	National Grid	9/4/2000	$16.90	$19.00	12.4%	43.4%	5.4%	$1,601
GPU, Inc.	FirstEnergy Corp.	8/8/00	$27.01	$36.50	35.1%	54.4%	19.1%	$1,809
Commonwealth Energy System	BEC Energy	12/5/98	$20.75	$44.10	112.6%	54.8%	61.7%	$2,456
Orange and Rockland Utilities, Inc.	Consolidated Edison, Inc.	5/10/98	$27.92	$58.50	109.5%	60.2%	65.9%	$2,521
Green Mountain Power Corp.	Gaz Metro LP	6/21/06	$22.79	$35.00	53.6%	32.8%	17.6%	$1,786
PacifiCorp	Scottish Power PLC	12/6/98	$13.47	$25.13	86.6%	54.5%	47.2%	$2,236
Nevada Power Company	Sierra Pacific Resources	4/29/98	$16.33	$26.00	59.2%	52.9%	31.3%	$1,995
KU Energy Corporation	LG&E Energy Corp.	5/20/97	$17.29	$40.71	135.5%	56.4%	76.4%	$2,679
MidAmerican Energy Holdings Company	CalEnergy	8/11/98	$13.65	$27.15	98.8%	60.4%	59.6%	$2,425
						Max:	116.90%	$3,295
						Min:	5.06%	$1,596
						Median:	49.46%	$2,270
						Mean:	52.06%	$2,310
						Std. Dev.:	31.52%	$479
						Count:	21	21

[1] Valuation based on median of transactions and TEP's Original Cost Rate Base (OCRB)

Valuation of TEP based on Market Multiples for the Proxy Companies

Transaction Value/EV Multiple:	111.42%
Averaging Period (days):	30
TEP Net Distribution Plant:	$1,788

	Company	Ticker	Enterprise Value ($millions)	Implied Market Value	Net Plant	Implied Market Value to Net Plant	Implied TEP Value ($ millions)
	American Electric Power Company, Inc.	AEP	$36,191	$40,325	$32,367	1.25	$2,227
	Cleco Corporation	CNL	$3,643	$4,059	$2,678	1.52	$2,709
	Empire District Electric Company	EDE	$1,547	$1,724	$1,472	1.17	$2,095
	Entergy Corporation	ETR	$23,837	$26,560	$17,667	1.50	$2,688
	Great Plains Energy Inc.	GXP	$6,688	$7,452	$6,911	1.08	$1,928
[1]	Hawaiian Electric Industries, Inc.	HE	$3,213	$3,580			
	IDACORP, Inc.	IDA	$3,556	$3,963	$3,225	1.23	$2,197
	NV Energy, Inc.	NVE	$8,742	$9,741	$8,805	1.11	$1,978
	Pinnacle West Capital Corporation	PNW	$8,737	$9,735	$9,230	1.05	$1,886
	PNM Resources, Inc.	PNM	$3,298	$3,674	$3,023	1.22	$2,173
	Portland General Electric Company	POR	$3,635	$4,050	$3,643	1.11	$1,988
	Southern Company	SO	$59,665	$66,481	$39,384	1.69	$3,018
	Westar Energy, Inc.	WR	$6,581	$7,333	$6,043	1.21	$2,169
	Max					1.69	$3,018
	Min					1.05	$1,886
	Mean					1.26	$2,255
	Std. Dev.					0.20	$358
	Median					1.21	$2,171

Notes:
[1] Implied Market Value = Enterprise value x (TV/EV) multiple.
[2] 2011 net plant data for the operating subsidiaries of Hawaiian Electric Industries were not available as of the date of this analysis.

Source: Bloomberg.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
GARY PIERCE- CHAIRMAN
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

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-12-____

TUCSON ELECTRIC POWER COMPANY

APPLICATION

TESTIMONY AND EXHIBITS

VOLUME 2 of 4

July 2, 2012

BEFORE THE ARIZONA CORPORATION COMMISSION

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TUCSON ELECTRIC POWER COMPANY

APPLICATION

TESTIMONY AND EXHIBITS

VOLUME 2 of 4

July 2, 2012

Direct Testimony of Karen G. Kissinger

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
GARY PIERCE- CHAIRMAN
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BRENDA BURNS

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-12-____

Direct Testimony of

Karen G. Kissinger

on Behalf of

Tucson Electric Power Company

July 2, 2012

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Exhibits:

Exhibit KGK-1	UniSource Energy Corporation & Tucson Electric Power Company Combined Form 10K for the year ended December 31, 2011
Exhibit KGK-2	Letter from the Federal Energy Regulatory Commission ("FERC") approving the accounting for the acquisition of Sundt Unit 4
Exhibit KGK-3	Request for and Approval by the Commission for an ITC amortization period for the Company

I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Karen G. Kissinger and my business address is 88 East Broadway, Tucson, Arizona, 85701.

Q. What is your employment position?

A. I am the Vice President, Controller and Chief Compliance Officer for UNS Energy Corporation ("UNS Energy"), formerly known as UniSource Energy Corporation. I am also Vice President, Controller and Chief Compliance Officer of Tucson Electric Power Company ("TEP" or "Company") and its sister utilities UNS Gas, Inc. ("UNS Gas") and UNS Electric, Inc. ("UNS Electric").

Q. What are your duties and responsibilities?

A. My responsibilities include internal and external financial reporting, plant and property accounting, payroll, tax planning and tax compliance reporting, and energy settlements for all UNS Energy owned utilities. I am also responsible for the UNS Energy Compliance Program, which focuses on corporate policies, practices, and procedures that are designed to assure that UNS Energy is in compliance with 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 UNS 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. 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 "E" Schedules (Financial Statements and Statistical Schedules). Finally, I am also sponsoring UniSource Energy Corporation and Tucson Electric Power Company's Combined Form 10K for the year ended December 31, 2011, which is attached as **Exhibit KGK-1.** I am 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 items:

- Inclusion of H. Wilson Sundt Generating Station ("Sundt") Unit 4 in rate base;
- Springerville Generating Station ("SGS") Unit 1 adjustment;

- Delayed Unitization adjustment; and
- Accumulated Deferred Income Tax ("ADIT") adjustment.

Further, I am the sponsoring witness for the following income statement pro forma accounting adjustments reflected on Schedule C-2:

(i) Generating Facilities Capital Leases (excluding SGS Unit 1);

(ii) Payroll Expense;

(iii) Employer Payroll Tax Expense;

(iv) Pension Expense;

(v) Retiree Medical Benefits;

(vi) Short-Term Incentive Compensation Expense;

(vii) Long-Term Incentive Compensation (Share-Based) and Supplemental Executive Retirement Plan ("SERP");

(viii) CC&B Allocation;

(ix) PeopleSoft Allocation;

(x) Depreciation Expense;

(xi) Property Tax Expense; and

(xii) Income Tax Expense.

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 the revenue requirement.

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 rate-making purposes. Certain events may have affected recorded transactions in an atypical manner. Moreover, some transactions – while eligible for reflection in the revenue requirement – 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 rate-making 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. Were 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 rate-making 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. <u>ACCOUNTING FOR THE SUNDT UNIT 4 ACQUISITION.</u>

Q. What is Sundt Unit 4?

A. Sundt Unit 4 is a 156-megawatt dual-fuel generating unit located in Tucson. Its conversion to accommodate coal-fired operation was completed in 1988 at which time it was sold and leased back to TEP. As more fully explained in the direct testimony of Company witness Mr. Kentton Grant, the Sundt Unit 4 leased assets were purchased by TEP in 2010.

Q. How did the Company account for Sundt Unit 4 prior to the 2010 acquisition?

A. After the sale-and-lease back, it was initially accounted for as an operating lease, with the periodic payments charged to rent expense. As a result of the modification of certain lease terms in connection with the Company's 1991 financial restructuring, the lease was re-characterized as a capital lease resulting in the recording of a lease obligation and corresponding capital lease asset. The lease obligation was periodically reduced by the principle portion of lease payments and the capital lease asset was amortized at a rate reflecting the life of the lease, with both the computed amortization provision and interest portion of lease payments charged to rent expense, reflective of the rate-making treatment described below. Subsequent capital additions to Sundt Unit 4 were accounted for as leasehold improvements and included in plant in service, and also depreciated at rates reflecting the remaining lease term. Fuel, other operations and maintenance ("O&M") expenses, and property taxes associated with Sundt Unit 4 were recorded in the respective expense accounts prescribed by the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts.

Q. **How is the Sundt Unit 4 lease currently reflected in rates?**

A. For rate-making purposes, the capital lease was re-characterized as an operating lease with an annual recovery allowance based on the average payments under the lease agreement. In connection therewith, the capital lease asset was excluded from rate base, and the lease obligation excluded from capital structure in the calculation of rate of return. Leasehold improvements related to the Sundt Unit 4 lease were included in the plant in service component of rate base. The annual operating lease recovery allowance, Sundt Unit 4 O&M costs, depreciation of the leasehold improvements and property taxes were included as operating expenses in cost of service.

Q. **Please describe the accounting occurring in connection with the Sundt Unit 4 acquisition.**

A. The acquisition process included three types of expenditures. First, the Company negotiated a $51.98 million purchase price, as more fully explained the Direct Testimony of Company witness Mr. Grant. When the irrevocable purchase commitment was made in January 2010, in accordance with Generally Accepted Accounting Principles

("GAAP"), $51.39 million, representing the present value of the purchase price, was added to the recorded value of the capital lease assets, raising the account balance to $188.6 million. The accumulated amortization associated with the recorded value of the capital lease amounted to $130.4 million. Second, the Company paid $5.3 million to satisfy the remaining obligation under the lease. Third, the Company incurred approximately $167,000 in legal fees in connection with the acquisition. In April 2010, the acquisition was completed. The sum of the present value of the purchase price, the net book value of the capital lease asset and the legal fees incurred amounted to $58.4 million and was charged to Account 102, Electric Plant Purchased.

In accordance with Electric Plant Instruction No. 5 ("EPI 5") in the FERC Uniform System of Accounts, $152 million, representing the original cost of the capital lease assets, was transferred from Account 102 to plant in service. EPI 5 also requires that the accumulated depreciation on the books of the seller, or a reasonable estimate if the actual is unknown or unobtainable, is to be removed from Account 102 and credited to accumulated depreciation. In this instance, TEP was unable to obtain the actual depreciation reserve from the seller, so we computed estimated accumulated depreciation based on the original costs of the assets and the portion of the expected service life of Sundt Unit 4 expired as of the purchase date. Accumulated depreciation was estimated to be $72.1 million and removed from Account 102 and credited to accumulated depreciation. After the foregoing transfers, there remained a credit balance of $21.5 million in Account 102, representing a negative acquisition adjustment. Consistent with FERC directives on accounting for negative acquisition adjustments, that amount was cleared from Account 102 and credited to accumulated depreciation as a sub group, to be amortized as a reduction of depreciation expense using the same rates that are used for depreciating the corresponding acquired assets. This is the same accounting treatment ordered by the Commission in connection with a negative acquisition adjustment resulting from the acquisition of what are now UNS Electric and UNS Gas from Citizens Communications in 2003.[1]

As part of the acquisition, TEP retained ownership of the leasehold improvements at Sundt Unit 4. However, with the termination of the lease, it would be inappropriate to continue to classify these assets as leasehold improvements. Accordingly, $57.5 million of recorded leasehold improvements were transferred to plant in service and the related $45.9 million of accumulated amortization was transferred to accumulated depreciation.

The end result of all the purchase accounting entries described above was a beginning balance of plant in service of $209.5 million, and a beginning balance of accumulated depreciation of $139.6 million, yielding a beginning balance of net plant in service of $69.9 million.

Q. Has your accounting for the acquisition of Sundt Unit 4 been approved by the FERC?

A. Yes, the accounting was approved by Mr. Bryan Craig, Director and Chief Accountant, Division of Audits, Office of Enforcement of FERC in a letter dated March 16, 2012. A copy of the authorization is attached as **Exhibit KGK-2**.

Q. How is Sundt Unit 4 reflected in this rate case?

A. The plant in service component of rate base includes the aforementioned transfers recorded at the time of the Sundt Unit 4 acquisition plus subsequent capital additions and asset retirements recorded through the end of the test year. Similarly, accumulated depreciation reflects the transfers recorded at the time of the acquisition plus depreciation provisions and salvage proceeds realized less asset retirements and removal costs

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[1] Commission Decision No. 66028 (July 3, 2003).

incurred in connection therewith through the end of the test year. Test year operating results reflect the O&M expense, depreciation and taxes incurred in connection with the operation of Sundt Unit 4. Annualized test year depreciation expense reflects the end-of-test year balance of Sundt Unit 4 plant in service and the newly-proposed depreciation rates sponsored by Dr. Ronald E. White, reduced by the amortization of the negative acquisition adjustment also based on the proposed new depreciation rates.

V. RATE BASE ADJUSTMENTS.

A. SGS Unit 1.

Q. Please describe TEP's leasehold interest in SGS Unit 1.

A. TEP leases Springerville Unit 1 under seven separate lease agreements that expire in January 2015. As discussed by TEP witness Kentton C. Grant in his direct testimony, the scheduled lease payments vary from period to period but are fixed by contract and are not tied to any market-based index or variable rate of interest. For financial reporting purposes, TEP accounts for these leases using the interest method of capital lease accounting. This requires TEP to record a lease obligation on its balance sheet equal to the net present value of scheduled rent payments and to record interest expense on the liability in each reporting period. This method of accounting also requires TEP to record a capital lease asset on its balance sheet and to amortize the asset on a straight-line basis over the term of the lease.

Q. How is SGS Unit 1 currently reflected in rates?

A. In the Company's last rate case, the Commission authorized a non-fuel cost recovery allowance for SGS Unit 1 of $25.67 per kW per month that reflected the levelized cost of the facility through the remainder of the primary lease term. In addition, the associated leasehold improvements were included in rate base at their depreciated original cost. SGS Unit 1 fuel costs are recovered separately through TEP's purchased power and fuel adjustor mechanism.

Q. What costs were included in the $25.67/kW/month allowance for non-fuel cost recovery?

A. This allowance included adjusted test-year amounts for non-fuel operating costs and property taxes, as well as a levelized amount of lease cost. The levelized lease cost included $81.1 million attributable to the SGS Unit 1 lease and $5.6 million associated with the Springerville Coal Handling Facilities lease. The SGS Unit 1 lease cost was based on the average annual lease payment to be paid by TEP over the remaining lease term (ending in January 2015). The total dollar amount of non-fuel costs was then divided by the 380 MW of capacity at SGS Unit 1 to arrive at a per-kW allowance that very nearly approximated the authorized value of $25.67/kW/month in the 2008 Settlement Agreement, approved in Decision No. 70628 on December 1, 2008 ("2008 Settlement Agreement").

Q. What rate-making treatment is TEP seeking for SGS Unit 1 in this rate case?

A. The Company is seeking a continuation of the existing rate-making treatment ordered in the last rate case. Test year adjusted operating costs reflect the $25.67/kW/month allowance for SGS Unit 1 and related common facilities leasehold improvements are included in rate base at their depreciated original cost.

Q. What non-fuel costs are included in the $25.67/kW/month allowance?

A. The same costs are included as in TEP's last rate case. Since no changes have occurred to either the SGS Unit 1 lease or the Coal Handling Facilities lease, as discussed in Mr. Grant's Direct Testimony, the same amount of levelized lease expense is included in the

$25.67/kW/month cost recovery allowance. Non-fuel operation and maintenance expenses, as well as property taxes, have been updated to reflect the 2011 test-year. The resulting non-fuel cost recovery can be summarized as follows:

	$ Millions	$/kW/mo.
SGS Unit 1 Lease Expense	$81.1	
Coal Handling Facilities Lease Expense	5.6	
Operation & Maintenance Expense	30.8	
Overhaul Maintenance Adjustment	(2.9)	
Property Tax Expense	3.7	
Subtotal	$118.3	$25.94
Adjustment to Reflect Allowed Recovery	(1.2)	(0.27)
Total	$117.1	$25.67

B. Delayed Unitization Adjustment.

Q. Please explain the Delayed Unitization Adjustment.

A. The adjustment for Delayed Unitization represents plant additions that were used and useful as of the end of the test year, but not part of the Balance in FERC Account 106, Completed Construction not Classified, as of December 31, 2011. The Delayed Unitization adjustment represents additional costs incurred on previously unitized projects and projects that were completed as of December 31, 2011 that became known subsequent to year-end 2011. The in-service date for these projects occurred in 2011 or before. Because these projects are used and useful, they should be included as part of test year rate base at December 31, 2011. Following is a summary of the adjustment by FERC plant account.

TEP Rate Case Adjustment by FERC Account
Additional Assets and Costs Place in Service for 2011
Dollars In Thousands

FERC	Asset Cost FA Additions	Asset Cost Delayed Plant	Asset Cost Difference	Accumulated Depreciation FA Additions	Accumulated Depreciation Delayed Plant	Accumulated Depreciation Difference
E303	$ 2,957	$ 3,037	$ (80)	$ 150	$ 195	$ (45)
E311	5,080	4,668	412	55	63	(8)
E312	15,976	15,937	39	139	153	(14)
E314	2,110	1,847	263	28	29	(1)
E315	1,566	1,219	347	(23)	(25)	2
E316	336	338	(2)	2	2	0
E341	20	0	20	0	0	0
E343	(53)	80	(133)	0	0	0
E344	21,565	19,944	1,621	44	42	2
E345	75	59	16	0	0	0
E360	20	5	15	0	0	0
E361	56	0	56	0	0	0
E362	611	373	238	6	2	4
E364	1,312	1,212	100	4	4	0
E365	892	152	740	3	1	2
E366	147	0	147	1	0	1
E367	2,179	0	2,179	22	0	22
E368	556	108	448	3	0	3
E369	(4)	234	(238)	0	0	0
E370	0	28	(28)	0	0	0
E373	1	0	1	0	0	0
E389	18	0	18	0	0	0
E390	2,668	1,983	685	6	3	3
E391	1,145	458	687	17	6	11
E392	92	47	45	1	0	1
E393	121	104	17	1	1	0
E394	64	65	(1)	2	1	1
E395	138	135	3	0	0	0
E396	142	0	142	0	0	0
E397	4,391	3,601	790	24	9	15
E398	15	14	1	0	0	0
EDST		0		6	1	5
Total	**$ 64,196**	**$ 55,648**	**$ 8,548**	**$ 491**	**$ 487**	**$ 4**

C. <u>Accumulated Deferred Income Tax ("ADIT").</u>

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, test year operating results, and the Company's existing income tax rate-making 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 often referred to as "inter-period income tax allocation," or "normalization".

Q. In order to better understand deferred income taxes, can you briefly describe the accounting for income taxes under GAAP?

A. Yes. Accounting for income taxes under GAAP is contained in the Accounting Standards Codification ("ASC") in Section 740 (formerly SFAS No. 109 *Accounting for Income Taxes* ("SFAS109")). The income tax calculation has three components: income taxes currently payable, deferred income taxes, and deferred investment tax credit ("ITC"). Taxes currently payable represents the income taxes payable to the U.S. Treasury in the current period as computed under the provisions of the Internal Revenue Code ("IRC"). There are differences between how certain items are treated under the IRC and GAAP. These differences are listed on Schedule M of the filed income tax return. Such differences between income tax treatment and book accounting treatment are either "timing/temporary differences" or "permanent differences".

Timing/temporary 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.

For book purposes, utility plant is capitalized and depreciated over the estimated useful life in a systematic and rational manner, typically straight-line. For income tax purposes, depreciation is computed over shorter lives using one of the accelerated methods contained in the IRC. Depreciation is generally considered a timing/temporary difference because both book and tax depreciation amounts are limited, over time, to the cost of the utility plant. Thus, in the early years tax depreciation will exceed book depreciation, but in the later years, book depreciation will exceed tax depreciation.

Other examples of timing/temporary differences include: (i) expenses that are deducted by utilities currently for tax purposes, but deferred on the books as regulatory assets for future recognition in rates (such as rate case expense); and (ii) expenses that are recognized for book purposes ahead of when they are deductible for income tax purposes (such as Retiree Medical Benefits).

Permanent differences also 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. Both of these items are included when determining book income, but are never included in the determination of taxable income on the income tax return.

Q. How are the income tax components calculated?

A. Income taxes currently payable are calculated on the estimated amount that the Company will pay based on the current year's taxable income (using the rules under the IRC). The journal entry to record this component is:

Current income tax expense	xxxxx	
Current income tax payable		xxxxx

Deferred income taxes are computed for timing/temporary differences, but not for permanent differences. The typical accounting for deferred tax involves identifying the tax effect of the timing/temporary difference and recording the following entry:

Deferred income tax expense	xxxxx	
Accumulated deferred income taxes		xxxxx

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.

It should be noted that the typical effect of timing/temporary differences is to reduce current income taxes and increase deferred income taxes, dollar for dollar with no "net" impact on the calculation of total income taxes.

Q. How do deferred income taxes affect public utility rate-making?

A. The reflection of deferred income taxes in rate-making is labeled "normalization." Some regulatory bodies permit utilities to recognize deferred income taxes associated with all timing/temporary differences in rate-making ("full normalization"), while others only permit the recognition of certain timing/temporary differences required by the IRC to be recognized in utility rate-making ("partial normalization"). To the extent that normalization is permitted in rate-making, 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. This treatment reflects 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. In effect, the ADIT represents a cost-free or interest-free loan from the U.S. Treasury.

The other rate-making approach to timing/temporary differences is when regulators do not permit deferred income tax expense as a recoverable cost in the rate-making process. This approach is known as "flow through" since, under this approach, the income tax reducing benefits of tax return deductions are "flowed-through" to the retail customer by a reduction of current income tax expense, without the offsetting deferred income tax expense. Because flow-through only applies to book-tax timing/temporary differences, any reduction in income taxes payable when a timing/temporary difference originates is offset by higher income taxes payable when the timing/temporary difference reverses (turns around). Of course, under a flow-through approach, there is no net ADIT to reduce rate base as the "interest free" loan has been provided to retail customers.

Q. What income tax rate-making authority has been granted to TEP?

A. Prior to 1979, TEP was a flow-through entity for rate-making purposes, meaning that it was not permitted to reflect deferred income taxes in rate-making. 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 Used 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 *SFAS No. 109* (now known as ASC740), for regulatory accounting purposes.

To the extent ASC740 requires the recording 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, we effectively exclude these amounts recorded on the Company's balance sheet in determining the appropriate amount of deferred tax assets and ADIT for rate-making purposes. An example of this treatment is the equity component of AFUDC. The equity component of AFUDC is capitalized for book purposes but is excluded from our income tax return. Under ASC740, the amount capitalized for books (the amount capitalized in the work order and depreciated) compared to the amount capitalized for income tax purposes (zero) represents a temporary difference that requires ADIT. For book purposes, we offset the ADIT on the equity component of AFUDC with a regulatory asset, thus recognizing we have not included such amounts on the tax return.

Q. Can you please explain why certain ADIT amounts which are recorded on the books pursuant to ASC740 have not been reflected in the calculation of rate base in this case?

A. As previously discussed, not every deferred tax asset or liability required to be recorded for GAAP is appropriate for inclusion in rate base. The following items have been omitted from rate base:

- Capital lease obligations – all deferred tax assets and liabilities related to TEP's capital lease obligations have been removed from ADIT for purposes of this case. For rate-making purposes, these leases are treated as operating leases and there is no timing difference to be accounted for on a regulatory basis.
- Deferred Grant-Energy Credit – for ASC740 purposes, the IRC § 48 (Energy Credit) is treated not as an ITC but as deferred revenue. This deferred tax asset has been excluded from the case because the Energy Credit is reflected in the rate-base reduction for deferred ITC. Additional discussion regarding the Energy Credit is provided later in my testimony.
- Deferred and Incentive Compensation – the deferred tax asset related to incentive compensation has been excluded because it has a short turnaround time. That is, the tax deduction is taken in the year following the year expensed for GAAP. Consistent with the historical treatment of such items in rate-making, we omit from rate base those deferred tax items which reverse quickly as they do not represent a long-term cost or benefit. The ADIT asset associated with deferred compensation has been omitted from rate base because the underlying plan assets are not included in rate base.
- Emission Allowances – the recovery of costs associated with emission allowances was considered in TEP's Transition Recovery Asset at the time of deregulation in 1999. The cost of these assets has been fully recovered from retail customers and

it is not appropriate to increase rate base with ADIT associated with assets no longer considered in the regulatory process.

- Retiree Medical Benefits – the ADIT associated with Retiree Medical Benefits has been excluded from rate base because the liability for future benefits is excluded from rate base.
- Sick and Vacation Time – this is another example of deferred tax assets with a short turnaround time and appropriately excluded from rate base.
- Demand Side Management ("DSM") Adjustor – this timing difference is associated with the regulatory asset for DSM costs incurred, but not yet recovered. The ADIT has been excluded from rate base in order to be consistent with the exclusion of the DSM regulatory asset from rate base.
- Pension – for GAAP purposes, the books reflect a liability for future benefits and a regulatory asset for amounts to be recovered from retail customers in the future. The deferred tax liability has been omitted from rate base to be consistent with the treatment of the related regulatory asset and the pension liability, which are also omitted.
- Purchased Power and Fuel Adjustment Clause ("PPFAC") – similar to the DSM adjustor, this ADIT is related to a regulatory asset for under-recovered fuel and purchased power costs. The ADIT liability is excluded in order to be consistent with the exclusion of the regulatory asset.
- Property Tax – the ADIT recorded for ASC740 is attributable to the recording of a regulatory asset on the books that recognizes the difference between the timing of property tax expense for regulatory purposes (cash basis) and when recognized for GAAP (accrual basis). Again, because the regulatory asset is excluded from rate base the ADIT liability is also excluded.

Q. Has there been a substantial change in ADIT since TEP's last rate case?

A. Yes. While there are not many new book/tax differences, the ADIT relating to accelerated depreciation has increased. This is a result of the bonus depreciation legislation included in the "Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010," under which the difference between book and tax depreciation is much larger than in prior years.

Q. Please explain the bonus depreciation provisions that have been legislated since TEP's last rate case.

A. Prior to 2007, there were various depreciation methods legislated by Congress that allowed varying degrees of acceleration of depreciation deductions for qualifying property. There were no bonus depreciation provisions available for assets placed in service in 2007. However the Economic Stimulus Act of 2008 reinstated 50% bonus depreciation for property acquired after December 31, 2007 and placed in service before January 1, 2009. Fifty percent bonus depreciation allows the taxpayer, at his election, to immediately deduct 50% of the cost of qualifying property at the time it is placed in service. The Economic Recovery and Stabilization Act of 2009 extended the provision one additional year through 2009, and the Creating Small Business Jobs Act again provided another one year extension through 2010.

On December 17, 2010 the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010 was signed into law. This legislation further extended the 50% bonus provisions to include assets placed in service prior to January 1, 2012. The bill also provided for 100% bonus depreciation in the case of qualifying property placed in service after September 8, 2010 and before January 1, 2012. 100% bonus depreciation allows the entire cost of qualifying assets to be deducted, at the taxpayer's election, at the time the asset is placed in service.

Q. Did TEP elect either 50% or 100% bonus depreciation on eligible property placed in service since the last rate case?

A. Yes, TEP elected the maximum amount of bonus depreciation allowable on all property placed in service since December 31, 2006. The effect of this election has been to create a net operating loss ("NOL") for federal income tax purposes for the 2011 tax year. For 2011, current income tax expense is zero and a deferred income tax asset has been created for the NOL carryforward.

Q. Have you included the ADIT asset associated with the NOL in rate base?

A. Yes. The ADIT asset associated with the NOL has been added to rate base to offset the reduction due to the depreciation ADIT that has reduced rate base. This amount has been added because it represents tax depreciation deductions from which the Company has yet to realize a cash benefit. Basic fairness would dictate that it is not appropriate for retail customers to receive the rate base reducing benefit of the ADIT related to accelerated depreciation when the Company has not yet received the benefit of this deduction. This issue is addressed in the Direct Testimony of James I. Warren filed on behalf of the Company.

Q. What other deferred tax assets not attributable to temporary/timing differences have you included in rate base?

A. Similar to the ADIT associated with NOLs, we have also included in rate base the deferred tax asset for Alternative Minimum Tax credits. This addition is also addressed in Mr. Warren's Direct Testimony.

Q. What gives rise to the Accumulated Deferred Income Tax Liability for Excess Deferred State Taxes that is included in ADIT?

A. On February 17, 2011, the Arizona legislature passed a bill reducing the state corporate income tax rate from the current rate of 6.968% to an ultimate rate of 4.9%. This reduction will be phased in beginning in 2014 with a reduction of approximately 0.5% per year until the income tax rate reaches 4.9% for 2017 and later years.

For purposes of ADIT presented in this case, the balance of Arizona deferred income taxes is presented at the rates in effect at the end of the test year, or 6.968%.

Q. How does TEP propose to treat the excess deferred state income taxes collected in prior years for rate-making purposes?

A. TEP proposes that the excess deferred taxes be used to reduce retail customer rates on the same schedule that the taxes would have been paid to the State of Arizona if the income tax rates had not been reduced. In other words, the excess deferred income taxes will be amortized as a reduction to deferred income tax expense as the underlying timing differences reverse.

The effect on Income Tax Expense is addressed in my testimony below.

D. <u>Accumulated Deferred ITC.</u>

Q. You previously mentioned a third tax component, Accumulated Deferred ITC. Please explain the adjustment for Accumulated Deferred ITC.

A. Unlike deferred taxes, which can be likened to an interest-free loan from the U.S. Treasury, the ITC can be likened to a grant or rebate. The ITC is a direct reduction of income taxes otherwise payable. It is calculated by multiplying a qualifying investment (generally, tangible personal property) times a statutory rate. Under GAAP, the preferred accounting for the ITC is to defer it on the balance sheet when realized on the income tax return, and then amortize the credit over the lives of the assets that generated the ITC. The journal entries are:

Current Income Tax Payable	xxxxx	
Deferred ITC		xxxxx

(To reduce income taxes otherwise payable due to claiming the ITC).

As explained below, for rate-making purposes TEP has made an election to share the ITC in accordance with IRC §46(f)(1), whereby the rate-making treatment for Accumulated Deferred ITC is a reduction to rate base that reflects the provision of non-investor capital due to a reduction in income taxes payable (benefitting the customer) with below-the-line amortization (benefitting the shareholder) each year. The ITC elected by TEP is found at IRC §48. (Energy Credit) and results from TEP's investment in solar generating facilities. IRC §48(a)(2) provides for a 30% ITC for investment in qualifying solar facilities placed in service prior to January 1, 2017. Further, IRC §50(c)(3)(A) requires that the depreciable tax basis of the underlying property be reduced by an amount equal to 50% of the energy credit taken with regard to the property. I discuss the accounting and rate-making treatment of this basis reduction below.

Q. What are the rules governing the accounting for ITC for public utilities?

A. The tax normalization rules are contained in IRC §46(f) (as in effect prior to the Revenue Reconciliation Act of 1990). IRC §50(d)(2) requires that these normalization rules be applied to the §48 Energy Credit when elected by a regulated utility. The normalization rules require all public utilities to elect one of the two available of normalization methods. The method elected by TEP is described in §46(f)(1) (as in effect prior to the Revenue Reconciliation Act of 1990).

Q. Please explain the requirements of IRC §46(f)(1).

A. This section provides that a regulated utility shall not reduce the base to which rate of return is applied by any portion of the credit unless the reduction is restored not less rapidly than ratably. "Ratably" is defined as the life used by the public utility for purposes of calculating book depreciation for the qualified property.

Q. What is the amortization period used by TEP to amortize ITC?

A. TEP amortizes the ITC over the tax life of the assets that generated the ITC. This treatment was authorized by the Commission Director of Utilities in a letter to TEP dated July 21, 1983 (attached as **Exhibit KGK-3**). In the case of solar generating facilities, the property is classified for depreciation purposes in IRC §168(e)(1) and qualifies for a five-year life for tax depreciation purposes. As the book life of the solar generating assets is 20 years, the use of the shorter life is in compliance with the normalization provisions of IRC §46(f)(1).

Q. How was the ITC rate-base reduction calculated in this case?

A. The ITC presented in this case is attributable to the solar facilities placed in service by TEP in 2010 and 2011. In 2010, TEP placed $14.0 million of qualifying property in service, resulting in an ITC of $4.2 million. In 2011, TEP placed $18.8 million of qualifying property in service, resulting in an ITC of $5.6 million. The unamortized ITC reducing rate base is the unamortized balance of these credits as of the end of the test year. In accordance with the amortization period granted TEP in **Exhibit KGK-3**, the credits are being amortized over the tax life of the qualifying property. Since the five-year tax depreciation recovery period authorized by IRC §167 is spread over six years, TEP uses a straight-line amortization period of six years with a half-year of amortization in the first and last years.

Q. Is there a corresponding adjustment to current or deferred income tax expense as a result of the ITC?

A. Yes, there is an adjustment to deferred income tax expense as a result of the ITC discussed later in my testimony.

Q. Has any adjustment been made to ADIT for the ITC that will be taken on the qualifying property included in Post Test Plant in Service?

A. No. TEP expects to elect the §48 Energy Credit with regard to the solar generating facilities included in Post Test Year Plant in Service but does not expect to be able to use the credits to reduce the federal tax liability in 2012. TEP does not expect to be able to use the ITC on its tax return until 2016.

Internal Revenue Service ("IRS") Private Letter Ruling 8326081 addresses this issue of when the benefits of ITC should be reflected in rates if the utility elected the normalization method provided for in §46(f)(2) (ratable amortization in cost of service), but the principles are the same for §46(f)(1). In this ruling, the IRS clearly states "the credit cannot be used to reduce the cost of service until it has been allowed for federal income tax purposes." In the ruling, the taxpayer was prohibited from reducing cost of service which provides benefits to retail customers. In the case of a company subject to the normalization provisions of §46(f)(1), such as TEP, the same rule would apply to prohibit the reduction of rate base for credits not yet allowed on the taxpayer's federal tax return.

V. OPERATING INCOME ADJUSTMENTS.

A. Generating Facilities Capital Leases (excluding SGS Unit 1).

Q. Please explain the Generating Facilities Capital Leases Adjustment (excluding SGS Unit 1).

A. The pro forma adjustment for Generating Facilities Capital Leases (excluding SGS Unit 1) converts the capital lease presentation required by GAAP recorded in the general ledger to the straight-line operating lease expense used for rate-making purposes. This means the effect of recording interest expense and depreciation for capital lease treatment is removed and replaced with rental expense on a straight-line basis. The straight-line basis for an operating lease is calculated as the sum of all the lease payments divided by the lease term, consistent with historical rate-making treatment.

Q. Why is this adjustment appropriate?

A. As stated above, the adjustment is consistent with prior rate-making treatment for these assets.

Q. Which leases are being adjusted?

A. The following leases were adjusted to reflect the straight-line operating lease basis for rate-making from the capital lease presentation (under GAAP) recorded in the general ledger:

- SGS Coal Handling Facilities; and
- SGS Common Facilities.

Q. Can you briefly summarize the adjustment calculation to convert these leases from GAAP capital leases to operating leases for rate-making purposes?

A. The adjustment removes the entire capital lease costs, recorded in the general ledger in 2011 and replaces the costs with the straight-line operating lease expense used for rate-making purposes. This approach is consistent with prior TEP rate cases.

B. Payroll Expense.

Q. Please explain the Payroll Expense Adjustment.

A. The Payroll Expense Adjustment is intended to reflect a normal level of salaries and wages in test year operating expenses. The Payroll Expense Adjustment was computed based on an average of O&M wages for 2010 and 2011, and reflects the known and measurable wage increases of 3.75% effective January 9, 2012 for classified employees, and approximately 1% effective March 19, 2012 for unclassified employees.

C. Payroll Tax Expense.

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 Expense Adjustment. TEP's effective employer's tax rate for 2011 was applied to the increased payroll expense reflected in the Payroll Expense Adjustment.

D. Pension Expense.

Q. Please explain the Pension Expense Adjustment.

A. The Pension Expense Adjustment adjusts test year operating expenses based on the most recent pension actuarial valuation (the latest estimate of pension expense), a known and measurable change.

E. Retiree Medical Benefits.

Q. Please explain the Retiree Medical Benefits Adjustment.

A. The Retiree Medical Benefits Adjustment adjusts operating expenses for the test year to reflect the most recent Retiree Medical Plan actuarial valuation (the latest estimate of the accrued period expense). The adjustment includes the amortization of the Transition Obligation Liability at January 1, 2006 to reflect the transition from the cash basis to accrual basis for rate-making.

Q. In Decision No. 70628, the Commission approved recovery of TEP's Retiree Medical Benefits on an accrual rather than a cash basis for rate-making purposes, provided that TEP met certain funding conditions that were enumerated in the rate case. Has TEP met the funding conditions?

A. Yes, TEP's compliance with the funding conditions is detailed in the table below:

Condition	Compliance
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;	Condition met. Beginning in the third quarter of 2009, TEP began making quarterly, cash payments to fund the irrevocable, independently managed external trust.
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;	TEP obtained an IRS determination letter dated May 8, 2011 that supports the tax-exempt status and all contributions are tax deductible.
Investments made by the trustee of the trust must be compatible with meeting the Retiree Medical Plan obligations as they come due;	Condition met. The funding and types of investments are adequate to meet current retiree medical expenses and administrative costs of the trust.
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;	Not applicable. The accumulated funds in the irrevocable trust are required to be used for retiree medical expenses and administrative costs of the trust.
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	Condition met. The irrevocable trust agreement, effective September 1, 2009; and the subsequent amended agreement, effective January 1, 2012, limit payments to retirees in accordance with the benefits under TEP's retiree medical plan, and the administrative costs of the trust.
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.	Not applicable, as the trust has not been terminated.

F. Short-Term Incentive Compensation Expense.

Q. What is Short-Term Incentive Compensation?

A. Short-Term Incentive (cash-based) Compensation is an integral part of TEP's compensation and benefits program. Incentive compensation may be viewed as a "lump-sum salary payment" because it is simply a core piece of compensation based on the benchmarked total compensation needed to attract and retain qualified personnel. The Short-Term Incentive Compensation is effectively withheld salary. As such, TEP could either raise annual salaries or use this "at risk" compensation plan targeted at achieving goals to benefit customers, and only pay the compensation upon completed performance.

Q. Which employees are eligible for the Short-Term Incentive Compensation program?

A. All non-union employees are eligible for the Short-Term Incentive Compensation program. 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. What are the benefits to TEP retail customers of having an "at risk" pay component of compensation as opposed to increasing an employee's annual salary amount?

A. The short-term incentive program benefits retail customers by enabling the entire organization to focus on key customer, operational and financial objectives. Having an "at risk" component of compensation allows a company to focus its effort toward achieving measurable, meaningful goals and only rewarding employees when those goals are met. For example, the goals of the TEP 2011 program benefited the TEP retail customers as follows:

Category	Goals	Benefit to Retail Customers
Customer	• Excellent operations • O&M cost containment	• Having goals that specifically target operations (system availability and reliability) and cost containment.
Community/ Environment	• Community volunteerism • Environmental focus: renewable energy and energy efficiency	• Partnering with the community helps to identify customer service needs and issues. • Meeting renewable goals established by the Commission.
Employee	• Safe work place • Improve processes	• Reducing injuries in the workplace reduces operating costs. • Making process improvements reduces operating costs.
Financial Strength	• Net income target • Incremental value	• Enhances the ability of the Company to conduct business. A financially strong company is better able to secure credit from vendors and lenders. This allows TEP to timely procure goods and services for operations, which promotes a higher quality of service to customers and lower operational costs. This also benefits the retail customer because the company is able to raise capital at a lower cost to build the infrastructure needed to serve the retail customers.

Using an incentive compensation program is less costly than increasing base salaries because incentive compensation does not automatically drive increases in other employee costs that are included in "base compensation" such as: vacation pay; sick pay; long-term disability; 401(K) employer matching contributions; and pension expense. As a result, the incentive compensation program is less costly than increasing base salaries.

Q. **What are other benefits to retail customers of the Short-Term Incentive Compensation program?**

A. Even though this program creates "at-risk" compensation for employees, it contributes to the overall employment package offered by TEP, allowing the Company to be competitive in attracting and retaining highly qualified employees. Retention of employees helps to reduce costs by having a more experienced work force to provide safe, reliable service to the retail customers. Attracting and retaining a qualified work-force, in addition to the retail customer benefits described in the preceding table, demonstrates that the Short-Term Incentive Compensation costs are prudent.

Q. Please explain the Short-Term Incentive Compensation Expense 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 Adjustment produces a pro forma test year expense level reflecting 50% of officers and other senior managements (collectively referred to as "Upper Management") average PEP for the past three years (2009-2011) and 100% of the remaining employees' average PEP for the same past three years.

Q. Please explain why part of the PEP expense is at 50% and part is at 100%.

A. To be more aligned with past Commission decisions, the recovery of PEP for Upper Management is limited to 50%. The following Commission decisions appear to provide support for differentiating between recovery of officer and non-officer incentive compensation:

- **Southwest Gas Corporation ("SWG") – Decision No. 70665**: allowed recovery of 50% of SWG's Management Incentive Program (MIP). As set forth in the direct testimony of Staff witness Ralph C. Smith (pages 27-28) in that docket, SWG's MIP only applied to upper management, specifically to: CEO, President, Executive VP, Senior VP, Vice President and Director/Senior Manager (non-officers). Employees below these upper management levels were not eligible for MIP.

- **Arizona Public Service Company ("APS") – Decision No. 69663**: allowed recovery of 100% of APS' Cash-Based Incentive Compensation program. As set forth in the direct testimony of APS witness Mark K. Gordon (page 11), the APS plan applied to a wide spectrum of employees and not just upper management. Mr. Gordon further testified (page 11) that, the APS plan *"has five distinct organization levels of participation – PNW Chair/CEO, Officer (includes APS President, EVP and VP), Senior Management, Management and Broad-Based Employees."* In Decision No. 69663, page 37, the Commission adopted the Staff's position of not opposing inclusion of the program expense because the APS' "at risk" pay program ties employee performance to the customer's benefit:

> APS' variable incentive program is an "at risk" pay program where a part of an employee's annual cash compensation is put at risk and expectations are established for the employee at the start of the year. If certain performance results are achieved, a predictable award will be earned based upon objective criteria. The actual amount of the award depends upon the achieved results. The intent of the plan is to: link pay with business performance and personal contributions to results; motivate participants to achieve higher levels of performance; communicate and focus on critical success measures; reinforce desired business behaviors, as well as results; and to reinforce an employee ownership culture. (APS Exhibit No. 51, Gordon Rebuttal, p. 8) Staff did not oppose inclusion of the TY variable incentive expense in cost of service, noting that although corporate earnings serve as a threshold or precondition to the payout, the TY level of expense is tied primarily to performance measures that directly benefit APS customers. (Staff Exhibit No. 43, Dittmer Direct, p. 110).

Q. If APS received 100% rate recovery of short-term incentive compensation for Upper Management in Decision No. 69663, why is TEP only asking for 50% recovery for short-term incentive compensation for Upper Management?

A. TEP is proposing 50% recovery for Upper Management because TEP's proposal is then consistent with both Decision Nos. 69663 and 70665. The underlying rationale for including 100% of APS' short-term incentive compensation expense in rates per APS' Decision No. 69663 appears applicable to TEP. However, in Decision No. 70665, as well as Decision No. 70011 (UNS Gas), the Commission allowed only 50% recovery of "at risk" pay based on balancing the interests of retail customers and shareholders. In consideration of the cost recovery rationale underlying the APS, SWG and UNS Gas decisions, TEP believes it is appropriate to separate Upper Management, who may focus more on both retail customers and shareholders, from the remaining employees, who focus on daily operations and service to retail customers.

Q. Are there more recent rate case decisions for both SWG and APS?

A. Yes. However, both cases were settled and the treatment of the cash-based incentive compensation is not clear.

Q. Does the cash-based Short-Term Incentive Compensation program result in salaries and wages that exceed the market?

A. No. When the Short-Term Incentive Compensation is combined with the employees' base salaries, the total cash compensation approximates the median of the market, based on the most recent benchmark studies. The benchmarking information demonstrates that the amounts are reasonable.

G. **<u>Long-Term Incentive (Stock-Based) Compensation and Supplemental Executive Retirement Plan ("SERP").</u>**

Q. Consistent with reducing Upper Management's short-term incentive expense by 50%, is it reasonable for TEP to recover 50% of the expenses from the Company's SERP and Officer Long-Term (Stock-Based) Incentive Compensation program?

A. Yes. The Long-Term Incentive Compensation program promotes the financial strength of TEP, which benefits the retail customers by optimizing operational costs, providing access to capital needed to fund operations, and promotes employee retention. TEP believes that equity awards encourage ownership of stock by executive officers and helps hold executive officers accountable for the long-term impact of their actions, which is in line with the interests of retail customers. The vesting provisions applicable to the awards encourage a focus on long-term operating performance, link compensation expense to the achievement of multi-year financial results, and help to retain executive officers.

The SERP expense is reasonable as it allows the Company to consistently provide benefits to all eligible employees without imposing limitations on select employees. The SERP expense is prudent as it is part of the compensation package needed to attract and retain highly qualified upper management.

Q. Is TEP requesting any recovery of these expenses in this case?

A. No. While TEP believes that 50% of the SERP and Long-Term Incentive Compensation programs are reasonable and prudent for recovery from retail customers, for purposes of this rate case, TEP is not requesting recovery of these costs. TEP reserves the right to request recovery of up to 100% of these costs in a future rate case. No pro forma adjustment is necessary because long-term incentive compensation and SERP expense is recorded below the line.

H. Customer Care and Billing ("CC&B") Allocation.

Q. Please explain the CC&B Allocation Adjustment.

A. The CC&B system is used to maintain customer information for serving and billing our customers. The CC&B system is the customer information system used by TEP, UNS Gas and UNS Electric. The CC&B costs are allocated to TEP, UNS Gas and UNS Electric based on the number of customers in each company.

The pro forma adjustment for the CC&B Allocation adjusts recorded test year expenses for the following known and measurable changes:

- TEP implemented a new Meter Data Management ("MDM") system in 2011 to capture meter reading information which is used for billing. The adjustment reflects depreciation for the new MDM system.
- TEP's new maintenance and support contract with Cognizant Technology Solutions U.S. Corporation ("Cognizant") for the CC&B system results in additional annual costs of approximately $1.8 million (based on straight-line expense of the annual fixed amounts over the contract term.) Even after allocating Cognizant costs to UNS Gas and UNS Electric, the result increased TEP's test year expense. This adjustment reflects the known and measurable expenses that are necessary to support the reporting requirements under Electric Energy Efficiency Standards and allow for stability of the system for billing our customers. In addition to the known fees described above, Cognizant may provide additional support to meet our business needs, for which Cognizant will bill at hourly rates. As the amount of necessary future additional hourly services

is not currently known and measurable, we have not adjusted the test year operating expenses for these amounts.

I. PeopleSoft Allocation.

Q. Please explain the PeopleSoft Allocation Adjustment.

A. The PeopleSoft system is used for payroll processing and human resource management. The system is used for all employees of UNS Energy. PeopleSoft system costs are allocated to each of the UNS Energy entities based on each entity's relative number of employees.

The PeopleSoft Allocation Adjustment adjusts operating expenses for the test year to normalize the expense. In 2011, the PeopleSoft system was upgraded, resulting in higher O&M expense for 2011 than in 2010 or 2009. Upgrades to the PeopleSoft system are necessary to maintain the operating system and occur periodically. The adjustment also causes the test year to reflect an average of 2009, 2010 and 2011 annual PeopleSoft expense for TEP (after allocation to UNS Gas, UNS Electric and Southwest Energy Solutions, Inc.)

J. Depreciation Expense.

Q. Please explain your proposed Depreciation Expense Adjustment.

A. The depreciation adjustment is intended to reflect in cost of service an annualized level of depreciation expense based on the depreciable plant in rate base as of the end of the test year, and the proposed new depreciation rates appearing in the depreciation study prepared and sponsored by Dr. Ronald White of Foster and Associates.

Q. Why is this adjustment necessary?

A. The amount of depreciation expense recorded on TEP's books during the test year reflects less than a full year of depreciation for assets placed into service during the period and that are included in rate base. Moreover, it includes depreciation computed on assets retired during the test year, and thus, is not included in rate base. Finally, it reflects the existing depreciation rates approved in the Company's last rate case. For rate-making, the cost of service should view test year costs prospectively, adjusted for the effect of known and measurable changes. This adjustment produces an annual depreciation amount consistent with the depreciable plant in rate base, and the new depreciation rates from Dr. White's study that meet the definition of being known and measurable.

Q. How was the adjustment calculated?

A. The adjustment was calculated by first computing pro forma annualized depreciation expense, and then deducting recorded test year depreciation expense. For generation assets, pro forma annual depreciation was computed by multiplying the end-of-test year plant balance in rate base for each generating unit and related depreciable FERC plant account, by the respective newly-proposed depreciation rate sponsored by Dr. White. For distribution and general plant accounts, pro forma annual depreciation was computed using the composite depreciation or amortization rates established by Dr. White for each such account, and multiplied by the end-of-test year balance in rate base. For certain plant assets, a portion of depreciation is capitalized as part of the cost constructing new assets; thus, such amounts were excluded in the calculation. No transmission assets are included in rate base; thus, none are included in Dr. White's study, and none are reflected in this depreciation annualization adjustment.

Q. What changes affecting depreciation have occurred since the last TEP rate case?

A. One change relates to the expected cost of decommissioning generation assets and the corresponding effect on depreciation rates. At the time the last TEP rate case was filed, the generation portion of the Company's operations was not considered as being cost-of-service regulated under the tenants of Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation* ("FAS 71"), now more generally referred to as ASC980. Accordingly, the Company was not accruing for any end-of-service life costs associated with generation assets other than those few having legal removal obligations subject to the requirements of Statement of Financial Accounting Standards No. 143, *Asset Retirement Obligations* ("FAS 143"), now referred to as ASC410. In the TEP application in that last rate case, test year depreciation expense was annualized using newly-proposed rates supported by a study that reflected the recovery of capital costs only.

In settling that rate case, the link between the cost of generation service and the prices allowed to be charged therefore was reestablished, thereby placing the Company back under the requirements of ASC980 on the effective date of the Commission's approval of the 2008 Settlement Agreement. In connection therewith, the 2008 Settlement Agreement provided for annual depreciation expense that included $21.6 million for the accrual of the net cost of removal for generation assets. Since then, TEP has been accounting for depreciation on a bifurcated basis, with capital cost recoveries and negative net salvage (the difference between accrued and realized costs of removal and salvage proceeds) computed and tracked separately within the depreciation reserve. The depreciation study sponsored by Dr. White in this rate case presents bifurcated rates with the capital recovery and negative net salvage portions separately identified to facilitate future tracking and financial reporting.

Realizing that the aforementioned $21.6 million annual removal cost accrual approved for generation depreciation was intended merely to be a placeholder, and in anticipation of this rate case filing, as more fully described in the Direct Testimony of Company witness Mr. Mark Mansfield, TEP retained the services of outside consultants to perform studies for the purpose of developing estimates of removal costs for all generation assets, both fully-owned by TEP and those in which TEP has a partial ownership interest. The generation rates produced by Dr. White's current study reflect decommissioning cost estimates for all TEP generation. Neither the Company's asset retirement obligation ("ARO") assets nor obligations are included in rate base in this rate case. Moreover, the related asset depreciation and obligation accretion expenses are excluded from the cost of service in this rate case.

Q. Has TEP provided decommissioning studies in connection with a depreciation rate request in prior rate cases?

A. No. The decommissioning studies prepared for this rate case are the first such studies performed by TEP and submitted to the Commission for its review in connection with a depreciation rate request.

Prior to 1989, TEP did not reflect decommissioning costs in the rates used to depreciate generation assets. As part of a 1988 depreciation study, TEP conducted a survey of decommissioning costs implicit in the rates being used by regional utilities for depreciating their generation assets. Based on the results of the survey, as part of a rate case filing, TEP submitted a depreciation study that reflected decommissioning cost estimates of 15% of original plant costs for steam generation and 10% for gas turbines. Those cost estimates and the resulting depreciation rates were approved by the Commission in Decision No. 56659 issued in October 1989.

At the time TEP discontinued the application of ASC980 in 1999, the Company's generation depreciation rates included negative net salvage factors reflecting 17% of original cost for steam generation assets and 11% for gas turbines. With the discontinuation of applying ASC980 to generation assets and the adoption of ASC410, TEP ceased accruing costs of removal for generation assets, until the settlement in the last rate case.

The next decommissioning costs estimates were those prepared in connection with TEP's adoption of FAS 143, now referred to as ASC410, in 2003. New, updated studies of expected removal costs were performed for those TEP generation assets that had been identified as having legal removal obligations. Those included certain assets located at Sundt, SGS, and the Navajo, Four Corners, San Juan, and later Luna Generating Stations.

Q. Are there other changes that have impacted the depreciation rates?

A. Yes. Another change since the last TEP rate case, as mentioned earlier in my testimony and the Direct Testimony of Mr. Grant, is the Company's acquisition of Sundt Unit 4 in 2010. Such assets were previously operated by TEP under a capital lease agreement, with the lease assets and related leasehold improvements depreciated over the life of the corresponding capital lease. In previous rate cases, the Sundt Unit 4 capital lease was treated as an operating lease with rent expense based on average annual payments under the lease agreements included in operating expenses for rate-making. Now that the Company has acquired these generating assets, they are reflected in Dr. White's deprecation study as plant in service with a designated service life consistent with other TEP steam generation resources and an estimate of end-of service life removal costs.

Other changes impacting depreciation include a request to adopt amortization accounting for Account No. 391.2 - Network and Information Technology Equipment and the telecommunications assets residing in Account No. 397 - Communications Equipment, to be consistent with such treatment already approved by the Commission for TEP affiliates UNS Gas and UNS Electric. This is in recognition that the assets recorded in these two accounts are typically relatively low cost, rapid turnover items, making individual tracking unnecessarily time-consuming and costly. The remaining Energy Management System ("EMS") and Supervisory Control and Data Acquisition ("SCADA") Equipment in Account 397 will be segregated into a separate group within Account 397 and continue to be depreciated using the group method. TEP has also increased the number of vehicle categories in Account No. 392 - Transportation Equipment from six to ten, in recognition of the various types of vehicles and the manner in which they are used, tracked, and maintained.

Finally, as explained in the Direct Testimony of Mr. Grant, TEP is requesting a change in the period for amortizing leasehold improvements associated with the Springerville Unit 1 and Coal Handling Facilities leases. Historically, leasehold improvements have been amortized over the term of the related capital lease. These leasehold improvements have been amortized over a period ending with the lease expiration in 2015. As explained in Mr. Grant's testimony, TEP is requesting that the amortization period be extended to 2021. The depreciation rates sponsored by Dr. White reflect such extensions.

K. <u>Property Tax Expense.</u>

Q. Please explain the Property Tax adjustment.

A. The Property Tax adjustment is a pro forma adjustment to test-year operating expense to reflect the final, adjusted plant in service at the end of the test-year, using the 2013 statutory assessment ratio of 19.5%, and average property tax rates expected to be in effect for the 2012 property tax year. To the extent more current tax rate information becomes available during this rate case proceeding, the Company will update the property tax adjustment.

Q. For purposes of the annual filing with the Arizona Department of Revenue, a consolidated property tax return is filed. Please describe this filing and how the consolidated effects have been considered in this case.

A. TEP is included in a consolidated property tax filing that includes UNS Energy and all of its subsidiaries that own utility operating assets. Specifically, the 2012 property tax return includes utility plant owned by TEP, UNS Gas, UNS Electric and UniSource Energy Development Company. The taxes are based on a consolidated full cash value that considers the depreciated values and ages of all of the utility assets in the group. This consolidated value is then allocated to the specific tax districts in which each company operates, based on the original cost of each company's operating property in that tax district. The rates for each district are then applied to this allocated value.

For purposes of this adjustment, the filing of a consolidated return is not taken into consideration. The assessed value used in this case takes into consideration only the depreciated values of TEP's assets.

L. <u>Income Tax Expense.</u>

Q. Please explain the Income Tax Expense adjustment.

A. The Income Tax Expense adjustment is a pro forma adjustment to test-year operating expenses to reflect income taxes based on final adjusted operating revenues, operating expenses, and rate base. It is computed in two parts. The first part is pro forma current income tax expense, with 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 re-compute current tax expense based on adjusted test-year operating revenues and expenses as 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 Commission has traditionally used this synchronization methodology - and most recently approved its use for UNS Gas in Decision No. 71623 (April 14, 2010).

The second part of the income tax adjustment is deferred income tax expense. Deferred income taxes are computed on the Schedule M items representing timing differences for which TEP has obtained normalization rate-making authority from the Commission as previously described in my direct testimony.

Q. What is the adjustment to Deferred Income Tax Expense as a result of the basis adjustment associated with the IRC §48 Energy Credit?

A. As previously discussed in my direct testimony, the election to take the §48 Energy Credit on qualifying property requires a reduction in the basis of the qualifying property for purposes of calculating tax depreciation. The result of this basis reduction is that future tax depreciation deductions will be reduced by an amount equal to one-half of the §48 Energy Credit, or 15% of the basis of the qualifying property.

This basis reduction effectively reduces the value of the §48 Energy Credit from 30% of the cost of the asset (the amount of the unamortized rate-base reduction) to 24.75% (assuming a 35% tax rate applied to the 15% basis reduction). This loss of benefit is reflected as an increase to deferred income tax expense each year as the basis difference reverses through the book depreciation timing difference.

Q. What is the adjustment to Deferred Income Tax Expense for Excess Deferred State Income Taxes?

A. As previously discussed in my direct testimony, TEP proposes to reduce state deferred income tax expense (and the revenue requirement) for the excess deferred state income taxes associated with utility operations as the underlying timing differences reverse. These timing differences will start to reverse with the lower tax rate beginning in 2014. The rates in this case are expected to be in effect beginning in 2013, but no excess deferred state income tax expense will reverse in that year as the rate change begins in 2014. Deferred state income tax expense has been reduced by the average amount of excess deferred taxes expected to reverse in 2014 through 2016.

VI. <u>SUMMARY OF THE "E" SCHEDULES.</u>

Q. Are you supporting the "E" schedules in the Company's rate filing?

A. Yes. The "E" schedules were 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 FERC Uniform System of Accounts, as required by AAC R14-2-212.G.2.

Q. Have there been any significant changes to TEP's accounting policies or principles since its last rate case?

A. Yes. In the last rate case, TEP used a 2006 test year. The following are the significant changes to TEP's accounting policies or principles since test year 2006.

2007

Effective in the first quarter of 2007, TEP implemented ASC740, Income Taxes FIN 48 – *Accounting for Uncertainty in Income Taxes – An Interpretation of FAS 109.* See discussion at TEP's 2007 Form 10-K, Note 10. Income Taxes.

2008

Effective in the first quarter of 2008, TEP implemented ASC820, Fair Value Measurement, formerly known as FAS 157, *Fair Value Measurement.* Effective in the fourth quarter of 2008, TEP also applied ASC 82-10-15, formerly known as *FSP FAS 157-3 Determining the Fair Value of a Financial Asset When the Market for That Asset Is not Active – issued and effective October 2008.* See discussion at TEP's 2008 Form 10-K, Note 13. Fair Value Measurements.

In December 2008, as a result of the 2008 TEP Rate Order, TEP reapplied ASC980 Regulated Operations (then known as FAS 71) to its generation operations. In addition, in December 2008, TEP began deferring its mark-to-market adjustments as regulatory assets/liabilities for derivative instruments that are expected to be recovered through the PPFAC. TEP also reflected the Fixed CTC Revenues to be refunded as part of the PPFAC. See discussion at TEP's 2008 Form 10-K, Note 2. Regulatory Matters.

2009

TEP made the following adjustments:

- **Springerville Unit 1**

  In 2006, we recorded an investment in 14.14% of Springerville Unit 1 lease equity transaction as a lease restructuring. We subsequently determined that the transaction was best characterized as a purchase of an interest in a trust accounted for using equity method accounting. As a result, at June 30, 2009, TEP recorded a net increase to Net Income of less than $0.5 million after tax. The net adjustment recorded in June 2009 included: (i) additional depreciation expense of $4 million; (ii) a reduction of interest expense on capital leases of $2 million; and (iii) $3 million of equity in earnings which is included in Other Income on the income statement. In addition, TEP recorded: (i) a $19 million increase to capital lease assets; (ii) a $4 million increase to accumulated amortization; (iii) a $3 million increase to capital lease obligations; and (iv) an $11 million decrease to investment in lease debt.

Q. Have the financial statements been audited?

A. Yes. PricewaterhouseCoopers LLP (Independent Certified Public Accountants) audited the Company's financial statements, for calendar years 2011, 2010 and 2009.

Q. Please describe Schedule E-1.

A. Schedule E-1 contains the comparative balance sheets of TEP for the test year ending December 31, 2011, and the two prior calendar years ending December 31, 2010, and December 31, 2009.

Q. Please describe Schedule E-2.

A. This Schedule sets forth comparative income statements for the test year ending December 31, 2011, and the two prior calendar years ending December 31, 2010 and 2009. 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, 2011 and the two prior calendar years ending December 31, 2010 and 2009.

Q. Please describe Schedule E-4.

A. This Schedule reports the changes that occurred in stockholders' equity (deficit) during the period beginning January 1, 2009 and ending December 31, 2011. 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, 2011 and December 31, 2010, and the net changes therein during 2011, 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, 2011 and the two prior calendar years ending December 31, 2010 and 2009.

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, 2011 and the two prior calendar years ending December 31, 2010 and 2009.

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, 2011. The footnotes and other statistical data contained therein provide additional information to facilitate understanding of the remaining information contained in Schedules E.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT

KGK-1

TUCSON ELECTRIC POWER CO

FORM 10-K
(Annual Report)

Filed 02/28/12 for the Period Ending 12/31/11

Address	ONE SOUTH CHURCH AVENUE SUITE 100 TUCSON, AZ 85701
Telephone	520-571-4000
CIK	0000100122
SIC Code	4911 - Electric Services
Fiscal Year	12/31

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2011

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) 88 E. Broadway Boulevard Tucson, AZ 85701 (520) 571-4000	86-0786732
1-5924	**TUCSON ELECTRIC POWER COMPANY** (An Arizona Corporation) 88 E. Broadway Boulevard Tucson, AZ 85701 (520) 571-4000	86-0062700

Securities registered pursuant to Section 12(b) of the Exchange Act:

Registrant	Title of Each Class	Name of Each Exchange on Which Registered
UniSource Energy Corporation	**Common Stock, no par value**	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Exchange Act:

Registrant	Title of Each Class	Name of Each Exchange on Which Registered
Tucson Electric Power Company	**Common Stock, without par value**	**N/A**

Indicate by check mark if the registrant is a well known seasoned issuer, as defined in Rule 405 of the Securities Act of 1933.

UniSource Energy Corporation	Yes ☒	No ☐
Tucson Electric Power Company	Yes ☐	No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934 (Exchange Act).

UniSource Energy Corporation	Yes ☐	No ☒
Tucson Electric Power Company	Yes ☐	No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act 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.

UniSource Energy Corporation	Yes ☒	No ☐
Tucson Electric Power Company	Yes ☒	No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

UniSource Energy Corporation	Yes ☒	No ☐
Tucson Electric Power Company	Yes ☒	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, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

UniSource Energy Corporation	Large Accelerated Filer ☒ Smaller Reporting Company ☐	Accelerated Filer ☐	Non-accelerated filer ☐
Tucson Electric Power Company	Large Accelerated Filer ☐ Smaller Reporting Company ☐	Accelerated Filer ☐	Non-accelerated filer ☒

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

UniSource Energy Corporation	Yes ☐	No ☒
Tucson Electric Power Company	Yes ☐	No ☒

The aggregate market value of UniSource Energy Corporation voting Common Stock held by non-affiliates of the registrant was $1,361,485,759 based on the last reported sale price thereof on the consolidated tape on June 30, 2011.

At February 21, 2012, 37,956,169 shares of UniSource Energy Corporation Common Stock, no par value (the only class of Common Stock), were outstanding.

At February 21, 2012, 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 2012 Annual Meeting of Shareholders are incorporated by reference into Part III.

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DEFINITIONS

The abbreviations and acronyms used in the 2011 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 Mellon, successor trustee, as supplemented
1999 Settlement Agreement	TEP's Settlement Agreement approved by the ACC in November 1999 that provided for electric retail competition and transition asset recovery
2008 TEP Rate Order	A rate order issued by the ACC resulting in a new retail rate structure for TEP, effective December 1, 2008
ACC	Arizona Corporation Commission
AMT	Alternative Minimum Tax
AOCI	Accumulated Other Comprehensive Income
APS	Arizona Public Service Company
ARO	Asset Retirement Obligation
BART	Best Available Retrofit Technology
Base O&M	A non-GAAP financial measure that represents the fundamental level of operating and maintenance expense related to our business
Base Rates	The portion of TEP's and UNS Electric's Retail Rates attributed to generation, transmission, distribution costs and customer charge; and UNSGas' delivery costs and customer charge
BMGS	Black Mountain Generating Station
Btu	British thermal unit(s)
CCRs	Coal combustion residuals
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
CO2	Carbon dioxide
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
EE Standards	Electric and Gas Energy Efficiency Standards
Emission Allowance(s)	An allowance issued by the Environmental Protection Agency which permits emission of one ton of sulfur dioxide or one ton of nitrogenoxide; 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
EL Paso	El Paso Electric Company
EPNG	El Paso Natural Gas Company
ESP	Energy Service Provider
Express Line	A dedicated 345-kV transmission line from Springerville Unit 2 to TEP's retail service area
FERC	Federal Energy Regulatory Commission
Fixed CTC	Competition Transition Charge that was included in TEP's retail rate for the purpose of recovering TEP's TRA; approximately $58 million is being credited to customers through the PPFAC
Four Corners	Four Corners Generating Station
GAAP	Generally Accepted Accounting Principles
Gas EE Standards	Gas Utility Energy Efficiency Standards
GHG	Greenhouse gases
GWh	Gigawatt-hour(s)
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
IRS	Internal Revenue Service
kWh	Kilowatt-hour(s)
kV	Kilovolt(s)
LIBOR	London Interbank Offered Rate
Long-Term Wholesale Margin Revenues	A non-GAAP measure that demonstrates the underlying profitability of TEP's long-term wholesale sales contracts
Luna	Luna Energy Facility
Mark-to-Market Adjustments	Forward energy sales and purchase contracts that are considered to be derivatives and are adjusted monthly by recording unrealized gains and losses to reflect the market prices at the end of each month
Millennium	Millennium Energy Holdings, Inc., a wholly-owned subsidiary of UniSource Energy
MMBtu	Million British Thermal Units
Mortgage Bonds	Bonds issued under the 1992 Mortgage
MW	Megawatt(s)
MWh	Megawatt-hour(s)
Navajo	Navajo Generating Station
NERC	North American Electric Reliability Corporation
NOx	Nitrogen oxide
NTUA	Navajo Tribal Utility Authority
O&M	Operations and Maintenance Expense
PGA	Purchased Gas Adjuster, a retail rate mechanism designed to recover the cost of gas purchased for retail gas customers
Pima Authority	The Industrial Development Authority of the County of Pima
PNM	Public Service Company of New Mexico
PPA	Power Purchase Agreement
PPFAC	Purchased Power and Fuel Adjustment Clause
PV	Photovoltaic
RES	Renewable Energy Standard and Tariff
Reimbursement Agreement	Reimbursement Agreement dated as of December 14, 2010 among TEP as borrower and a group of financial institutions
Retail Margin Revenues	A non-GAAP financial measure that demonstrates the underlying revenue trend and performance of our core utility businesses.
Retail Rates	Rates designed to allow a regulated utility an opportunity to recover its reasonable operating and capital costs and earn a return on its utility plant in service
Rules	Retail Electric Competition Rules
Sabinas	Carboelectrica Sabinas, S. de R.L. de C.V., a Mexican limited liability company; prior to June 2009, Millennium owned 50% of Sabinas
San Carlos	San Carlos Resources Inc., a wholly-owned subsidiary of TEP
San Juan	San Juan Generating Station
SERP	Supplemental Executive Retirement Plan
SCR	Selective catalytic reduction
SES	Southwest Energy Solutions, a wholly-owned subsidiary of Millennium
SO2	Sulfur dioxide
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
Springerville Unit 4	Unit 4 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
Sundt Unit 4	Unit 4 of the H. Wilson Sundt Generating Station
SWG	Southwest Gas Corporation
TEP	Tucson Electric Power Company, the principal subsidiary of UniSource Energy
TEP Credit Agreement	Second Amended and Restated Credit Agreement between TEP and a syndicate of Banks, dated as of November 9, 2010 (as amended)
TEP Letter of Credit Facility	Letter of credit facility under the TEP Credit Agreement
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)
TRA	Transition Recovery Asset, a $450 million regulatory asset established in TEP's 1999 Settlement Agreement that was fully recovered in May 2008
Transwestern	Transwestern Pipeline Company
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
UniSource Credit Agreement	Second Amended and Restated Credit Agreement between UniSource Energy and a syndicate of banks, dated as of November 9, 2010 (as amended)
UniSource Energy	UniSource Energy Corporation
UNS Electric	UNS Electric, Inc., a wholly-owned subsidiary of UES
UNS Electric Term Loan	Four-year $30 million term loan agreement dated as of August 10, 2011.
UNS Gas	UNS Gas, Inc., a wholly-owned subsidiary of UES
UNS Gas/UNS Electric Revolver	Revolving credit facility under the Second 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 November 9, 2010 (as amended)
Valencia	Valencia power plant owned by UNS Electric
VEBA	Voluntary Employee Beneficiary Association
WAPA	Western Area Power Administration

PART I

This combined Form 10-K is being filed separately by UniSource Energy Corporation and Tucson Electric Power Company (collectively, the Registrants). Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. TEP does not make any representation as to information relating to any other subsidiary of UniSource Energy.

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 elsewhere 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 with no significant operations of its own. UniSource Energy's operating subsidiaries are separate legal entities with their own assets and liabilities. UniSource Energy owns the outstanding common stock of Tucson Electric Power Company (TEP), UniSource Energy Services, Inc. (UES), UniSource Energy Development Company (UED), and Millennium Energy Holdings, Inc. (Millennium).

Our business includes three primary business segments: TEP; UNS Gas, Inc. (UNS Gas); and UNS Electric, Inc. (UNS Electric). TEP is an electric utility serving the community of Tucson, Arizona. UES provides gas and electric service to more than 30 communities in northern and southern Arizona through its two operating subsidiaries, UNS Gas and UNS Electric.

Other subsidiaries include UED, which developed the Black Mountain Generating Station (BMGS) in northwestern Arizona in 2008. The facility, which includes two natural gas-fired combustion turbines, initially provided energy to UNS Electric through a power sales agreement. In July 2011, UNS Electric purchased BMGS from UED, leaving UED with no significant remaining assets. This transaction did not impact UniSource Energy's consolidated financial statements.

Millennium has existing investments in unregulated businesses that represented less than 1% of UniSource Energy's total assets as of December 31, 2011. We have no new investments planned for Millennium. Southwest Energy Solutions (SES) is a subsidiary of Millennium that provides supplemental labor and meter reading services to 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. TEP and UniSource Energy exchanged shares of stock in 1998, making TEP a subsidiary of UniSource Energy.

BUSINESS SEGMENT CONTRIBUTIONS

The table below shows the contributions to our consolidated after-tax earnings by our three business segments.

	2011	2010	2009
		-Millions of Dollars-	
TEP	$ 85	$ 108	$ 91
UNS Gas	10	9	7
UNS Electric	18	15	11
Other (1)	(3)	(19)	(3)
Consolidated Net Income	$ 110	$ 113	$ 106

(1) Includes: UniSource Energy parent company expenses; interest expense (net of tax) on UniSource Energy Convertible Senior Notes and on the UniSource Credit Agreement; Millennium; and UED.

See Note 3 for additional financial information regarding our business segments.

References in this report to "we" and "our" are to UniSource Energy and its subsidiaries, collectively.

Rates and Regulation of TEP, UNS Gas and UNS Electric

The Arizona Corporation Commission (ACC) regulates portions of TEP, UNS Gas and UNS Electric's utility accounting practices and energy rates. The ACC has authority over rates charged to retail customers, the issuance of securities, and transactions with affiliated parties. Our regulated utility Retail Rates for retail electric and natural gas service are determined on a "cost of service" basis. Retail Rates are designed to provide, after recovery of allowable operating expenses, an opportunity for our utility businesses to earn a reasonable return on rate base. Rate base is generally determined by reference to the original 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 increase rate base while depreciation and retirements of utility plant reduce rate base.

Retail Rates charged by TEP, UNS Gas and UNS Electric also include pass-through mechanisms that allow each utility to recover the actual costs of its fuel, transmission, and energy purchases.

The Federal Energy Regulatory Commission (FERC) regulates the terms and prices of transmission services and wholesale electricity sales, wholesale transport and purchases of natural gas and portions of our accounting practices. TEP and UNS Electric have FERC tariffs to sell power at market-based rates.

TE P

TEP was incorporated in the State of Arizona in 1963. TEP is the principal operating subsidiary of UniSource Energy. In 2011, TEP's electric utility operations contributed 77% 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 approximately 404,000 retail customers in southeastern Arizona. TEP's service territory covers 1,155 square miles and includes a population of approximately one million people in the greater Tucson metropolitan area in Pima County, as well as parts of Cochise County. TEP also sells electricity to other utilities and power marketing entities in the western United States.

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 economic conditions, seasonal weather patterns, demand side management (DSM) initiatives and increasing use of energy efficient products, and opportunities for customers to generate their own electricity.

Customer Base

The table below shows the percentage distribution of TEP's energy sales by major customer class over the last three years. Over the next several years, the retail energy consumption by customer class is expected to be similar to the historical distribution.

	2011	2010	2009
Residential	42%	42%	42%
Commercial	21%	21%	21%
Non-mining Industrial	23%	23%	23%
Mining	11%	12%	11%
Public Authority	3%	2%	3%

Local, regional, and national economic factors can impact the growth in the number of customers in TEP's service territory. In 2009, 2010 and 2011, TEP's average number of retail customers increased by less than 1% per year.

Two of TEP's largest retail customers are in the copper mining industry. TEP's kilowatt-hour (kWh) sales to mining customers depend on a variety of factors including the market price of copper, the Retail Rate paid by mining customers, and the mines' potential development of their own electric generation resources. TEP's kWh sales to mining customers increased by 0.3% in 2011 and 1.4% in 2010 as a result of increased production due to high copper prices.

We expect the number of TEP's retail customers to increase at a rate of approximately 0.5% in 2012 and approximately 0.9% in 2013.

Sales Volumes

Weak economic conditions and the implementation of energy efficiency programs have had a negative impact on electricity sales. In 2009 and 2010, TEP's retail kWh sales declined by 1.4% and 0.8%, respectively. In 2011, TEP's retail kWh sales were 0.4% above 2010 due in part to a 0.3% increase in the average number of retail customers. In 2012, we expect kWh sales to TEP's retail customers to be near the same level as 2011.

Energy Service Providers

Although the ACC's Retail Electric Competition Rules contemplated that TEP's retail customers may be eligible to choose an alternative energy service provider (ESP), portions of those Rules have been invalidated by the Arizona courts and there are no ESPs currently authorized to provide alternative retail electric service to TEP's customers. See *Rates and Regulation,* below for more information regarding the status of retail competition in Arizona.

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 *Generating and Other Resources, Purchases and Interconnections* , below.

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 generating capacity and energy (usually in the first, second and fourth calendar quarters), its wholesale sales consist primarily of two types of sales:

Long-Term Sales

Long-term wholesale sales contracts cover periods of more than one year. TEP typically uses its own generation to serve the requirements of its long-term wholesale customers. TEP currently has long-term contracts with three entities to sell energy:

- From January 1, 2012 through the end of the contract in May 2016, SRP is required to purchase 500,000 MWh of on-peak energy per year. TEP does not receive a demand charge and the price of energy is based on a discount to the Palo Verde Market Index. Prior to June 1, 2011, TEP received an annual demand charge of approximately $22 million.

- Navajo Tribal Utility Authority (NTUA) expires in December 2015. TEP serves the portion of NTUA's load that is not served by the authority's allocation of federal hydroelectric power. Over the last three years, sales to NTUA averaged 225,000 MWh per year. Since 2010, the price of 50% of the MWh sales to NTUA from June to September has been based on the Palo Verde Market Index. In 2011, approximately 12% of the total energy sold to NTUA was priced based on the Palo Verde Market Index. The remaining power sales occur at a fixed price under TEP's contract with NTUA.
- Tohono O'odham Utility Authority—2 MW, expires in 2014.

Short-Term Sales

Forward contracts commit TEP 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. TEP also engages in short-term sales by selling energy in the daily or hourly markets at fluctuating spot market prices and making other non-firm energy sales. All revenues from short-term wholesale sales offset fuel and purchased power costs and are passed through to TEP retail customers. TEP uses short-term wholesale sales as part of its hedging strategy to reduce customer exposure to fluctuating power prices. See *Rates and Regulation,* below.

See *Item 7. – Management's Discussion and Analysis of Financial Condition and Results of Operations, Tucson Electric Power Company, Factors Affecting Results of Operations,* for additional discussion of TEP's wholesale marketing activities.

GENERATING A ND OTHER RESOURCES

At December 31, 2011, TEP owned or leased 2,262 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	401	TEP	100.0	401
Springerville Station	2	Springerville, AZ	1990	Coal	403	TEP	100.0	403
San Juan Station	1	Farmington, NM	1976	Coal	340	PNM	50.0	170
San Juan Station	2	Farmington, NM	1973	Coal	340	PNM	50.0	170
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	555	PNM	33.3	185
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	4	Tucson, AZ	1967	Coal/Gas	156	TEP	100.0	156
Sundt Internal Combustion Turbines		Tucson, AZ	1972-1973	Gas/Oil	50	TEP	100.0	50
DeMoss Petrie		Tucson, AZ	1972	Gas/Oil	75	TEP	100.0	75
North Loop		Tucson, AZ	2001	Gas	95	TEP	100.0	95
Springerville Solar Station		Springerville, AZ	2002-2010	Solar	6	TEP	100.0	6
Community Solar Projects		Tucson, AZ	2010	Solar	7	TEP	100.0	7
Total TEP Capacity (2)								2,262

(1) Leased asset as of December 31, 2011.

(2) Excludes 1,009 MW of additional resources, which consist of certain capacity purchases and interruptible retail load. At December 31, 2011, total owned capacity was 1,861 MW and leased capacity was 401 MW.

Springerville Generating Station

Springerville Unit 1 is leased by TEP and Unit 2 is owned by San Carlos, a wholly-owned subsidiary of TEP. TEP's other interests in the Springerville Generating Station include 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 the remaining 50% interest in the Springerville Common Facilities.

In December 2011, TEP and the owner participants of the Springerville Unit 1 Leases completed a formal appraisal procedure to determine the fair market value purchase price. The formal appraisal process was completed in accordance with the Springerville Unit 1 lease agreements. The purchase price was determined to be $478 per kW of capacity. TEP has until September 2013 to give notice that it will exercise its purchase option, with the purchase occurring in January 2015. TEP can choose to exercise this option to purchase any or all of the lease interests not currently owned by TEP; TEP currently owns a 14% undivided interest in Springerville Unit 1. If TEP chooses to purchase all of the remaining interests in Springerville Unit 1 from the owner participants, the aggregate purchase price would be $159 million.

The Springerville Common Facilities Leases, which expire in 2017 and 2021, have optional fair market value renewal options as well as a fixed-price purchase provision. The fixed prices to acquire the leased interests in the Springerville Common Facilities are $38 million in 2017 and $68 million in 2021.

In 1984, TEP sold and leased back the Springerville Coal Handling Facilities. Since entering the lease, TEP purchased a 13% ownership interest in the Springerville Coal Handling Facilities. The terms of the Springerville Coal Handling Facilities Leases expire in 2015 but have optional fixed-rate renewal options if certain conditions are satisfied as well as a fixed-price purchase provision of $120 million.

See Note 6 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 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.

In 2010, TEP purchased 100% of the equity interest in the Sundt Unit 4 lease for approximately $51 million, redeemed the outstanding Sundt Unit 4 lease debt of $5 million, and terminated the lease agreement.

Renewable Energy Resources

<u>Owned Resources</u>

As of December 31, 2011, TEP's owned photovoltaic (PV) solar generating capacity totaled 13 MW. The Springerville Generating Station solar system, which is located near TEP's Springerville coal-fired facility in eastern Arizona, includes 43,380 PV modules, with a total capacity of 6 MW. TEP's remaining 7 MW of PV solar generating capacity is located in the city of Tucson.

<u>Power Purchase Agreements</u>

In order to meet the ACC's renewable energy requirements, TEP has power purchase agreements (PPAs) for 130 MW of capacity from solar resources, 50 MW of capacity from wind resources and 2 MW of capacity from a landfill gas generation plant. As of December 31, 2011, approximately 2 MW of contracted solar resources and 50 MW of contracted wind resources were operational. The remaining resources are expected to be developed over the next several years. The solar PPAs contain options that would allow TEP to purchase all or part of the related project at a future period. See *Rates and Regulation, Renewable Energy Standard and Tariff* below for more information.

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.

TEP typically uses generation from its gas-fired units, supplemented by purchased power, to meet the summer peak demands of its retail customers. Some of these PPAs are price-indexed to natural gas prices. Due to its increasing seasonal gas and purchased power usage, TEP hedges a portion of its total natural gas exposure with fixed price contracts for a maximum of three years. TEP also purchases energy in the daily and hourly markets to meet higher than anticipated demands, to cover unplanned generation outages, or when doing so is more economical than generating its own energy.

TEP is a member of a regional reserve-sharing organization and has reliability and power sharing relationships with other utilities. 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.

As a result of the Energy Policy Act of 2005, owners and operators of bulk power transmission systems, including TEP, are subject to mandatory reliability standards that are developed and enforced by the North American Electric Reliability Corporation (NERC) and subject to the oversight of the FERC. TEP periodically reviews its operating policies and procedures to ensure continued compliance with these standards.

Springerville Units 3 and 4

Springerville Units 3 and 4 are each approximately 400 MW coal-fired generating facilities that are operated, but not owned by TEP. These facilities are located at the same site as TEP's Springerville Units 1 and 2. The owners of Units 3 and 4 compensate TEP for operating the facilities and pay an allocated portion of the fixed costs related to the Springerville Common Facilities and Coal Handling Facilities. See *Item 7. – Management's Discussion and Analysis of Financial Condition and Results of Operations, Tucson Electric Power Company, Factors Affecting Results of Operations, Springerville Units 3 and 4* .

Peak Demand and Resources

Peak Demand	2011	2010	2009	2008	2007
			-MW-		
Retail Customers	2,334	2,333	2,354	2,376	2,386
Firm Sales to Other Utilities	322	340	385	394	369
Coincident Peak Demand (A)	2,656	2,673	2,739	2,770	2,755
Total Generating Resources	2,262	2,245	2,229	2,204	2,204
Other Resources (1)	1,009	799	781	966	785
Total TEP Resources (B)	3,271	3,044	3,010	3,170	2,989
Total Margin (B) – (A)	615	371	271	400	234
Reserve Margin (% of Coincident Peak Demand)	23%	14%	10%	14%	8%

(1) Other Resources include firm power purchases and interruptible retail and wholesale loads. Additional firm power purchases were made in 2009 and 2010 to displace more expensive owned gas generation.

Peak demand occurs during the summer months due to the cooling requirements of TEP's retail customers. Retail peak demand varies from year-to-year due to weather, economic conditions and other factors. TEP's retail peak demand declined from 2008 to 2010 due primarily to weak economic conditions and the implementation of energy efficiency programs.

The chart above shows the relationship over a five-year period between TEP's peak demand and its energy resources. TEP's total 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's reserve margin in 2011 was in compliance with reliability criteria set forth by the Western Electricity Coordinating Council, a regional council of NERC.

Forecasted retail peak demand for 2012 is 2,269 MW, compared with actual peak demand of 2,334 MW in 2011 when cooling degree days exceeded the ten-year average by 4%. TEP's 2012 estimated retail peak demand is based on normal weather patterns. TEP believes existing generation capacity and power purchase agreements are sufficient to meet expected demand in 2012.

Future Generating Resources

TEP will add generating resources and/or import capability to meet forecasted retail and firm wholesale load. TEP anticipates that additional import capacity and/or additional local peaking resources of 75 to 150 MW may be required by 2018. TEP expects to add approximately 5 MW of new solar PV resources in 2012.

FUEL SUPP LY

Fuel Summary

Fuel cost and usage information is provided below:

	Average Cost per MMBtu Consumed			Percentage of Total Btu Consumed		
	2011	2010	2009	2011	2010	2009
Coal	$ 2.42	$ 2.23	$ 2.11	92%	90%	90%
Gas	$ 5.20	$ 4.69	$ 4.51	8%	10%	10%
All Fuels	$ 2.65	$ 2.47	$ 2.34	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. More than 90% of TEP's coal supply is purchased under long-term contracts, which results in more predictable prices. The average cost per ton of coal, including transportation, for 2011, 2010 and 2009 was $46.64, $41.99, and $39.81, respectively .

Station	Coal Supplier	2011 Coal Consumption (tons in 000's)	Contract Expiration	Avg. Sulfur Content	Coal Obtained From (A)
Springerville	Peabody Coalsales	3,123	2020	0.9%	Lee Ranch Coal Co.
Four Corners	BHP Billiton	387	2016	0.8%	Navajo Indian Tribe
San Juan	San Juan Coal Co.	1,217	2017	0.8%	Federal and State Agencies
Navajo	Peabody Coalsales	529	2019	0.4%	Navajo and Hopi Indian Tribes
Sundt	Peabody Coalsales	265	2012	0.5%	Twentymile 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 operator, and sole owner (or lessee), of the Springerville Units 1 and 2 and Sundt Unit 4. The coal supplies for 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 Springerville Units 1 and 2 for their presently estimated remaining lives.

The coal supplies for Sundt are transported approximately 1,300 miles by railroad from Colorado. Prior to 2010, Sundt Unit 4 was predominantly fueled by coal; however, the generating station also can be operated with natural gas. Both fuels are combined with methane, a renewable energy resource, piped in from a nearby landfill. Since 2010, TEP has fueled Sundt Unit 4 with both coal and natural gas depending on which resource is most economic. In 2012, TEP expects to fuel Sundt Unit 4 with natural gas. See Note 4 for more information.

Generating Facilities Operated by Others

TEP also participates in jointly-owned coal-fired generating facilities at the Four Corners Generating Station (Four Corners), the Navajo Generating Station (Navajo) and the San Juan Generating Station (San Juan). Four Corners, which is operated by Arizona Public Service (APS), and San Juan, which is operated by PNM, are mine-mouth generating stations located adjacent to the coal reserves. Navajo, which is operated by SRP, obtains its coal supply from a nearby coal mine and a dedicated rail delivery system. 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 presently estimated lives of the stations.

Natural Gas Supply

TEP typically uses generation from its facilities fueled by natural gas, in addition to energy from its coal-fired facilities and purchased power, to meet the summer peak demands of its retail customers and local reliability needs. TEP purchases gas from Southwest Gas Corporation under a retail tariff for North Loop's 95 MWs of internal combustion turbines and receives distribution service under a transportation agreement for DeMoss Petrie, a 75 MW internal combustion turbine. TEP purchases capacity from El Paso Natural Gas Company (EPNG) for transportation from the San Juan and Permian Basins to its Sundt plant under a contract that expires in April 2013, with right-of-first-refusal for continuation thereafter. TEP also buys gas from third-party suppliers for Sundt and DeMoss Petrie.

TEP purchases gas transportation for Luna from EPNG from the Permian Basin to the plant site under an agreement effective through January 2017, with right-of-first-refusal for continuation thereafter. TEP purchases gas for its share of Luna from various suppliers in the Permian Basin region.

TRANSMISSION ACCESS

TEP has transmission access and power transaction arrangements with over 120 electric systems or suppliers. TEP also has various ongoing projects that are designed to increase access to the regional wholesale energy market and improve the reliability, capacity and efficiency of its existing transmission and distribution systems.

TEP is participating in the continuation of the 500 kV transmission line from the Pinal West substation to the Pinal Central substation. TEP is also in the process of obtaining permits to build a 40-mile 500-kV transmission line from the Pinal Central substation to the Tortolita substation northwest of Tucson to further enhance its ability to access the region's energy resources. TEP expects the transmission lines to be in service in 2014. As a result of these high-voltage transmission additions, TEP anticipates that its ability to import energy into its service territory should increase by at least 250 MW.

Tucson to Nogales Transmission Line

TEP and UNS Electric are parties to a project development agreement initiated in 2000 for the joint construction of a 60-mile 345kV transmission line from Tucson to Nogales, Arizona. The project development agreement was initiated in response to an order by the ACC to improve reliability to UNS Electric's retail customers in Nogales and surrounding Santa Cruz County by building a second transmission line to Nogales. TEP received approval from the ACC for construction along a specific route in 2002. However, due to an impasse with the US Forest Service, UNS Electric has taken alternative steps towards improving service reliability in the area.

As of December 31, 2011, TEP had capitalized $11 million related to the project, including $2 million of land and land rights. If TEP does not receive the required approvals or abandons the project, TEP believes that cost recovery is probable for prudent and reasonably incurred costs related to the project as a consequence of the ACC's requirement for a second transmission line serving Santa Cruz County.

RATES AND REGULATION

Purchased Power and Fuel Adjustment Clause

The PPFAC allows TEP to recover its fuel, transmission, and purchased power costs, including demand charges, and the prudent costs of contracts for hedging fuel and purchased power costs from its retail customers. The PPFAC consists of a forward component and a true-up component.

- The forward component is updated on April 1 of each year. The forward component is based on the forecasted fuel and purchased power costs for the 12-month period from April 1 to March 31 of the following year, less the base fuel, transmission, and purchased power costs embedded in Base Rates.
- The true-up component will reconcile any over/under collected amounts from the preceding 12-month period and will be credited to or recovered from customers in the subsequent year.
- For the 12 month period ending March 31, 2012, the PPFAC rate of 0.5 cents per kWh includes a forward component charge of 0.1 cents per kWh and the true-up component charge of 0.4 cents per kWh.

As part of the reconciliation of fuel and purchased power costs and PPFAC revenues, TEP credits, among other things, 100% of short-term wholesale revenues against the recoverable costs.

As part of the 2008 Rate Order, TEP was required to credit $58 million of previously collected revenues to customers through the PPFAC. As a result, the PPFAC charge has been zero since it became effective in January 2009. As of November 2011, the $58 million was fully refunded to customers and TEP began deferring the PPFAC eligible costs until a new PPFAC rate is approved by the ACC.

In February 2012, TEP filed its annual PPFAC update report with the ACC. TEP is requesting an increase in the total PPFAC rate from approximately 0.5 cents per kWh to 0.8 cents per kWh. The proposed PPFAC rate includes a forward component charge of approximately 0.3 cents per kWh and a true-up component charge of approximately 0.5 cents per kWh. TEP's proposed PPFAC rate, including the forward component, is expected to collect approximately $77 million of under-collected fuel and purchased power costs. If the ACC approves TEP's PPFAC filing, it is anticipated that the new PPFAC rate would be implemented on April 1, 2012.

Base Rate Increase Moratorium

TEP's Base Rates are frozen through December 31, 2012. TEP is prohibited from submitting an application for new Base Rates before June 30, 2012. The test year to be used in TEP's next Base Rate application must conclude no earlier than December 31, 2011.

Notwithstanding the Base Rate increase moratorium, Base Rates and adjustor mechanisms may be changed in emergency conditions beyond TEP's control if the ACC concludes such changes are required to protect the public interest. The moratorium does not preclude TEP from seeking rate relief in the event of the imposition of a federal carbon tax or related regulations.

Renewable Energy Standard and Tariff

The ACC's Renewable Energy Standard and Tariff (RES) requires TEP, UNS Electric and other affected utilities to increase their use of renewable energy each year until it represents at least 15% of their total annual retail energy requirements in 2025. Affected utilities must file annual RES implementation plans for review and approval by the ACC. The approved cost of carrying out those plans is recovered from retail customers through the RES surcharge. Any RES surcharge collections above or below the costs incurred to implement the plans are deferred and reflected in TEP's financial statements as a regulatory asset or liability.

In 2011, TEP spent $34 million on its 2011 RES implementation and met the 2011 renewable energy target of 3%. TEP expects to collect $30 million in surcharges from retail customers in 2012 to implement its RES plan and expects to meet the 2012 renewable energy target of 3.5%.

For more information, see *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Tucson Electric Power Company, Factors Affecting Results of Operations, Renewable Energy Standard and Tariff.*

Electric Energy Efficiency Standards and Decoupling

In August 2010, the ACC approved EE Standards designed to require TEP, UNS Electric and other affected electric utilities to implement cost-effective programs to reduce customers' energy consumption. In 2011, TEP estimates its programs saved energy equal to 1.4% of its 2010 sales. In 2012, the EE Standards target total kWh savings of 3.0% of 2011 sales. The EE Standards increase annually thereafter up to a targeted cumulative annual reduction in retail kWh sales of 22% by 2020.

In January 2012, TEP filed a modification to its Energy Efficiency Implementation Plan with the ACC. The proposal includes a request for an increase in the performance incentive based on TEP's ability to meet the EE targets for 2012 and for 2013. TEP's proposed annual performance incentive for 2012 and 2013 ranges from $6 million to $8 million. TEP expects the ACC to issue a decision on this matter in the first quarter of 2012.

The EE Standards can be met by new and existing DSM programs, direct load control programs and energy efficient building codes. The EE Standards provide for the recovery of costs incurred to implement DSM programs. TEP's programs and rates charged to customers for such programs are subject to annual approval by the ACC.

<u>Decoupling</u>

In December 2010, the ACC issued a policy statement recognizing the need to adopt rate decoupling or another mechanism to make Arizona's EE Standards viable. A decoupling mechanism is designed to encourage energy conservation by restructuring utility Retail Rates to separate the recovery of fixed costs from the level of energy consumed. The policy statement allows affected utilities to file rate decoupling proposals in their next general rate case. TEP expects to file its next general rate case on or after June 30, 2012.

Retail Electric Competition Rules

In 1999, the ACC approved the Retail Electric Competition Rules (Rules) that provided a framework for the introduction of retail electric competition in Arizona. Certain portions of the ACC Rules that enabled ESPs to compete in the retail market were invalidated by an Arizona Court of Appeals decision in 2005. In 2008, the ACC opened an administrative proceeding to address the Rules. Unless and until the ACC clarifies the Rules or authorizes alternative ESPs to provide retail electric service, and ESPs offer to provide energy in TEP's service area, it is not possible for TEP's retail customers to use alternative ESPs. We cannot predict what changes, if any, the ACC will make to the Rules.

TEP'S UTILITY OPERATING STATISTICS

	2011	2010	2009	2008	2007
Generation and Purchased Power – kWh (000)					
Remote Generation	10,005,127	9,077,032	9,134,183	10,438,864	11,001,318
Local Tucson Generation (Oil, Gas & Coal)	906,496	1,492,885	1,131,399	1,016,254	1,065,778
Purchased Power	2,686,918	2,759,912	3,677,925	3,077,619	1,713,125
Total Generation and Purchased Power	13,598,541	13,329,829	13,943,507	14,532,737	13,780,221
Less Losses and Company Use	794,171	768,819	780,529	638,302	625,073
Total Energy Sold	12,804,370	12,561,010	13,162,978	13,894,435	13,155,148
Sales – kWh (000)					
Residential	3,888,011	3,869,540	3,905,696	3,852,707	4,004,797
Commercial	1,972,526	1,963,469	1,988,356	2,034,453	2,057,982
Industrial	2,145,163	2,138,749	2,160,946	2,263,706	2,341,025
Mining	1,083,071	1,079,327	1,064,830	1,095,962	983,173
Public Authorities	243,336	240,703	250,915	255,817	247,430
Total – Electric Retail Sales	9,332,107	9,291,788	9,370,743	9,502,645	9,634,407
Electric Wholesale Sales	3,472,263	3,269,222	3,792,235	4,391,790	3,520,741
Total Electric Sales	12,804,370	12,561,010	13,162,978	13,894,435	13,155,148
Operating Revenues (000)					
Residential	$ 383,908	$ 372,212	$ 377,761	$ 351,079	$ 362,967
Commercial	223,621	217,032	219,694	211,639	213,364
Industrial	164,024	159,937	163,720	164,849	168,279
Mining	65,720	62,112	61,033	55,619	48,707
Public Authorities	20,024	19,128	19,865	19,146	18,332
RES and DSM	46,633	37,767	25,443	2,781	—
Other	—	—	—	415	4,822
Total – Electric Retail Sales	903,930	868,188	867,516	805,528	816,471
CTC To Be Refunded	—	—	—	(58,092)	—
Wholesale Revenue- Long-Term	41,056	55,653	48,249	57,493	55,788
Wholesale Revenue- Short-Term	72,798	71,435	84,410	197,754	126,732
California Power Exchange Provision for Wholesale Refunds	—	(2,970)	(4,172)	—	—
Transmission	16,392	20,863	18,974	17,173	14,842
Other Revenues	122,210	112,098	84,361	72,292	56,956
Total Operating Revenues	$ 1,156,386	$ 1,125,267	$ 1,099,338	$ 1,092,148	$ 1,070,789
Customers (End of Period)					
Residential	367,396	366,217	365,157	363,861	361,945
Commercial	36,203	35,877	35,759	35,432	34,759
Industrial	636	635	629	633	641
Mining	2	2	2	2	2
Public Authorities	62	62	61	61	61
Total Retail Customers	404,299	402,793	401,608	399,989	397,408
Average Retail Revenue per kWh Sold (cents)					
Residential	9.9	9.6	9.7	9.1	9.1
Commercial	11.3	11.1	11.0	10.4	10.4
Industrial and Mining	7.1	6.9	7.0	6.6	6.6
Average Retail Revenue per kWh Sold	9.7	9.3	9.3	8.5	8.5
Average Revenue per Residential Customer	$ 1,047	$ 1,018	$ 1,036	$ 968	$ 1,009
Average kWh Sales per Residential Customer	10,606	10,579	10,708	10,621	11,129

ENVIRONMENTAL MATTERS

Air and water quality, resource extraction, waste management and land use are regulated by federal, state and local authorities. TEP facilities are in substantial compliance with existing regulations.

Clean Air Act Requirements

TEP generating facilities are subject to Environmental Protection Agency (EPA) limits on the amount of sulfur dioxide (SO_2), nitrogen oxide (NOx) and other emissions released into the atmosphere. TEP capitalized $8 million in 2011, $18 million in 2010 and $24 million in 2009 in construction costs to comply with environmental requirements, including TEP's share of new pollution control equipment installed at San Juan described below. TEP expects to capitalize environmental compliance costs of $7 million in 2012 and $25 million in 2013.

TEP recorded operating expenses of $12 million in 2011, $14 million in 2010 and $13 million in 2009 related to environmental compliance. TEP expects to record $14 million in operating expenses related to environmental compliance in 2012. TEP may incur additional costs to comply with 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.

TEP has sufficient Emission Allowances to comply with acid rain SO_2 regulations.

EPA Information Request

TEP has submitted its response to the request received in 2010 from the EPA under Section 114 of the Clean Air Act for information regarding projects and operations at the Sundt Generating Station. TEP owns and operates all four units at Sundt. Units 1, 2 and 3 can be operated on either natural gas or diesel oil. Unit 4 can be operated on either natural gas or coal.

The EPA uses information obtained from such requests to determine if additional action is necessary. TEP can neither predict whether the EPA will take further action at Sundt nor project the impact of any such action.

Hazardous Air Pollutant Requirements

The Clean Air Act requires the EPA to develop emission limit standards for hazardous air pollutants that reflect the maximum achievable control technology. In 2009, the EPA entered into a consent order through which it agreed to develop rules establishing standards for the control of emissions of mercury and other hazardous air pollutants from electric generating units. The EPA issued the final rule in December 2011.

Navajo

Based on the EPA's final standards, mercury and particulate emission control equipment may be required at Navajo by 2015. TEP's share of the estimated capital cost of this equipment for Navajo is less than $1 million for mercury control and approximately $43 million if the installation of baghouses to control particulates is necessary.

Springerville

Based on the EPA's final standards, mercury emission control equipment may be required at Springerville by 2015. The estimated capital cost of this equipment for Springerville Units 1 and 2 is approximately $5 million. The annual operating cost associated with the mercury emission control equipment is expected to be approximately $3 million.

San Juan

Current emission controls at San Juan are expected to be adequate to achieve compliance with the EPA's final standards.

Sundt

TEP does not anticipate the final EPA rule will have a material impact on TEP's capital expenditures related to Sundt Unit 4.

Four Corners

Based on the EPA's final standards, mercury emission control equipment may be required at Four Corners by 2015. The estimated capital cost of this equipment is less than $1 million. The annual operating cost associated with the mercury emission control equipment is expected to be less than $1 million.

Climate Change

In 2007, the Supreme Court ruled in Commonwealth of Massachusetts, et al. v. EPA that carbon dioxide (CO_2) and other greenhouse gases (GHGs) are air pollutants under the Clean Air Act. In 2009, the EPA issued a final Endangerment Finding stating that GHGs endanger public health and welfare. The EPA issued final GHG regulations for new motor vehicles in 2010, triggering GHG permitting requirements for power plants under the Clean Air Act. As of January 2, 2011, air quality permits for new sources and modifications of existing sources must include an analysis for GHG controls. In the near term, based on our current construction plans, we do not expect the new permitting requirements to impact TEP or UNS Electric.

While the debate over the direction of domestic climate policy continues on the national level, several states have developed state-specific policies or regional initiatives to reduce GHG emissions. In 2007, the governors of several western states, including the then-governor of Arizona, signed the Western Regional Climate Action Initiative (the Western Climate Initiative) which directed their respective states to develop a regional target for reducing greenhouse gases. The states in the Western Climate Initiative announced a target of reducing greenhouse gas emissions by 15% below 2005 levels by 2020. In 2008, the Western Climate Initiative participants submitted their design recommendation for the Western Climate Initiative cap-and-trade program for greenhouse gas emissions, with an implementation date set for 2012.

In 2010, New Mexico adopted regulations limiting GHG emissions from power plants and providing for participation in the Western Climate Initiative. Several parties filed petitions to repeal those regulations and the New Mexico Environmental Improvement Board held hearings on the repeal petitions in November and December 2011. In February 2012, the New Mexico Environmental Improvement Board repealed some, but not all, of the GHG regulations and will deliberate on the repeal of the remaining regulations in March 2012. We cannot predict if, or when, the remaining regulations will impact the generating output or cost of operations at San Juan and Luna.

Based on the competing proposals to regulate GHG emissions by federal, state, and local regulatory and legislative bodies and uncertainty in the regulatory and legislative processes, the scope of such requirements and initiatives and their effect on our operations cannot be determined at this time.

Regional Haze Rules

The EPA's regional haze rules require emission controls known as Best Available Retrofit Technology (BART) for certain industrial facilities emitting air pollutants that reduce visibility. The rules call for all states to establish goals and emission reduction strategies for improving visibility in national parks and wilderness areas and to submit a state implementation plan to the EPA for approval. Navajo and Four Corners are located on the Navajo Indian Reservation and therefore are not subject to state regulatory jurisdictions. The EPA is the lead regulatory agency for these plants in terms of regional haze planning.

Compliance with the EPA's BART determinations, coupled with the financial impact of future climate change legislation, other environmental regulations and other business considerations, could jeopardize the economic viability of the San Juan, Four Corners and Navajo plants or the ability of individual participants to meet their obligations and maintain participation in these plants. TEP cannot predict the ultimate outcome of these matters.

San Juan

In August 2011, EPA Region VI issued a Federal Implementation Plan (FIP) establishing new emission limits for NOx, SO_2 and sulfuric acid emissions at the San Juan Generating Station. The FIP requires the installation of Selective Catalytic Reduction (SCR) technology with sorbent injection on all four units within five years in order to reduce NOx and control sulfuric acid emissions. San Juan is able to meet the FIP's SO_2 limit with current emissions control equipment. Based on two cost analyses commissioned by PNM, TEP's share of the cost to install SCR with sorbent injection is estimated to be between $180 and $200 million.

In September 2011, PNM filed a petition to review the Federal Implementation Plan with the 10th Circuit Court of Appeals challenging various aspects of that plan. In addition, PNM filed a request with the EPA to stay the five-year installation timeframe for environmental upgrades ordered by the Federal Implementation Plan until the 10th Circuit considers and rules on the petition to review.

In October 2011, PNM filed a Petition for Reconsideration of the Federal Implementation Plan. PNM also filed a Request to Stay the effective date of the final BART Federal Implementation Plan under the Clean Air Act with the EPA. In November 2011, PNM filed with the 10th Circuit a Motion to Stay the Federal Implementation Plan. WildEarth Guardians, Dine Citizens against Ruining our Environment, National Parks Conservation Association, New Energy Economy, San Juan Citizens Alliance and Sierra Club were granted leave to intervene in PNM's petition to review in the 10th Circuit. Neither the Petition in the 10th Circuit, nor the Petition for Reconsideration by the EPA delays the implementation timeframe unless a stay is granted. WildEarth Guardians filed a separate appeal against the EPA challenging the five-year, rather than three-year, implementation schedule. PNM was granted leave to intervene in that appeal.

In October 2011, Governor Susana Martinez of New Mexico and the New Mexico Environment Department filed a Petition for Review of the EPA's final Federal Implementation Plan determination in the 10th Circuit and a Petition for Reconsideration of the rule with the EPA. In November 2011, the New Mexico Governor and Environment Department filed a motion with the 10th Circuit to stay the rule. These appeals and motions are all currently pending.

Four Corners

In February 2011, the EPA supplemented the proposed FIP for the BART determination at Four Corners that it had originally issued in 2010. If approved, the revised plan would require the installation of SCR on Units 4 and 5 by 2018. TEP's estimated share of the capital costs to install SCR is approximately $35 million.

Navajo

The EPA is expected to issue a proposed rule establishing the BART for Navajo following the consideration of a report by the National Renewable Energy Laboratory (NREL) in partnership with the Department of the Interior and the Department of Energy. The report addresses potential energy, environmental and economic issues related to compliance with the regional haze rule. The report was submitted to the EPA in January 2012. A final BART rule is expected later in 2012. If the EPA determines that SCR is required at Navajo, the capital cost impact to TEP is estimated to be $42 million. In addition, the installation of SCR at Navajo could increase the plant's particulate emissions, necessitating the installation of baghouses. If baghouses are required, TEP's estimated share of the capital expenditure for the required baghouses would be approximately $43 million. The cost of required pollution controls will not be known until final determinations are made by the regulatory agencies. TEP anticipates that if the EPA finalizes a BART rule for Navajo that requires SCR, the owners would have five years to achieve compliance.

Coal Combustion Residuals

In 2010, the EPA published its proposed regulations governing the handling and disposal of coal ash and other coal combustion residuals (CCRs). The EPA has proposed regulating CCRs as either non-hazardous solid waste or hazardous waste. The hazardous waste alternative would require additional capital investments and operational costs associated with storage and handling at plants and transportation to the disposal locations. Both the hazardous waste and non-hazardous solid waste alternatives would require liners for new ash landfills or expansions to existing ash landfills. The rules will apply to CCRs produced by all of TEP's coal-fired generating assets. San Juan may also be subject to separate regulations being drafted by the Office of Surface Mining Reclamation and Enforcement because it disposes of CCRs in surface mine pits.

The EPA has not yet indicated a preference for an alternative. Each option would allow CCRs to be beneficially reused or recycled as components of other products. The EPA has indicated that it will issue a final rule by the end of 2012. The financial impact of this rulemaking to TEP, if any, cannot be determined at this time.

Ozone National Ambient Air Quality Standard

In September 2011, President Obama ordered the EPA to withdraw its reconsideration of the 2008 National Ambient Air Quality Standard for Ozone. The ozone standard is scheduled to be updated in 2013 as required by the Clean Air Act.

UNS GAS

SERVICE TERRITORY AND CUSTOMERS

UNS Gas is a gas distribution company serving approximately 148,000 retail customers in Mohave, Yavapai, Coconino, and Navajo counties in northern Arizona, as well as Santa Cruz County in southeastern Arizona. These counties comprise approximately 50% of the territory in the state of Arizona, with a population of approximately 700,000. UNS Gas' customer base is primarily residential. Sales to residential customers provided approximately 60% of total revenues in 2011, while sales to other retail customer classes accounted for about 36% of total revenues.

UNS Gas' annual retail customer growth rate was less than 1% from 2009 through 2011. In 2012, we expect UNS Gas' retail customer base to increase by less than 1%.

GAS SUPPLY AN D TRANSMISSION

UNS Gas directly manages its gas supply and transportation contracts. The market price for gas varies based upon the period during which the commodity is purchased and is affected by weather, supply issues, the economy and other factors. UNS Gas hedges its gas supply prices by entering into fixed price forward contracts and financial swaps at various times during the year to provide more stable prices to its customers. These purchases and hedges 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 EPNG and Transwestern Pipeline Company (Transwestern) interstate pipeline systems under firm transportation agreements with combined capacity sufficient to meet UNS Gas' 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 and also the Griffith Power Plant in Mohave County.

UNS Gas signed a separate agreement with Transwestern for transportation capacity rights on the Phoenix Lateral Extension Line. The 15-year agreement began in 2009, when construction of that pipeline was completed. UNS Gas' average daily capacity right is 126,100 therms per day, with an average of 221,900 therms per day in the winter season (November through March).

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 REGUL ATION

2011 UNS Gas Rate Filing

Due to increases in capital and operating costs, UNS Gas filed a general rate case with the ACC in April 2011 requesting higher Base Rates. The proposed Retail Rates include a higher fixed service charge and a decoupling mechanism to assist in recovering the company's authorized fixed costs under the EE Standards. The table below summarizes UNS Gas' request.

Test year – 12 months ended Dec. 31, 2010	Initial Request by UNS Gas
Original cost rate base	$184 million
Revenue deficiency	$5.6 million
Total rate increase (over test year revenues)	3.8%
Cost of equity	10.5%
Actual capital structure	51% equity / 49% debt
Weighted average cost of capital	8.7%

In January 2012, the ACC Staff filed testimony recommending a Base Rate increase of $2.7 million as well as a mechanism to enable UNS Gas to recover lost fixed-cost revenues as a result of implementing the ACC's EE Standards. In February 2012, UNS Gas filed testimony indicating that management is willing to agree with ACC Staff's recommendations in the context of this rate proceeding. Hearings before an ACC administrative law judge concluded in February 2012. UNS Gas expects the ACC to issue a final order in the second quarter of 2012. If the proposed Base Rate increase is approved, UNS Gas indicated that it would file a proposal with the ACC requesting to return the over-collected PGA bank balance to customers. See *Purchased Gas Adjustor (PGA),* below, for more information.

2010 UNS Gas Rate Order

Effective April 2010, UNS Gas implemented a Base Rate increase of $3 million, or 2%.

Purchased Gas Adjustor (PGA)

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 monthly gas and transportation costs and the rolling 12-month average cost of gas and transportation is deferred and recovered or returned to customers through the PGA mechanism.

The PGA mechanism has two components, the PGA factor and the PGA surcharge or surcredit. The PGA factor is a mechanism that calculates the twelve-month rolling weighted average gas cost and automatically adjusts monthly, subject to limitations on how much the price per therm may change in a 12-month period. The annual cap on the maximum increase in the PGA factor is $0.15 per therm in a 12-month period.

At any time UNS Gas' PGA balancing account, called the PGA bank balance, is under-recovered, UNS Gas may request a PGA surcharge with the goal of collecting the amount deferred from customers over a period deemed appropriate by the ACC. When the PGA bank balance reaches an over-collected balance of $10 million on a billed-to-customers basis, UNS Gas is required to make a filing with the ACC to determine how the over-collected balance should be returned to customers. On December 31, 2011, the PGA bank balance was over-collected by $8 million on a billed-to-customers basis.

Gas Utility Energy Efficiency Standards and Decoupling

In August 2010, the ACC approved new Gas Utility Energy Efficiency Standards (Gas EE Standards) designed to require UNS Gas and other affected utilities to implement cost-effective DSM programs. In 2011, the Gas EE Standards targeted total retail therm savings equal to 0.5% of 2010 sales; UNS Gas estimates its total savings in 2011 were 0.25%. Targeted savings increase annually in subsequent years until they reach a cumulative annual reduction in retail therm sales of 6% by 2020.

The Gas EE Standards can be met by: new and existing DSM programs, renewable energy technology that displaces gas, and by a portion of energy efficient building codes. The Gas EE Standards provide for the recovery of costs incurred to implement DSM programs. UNS Gas' DSM programs and Retail Rates charged to customers for these programs are subject to ACC approval.

In December 2010, the ACC approved a policy statement recognizing the need to adopt rate decoupling or another mechanism to make Arizona's Gas EE Standards viable. For more information about decoupling, see *TEP, Rates and Regulation, Electric Energy Efficiency Standards and Decoupling* , above.

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' facilities are in substantial compliance with existing regulations. See *Item. 1 – Business, TEP, Environmental Matters* , for more information.

UNS ELECTRIC

SERVICE TERRITORY AND CUSTOMERS

UNS Electric is a vertically integrated electric utility company serving approximately 91,000 retail customers in Mohave and Santa Cruz counties. These counties have a combined population of approximately 240,000. The average number of retail customers grew by less than 1% in 2009, 2010 and 2011. We estimate that UNS Electric's retail customer base will increase by less than 1% in 2012. UNS Electric's customer base is primarily residential, with some small commercial and both light and heavy industrial customers. Peak demand for 2011 was 438 MW.

POWER SUPPLY AND TRANSMISSION

Purchased Energy

UNS Electric relies on a portfolio of long, intermediate and short-term purchases to meet customer load requirements.

Generating Resources

UNS Electric owns and operates Black Mountain Generating Station (BMGS), a 90 MW gas-fired facility located near Kingman, Arizona. In July 2011, UNS Electric purchased BMGS from UED. UNS Gas purchases and transports natural gas to BMGS for UNS Electric under long-term natural gas transportation and sales agreements. See *Rates and Regulation, 2010 UNS Electric Rate Order* , below for more information.

UNS Electric also 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 62 MW of peaking resources. The facility is directly interconnected with the distribution system serving the city of Nogales and the surrounding areas.

Renewable Energy Resources

UNS Electric has agreed to purchase the output of a combined wind farm and solar generating facility located near Kingman. The above-market cost of energy purchased through the 20-year PPA will be recovered through the RES surcharge. For more information see *Rates and Regulation, Renewable Energy Standard and Tariff* below.

Future Generating Resources

UNS Electric invested $5 million in 2011 in company-owned solar PV capacity and expects to invest approximately $5 million annually from 2012 through 2014 to build about 1.25 MW per year in company-owned solar PV capacity. See *Item 7. – Management's Discussion and Analysis of Financial Condition and Results of Operations, UNS Electric, Factors Affecting Results of Operations, Renewable Energy Standard and Tariff* for more information.

Transmission

UNS Electric imports the power generated at BMGS into its Mohave County and Santa Cruz County service territories over Western Area Power Administration's (WAPA) transmission lines. UNS Electric has a network transmission service agreement for its primary transmission capacity with WAPA for the Parker-Davis system that expires in August 2016. UNS Electric also has a long-term electric point-to-point transmission capacity agreement with WAPA for the Southwest Intertie system that expires in June 2016.

UNS Electric plans to upgrade the existing 115 kV transmission line serving Santa Cruz County to 138 kV by October 2014 to improve service reliability. This upgrade is included in UNS Electric's current capital expenditures forecast. See *Item 7. – Management's Discussion and Analysis of Financial Condition and Results of Operations, UNS Electric, Liquidity and Capital Resources* for more information.

RATES AND REGULATION

2010 UNS Electric Rate Order

In 2010, the ACC authorized a Base Rate increase of $7.4 million, or 4%, effective October 1, 2010.

The 2010 UNS Electric Rate Order approved UNS Electric's purchase of BMGS from UED, subject to FERC approval and other conditions. FERC approved the purchase in June 2011.

The 2010 UNS Electric Rate Order also approved a plan for UNS Electric to invest $5 million each year from 2011 through 2014 in solar projects that would be owned by UNS Electric. See *Item 7. – Management's Discussion and Analysis of Financial Condition and Results of Operations, UNS Electric, Factors Affecting Results of Operations, Renewable Energy Standard and Tariff* , for more information.

In compliance with the 2010 Rate Order, UNS Electric expects to file a rate case in the second half of 2012.

Purchased Power and Fuel Adjustment Clause

The PPFAC allows UNS Electric to recover its fuel, transmission, and purchased power costs, including demand charges, and the prudent costs of contracts for hedging fuel and purchased power costs from its retail customers. The PPFAC consists of a forward component and a true-up component.

- The forward component is updated on June 1 of each year. The forward component is based on the forecasted fuel, transmission, and purchased power costs for the 12-month period from June 1 of the current year to May 31 of the following year, less the base fuel, transmission, and purchased power costs embedded in Base Rates. The cap on the PPFAC forward component, over the 6.77 cents per kWh in Base Rates, is 1.845 cents per kWh.
- The true-up component will reconcile any over/under collected amounts from the preceding 12 month period and will be credited to or recovered from customers in the subsequent year.

Renewable Energy Standard and Tariff

The ACC's RES requires UNS Electric, TEP and other affected utilities to increase their use of renewable energy each year until it represents at least 15% of their total annual retail energy requirements in 2025. Affected utilities must file annual RES implementation plans for review and approval by the ACC. The approved costs of carrying out those plans are recovered from retail customers through the RES surcharge. Any surcharge collections above or below the costs incurred to implement the plans are deferred and reflected in UNS Electric's financial statements as a regulatory asset or liability.

In 2011, UNS Electric spent $5 million on RES implementation and met the 2011 renewable energy target of 3%. UNS Electric expects to collect $8 million in surcharges from retail customers in 2012 to implement its RES plan and expects to meet the 2012 renewable energy target of 3.5%.

For more information see *Power Supply and Transmission* , *Renewable Energy Resources,* above, and *Item 7. Management's Discussion and Analysis, UNS Electric, Factors Affecting Results of Operations, Renewable Energy Standard and Tariff.*

Energy Efficiency Standards and Decoupling

In 2010, the ACC approved EE Standards designed to require UNS Electric, TEP, and other affected electric utilities to implement cost effective DSM programs. For more information, see *TEP, Rates and Regulation, Electric Energy Efficiency Standards and Decoupling* , above.

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 its facilities are in substantial compliance with all existing regulations and will be in compliance with expected environmental regulations. See *Item. 1 – Business, TEP, Environmental Matters* , for more information.

OTHER NON-REPORTABLE SEGMENTS

Millenniu m

As of December 31, 2011, Millennium had assets of $20 million including a $15 million note receivable (see *Sabinas* below), and cash and cash equivalents of $5 million. In total, Millennium's assets represented less than 1% of UniSource Energy's total consolidated assets. See *Item 7. – Management's Discussion and Analysis of Financial Condition and Results of Operations, Other Non-Reportable Business Segments,* for more information.

Sabinas

In 2009, Millennium sold its 50% interest in Sabinas and recorded a $6 million pre-tax gain on the sale.

Millennium received an upfront $5 million cash payment in January 2009. Other key terms of the transaction included a three-year, 6% interest-bearing, collateralized $15 million note, which matures in June 2012.

SES

SES, a wholly owned subsidiary of Millennium, provides electrical contracting and meter reading services in Arizona, as well as other services at the Springerville Generating Station.

EMPLOYEES (As of December 31, 2011)

TEP had 1,391 employees, of which approximately 51% are represented by the International Brotherhood of Electrical Workers (IBEW) Local No. 1116. A collective bargaining agreement between the IBEW and TEP expires in January 2013.

UNS Gas had 187 employees, of which 108 employees were represented by IBEW Local No. 1116 and 5 employees were represented by IBEW Local No. 387. The agreements with the IBEW Local No. 1116 and No. 387 expire in June 2012 and February 2014, respectively.

UNS Electric had 154 employees, of which 27 employees were represented by the IBEW Local No. 387 and 96 employees were represented by the IBEW Local No. 769. The existing agreements with the IBEW Local No. 387 and No. 769 expire in February 2014 and June 2013, respectively.

SES had 272 employees, of which approximately 96% are represented by unions. Of the employees represented by unions, 236 are represented by IBEW Local No. 1116 and 25 by IBEW Local No. 570; these agreements expire on December 31, 2012, and May 31, 2012, respectively.

EXECUTIVE OFFICERS OF THE REGISTRANTS

Executive Officers – UniSource Energy and TEP

Executive Officers of UniSource Energy and TEP, who are elected annually by UniSource Energy's Board of Directors and TEP's Board of Directions, respectively, are as follows:

Name	Age	Position(s) Held	Executive Officer Since
Paul J. Bonavia	60	Chairman and Chief Executive Officer	2009
David G. Hutchens	45	President	2007
Michael J. DeConcini	47	Senior Vice President, Operations	1999
Kevin P. Larson	55	Senior Vice President and Chief Financial Officer(1)	2000
Philip J. Dion III	43	Vice President, Public Policy	2008
Kentton C. Grant	53	Vice President, Finance and Rates(2)	2007
Todd C. Hixon	45	Vice President and General Counsel	2011
Arie Hoekstra	64	Vice President, Generation	2007
Karen G. Kissinger	57	Vice President, Controller and Chief Compliance Officer	1998
Thomas A. McKenna	63	Vice President, Engineering	2007
Catherine E. Ries	52	Vice President, Human Resources	2007
Herlinda H. Kennedy	50	Corporate Secretary	2006

(1) Mr. Larson is also Treasurer at UniSource Energy.

(2) Mr. Grant is also Treasurer at TEP.

Paul J. Bonavia Mr. Bonavia has served as Chairman and Chief Executive Officer of UniSource Energy and TEP since January 2009; he also served as President from January 2009 to December 2011. Prior to joining UniSource Energy, Mr. Bonavia served as President of the Utilities Group of Xcel Energy. Mr. Bonavia previously served as President of Xcel Energy's Commercial Enterprises business unit and President of the company's Energy Markets unit.

David G. Hutchens Mr. Hutchens has served as President of UniSource Energy and TEP since December 2011. In March 2011, Mr. Hutchens was named Executive Vice President of UniSource Energy and TEP. In May 2009, Mr. Hutchens was named Vice President of Energy Efficiency and Resource Planning. In January 2007, Mr. Hutchens was elected Vice President of Wholesale Energy at UniSource Energy and TEP. Mr. Hutchens joined TEP in 1995.

Michael J. DeConcini Mr. DeConcini has served as Senior Vice President, Operations of UniSource Energy since May 2010 and Senior Vice President and Chief Operating Officer of TEP from May 2009 to December 2011 when his title at TEP was changed to Senior Vice President, Operations. Mr. DeConcini joined TEP in 1988 and 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.

Kevin P. Larson Mr. Larson has served as Senior Vice President and Chief Financial Officer of UniSource Energy and TEP since September 2005. Mr. Larson is also Treasurer of UniSource Energy. Mr. Larson joined TEP in 1985 and thereafter held various positions in its finance department and investment subsidiaries. He was elected Treasurer in August 1994 and Vice President in March 1997. In October 2000, he was elected Vice President and Chief Financial Officer.

Philip J. Dion III Mr. Dion has served as Vice President of Public Policy of UniSource Energy and TEP since April 2010. Mr. Dion joined UniSource Energy in February 2008 as Vice President of Legal and Environmental Services. Prior to joining UniSource Energy, Mr. Dion was chief of staff and chief legal advisor to Commissioner Marc Spitzer of the FERC. Mr. Dion previously worked in various roles at the ACC, including as an administrative law judge and as an advisor to Mr. Spitzer, prior to his appointment to FERC.

Kentton C. Grant	Mr. Grant has served as Vice President of Finance and Rates of UniSource Energy and TEP since January 2007. Mr. Grant also serves as Treasurer of TEP. Mr. Grant joined TEP in 1995.
Todd C. Hixon	Mr. Hixon has served as Vice President and General Counsel of UniSource Energy and TEP since May 2011. Mr. Hixon joined TEP's legal department in 1998 and served in a variety of capacities, most recently serving as Associate General Counsel.
Arie Hoekstra	Mr. Hoekstra has served as Vice President of Generation of UniSource Energy and TEP since January 2007. Mr. Hoekstra joined TEP in 1979 and thereafter served in various positions at TEP's generating stations in Tucson and Springerville.
Karen G. Kissinger	Ms. Kissinger has served as Vice President, Controller and Principal Accounting Officer of UniSource Energy and TEP since January 1998 and has served as Chief Compliance Officer since 2003. Ms. Kissinger joined TEP as Vice President and Controller in January 1991.
Thomas A. McKenna	Mr. McKenna has served as Vice President of Engineering of UniSource Energy and TEP since January 2007. Mr. McKenna joined Nations Energy Corporation (a wholly-owned subsidiary of Millennium) in 1998.
Catherine E. Ries	Ms. Ries has served as Vice President of Human Resources of UniSource Energy and TEP since June 2007. Prior to joining UniSource Energy, Ms. Ries worked for Clopay Building Products, a division of Griffon Corporation, from 2000 to 2007, and held the position of Vice President of Human Resources.
Herlinda H. Kennedy	Ms. Kennedy has served as Corporate Secretary of UniSource Energy and TEP since September 2006. Ms. Kennedy joined TEP in 1980 and was named assistant Corporate Secretary in 1999.

SEC REPORTS AVAILABLE ON UNISOURCE ENERGY'S WEBSIT E

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 practical 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 Investors 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, which applies to the Board of Directors and all officers and employees of UniSource Energy and its subsidiaries, and any amendments or any waivers 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. These risks and uncertainties fall primarily into five major categories: revenues, regulatory, environmental, financial and operational.

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REVENUES

National and local economic conditions can have a significant impact on the results of operations, net income and cash flows at TEP, UNS Gas and UNS Electric.

Economic conditions have contributed significantly to a reduction in TEP's retail customer growth and lower energy usage by the company's residential, commercial and industrial customers. As a result of weak economic conditions, TEP's average retail customer base grew by less than 1% per year in 2008 through 2011 compared with average increases of approximately 2% per year from 2003 to 2007. In 2011, total retail kWh sales were 0.4% above 2010 levels. TEP estimates that a 1% decrease in annual retail sales could reduce pre-tax net income and pre-tax cash flows by approximately $6 million.

Similar impacts were felt at UNS Gas and UNS Electric. Annual increases in the number of retail customers at both companies remained below 1% in 2008 through 2011 compared with average annual growth rates of 3% from 2003 to 2007. We estimate that a 1% decrease in annual retail sales at UNS Gas and UNS Electric could reduce pre-tax net income and pre-tax cash flows by less than $1 million.

TEP's Base Rates are frozen through December 31, 2012, which could limit our ability to cope with the impact of risks and uncertainties and negatively affect TEP's results of operations, net income and cash flows.

Under the terms of the 2008 TEP Rate Order, TEP is prohibited from submitting an application for new Base Rates before June 30, 2012. New Base Rates would not be in effect until approval by the ACC, which is not anticipated to occur before the third quarter of 2013. If the cost of serving TEP's customers rises more quickly than the revenues it collects from customers, TEP's results of operations, net income and cash flows could be negatively impacted.

New technological developments and the implementation of new Energy Efficiency Standards may have a significant impact on retail sales, which could negatively impact UniSource Energy's results of operations, net income and cash flows.

Heightened awareness of energy costs has increased demand for products intended to reduce consumers' use of electricity. TEP and UNS Electric also are promoting DSM programs designed to help customers reduce their energy use, and these efforts will increase significantly under new energy efficiency rules approved in 2010 by the ACC. Unless the ACC makes a specific provision for the recovery of usage-based revenues lost to these energy efficiency programs, the reduced retail sales that would result from the success of these efforts would negatively impact the results of operations, net income and cash flows of TEP and UNS Electric.

The revenues, results of operations and cash flows of TEP, UNS Gas and UNS Electric are seasonal, and are subject to weather conditions and customer usage patterns, which are beyond the companies' control.

TEP typically earns the majority of its operating revenue and net income in the third quarter because retail customers increase their air conditioning usage during Tucson's hot summer weather. Conversely, TEP's first quarter net income is typically limited by relatively mild winter weather in its retail service territory. UNS Electric's earnings follow a similar pattern, while UNS Gas' sales peak in the winter during home heating season. Cool summers or warm winters may reduce customer usage at all three companies, adversely affecting operating revenues, cash flows and net income by reducing sales. TEP estimates that a 1% decrease in annual retail sales could reduce pre-tax net income and pre-tax cash flows by approximately $6 million. We estimate that a 1% decrease in annual retail sales at UNS Gas and UNS Electric could reduce pre-tax net income and pre-tax cash flows by less than $1 million.

REGULATORY

TEP, UNS Gas and UNS Electric are subject to regulation by the ACC, which sets the companies' Retail Rates and oversees many aspects of their business in ways that could negatively affect the companies' results of operations, net income and cash flows.

The ACC is a constitutionally created body composed of five elected commissioners. Commissioners are elected state-wide for staggered four-year terms and are limited to serving a total of two terms. As a result, the composition of the commission, and therefore its policies, are subject to change every two years.

The ACC is charged with setting retail electric and gas rates that provide utility companies with an opportunity to recover their costs of service and earn a reasonable rate of return. The decisions these elected officials make on such matters impact the net income and cash flows of TEP, UNS Gas and UNS Electric.

Changes in federal energy regulation may negatively affect the results of operations, net income and cash flows of TEP, UNS Gas and UNS Electric.

TEP, UNS Gas and UNS Electric are subject to the impact of 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 electric utility subsidiaries are subject to regulation by the 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.

ENVIRONMENTAL

UniSource Energy's utility subsidiaries are subject to numerous environmental laws and regulations that may increase their cost of operations or expose them to environmentally-related litigation and liabilities. Many of these regulations could have a significant impact on TEP due to its reliance on coal as its primary fuel for energy generation.

Numerous federal, state and local environmental laws and regulations affect present and future operations. Those laws and regulations include rules regarding air emissions, water use, wastewater discharges, solid waste, hazardous waste and management of coal combustion residuals.

These laws and regulations can contribute to higher capital, operating and other costs, particularly with regard to enforcement efforts focused on existing power plants and new compliance standards related to new and existing power plants. These laws and regulations generally require us to obtain and comply with a wide variety of environmental licenses, permits, authorizations and other approvals. Both public officials and private individuals may seek to enforce applicable environmental laws and regulations. Failure to comply with applicable laws and regulations may result in litigation, and the imposition of fines, penalties and a requirement for costly equipment upgrades by regulatory authorities.

We cannot provide assurance that existing environmental laws and regulations will not be revised or that new environmental laws and regulations will not be adopted or become applicable to our facilities. Increased compliance costs or additional operating restrictions from revised or additional regulation could have an adverse effect on our results of operations, particularly if those costs are not fully recoverable from our ratepayers. TEP's obligation to comply with the EPA's BART determinations as a participant in the San Juan, Four Corners and Navajo plants, coupled with the financial impact of future climate change legislation, other environmental regulations and other business considerations, could jeopardize the economic viability of these plants or the ability of individual participants to meet their obligations and continue their participation in these plants. TEP cannot predict the ultimate outcome of these matters.

TEP also is contractually obligated to pay a portion of the environmental reclamation costs incurred at generating stations in which it has a minority interest and is obligated to pay similar costs 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.

New federal regulations to limit greenhouse gas emissions could increase TEP's cost of operations and result in a change in the composition of TEP's coal-dominated generating fleet.

Based on the finding by the EPA in December 2009 that emissions of greenhouse gases endanger public health and welfare, the agency is in the process of regulating greenhouse gas emissions. In addition, there are proposals and ongoing studies at the state, federal and international levels to address global climate change that could also result in the regulation of carbon dioxide (CO_2) and other greenhouse gases. Any future regulatory actions taken to address global climate change represent a business risk to our operations. In 2011, 73% of TEP's total energy resources came from its coal-fueled generating facilities.

Reductions in CO_2 emissions to the levels specified by some proposals could be materially adverse to our financial position or results of operations if associated costs of control or limitation cannot be recovered from customers.

Any future legislation or regulation addressing climate change could produce a number of other results including costly modifications to, or reexamination of the economic viability of, our existing coal plants; changes in the overall fuel mix of our generating fleet; or additional costs to fund energy efficiency activities. The impact of legislation or regulation to address global climate change would depend on the specific terms of those measures and cannot be determined at this time.

FINANCIAL

Volatility or disruptions in the financial markets may increase our financing costs, limit our access to the credit markets and increase our pension funding obligations, which may adversely affect our liquidity and our ability to carry out our financial strategy.

We rely on access to the bank markets and capital markets as a significant source of liquidity and for capital requirements not satisfied by the cash flow from our operations. Market disruptions such as those experienced over the last four years in the United States and abroad may increase our cost of borrowing or adversely affect our ability to access sources of liquidity needed to finance our operations and satisfy our obligations as they become due. These disruptions may include turmoil in the financial services industry, including substantial uncertainty surrounding particular lending institutions and counterparties we do business with, unprecedented volatility in the markets where our outstanding securities trade, and general economic downturns in our utility service territories. If we are unable to access credit at competitive rates, or if our borrowing costs dramatically increase, our ability to finance our operations, meet our short-term obligations and execute our financial strategy could be adversely affected.

Changing market conditions could negatively affect the market value of assets held in our pension and other postretirement pension plans and may increase the amount and accelerate the timing of required future funding contributions.

UniSource Energy's net income and cash flows can be adversely affected by rising interest rates.

As of February 21, 2012, TEP had $215 million of tax-exempt variable rate debt obligations, $50 million of which was hedged with a fixed for floating interest rate swap through September 2014. The interest rates are set weekly with maximum interest rates of 20% on $178 million of debt obligations and 10% on the remaining $37 million. The average weekly interest rate ranged from 0.05% to 0.34% in 2011. A 100 basis point increase in the average interest rates on this debt over a twelve-month period would increase TEP's interest expense by approximately $2 million.

UniSource Energy, TEP, UNS Gas and UNS Electric also are subject to risk resulting from changes in the interest rate on their borrowings under revolving credit facilities. Revolving credit borrowings may be made on a spread over LIBOR or an Alternate Base Rate. Each of these agreements is a committed facility and expires in November 2016.

If capital market conditions result in rising interest rates, the resulting increase in the cost of variable rate borrowings would negatively impact UniSource Energy's, TEP's, UNS Gas' and UNS Electric's results of operations, net income and cash flows.

TEP, UNS Gas and UNS Electric may be required to post margin under their power and fuel supply agreements, which could negatively impact their liquidity.

TEP, UNS Gas and UNS Electric secure power and fuel supply resources to serve their respective retail customers. The agreements under which TEP, UNS Gas and UNS Electric contract 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 creditworthiness of the respective companies.

In order to post such credit enhancement, TEP, UNS Gas and UNS Electric would have to use available cash, draw under their revolving credit agreements, or issue letters of credit under their revolving credit agreements.

The maximum amount TEP may use under its revolving credit facility is $200 million. As of February 21, 2012, TEP had $114 million available to borrow under its revolving credit facility. The maximum amount UNS Gas or UNS Electric may use under their revolving credit facility is $70 million, so long as the combined amount drawn by both companies does not exceed $100 million. As of February 21, 2012, UNS Gas and UNS Electric had $64 million and $70 million, respectively, to borrow under their revolving credit facility. From time to time, TEP, UNS Gas and UNS Electric use their respective revolving credit facilities to post collateral. If additional collateral is required, it may negatively impact TEP, UNS Gas and/or UNS Electric's ability to fund their capital requirements. As of December 31, 2011, TEP and UNS Electric had posted $1 million, and $6 million, respectively, with counterparties in the form of cash or letters of credit.

UniSource Energy and its subsidiaries have debt which could adversely affect their 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, 2011, the ratio of total debt (including capital lease obligations net of investments in lease debt) to total capitalization for UniSource Energy and its subsidiaries was 67%. This debt level:

- requires UniSource Energy and its subsidiaries to dedicate a substantial portion of their cash flow to pay principal and interest on their debt, which could reduce the funds available for working capital, capital expenditures, acquisitions and other general corporate purposes; and
- could limit UniSource Energy and its subsidiaries' ability to borrow additional amounts for working capital, capital expenditures, acquisitions, dividends, debt service requirements, execution of its business strategy or other purposes.

The cost of purchasing TEP's leased assets, or the cost of procuring alternate sources of generation or purchased power in 2015, could require significant outlays of cash in one year, which could be difficult to finance.

TEP leases the following generation facilities under separate sale and leaseback arrangements that expire in 2015:

Leased Asset	Expiration	Purchase Option
Springerville Unit 1	2015	Fair market value purchase option of $159 million
Springerville Coal Handling Facilities	2015	Fixed price purchase option of $120 million

TEP may renew the leases or purchase the assets when the leases expire in 2015. The renewal and purchase options for Springerville Unit 1 are for fair market value, with the fair market value purchase price having been determined in December 2011 through an appraisal process to be $159 million. The Springerville Coal Handling Facilities can be purchased in 2015 for a fixed price of $120 million. TEP also leases a 50% undivided interest in Springerville Common Facilities with primary lease terms ending in 2017 and 2021. Upon expiration of the Springerville 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 owners of Springerville Units 3 and 4 to purchase such facilities. Upon acquisition by TEP, the owner of Springerville Unit 3 has the option and the owner of Springerville Unit 4 has the obligation to purchase from TEP a 14% interest in the Common Facilities and a 17% interest in the Coal Handling Facilities.

Regulatory rules and other restrictions limit the ability of TEP, UNS Gas and UNS Electric to make distributions to UniSource Energy.

As a holding company, UniSource Energy 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 to affiliates 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; and

- TEP, UNS Gas and UNS Electric must be in compliance with their respective debt agreements to make dividend payments to UniSource Energy.

Unanticipated financing needs or reductions to net income could adversely impact our ability to comply with financial covenants in the UniSource Energy, TEP and UES Credit Agreements.

The UniSource Energy, TEP and UES credit and reimbursement agreements include a maximum leverage ratio. The leverage ratios are calculated as the ratio of total indebtedness to total capital. The ability to comply with these covenants could be adversely impacted by unanticipated borrowing needs or unexpected charges to earnings or shareholder equity. In the event that we seek to renegotiate these provisions to provide additional flexibility, we may need to pay fees or increased interest rates on borrowings as a condition to any amendments or waivers.

OPERATIONAL

The operation of electric generating stations involves risks that could result in unplanned outages or reduced generating capability that could adversely affect TEP's or UNS Electric's results of operations, net income and cash flows.

The operation of electric generating stations involves certain risks, including equipment breakdown or failure, interruption of fuel supply and lower than expected levels of efficiency or operational performance. Unplanned outages, including extensions of planned outages due to equipment failure or other complications, occur from time to time and are an inherent risk of our business. If TEP's or UNS Electric's generating stations operate below expectations, TEP or UNS Electric could be adversely affected.

The operation of electric transmission and distribution systems involves a risk of significant unplanned outages that could adversely affect TEP's and UNS Electric's businesses, results of operations, net income and cash flows.

The operation of electric transmission and distribution systems involves certain risks, including equipment failure and damage caused by storms, fires or other hazards. Unplanned outages occur from time to time and are an inherent risk of our business. If TEP's or UNS Electric's transmission and distribution systems experience a significant failure, TEP or UNS Electric could be adversely affected.

TEP could be subject to higher costs and the possibility of significant penalties as a result of mandatory transmission standards.

As a result of the Energy Policy Act of 2005, owners and operators of bulk power transmission systems, including TEP, are subject to mandatory transmission standards developed and enforced by NERC and subject to the oversight of FERC. Compliance with modified or new transmission standards may subject TEP to higher operating costs and increased capital costs. Failure to comply with the mandatory transmission standards could subject TEP to sanctions, including substantial monetary penalties.

We may be subject to cyber attacks and information security risks.

As operators of critical energy infrastructure, we may face a heightened risk of cyber attack, and our corporate and informational technology systems may be vulnerable to disability or failures as a result of unauthorized access due to hacking, viruses, acts of war or terrorism and other causes. In addition, our utility business requires access to sensitive customer data, including personal and credit information, in the ordinary course of business. If, despite our security measures, a significant or widely publicized breach occurred, we could have our operations disrupted, property damaged and customer information stolen; experience substantial loss of revenues, response costs and other financial loss; and be subject to increased regulation, litigation and damage to our reputation, any of which could have a negative impact on our business and results of operations.

TEP or UNS Electric might not be able to secure adequate right-of-way to construct transmission lines and distribution-related facilities, and could be required to find alternate ways to provide adequate sources of energy and maintain reliable service for their customers.

TEP and UNS Electric rely on federal, state and local governmental agencies to secure right-of-way and siting permits to construct transmission lines and distribution-related facilities. If adequate right-of-way and siting permits to build new transmission lines cannot be secured:

- TEP and UNS Electric may need to rely on more costly alternatives to provide energy to their customers;
- TEP and UNS Electric may not be able to maintain reliability in their service areas; or
- TEP and UNS Electric's ability to provide electric service to new customers may be negatively impacted.

ITEM 1B. – UNRES OLVED STAFF COMMENTS

None.

ITEM 2. – PROPERTIES

TEP PROPERTIES

TEP's transmission facilities, located in Arizona and New Mexico, transmit the output 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, TEP, Generating and Other Resources*). The transmission system is interconnected at various points in Arizona and New Mexico with other regional utilities. TEP has arrangements with approximately 140 companies to interchange generation capacity and transmission of energy.

As of December 31, 2011, TEP owned or participated in an overhead electric transmission and distribution system consisting of:

- 512 circuit-miles of 500-kV lines;
- 1,088 circuit-miles of 345-kV lines;
- 405 circuit-miles of 138-kV lines;
- 479 circuit-miles of 46-kV lines; and
- 2,615 circuit-miles of lower voltage primary lines.

TEP's underground electric distribution system includes 4,389 cable-miles. TEP owns approximately 76% of the poles on which its lower voltage lines are located. Electric substation capacity consists of 103 substations with a total installed transformer capacity of 13,266,850 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, is not subject to the lien.

The electric generating stations (except as noted below), administrative 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 places in the public domain, as well as in 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 property owned 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 also has acquired easements for transmission facilities related to San Juan, Four Corners, and Navajo across the Zuni, Navajo and Tohono O'dham 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):

- Springerville Coal Handling Facilities;
- a 50% undivided interest in the Springerville Common Facilities; and
- Springerville Unit 1 and the remaining 50% undivided interest in the Springerville Common Facilities.

See Note 6 *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 PRO PERTIES

UNS Gas

As of December 31, 2011, UNS Gas' transmission and distribution system consisted of approximately 31 miles of steel transmission mains, 4,220 miles of steel and plastic distribution piping, and 137,160 customer service lines.

UNS Electric

As of December 31, 2011, UNS Electric's transmission and distribution system consisted of approximately 56 circuit-miles of 115-kV transmission lines, 274 circuit-miles of 69-kV transmission lines, and 3,616 circuit-miles of underground and overhead distribution lines. UNS Electric also owns the 65 MW Valencia plant, the 90 MW BMGS as well as 39 substations having a total installed capacity of 1,494,000 kilovolt amperes.

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 places in the public domain, as well as 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.

ITEM 3. – LEGAL PROCEEDINGS

Right of Way Matters

TEP was a defendant in a class action filed in February 2009 in the United States District Court in Albuquerque, New Mexico by members of the Navajo Nation. The plaintiffs alleged, among other things, that the rights of way for defendants' transmission lines on Navajo lands were improperly granted and that the compensation paid for such rights of way was inadequate. The plaintiffs were requesting, among other things, that the transmission lines on these lands be removed. In June 2009, TEP and the other defendants filed motions to dismiss the lawsuit on procedural grounds. In March 2010, the Court granted several of the defendants' motions to dismiss and entered a final judgment dismissing the case in April 2010. The plaintiffs filed a Notice of Appeal with the Bureau of Indian

Affairs (BIA) in May 2010, appealing the BIA's decision to grant the rights of way that were the subject of the now-dismissed complaint. In June 2010, the BIA found that the Notice of Appeal failed to meet the minimum filing requirements. In September 2010, the plaintiffs filed new Notices of Appeal concerning the same rights of way. The appeals are currently pending. TEP cannot predict the outcome of these appeals.

In addition, see legal proceedings described in Note 4 .

ITEM 4. – MINE SAFETY DISCLOSURES

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 21, 2012, the closing price was $37.76, with 8,339 shareholders of record.

TEP's common stock is wholly-owned by UniSource Energy and is not listed for trading on any stock exchange.

Dividends

UniSource Energy

UniSource Energy's Board of Directors expects to continue to pay regular quarterly cash dividends on our common stock; however, such dividends are subject to the Board's evaluation of our financial condition, earnings, cash flows and dividend policy.

On February 24, 2012, UniSource Energy declared a first quarter cash dividend of $0.43 per share on its common stock. The first quarter dividend, totaling approximately $16 million, will be paid March 22, 2012, to shareholders of record at the close of business March 12, 2012. The table below summarizes UniSource Energy's dividends paid in 2009 through 2011.

	2011	2010	2009
Quarterly Dividend Per Common Share	$ 0.42	$ 0.39	$ 0.29
Annual Dividend Per Common Share	$ 1.68	$ 1.56	$ 1.16
Common Stock Dividends Paid	$ 62 million	$ 57 million	$ 41 million

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. The TEP Board of Directors typically declares a dividend at the end of each year.

TEP

TEP did not pay any dividends to UniSource Energy in 2011. TEP declared and paid cash dividends to UniSource Energy of $60 million in 2010 and $60 million in 2009.

TEP can pay dividends if it maintains compliance with the TEP Credit Agreement and certain financial covenants. As of December 31, 2011, 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 for TEP to pay dividends from current year earnings.

UNS Gas

UNS Gas paid dividends to UniSource Energy of $10 million in both 2011 and 2010. In February 2012, UNS Gas paid a $10 million dividend to UniSource Energy. UNS Gas' ability to pay future dividends will depend on the cash needs for capital expenditures and various other factors.

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. As of December 31, 2011, UNS Gas was in compliance with the terms of its note purchase agreement.

UNS Electric

As of December 31, 2011, UNS Electric had not paid dividends to UniSource Energy. UNS Electric's ability to pay dividends will depend on the cash needs for capital expenditures and various other factors.

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. As of December 31, 2011, UNS Electric was in compliance with the terms of its note purchase agreement.

Other Non-Reportable Segments

In 2011, 2010, and 2009 UED paid dividends to UniSource Energy of $39 million, $9 million and $30 million, respectively. Of those dividends paid by UED, the portions representing a return of capital were $28 million in 2011, $4 million in 2010 and $30 million in 2009.

See *Item 7. – Management's Discussion and Analysis of Financial Condition and Results of Operations, UniSource Energy Consolidated, Liquidity and Capital Resources, Dividends on Common Stock*

Common Stock Dividends and Price Ranges

Quarter:	2011 Market Price per Share of Common Stock [1] High	2011 Market Price per Share of Common Stock [1] Low	2011 Dividends Declared	2010 Market Price per Share of Common Stock [1] High	2010 Market Price per Share of Common Stock [1] Low	2010 Dividends Declared
First	$ 37.74	$ 34.84	$ 0.42	$ 33.54	$ 29.13	$ 0.39
Second	38.71	35.47	0.42	34.42	29.04	0.39
Third	38.55	34.36	0.42	33.75	29.85	0.39
Fourth	39.25	34.28	0.42	36.92	33.19	0.39
Total			$ 1.68			$ 1.56

(1) UniSource Energy's common stock price as reported by the New York Stock Exchange.

Convertible Senior Notes

In March 2005, UniSource Energy issued $150 million of 4.50% convertible bonds due 2035. Each $1,000 of convertible bonds can be converted into 28.814 shares of UniSource Energy common stock at any time. The conversion ratio represents a conversion price of approximately $34.71 per share of common stock and is subject to adjustments including an adjustment to reduce the conversion price upon the payment of quarterly dividends in excess of $0.19 per share. As of February 21, 2012, there were $115 million of convertible bonds outstanding. See *Item 7.- Management's Discussion and Analysis of Financial Condition and Results of Operations, UniSource Energy Consolidated, Liquidity and Capital Resources, Convertible Senior Notes,* below, for more information.

Issuer Purchases of Common Equity

UniSource Energy did not purchase any of its common stock during 2011, 2010, or 2009.

ITEM 6. – SELECTED CONSOLIDATED FINANCIAL DATA

UniSource Energy	2011	2010*	2009*	2008*	2007*
			- In Thousands - (except per share data)		
Summary of Operations					
Operating Revenues	**$ 1,509,515**	$ 1,453,966	$ 1,397,052	$ 1,410,407	$ 1,381,660
Net Income	**$ 109,975**	$ 112,984	$ 105,901	$ 16,955	$ 60,712
Basic Earnings per Share:					
Net Income	**$ 2.98**	$ 3.10	$ 2.95	$ 0.47	$ 1.70
Diluted Earnings per Share:					
Net Income	**$ 2.75**	$ 2.86	$ 2.73	$ 0.53	$ 1.62
Shares of Common Stock Outstanding					
Average	**36,962**	36,415	35,858	35,632	35,486
End of Year	**36,918**	36,542	35,851	35,458	35,315
Year-end Book Value per Share	**$ 24.07**	$ 22.73	$ 21.18	$ 19.35	$ 19.65
Cash Dividends Declared per Share	**$ 1.68**	$ 1.56	$ 1.16	$ 0.96	$ 0.90
Financial Position					
Total Utility Plant – Net	**$ 3,182,263**	$ 2,961,498	$ 2,785,714	$ 2,617,693	$ 2,407,295
Investments in Lease Debt and Equity	**$ 65,829**	$ 103,844	$ 132,168	$ 126,672	$ 152,544
Other Investments and Other Property	**$ 34,205**	$ 61,676	$ 60,239	$ 64,096	$ 70,677
Total Assets	**$ 3,985,231**	$ 3,791,243	$ 3,610,065	$ 3,503,821	$ 3,189,747
Long-Term Debt	**$ 1,517,373**	$ 1,352,977	$ 1,307,795	$ 1,313,615	$ 993,870
Non-Current Capital Lease Obligations	**352,720**	429,074	488,349	513,517	530,973
Common Stock Equity	**888,474**	830,756	759,329	686,090	693,958
Total Capitalization	**$ 2,758,567**	$ 2,612,807	$ 2,555,473	$ 2,513,222	$ 2,218,801
Selected Cash Flow Data					
Net Cash Flows From Operating Activities	**$ 337,320**	$ 346,920	$ 347,310	$ 273,767	$ 320,642
Capital Expenditures	**$ (374,122)**	$ (330,629)	$ (294,020)	$ (354,080)	$ (243,242)
Other Investing Cash Flows (1)	**47,034**	25,569	(2,624)	(95,493)	27,961
Net Cash Flows From Investing Activities	**$ (327,088)**	$ (305,060)	$ (296,644)	$ (449,573)	$ (215,281)
Net Cash Flows From Financing Activities	**$ (1,441)**	$ (51,183)	$ (28,916)	$ 140,605	$ (119,229)
Ratio of Earnings to Fixed Charges (2)	**2.46**	2.64	2.48	1.28	1.71

TEP	2011	2010*	2009*	2008*	2007*
			-Thousands of Dollars-		
Summary of Operations					
Operating Revenues	**$ 1,156,386**	$ 1,125,267	$ 1,099,338	$ 1,092,148	$ 1,070,789
Net Income	**$ 85,334**	$ 108,260	$ 90,688	$ 7,206	$ 55,591
Financial Position					
Total Utility Plant – Net	**$ 2,650,652**	$ 2,410,077	$ 2,261,325	$ 2,120,619	$ 1,957,506
Investments in Lease Debt and Equity	**65,829**	103,844	132,168	126,672	152,544
Other Investments and Other Property	**32,313**	43,588	31,813	31,291	35,460
Total Assets	**$ 3,275,484**	$ 3,075,978	$ 2,922,062	$ 2,847,408	$ 2,567,808
Long-Term Debt	**$ 1,080,373**	$ 1,003,615	$ 903,615	$ 903,615	$ 682,870
Non-Current Capital Lease Obligations	**352,720**	429,074	488,311	513,370	530,714
Common Stock Equity	**824,943**	709,884	650,591	589,613	580,512
Total Capitalization	**$ 2,258,036**	$ 2,142,573	$ 2,042,517	$ 2,006,598	$ 1,794,096
Selected Cash Flow Data					
Net Cash Flows From Operating Activities	**$ 268,294**	$ 302,483	$ 268,064	$ 265,756	$ 262,714
Capital Expenditures	**$ (351,890)**	$ (277,309)	$ (240,079)	$ (291,990)	$ (161,141)
Other Investing Cash Flows (1)	**39,879**	24,273	(9,522)	(95,814)	25,414
Net Cash Flows From Investing Activities	**$ (312,011)**	$ (253,036)	$ (249,601)	$ (387,804)	$ (135,727)
Net Cash Flows From Financing Activities	**$ 51,452**	$ (51,882)	$ (29,320)	$ 128,713	$ (120,088)
Ratio of Earnings to Fixed Charges (2)	**2.42**	2.76	2.58	1.18	1.78

* As revised. See Note 1 to the financial statements for more information.

(1) Other Investing Cash Flows in 2008 includes the $133 million deposit to Trustee for Repayment of Collateral Trust Bonds.

(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, interest on operating lease payments, and expense on indebtedness.

See *Item 7. – Management's Discussion and Analysis of Financial Condition and Results of Operations.*

ITEM 7. – MANAGEMEN T'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 2011 compared with 2010, and 2010 compared with 2009;
- factors which affect our results and outlook;
- liquidity, capital needs, capital resources, and contractual obligations;
- dividends; and
- critical accounting policies.

UniSource Energy Corporation (UniSource Energy) is a utility services holding company engaged, through its subsidiaries, in the electric generation and energy delivery business. Each of UniSource Energy's subsidiaries is a separate legal entity with its own assets and liabilities. UniSource Energy owns 100% of Tucson Electric Power Company (TEP), UniSource Energy Services, Inc. (UES), Millennium Energy Holdings, Inc. (Millennium), and UniSource Energy Development Company (UED).

TEP is a regulated public utility and UniSource Energy's largest operating subsidiary, representing approximately 82% of UniSource Energy's total assets as of December 31, 2011. TEP generates, transmits and distributes electricity to approximately 404,000 retail electric customers in a 1,155 square mile area in southeastern Arizona. TEP also sells electricity to other utilities and power marketing entities, located primarily in the western U.S. In addition, TEP operates Springerville Unit 3 on behalf of Tri-State Generation and Transmission Association, Inc. (Tri-State) and Springerville Unit 4 on behalf of Salt River Project Agriculture Improvement and Power District (SRP).

UES holds the common stock of UNS Gas, Inc. (UNS Gas) and UNS Electric, Inc. (UNS Electric). UNS Gas is a regulated gas distribution company with approximately 148,000 retail customers in Mohave, Yavapai, Coconino, and Navajo counties in northern Arizona, as well as in Santa Cruz County in southern Arizona. UNS Electric is a regulated vertically integrated public utility with approximately 91,000 retail customers in Mohave and Santa Cruz counties.

UED developed the Black Mountain Generating Station (BMGS) in northwestern Arizona. The facility includes two natural gas-fired combustion turbines. Prior to July 2011, UNS Electric received energy from BMGS through a power sales agreement with UED. In July 2011, UNS Electric purchased BMGS from UED, leaving UED with no significant remaining assets. The transaction had no impact on UniSource Energy's consolidated financial statements.

Millennium's investments in unregulated businesses represent less than 1% of UniSource Energy's assets as of December 31, 2011.

Our business is comprised of three reporting segments – TEP, UNS Gas, and UNS Electric.

References to "we" and "our" are to UniSource Energy and its subsidiaries, collectively.

<u>UNISOURCE ENE RGY CONSOLIDATED</u>

OUTLOOK AND STRAT EGIES

Our financial prospects and outlook are affected by many factors including: the TEP 2008 Rate Order that freezes Base Rates through 2012; national and regional economic conditions; volatility in the financial markets; environmental laws and regulations; and other regulatory factors. Our plans and strategies include the following:

- Focusing on our core utility businesses through operational excellence, investing in utility rate base, emphasizing customer satisfaction, maintaining a strong community presence, and achieving constructive regulatory outcomes.

- Developing strategic responses to new environmental regulations and potential new legislation, including potential limits on greenhouse gas emissions. We are evaluating TEP's existing mix of generation resources and defining steps to achieve environmental objectives that provide an appropriate return on investment and are consistent with earnings growth.
- Expanding TEP's and UNS Electric's portfolio of renewable energy resources and programs to meet Arizona's Renewable Energy Standard while creating ownership opportunities for renewable energy projects that benefit customers, shareholders, and the communities we serve.
- Developing strategic responses to Arizona's Energy Efficiency Standards that protect the financial stability of our utility businesses and provide benefits to our customers.

RESULT S OF OPERATIONS

Contribution by Business Segment

We conduct our business through three primary business segments – TEP, UNS Gas, and UNS Electric. The table below shows the contributions to our consolidated after-tax earnings by these business segments.

	2011	2010	2009
TEP	$ 85	$ 108	$ 91
UNS Gas	10	9	7
UNS Electric	18	15	11
Other Non-Reportable Segments and Adj. (1)	(3)	(19)	(3)
Consolidated Net Income	$ 110	$ 113	$ 106

(1) Includes: UniSource Energy parent company expenses; Millennium; and UED.

Revision of Prior Period Financial Statements

In the second and third quarters of 2011, we identified errors related to amounts recorded, at their dollar value, owed to or payable by TEP for electricity deliveries settled in-kind or to be settled in-kind during prior years under three of our transmission agreements. In the second quarter of 2011, we also identified errors in prior years in the calculation of income tax expense arising from not treating Allowance for Equity Funds Used During Construction (AFUDC) as a permanent book to tax difference.

We assessed the materiality of these errors on prior period financial statements and concluded they were not material to any prior annual or interim periods; however, the cumulative impact, if recognized in 2011, could be material to results in 2011. In accordance with Staff Accounting Bulletin 108 and as set forth in Note 1 to the Financial Statements in our Quarterly Report on Form 10-Q for the quarters ended June 30, 2011, and September 30, 2011, we revised our prior period financial statements to correct these errors. See Note 1 for more information.

Executive Overview

2011 Compared with 2010

TEP

TEP reported net income of $85 million in 2011 compared with $108 million in 2010. The decrease in net income was due primarily to: a decline in long-term wholesale margin revenues; a decrease in wholesale transmission revenues; an increase in Base O&M; higher depreciation expense; and an increase in interest expense. Those factors were partially offset by the recognition of a gain related to the settlement of a dispute with El Paso Electric. See *Tucson Electric Power, Results of Operations* below for more information.

UNS Gas and UNS Electric

UNS Gas reported net income of $10 million in 2011 compared with net income of $9 million in 2010. See *UNS Gas, Results of Operations,* below for more information.

UNS Electric reported net income of $18 million in 2011 compared with net income of $15 million in 2010. The increase is due in part to a Base Rate increase that took effect in October 2010. See *UNS Electric, Results of Operations,* below for more information.

Other Non-Reportable Segments

Millennium's financial results are included in UniSource Energy's Other Non-Reportable Segments. Millennium reported net income of $2 million in 2011 compared with a net loss of $13 million in 2010. Millennium's results in the 2010 reflect losses related to the write-off of deferred taxes and impairment losses. See *Other Non-Reportable Segments, Results of Operations,* below, for more information.

2010 Compared with 2009

TEP

TEP reported net income of $108 million in 2010 compared with net income of $91 million in 2009. The increase was due primarily to: a $17 million decrease in depreciation and amortization expense resulting from a change in depreciation rates for TEP's transmission assets, the purchase of Sundt Unit 4, and a decline in amortization on capital lease obligations (the decrease excludes adjustments made to depreciation and amortization in 2009 related to an investment in Springerville Unit 1 lease equity); operating benefits of $11 million related to the start of commercial operation of Springerville Unit 4 in December 2009; a $3 million decrease in Base O&M resulting from a decline in planned power plant maintenance outages, cost-containment efforts and lower pension and post retirement medical expense; and a $5 million decrease in retail margin revenues resulting from a 0.8% decrease in retail kWh sales.

UNS Gas and UNS Electric

UNS Gas reported net income of $9 million in 2010 compared with $7 million in 2009. The increase was due primarily to an increase in retail sales due to colder winter weather and an increase in Base Rates that took effect in April 2010.

UNS Electric reported net income of $15 million in 2010 compared with $11 million in 2009. The increase was due primarily to an increase in demand from a mining customer; the addition of a new industrial customer; and an increase in Base Rates that took effect in October 2010; and a pre-tax gain of $3 million related to the settlement of a dispute regarding wholesale energy transactions.

Other Non-Reportable Segments

Millennium recorded a net loss of $13 million in 2010 compared with net income of $2 million in 2009. The net loss in 2010 resulted from several factors, including the write-off of deferred tax assets and impairment losses on certain investments.

O&M

The table below summarizes the items included in UniSource Energy's O&M expense.

	2011	2010	2009
		-Millions of Dollars-	
TEP Base O&M (non-GAAP) (1)	$ 237	$ 228	$ 231
UNS Gas Base O&M (non-GAAP) (1)	24	25	25
UNS Electric Base O&M (non-GAAP) (1)	20	21	21
Consolidating Adjustments and Other (2)	(11)	(9)	(7)
UniSource Energy Base O&M (non-GAAP)	270	265	270
Reimbursed Expenses Related to Springerville Units 3 & 4	63	65	41
Expenses Related to Customer-Funded Renewable Energy and Demand Side Management Programs	46	40	23
Total UniSource Energy O&M (GAAP)	$ 379	$ 370	$ 334

(1) Base O&M, a non-GAAP financial measure, should not be considered as an alternative to Other O&M, which is determined in accordance with GAAP. We believe Base O&M provides useful information to investors because it represents the fundamental level of operating and maintenance expense related to our core business. Base O&M excludes expenses that are directly offset by revenues collected from customers and other third parties.

(2) Includes Millennium, UED, and UniSource Energy stand-alone O&M, and inter-company eliminations.

LIQUIDITY AND CA PITAL RESOURCES

Liquidity

Dividends from UniSource Energy's subsidiaries, primarily TEP, represent the parent company's main source of liquidity. Under UniSource Energy's tax sharing agreement, 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 and each of its segments.

Balances as of February 21, 2012	*Cash and Cash* Equivalents	Borrowings under Revolving Credit Facility (1)	Amount Available under Revolving Credit Facility
		-Millions of Dollars-	
UniSource Energy Stand-Alone	$ 5	$ 52	$ 73
TEP	21	86	114
UNS Gas	40	—	70(2)
UNS Electric	6	6	64(2)
Other	6(3)	N/A	N/A
Total	$ 78		

(1) Includes LOCs issued under revolving credit facilities.

(2) Either UNS Gas or UNS Electric may borrow up to a maximum of $70 million; the total combined amount borrowed by both companies cannot exceed $100 million.

(3) Includes cash and cash equivalents at Millennium and UED.

Short-term Investments

UniSource Energy's short-term investment policy governs the investment of excess cash balances. We regularly review and update this policy in response to market conditions. As of December 31, 2011, UniSource Energy's short-term investments included highly-rated and liquid money market funds, certificates of deposit, and commercial paper. These short-term investments are classified as Cash and Cash Equivalents on the Balance Sheet.

Access to Revolving Credit Facilities

UniSource Energy and its three primary subsidiaries have access to working capital through revolving credit agreements with lenders. Each of these agreements is a committed facility that expires in November 2016. The TEP and UNS Gas/UNS Electric Credit Agreements may be used for revolving borrowings as well as to issue letters of credit. TEP, UNS Gas, and UNS Electric each issue letters of credit from time to time to provide credit enhancement to counterparties for their power or gas procurement and hedging activities. The UniSource Credit Agreement also may be used to issue letters of credit for general corporate purposes.

We believe that we have sufficient liquidity under our revolving credit facilities to meet short-term working capital needs and to provide credit enhancement as necessary under energy procurement and hedging agreements. See *Item 7A . Quantitative and Qualitative Disclosures about Market Risk, Credit Risk* , below.

Liquidity Outlook

In November 2011, UniSource Energy, TEP, UNS Gas, and UNS Electric each amended and extended their respective Credit Agreements that were due to expire in 2014 to extend the expiration dates to November 2016.

UniSource Energy Consolidated Cash Flows

	2011	2010	2009
		-Millions of Dollars-	
Operating Activities	$ 337	$ 347	$ 347
Investing Activities	(327)	(305)	(297)
Financing Activities	(1)	(51)	(29)

UniSource Energy's operating cash flows are generated primarily by the 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. UniSource Energy, TEP, UNS Gas and UNS Electric use their revolving credit facilities to fund their business activities during periods when sales are seasonally lower.

Capital expenditures at TEP, UNS Gas and UNS Electric represent the primary use of cash for investing activities. Cash used for investing and financing activities can fluctuate year-to-year depending on: capital expenditures, repayments and borrowings under revolving credit facilities; debt issuances or retirements; capital lease payments by TEP; and dividends paid by UniSource Energy to its shareholders.

Operating Activities

In 2011, net cash flows from operating activities were $10 million lower than they were in 2010 due to:

- a $32 million increase in O&M costs due in part to higher planned generating plant outage costs, higher up-front incentive payments for customer-installed solar systems, and higher DSM payments; and
- a $17 million increase in taxes other than income taxes paid due to a higher sales tax rate effective in June 2010 and sales taxes paid on higher retail kWh sales;

partially offset by

- a $14 million increase in cash receipts from electric and gas sales, net of fuel and purchased energy costs. The increase was due in part to: a Base Rate increase at UNS Gas in April 2010; a Base Rate increase at UNS Electric in October 2010; an increase in retail electric sales; higher fuel and purchased power cost recoveries from UNS Electric customers; and higher sales tax collections from customers resulting from a 1% increase in the sales tax rate that took effect in June 2010; and
- a $26 million decrease in income taxes paid net of income tax refunds due to lower taxable income resulting from bonus depreciation deductions.

Investing Activities

Net cash flows used for investing activities increased by $22 million in 2011. Capital expenditures during 2011 were $374 million compared with $331 million last year. TEP's 2011 capital expenditures include $85 million related to construction of a new administrative headquarters. Capital expenditures in 2010 included the purchase of Sundt Unit 4 by TEP for $51 million. Investing activities in 2011 included a $13 million increase in proceeds from investments in Springerville lease debt.

Capital Expenditures Forecast

	Actual	Estimated				
	2011	2012	2013	2014	2015	2016
				-Millions of Dollars-		
TEP	$ 352	$ 289	$ 346	$ 379	$ 331	$ 418
UNS Gas	13	11	12	13	14	14
UNS Electric (1)	33	34	41	41	31	35
Consolidating Adjustments (2)	(24)	—	—	—	—	—
UniSource Energy Consolidated	$ 374	$ 334	$ 399	$ 433	$ 376	$ 467

(1) UNS Electric purchased BMGS from UED for approximately $63 million in 2011. Since this is an inter-company transaction, it is not included in the chart, as it is eliminated from UniSource Energy consolidated capital expenditures. See *UNS Electric , Factors Affecting Results of Operations, Rates,* below, for more information.

(2) Consolidating adjustments of approximately $24 million represent costs incurred during 2010 at UniSource Energy for the construction of a new administrative headquarters building. These costs were reimbursed to UniSource Energy when TEP purchased the building in November 2011.

TEP's estimated capital expenditures exclude the potential purchase of interests in Springerville Unit 1 for $159 million and the potential purchase of interests in the Springerville Coal Handling Facilities for $120 million upon the expiration of their respective leases in January 2015.

These estimates are subject to continuing review and adjustment. Actual capital expenditures may differ from these estimates due to changes in business conditions, construction schedules, environmental requirements, state or federal regulations and other factors.

For more information regarding TEP's capital expenditures, see *Tucson Electric Power Company, Liquidity and Capital Resources, Investing Activities, Capital Expenditures,* below.

Financing Activities

Net cash flows used for financing activities were $50 million lower in 2011 compared with 2010 primarily due to:

- a $16 million increase in proceeds from the issuance of long-term debt (net of long-term debt repayments and issuance/retirement costs);
- a $70 million increase in borrowings (net of repayments) under revolving credit facilities;

  partially offset by

- an $18 million increase in payments on capital lease obligations;
- a $5 million increase in common stock dividends paid; and
- a $7 million decrease in cash from other financing activities.

Capital Contributions

In July 2011, UniSource Energy contributed $20 million in capital to UNS Electric to help fund its purchase of BMGS from UED.

In December 2011, UniSource Energy contributed $30 million in capital to TEP.

In 2010, UED paid UniSource Energy a $9 million dividend, of which $4 million represented a return of capital distribution. UniSource Energy contributed $15 million in capital to TEP in 2010 to help fund the purchase of Sundt Unit 4.

See *Other Non-Reportable Business Segments, UED* and *Tucson Electric Power Company, Liquidity and Capital Resources* , below for more information.

UniSource Credit Agreement

In November 2011, UniSource Energy amended its existing credit agreement (the UniSource Credit Agreement). The UniSource Credit Agreement consists of a $125 million revolving credit and revolving letter of credit facility. The amendment extended the term of the UniSource Credit Agreement by two years to November 2016. As of December 31, 2011, there was $57 million outstanding at a weighted average interest rate of 2.0%.

The UniSource Credit Agreement restricts additional indebtedness, liens, mergers and sales of assets. The UniSource Credit Agreement also requires UniSource Energy to meet a minimum cash flow to interest coverage ratio determined on a UniSource Energy stand-alone basis. Additionally, UniSource Energy cannot exceed a maximum leverage ratio determined on a consolidated basis. Under the terms of the UniSource Credit Agreement, UniSource Energy may pay dividends so long as it maintains compliance with the agreement.

As of December 31, 2011, we were in compliance with the terms of the UniSource Credit Agreement.

Interest Rate Risk

UniSource Energy is subject to interest rate risk resulting from changes in interest rates on its borrowings under the revolving credit facility. The interest paid on revolving credit borrowings is variable. UniSource Energy may be required to pay higher rates of interest on borrowings under its revolving credit facility if LIBOR and other benchmark interest rates increase. See *Item 7A. Quantitative and Qualitative Disclosures about Market Risk, Credit Risk* , below.

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 can be converted into 28.814 shares of UniSource Energy common stock at any time. The conversion ratio represents a conversion price of approximately $34.71 per share of common stock and is subject to adjustments including an adjustment to reduce the conversion price upon the payment of quarterly dividends in excess of $0.19 per share.

On December 28, 2011, UniSource Energy gave notice of a partial redemption of the Convertible Senior Notes by calling $35 million of the $150 million outstanding. The redemption period ended on January 12, 2012. Holders of the called Convertible Senior Notes had the option of converting their interests to common stock or redeeming the Convertible Senior Notes at par plus accrued interest. The notes were convertible into shares of UniSource Energy's common stock at a conversion rate of 28.814 shares per $1,000 principal amount of Convertible Senior Notes. Approximately $33.5 million of the Convertible Senior Notes selected for redemption converted their interests into approximately 964,000 shares of UniSource Energy's common stock. The remaining $1.5 million was redeemed for cash on January 12, 2012.

The closing price of UniSource Energy's Common Stock was $37.76 on February 21, 2012.

UniSource Energy has the option to redeem the remaining Convertible Senior 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 Convertible Senior Notes will have the right to 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 specified fundamental changes involving UniSource Energy occur. The repurchase price will be 100% of the principal amount of the remaining notes plus accrued and unpaid interest.

Contractual Obligations

The following chart displays UniSource Energy's consolidated contractual obligations by maturity and by type of obligation as of December 31, 2011.

UniSource Energy's Contractual Obligations
- Millions of Dollars -

Payment Due in Years Ending December 31,	2012	2013	2014	2015	2016	2017 and after	Other	Total
Long Term Debt								
Principal [1] [9]	$ —	$ —	$ 37	$ 130	$ 235	$ 1,115	$ —	$ 1,517
Interest [2]	73	73	73	73	67	728	—	1,087
Capital Lease Obligations [3]	118	122	195	23	18	61	—	537
Operating Leases	2	2	2	1	1	10	—	18
Purchase Obligations:								
Fuel [4]	107	71	68	50	47	96	—	439
Purchased Power	83	61	48	16	16	227	—	451
Transmission	7	5	5	4	4	23	—	48
Other Long-Term Liabilities [5] :								
Pension & Other Post Retirement Obligations [6]	28	5	6	6	6	34	—	85
Acquisition of Springerville Coal Handling and Common Facilities [7]	—	—	—	120	—	106	—	226
Solar Equipment [8]	12	12	—	—	—	—	—	24
Unrecognized Tax Benefits	—	—	—	—	—	—	29	29
Total Contractual Cash Obligations	$ 430	$ 351	$ 434	$ 423	$ 394	$ 2,400	$ 29	$ 4,461

(1) TEP's variable rate IDBs are secured by letters of credit issued pursuant to the TEP Credit Agreement, which expires in 2016, and 2010 Reimbursement Agreement, which expires in 2014. Although the variable rate IDBs mature between 2018 and 2032, the above maturity reflects a redemption or repurchase of such bonds as though the letters of credit terminate without replacement upon expiration of the TEP Credit Agreement in 2016 and the 2010 Reimbursement Agreement in 2014.

(2) Excludes interest on revolving credit facilities.

(3) Effective with commercial operation of Springerville Unit 3 in July 2006 and Unit 4 in December 2009, Tri-State and SRP are reimbursing TEP for various operating costs related to the common facilities on an ongoing basis, including a total of $14 million annually related to the Springerville Common and Springerville Coal Handling Facilities Leases. TEP remains the obligor under these capital leases, and Capital Lease Obligations do not reflect any reduction associated with this reimbursement.

(4) Excludes TEP's liability for final environmental reclamation at the coal mines which supply the San Juan and Four Corners generating stations as the timing of payment has not been determined. See Note 4 .

(5) Excludes asset retirement obligations expected to occur through 2066.

(6) These obligations represent TEP's and UES' expected contributions to pension plans in 2012, TEP's expected benefit payments for its unfunded Supplemental Executive Retirement Plan 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 2012 for their funded pension plans due to the significant impact that returns on plan assets and changes in discount rates might have on such amounts. TEP previously funded the postretirement benefit plan on a pay-as-you-go basis. In 2009, TEP established a VEBA Trust to partially fund expected future benefits for union employees. Benefit payments are not expected to be made from the Trust for several years. The 2012 obligation includes expected VEBA contributions. VEBA contributions for periods beyond 2012 cannot be determined at this time.

(7) TEP has agreed with the owners of Springerville Units 3 and 4 that, prior to expiration of the Springerville Coal Handling Facilities and Common Leases, TEP will either renew such leases or exercise its fixed price purchase option under such leases and acquire the leased facilities. TEP has the option of purchasing the facilities at the end of the initial lease term or after one or more renewal periods through 2025 for the Springerville Common Facilities and through 2035 for the Springerville Coal Handling Facilities. The table above reflects the purchase as if TEP exercised the fixed price purchase option at the end of the initial lease term. Upon such acquisitions by TEP, the owners of Springerville Unit 3 have the option and the owner of Springerville Unit 4 has the obligation to purchase from TEP a 17% interest in the Springerville Coal Handling Facilities and a 14% interest in the Springerville Common Facilities.

(8) TEP has a commitment to purchase 9 MW of photovoltaic equipment through December 2013. 6 MW were approved by the ACC, and 3 MW remain subject to ACC approval, which is expected in the fourth quarter of 2012.

(9) In January 2012, UniSource Energy redeemed $35 million of its convertible senior notes. Pursuant to the redemption, substantially all of the notes were converted into approximately 1 million shares of UniSource Energy Common Stock.

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 arrangements contains acceleration clauses or other consequences triggered by changes in our stock price.

Dividends on Common Stock

On February 24, 2012, UniSource Energy declared a first quarter cash dividend of $0.43 per share on its common stock. The first quarter dividend, totaling approximately $16 million, will be paid March 22, 2012 to shareholders of record at the close of business March 12, 2012. The table below summarizes UniSource Energy's dividends paid in 2009 through 2011.

	2011	2010	2009
Quarterly Dividend Per Common Share	$ 0.42	$ 0.39	$ 0.29
Annual Dividend Per Common Share	$ 1.68	$ 1.56	$ 1.16
Common Stock Dividends Paid	$ 62 million	$ 57 million	$ 41 million

Income Tax Position

As of December 31, 2011, UniSource Energy and TEP had the following carry-forward amounts:

	UniSource Energy		TEP	
	Amount	Expiring Year	Amount	Expiring Year
	-Amounts in Millions of Dollars-			
Capital Loss	$ 8	2015	$ —	—
Federal Net Operating Loss	230	2031	212	2031
State Net Operating Loss	—	2016	13	2016
State Credits	1	2016	2	2016
AMT Credit	43	None	25	None

The 2010 Federal Tax Relief Act includes provisions that make qualified property placed into service between September 8, 2010 and January 1, 2012 eligible for 100% bonus depreciation for tax purposes. The same law makes qualified property placed in service during 2012 eligible for 50% bonus depreciation for tax purposes. This is an acceleration of tax benefits UniSource Energy otherwise would have received over 20 years. As a result of these provisions, UniSource Energy did not pay any federal income taxes for the tax year 2011 and does not expect to pay any federal income taxes for 2012.

TUCSON ELECTRIC POWER CO MPANY

RESULTS OF OPERATI ONS

Executive Summary

TEP's financial condition and results of operations are the principal factors affecting the financial condition and results of operations of UniSource Energy. The following discussion relates to TEP's utility operations, unless otherwise noted.

2011 Compared with 2010

TEP recorded net income of $85 million in 2011 compared with $108 million in 2010. The following factors contributed to the decrease in TEP's net income:

- a $15 million decline in long-term wholesale margin revenues resulting primarily from a change in the pricing of energy sold under the SRP wholesale contract effective June 1, 2011;
- a $5 million decrease in wholesale transmission revenues. In the first quarter of 2010, transmission revenues benefitted from the temporary sale of transmission capacity to SRP;
- an $9 million increase in Base O&M primarily due to TEP's share of planned generating plant maintenance expense at San Juan; and
- a $5 million increase in depreciation expense as a result of an increase in plant-in-service;

  partially offset by
- a $7 million pre-tax gain related to the settlement of a dispute with El Paso Electric; and
- a $3 million loss recorded in 2010 related to the settlement of disputed wholesale power transactions.

2010 Compared with 2009

TEP recorded net income of $108 million in 2010 compared with net income of $91 million in 2009. The following factors contributed to the change in TEP's net income:

- $11 million of pre-tax benefits recognized by TEP related primarily to Springerville Unit 4 for operating fees and contributions toward common facility costs received from the owner of Springerville Unit 4. Commercial operation of the unit began in December 2009. See *Factors Affecting Results of Operations, Springerville Units 3 and 4* , below for more information;
- a $10 million decrease in depreciation expense due to lower depreciation rates on TEP's transmission assets and a lengthened depreciation period for leasehold improvements at Sundt Unit 4, partially offset by depreciation related to an increase in plant-in-service. The decrease excludes a $7 million adjustment that increased depreciation expense in the second quarter of 2009, related to a change in accounting for TEP's investment in Springerville Unit 1 lease equity. See *Factors Affecting Results of Operations,* below for more information;
- a $3 million decrease in base O&M expense, which excludes costs directly offset by customer surcharges for renewable energy and demand side management programs and third party reimbursements. The decrease resulted from a decline in pension and postretirement medical expense and lower power plant maintenance expense. See *Operating Expenses, O&M,* below for more information;
- a $7 million decrease in amortization expense due to a decline in the balance of capital lease obligations. The decrease excludes a $3 million adjustment made in the second quarter of 2009 that decreased amortization expense. The adjustment was related to a change in accounting for TEP's investment in Springerville Unit 1 lease equity;
- a $5 million decrease in interest expense on capital lease obligations, excluding an adjustment made in 2009 related to an investment in Springerville Unit 1 lease equity. As TEP pays down its capital lease obligations over time, the resulting interest expense also declines. The decrease in capital lease interest expense was offset by a $5 million decline in interest income during 2010. TEP's investment in lease debt balance, and resulting interest income, also declines over time as TEP pays down its capital lease obligations;
- a $3 million increase in long-term wholesale margin revenues due primarily to an increase in sales volumes to one of TEP's long-term wholesale customers; and
- a $2 million increase in wholesale transmission revenues as TEP temporarily provided transmission capacity for Springerville Unit 4 during the first quarter of 2010.

These factors were partially offset by:

- an $8 million decrease in total other income due in part to interest related to an income tax refund received in 2009 and a decline in gains recognized on company owned life insurance. The decrease excludes a $3 million adjustment that increased other income in the second quarter of 2009, related to a change in accounting for TEP's investment in Springerville Unit 1 lease equity;
- a $6 million increase in interest expense on long-term debt due primarily to the conversion of $130 million of debt from a variable rate to a fixed rate. Although the fixed interest rate is higher than the variable interest rate that was in effect at the time of the conversion, the fixed rate conversion reduced TEP's future interest rate risk and provided other benefits; and
- a $5 million decrease in total retail margin revenues. Weather, the implementation of energy efficiency measures and weak economic conditions contributed to a 0.8% decrease in kWh sales compared with 2009. Cooling Degree Days during 2010 were 3.5% below 2009.

In June 2009, TEP adjusted its accounting for a 2006 investment in 14% of Springerville Unit 1 lease equity. As a result, TEP recorded a net increase to the income statement of $0.6 million, before tax. The adjustment recorded in June 2009 for the period from July 2006 through June 2009 included additional depreciation expense of $7 million; a reduction in amortization expense of $3 million; a reduction of interest expense on capital leases of $2 million; and $3 million of equity in earnings, which is included in Other Income on the income statement.

Utility Sales and Revenues

Customer growth, weather, economic conditions and other consumption factors affect retail sales of electricity. Electric wholesale revenues are affected by prices in the wholesale energy market, the availability of TEP's generating resources, and the level of wholesale forward contract activity.

The table below provides trend information on retail sales by major customer class over the last three years as well as weather data for TEP's service territory.

Energy Sales, kWh (in millions)	2011	2010	2011 vs. 2010 % Change*	2009	2010 vs. 2009 % Change*
Electric Retail Sales:					
Residential	3,888	3,870	0.5%	3,906	(0.9%)
Commercial	1,973	1,963	0.5%	1,988	(1.3%)
Industrial	2,145	2,139	0.3%	2,161	(1.0%)
Mining	1,083	1,079	0.3%	1,065	1.4%
Public Authorities	243	241	1.1%	251	(4.1%)
Total Electric Retail Sales	9,332	9,292	0.4%	9,371	(0.8%)
Retail Margin Revenues (in millions):					
Residential	$ 252	$ 252	0.2%	$ 254	(0.9%)
Commercial	160	159	0.6%	160	(0.5%)
Industrial	95	97	(2.1%)	100	(3.1%)
Mining	32	31	1.9%	30	3.0%
Public Authorities	12	12	0.8%	12	(2.4%)
Total Retail Margin Revenues (Non-GAAP)**	$ 551	$ 551	0.0%	$ 556	(1.0%)
PPFAC Revenues	307	279	9.6%	287	(2.2%)
RES and DSM Revenues	46	38	23.3%	25	48.8%
Total Retail Revenues (GAAP)	$ 904	$ 868	4.1%	$ 868	0.1%
Avg. Retail Margin Revenue (cents / kWh):					
Residential	6.48	6.50	(0.3%)	6.49	0.2%
Commercial	8.11	8.10	0.1%	8.04	0.8%
Industrial	4.42	4.53	(2.4%)	4.62	(2.1%)
Mining	2.92	2.87	1.7%	2.82	1.6%
Public Authorities	5.05	5.07	(0.4%)	4.98	1.7%
Avg. Retail Margin Revenue / kWh	5.90	5.93	(0.5%)	5.93	(0.1%)
Avg. PPFAC Revenue / kWh	3.29	3.01	9.3%	3.05	(1.4%)
Avg. RES & DSM Revenue / kWh	0.50	0.41	22.0%	0.27	50.0%
Total Avg. Retail Revenue / kWh	9.69	9.35	3.7%	9.25	0.9%
Cooling Degree Days					
Actual	1,528	1,543	(1.0%)	1,599	(3.5%)
10-Year Average	1,473	1,468	NM	1,469	NM
Heating Degree Days					
Actual	1,597	1,469	8.7%	1,287	14.1%
10-Year Average	1,417	1,430	NM	1,434	NM

* Percent change calculated on un-rounded data; may not correspond to data shown in table.

** Retail Margin Revenues, a non-GAAP financial measure, should not be considered as an alternative to Net Electric Retail Sales, which is determined in accordance with GAAP. Retail Margin Revenues excludes: (i) revenues collected from retail customers that are directly offset by expenses recorded in other line items; and (ii) revenues collected from third parties that are unrelated to kWh sales to retail customers. We believe the change in Retail Margin Revenues between periods provides useful information to investors because it demonstrates the underlying revenue trend and performance of our core utility business. Retail Margin Revenues represents the portion of retail operating revenues available to cover the operating expenses of our core utility business.

Residential

In 2011, residential kWh sales increased by 0.5% compared with 2010 due in part to a 0.2% increase in the number of residential customers. Residential margin revenues in 2011 were unchanged compared with 2010.

Commercial

Commercial kWh sales increased by 0.5% compared with 2010 due primarily to a 0.6% increase in the number of commercial customers. Commercial margin revenues increased by $1 million, or 0.6%, compared with 2010.

Industrial

Industrial kWh sales increased by 0.3% in 2011 compared with 2010, while margin revenues declined by 2.1%. The decline in margin revenues, despite higher kWh sales, resulted from a change in usage patterns by certain industrial customers that reduced their demand charges paid to TEP.

Mining

The continuation of high copper prices led to increased mining activity, resulting in a 0.3% increase in sales volumes in 2011 compared with 2010. Margin revenues from mining customers increased by 1.9% over 2010, due to higher energy consumption and changing usage patterns which resulted in higher demand charges paid to TEP.

2010 Compared with 2009

Residential

Residential kWh sales were 0.9% lower in 2010 compared with 2009, which led to a decrease in residential margin revenues of $2 million. The decline in residential kWh sales can be attributed to a 3.5% decrease in Cooling Degree Days compared with 2009, weak local economic conditions and energy efficiency measures.

Commercial

Commercial kWh sales in 2010 were 1.3% below 2009 levels. A decline in Cooling Degree Days and weak economic conditions contributed to the sales decline. The lower sales volumes, and resulting lower demand charges, led to a decline in commercial margin revenues of $1 million.

Industrial

Industrial kWh sales declined by 1.0% compared with 2009, due primarily to weak economic conditions. Margin revenues from industrial customers decreased by 3.1%, or $3 million due to changing usage patterns that reduced demand charges.

Mining

Higher copper prices led to increased mining activity resulting in a 1.4% increase in sales volumes in 2010 compared with 2009. Margin revenues from mining customers increased $1 million, or 3.0%, compared with the prior year due to changing usage patterns that increased demand charges.

Wholesale Sales and Transmission Revenues

	2011	2010	2009
Long-Term Wholesale Revenues:		-Millions of Dollars-	
Long-Term Wholesale Margin Revenues (Non-GAAP)*	$ 13	$ 28	$ 25
Fuel and Purchased Power Expense Allocated to Long- Term Wholesale Revenues	28	28	23
Total Long-Term Wholesale Revenues	$ 41	$ 56	$ 48
Transmission Revenues	16	21	19
Short-Term Wholesale Revenues	73	64	86
Electric Wholesale Sales (GAAP)	**$ 130**	**$ 141**	**$ 153**

* Long-Term Wholesale Margin Revenues, a non-GAAP financial measure, should not be considered as an alternative to Electric Wholesale Sales, which is determined in accordance with GAAP. We believe the change in Long-Term Wholesale Margin Revenues between periods provides useful information to investors because it demonstrates the underlying profitability of TEP's long-term wholesale sales contracts. Long-Term Wholesale Margin Revenues represents the portion of long-term wholesale revenues available to cover the operating expenses of our core utility business.

Long-term wholesale margin revenues from long-term wholesale contracts were $15 million lower than in 2010. The decrease was due primarily to a change in pricing under the SRP contract. See *Factors Affecting Results of Operations, Long-Term Wholesale Sales, Salt River Project,* below, for more information.

Wholesale transmission revenues in 2011 decreased by $5 million compared with 2010. In 2010, TEP provided short-term transmission capacity to SRP for Springerville Unit 4.

TEP credits all revenues from short-term wholesale sales and 90% of the margin on wholesale trading activity against the fuel and purchased power costs eligible for recovery in the PPFAC. There was no wholesale trading activity in 2009, 2010 and 2011.

In April 2010, TEP settled all remaining claims arising from certain of its transactions with the California Power Exchange (CPX) and the California Independent System Operator (CISO) during the California energy crisis of 2000 and 2001. As a result of this settlement, TEP recorded a $3 million pre-tax charge against income in the first quarter of 2010. In December 2009, TEP recorded a pre-tax charge of $4 million against income also related to transactions with the CPX and CISO in 2000 and 2001.

Other Revenues

	2011	2010	2009
		-Millions of Dollars-	
Revenue related to Springerville Units 3 and 4 [1]	$ 97	$ 97	$ 60
Other Revenue	26	22	23
Total Other Revenue	$ 123	$ 119	$ 83

[1] Represents reimbursements for expenses incurred by TEP related to the operation of Springerville Units 3 and 4.

In addition to reimbursements related to Springerville Units 3 and 4, TEP's other revenues include: inter-company revenues from UNS Gas and UNS Electric for corporate services provided by TEP; and miscellaneous service-related revenues such as power pole attachments, damage claims and customer late fees.

Operating Expenses

2011 Compared with 2010

Fuel and Purchased Power Expense

TEP's fuel and purchased power expense and energy resources for 2011, 2010 and 2009 are detailed below:

TEP	Generation and Purchased Power			Fuel and Purchased Power Expense		
	2011	2010	2009	2011	2010	2009
		-Millions of kWh-			-Millions of Dollars-	
Coal-Fired Generation	9,946	9,481	9,272	$ 254	$ 217	$ 198
Gas-Fired Generation	929	1,078	992	55	60	76
Renewable Generation	37	32	30	—	—	—
Total Generation	10,912	10,591	10,294	309	277	274
Purchased Power	2,687	2,846	3,810	106	119	145
Reimbursed Fuel Expense	—	—	—	8	7	5
Transmission	—	—	—	(1)	3	3
Increase (Decrease) to Reflect PPFAC Treatment	—	—	—	(6)	(21)	(18)
Total Resources	13,599	13,437	14,104	$ 416	$ 385	$ 409
Less Line Losses and Company Use	(795)	(876)	(941)			
Total Energy Sold	12,804	12,561	13,163			

Generation

Total generating output increased during 2011 compared with 2010. The higher output was primarily due to the increased availability of TEP's largest coal-fired generating plants, Springerville Units 1 and 2. In 2010, Springerville Units 1 and 2 experienced unplanned outages, in addition to a planned maintenance outage at Springerville Unit 1.

Purchased Power

Purchased power volumes decreased in 2011 compared with 2010. The lower volume of power purchases was primarily due to the increased availability of TEP's coal-fired generating resources.

The table below summarizes TEP's cost per kWh generated or purchased.

	2011	2010	2009
		-cents per kWh generated-	
Coal	2.56	2.29	2.14
Gas	5.99	5.58	7.66
Purchased Power	3.94	4.17	3.79

Market Prices

As a participant in the western U.S. wholesale power markets, TEP is affected by changes in market conditions. We cannot predict whether changes in various factors that influence demand and supply will cause prices to change during 2012.

Average Market Price for Around-the-Clock Energy		$/MWh
2011	$	30
2010		34
2009	$	30

Average Market Price for Natural Gas		$/MMBtu
2011	$	3.89
2010		4.18
2009	$	3.34

O&M

The table below summarizes the items included in TEP's O&M expense.

		2011		2010		2009
				-Millions of Dollars-		
Base O&M (Non-GAAP) (1)	$	237	$	228	$	231
O&M recorded in Other Expense		(8)		(7)		(7)
Reimbursed expenses related to Springerville Units 3 and 4		63		65		41
Expenses related to customer funded renewable energy and DSM programs		39		31		18
Total O&M (GAAP)	$	331	$	317	$	283

(1) Base O&M, a non-GAAP financial measure, should not be considered as an alternative to Other O&M, which is determined in accordance with GAAP. We believe Base O&M provides useful information to investors because it represents the fundamental level of operating and maintenance expense related to our business. Base O&M excludes expenses that are directly offset by revenues collected from customers and other third parties.

TEP's base O&M expense in 2011 was $237 million, or $9 million above 2010. The increase is due primarily to unplanned outages at San Juan in 2011.

Income Tax Expense

In 2011, TEP's effective tax rate was 38% compared with 36% in 2010. The increase is primarily due to a decrease in federal deductions along with federal and state tax credits. See Note 8 for more information.

2010 Compared with 2009

Generation

Coal-related fuel expense in 2010 increased by $19 million compared with 2009 due primarily to the switching of fuel at Sundt Unit 4 from natural gas to coal. TEP fueled Sundt 4 on coal for eight months in 2010, compared with two months in 2009. Gas-related fuel expense decreased in 2010 due primarily to a decrease in realized losses on gas hedging activities.

Purchased Power

Purchased power volumes and expense during 2010 were lower than 2009 due to a decrease in short-term wholesale sales activity, an increase in coal-fired generating output, and a decline in retail sales volumes.

O&M

TEP's base O&M expense in 2010 was $228 million, or $3 million below 2009. The decline is due primarily to fewer plant maintenance outages and a decrease in pension and postretirement medical expense in 2010 compared with 2009.

FACTORS AFFECTING RESULTS OF OPERATIONS

Base Rate Increase Moratorium

Pursuant to the 2008 TEP Rate Order, TEP's Base Rates are frozen through at least December 31, 2012. TEP is prohibited from submitting an application for new Base Rates before June 30, 2012. The test year to be used in TEP's next Base Rate application cannot end earlier than December 31, 2011.

Notwithstanding the rate increase moratorium, Base Rates and adjustor mechanisms may change under emergency conditions beyond TEP's control if the ACC concludes such changes are required to protect the public interest. The moratorium does not preclude TEP from seeking rate relief in the event of the imposition of a federal carbon tax or related federal carbon regulations.

Springerville Units 3 and 4

TEP operates and receives annual benefits in the form of rental payments and other fees and cost savings from operating Springerville Unit 3 on behalf of Tri-State and Springerville Unit 4 on behalf of SRP. Springerville Unit 4 began commercial operations in December 2009. TEP recorded pre-tax income of $24 million in 2011 and 2010, and $13 million in 2009 related to the operation of these units. The table below summarizes the income statement line items where TEP records revenues and expenses related to Springerville Units 3 and 4.

	2011	2010	2009
		-Millions of Dollars-	
Other Revenues	$ 97	$ 97	$ 60
Fuel Expense	(8)	(7)	(5)
Operations and Maintenance Expense	(63)	(65)	(41)
Taxes Other Than Income Taxes	(2)	(1)	(1)
Total Pre-Tax Income	$ 24	$ 24	$ 13

Pension and Postretirement Benefit Expense

The table below summarizes TEP's pension and other postretirement benefit expenses charged to O&M in 2009, 2010, and 2011. See Note 9 for more information.

	2011	2010	2009
		-Millions of Dollars-	
Pension Expense Charged to O&M	$ 10	$ 9	$ 12
Other Postretirement Benefit Expense Charged to O&M	4	4	4
Total	$ 14	$ 13	$ 16

In 2012, TEP expects to charge $10 million of pension and $5 million of other postretirement benefit expense to O&M.

Long-Term Wholesale Sales

In 2011 and 2010, TEP's margin on long-term wholesale sales was $13 million and $28 million, respectively. TEP's two primary long-term wholesale contracts are with SRP and NTUA.

Salt River Project

Prior to June 1, 2011, under the terms of the SRP contract, TEP received a monthly demand charge of approximately $1.8 million, or $22 million annually, and sold the energy at a price based on TEP's average fuel cost. From June 1, 2011 to December 31, 2011, SRP was required to purchase 73,000 MWh per month. From January 1, 2012 through the end of the contract in May 2016, SRP is required to purchase 500,000 MWh of on-peak energy per year. TEP does not receive a demand charge and the price of energy is based on a discount to the price of on-peak power on Palo Verde Market Index. As of February 21, 2012, the average forward price of on-peak power on the Palo Verde Market Index for the calendar year 2012 was $30.33 MWh.

Navajo Tribal Utility Authority

TEP serves the portion of NTUA's load that is not served from NTUA's allocation of federal hydroelectric power. Over the last three years, sales to NTUA averaged 225,000 MWh. Since 2010, the price of 50% of the MWh sales from June to September has been based on the Palo Verde Market Index. In 2011, approximately 12% of the total energy sold to NTUA was priced based on the Palo Verde Market Index. The remaining power sales occur at a fixed price under TEP's contract with NTUA.

For more information on long-term wholesale sales, see *Item. 1 Business, TEP, Service Area and Customers, Wholesale Business.*

Electric Energy Efficiency Standards (EE Standards)

In August 2010, the ACC approved new EE Standards designed to require TEP, UNS Electric and other affected electric utilities to implement cost-effective programs to reduce customers' energy consumption. In 2011, TEP's programs saved energy equal to approximately 1.4% of its 2010 sales. In 2012, the EE Standards target total kWh savings of 3% of 2011 sales. The EE Standards increase annually thereafter up to a targeted cumulative annual reduction in retail kWh sales of 22% by 2020.

The EE Standards can be met by new and existing DSM programs, direct load control programs and energy efficient building codes. The EE Standards provide for the recovery of costs incurred to implement DSM programs. TEP's programs and Retail Rates charged to customers for such programs are subject to annual approval by the ACC.

In January 2012, TEP filed a modification to its Energy Efficiency Implementation Plan with the ACC. The proposal includes a request for an increase in the performance incentive based on TEP's ability to meet the EE targets for 2012 and for 2013. TEP's proposed annual performance incentive for 2012 and 2013 ranges from $6 million to $8 million. TEP expects the ACC to issue a decision on this matter in the first quarter of 2012.

Decoupling

In December 2010, the ACC issued a policy statement recognizing the need to adopt rate decoupling or another mechanism to make Arizona's EE Standards viable. A decoupling mechanism is designed to encourage energy conservation by restructuring utility Retail Rates to separate the recovery of fixed costs from the level of energy consumed. The policy statement allows affected utilities to file rate decoupling proposals in their next general rate case. TEP expects to file its next general rate case on or after June 30, 2012.

Competition

New technological developments and the implementation of EE Standards may reduce energy consumption by TEP's retail customers. TEP's customers also have the ability to install renewable energy technologies and conventional generation units that could reduce their reliance on TEP's services. Self-generation by TEP's customers 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. See *Item 1. Business, TEP, Rates and Regulation, Electric Energy Efficiency Standards and Decoupling* for more information.

Renewable Energy Standard and Tariff

In 2010, the ACC approved a funding mechanism that allows TEP to recover operating costs, depreciation, property taxes, and a return on investments in company-owned solar projects through RES funds until such costs are reflected in TEP's Base Rates. TEP invested $14 million in two solar projects that were completed in December 2010 and began cost recovery through the RES surcharge in January 2011. During 2011, TEP earned approximately $1 million pre-tax on its 2010 investment in solar projects. In accordance with the funding mechanism approved by the ACC in 2010, TEP could earn approximately $1 million pre-tax in 2012 on solar investments made in 2010 and 2011.

In December 2011, the ACC approved TEP's RES implementation plan including investments of $28 million in 2012 and $8 million in 2013 for company-owned solar projects. In 2011, TEP's renewable energy investments totaled $28 million. In accordance with the funding mechanism approved by the ACC, TEP could earn approximately $1 million pre-tax in 2012 on solar investments made in 2010 and 2011 and approximately $4 million pre-tax in 2013. For more information see *Item 1. Business, TEP, Rates and Regulation, Renewable Energy Standard and Tariff.*

Sales to Mining Customers

The continuation of copper prices of $3 per pound has led to increased mining activity at the copper mines operating in TEP's service area. TEP's mining customers have indicated they are taking initial steps to increase production either through expansion of their current mining operations or by the re-opening of non-operational mine sites. If efforts to increase production are successful, TEP's mining load could increase by up to 100 MW over the next several years. The market price for copper and the ability to obtain necessary permits could affect the mining industry's expansion plans.

In 2011, sales to TEP's mining customers increased 0.3% compared with 2010 and represented 11% of TEP's total retail kWh sales and 6% of total retail margin revenues.

In addition to the mining customers TEP currently serves, in 2007, Augusta Resources Corporation (Augusta) filed a plan of operations with the United States Forest Service (USFS) for the proposed Rosemont Copper Mine near Tucson, Arizona. The Rosemont mine requires electric service from TEP via a 138kV transmission line for the construction and ongoing operation of the mine. A certificate of environmental compatibility (CEC) from the ACC's line siting committee was approved in December 2011 for the 138 kV transmission line. Appeals have been filed relative to the issuance of the CEC. If the Rosemont Copper Mine reaches full production, it would become TEP's largest retail customer. TEP would serve approximately 100 MW of the Rosemont Copper Mine's total estimated load of approximately 110 MW.

TEP cannot predict if or when existing mines will expand operations or new or re-opened mines will commence operations.

Interest Rates

TEP is exposed to interest rate risk resulting from changes in interest rates on certain of its variable rate debt obligations, as well as borrowings under its revolving credit facility. As a result, TEP may be required to pay significantly higher rates of interest on outstanding variable rate debt and borrowings under its revolving credit facility. At December 31, 2011 TEP had $215 million in tax-exempt variable rate debt outstanding. The interest rates on TEP's tax-exempt variable rate debt are reset weekly by its remarketing agents. The maximum interest payable under the indentures for the bonds is 10% on the $37 million of bonds and 20% on the other $178 million. During 2011, the average rates paid ranged from 0.05% to 0.34%. At February 21, 2012, the average rate on the debt was 0.26%.

TEP has a fixed-for-floating interest rate swap in place to hedge $50 million of its variable rate IDBs.

TEP is also subject to interest rate risk resulting from changes in interest rates on its borrowings under the revolving credit facility. The interest paid on revolving credit borrowings is variable. If LIBOR and other benchmark interest rates increase, TEP may be required to pay higher rates of interest on borrowings under its revolving credit facility. See Item 7A. *Quantitative and Qualitative Disclosures about Market Risk, Interest Rate Risk* , below.

San Juan Mine Fire

In September 2011, a fire at the underground mine that provides coal to San Juan caused mining operations to shut down. TEP owns approximately 20% of San Juan, which is operated by PNM. As we are unable to predict when operations will resume at the mine, we and the other owners of San Juan are considering alternatives for operating the facility.

However, based on information we have received to date, we do not expect the mine fire to have a material effect on our financial condition, results of operations, or cash flows due to the current inventory of previously mined coal and the current low market price of wholesale power. TEP expects that any incremental fuel and purchased power costs would be recoverable from customers through the PPFAC, subject to ACC approval.

Fair Value Measurements

TEP's income statement exposure to risk is mitigated as TEP reports the change in fair value of energy contract derivatives as a regulatory asset or a regulatory liability, or as a component of AOCI rather than in the income statement. See Note 11 for more information.

LIQUIDITY AND CAPITAL RESOURCES

TEP Cash Flows

The table below shows the cash available to TEP after capital expenditures, scheduled debt payments and payments on capital lease obligations:

	2011	2010	2009
Net Cash Flows – Operating Activities (GAAP)	$ 268	$ 302	$ 268
Amounts from Statements of Cash Flows:			
Less: Capital Expenditures (1)	(352)	(277)	(240)
Net Cash Flows after Capital Expenditures (Non-GAAP)*	(84)	25	28
Amounts From Statements of Cash Flows:			
Less: Retirement of Capital Lease Obligations	(74)	(56)	(24)
Plus: Proceeds from Investment in Lease Debt	38	26	13
Net Cash Flows after Capital Expenditures and Required Payments on Debt and Capital Lease Obligations (Non-GAAP)*	$ (120)	$ (5)	$ 17

(1) 2010 includes a $51 million payment for the purchase of Sundt Unit 4 lease equity.

	2011	2010	2009
Net Cash Flows – Operating Activities (GAAP)	$ 268	$ 302	$ 268
Net Cash Flows – Investing Activities (GAAP)	(312)	(253)	(250)
Net Cash Flows – Financing Activities (GAAP)	51	(52)	(29)
Net Cash Flows after Capital Expenditures (Non-GAAP)*	(84)	25	28
Net Cash Flows after Capital Expenditures and Required Payments on Debt and Capital Lease Obligations (Non-GAAP)*	(120)	(5)	17

* Net Cash Flows after Capital Expenditures and Net Cash Flows Available after Capital Expenditures and Required Payments on Debt and Capital Lease Obligations, 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. We believe that Net Cash Flows after Capital Expenditures and Net Cash Flows Available after Capital Expenditures and Required Payments on Debt and Capital Lease Obligations provide useful information to investors as measures of TEP's ability to fund capital requirements, make required principal payments on debt and capital lease obligations (net), and pay dividends to UniSource Energy.

Liquidity Outlook

During 2012, TEP expects to generate sufficient internal cash flows to fund the majority of its capital expenditures and operating activities. 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.

Operating Activities

In 2011, net cash flows from operating activities decreased by $34 million compared with 2010. Net cash flows were impacted by:

- a $38 million increase in O&M costs due in part to higher generating plant outage costs, higher up-front incentive payments for customer-installed solar systems, and higher DSM payments;
- a $5 million increase in taxes other than income taxes due to a higher sales tax rate effective in June 2010 and sales taxes paid on higher retail kWh sales; and
- a $10 million decrease in cash receipts from electric sales, net of fuel and purchased power costs. This decrease was due to higher coal costs and lower long-term wholesale margins compared with 2010;

  partially offset by

- a $17 million decrease in income taxes paid due to lower taxable income resulting from bonus depreciation deductions.

Investing Activities

Net cash flows used for investing activities increased by $59 million in 2011 compared with 2010. Capital expenditures during 2011 were $75 million higher than in 2010, which was partially offset by a $13 million increase in proceeds from the return of investment in Springerville lease debt.

Capital Expenditures

TEP's forecasted capital expenditures are summarized below:

	2012	2013	2014	2015	2016
			-Millions of Dollars-		
Transmission and Distribution	$ 158	$ 179	$ 129	$ 99	$ 118
Generation Facilities	57	80	93	72	169
Renewable Energy Generation	32	30	30	30	30
Environmental	2	19	89	94	64
General and Other	40	38	38	36	37
Total	$ 289	$ 346	$ 379	$ 331	$ 418

TEP's estimated capital expenditures in 2015 exclude the potential $159 million purchase of interests in Springerville Unit 1 and the potential $120 million purchase of interests in Springerville Coal Handling Facilities upon the expiration of their respective leases in January 2015. See *Capital Lease Obligations* , below for more information.

TEP's capital expenditures also exclude the estimated cost to construct a proposed Tucson to Nogales, Arizona 345 KV transmission line of $120 million. See *Item 1. Business, TEP, Transmission Access, Tucson to Nogales Transmission Line* for more information.

All of these estimates are subject to continuing review and adjustment. Actual capital expenditures may be different from these estimates due to changes in business conditions, construction schedules, environmental requirements, state or federal regulations and other factors.

Investments in Springerville Lease Debt

At December 31, 2011, TEP had $29 million of investments in lease debt on its balance sheet. Unless TEP makes new investments in lease debt, the investment in lease debt balance declines over time due to the amortization of lease debt that occurs as a result of the normal payments TEP makes on its capital lease obligations. The Springerville Unit 1 and Springerville Coal Handling Facilities leases expire in 2015.

See Note 6 for more information .

Financing Activities

In 2011, net cash from financing activities was $103 million higher than in 2010 due to: a $45 million increase in borrowings (net of repayments) under TEP's revolving credit facility; a $15 million increase in capital contributions from UniSource Energy in 2011; and a $60 million reduction in dividends paid to UniSource Energy during 2011; partially offset by an $18 million increase in payments on capital lease obligations.

TEP Credit Agreement

In November 2011, TEP amended and extended its existing credit agreement (the TEP Credit Agreement). The TEP Credit Agreement consisted of a $200 million revolving credit and revolving letter of credit facility and a $341 million letter of credit facility to support variable rate tax-exempt bonds. The amendment extended the term of the TEP Credit Agreement by two years to November 2016.

In December 2011, TEP reduced its letter of credit facility from $341 million to $186 million, following the repurchase of $150 million of variable rate IDBs and the cancellation of $155 million of LOCs supporting those bonds. The TEP Credit Agreement is secured by $386 million of Mortgage Bonds. See *2011 Bond Issuances, Purchase and Redemptions,* below.

At December 31, 2011, TEP had $10 million in borrowings outstanding and $1 million of letters of credit issued under the revolving credit facility.

The TEP Credit Agreement contains restrictions on liens, mergers and sale of assets. The TEP Credit Agreement also requires TEP not to exceed 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, 2011, TEP was in compliance with the terms of the TEP Credit Agreement.

TEP Reimbursement Agreement

In December 2010, TEP entered into a four-year $37 million reimbursement agreement (2010 TEP Reimbursement Agreement). A $37 million letter of credit was issued pursuant to the 2010 TEP Reimbursement Agreement. The letter of credit supports $37 million aggregate principal amount of variable rate tax-exempt IDBs that were issued on behalf of TEP in December 2010.

The 2010 TEP Reimbursement Agreement contains substantially the same restrictive covenants as the TEP Credit Agreement described above. As of December 31, 2011, TEP was in compliance with the terms of the 2010 TEP Reimbursement Agreement.

Capital Contribution from UniSource Energy

In December 2011, UniSource Energy contributed $30 million of capital to TEP.

In March 2010, UniSource Energy contributed $15 million of capital to TEP. TEP used the proceeds to help fund the purchase of Sundt Unit 4.

In March 2009, UniSource Energy contributed $30 million of capital to TEP. TEP used the proceeds to purchase Springerville Unit 1 lease debt.

2011 Bond Issuances, Purchases and Redemptions

In November 2011, TEP issued $250 million in unsecured notes due in November 2021 (TEP Notes). The TEP Notes bear interest at 5.15% and are callable prior to August 2021 with a make-whole redemption premium. The TEP Notes contain a limitation on the amount of secured debt that TEP may have outstanding. TEP used the net proceeds from the sale of the TEP Notes to (i) repurchase $150 million of its tax-exempt variable rate bonds, (ii) redeem approximately $22 million of fixed rate bonds with a coupon of 6.1% and (iii) repay $78 million on its revolving credit facility.

The $150 million of tax-exempt variable rate debt purchased by TEP was not retired but will be held in treasury and may be reissued or refunded in the future.

2010 Bond Issuances

In 2010, $137 million of tax-exempt bonds were issued on behalf of TEP, with $37 million of such bonds being applied to redeem a corresponding amount of outstanding tax-exempt bonds. In addition, in 2010 TEP converted the interest rate mode on $100 million of tax-exempt bonds from a variable rate to a fixed rate.

Tax-Exempt Bonds

TEP has financed a substantial portion of utility plant assets with revenue bonds issued by governmental entities on TEP's behalf. The interest on these bonds is excluded from gross income of the bondholder for federal income tax purposes. The proceeds of the bonds are loaned to TEP, with TEP agreeing to repay the loans by making payments in amounts and at times to enable payments of principal of and interest on the tax-exempt bonds to be paid when due. Of the $831 million of tax-exempt bonds outstanding as of December 31, 2011, $616 million are unsecured and bear interest at fixed rates and $215 million are variable rate bonds. The variable rate bonds accrue interest at a weekly rate, with bondholders having the right to require their bonds to be purchased upon demand at a purchase price of par plus accrued interest. Variable rate bonds which have been put for purchase are generally remarketed to third parties to pay the purchase price. Payments of principal, interest and purchase price on the variable rate bonds are supported by direct-pay letters of credit, with TEP being required to reimburse the letter of credit banks for drawings on the letters of credit. See *TEP Credit Agreement* and *TEP Reimbursement Agreement* for more information.

Mortgage Indenture

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. The 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 mortgage indenture.

At December 31, 2011, TEP had a total of $423 million in outstanding Mortgage Bonds, consisting of $386 million in bonds securing the TEP Credit Agreement, and $37 million in bonds securing the 2010 TEP Reimbursement Agreement.

Capital Lease Obligations

At December 31, 2011, TEP had $430 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.

Leases	Capital Lease Obligation Balance -Millions of Dollars-	Expiration	Renewal/Purchase Option
Springerville Unit 1 (1)	$ 253	2015	Fair market value purchase option of $159 million
Springerville Coal Handling Facilities Lease	65	2015	Fixed price purchase option of $120 million (2)
Springerville Common Facilities (3)	112	2017 and 2021	Fixed price purchase option of $106 million (2)
Total Capital Lease Obligations	$ 430		

(1) The Springerville Unit 1 Leases cover both Unit 1 and an undivided one-half interest in certain Springerville Common Facilities.

(2) TEP agreed with Tri-State, the owner of Springerville Unit 3 and SRP, the owner of Springerville Unit 4, that if the Springerville Coal Handling Facilities and Common Leases are not renewed, TEP will exercise the purchase options under these contracts. SRP will then be obligated to buy a portion of these facilities and Tri State will then be obligated to either 1) buy a portion of these facilities; or 2) continue making payments to TEP for the use of these facilities.

(3) The Springerville Common Facilities Leases cover an undivided one-half interest in certain Springerville Common Facilities.

TEP's capital lease obligation balances decline over time due to the normal capital lease payments made by TEP. See Note 6 for more information about the fixed purchase price amounts.

Contractual Obligations

The following chart displays TEP's contractual obligations as of December 31, 2011 by maturity and by type of obligation.

TEP's Contractual Obligations
- Millions of Dollars -

Payment Due in Years Ending December 31,	2012	2013	2014	2015	2016	2017 and after	Other	Total
Long Term Debt								
Principal	$ —	$ —	$ 37	$ —	$ 178	$ 866	$ —	$ 1,081
Interest	53	53	53	53	53	551	—	816
Capital Lease Obligations	118	122	195	23	18	61	—	537
Operating Leases	2	2	2	1	1	10	—	18
Purchase Obligations:								
Fuel (including Transportation)	84	59	58	44	41	75	—	361
Purchased Power [1]	29	21	17	13	13	184	—	277
Transmission	3	3	3	3	3	23	—	38
Other Long-Term Liabilities:								
Pension & Other Post Retirement Obligations	26	5	6	6	6	34	—	83
Acquisition of Springerville Coal Handling and Common Facilities	—	—	—	120	—	106	—	226
Solar Equipment	12	12	—	—	—	—	—	24
Unrecognized Tax Benefits	—	—	—	—	—	—	24	24
Total Contractual Cash Obligations	$ 327	$ 277	$ 371	$ 263	$ 313	$ 1,910	$ 24	$ 3,485

1 Purchased Power includes two long-term Power Purchase Agreements (PPAs) with renewable energy generation producers to meet compliance under the RES tariff. The facilities achieved commercial operation in 2011. TEP is obligated to purchase 100% of the output from these facilities. The table above includes estimated future payments based on expected power deliveries under these contracts through 2031. TEP has entered into additional long-term renewable PPAs to comply with the RES tariff; however, TEP's obligation to accept and pay for electric power under these agreements does not begin until the facilities are constructed and operational.

See *UniSource Energy Consolidated, Liquidity and Capital Resources, Contractual Obligations* , above, for a description of these obligations.

We have reviewed our contractual obligations and provide the following additional information:

- TEP's Credit Agreement contains pricing 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, and the amount of fees it pays for its letters of credit and unused commitments. A downgrade in TEP's credit ratings would not cause a restriction in TEP's ability to borrow under its revolving credit facility.
- TEP's Credit Agreement contains certain financial and other restrictive covenants, including a leverage test. Failure to comply with these covenants would entitle the lenders to accelerate the maturity of all amounts outstanding. At December 31, 2011, 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 credit enhancements in the form of cash or a letter of credit due to exposures exceeding unsecured credit limits provided to TEP, 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, 2011, TEP had posted a $1 million letter of credit as collateral with counterparties for credit enhancement.

Dividends on Common Stock

TEP did not pay any dividends to UniSource Energy in 2011. TEP declared and paid dividends to UniSource Energy of $60 million in 2010 and $60 million in 2009.

TEP can pay dividends if it maintains compliance with the TEP Credit Agreement, the 2010 Reimbursement Agreement, and certain financial covenants. As of December 31, 2011, TEP was in compliance with the terms of the TEP Credit Agreement and the 2010 Reimbursement 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 for TEP to pay dividends from current year earnings.

UNS GAS

RESULTS OF OPERATIONS

UNS Gas reported net income of $10 million in 2011, $9 million in 2010 and $7 million in 2009. We expect operations at UNS Gas to vary with the seasons, with peak energy usage occurring in the winter months.

The table below provides summary financial information for UNS Gas.

	2011	2010	2009
		-Millions of Dollars-	
Gas Revenues	$ 148	$ 146	$ 149
Other Revenues	3	4	4
Total Operating Revenues	151	150	153
Purchased Gas Expense	90	91	99
Other Operations and Maintenance Expense	25	26	25
Depreciation and Amortization	9	8	7
Taxes Other Than Income Taxes	3	3	3
Total Other Operating Expenses	127	128	134
Operating Income	24	22	19
Total Interest Expense	7	7	6
Income Tax Expense	7	6	6
Net Income	$ 10	$ 9	$ 7

The table below shows UNS Gas' therm sales and revenues for 2011, 2010 and 2009.

	2011	2010	Increase (Decrease) Amount	Increase (Decrease) Percent*	2009
Energy Sales, Therms (in millions)					
Gas Retail Sales:					
Residential	74	73	1	1.2%	70
Commercial	31	30	1	2.9%	30
Industrial	2	2	—	22.9%	2
Public Authorities	7	7	—	(0.2%)	6
Total Gas Retail Sales	114	112	2	1.9%	108
Negotiated Sales Program (NSP)	26	28	(2)	(8.4%)	30
Total Gas Sales	140	140	—	(0.2%)	138
Gas Revenues (in millions):					
Retail Margin Revenues:					
Residential	$ 40	$ 39	$ 1	2.6%	$ 36
Commercial	11	10	1	4.9%	10
Industrial	—	—	—	21.9%	—
Public Authorities	2	2	—	4.8%	2
Total Retail Margin Revenues (Non-GAAP)**	53	51	2	3.1%	48
Transport and NSP	17	17	—	(4.6%)	16
DSM	1	1	—	10.0%	1
Retail Fuel Revenues	77	77	—	1.0%	84
Total Gas Revenues (GAAP)	$ 148	$ 146	$ 2	1.2%	$ 149
Weather Data:					
Heating Degree Days					
Year Ended December 31	25,794	25,457	337	1.3%	24,305
10-Year Average	24,894	24,828	NM	NM	24,739

- Percent change calculated on unrounded data and may not correspond exactly to data shown in table.

** Retail Margin Revenues, a non-GAAP financial measure, should not be considered as an alternative to Total Gas Revenues, which is determined in accordance with GAAP. Retail Margin Revenues excludes revenues collected from retail customers that are directly offset by expenses recorded in other line items. We believe the change in Retail Margin Revenues between periods provides useful information to investors because it demonstrates the underlying revenue trend and performance of our core utility business. Retail Margin Revenues represents the portion of retail operating revenues available to cover the operating expenses of our core utility business.

Retail therm sales during 2011 increased by 1.9% compared with 2010 due in part to a 1.3% increase in heating degree days and an increase in the number of retail customers. Retail margin revenues increased by 3.1%, or $2 million, during 2011 due in part to colder winter weather and a Base Rate increase that was implemented in April 1, 2010. As of December 31, 2011, UNS Gas had approximately 148,000 retail customers, which represents an increase of less than 1% compared with the end of 2010.

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 PGA mechanism which reduces the gas commodity price.

FACTORS AFFECTING RESULTS OF OPERATIONS

Competition

New technological developments and the implementation of Gas EE Standards may reduce energy consumption by UNS Gas' retail customers. Customers of UNS Gas also have the ability to switch from gas to an alternate energy source that could reduce their reliance on services provided by UNS Gas. See *Item 1. Business, UNS Gas, Rates and Regulation, Gas Utility Energy Efficiency Standards and Decoupling* for more information.

Rates

See *Item 1. Business, UNS Gas, Rates and Regulation, 2011 UNS Gas Rate Filing.*

Interest Rates

UNS Gas is subject to interest rate risk resulting from changes in interest rates on its borrowings under its revolving credit facility. The interest paid on revolving credit borrowings is variable. If LIBOR or other benchmark interest rates increase, UNS Gas may be required to pay higher rates of interest on borrowings under its revolving credit facility. See *Item 7A. Quantitative and Qualitative Disclosures about Market Risk, Interest Rate Risk* , below.

Fair Value Measurements

UNS Gas' income statement exposure to risk is mitigated as UNS Gas reports the change in fair value of energy contract derivatives as a regulatory asset or a regulatory liability rather than in the income statement. See Note 11 for more information.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity Outlook

UNS Gas' capital requirements consist primarily of capital expenditures. In 2011, capital expenditures were $13 million. UNS Gas expects operating 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 contributions from UniSource Energy.

Operating Cash Flow and Capital Expenditures

The table below provides summary cash flow information for UNS Gas.

	2011	2010	2009
		-Millions of Dollars-	
Cash Provided By (Used In):			
Operating Activities	$ 32	$ 18	$ 37
Investing Activities	(12)	(9)	(13)
Financing Activities	(11)	(11)	—
Net Increase (Decrease in Cash)	9	(2)	24
Beginning Cash	29	31	7
Ending Cash	$ 38	$ 29	$ 31

Operating cash flows increased in 2011 due in part to the temporary over-collection of PGA gas costs from customers.

UNS Gas/UNS Electric Revolver

In November 2011, UNS Gas and UNS Electric amended their existing unsecured credit agreement. The UNS Electric/UNS Gas Revolver consists of a $100 million unsecured revolving credit and revolving letter of credit facility. Either company can borrow up to a maximum of $70 million as long as the combined amount borrowed does not exceed $100 million. The amendment extended the term of the UNS Electric/UNS Gas Revolver by two years to November 2016.

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.

The UNS Gas/UNS Electric Revolver restricts additional indebtedness, liens, and mergers. It also requires each borrower not to exceed a maximum leverage ratio. Each borrower may pay dividends so long as it maintains compliance with the agreement. As of December 31, 2011, UNS Gas and UNS Electric each were in compliance with the terms of the UNS Gas/UNS Electric Revolver.

UNS Gas expects to draw upon the UNS Gas/UNS Electric Revolver from time to time for seasonal working capital purposes, to fund a portion of its capital expenditures, or to issue letters of credit to provide credit enhancement for its natural gas procurement and hedging activities. As of December 31, 2011, UNS Gas had no outstanding borrowings or letters of credit under the UNS Gas/UNS Electric Revolver.

Senior Unsecured Notes

UNS Gas has $100 million of senior unsecured notes outstanding, of which $50 million matures in 2015 and $50 million matures in 2026.

All of UNS Gas' senior unsecured notes are guaranteed by UES. The note purchase agreements for UNS Gas restrict transactions with affiliates, mergers, liens, restricted payments and incurrence of indebtedness. The agreements also contain a minimum net worth test. As of December 31, 2011, UNS Gas was in compliance with the terms of its note purchase agreements.

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 $5 million in short-term debt.

Note Issuance

In August 2011, UNS Gas issued $50 million of 5.39% senior unsecured notes. The proceeds were used to pay off $50 million of senior unsecured notes that matured in August 2011.

Contractual Obligations

UNS Gas Supply Contracts

UNS Gas directly manages its gas supply and transportation contracts. The market price for gas varies based upon the period during which the commodity is purchased. UNS Gas has firm transportation agreements with capacity sufficient to meet its current load requirements. These contracts expire in various years between 2012 and 2023. These costs are passed through to UNS Gas' customers via the PGA.

UNS Gas hedges its gas supply prices by entering into fixed price forward contracts and financial swaps at various times during the year to provide more stable prices to its customers. These purchases and hedges 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 45% of its expected monthly consumption for the 2011/2012 winter season (November through March). Additionally, UNS Gas has approximately 38% of its expected gas consumption hedged for April through October 2012, and 32% hedged for the period November 2012 through March 2013.

The following table displays UNS Gas' contractual obligations as of December 31, 2011 by maturity and by type of obligation.

UNS Gas Contractual Obligations
-Millions of Dollars-

Payment Due in Years Ending December 31,	2012	2013	2014	2015	2016	2017 and after	Other	Total
Long Term Debt								
Principal	$ —	$ —	$ —	$ 50	$ —	$ 50	$ —	$ 100
Interest	6	6	6	6	3	27	—	54
Purchase Obligations—Fuel	23	12	10	6	6	21	—	78
Pension & Other Post Retirement Obligations	1	—	—	—	—	—	—	1
Unrecognized Tax Benefits	—	—	—	—	—	—	1	1
Total Contractual Cash Obligations	$ 30	$ 18	$ 16	$ 62	$ 9	$ 98	$ 1	$ 234

UNS Gas conducts certain of its gas procurement and risk management activities under agreements whereby UNS Gas may be required to post margin due to changes in contract values, a change in UNS Gas' creditworthiness or exposures exceeding credit limits provided to UNS Gas. As of December 31, 2011, UNS Gas had not posted any such credit enhancements.

Dividends on Common Stock

UNS Gas paid dividends to UniSource Energy of $10 million in 2010, 2011, and in February 2012. UNS Gas' ability to pay future dividends will depend on the cash needs for capital expenditures and various other factors.

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. As of December 31, 2011, UNS Gas was in compliance with the terms of its note purchase agreement. See *Senior Unsecured Notes* , above.

UNS ELECTRIC

RESULTS OF OPERATIONS

In its September 2010 UNS Electric rate order, the ACC approved UNS Electric's purchase of BMGS from UED, subject to FERC approval and other conditions. FERC approved the purchase in June 2011, and UNS Electric completed the purchase of BMGS for $63 million on July 1, 2011. In accordance with accounting rules related to the transfer of a business held under common control, we reflect UNS Electric's purchase of BMGS as if it occurred on January 1, 2009. The transaction had no impact on UniSource Energy's consolidated financial statements for 2009 or 2010.

UNS Electric had net income of $18 million in 2011, compared with net income of $15 million in 2010. The increase is due primarily to a rate increase that was implemented in October 2010.

Results in 2010 included $3 million of pre-tax income related to a settlement with Arizona Public Service Company for refunds related to transactions with the California Power Exchange.

As with TEP, UNS Electric's operations are generally seasonal in nature, with peak energy demand occurring in the summer months.

The table below provides summary financial information for UNS Electric.

	2011	2010	2009
		-Millions of Dollars-	
Retail Electric Revenues	$ 182	$ 183	$ 180
Wholesale Electric Revenues	37	31	5
Other Revenues	2	2	2
Total Operating Revenues	221	216	187
Purchased Energy and Fuel Expense	137	137	116
Other Operations and Maintenance Expense	27	29	26
Depreciation and Amortization Expense	17	17	16
Taxes Other Than Income Taxes	4	4	4
Total Other Operating Expenses	185	187	162
Operating Income	36	29	25
Other Income	—	3	—
Total Interest Expense	7	7	7
Income Tax Expense	11	10	7
Net Income	$ 18	$ 15	$ 11

The table below summarizes UNS Electric's kWh sales and margin revenues for 2011, 2010 and 2009.

	2011	2010	Increase (Decrease) Amount	Percent*	2009
Energy Sales, kWh (in millions)					
Electric Retail Sales:					
Residential	828	820	8	0.9%	814
Commercial	602	606	(4)	(0.7%)	608
Industrial	221	219	2	0.8%	197
Mining	200	210	(10)	(4.2%)	163
Public Authorities	2	2	—	(16.3%)	2
Total Electric Retail Sales	1,853	1,857	(4)	(0.2%)	1,784
Electric Retail Revenues (in millions):					
Retail Margin Revenues:					
Residential	$ 31	$ 27	$ 4	13.9%	$ 21
Commercial	29	27	2	5.9%	22
Industrial	9	9	—	4.7%	7
Mining	7	6	1	22.2%	3
Public Authorities	—	—	—	(25.0%)	—
Total Retail Margin Revenues (Non-GAAP)**	$ 76	$ 69	$ 7	10.0%	$ 53
Retail Fuel Revenues	99	105	(6)	(5.6%)	121
DSM and RES Revenues	7	9	(2)	(22.4%)	6
Total Retail Revenues (GAAP)	$ 182	$ 183	$ (1)	(0.5%)	$ 180

Weather – Cooling Degree Days	2011	2010			2009
Year Ended December 31	9,092	8,821	271	3.1%	9,183
10-Year Average	8,994	9,031	NM	NM	9,059

* Percent change calculated on unrounded data and may not correspond exactly to data shown in table.

** Retail Margin Revenues, a non-GAAP financial measure, should not be considered as an alternative to Total Retail Revenues, which is determined in accordance with GAAP. Retail Margin Revenues exclude revenues collected from retail customers that are directly offset by expenses recorded in other line items. We believe the change in Retail Margin Revenues between periods provides useful information to investors because it demonstrates the underlying revenue trend and performance of our core utility business. Retail Margin Revenues represents the portion of retail operating revenues available to cover the operating expenses of our core utility business.

In 2011, retail kWh sales decreased by 0.2% compared with 2010. A 4% Base Rate increase that took effect in October 2010, contributed to a $7 million increase in retail margin revenues in 2011 compared with 2010.

As of December 31, 2011, UNS Electric had approximately 91,000 retail customers, which was an increase of less than 1% compared with 2010.

Wholesale revenues increased by $6 million in 2011 due to an increase in short-term wholesale sales. All revenues from wholesale sales are credited against costs recovered through UNS Electric's PPFAC.

FACTORS AFFECTING RESULTS OF OPERATIONS

Competition

New technological developments and the implementation of EE Standards may reduce energy consumption by UNS Electric's retail customers. UNS Electric's customers also have the ability to install renewable energy technologies and conventional generation units that could reduce their reliance on UNS Electric's services. Self-generation by UNS Electric's customers has not had a significant impact to date. See *Item 1. Business, UNS Electric, Rates and Regulation, Energy Efficiency Standards and Decoupling* for more information.

Rates

See *Item 1. Business, UNS Electric, Rates and Regulation, 2010 UNS Electric Rate Order* for more information.

Mining Customer

UNS Electric's largest customer, a copper mine located near Kingman, Arizona, began generating a portion of its own electricity needs in 2011. In 2012, UNS Electric expects its mining kWh sales to decrease by approximately 50% compared with 2011; however, due to UNS Electric's retail rate structure, UNS Electric expects the margin revenues from this customer to be near the same level as 2011. In 2011, UNS Electric's mining-related margin revenues were $7 million.

Renewable Energy Standard and Tariff

As part of the 2010 UNS Electric rate order, the ACC authorized UNS Electric to recover operating costs, depreciation, property taxes and a return on its investment in company-owned solar projects through RES funds until these costs are reflected in its Base Rates. Under these terms, UNS Electric expects to invest $5 million annually in 2012 through 2014 in solar photovoltaic projects. We estimate that each $5 million investment would build approximately 1.25 MW of solar capacity. For more information, see *Item 1. Business, UNS Electric, Rates and Regulation, Renewable Energy Standard and Tariff.*

Interest Rates

UNS Electric is subject to interest rate risk resulting from changes in interest rates on its borrowings under its revolving credit facility. The interest paid on revolving credit borrowings is variable. If LIBOR or other benchmark interest rates increase, UNS Electric may be required to pay higher rates of interest on borrowings under its revolving credit facility. See *Item 7A. Quantitative and Qualitative Disclosures about Market Risk, Interest Rate Risk* , below.

Fair Value Measurements

UNS Electric's income statement exposure to risk is mitigated as UNS Electric reports the change in fair value of energy contract derivatives as a regulatory asset or a regulatory liability rather than in the income statement. See Note 11 for more information.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity Outlook

In 2011, UNS Electric's capital expenditures were $96 million which included the purchase of BMGS for $63 million from an affiliate, UED. Going forward, UNS Electric expects operating cash flows to fund a large portion of its construction expenditures. Additional sources of funding future capital expenditures could include draws on the UNS Gas/UNS Electric Revolver, additional credit lines, the issuance of long-term debt, or capital contributions from UniSource Energy.

Operating Cash Flow

The table below provides summary cash flow information for UNS Electric.

	2011	2010	2009
		-Millions of Dollars-	
Cash Provided By (Used In):			
Operating Activities	$ 43	$ 34	$ 48
Investing Activities	(93)	(23)	(28)
Financing Activities	44	(10)	(19)
Net Increase (Decrease in Cash)	(6)	1	1
Beginning Cash	11	10	9
Ending Cash	$ 5	$ 11	$ 10

Operating cash flows increased in 2011 due in part to a Base Rate increase that became effective in October 2010 as well as an increase in wholesale sales.

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, to fund a portion of its capital expenditures or to issue letters of credit to provide credit enhancement for its energy procurement and hedging activities. At February 21, 2012, UNS Electric had $6 million outstanding under the UNS Gas/UNS Electric Revolver.

Senior Unsecured Notes

UNS Electric has $100 million of senior unsecured notes outstanding, consisting of $50 million of 6.50% notes due in 2015 and $50 million of 7.10% notes due August 2023. The notes are guaranteed by UES. The note purchase agreement for UNS Electric contains certain restrictive covenants, including restrictions on transactions with affiliates, mergers, liens to secure indebtedness, restricted payments, and incurrence of indebtedness. As of December 31, 2011, 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.

UNS Electric Credit Agreement

In August 2011, UNS Electric entered into a four-year $30 million variable rate term loan credit agreement. UNS Electric used the $30 million in proceeds to repay borrowings under its revolving credit facility. The interest rate currently in effect is three-month LIBOR plus 1.25%. At the same time, UNS Electric entered into a fixed-for-floating interest rate swap in which UNS Electric will pay a fixed rate of 0.97% and receive a three month LIBOR rate on a $30 million notional amount over a four year period ending August 10, 2015. The UNS Electric term loan credit agreement, included in Long-Term Debt in the balance sheet, is guaranteed by UES.

The term loan credit agreement contains certain restrictive covenants for UNS Electric and UES. The covenants include restrictions on transactions with affiliates, restricted payments, additional indebtedness, liens and mergers. UNS Electric must meet an interest coverage ratio to issue additional debt. However, UNS Electric may, without meeting these tests, refinance indebtedness and incur short-term debt in an amount not to exceed $5 million. The credit agreement also requires UNS Electric to maintain a maximum leverage ratio, and allows UNS Electric to pay dividends so long as it maintains compliance with the credit agreement. As of December 31, 2011, UNS Electric was in compliance with the terms of the credit agreement.

Contractual Obligations

UNS Electric Power Supply and Transmission Contracts

UNS Electric enters into various power supply agreements for periods of one to five years. Certain of these contracts are at a fixed price per MW and others are indexed to natural gas prices.

UNS Electric's power purchase contracts and risk management activities are subject to master agreements that may require UNS Electric to post margin due to changes in contract values or if there has been a material change in UNS Electric's creditworthiness, or exposures exceeding credit limits provided to UNS Electric. As of December 31, 2011, UNS Electric had posted $6 million of such credit enhancements in the form of letters of credit.

UNS Electric imports the power it purchases over the Western Area Power Administration's (WAPA) transmission lines. See *Item 1. Business, UNS Electric, Power Supply and Transmission, Transmission* for more information.

The following table displays UNS Electric's contractual obligations as of December 31, 2011 by maturity and by type of obligation.

UNS Electric Contractual Obligations
-Millions of Dollars-

Payment Due in Years Ending December 31,	2012	2013	2014	2015	2016	2017 and after	Other	Total
Long Term Debt:								
Principal	$ —	$ —	$ —	$ 80	$ —	$ 50	$ —	$ 130
Interest	7	7	7	7	4	25	—	57
Purchase Obligations:								
Purchased Power [1]	54	40	31	3	3	43	—	174
Transmission	4	2	2	1	1	—	—	10
Pension & Other Post Retirement Obligations	1	—	—	—	—	—	—	1
Unrecognized Tax Benefits	—	—	—	—	—	—	4	4
Total Contractual Cash Obligations	$ 66	$ 49	$ 40	$ 91	$ 8	$ 118	$ 4	$ 376

1 Purchased Power includes a long-term Power Purchase Agreement (PPA) with a renewable energy generation producer to meet compliance under the RES tariff. The facility achieved commercial operation in September 2011. UNS Electric is obligated to purchase 100% of the output from this facility. The table above includes estimated future payments based on expected power deliveries under the contract through 2031. UNS Electric has entered into additional long-term renewable PPAs to comply with the RES tariff; however, UNS Electric's obligation to accept and pay for electric power under these agreements does not begin until the facilities are constructed and operational.

Dividends on Common Stock

As of December 31, 2011, UNS Electric had not paid dividends to UniSource Energy. UNS Electric's ability to pay dividends will depend on the cash needs for capital expenditures and various other factors.

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. As of December 31, 2011, UNS Electric was in compliance with the terms of its note purchase agreement. See *Senior Unsecured Notes* , above.

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.

	2011	2010	2009
		- Millions of Dollars -	
Millennium	$ 2	$ (13)	$ 2
Other (1)	(5)	(6)	(5)
Total Other Net Loss	$ (3)	$ (19)	$ (3)

(1) Includes parent company expenses, UED and reconciling adjustments.

Millennium

Millennium recorded net income of $2 million in 2011 compared with a net loss of $13 million in 2010. The net loss in 2010 resulted from several factors including the write-off of deferred tax assets and impairment losses on certain investments. Millennium's results in 2009 included a $6 million pre-tax gain on the sale of an investment.

In December 2011 and December 2010, Millennium received annual interest payments of $1 million on its $15 million note receivable from Mimosa.

UniSource Energy Parent Company

UniSource Energy parent company expenses primarily include interest expense (net of tax) related to the UniSource Energy Convertible Senior Notes and the UniSource Credit Agreement.

UED

In its September 2010 UNS Electric rate order, the ACC approved UNS Electric's purchase of BMGS from UED, subject to FERC approval and other conditions. FERC approved the purchase in June 2011, and UNS Electric completed the purchase of BMGS for $63 million on July 1, 2011.

In 2011, UED paid dividends of $39 million to UniSource Energy of which $28 million represented a return of capital. In 2010, UED paid a $9 million dividend to UniSource Energy, of which $4 million represented a return of capital. In 2009, UED paid a $30 million dividend to UniSource Energy which also represented a return of capital.

FACTORS AFFECTING RESULTS OF OPERATIONS

Millennium Investments

Millennium is in the process of exiting its remaining investments which may yield gains or losses. At December 31, 2011, Millennium had assets of $20 million including a $15 million note receivable and a cash balance of $5 million.

In July 2011, Millennium sold a building for $3 million resulting in an after-tax gain of approximately $1 million.

In June 2009, Millennium finalized the sale of its 50% interest in Sabinas to Mimosa. The terms called for an upfront $5 million payment which Millennium received in January 2009. Other key terms of the transaction include a three-year, 6% interest-bearing, collateralized $15 million note from Mimosa due June 2012. In June 2009, Millennium recorded a $6 million pre-tax gain on the sale.

Millennium made $3 million in dividend payments to UniSource Energy in 2011, $8 million in 2010 and $3 million in 2009. All of these dividends represented return of capital distributions. Millennium's remaining commitment for all of its investments combined is less than $1 million.

CRITICAL ACCOUNTING POLICIES

The preparation of the financial statements in accordance with U.S. Generally Accepted Accounting Principles (GAAP) requires management to apply accounting policies and make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. UniSource Energy considers the areas described in the Critical Accounting Policies as those that could yield materially different financial statement results based on application and interpretation of accounting policy. Since making estimates and assumptions are subjective and complex, actual results could differ in subsequent periods. For additional information on UniSource Energy's other significant accounting policies and recently issued accounting standards see Note 1.

Accounting for Rate Regulation

We generally use the same accounting policies and practices used by unregulated companies for financial reporting under GAAP. However, sometimes these principles require special accounting treatment for regulated companies to show the effect of regulation. For example, the ACC can determine that we are allowed to recover certain expenses at a designated time in the future. In this situation, we defer these items as regulatory assets on the balance sheet and then reflect the costs as expenses when we are allowed to recover the costs from ratepayers. Similarly, certain revenue items may be deferred as regulatory liabilities and not reflected as revenue until Retail Rates to customers are reduced. We evaluate regulatory assets each period and believe recovery is probable.

If in the future a portion of operations no longer meets regulatory accounting criteria, the impact would be material to the financial statements. If we stopped applying regulatory accounting to all our regulated operations, we would write off the related balances of regulatory assets as an expense and record the regulatory liabilities as revenue on the income statement or in accumulated other comprehensive income (AOCI).

At December 31, 2011, regulatory assets net of regulatory liabilities totaled $4 million at TEP and $15 million at UNS Electric. Regulatory liabilities net of regulatory assets totaled $26 million at UNS Gas. We regularly assess whether we can continue to apply regulatory accounting to cost-based rate regulated operations. Expectations of future recovery are generally based on orders issued by regulatory commissions and historical experience. There are no current or expected proposals or changes in the regulatory environment that impact the probability of future recovery of these assets. See Note 2.

Accounting for Asset Retirement Obligations

TEP

TEP is required 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. This includes obligations resulting from conditional future events. TEP incurs legal obligations as a result of environmental and other governmental regulations, contractual agreements and other factors. To estimate the liability, management must use significant judgment and assumptions in: determining whether a legal obligation exists to remove assets; estimating the probability of a future event for a conditional obligation; estimating the fair value of the cost of removal; estimating when final removal will occur; and estimating the credit-adjusted risk-free interest rates to be used to discount the 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.

A liability for the fair value of an asset retirement obligation (ARO) is recognized in the period in which it is incurred if it can be reasonably estimated, with the offsetting associated asset retirement costs capitalized as a part of the carrying amount of the long-lived assets. The asset retirement cost is subsequently charged to depreciation expense over its useful life. Upon retirement of the asset, TEP either settles the obligation for its recorded amount or incurs a gain or loss if the actual costs differ from the recorded amount.

TEP 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. Additionally, TEP entered into a ground lease agreement with Campus Research Corporation for the installation of photovoltaic (PV) assets. The provisions of the PV ground lease require TEP to remove the PV facilities upon expiration of the lease in 2031. The legal retirement obligation related to the PV assets is estimated to be approximately $4 million at the retirement date. TEP also has certain environmental obligations at the Luna, San Juan, Sundt and Springerville Generating Stations. TEP estimated that its share of the cost to remove the Navajo and Four Corners facilities and settle the Luna, San Juan, Sundt and Springerville environmental obligations will be approximately $160 million at the retirement dates. No other legal obligations to retire generation plant assets were identified.

TEP has various transmission and distribution lines that operate under leases and rights-of-way that contain end dates and restrictive 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 such there are no legal obligations that require application of the accounting requirements for asset retirement obligations. Nevertheless, included in the revenue requirement underlying the Company's electric service Retail Rates is a component of depreciation expense intended to enable TEP to accrue the future costs of retiring assets for which no legal obligations exists. The accumulated balance of such accruals, less actual removal costs incurred, net of salvage proceeds realized, is reported as a regulatory liability. See Note 2 for details regarding net cost of removal for interim retirements.

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. See Note 2.

Pension and Other Postretirement Benefit Plan Assumptions

TEP, UNS Gas and UNS Electric 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 are reasonable based on prior experience, market conditions and the advice of plan actuaries. Note 9 discusses the rate of return and discount rate used in the calculation of pension plan and other postretirement plan obligations for TEP, UNS Gas and UNS Electric.

TEP is required to recognize the underfunded status of its defined benefit pension and other postretirement plans as a liability. The underfunded status is 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. As the funded status, discount rates and actuarial facts change, the liability will vary significantly in future years. TEP records the underfunded amount for its pension and other postretirement obligations as a liability and a regulatory asset to reflect expected recovery of pension and other postretirement obligations through Retail Rates.

At December 31, 2011, TEP discounted its future pension plan obligations at 5.0% and its other postretirement plan obligations at a rate of 4.7%. The discount rate for future pension plan and other postretirement plan obligations is determined annually based on the rates currently available on high-quality, non-callable, long-term bonds. The discount rate is based on a corporate yield curve using an average yield between the 60 th and 90 th percentile of AA-graded U.S. corporate bonds with future cash flows that match the timing and amount of expected future benefit payments. For TEP's pension plans, a 25-basis point change in the discount rate would increase or decrease the projected benefit obligation (PBO) by approximately $9 million and the 2012 plan expense by $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 less than $1 million.

TEP calculates the market-related value of pension plan assets using the fair value of the assets on the measurement date. TEP assumed that its pension plans' assets would generate a long-term rate of return of 7.0% at December 31, 2011. In establishing its assumption as to the expected return on assets, TEP reviews the asset allocation and develops return assumptions for each asset class based on advice from an investment consultant and the pension's 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 assets increases. A 25-basis point change in the expected return on assets would impact pension expense in 2012 by less than $1 million.

TEP used a current year health care cost trend rate of 6.9% in valuing its postretirement benefit obligation at December 31, 2011. This rate reflects both market conditions and historical experience. Assumed health care cost trend rates have a significant effect on the amounts reported for health care plans. A one-percentage point change in assumed health care cost trend rates would change the postretirement benefit obligation by approximately $5 million and the related plan expense in 2012 by less than $1 million.

In 2012, TEP will incur pension and other postretirement benefit costs of approximately $14 million and $6 million, respectively. TEP expects to charge approximately $15 million of these costs to O&M expense, $3 million to capital and $2 million to Other Expense. TEP expects to make pension plan contributions of $20 million in 2012. In 2009, TEP established a Voluntary Employee Beneficiary Association (VEBA) trust to fund its other postretirement benefit plan. In 2012, TEP expects to make benefit payments to retirees under the postretirement benefit plan of approximately $4 million and contributions to the VEBA trust of $2 million.

UNS Gas and UNS Electric discounted their future pension plan obligations using a rate of 4.9% at December 31, 2011. For UNS Gas and UNS Electric's pension plan, a 25-basis point change in the discount rate would impact the benefit obligation and 2012 pension expense by less than $1 million. UNS Gas and UNS Electric will record pension expense of $2 million in 2012, of which less than $1 million will be capitalized. UNS Gas and UNS Electric expect to make combined pension plan contributions of $3 million in 2012.

UNS Gas and UNS Electric discounted their other postretirement plan obligations using a rate of 4.7% at December 31, 2011. UNS Gas and UNS Electric will record postretirement medical benefit expense and make benefit payments to retirees under the postretirement benefit plan of less than $1 million in 2012.

Accounting for Derivative Instruments and Hedging Activities

Commodity Derivative Contracts

TEP, UNS Gas and UNS Electric enter into forward contracts to purchase or sell capacity or energy at contract prices 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. TEP and UNS Gas enter into forward gas commodity price swap agreements to lock in fixed prices on a portion of forecasted summer gas purchases.

Unrealized gains and losses on commodity derivative contracts entered into for retail customer load are recorded as either a regulatory asset or regulatory liability on the balance sheets of TEP, UNS Gas and UNS Electric. There are no current or expected proposals or changes in the regulatory environment that impact the probability of future recovery of these assets through the PPFAC or PGA mechanisms.

The market prices used to determine fair values for TEP, UNS Gas and UNS Electric's derivative instruments at December 31, 2011, are estimated based on various factors including broker quotes, exchange prices, over the counter prices and time value.

TEP, UNS Gas and UNS Electric manage 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.

Interest Rate Swaps

TEP hedges the cash flow risk associated with unfavorable changes in the variable interest rates related to LIBOR on the Springerville Common Facilities Lease. At December 31, 2011, TEP hedged approximately $29 million and $34 million of variable rate lease debt payments for the Springerville Common Facilities Lease to a fixed rate through July 1, 2014, and through January 2, 2020, respectively. In August 2009, TEP entered into a swap that had the effect of converting $50 million of variable rate industrial development bonds to a fixed rate from September 2009 through September 2014.

In August 2011, UNS Electric entered into an interest rate swap with the effect of converting the variable interest rate for their $30 million term loan to a fixed rate from August 2011 through August 2015. See Note 6.

Commodity Cash Flow Hedge

TEP hedges the cash flow risk associated with a six-year power wholesale supply agreement using a six-year power purchase swap agreement. Unrealized gains and losses are recorded in AOCI. See Note 1 for additional details regarding Cash Flow Hedges.

See *Item 7A. Quantitative and Qualitative Disclosures about Market Risk, Commodity Price Risk.*

Unbilled Revenue

TEP, UNS Gas and UNS Electric's retail revenues, which are recognized in the period that electricity or energy is delivered and consumed by customers, include unbilled revenue based on an estimate of MWh/therms delivered 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 MWh/therms delivered to the MWh/therms billed to TEP, UNS Gas and UNS Electric's retail customers. The excess of estimated MWh/therms delivered over MWh/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 Retail Rates for each customer class. Due to the seasonal fluctuations of TEP and UNS Electric's actual load, the unbilled revenue amount increases during the spring and summer and decreases during the fall and winter. Conversely the unbilled revenue amount for UNS Gas sales increases during the fall and winter and decreases during the spring and summer. A provision for uncollectible accounts is recorded as a component of operations and maintenance expense.

Plant Asset Depreciable Lives

TEP, UNS Gas and UNS Electric have significant investments in electric generation assets and electric and natural gas transmission and distribution assets. We calculate depreciation expense based on our estimate of the useful lives of our plant assets and expected net removal costs. Useful life of plant assets is further detailed in Note 5. Changes to depreciation estimates resulting from a change of estimated service life or removal costs could have a significant impact on the amount of depreciation expense recorded on the income statement. The estimated useful lives and depreciation rates presently used to calculate depreciation expense for electric generation and distribution assets for TEP, UNS Gas and UNS Electric have been approved by the ACC in prior rate decisions. Depreciation rates for such assets cannot be changed without ACC approval. For current approved ACC depreciation rates see Note 1. Depreciation rates for electric transmission assets fall under the jurisdiction of the FERC.

In January 2010, TEP obtained an updated depreciation study which indicated that its transmission assets' depreciable lives should be extended. As a result, TEP adopted new transmission depreciation rates effective January 2010, which have the effect of reducing depreciation expense by approximately $14 million annually.

Income Taxes

Due to the differences between GAAP and income tax laws, many transactions are treated differently for income tax purposes than they are in the financial statements. We account for this difference by recording deferred income tax assets and liabilities using the effective income tax rate at our balance sheet date.

Consolidated income tax liabilities are allocated to subsidiaries based on their taxable income and deductions as reported in the consolidated tax return.

A valuation allowance is established against deferred tax assets for which management believes it is more likely than not that the deferred asset will not be realized. In making this judgment, management evaluates all available evidence and gives more weight to objective verifiable evidence. At December 31, 2011, UniSource Energy had a $7 million valuation allowance. The valuation allowances related to unregulated investments' losses are treated as capital losses for income tax purposes. If UniSource Energy incurs additional capital losses in the future, a valuation allowance will be recorded against the deferred tax asset unless management can identify future capital gains to offset the losses. For additional information see Note 8.

RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

The following recently issued accounting standards are not yet reflected in the UniSource Energy and TEP financial statements:

- The Financial Accounting Standards Board (FASB) issued authoritative guidance that will eliminate the current option to report other comprehensive income in the statement of changes in equity. An entity can elect to present items of net income and other comprehensive income in one continuous statement, or in two separate but consecutive statements. We will be required to comply in the first quarter of 2012 and plan to present a separate statement of other comprehensive income.
- The FASB issued authoritative guidance that changed some fair value measurement principles and disclosure requirements. The most significant disclosure change is expansion of required information for unobservable inputs. We will be required to comply in the first quarter of 2012, and we do not expect this pronouncement to have a material impact on the valuation techniques used to estimate the fair value of assets and liabilities.
- The FASB issued authoritative guidance that requires entities to disclose both gross and net information about instruments and transactions eligible for offset in the statement of financial position as well as instruments and transactions subject to an agreement similar to a master netting arrangement. In addition, the standard requires disclosure of collateral received and posted in connection with master netting arrangements. We will be required to comply in the first quarter of 2013.

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 that 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 Item *1A. Risk Factors* , *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations* , and other parts of this report: state and federal regulatory and legislative decisions and actions; regional economic and market conditions which could affect customer growth and energy usage; weather variations affecting energy usage; the cost of debt and equity capital and access to capital markets; the performance of the stock market and changing interest rate environment, which affect the value of our pension and other postretirement benefit plan assets and the related contribution requirements and expense; unexpected increases in O&M expense; resolution of pending litigation matters; changes in accounting standards; changes in critical accounting estimates; the ongoing restructuring of the electric industry; changes to long-term contracts; the cost of fuel and power supplies; cyber attacks or challenges to our information security; and the performance of TEP's generating plants.

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 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 generation operations departments of UniSource Energy. To limit TEP, UNS Gas and UNS Electric'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 and UNS Electric's exposure to credit risk, the Risk Management Committee reviews counterparty credit exposure as well as credit policies and limits.

Interest Rate Risk

Long-Term Debt

TEP is exposed to interest rate risk resulting from changes in interest rates on certain of its variable rate debt obligations. At December 31, 2011 and December 31, 2010, TEP had $215 million and $365 million, respectively, in tax-exempt variable rate debt outstanding. The interest rates on TEP's tax-exempt variable rate debt are reset weekly by its remarketing agents. The maximum interest rate payable under the indentures for these bonds is 10% for $37 million of variable rate IDBs, and 20% on the remaining $178 million in variable rate IDBs. The average interest rate on TEP's variable rate debt (excluding letter of credit fees) was 0.18% in 2011 and 0.26% in 2010. The average weekly interest rate ranged from 0.05% to 0.34% in 2011 and 0.17% to 0.39% during 2010. Although short-term interest rates have been relatively low and stable in 2011 and 2010, TEP may still be subject to volatility in its tax-exempt variable rate debt. A 100 basis point increase in average interest rates on this debt, over a twelve month period, would result in a decrease in TEP's pre-tax net income of approximately $2 million.

TEP manages its exposure to variable interest rate risk by entering into interest rate swaps and financing transactions to rebalance its mix of variable rate and fixed rate long-term debt.

TEP has fixed-for-floating interest rate swaps in place to hedge floating rate interest rate risk associated with $63 million of Springerville Common Facilities lease debt and $50 million of its variable rate IDBs. In addition, in 2010 and 2011, TEP entered into the following transactions to change its mix of fixed and floating rate debt.

- In 2010, TEP converted the interest rate on its $130 million IDBs from a variable rate to an unsecured fixed rate of 5.75% through maturity in 2029;
- In 2010, TEP refinanced $37 million of its 7.125% unsecured fixed rate IDBs with variable rate IDBs; and
- TEP issued $250 million of 5.15% unsecured notes in 2011, and repurchased $150 million of variable rate IDBs to hold in treasury, and redeemed $22 million of its 6.1% unsecured fixed-rate IDBs.

As a result of these transactions, TEP's variable rate debt comprised approximately 15% and 31% of its total long-term debt at December 31, 2011 and 2010, respectively.

In August 2011, UNS Electric entered into a fixed-for-floating interest rate swap in which UNS Electric will pay a fixed rate of 0.97% and receive a three-month LIBOR rate on a $30 million notional amount through August 2015 to hedge the interest rate risk associated with its $30 million credit agreement.

Interest Rate Swaps

To adjust the value of TEP's interest rate swaps, classified as a cash flow hedge, to fair value in Other Comprehensive Income, TEP recorded the following net unrealized gains (losses):

	2011	2010	2009
		- Millions of Dollars -	
Unrealized Gains (Losses)	$ (5)	$ (8)	$ 1

Revolving Credit Facilities

UniSource Energy, TEP, UNS Gas and UNS Electric are also subject to interest rate risk resulting from changes in interest rates on their borrowings under revolving credit facilities. Revolving credit borrowings may be made on the basis of a spread over LIBOR or an Alternate Base Rate. With the recent disruptions in the financial markets, the spread between LIBOR and other similar maturity short-term rates, such as U.S. Treasury securities, has been significantly higher than historical relationships. As a result, UniSource Energy, TEP, UNS Gas and UNS Electric may experience significant volatility in the rates paid on LIBOR borrowings under their revolving credit facilities.

Marketable Securities Risk

UniSource Energy has a short-term investment policy which governs the investment of excess cash balances by UniSource Energy and its subsidiaries. We review this policy periodically in response to market conditions to adjust, if necessary, the maturities and concentrations by investment type and issuer in the investment portfolio. As of December 31, 2011, UniSource Energy's short-term investments consisted of liquid, highly-rated money market funds, commercial paper, and certificates of deposit. These short-term investments are classified as Cash and Cash Equivalents on the balance sheet.

TEP had marketable securities comprised of investments in lease debt and equity with an estimated fair value of $50 million at December 31, 2011, and $111 million at December 31, 2010. At December 31, 2011, the carrying value exceeded fair value by $16 million. No impairment was recorded as TEP expects to recover the full carrying value of its lease equity investment in future Retail Rates. At December 31, 2010, the fair value exceeded the carrying value by $6 million. These securities represent TEP's investments in lease debt and equity 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

TEP

TEP is exposed to commodity price risk primarily relating to changes in the market price of electricity, natural gas, and coal. This risk is mitigated through a PPFAC mechanism which fully recovers the actual retail fuel and purchased power costs incurred on a timely basis from TEP's retail customers. The PPFAC mechanism has a forward component and a true-up component. The forward component of the PPFAC rate is based on forecasted fuel and purchased power costs. The true-up component reconciles actual fuel and purchased power costs with the amounts collected in the prior year and any amounts under/over-collected will be collected from/credited to customers. If the actual price of power is higher than the forecasted PPFAC rate, TEP is exposed to the price difference until the subsequent 12-month period when the true-up component is adjusted to allow the recovery of this difference.

<u>Purchases and Sales of Energy</u>

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 physical position in the third quarter and must have owned generation backing up all physical 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.

TEP's risk management policies also allow for financial purchases and sales of energy subject to specified risk parameters established and monitored by the Risk Management Committee. These include financial trades in a futures account on an exchange, with the intent of optimizing market opportunities.

The majority of TEP's forward contracts are considered to be "normal purchases and sales" of electric energy and are therefore not accounted for as derivatives. 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 are not considered to be "normal purchases and sales" and therefore are accounted for as derivatives. 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.

<u>Long-Term Wholesale Sales</u>

Prior to June 1, 2011, under the terms of the SRP contract, TEP received a monthly demand charge of approximately $1.8 million, or $22 million annually, and sold the energy at a price based on TEP's average fuel cost. From June 1, 2011 to December 31, 2011, SRP was required to purchase 73,000 MWh per month. From January 1, 2012 through the end of the contract in May 2016, SRP is required to purchase 500,000 MWh of on-peak energy per year. TEP does not receive a demand charge and the price of energy is based on a discount to the price of on-peak power on Palo Verde Market Index. As of February 21, 2012, the average forward price of on-peak power on the Palo Verde Market Index for the calendar year 2012 was $30.33 MWh.

The chart below summarizes the annual change in pre-tax income if the market price of power on the Palo Verde Market Index changes by $5 per MWh.

	Change in Per MWh Price	
	$5 Increase	$5 Decrease
	-Millions of Dollars-	
Change in Pre-Tax Income	$ 3	$ (3)

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 power purchases, 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 power purchases 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.

As required by fair value accounting rules, for the year ended December 31, 2011, TEP considered the impact of non-performance risk in the measurement of fair value of its derivative assets and derivative liabilities net of collateral posted. The adjustment required for TEP was less than $0.5 million at December 31, 2011.

To adjust the value of its commodity derivatives to fair value in Regulatory Assets or Regulatory Liabilities, TEP recorded the following net unrealized gains (losses):

	2011	2010	2009
		- Millions of Dollars -	
Unrealized Gains (Losses)	$ (2)	$ 4	$ 11

The chart below displays the valuation methodologies and maturities of TEP's power and gas derivative contracts.

	Unrealized Gain (Loss) of TEP's Hedging Activities - Millions of Dollars -			
Source of Fair Value at Dec. 31, 2011	Maturity 0 –6 months	Maturity 6 –12 months	Maturity over 1 yr.	Total Unrealized Gain (Loss)
Prices actively quoted	$ (3)	$ (5)	$ (3)	$ (11)
Prices based on models and other valuation methods	—	1	1	2
Total	$ (3)	$ (4)	$ (2)	$ (9)

Sensitivity Analysis of Derivatives

TEP uses sensitivity analysis to measure the impact of favorable and unfavorable changes in market prices on the fair value of its derivative forward contracts. TEP records unrealized gains and losses as either a regulatory asset or regulatory liability. As contracts settle, the unrealized gains and losses are reversed and realized gains or losses are recorded to the PPFAC. The chart below summarizes the change in unrealized gains or losses if market prices increase or decrease by 10%.

	- Millions of Dollars -	
Change in Market Price As of December 31, 2011	10% Increase	10% Decrease
Non-Cash Flow Hedges		
Forward power sales and purchase contracts	$ 2	$ (2)

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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 is determined by the cost of Powder River Basin coal delivered to Springerville Unit 3 subject to a floor and ceiling. This range would be from $19.30 to $26.15 per ton. TEP estimates its future minimum annual payments under this contract to be $14 million from 2012 through 2020.

TEP does not have a long-term coal supply contract for Sundt Unit 4. TEP purchases coal for Sundt Unit 4 on the spot market and can supply that unit with natural gas when the price is competitive with coal. Coal burned at Sundt Unit 4 represents less than 10% of TEP's total coal consumption. In December 2011, the take-or-pay obligations under a coal transportation agreement previously effective through December 2015 were terminated. As a result, TEP is relieved of a $4 million obligation recognized under this contract in December 2010. TEP reversed a $4 million regulatory asset. TEP has a short-term coal supply contract for Sundt Unit 4 ending December 31, 2012, and has hedged gas costs through September 2012.

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. 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, Liquidity and Capital Resources, Contractual Obligations* and Note 4.

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 or entering into financial gas swaps 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.

As required by fair value accounting rules, for the year ended December 31, 2011, UNS Gas considered the impact of non-performance risk in the measurement of fair value of its derivative assets and derivative liabilities net of collateral posted. The adjustment required for UNS Gas was less than $0.5 million at December 31, 2011.

To adjust the value of its commodity derivatives to fair value in Regulatory Assets or Regulatory Liabilities, UNS Gas recorded the following net unrealized gains (losses):

	2011	2010	2009
		- Millions of Dollars -	
Unrealized Gains (Losses)	$ (1)	$ (2)	$ 6

For UNS Gas' forward gas purchase contracts, a 10% decrease in market prices would result in an increase in unrealized net losses reported as a regulatory asset of $2 million, while a 10% increase in market prices would result in a decrease in unrealized net losses reported as a reduction in regulatory assets of $2 million.

UNS Electric

UNS Electric is exposed to commodity price risk from changes in the price for electricity and natural gas. This risk is mitigated through a PPFAC mechanism which allows for the recovery of costs from retail customers. The PPFAC mechanism has a forward component and a true-up component. The forward component of the PPFAC rate is based on forecasted fuel and purchased power costs. The true-up component reconciles actual fuel and purchased power costs with the amounts collected in the prior year and any amounts under/over-collected will be collected from/credited to customers. If the actual price of power is higher than the forecasted PPFAC rate, UNS Electric is exposed to the price difference until the subsequent 12-month period when the true-up component is adjusted to allow the recovery of this difference.

UNS Electric enters into various power supply agreements for periods of one to five years. Certain of these contracts are at a fixed price per MW and others are indexed to natural gas prices. UNS Electric estimates its future minimum payments under these contracts to be $51 million in 2012, $37 million in 2013, and $28 million in 2014 based on natural gas prices at December 31, 2011.

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 sales and purchase contracts, a 10% decrease in market prices would result in an increase in unrealized net gains reported as a regulatory asset of $5 million, while a 10% increase in market prices would result in a decrease in unrealized net gains reported as a reduction in regulatory assets of $5 million.

UNS Electric hedges a portion of its natural gas exposure from gas-indexed purchased power agreements with fixed price contracts. In addition, UNS Electric hedges a portion of its anticipated natural gas exposure from plant fuel. UNS Electric currently has approximately 53% of this aggregate summer exposure hedged for the summer of 2012. UNS Electric will satisfy its remaining gas and purchased power needs through a combination of additional forward purchases and purchases in the short-term and spot markets.

UNS Electric considered the impact of non-performance risk in the measurement of fair value of its derivative assets and derivative liabilities net of collateral posted. The adjustment required for UNS Electric was less than $0.5 million at December 31, 2011.

To adjust the value of its commodity derivatives to fair value in Regulatory Assets or Regulatory Liabilities, UNS Electric recorded the following net unrealized gains (losses):

	2011	2010	2009
		- Millions of Dollars-	
Unrealized Gains (Losses)	$ 1	$ (2)	$ 12

For UNS Electric's forward gas purchase contracts, a 10% decrease in market prices would result in an increase in unrealized net losses reported as a regulatory asset of $1 million, while a 10% increase in market prices would result in a decrease in unrealized net losses reported as a reduction in regulatory assets of $1 million.

Credit Risk

UniSource Energy is exposed to credit risk in its energy-related marketing 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 standard agreements which allow 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. A positive number means that we are exposed to the creditworthiness of our counterparties. If exposure exceeds credit limits or contractual collateral thresholds, we may request that a counterparty provide credit enhancement in the form of cash collateral or a letter of credit. Conversely, a negative exposure means that a counterparty is exposed to the creditworthiness of TEP, UNS Gas or UNS Electric. If such exposure exceeds credit limits or collateral thresholds, we may be required to post collateral in the form of cash or letters of credit.

TEP, UNS Gas and UNS Electric each have entered into short-term and long-term transactions with several financial institution counterparties with terms of one month through five years. Due to the recent turmoil in the financial and credit markets, we have been closely monitoring our transactions with financial institutions. As of December 31, 2011, the combined credit exposure to TEP, UNS Gas and UNS Electric from financial institution counterparties was approximately $4 million.

As of December 31, 2011, TEP's total credit exposure related to its wholesale marketing and gas hedging activities was approximately $17 million. TEP had one non-investment grade counterparty with exposure of greater than 10% of its total credit exposure, totaling approximately $4 million. TEP's total exposure to non-investment grade counterparties was $4 million.

At December 31, 2011, TEP posted no cash collateral and $1 million in letters of credit as credit enhancements with its counterparties, and did not hold any collateral from its counterparties.

UNS Gas is subject to credit risk from non-performance by its supply and hedging counterparties to the extent that these contracts have a mark-to-market value in favor of UNS Gas. As of December 31, 2011, UNS Gas had purchased under fixed price contracts approximately 32% of its expected consumption for the 2012/2013 winter season. At December 31, 2011, UNS Gas had no mark-to-market credit exposure under its supply and hedging contracts . As of December 31, 2011, UNS Gas had posted no cash collateral and no letters of credit as credit enhancements with its counterparties, and did not hold any collateral from counterparties.

UNS Electric enters into energy purchase agreements as well as gas hedging contracts to hedge the risk in its gas-indexed power purchase agreements. To the extent that such contracts have a positive mark-to-market value, UNS Electric is exposed to credit risk under those contracts. At December 31, 2011, UNS Electric had $1 million in credit exposure under such contracts. As of December 31, 2011, UNS Electric had posted $6 million in letters of credit and no cash collateral as credit enhancements with its counterparties and had not collected any collateral margin from its counterparties.

ITEM 8. – CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

UniSource Energy—Management's Report on Internal Controls Over Financial Reporting

UniSource Energy'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 UniSource Energy's internal control over financial reporting as of December 31, 2011. 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, 2011, UniSource Energy's internal control over financial reporting was effective.

The effectiveness of UniSource Energy's internal control over financial reporting as of December 31, 2011, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report in Item 8 of this Annual Report on Form 10-K.

Tucson Electric Power Company—Management's Report on Internal Controls Over Financial Reporting

Tucson Electric Power Company'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 Tucson Electric Power Company's internal control over financial reporting as of December 31, 2011. 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, 2011, Tucson Electric Power Company's internal control over financial reporting was effective.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of
UniSource Energy Corporation:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of UniSource Energy Corporation and its subsidiaries at December 31, 2011 and December 31, 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 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. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Controls Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide 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.

/s/PricewaterhouseCoopers LLP
PricewaterhouseCoopers LLP
Phoenix, Arizona
February 27, 2012

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholder of
Tucson Electric Power Company:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Tucson Electric Power Company and its subsidiaries at December 31, 2011 and December 31, 2010 and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 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) presents 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.

/s/PricewaterhouseCoopers LLP
PricewaterhouseCoopers LLP
Phoenix, Arizona
February 27, 2012

UNISOURCE ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF INCOME

	Years Ended December 31, 2011	2010	2009
	- Thousands of Dollars - (Except Per Share Amounts)		
Operating Revenues			
Electric Retail Sales	**$ 1,085,822**	$ 1,051,002	$ 1,047,619
Electric Wholesale Sales	**163,159**	151,962	131,255
California Power Exchange (CPX) Provision for Wholesale Refunds	**—**	(2,970)	(4,172)
Gas Revenue	**145,053**	141,036	144,609
Other Revenues	**115,481**	112,936	77,741
Total Operating Revenues	**1,509,515**	1,453,966	1,397,052
Operating Expenses			
Fuel	**324,520**	295,652	296,248
Purchased Energy	**307,423**	307,288	296,861
Transmission	**7,334**	10,945	10,181
Decrease to Reflect PPFAC/PGA Recovery Treatment	**(4,932)**	(29,622)	(14,553)
Total Fuel and Purchased Energy	**634,345**	584,263	588,737
Other Operations and Maintenance	**379,220**	370,037	333,579
Depreciation	**133,832**	128,215	144,960
Amortization	**30,983**	28,094	31,058
Taxes Other Than Income Taxes	**49,463**	46,243	45,858
Total Operating Expenses	**1,227,843**	1,156,852	1,144,192
Operating Income	**281,672**	297,114	252,860
Other Income (Deductions)			
Interest Income	**4,568**	7,779	12,072
Other Income	**8,293**	11,038	18,063
Other Expense	**(5,249)**	(15,202)	(5,292)
Total Other Income (Deductions)	**7,612**	3,615	24,843
Interest Expense			
Long-Term Debt	**73,217**	65,020	58,134
Capital Leases	**40,359**	46,740	49,270
Other Interest Expense	**2,535**	1,651	3,468
Interest Capitalized	**(3,753)**	(2,587)	(2,302)
Total Interest Expense	**112,358**	110,824	108,570
Income Before Income Taxes	**176,926**	189,905	169,133
Income Tax Expense	**66,951**	76,921	63,232
Net Income	**$ 109,975**	$ 112,984	$ 105,901
Weighted-Average Shares of Common Stock Outstanding (000)			
Basic	**36,962**	36,415	35,858
Diluted	**41,609**	41,041	40,450
Earnings per Share			
Basic	**$ 2.98**	$ 3.10	$ 2.95
Diluted	**$ 2.75**	$ 2.86	$ 2.73
Dividends Declared per Share	**$ 1.68**	$ 1.56	$ 1.16

See Notes to Consolidated Financial Statements.

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UNISOURCE ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2011	2010	2009
	- Thousands of Dollars -		
Cash Flows from Operating Activities			
Cash Receipts from Electric Retail Sales	**$ 1,163,537**	$ 1,142,364	$ 1,145,051
Cash Receipts from Electric Wholesale Sales	**183,151**	194,580	175,679
Cash Receipts from Gas Sales	**159,529**	157,397	162,725
Cash Receipts from Operating Springerville Units 3 & 4	**104,754**	102,563	68,951
Cash Receipts from Wholesale Gas Sales	**12,404**	422	716
Performance Deposits Received	**7,050**	18,470	34,630
Interest Received	**6,334**	10,026	13,470
Income Tax Refunds Received	**4,672**	341	20,242
Other Cash Receipts	**23,937**	32,011	26,176
Purchased Energy Costs Paid	**(328,713)**	(364,132)	(334,481)
Payment of Other Operations and Maintenance Costs	**(291,607)**	(255,988)	(246,895)
Fuel Costs Paid	**(281,441)**	(247,484)	(300,810)
Taxes Other Than Income Taxes Paid, Net of Amounts Capitalized	**(179,766)**	(163,037)	(161,574)
Wages Paid, Net of Amounts Capitalized	**(122,370)**	(125,893)	(122,245)
Interest Paid, Net of Amounts Capitalized	**(68,027)**	(59,749)	(54,641)
Capital Lease Interest Paid	**(32,103)**	(38,646)	(38,598)
Wholesale Gas Costs Paid	**(11,822)**	—	—
Performance Deposits Paid	**(4,550)**	(19,220)	(22,260)
Income Taxes Paid	**(700)**	(22,797)	(9,050)
Other Cash Payments	**(6,949)**	(14,308)	(9,776)
Net Cash Flows - Operating Activities	**337,320**	346,920	347,310
Cash Flows from Investing Activities			
Capital Expenditures	**(374,122)**	(279,240)	(294,020)
Purchase of Intangibles - Renewable Energy Credits	**(5,992)**	(7,514)	—
Purchase of Sundt Unit 4 Lease Asset	—	(51,389)	—
Purchase of Springerville Lease Debt	—	—	(31,375)
Prepayment Deposits on UED Debt	—	(3,188)	(3,625)
Other Cash Payments	**(578)**	(2,302)	(868)
Return of Investments in Springerville Lease Debt	**38,353**	25,615	12,736
Other Cash Receipts	**15,251**	12,958	20,508
Net Cash Flows - Investing Activities	**(327,088)**	(305,060)	(296,644)
Cash Flows from Financing Activities			
Proceeds from Borrowings Under Revolving Credit Facilities	**391,000**	239,000	203,000
Proceeds from Issuance of Long-Term Debt	**340,285**	127,815	—
Proceeds from Stock Options Exercised	**8,115**	13,391	3,441
Proceeds from Issuance of Short-Term Debt	—	—	30,000
Other Cash Receipts	**4,743**	12,406	8,937
Repayments of Borrowings Under Revolving Credit Facilities	**(351,000)**	(268,500)	(198,000)
Repayments of Long-Term Debt	**(252,125)**	(51,592)	(6,000)
Payments of Capital Lease Obligations	**(74,381)**	(55,997)	(24,192)
Common Stock Dividends Paid	**(61,904)**	(56,590)	(41,429)
Payments of Debt Issue/Retirement Costs	**(4,361)**	(8,341)	(2,268)
Other Cash Payments	**(1,813)**	(2,775)	(2,405)
Net Cash Flows - Financing Activities	**(1,441)**	(51,183)	(28,916)
Net Increase (Decrease) in Cash and Cash Equivalents	**8,791**	(9,323)	21,750
Cash and Cash Equivalents, Beginning of Year	**67,599**	76,922	55,172
Cash and Cash Equivalents, End of Year	**$ 76,390**	$ 67,599	$ 76,922
Non-Cash Financing Activity			
Repayment of UED Short-Term Debt	**$ —**	$ (3,188)	$ (3,625)

See Note 15 for supplemental cash flow information.

See Notes to Consolidated Financial Statements.

UNISOURCE ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS

	December 31, 2011	December 31, 2010
	- Thousands of Dollars -	
ASSETS		
Utility Plant		
Plant in Service	**$ 4,856,108**	$ 4,452,928
Utility Plant Under Capital Leases	**582,669**	583,374
Construction Work in Progress	**89,749**	210,971
Total Utility Plant	**5,528,526**	5,247,273
Less Accumulated Depreciation and Amortization	**(1,869,300)**	(1,824,843)
Less Accumulated Amortization of Capital Lease Assets	**(476,963)**	(460,932)
Total Utility Plant - Net	**3,182,263**	2,961,498
Investments and Other Property		
Investments in Lease Debt and Equity	**65,829**	103,844
Other	**34,205**	61,676
Total Investments and Other Property	**100,034**	165,520
Current Assets		
Cash and Cash Equivalents	**76,390**	67,599
Accounts Receivable - Customer	**94,585**	98,333
Unbilled Accounts Receivable	**51,464**	53,084
Allowance for Doubtful Accounts	**(5,572)**	(6,125)
Fuel Inventory	**33,263**	29,216
Materials and Supplies	**82,649**	65,832
Derivative Instruments	**11,966**	5,214
Regulatory Assets - Current	**97,056**	56,962
Deferred Income Taxes - Current	**23,158**	30,822
Other	**32,577**	30,091
Total Current Assets	**497,536**	431,028
Regulatory and Other Assets		
Regulatory Assets - Noncurrent	**173,199**	192,966
Derivative Instruments	**2,019**	9,806
Other Assets	**30,180**	30,425
Total Regulatory and Other Assets	**205,398**	233,197
Total Assets	**$ 3,985,231**	$ 3,791,243

See Notes to Consolidated Financial Statements.

(Consolidated Balance Sheets Continued)

UNISOURCE ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS

	December 31, 2011	December 31, 2010
	- Thousands of Dollars -	
CAPITALIZATION AND OTHER LIABILITIES		
Capitalization		
Common Stock Equity	**$ 888,474**	$ 830,756
Capital Lease Obligations	**352,720**	429,074
Long-Term Debt	**1,517,373**	1,352,977
Total Capitalization	**2,758,567**	2,612,807
Current Liabilities		
Current Obligations Under Capital Leases	**77,482**	60,347
Current Maturities of Long-Term Debt	**—**	57,000
Borrowing Under Revolving Credit Facility	**10,000**	—
Accounts Payable - Trade	**109,759**	108,950
Interest Accrued	**38,302**	39,120
Accrued Taxes Other than Income Taxes	**41,997**	39,140
Accrued Employee Expenses	**24,917**	26,969
Customer Deposits	**32,485**	29,795
Regulatory Liabilities - Current	**41,911**	69,483
Derivative Instruments	**36,467**	30,574
Other	**5,151**	1,678
Total Current Liabilities	**418,471**	463,056
Deferred Credits and Other Liabilities		
Deferred Income Taxes - Noncurrent	**300,326**	246,466
Regulatory Liabilities - Noncurrent	**234,945**	201,329
Derivative Instruments	**20,403**	22,969
Pension and Other Postretirement Benefits	**139,356**	127,343
Other	**113,163**	117,273
Total Deferred Credits and Other Liabilities	**808,193**	715,380
Commitments, Contingencies, and Proposed Environmental Matters (Note 4)		
Total Capitalization and Other Liabilities	**$ 3,985,231**	$ 3,791,243

See Notes to Consolidated Financial Statements.

(Consolidated Balance Sheets Concluded)

UNISOURCE ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CAPITALIZATION

			December 31, 2011	2010
			- Thousands of Dollars -	
COMMON STOCK EQUITY				
Common Stock-No Par Value			$ 725,903	$ 715,687
	2011	**2010**		
Shares Authorized	75,000,000	75,000,000		
Shares Outstanding	36,918,024	36,541,954		
Accumulated Earnings			172,655	124,838
Accumulated Other Comprehensive Loss			(10,084)	(9,769)
Total Common Stock Equity			888,474	830,756
PREFERRED STOCK				
No Par Value, 1,000,000 Shares Authorized, None Outstanding			—	—
CAPITAL LEASE OBLIGATIONS				
Springerville Unit 1			253,481	302,229
Springerville Coal Handling Facilities			65,022	76,583
Springerville Common Facilities			111,699	110,571
Other			—	38
Total Capital Lease Obligations			430,202	489,421
Less Current Maturities			(77,482)	(60,347)
Total Long-Term Capital Lease Obligations			352,720	429,074
LONG-TERM DEBT				
Issue	**Maturity**	**Interest Rate**		
UniSource Energy:				
Convertible Senior Notes	2035	4.50%	150,000	150,000
Credit Agreement	2016	Variable	57,000	27,000
Tucson Electric Power Company:				
Variable Rate IDBs	2014 - 2016	Variable	215,300	365,300
Unsecured Fixed Rate IDBs	2020 - 2040	3.25% to 6.375%	615,855	638,315
Unsecured Notes	2021	5.15%	249,218	—
UNS Gas and UNS Electric:				
Senior Unsecured Notes	2015 - 2026	5.39% to 7.1%	230,000	200,000
UED:				
Secured Term Loan	2012	Variable	—	29,362
Total Stated Principal Amount			1,517,373	1,409,977
Less Current Maturities			—	(57,000)
Total Long-Term Debt			1,517,373	1,352,977
Total Capitalization			$ 2,758,567	$ 2,612,807

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 Earnings	Accumulated Other Comprehensive Loss	Total Stockholders' Equity
		- Thousands of Dollars -			
Balances at December 31, 2008	35,458	$ 687,360	$ 5,590	$ (6,855)	$ 686,095
Comprehensive Income:					
2009 Net Income			105,901		105,901
Unrealized Loss on Cash Flow Hedges (net of $33 income taxes)				51	51
Reclassification of Realized Losses on Cash Flow Hedges to Net Income (net of $690 income taxes)				1,053	1,053
Employee Benefit Obligations Amortization of SERP Net Prior Service Cost Included in Net Periodic Benefit Cost (net of $33 income taxes)				(51)	(51)
Total Comprehensive Income					106,954
Dividends, Including Non-Cash Dividend Equivalents			(42,566)		(42,566)
Shares Issued under Deferred Compensation Plans	10	279			279
Shares Issued for Stock Options	282	4,077			4,077
Shares Issued Under Stock Compensation Plans	101	—			—
Other		4,490			4,490
Balances at December 31, 2009	35,851	$ 696,206	$ 68,925	$ (5,802)	$ 759,329
Comprehensive Income:					
2010 Net Income			112,984		112,984
Unrealized Loss on Cash Flow Hedges (net of $4,216 income taxes)				(6,431)	(6,431)
Reclassification of Realized Losses on Cash Flow Hedges to Net Income (net of $2,140 income taxes)				3,264	3,264
Employee Benefit Obligations Amortization of SERP Net Prior Service Cost Included in Net Periodic Benefit Cost (net of $523 income taxes)				(800)	(800)
Total Comprehensive Income					109,017
Dividends, Including Non-Cash Dividend Equivalents			(57,071)		(57,071)
Shares Issued under Deferred Compensation Plans	16	519			519
Shares Issued for Stock Options	660	12,756			12,756
Shares Issued Under Stock Compensation Plans	15	—			—
Other		6,206			6,206
Balances at December 31, 2010	36,542	$ 715,687	$ 124,838	$ (9,769)	$ 830,756
Comprehensive Income:					
2011 Net Income			109,975		109,975
Unrealized Loss on Cash Flow Hedges (net of $2,376 income taxes)				(3,626)	(3,626)
Reclassification of Realized Losses on Cash Flow Hedges to Net Income (net of $1,412 income taxes)				2,153	2,153
Employee Benefit Obligations Amortization of SERP Net Prior Service Cost Included in Net Periodic Benefit Cost (net of $804 income taxes)				1,158	1,158
Total Comprehensive Income					109,660
Dividends, Including Non-Cash Dividend Equivalents			(62,158)		(62,158)
Shares Issued for Stock Options	319	8,176			8,176
Shares Issued Under Stock Compensation Plans	57	—			—
Other		2,040			2,040
Balances at December 31, 2011	36,918	$ 725,903	$ 172,655	$ (10,084)	$ 888,474

* UniSource Energy has 75 million authorized shares of Common Stock.

We describe limitations on our ability to pay dividends in Note 7.

See Notes to Consolidated Financial Statements.

TUCSON ELECTRIC POWER COMPANY
CONSOLIDATED STATEMENTS OF INCOME

	Years Ended December 31,		
	2011	2010	2009
	- Thousands of Dollars -		
Operating Revenues			
Electric Retail Sales	**$ 903,930**	$ 868,188	$ 867,516
Electric Wholesale Sales	**129,861**	141,103	153,306
California Power Exchange (CPX) Provision for Wholesale Refunds	**—**	(2,970)	(4,172)
Other Revenues	**122,595**	118,946	82,688
Total Operating Revenues	**1,156,386**	1,125,267	1,099,338
Operating Expenses			
Fuel	**318,268**	284,744	279,303
Purchased Power	**105,766**	118,716	144,529
Transmission	**(1,435)**	3,254	3,066
Decrease to Reflect PPFAC Recovery Treatment	**(6,165)**	(21,541)	(18,186)
Total Fuel and Purchased Energy	**416,434**	385,173	408,712
Other Operations and Maintenance	**330,801**	316,625	282,986
Depreciation	**104,894**	99,510	116,970
Amortization	**34,650**	32,196	35,931
Taxes Other Than Income Taxes	**40,226**	37,732	37,406
Total Operating Expenses	**927,005**	871,236	882,005
Operating Income	**229,381**	254,031	217,333
Other Income (Deductions)			
Interest Income	**3,567**	6,707	11,471
Other Income	**5,693**	6,629	10,996
Other Expense	**(12,037)**	(11,506)	(9,589)
Total Other Income (Deductions)	**(2,777)**	1,830	12,878
Interest Expense			
Long-Term Debt	**49,858**	42,378	36,226
Capital Leases	**40,358**	46,734	49,258
Other Interest Expense	**1,127**	433	1,571
Interest Capitalized	**(2,073)**	(1,880)	(1,752)
Total Interest Expense	**89,270**	87,665	85,303
Income Before Income Taxes	**137,334**	168,196	144,908
Income Tax Expense	**52,000**	59,936	54,220
Net Income	**$ 85,334**	$ 108,260	$ 90,688

See Notes to Consolidated Financial Statements.

TUCSON ELECTRIC POWER COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2011	2010	2009
	- Thousands of Dollars -		
Cash Flows from Operating Activities			
Cash Receipts from Electric Retail Sales	**$ 963,247**	$ 947,498	$ 944,873
Cash Receipts from Electric Wholesale Sales	**152,618**	190,779	199,918
Cash Receipts from Operating Springerville Units 3 & 4	**104,754**	102,563	68,951
Reimbursement of Affiliate Charges	**18,448**	18,356	19,998
Cash Receipts from Wholesale Gas Sales	**11,825**	—	—
Income Tax Refunds Received	**7,492**	3,369	14,462
Interest Received	**5,367**	8,998	12,768
Performance Deposits Received	**1,640**	5,040	14,000
Other Cash Receipts	**17,971**	18,389	19,440
Payment of Other Operations and Maintenance Costs	**(283,560)**	(245,050)	(233,075)
Fuel Costs Paid	**(276,030)**	(236,436)	(282,653)
Taxes Other Than Income Taxes Paid, Net of Amounts Capitalized	**(139,728)**	(134,540)	(124,053)
Purchased Power Costs Paid	**(117,224)**	(169,658)	(185,129)
Wages Paid, Net of Amounts Capitalized	**(100,942)**	(101,815)	(97,289)
Interest Paid, Net of Amounts Capitalized	**(45,433)**	(38,232)	(33,128)
Capital Lease Interest Paid	**(32,103)**	(38,640)	(38,586)
Wholesale Gas Costs Paid	**(11,822)**	—	—
Income Taxes Paid	**(2,346)**	(19,663)	(14,606)
Performance Deposits Paid	**(1,640)**	(5,040)	(14,000)
Other Cash Payments	**(4,240)**	(3,435)	(3,827)
Net Cash Flows - Operating Activities	**268,294**	302,483	268,064
Cash Flows from Investing Activities			
Capital Expenditures	**(351,890)**	(225,920)	(240,079)
Purchase of Intangibles - Renewable Energy Credits	**(5,111)**	(7,903)	—
Purchase of Sundt Unit 4 Lease Asset	—	(51,389)	—
Purchase of Springerville Lease Debt	—	—	(31,375)
Other Cash Payments	**(558)**	(1,483)	(411)
Return of Investments in Springerville Lease Debt	**38,353**	25,615	12,736
Other Cash Receipts	**7,195**	8,044	9,528
Net Cash Flows - Investing Activities	**(312,011)**	(253,036)	(249,601)
Cash Flows from Financing Activities			
Proceeds from Issuance of Long-Term Debt	**260,285**	118,245	—
Proceeds from Borrowings Under Revolving Credit Facility	**220,000**	177,000	171,000
Equity Investment from UniSource Energy	**30,000**	15,000	30,000
Other Cash Receipts	**2,458**	3,241	2,447
Repayments of Borrowings Under Revolving Credit Facility	**(210,000)**	(212,000)	(146,000)
Repayments of Long-Term Debt	**(172,460)**	(30,000)	—
Payments of Capital Lease Obligations	**(74,343)**	(55,889)	(24,091)
Payments of Debt Issue/Retirement Costs	**(3,594)**	(5,988)	(1,329)
Dividends Paid to UniSource Energy	—	(60,000)	(60,000)
Other Cash Payments	**(894)**	(1,491)	(1,347)
Net Cash Flows - Financing Activities	**51,452**	(51,882)	(29,320)
Net Increase (Decrease) in Cash and Cash Equivalents	**7,735**	(2,435)	(10,857)
Cash and Cash Equivalents, Beginning of Year	**19,983**	22,418	33,275
Cash and Cash Equivalents, End of Year	**$ 27,718**	$ 19,983	$ 22,418

See Note 15 for supplemental cash flow information.

See Notes to Consolidated Financial Statements.

TUCSON ELECTRIC POWER COMPANY
CONSOLIDATED BALANCE SHEETS

	December 31, 2011	December 31, 2010
	- Thousands of Dollars -	
ASSETS		
Utility Plant		
Plant in Service	**$ 4,222,236**	$ 3,863,431
Utility Plant Under Capital Leases	**582,669**	582,669
Construction Work in Progress	**76,517**	153,981
Total Utility Plant	**4,881,422**	4,600,081
Less Accumulated Depreciation and Amortization	**(1,753,807)**	(1,729,747)
Less Accumulated Amortization of Capital Lease Assets	**(476,963)**	(460,257)
Total Utility Plant - Net	**2,650,652**	2,410,077
Investments and Other Property		
Investments in Lease Debt and Equity	**65,829**	103,844
Other	**32,313**	43,588
Total Investments and Other Property	**98,142**	147,432
Current Assets		
Cash and Cash Equivalents	**27,718**	19,983
Accounts Receivable - Customer	**71,435**	78,200
Unbilled Accounts Receivable	**32,386**	32,217
Allowance for Doubtful Accounts	**(3,766)**	(4,106)
Accounts Receivable - Due from Affiliates	**4,049**	5,444
Fuel Inventory	**32,981**	29,209
Materials and Supplies	**70,749**	54,732
Derivative Instruments	**1,439**	1,318
Regulatory Assets - Current	**71,747**	34,023
Deferred Income Taxes - Current	**21,678**	32,077
Other	**13,753**	26,467
Total Current Assets	**344,169**	309,564
Regulatory and Other Assets		
Regulatory Assets - Noncurrent	**157,386**	182,304
Derivative Instruments	**1,398**	1,834
Other Assets	**23,737**	24,767
Total Regulatory and Other Assets	**182,521**	208,905
Total Assets	**$ 3,275,484**	$ 3,075,978

See Notes to Consolidated Financial Statements.

(Consolidated Balance Sheets Continued)

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TUCSON ELECTRIC POWER COMPANY
CONSOLIDATED BALANCE SHEETS

	December 31, 2011	December 31, 2010
	- Thousands of Dollars -	
CAPITALIZATION AND OTHER LIABILITIES		
Capitalization		
Common Stock Equity	**$ 824,943**	$ 709,884
Capital Lease Obligations	**352,720**	429,074
Long-Term Debt	**1,080,373**	1,003,615
Total Capitalization	**2,258,036**	2,142,573
Current Liabilities		
Current Obligations Under Capital Leases	**77,482**	60,309
Borrowing Under Revolving Credit Facility	**10,000**	-
Accounts Payable - Trade	**84,508**	77,021
Accounts Payable - Due to Affiliates	**4,827**	3,990
Interest Accrued	**30,877**	31,771
Accrued Taxes Other than Income Taxes	**32,155**	29,873
Accrued Employee Expenses	**21,356**	23,710
Customer Deposits	**23,743**	21,191
Derivative Instruments	**9,040**	7,288
Regulatory Liabilities - Current	**23,702**	58,936
Other	**4,524**	3,379
Total Current Liabilities	**322,214**	317,468
Deferred Credits and Other Liabilities		
Deferred Income Taxes - Noncurrent	**263,225**	227,615
Regulatory Liabilities - Noncurrent	**200,599**	170,223
Derivative Instruments	**14,142**	11,650
Pension and Other Postretirement Benefits	**130,660**	120,590
Other	**86,608**	85,859
Total Deferred Credits and Other Liabilities	**695,234**	615,937
Commitments, Contingencies, and Proposed Envirionmental Matters (Note 4)		
Total Capitalization and Other Liabilities	**$ 3,275,484**	$ 3,075,978

See Notes to Consolidated Financial Statements.

(Consolidated Balance Sheets Concluded)

TUCSON ELECTRIC POWER COMPANY
CONSOLIDATED STATEMENTS OF CAPITALIZATION

			December 31, 2011	December 31, 2010
			- Thousands of Dollars -	
COMMON STOCK EQUITY				
Common Stock-No Par Value			$ 888,971	$ 858,971
	2011	2010		
Shares Authorized	75,000,000	75,000,000		
Shares Outstanding	32,139,434	32,139,434		
Capital Stock Expense			(6,357)	(6,357)
Accumulated Deficit			(47,627)	(132,961)
Accumulated Other Comprehensive Loss			(10,044)	(9,769)
Total Common Stock Equity			824,943	709,884
PREFERRED STOCK				
No Par Value, 1,000,000 Shares Authorized, None Outstanding			—	—
CAPITAL LEASE OBLIGATIONS				
Springerville Unit 1			253,481	302,229
Springerville Coal Handling Facilities			65,022	76,583
Springerville Common Facilities			111,699	110,571
Total Capital Lease Obligations			430,202	489,383
Less Current Maturities			(77,482)	(60,309)
Total Long-Term Capital Lease Obligations			352,720	429,074
LONG-TERM DEBT				
Issue	***Maturity***	***Interest Rate***		
Variable Rate IDBs	2014 - 2016	Variable	215,300	365,300
Unsecured Fixed Rate IDBs	2020 - 2040	3.25% to 6.375%	615,855	638,315
Unsecured Notes	2021	5.15%	249,218	—
Total Long-Term Debt			1,080,373	1,003,615
Total Capitalization			$ 2,258,036	$ 2,142,573

See Notes to Consolidated Financial Statements.

TUCSON ELECTRIC POWER COMPANY
CONSOLIDATED STATEMENTS 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, 2008	**$ 813,971**	**$ (6,357)**	**$ (211,146)**	**$ (6,855)**	**$ 589,613**
Comprehensive Income:					
2009 Net Income			90,688		90,688
Unrealized Loss on Cash Flow Hedges (net of $33 income taxes)				51	51
Reclassification of Realized Losses on Cash Flow Hedges to Net Income (net of $690 income taxes)				1,053	1,053
Employee Benefit Obligations Amortization of SERP Net Prior Service Cost Included in Net Periodic Benefit Cost (net of $33 income taxes)				(51)	(51)
Total Comprehensive Income					91,741
Capital Contribution from UniSource Energy	30,000				30,000
Dividends			(60,763)		(60,763)
Balances at December 31, 2009	**843,971**	**(6,357)**	**(181,221)**	**(5,802)**	**650,591**
Comprehensive Income:					
2010 Net Income			108,260		108,260
Unrealized Loss on Cash Flow Hedges (net of $4,216 income taxes)				(6,431)	(6,431)
Reclassification of Realized Losses on Cash Flow Hedges to Net Income (net of $2,140 income taxes)				3,264	3,264
Employee Benefit Obligations Amortization of SERP Net Prior Service Cost Included in Net Periodic Benefit Cost (net of $523 income taxes)				(800)	(800)
Total Comprehensive Income					104,293
Capital Contribution from UniSource Energy	15,000				15,000
Dividends Paid			(60,000)		(60,000)
Balances at December 31, 2010	**858,971**	**(6,357)**	**(132,961)**	**(9,769)**	**709,884**
Comprehensive Income:					
2011 Net Income			85,334		85,334
Unrealized Loss on Cash Flow Hedges (net of $2,331 income taxes)				(3,555)	(3,555)
Reclassification of Realized Losses on Cash Flow Hedges to Net Income (net of $1,390 income taxes)				2,122	2,122
Employee Benefit Obligations Amortization of SERP Net Prior Service Cost Included in Net Periodic Benefit Cost (net of $804 income taxes)				1,158	1,158
Total Comprehensive Income					85,059
Capital Contribution from UniSource Energy	30,000				30,000
Balances at December 31, 2011	**$ 888,971**	**$ (6,357)**	**$ (47,627)**	**$ (10,044)**	**$ 824,943**

We describe limitations on our ability to pay dividends in Note 7.

See Notes to Consolidated Financial Statements.

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
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 utility services holding company engaged, through its subsidiaries, in the electric generation and energy delivery business. Each of UniSource Energy's subsidiaries is a separate legal entity with its own assets and liabilities. UniSource Energy owns 100% of Tucson Electric Power Company (TEP), UniSource Energy Services, Inc. (UES), Millennium Energy Holdings, Inc. (Millennium), and UniSource Energy Development Company (UED).

TEP is a regulated public utility and UniSource Energy's largest operating subsidiary, representing approximately 82% of UniSource Energy's total assets as of December 31, 2011. TEP generates, transmits and distributes electricity to approximately 404,000 retail electric customers in a 1,155 square mile area in southeastern Arizona. TEP also sells electricity to other utilities and power marketing entities, located primarily in the western U.S. In addition, TEP operates Springerville Unit 3 on behalf of Tri-State Generation and Transmission Association, Inc. (Tri-State) and Springerville Unit 4 on behalf of Salt River Project Agriculture Improvement and Power District (SRP).

UES holds the common stock of two regulated public utilities, UNS Gas, Inc. (UNS Gas) and UNS Electric, Inc. (UNS Electric). UNS Gas is a regulated gas distribution company, which services approximately 148,000 retail customers in Mohave, Yavapai, Coconino, and Navajo counties in northern Arizona, as well as in Santa Cruz County in southern Arizona. UNS Electric is a regulated public utility, which generates, transmits and distributes electricity to approximately 91,000 retail customers in Mohave and Santa Cruz counties.

UED developed the Black Mountain Generating Station (BMGS) in northwestern Arizona. The facility includes two natural gas-fired combustion turbines. Prior to July 2011, UNS Electric received energy from BMGS through a power sales agreement with UED. In July 2011, UNS Electric purchased BMGS from UED, leaving UED with no significant remaining assets. The transaction had no impact on UniSource Energy's consolidated financial statements.

Millennium's investments in unregulated businesses represent less than 1% of UniSource Energy's assets as of December 31, 2011. Millennium's $13 million net loss for 2010, which reflected impairment losses, caused it to be a reportable segment at December 31, 2010. Millennium is not a reportable segment at December 31, 2011.

Our business is comprised of three reporting segments – TEP, UNS Gas, and UNS Electric.

References to "we" and "our" are to UniSource Energy and its subsidiaries, collectively.

REVISION OF PRIOR PERIOD FINANCIAL STATEMENTS

In the second and third quarters of 2011, we identified errors related to amounts recorded as owed to or payable by TEP for electricity deliveries settled in-kind or to be settled in-kind during prior years under our transmission, interconnection and certain joint operating agreements. These agreements typically provide that the parties to such agreements will monitor transmission and delivery losses and other energy imbalances and make payments to each other to compensate for any losses and imbalances. Payments for such losses and imbalances are made in-kind with energy (MWh) rather than cash. The amount of these losses and imbalances is typically a very low portion of the energy flows subject to these agreements and is usually settled on a one day or one month lag. We also identified minor errors to prior year amounts billed to third parties for operations and maintenance expense. Separately, in the second quarter of 2011, we identified errors in prior years in the calculation of income tax expense arising from not treating Allowance for Equity Funds Used During Construction (AFUDC) as a permanent book to tax difference.

We assessed the materiality of these errors on prior period financial statements and concluded they were not material to any prior annual or interim periods, but the cumulative impact, if recognized in 2011, could be material to the annual period ending December 31, 2011 and the interim period ended June 30, 2011. As a result, in accordance with Staff Accounting Bulletin 108, we revised our prior period financial statements to correct these

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

errors. We assessed the materiality of the third quarter 2011 errors, together with the errors identified in the first half of 2011, on prior period financial statements and concluded that, while they were not material to any prior annual or interim periods, we should update the prior revision to reflect all of the errors identified in 2011.

The income tax adjustment affected fiscal years 2003 through 2010 for UniSource Energy and fiscal years 2009 and 2010 for TEP. The adjustment for transmission and delivery losses and energy imbalances settled in-kind or to be settled in-kind affected fiscal years 2004 through 2010. The operations and maintenance expense adjustment affected fiscal years 2006 through 2010. The revision increased UniSource Energy's net income by $2 million for each of the years ended December 31, 2010 and 2009. The revision increased TEP's net income by $1 million for each of the years ended December 31, 2010 and 2009. UniSource Energy's Accumulated Earnings increased by $7 million for the periods prior to January 1, 2009, as a result of the revisions.

The revised amounts include reclassifications to conform to the current year presentation. TEP reclassified Other Operations and Maintenance costs of $7 million in 2010, and $6 million in 2009 to Other Expense to correctly account for the regulatory treatment of certain expenses.

The revision and reclassifications impacted statements of income and balance sheets as shown in the tables below:

	UniSource Energy		TEP	
	Year Ended December 31, 2010			
	As Reported	As Revised	As Reported	As Revised
	-Thousands of Dollars- (Except Per Share Amounts)			
Income Statement				
Electric Wholesale Sales	$ 151,673	$ 151,962	$ 140,815	$ 141,103
Fuel	296,980	295,652	286,071	284,744
Purchased Energy	307,288	307,288	118,716	118,716
Decrease to Reflect PPFAC/PGA Recovery Treatment	(31,105)	(29,622)	(23,025)	(21,541)
Other Operations and Maintenance	370,067	370,037	323,537	316,625
Income Tax Expense	78,266	76,921	61,057	59,936
Net Income	111,477	112,984	106,978	108,260
Basic EPS	3.06	3.10	N/A	N/A
Diluted EPS	2.82	2.86	N/A	N/A
Balance Sheet				
Accounts Receivable -Customer	91,556	98,333	71,425	78,200
Deferred Income Taxes –Current Assets	32,386	30,822	33,640	32,077
Regulatory Assets -Noncurrent	196,736	192,966	186,074	182,304
Common Stock Equity	828,368	830,756	707,495	709,884
Accounts Payable -Trade	109,896	108,950	77,967	77,021
Deferred Income Taxes –Noncurrent Liabilities	246,466	246,466	227,615	227,615

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	UniSource Energy		TEP	
	Year Ended December 31, 2009			
	As Reported	As Revised	As Reported	As Revised
	-Thousands of Dollars- (Except Per Share Amounts)			
Income Statement				
Electric Wholesale Sales	$ 130,904	$ 131,255	$ 152,955	$ 153,306
Fuel	298,655	296,248	281,710	279,303
Purchased Energy	296,861	296,861	144,528	144,529
Decrease to Reflect PPFAC/PGA Recovery Treatment	(17,091)	(14,553)	(20,724)	(18,186)
Other Operations and Maintenance	333,887	333,579	289,765	282,986
Income Tax Expense	64,348	63,232	55,130	54,220
Net Income	104,258	105,901	89,248	90,688
Basic EPS	2.91	2.95	N/A	N/A
Diluted EPS	2.69	2.73	N/A	N/A

BASIS OF PRESENTATION

We consolidate our investments in subsidiaries when we hold a majority of the voting stock and we can exercise control over the operations and policies of the company. Consolidation means accounts of the parent and subsidiary are combined and intercompany balances and transactions are eliminated. Intercompany profits on transactions between regulated entities are not eliminated.

We used the equity and cost methods to report Millennium's investments until the assets became fully impaired in 2010. See Note 13.

USE OF ACCOUNTING ESTIMATES

Management makes estimates and assumptions when preparing financial statements under generally accepted accounting principles (GAAP) in the U.S. These estimates and assumptions affect:

- Assets and liabilities in our balance sheets at the dates of the financial statements;
- Our disclosures about contingent assets and liabilities at the dates of the financial statements; and
- Our revenues and expenses in our income statements during the periods presented.

Because these estimates involve judgments based upon our evaluation of relevant facts and circumstances, actual amounts may differ from the estimates.

ACCOUNTING FOR RATE REGULATION

We generally use the same accounting policies and practices used by unregulated companies. However, sometimes regulatory accounting requires that rate-regulated companies apply special accounting treatment to show the effect of rate regulation. For example, we capitalize certain costs that would be included as expense in the current period by unregulated companies. Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in customer Retail Rates. Regulatory liabilities generally represent expected future costs that have already been collected from customers or items that are expected to be returned to customers through billing reductions. We evaluate regulatory assets each period and believe recovery is probable. If future recovery of costs ceases to be probable, the assets would be written off as a charge in current period earnings.

We apply regulatory accounting as the following conditions exist:

- An independent regulator sets rates;
- The regulator sets the rates to recover the specific enterprise's costs of providing service; and
- Rates are set at levels that will recover the entity's costs and can be charged to and collected from customers.

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

UTILITY PLANT

Utility Plant includes the business property and equipment that supports electric and gas services, consisting primarily of generation, transmission and distribution facilities. We report utility plant at original cost. Original cost includes materials and labor, contractor services, construction overhead (where applicable), and an Allowance for Funds Used During Construction (AFUDC).

We record the cost of repairs and maintenance, including planned major overhauls to Other Operations and Maintenance Expense on the income statements as the costs are incurred.

When a unit of regulated property is retired, we reduce accumulated depreciation by the original cost plus removal costs less any salvage value. There is no income statement impact.

AFUDC and Capitalized Interest

AFUDC reflects the cost of debt or equity funds used to finance construction and is capitalized as part of the cost of regulated utility plant. AFUDC amounts capitalized are included in rate base for establishing Retail Rates. For operations that do not apply regulatory accounting, we capitalize interest related only to debt as a cost of construction. The interest capitalized that relates to debt reduces Other Interest Expense on the income statements. The cost capitalized for equity funds is recorded as Other Income.

Average AFUDC Rate on Regulated Construction Expenditures	2011	2010	2009
TEP	6.72%	6.65%	6.40%
UNS Gas	8.32%	8.19%	7.05%
UNS Electric	8.18%	8.22%	7.62%

UniSource Energy capitalized interest at a rate of 3.30% for 2011 and 1.96% for 2010 related to the development of a new corporate headquarters.

Depreciation

We compute depreciation for owned utility plant on a group method straight-line basis at depreciation rates based on the economic lives of the assets. See Note 5. The ACC approves depreciation rates for all utility plant. TEP transmission assets are subject to FERC jurisdiction. Depreciation rates are based on average useful lives and reflect estimated removal costs, net of estimated salvage value for interim retirements. Below are the summarized average annual depreciation rates for all utility plants.

	TEP	UNS Gas	UNS Electric	UED
2011	3.15%	3.32%	4.31%	3.03%
2010	3.14%	2.83%	4.35%	2.57%
2009	3.64%	2.76%	4.33%	2.57%

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Computer Software Costs

We capitalize costs incurred to purchase and develop computer software for internal use 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 Utility Plant under Capital Leases

TEP financed the following generation assets with capital leases: Springerville Common Facilities, Springerville Unit 1 and the Springerville Coal Handling Facilities. The amount of lease expense incurred for TEP's generation-related capital leases consists of amortization expense, as described in Note 5, and Interest Expense on Capital Leases as reflected on the income statements. The lease terms are described in Note 6.

INVESTMENTS IN LEASE DEBT AND EQUITY

TEP holds investments in lease debt in TEP's Springerville Unit 1 capital leases. These holdings are considered held-to-maturity investments because TEP has the ability and intent to hold them until maturity. TEP records these investments at amortized cost and recognizes interest income. The fair value of these investments is described in Note 11. These investments do not reduce the capital lease obligations reflected on the balance sheet because there is no legal right of offset. TEP makes lease payments to a trustee who then distributes the payments to debt and equity holders.

TEP accounts for its 14% equity interest in the Springerville Unit 1 lease trust using the equity method.

JOINTLY-OWNED FACILITIES

TEP has investments in several generation and transmission facilities jointly-owned with other companies. These projects are accounted for on a proportionate consolidation basis. See Note 5.

ASSET RETIREMENT OBLIGATIONS

TEP and UNS Electric record a liability for the estimated present value of a conditional asset retirement obligation as follows:

- When it is 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 it can reasonably estimate the fair value.

When the liability is initially recorded at net present value, TEP and UNS Electric capitalize the cost by increasing the carrying amount of the related long-lived asset. TEP and UNS Electric adjust the liability to its present value by recognizing accretion expense in Other Operations and Maintenance expense, and the capitalized cost is depreciated in Depreciation and Amortization expense over the useful life of the related asset.

TEP and UNS Electric record cost of removal for generation assets that are recoverable through Retail Rates charged to customers. See Note 2. We record cost of removal for transmission and distribution assets through depreciation rates and recover those amounts in Retail Rates charged to customers. There are no legal obligations associated with these assets. We have recorded an obligation for estimated costs of removal as regulatory liabilities.

EVALUATION OF ASSETS FOR IMPAIRMENT

We evaluate long-lived assets and investments for impairment whenever events or circumstances indicate the carrying value of the assets may be impaired. If discounted expected future cash flows are less than the carrying value of the asset, an impairment loss is recognized if the impairment is other than temporary and the loss is not recoverable through rates, and the asset is written down to the fair value of the asset.

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DEFERRED FINANCING COSTS

We defer the costs to issue debt and amortize such costs to interest expense on a straight-line basis over the life of the debt as this approximates the effective interest method. These costs include underwriters' commissions, discounts or premiums, and other costs such as legal, accounting, regulatory fees and printing costs.

We defer and amortize the gains and losses on reacquired debt associated with regulated operations to interest expense over the remaining life of the original debt.

UTILITY OPERATING REVENUES

We record utility operating revenues when services or commodities are delivered to customers. Operating revenues include an estimate for unbilled revenues from service that has been provided but not billed by the end of an accounting period.

We determine amounts delivered through periodic readings of customer meters. At the end of the month, the usage since the last meter reading is estimated and the corresponding unbilled revenue is calculated. Unbilled revenue is estimated based on daily generation or purchased volumes, estimated customer usage by class, estimated line losses and estimated average customer Retail Rates. Accrued unbilled revenues are reversed the following month when actual billings occur. The accuracy of the unbilled revenue estimate is affected by factors that include fluctuations in energy demands, weather, line losses, customer Retail Rates and changes in the composition of customer classes.

We are authorized a rate-adjustment mechanism that provides for the recovery of actual fuel, transmission and purchased power/energy cost. The revenue surcharge or surcredit adjusts the customers' retail rate for delivered electricity or gas to collect or return under- or over- recovered energy costs. The ACC revises these rate-adjustment mechanisms periodically (annually for TEP and UNS Electric; monthly for UNS Gas) and may increase or decrease the level of costs recovered through Retail Rates for any difference between the total amount collected under the clauses and the recoverable costs incurred. See Note 2.

Arizona's mandatory Renewable Energy Standard (RES) requires TEP and UNS Electric to increase their use of renewable energy and allows recovery of RES compliance costs through a surcharge to customers. We charge customers a Demand Side Management (DSM) surcharge to recover the cost of ACC-approved energy efficiency programs. We defer differences between actual RES or DSM qualified costs incurred and the recovery of such costs through the RES and DSM surcharges. Cost over-recoveries (the excess of cost recoveries through the RES and DSM surcharges over actual qualified costs incurred) are deferred as regulatory liabilities and cost under-recoveries (the excess of actual qualified costs incurred over cost recoveries through the RES and DSM surcharges) are deferred as regulatory assets. The surcharges are reset annually and incorporate an adjustor mechanism that, upon approval of the ACC, allows us to apply any shortage or surplus in the prior year's program expenses to the subsequent year's RES or DSM surcharge. See Note 2.

For contracts that are not settled with energy, TEP nets the sales contracts with the purchase power contracts and reflects the net amount as Electric Wholesale Sales. The corresponding cash receipts are recorded in the statement of cash flows as Cash Receipts from Electric Wholesale Sales, while cash payments are recorded as Purchased Energy Costs Paid.

We record an Allowance for Doubtful Accounts to reduce accounts receivable for amounts estimated to be uncollectible. The allowance is determined based on historical bad debt patterns, retail sales and economic conditions. We refer uncollected accounts to external collection agencies after 90 days.

TEP recognizes revenue from operating Springerville Unit 3 and Unit 4 on behalf of Tri-State and SRP as Other Revenues. Effective with commercial operation of Springerville Unit 3 in July 2006 and Springerville Unit 4 in December 2009, Tri-State and SRP reimburse TEP for various operating costs at the Springerville generating station. Tri-State and SRP also pay TEP for the use of the Springerville Common Facilities and the Springerville Coal Handling Facilities which are recorded as Other Revenues. Operating expenses are recorded in the respective line item of the income statements based on the nature of service or materials provided.

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

INVENTORY

Materials and supplies consist of transmission, distribution and generation construction and repair materials. We record fuel, materials and supply inventories at the lower of weighted average cost or market prices. We capitalize handling and procurement costs (such as materials, labor, overhead costs and transportation costs) as part of the cost of the inventory.

RECOVERY OF FUEL AND PURCHASED ENERGY COSTS

TEP and UNS Electric Purchased Power and Fuel Adjustment Clause (PPFAC)

TEP and UNS Electric defer differences between actual fuel, transmission and purchased power costs and current PPFAC costs incurred and the recovery of such costs in base rates. Cost over-recoveries (the excess of fuel costs recoveries in Base Rates over actual costs incurred) are deferred as regulatory liabilities and cost under-recoveries (the excess of actual costs incurred over fuel costs recovered in Base Rates) are deferred as regulatory assets. See Note 2.

UNS Gas Purchased Gas Adjustor (PGA)

UNS Gas defers the difference between actual gas costs incurred and the recovery of such costs under a Purchased Gas Adjustor (PGA) mechanism. Gas cost over-recoveries (the excess of gas costs recovered under the PGA mechanism over actual gas costs incurred) are deferred as regulatory liabilities and under-recoveries (the excess of actual gas costs incurred over gas costs recovered via the PGA mechanism) are deferred as regulatory assets. See Note 2.

RENEWABLE ENERGY CREDITS (RECs)

The ACC uses Renewable Energy Credits (RECs) to measure compliance with the RES requirements. A REC equals one kWh generated from renewable resources. The cost of REC purchases are qualified renewable expenditures recoverable through the RES surcharge. When TEP or UNS Electric purchase renewable energy, the premium paid above conventional power is the REC cost, a qualified cost recoverable through the RES surcharge, and the remaining cost is recoverable through the PPFAC.

When RECs are purchased, TEP and UNS Electric record the cost of the RECs as Other Assets, and a corresponding regulatory liability, to reflect the obligation to use the RECs for future RES compliance. Unretired RECs are recorded as Other Assets on the balance sheet. RECs are expensed to the income statements when the RECs are reported to the ACC for compliance with the RES requirements. See Note 2.

INCOME TAXES

Due to the difference between GAAP and income tax laws, many transactions are treated differently for income tax purposes than they are in the financial statements. Temporary differences are accounted for by recording deferred income tax assets and liabilities on our balance sheets. These assets and liabilities are recorded using income tax rates expected to be in effect when the deferred tax assets and liabilities are realized or settled. We record a valuation allowance to reduce deferred tax assets when we believe it is more likely than not that the deferred asset will not be realized.

Tax benefits are recognized in the financial statements when it is more likely than not that a tax position will be sustained upon examination by the tax authorities based on the technical merits of the position. The tax benefit recorded is the largest amount that is more than 50% likely to be realized upon ultimate settlement with the tax authority, assuming full knowledge of the position and all relevant facts. Interest Expense includes interest accrued by UniSource Energy and TEP on tax positions taken on tax returns which have not been reflected in the financial statements.

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Prior to 1990, TEP flowed through to ratepayers certain accelerated tax benefits related to utility plant as the benefits were recognized on tax returns. Regulatory Assets – Noncurrent includes Income Taxes Recoverable Through Future Rates, which reflects the future revenues due us from ratepayers as these tax benefits reverse. See Note 2.

We account for Federal Energy Credits using the grant accounting model. The credit is treated as deferred revenue, which is recognized over the depreciable life of the underlying asset. The deferred tax benefit of the credit is treated as a reduction to income tax expense in the year the credit arises. This benefit is offset by the tax expense attributable to the reduction in tax basis required to be recognized. All other federal and state income tax credits are treated as a reduction to income tax expense in the year the credit arises.

Consolidated income tax liabilities are allocated to subsidiaries based on their taxable income as reported in the consolidated tax return.

TAXES OTHER THAN INCOME TAXES

We act as conduits or collection agents for sales taxes, utility taxes, franchise fees and regulatory assessments. As we bill customers for these taxes and assessments, we record trade receivables. At the same time, we record liabilities payable to governmental agencies for these taxes and assessments. These amounts are not reflected in the income statements.

DERIVATIVE FINANCIAL INSTRUMENTS

Risks and Overview

We are exposed to energy price risk associated with gas and purchased power requirements, volumetric risk associated with seasonal load, and operational risk associated with power plants, transmission and transportation systems. We reduce our energy price risk through a variety of derivative and non-derivative instruments. The objectives for entering into such contracts include: creating price stability; ensuring we can meet load and reserve requirements; and reducing exposure to price volatility that may result from delayed recovery under the PPFAC or PGA. See Note 2.

We consider the effect of counterparty credit risk in determining the fair value of derivative instruments that are in a net asset position after incorporating collateral posted by counterparties and allocate the credit risk adjustment to individual contracts. We also consider the impact of our own credit risk after considering collateral posted on instruments that are in a net liability position and allocate the credit risk adjustment to all individual contracts.

We present cash collateral and derivative assets and liabilities associated with the same counterparty separately in our financial statements, and we bifurcate all derivatives into current and long-term portions on the balance sheet.

Cash Flow Hedges

TEP hedges the cash flow risk associated with unfavorable changes in the variable interest rates related to the Springerville Common Facilities Lease and variable rate industrial development bonds. In addition, TEP hedges the cash flow risk associated with a six-year power supply agreement using a six-year power purchase swap agreement. UNS Electric entered into a cash flow hedge in August 2011 to fix the UNS Electric term loan variable interest rate. TEP and UNS Electric account for cash flow hedges as follows:

- The effective portion of the changes in the fair value of the interest rate swaps and TEP's six-year power purchase swap agreement are recorded in Accumulated Other Comprehensive Income (AOCI) and the ineffective portion, if any, is recognized in earnings; and
- When TEP and UNS Electric determine a contract is no longer effective in offsetting the changes in cash flow of a hedged item, TEP and UNS Electric recognize the changes in fair value in earnings. The unrealized gains and losses at that time remain in AOCI and are reclassified into earnings as the underlying hedged transaction occurs.

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

We formally assess, both at the hedge's inception and on an ongoing basis, whether the derivatives have been and are expected to remain highly effective in offsetting changes in the cash flows of hedged items. We discontinue hedge accounting when: (1) the derivative is no longer effective in offsetting changes in the fair value or cash flows of a hedged item; (2) the derivative expires or is sold, terminated, or exercised; (3) it is no longer probable that the forecasted transaction will occur; or (4) we determine that designating the derivative as a hedging instrument is no longer appropriate.

Mark-to-Market

- **TEP**

  TEP's hedges, such as forward power purchase contracts indexed to gas, short-term forward power sales contracts, or call and put options (gas collars), that did not qualify for either cash flow hedge accounting treatment or the normal scope exception are considered mark-to-market transactions. TEP hedges a portion of its monthly natural gas exposure for plant fuel, gas-indexed purchased power and spot market purchases with fixed price contracts for a maximum of three years. Unrealized gains and losses are recorded as either a regulatory asset or regulatory liability to the extent they qualify for recovery through the PPFAC.

  In 2009 through 2011 we had no trading activity.

- **UNS Gas**

  UNS Gas enters into derivative contracts such as forward gas purchases and gas swaps, creating price stability and reducing exposure to natural gas price volatility that may result in delayed recovery under the PGA. Unrealized gains and losses are recorded as either a regulatory asset or regulatory liability, as the UNS Gas PGA mechanism permits the recovery of the cost of hedging contracts.

- **UNS Electric**

  UNS Electric hedges a portion of its purchased power exposure to fixed price and natural gas-indexed contracts with forward power purchases, financial gas swaps, and call and put options. Unrealized gains and losses are recorded as either a regulatory asset or regulatory liability, as the UNS Electric PPFAC mechanism allows recovery of the prudent costs of contracts for hedging fuel and purchased power costs.

Normal Purchase and Normal Sale

We enter into forward energy purchase and sales contracts, including call options, to support our current load forecasts, with counterparties for load serving requirements or counterparties with generating capacity. These contracts are not required to be marked-to-market and are accounted for on an accrual basis. We evaluate our counterparties on an ongoing basis for non-performance risk to ensure it does not impact our ability to obtain the normal scope exception.

PENSION AND OTHER POSTRETIREMENT BENEFITS

We sponsor noncontributory, defined benefit pension plans for substantially all employees and certain affiliate employees. Benefits are based on employees' years of service and average compensation. We also maintain a Supplemental Executive Retirement Plan for upper management. TEP also provides limited health care and life insurance benefits for retirees.

Pension and other postretirement benefit expense are determined by actuarial valuations, based on assumptions that we evaluate annually. See Note 9.

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 2. REGULATORY MATTERS

RATES AND REGULATION

The ACC and the FERC each regulate portions of the utility accounting practices and rates used by TEP, UNS Gas and UNS Electric. The ACC regulates rates charged to retail customers, the siting of generation and transmission facilities, the issuance of securities, and transactions with affiliated parties. The FERC regulates terms and prices of transmission services and wholesale electricity sales.

TEP 2008 Rate Order

The 2008 TEP Rate Order, issued by the ACC and effective December 1, 2008, provided an average base rate increase of 6% over TEP's previous Base Rates; an 8% authorized rate of return on original cost rate base; a fuel rate included in Base Rates of 2.9 cents per kilowatt-hour (kWh); a PPFAC effective January 1, 2009; and a base rate increase moratorium through January 1, 2013.

2010 UNS Gas Rate Order

Effective April 2010, the ACC approved a base rate increase of 2% ($3 million), including an 8% authorized rate of return on original cost rate base.

Pending UNS Gas Rate Case

In April 2011, UNS Gas filed a general rate case (on a cost-of-service basis) with the ACC requesting a base rate increase of 3.8% to cover a revenue deficiency of $5.6 million.

In February 2012, ACC Staff recommended a base rate increase of $2.7 million as well as a mechanism to enable UNS Gas to recover lost fixed-cost revenues as a result of implementing the ACC's EE Standards. The ACC is expected to issue a final order in the second quarter of 2012.

2008 UNS Electric Rate Order

In May 2008, the ACC approved a base rate increase of 2.5% ($4 million) effective June 2008.

2010 UNS Electric Rate Order

In September 2010, the ACC approved a base rate increase of 4% ($7 million), including an 8% authorized rate of return on original cost rate base, effective October 1, 2010. The ACC approved new depreciation rates effective in October 2010.

In July 2011, UNS Electric completed the ACC and FERC approved purchase of BMGS from UED for $63 million, UED's book value for the assets. BMGS was included in UNS Electric's rate base through a revenue-neutral rate reclassification of approximately 0.7 cents per kWh from base power supply rate to non-fuel Base Rates.

COST RECOVERY MECHANISMS

TEP, UNS Gas and UNS Electric have received regulatory decisions that allow for more timely recovery of certain costs through the following recovery mechanisms.

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Purchased Power and Fuel Adjustment Clause (PPFAC)

The PPFAC provides for the adjustment of Retail Rates to reflect variations in retail fuel, transmission and purchased power costs, including demand charges, and the prudent costs of contracts for hedging fuel. TEP and UNS Electric record deferrals for recovery or refund to the extent actual retail fuel, transmission and purchased power costs vary from the fuel rate and current PPFAC rates. The TEP PPFAC became effective in January 2009. A PPFAC rate adjustment is made annually each April 1st (unless otherwise approved by the ACC) and goes into effect for the subsequent 12-month period automatically unless suspended by the ACC. UNS Electric's PPFAC rate adjustment is made annually each June 1 st, effective for the subsequent 12-month period.

The PPFAC rate includes (a) a "Forward Component," under which TEP and UNS Electric recover or refund differences between forecasted fuel, transmission and purchased power costs for the upcoming calendar year and those embedded in the fuel rate and the current PPFAC rates; (b) a "True-up Component," which reconciles differences between actual fuel, transmission and purchased power costs and those recovered through the combination of the fuel rate and the forward component for the preceding 12-month period.

The table below summarizes TEP's and UNS Electric's PPFAC rates in cents per kWh that are compared against actual fuel cost to create regulatory assets or liabilities:

	2011			2010		
	June - December	April - May	January - March	June – December	April - May	January - March (2)
TEP						
PPFAC	0.53	0.53	0.09	0.09	0.09	0.18
CTC (1)	(0.53)	(0.53)	(0.09)	(0.09)	(0.09)	(0.18)
Total PPFAC Rate	—	—	—	—	—	—
UNS Electric	(0.88)	0.08	0.08	(0.28)	(1.06)	(1.06)

(1) Competition Transition Charge

(2) TEP's first PPFAC rate began April 2009 at 0.18 cents per kWh. UNS Electric's PPFAC rate from January to May 2009 was 1.50 cents per kWh, and the PPFAC rate from June to December 2009 was (1.06) cents per kWh.

As part of the 2008 Rate Order, TEP was required to credit previously collected revenues to customers through the PPFAC. As a result, the PPFAC charge has been zero since it became effective in January 2009. In November 2011, the Fixed CTC revenue was fully refunded to customers and TEP began deferring the PPFAC eligible costs until a new PPFAC rate is approved by the ACC.

The following table shows the changes in TEP's PPFAC related accounts and the impacts on revenue and expense for the year ended December 31, 2011:

	Assets (Liability) at December 31,		Year Ended December 31, 2011	
	2011	2010	Increase to Revenue	Reduction to Fuel and Purchased Power Expense
	-Millions of Dollars-			
PPFAC - Fixed CTC Revenue to be Refunded (current and noncurrent)	$ —	$ (36)	$ 36	
PPFAC (current and noncurrent)	$ 60	$ 54		$ 6

For the year ended December 31, 2010, changes in the deferred PPFAC regulatory asset (liability) resulted in a $10 million increase to revenue and a $22 million decrease to fuel and purchased power expense.

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

UNS Gas Purchased Gas Adjustor (PGA)

The PGA mechanism provides for the adjustment of Retail Rates to reflect variations in natural gas costs. UNS Gas records deferrals for recovery or refund to the extent actual natural gas costs vary from the PGA rate. The PGA rate reflects a weighted, rolling average of the gas costs incurred by UNS Gas over the preceding 12 months. The PGA rate automatically adjusts monthly, but it is restricted from rising or falling more than $0.15 per therm in a twelve-month period. UNS Gas is required to request an additional surcredit if deferral balances reflect $10 million or more on a billed basis.

The PGA rate ranged from $0.6593 to $0.7296 cents per therm in 2011, and ranged from $0.6433 to $0.7306 cents per therm in 2010.

RES and Energy Efficiency Standards

The ACC has a mandatory RES that requires TEP and UNS Electric to expand their use of renewable energy through efforts funded by customer surcharges. TEP and UNS Electric are required to file five-year implementation plans with the ACC and annually seek approval for the upcoming year's RES funding amount. Similarly, TEP, UNS Gas and UNS Electric recover the cost of ACC-approved energy efficiency programs through DSM surcharges established by the ACC.

The following table shows RES and DSM tariffs collected:

	TEP RES	UNS Electric RES	TEP DSM	UNS Gas DSM	UNS Electric DSM
			-Millions of Dollars-		
2011	$ 35	$ 7	$ 11	$ 1	$ 2
2010	32	7	10	1	2
2009	29	5	7	1	1

Renewable Energy Standard

In 2010, the ACC approved:

- A funding mechanism for approximately $14 million of TEP-owned renewable energy projects in 2010, and approximately $5 million in UNS Electric owned solar projects per year between 2011 and 2014. TEP's projects were completed in 2010, and TEP began recovering its costs through the RES tariff in January 2011.
- TEP's 2011 RES implementation plan. As approved by the plan, TEP invested $28 million in TEP-owned solar projects in 2011.

In 2011, the ACC approved TEP's 2012 RES implementation plan. The plan allows TEP to invest $28 million in 2012, and $8 million in 2013 for TEP-owned solar projects.

The funding mechanism allows TEP and UNS Electric to use RES funds to recover operating costs, depreciation, and property taxes and to earn a return on company-owned solar projects until the projects can be incorporated in Base Rates.

TEP and UNS Electric entered into multiple ACC approved long-term purchase power agreements with companies developing renewable energy generation facilities. TEP and UNS Electric are required to purchase the full output of each facility for 20 years. Both utilities are authorized to recover a portion of the cost of renewable energy through the PPFAC, with the balance of costs recoverable through the RES tariff.

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Electric Energy Efficiency Standards

In 2010, the ACC approved new Electric Energy Efficiency (EE) Standards designed to require TEP and UNS Electric to implement cost-effective Demand Side Management (DSM) programs, effective in 2011. In 2011, the EE Standards targeted total retail kWh savings equal to 1.25% of 2010 sales increasing to 22% by 2020. The EE Standards provide for a DSM surcharge to recover the costs to implement DSM programs.

In January 2012, the ACC granted UNS Electric a waiver from complying with the 2011 and 2012 EE Standards.

The ACC approved new Gas EE Standards which required UNS Gas to implement cost effective DSM programs to reduce total retail therm sales in 2011, by 701,113 therms, or 0.5% of 2010 sales. Targeted savings increase annually in subsequent years until they reach a cumulative annual reduction in retail therm sales of 6% by 2020.

In January 2012, TEP filed a modification to its 2012/2013 Energy Efficiency Implementation Plan with the ACC. The proposal includes a request for an increase in the performance incentive based on TEP's ability to meet the EE targets for 2012 and for 2013. TEP's proposed annual performance incentive in each of 2012 and 2013 ranges from $6 million to $8 million.

Renewable Energy Credits

The following table shows the REC activity for 2011 and 2010:

	UniSource Energy		TEP	
	December 31,		December 31,	
	2011	2010	2011	2010
	-Millions of Dollars-			
Beginning Balance, included in Other Assets	$ 3	$ —	$ 2	$ —
RECs Purchased	6	8	5	8
RECs Recovered Through Revenues (RES surcharge)	(8)	(5)	(7)	(6)
Ending Balance, included in Other Assets	$ 1	$ 3	$ —	$ 2

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Regulatory Assets and Liabilities

The following tables summarize regulatory assets and liabilities:

	December 31, 2011			
	TEP	UNS Gas	UNS Electric	UniSource Energy
	-Millions of Dollars-			
Regulatory Assets—Current				
Property Tax Deferrals [1]	$ 16	$ —	$ —	$ 16
Derivative Instruments (Notes 11 and 16)	7	7	10	24
Deregulation Costs [2]	3	—	—	3
PPFAC [3]	34	—	7	41
DSM [3]	8	—	1	9
Other Current Regulatory Assets [4]	4	—	—	4
Total Regulatory Assets—Current	72	7	18	97
Regulatory Assets—Noncurrent				
Pension and Other Postretirement Benefits (Note 9)	107	3	4	114
Income Taxes Recoverable through Future Revenues [5]	10	—	2	12
PPFAC/PGA [3]	6	—	—	6
PPFAC—Final Mine Reclamation and Retiree Health Care Costs [6]	20	—	—	20
Derivative Instruments (Notes 11 and 16)	2	2	3	7
Other Regulatory Assets [4]	12	1	1	14
Total Regulatory Assets—Noncurrent	157	6	10	173
Regulatory Liabilities—Current				
PPFAC/PGA [7]	—	(15)	—	(15)
RES [7]	(22)	—	(3)	(25)
Other Current Regulatory Liabilities	(2)	—	—	(2)
Total Regulatory Liabilities—Current	(24)	(15)	(3)	(42)
Regulatory Liabilities—Noncurrent				
Net Cost of Removal for Interim Retirements [8]	(198)	(23)	(10)	(231)
Other Regulatory Liabilities	(3)	(1)	—	(4)
Total Regulatory Liabilities—Noncurrent	(201)	(24)	(10)	(235)
Total Net Regulatory Assets (Liabilities)	$ 4	$ (26)	$ 15	$ (7)

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	December 31, 2010			
	TEP	UNS Gas	UNS Electric	UniSource Energy
	-Millions of Dollars-			
Regulatory Assets—Current				
Property Tax Deferrals (1)	$ 16	$ —	$ —	$ 16
Derivative Instruments (Notes 11 and 16)	5	8	12	25
Deregulation Costs (2)	4	—	—	4
PPFAC (3)	—	—	3	3
DSM (3)	5	—	—	5
Other Current Regulatory Assets (4)	4	—	—	4
Total Regulatory Assets—Current	34	8	15	57
Regulatory Assets—Noncurrent				
Pension and Other Postretirement Benefits (Note 9)	90	2	2	94
Income Taxes Recoverable through Future Revenues (5)	22	—	1	23
PPFAC/PGA (3)	37	—	—	37
PPFAC—Final Mine Reclamation and Retiree Health Care Costs (6)	17	—	—	17
Deregulation Costs (2)	3	—	—	3
Derivative Instruments (Notes 11 and 16)	—	2	2	4
Other Regulatory Assets (4)	13	2	—	15
Total Regulatory Assets—Noncurrent	182	6	5	193
Regulatory Liabilities—Current				
PPFAC/PGA (7)	—	(9)	—	(9)
PPFAC—Fixed CTC Revenue to be Refunded (7)	(36)	—	—	(36)
RES (7)	(22)	—	(1)	(23)
Other Current Regulatory Liabilities	(1)	—	—	(1)
Total Regulatory Liabilities—Current	(59)	(9)	(1)	(69)
Regulatory Liabilities—Noncurrent				
Net Cost of Removal for Interim Retirements (8)	(169)	(22)	(9)	(200)
Other Regulatory Liabilities	(1)	—	—	(1)
Total Regulatory Liabilities—Noncurrent	(170)	(22)	(9)	(201)
Total Net Regulatory Assets (Liabilities)	$ (13)	$ (17)	$ 10	$ (20)

Regulatory assets are either being collected in Retail Rates or are expected to be collected through Retail Rates in a future period. We describe regulatory assets and state when we earn a return below:

(1) Property Tax is recovered over an approximately six-month period as costs are paid, rather than as costs are accrued.

(2) Deregulation costs represent deferred expenses that TEP incurred to comply with various ACC deregulation orders, as authorized by the ACC. TEP earns a return on this asset and is recovering these costs through Retail Rates over a four-year period ending November 2012.

(3) See Cost Recovery Mechanisms discussion.

(4) TEP's other assets include unamortized loss on reacquired debt (recovery through 2032); coal contract amendment (recovery through 2017); and other assets (recovery through 2014). UNS Gas' other assets consist of rate case costs (recovery over 3 years), and costs of the low income assistance program.

(5) Income Taxes Recoverable through Future Revenues are amortized over the life of the assets.

(6) Final Mine Reclamation and Retiree Health Care Costs stem from TEP's jointly-owned facilities at San Juan, Four Corners and Navajo. TEP is required to recognize the present value of its liability associated with final mine reclamation and retiree health care obligations. TEP recorded a regulatory asset because TEP is permitted to fully recover these costs through the PPFAC when the costs are invoiced by the miners. TEP expects to recover these costs over the remaining life of the mines, which is estimated to be between 15 and 21 years.

Regulatory liabilities represent items that TEP either expects to pay to customers through billing reductions in future periods or plans to use for the purpose for which they were collected from customers, as described below:

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(7) See Cost Recovery Mechanisms discussion above.

(8) Net Cost of Removal for Interim Retirements represents an estimate of the cost of future asset retirement obligations net of salvage value. These are amounts collected through revenue for the net cost of removal of interim retirements for transmission, distribution, general and intangible plant which are not yet expended. TEP and UNS Electric have also collected amounts for generation plant, which they have not yet expended.

Income Statement Impact of Applying Regulatory Accounting

Regulatory accounting had the following effects on TEP's net income:

	Years Ended December 31,		
	2011	2010	2009
	-Millions of Dollars-		
TEP			
Operating Revenues			
Amortization of the Fixed CTC Revenue to be Refunded	$ 36	$ 10	$ 13
Operating Expenses			
Depreciation (related to Net Cost of Removal for Interim Retirements)	(29)	(30)	(41)
Deferral of PPFAC Costs	6	22	18
Other	—	(8)	(16)
Non-Operating Income/Expenses			
Long-Term Debt (Amortization of Loss on Reacquired Debt Costs)	1	1	—
AFUDC—Equity	4	4	4
Income Taxes—Deferral	(8)	1	—
Offset by the Tax Effect of the Above Adjustments	(4)	—	9
Net (Decrease)/Increase to Net Income	$ 6	$ —	$ (13)

UNS Gas and UNS Electric would have recognized the difference between expected and actual purchased energy costs and commodity derivative unrealized gains or losses as a change in income statement expense, rather than as a change in regulatory balances.

	Years Ended December 31,		
	2011	2010	2009
	-Millions of Dollars-		
UNS Gas			
Net (Decrease)/Increase to Net Income	$ (5)	$ (1)	$ 6
UNS Electric			
Net (Decrease)/Increase to Net Income	3	(7)	7

Future Implications of Discontinuing Application of Regulatory Accounting

We regularly assess whether we can continue to apply regulatory accounting to regulated operations, and concluded regulatory accounting is applicable. If we stopped applying regulatory accounting to our regulated operations the following would occur:

- Regulatory pension assets would be reflected in AOCI;
- We would write-off remaining regulatory assets as an expense and regulatory liabilities as income on the income statements;
- At December 31, 2011, based on the regulatory assets balances, net of regulatory liabilities:

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

- TEP would have recorded an extraordinary after-tax gain of $62 million and an after-tax loss in AOCI of $64 million;
- UNS Gas would have recorded an extraordinary after-tax gain of $18 million and an after-tax loss in AOCI of $2 million; and
- UNS Electric would have recorded an extraordinary after-tax loss of $6 million and an after-tax loss in AOCI of $3 million.

While future regulatory orders and market conditions may affect cash flows, our cash flows would not be affected if we stopped applying regulatory accounting to our regulated operations.

NOTE 3. 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 regulated electric utility business, is our largest subsidiary;

(2) UNS Gas is a regulated gas distribution utility business; and

(3) UNS Electric is a regulated electric utility business.

Results for the UniSource Energy and UES holding companies, Millennium and UED are included in Other below.

In accordance with accounting rules related to the transfer of a business held under common control, we reflect UNS Electric's purchase of BMGS as if it occurred on January 1, 2009. UNS Electric's net income and reconciling adjustments in the table below increased by $3 million for the year ended December 31, 2011, and $5 million for each of the years ended December 31, 2010 and 2009. The transaction had no impact on UniSource Energy's consolidated financial statements. In addition, the segments disclosed in the 2010 and 2009 sections of the table below were revised to move Millennium into the "Other" segment as it is no longer a reportable segment.

We disclose selected financial data for our reportable segments in the following tables:

2011	Reportable Segments TEP	UNS Gas	UNS Electric	Other	Reconciling Adjustments	UniSource Energy
	-Millions of Dollars-					
Income Statement						
Operating Revenues-External	$ 1,141	$ 149	$ 219	$ —	$ 1	$ 1,510
Operating Revenues- Intersegment	15	2	2	23	(42)	—
Depreciation and Amortization	140	8	17	1	(1)	165
Interest Income	4	—	—	1	—	5
Interest Expense	89	7	7	9	—	112
Income Tax Expense (Benefit)	52	7	11	(1)	(2)	67
Net Income (Loss)	85	10	18	—	(3)	110
Cash Flow Statement						
Capital Expenditures	(352)	(13)	(96)	(34)	121	(374)
Balance Sheet						
Total Assets	3,275	319	370	1,172	(1,151)	3,985

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Reportable Segments					
2010	TEP	UNS Gas	UNS Electric	Other	Reconciling Adjustments	UniSource Energy
	-Millions of Dollars-					
Income Statement						
Operating Revenue-External	$ 1,096	$ 144	$ 213	$ —	$ 1	$ 1,454
Operating Revenue- Intersegment	29	6	2	28	(65)	—
Depreciation and Amortization	132	8	16	2	(2)	156
Interest Income	7	—	—	1	—	8
Interest Expense	88	7	7	9	—	111
Net Loss from Equity Method Investments	—	—	—	(6)	—	(6)
Income Tax Expense (Benefit)	60	6	10	4	(3)	77
Net Income (Loss)	108	9	15	(14)	(5)	113
Cash Flow Statement						
Capital Expenditures	(277)	(12)	(24)	(18)	—	(331)
Balance Sheet						
Total Assets	3,076	310	356	1,152	(1,103)	3,791
2009						
Income Statement						
Operating Revenues-External	$ 1,065	$ 148	$ 183	$ —	$ 1	$ 1,397
Operating Revenues- Intersegment	34	5	4	28	(71)	—
Depreciation and Amortization	153	7	16	2	(2)	176
Interest Income	11	—	—	1	—	12
Net Gain from Equity Method Investments	—	—	—	5	—	5
Interest Expense	85	6	7	11	—	109
Income Tax Expense (Benefit)	54	5	7	—	(3)	63
Net Income (Loss)	91	7	11	2	(5)	106
Cash Flow Statement						
Capital Expenditures	(240)	(15)	(29)	(10)	—	(294)

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Reconciling adjustments consist of the elimination of intersegment revenue resulting from the following transactions, and they are eliminated in consolidation:

	Reportable Segments			
	TEP	UNS Gas	UNS Electric	Other
	-Millions of Dollars-			
Intersegment Revenue				
2011:				
Wholesale Sales—TEP to UNS Electric (4)	$ 2	$ —	$ —	$ —
Wholesale Sales—UNS Electric to TEP (4)	—	—	2	—
Wholesale Sales—UED to UNS Electric	—	—	—	5
Wholesale Sales—UNS Gas to TEP (5)	—	—	—	—
Gas Revenue—UNS Gas to UNS Electric	—	2	—	—
Other Revenue—TEP to Affiliates (1)	10	—	—	—
Other Revenue—Millennium to TEP, UNS Electric, & UNS Gas (2)	—	—	—	18
Other Revenue—TEP to UNS Electric (3)	3	—	—	—
Total Intersegment Revenue	$ 15	$ 2	$ 2	$ 23
2010:				
Wholesale Sales—TEP to UNS Electric (4)	$ 18	$ —	$ —	$ —
Wholesale Sales—UNS Electric to TEP (4)	—	—	2	—
Wholesale Sales—UED to UNS Electric	—	—	—	11
Wholesale Sales—UNS Gas to TEP (5)	—	1	—	—
Gas Revenue—UNS Gas to UNS Electric	—	5	—	—
Other Revenue—TEP to Affiliates (1)	8	—	—	—
Other Revenue—Millennium to TEP, UNS Electric, & UNS Gas (2)	—	—	—	17
Other Revenue—TEP to UNS Electric (3)	3	—	—	—
Total Intersegment Revenue	$ 29	$ 6	$ 2	$ 28
2009:				
Wholesale Sales—TEP to UNS Electric (4)	$ 23	$ —	$ —	$ —
Wholesale Sales—UNS Electric to TEP (4)	—	—	4	—
Wholesale Sales—UED to UNS Electric	—	—	—	12
Gas Revenue—UNS Gas to UNS Electric	—	5	—	—
Other Revenue—TEP to Affiliates (1)	8	—	—	—
Other Revenue—Millennium to TEP, UNS Electric, & UNS Gas (2)	—	—	—	16
Other Revenue—TEP to UNS Electric (3)	3	—	—	—
Total Intersegment Revenue	$ 34	$ 5	$ 4	$ 28

(1) Common costs (systems, facilities, etc.) are allocated on a cost-causative basis and recorded as revenue by TEP. Management believes this method of allocation is reasonable.

(2) Millennium provides a supplemental workforce and meter-reading services to TEP, UNS Gas and UNS Electric. Amounts are based on costs of services performed, and management believes that the charges for services are reasonable. Millennium charged TEP $17 million in 2011, $16 million in 2010, and $15 million in 2009 for these services.

(3) TEP charged UNS Electric for control area services based on a FERC approved tariff.

(4) TEP and UNS Electric sell power to each other at Dow Jones Four Corners Daily Index prices.

(5) Starting in 2010, UNS Gas provides gas to TEP for generation of power at third-party market prices.

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. Direct costs charged by TEP to affiliates were $10 million in 2011, 2010, and 2009.

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

UniSource Energy incurs corporate costs that are allocated to TEP and its other subsidiaries. Corporate costs are allocated based on a weighted-average of three factors: assets, payroll and revenues. Management believes this method of allocation is reasonable and approximates the cost that TEP would have incurred as a standalone entity. Charges allocated to TEP were $2 million in 2011, $3 million in 2010, and $2 million in 2009.

Other

Other significant reconciling adjustments include intercompany interest between UniSource Energy and UED, the elimination of investments in subsidiaries held by UniSource Energy and reclassifications of deferred tax assets and liabilities.

NOTE 4. COMMITMENTS, CONTINGENCIES, AND PROPOSED ENVIRONMENTAL MATTERS

TEP COMMITMENTS

Firm Purchase Commitments

At December 31, 2011, TEP had the following firm non-cancelable purchase commitments (minimum purchase obligations) and operating leases:

	Purchase Commitments						
	2012	2013	2014	2015	2016	Thereafter	Total
	-Millions of Dollars-						
Fuel (including Transportation)	$ 84	$ 59	$ 58	$ 44	$ 41	$ 75	$ 361
Purchased Power	29	21	17	13	13	184	277
Solar Equipment	12	12	—	—	—	—	24
Transmission	3	3	3	3	3	23	38
Operating Leases	2	2	2	1	1	10	18
Total Unrecognized Firm Commitments	$ 130	$ 97	$ 80	$ 61	$ 58	$ 292	$ 718

Fuel, Purchased Power and Transmission Contracts

TEP has long-term contracts for the purchase and delivery of coal and natural gas with various expiration dates from 2012 through 2020. Amounts paid under these contracts depend on actual quantities purchased and delivered. Some of these contracts include a price adjustment clause that will affect the future cost. TEP expects to spend more to meet its fuel requirements than the minimum purchase obligations outlined above.

TEP has agreements with utilities and other energy suppliers for purchased power to meet system load and energy requirements, replace generation from company-owned units under maintenance and during outages, and meet operating reserve obligations. In general, these contracts provide for capacity payments and energy payments based on actual power taken under the contracts. These contracts expire in various years between 2012 and 2014. Certain of these contracts are at a fixed price per MW and others are indexed to natural gas prices. The commitment amounts included in the table are based on projected market prices as of December 31, 2011.

Additionally, Purchased Power includes two 20-year Power Purchase Agreements (PPAs) with renewable energy generation facilities that achieved commercial operation in 2011. TEP is obligated to purchase 100% of the output from these facilities. TEP has additional long-term renewable PPAs to comply with the RES requirements; however, TEP's obligation to purchase power under these agreements does not begin until the facilities are operational.

Fuel, purchased power and transmission costs are recoverable from customers through the PPFAC.

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Solar Equipment

TEP has a commitment to purchase 9 MW of photovoltaic equipment through December 2013. The ACC approved 6 MW, and we are seeking approval from the ACC for the remaining 3 MW in 2012. TEP spent $10 million in 2011 under this contract. TEP earns a return on company-owned solar projects. See Note 2.

Operating Leases

TEP's aggregate operating lease expense is primarily for rail cars, office facilities and computer equipment, with varying terms, provisions, and expiration dates. This expense totaled $2 million in each of 2011, 2010, and 2009.

UNS GAS and UNS ELECTRIC COMMITMENTS

At December 31, 2011, UNS Gas had firm non-cancelable purchase commitments for fuel, including transportation, as described in the table below:

	Purchase Commitments						
	2012	2013	2014	2015	2016	Thereafter	Total
	-Millions of Dollars-						
Total Unrecognized Firm Commitments – Fuel	$ 23	$ 12	$ 10	$ 6	$ 6	$ 21	$ 78

UNS Gas purchases gas from various suppliers at market prices. However, UNS Gas' risk of loss due to increased costs (as a result of changes in market prices of fuel) is mitigated through the use of the PGA, which provides for the pass-through of actual commodity costs to customers. UNS Gas' forward gas purchase agreements expire through 2015. Certain of these contracts are at a fixed price per MMBtu and others are indexed to natural gas prices. The commitment amounts included in the table above are based on market prices as of December 31, 2011. UNS Gas has firm transportation agreements with capacity sufficient to meet its load requirements. These contracts expire in various years between 2012 and 2024.

At December 31, 2011, UNS Electric had various firm non-cancelable purchase commitments as described in the table below:

	Purchase Commitments						
	2012	2013	2014	2015	2016	Thereafter	Total
	-Millions of Dollars-						
Purchased Power	$ 54	$ 40	$ 31	$ 3	$ 3	$ 43	$ 174
Transmission	4	2	2	1	1	—	10
Total Unrecognized Firm Commitments	$ 58	$ 42	$ 33	$ 4	$ 4	$ 43	$ 184

UNS Electric enters into agreements with various energy suppliers for purchased power at market prices to meet its energy requirements. In general, these contracts provide for capacity payments and energy payments based on actual power taken under the contracts. These contracts expire in various years through 2014. Certain of these contracts are at a fixed price per MW, and others are indexed to natural gas prices. The commitment amounts included in the table above are based on market prices as of December 31, 2011. Purchased power commitments also include one 20-year PPA with a renewable energy generation facility that achieved commercial operation in September 2011. UNS Electric is obligated to purchase 100% of the output from this facility.

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 2012 and 2016. However, the effects of both purchased power and transmission cost adjustments are mitigated through a purchased power rate-adjustment mechanism.

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

UNS Gas and UNS Electric have operating lease expense, primarily for office facilities and computer equipment, with varying terms and expiration dates. The expense was $1 million in each of the years 2011, 2010, and 2009. UNS Gas' and UNS Electric's estimated future minimum payments under non-cancelable operating leases are less than $1 million per year for 2012 through 2017.

TEP CONTINGENCIES

San Juan Mine Fire

In September 2011, a fire at the underground mine that provides coal to San Juan caused mining operations to shut down. TEP owns approximately 20% of San Juan, which is operated by PNM. As we are unable to predict when operations will resume at the mine, we and the other owners of San Juan are considering alternatives for operating the facility.

However, based on information we have received to date, we do not expect the mine fire to have a material effect on our financial condition, results of operations, or cash flows due to the current inventory of previously mined coal and the current low market price of wholesale power. TEP expects that any incremental fuel and purchased power costs would be recoverable from customers through the PPFAC, subject to ACC approval.

Claims Related to San Juan Generating Station

In April 2010, the Sierra Club filed a citizens' suit under the Resource Conservation and Recovery Act (RCRA) and the Surface Mine Control and Reclamation Act (SMCRA) in the U.S. District Court for the District of New Mexico against PNM, as operator of San Juan; PNM's parent PNM Resources, Inc. (PNMR); San Juan Coal Company (SJCC), which operates the San Juan mine that supplies coal to San Juan; and SJCC's parent BHP Minerals International Inc. (BHP). The Sierra Club alleges in the suit that certain activities at San Juan and the San Juan mine associated with the treatment, storage and disposal of coal and coal combustion residuals (CCRs), primarily coal ash, are causing imminent and substantial harm to the environment, including ground and surface water in the region, and that placement of CCRs at the mine constitute "open dumping" in violation of RCRA. The RCRA claims are asserted against PNM, PNMR, SJCC and BHP. The suit also includes claims under SMCRA which are directed only against SJCC and BHP. The suit seeks the following relief: an injunction requiring the parties to undertake certain mitigation measures with respect to the placement of CCRs at the mine or to cease placement of CCRs at the mine; the imposition of civil penalties; and attorney's fees and costs. With the agreement of the parties, the court entered a stay of the action in August 2010, to allow the parties to try to address the Sierra Club's concerns. If the parties are unable to settle the matter, PNM has indicated that it plans an aggressive defense of the RCRA claims in the suit.

SJCC operates an underground coal mine in an area where certain gas producers have oil and gas leases with the federal government, the State of New Mexico and private parties. These gas producers allege that SJCC's underground coal mine interferes with their operations, reducing the amount of natural gas they can recover. SJCC has compensated certain gas producers for any remaining production from wells deemed close enough to the mine to warrant plugging and abandoning them. These settlements, however, do not resolve all potential claims by gas producers in the area. TEP cannot estimate the impact of any future claims by these gas producers on the cost of coal at San Juan.

TEP owns 50% of San Juan Units 1 and 2, which represents approximately 20% of the total generation capacity of the entire San Juan Generating Station, and is responsible for its share of any resulting liabilities.

Claims Related to Four Corners Generating Station

In October 2011, EarthJustice, on behalf of several environmental organizations, filed a lawsuit in the United States District Court for the District of New Mexico against APS and the other Four Corners Generating Station (Four Corners) participants alleging violations of the Prevention of Significant Deterioration (PSD) provisions of the Clean Air Act at Four Corners. Among other things, the plaintiffs seek to have the court enjoin operations at Four Corners until any required PSD permits are issued and order the payment of civil penalties, including a beneficial mitigation project.

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

TEP owns 7% of Four Corners Units 4 and 5 and is liable for its share of any resulting liabilities.

TEP cannot predict the final outcome of the claims relating to San Juan and Four Corners, and, due to the general and non-specific nature of the claims and the indeterminate scope and nature of the injunctive relief sought for these claims, estimates of the range of loss cannot be determined at this time. TEP accrued estimated losses of less than $1 million in 2011 in respect of these claims.

Mine Closure Reclamation at Generating Stations Not Operated by TEP

TEP pays ongoing reclamation costs related to coal mines that supply generating stations in which TEP has an ownership interest but does not operate. TEP is liable for a portion of final reclamation costs upon closure of these mines. TEP's share of the reclamation costs for coal supply agreements expiring in 2016 through 2019 is approximately $26 million. TEP recognizes this cost over the remaining terms of these coal supply agreements and had recorded liabilities of $13 million at December 31, 2011, and $11 million at December 31, 2010.

Amounts recorded for final reclamation are subject to various assumptions, such as estimations of reclamation costs, the dates when final reclamation will occur, and the credit-adjusted risk-free interest rate to be used to discount future liabilities. As these assumptions change, TEP will prospectively adjust the expense amounts for final reclamation over the remaining coal supply agreement terms. TEP does not believe that recognition of its final reclamation obligations will be material to TEP in any single year because recognition will occur over the remaining terms of its coal supply agreements.

TEP's PPFAC allows TEP to pass through most fuel costs (including final reclamation costs) to customers. Therefore, TEP classifies these costs as a regulatory asset. TEP will increase the regulatory asset and the reclamation liability over the remaining life of the coal supply agreements on an accrual basis and recover the regulatory asset through the PPFAC as final mine reclamation costs are paid to the coal suppliers.

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. UNS Electric's participation in this project was initiated in response to an order by the ACC to improve the reliability of electric service in Nogales. That order was issued before UniSource Energy purchased the electric system in Nogales and surrounding Santa Cruz County from Citizens Utilities in August 2003.

In 2002, the ACC authorized construction of the proposed 345-kV line along a route identified as the Western Corridor subject to a number of conditions, including the issuance of all required permits from state and federal agencies. The U.S. Forest Service subsequently expressed its preference for a different route in its final Environmental Impact Statement for the project. TEP and UNS Electric are considering options for the project. If a decision is made to pursue an alternative route, approvals will be needed from the ACC, the Department of Energy, U.S. Forest Service, Bureau of Land Management, and the International Boundary and Water Commission. As of December 31, 2011, and December 31, 2010, TEP had capitalized $11 million related to the project, including $2 million to secure land and land rights. If TEP does not receive the required approvals or abandons the project, TEP believes cost recovery is probable for prudent and reasonably incurred costs related to the project as a consequence of the ACC's requirement for a second transmission line serving the Nogales, Arizona area.

RESOLUTION OF CONTINGENCIES

Settlement of El Paso Electric Dispute

In November 2011, a settlement agreement between TEP and El Paso became effective after receiving FERC approval in August 2011. The settlement resolved a dispute over transmission service from Luna to TEP's system, totaling $11 million, under the 1982 Power Exchange and Transmission Agreement between the parties (Exchange Agreement).

The settlement reduced TEP's rights for transmission under the Exchange Agreement from 200 MW to 170 MW and required TEP to pay El Paso a lump-sum of $5 million, equivalent to the total amount that TEP would have paid El Paso for 30 MW of transmission from February 1, 2006, through the settlement date, including interest.

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Under the PPFAC mechanism, TEP is allowed to recover $2 million of this additional transmission expense from its customers. In accordance with the settlement agreement, TEP has entered into two new firm transmission service agreements under El Paso's Open Access Transmission Tariff for a total of 40 MW. The settlement agreement also required El Paso to withdraw its appeal before the United States Court of Appeals District of Columbia Circuit and required TEP to withdraw its related complaint before the Arizona District of the United States District Court.

TEP recognized a pre-tax gain of approximately $7 million, including interest, in the third quarter of 2011. To reflect the gain, TEP recorded a $7.1 million net reduction to Transmission Expense, $0.9 million of Interest Income, and $0.6 million of Interest Expense on the income statements. TEP recorded the payment of $5 million in Purchased Power in the cash flow statements.

Take-Or-Pay Accrual for Coal Transportation Agreement

In December 2010, TEP recorded a $4 million liability and regulatory asset for take-or-pay obligations under a coal transportation agreement for Sundt Unit 4, effective through December 2015. In December 2011, TEP's take-or-pay obligations were terminated. As a result, TEP reversed its $4 million liability and regulatory asset.

Claims Related to Navajo Generating Station

In June 1999, the Navajo Nation filed suit in the U.S. District Court for the District of Columbia (D.C. Lawsuit) against parties including SRP; several Peabody Coal Company entities including Peabody Western Coal Company (Peabody), the coal supplier to Navajo Generating Station (Navajo); Southern California Edison Company (SCE); and other defendants. Although TEP is not a named defendant in the D.C. Lawsuit, TEP owns 7.5% of Navajo Units 1, 2 and 3. The D.C. Lawsuit alleged, among other things, that the defendants obtained a favorable coal royalty rate on the lease agreements under which Peabody mines coal by improperly influencing the outcome of a federal administrative process pursuant to which the royalty rate was to be adjusted. The suit initially sought $600 million in damages, treble damages, punitive damages of not less than $1 billion, and the ejection of defendants from all possessory interests and Navajo Tribal lands arising out of the primary coal lease.

In July 2001, the District Court dismissed all claims against SRP. In April 2010, the Navajo Nation filed a Second Amended Complaint which dropped the treble damages claim. In August 2011, the Navajo Nation, Peabody, SCE and SRP executed a written settlement agreement in return for the Navajo Nation's dismissal of all claims in the D.C. Lawsuit. SRP asked that the Navajo participants, including TEP, contribute toward the settlement based on their respective ownership interests in the Navajo plant, which for TEP is 7.5%. TEP paid SRP the requested contribution which did not have a material impact on TEP's financial statements.

In 2004, Peabody filed a complaint in the Circuit Court for the City of St. Louis, Missouri against the participants at Navajo, including TEP, for reimbursement of royalties and other costs arising out of the D.C. Lawsuit. In July 2008, the parties entered into a joint stipulation of dismissal of these claims which was approved by the Circuit Court. TEP does not believe the lawsuit will be re-filed based upon the final outcome of the D.C. Lawsuit.

PROPOSED ENVIRONMENTAL MATTERS

ENVIRONMENTAL REGULATION

TEP's generating facilities are subject to Environmental Protection Agency (EPA) limits on the amount of sulfur dioxide (SO_2), nitrogen oxide (NOx) and other emissions released into the atmosphere. TEP capitalized $8 million in 2011, $18 million in 2010 and $24 million in 2009 in construction costs to comply with environmental requirements, including TEP's share of new pollution control equipment installed at San Juan Generating Station (San Juan) described below. TEP expects to capitalize environmental compliance costs of $7 million in 2012 and $25 million in 2013. In addition, TEP recorded operating expenses of $12 million in 2011, $14 million in 2010 and $13 million in 2009 related to environmental compliance. TEP expects environmental expenses to be $14 million in 2012.

TEP may incur additional costs to comply with future changes in federal and state environmental laws, and regulations and permit requirements at its electric generating facilities. Compliance with these changes may reduce operating efficiency.

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Hazardous Air Pollutant Requirements

The Clean Air Act requires the EPA to develop emission limit standards for hazardous air pollutants that reflect the maximum achievable control technology. The EPA is required to develop rules establishing standards for the control of emissions of mercury and other hazardous air pollutants from electric generating units. The EPA issued the final rule in December 2011.

Navajo

Based on the EPA's final standards, mercury and particulate emission control equipment may be required at Navajo by 2015. TEP's share of the estimated capital cost of this equipment is less than $1 million for mercury control and approximately $43 million if the installation of baghouses to control particulates is necessary.

Springerville

Based on the EPA's final standards, mercury emission control equipment may be required at Springerville by 2015. The estimated capital cost of this equipment for Springerville Units 1 and 2 is approximately $5 million. The annual operating cost associated with the mercury emission control equipment is expected to be approximately $3 million.

San Juan

Current emission controls at San Juan are expected to be adequate to achieve compliance with the EPA's final federal standards.

Sundt

TEP does not anticipate the final EPA rule will have a material capital impact on Sundt Unit 4.

Four Corners

Based on the EPA's final standards, mercury emission control equipment may be required at Four Corners by 2015. The estimated capital cost of this equipment is less than $1 million. The annual operating cost associated with the mercury emission control equipment is expected to be less than $1 million.

Regional Haze Rules

The EPA's regional haze rules require emission controls known as Best Available Retrofit Technology (BART) for certain industrial facilities emitting air pollutants that reduce visibility. The rules call for all states to establish goals and emission reduction strategies for improving visibility in national parks and wilderness areas and to submit a state implementation plan to the EPA for approval. Navajo and Four Corners are located on the Navajo Indian Reservation and therefore are not subject to state regulatory jurisdictions. The EPA oversees regional haze planning for these plants.

Compliance with the EPA's BART determinations, coupled with the financial impact of future climate change legislation, other environmental regulations and other business considerations could jeopardize the economic viability of the San Juan, Four Corners and Navajo plants or the ability of individual participants to meet their obligations and maintain participation in these plants. TEP cannot predict the ultimate outcome of these matters.

San Juan

In August 2011, EPA Region VI issued a Federal Implementation Plan (FIP) establishing new emission limits for NOx, SO_2 and sulfuric acid emissions at the San Juan Generating Station. The FIP requires the installation of Selective Catalytic Reduction (SCR) technology with sorbent injection on all four units within five years to reduce NOx and control sulfuric acid emissions. Based on two cost analyses commissioned by PNM, TEP's share of the cost to install SCR with sorbent injection is estimated to be between $180 million and $200 million.

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In September 2011, PNM filed a petition to review the Federal Implementation Plan with the 10th Circuit Court of Appeals challenging various aspects of that plan. In addition, PNM filed a request with the EPA to stay the five-year installation timeframe for environmental upgrades ordered by the Federal Implementation Plan until the 10th Circuit considers and rules on the petition to review.

In October 2011, PNM filed a Petition for Reconsideration of the Federal Implementation Plan. PNM also filed a Request to Stay the effective date of the final BART Federal Implementation Plan under the Clean Air Act with the EPA. In November 2011, PNM filed with the 10th Circuit a Motion to Stay the Federal Implementation Plan. WildEarth Guardians, Dine Citizens against Ruining our Environment, National Parks Conservation Association, New Energy Economy, San Juan Citizens Alliance and Sierra Club were granted leave to intervene in PNM's petition to review in the 10th Circuit. Neither the Petition in the 10th Circuit, nor the Petition for Reconsideration by the EPA delays the implementation timeframe unless a stay is granted. WildEarth Guardians filed a separate appeal against the EPA challenging the five-year, rather than three-year, implementation schedule. PNM was granted leave to intervene in that appeal.

In October 2011, Governor Susana Martinez of New Mexico and the New Mexico Environment Department filed a Petition for Review of the EPA's final Federal Implementation Plan determination in the 10th Circuit and a Petition for Reconsideration of the rule with the EPA. In November 2011, the New Mexico Governor and Environment Department filed a motion with the 10th Circuit to stay the rule. These appeals and motions are all currently pending.

Four Corners

In February 2011, the EPA supplemented the proposed FIP for the BART determination at Four Corners that would require the installation of SCR on Units 4 and 5 by 2018. TEP's estimated share of the capital costs to install SCR is approximately $35 million.

Navajo

The EPA is expected to issue a proposed rule establishing the BART for Navajo following the consideration of a report by the National Renewable Energy Laboratory (NREL) in partnership with the Department of the Interior and the Department of Energy. The report addresses potential energy, environmental and economic issues related to compliance with the regional haze rule. The report was submitted to the EPA in January 2012. If the EPA determines that SCR is required at Navajo, the capital cost impact to TEP is estimated to be $42 million. In addition, the installation of SCR at Navajo could increase the plant's particulate emissions, necessitating the installation of baghouses. If baghouses are required, TEP's estimated share of the capital expenditure for the required baghouses would be approximately $43 million. The cost of required pollution controls will not be known until final determinations are made by the regulatory agencies. TEP anticipates that if the EPA finalizes a BART rule for Navajo that requires SCR, the owners would have five years to achieve compliance.

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 5. UTILITY PLANT AND JOINTLY-OWNED FACILITIES

UTILITY PLANT

The following table shows Utility Plant in Service by major class.

	UniSource Energy December 31,		TEP December 31,	
	2011	2010	2011	2010
	-Millions of Dollars-			
Plant in Service:				
Electric Generation Plant	$ 1,879	$ 1,787	$ 1,795	$ 1,709
Electric Transmission Plant	810	741	766	705
Electric Distribution Plant	1,453	1,368	1,234	1,168
Gas Distribution Plant	233	224	—	—
Gas Transmission Plant	18	18	—	—
General Plant	331	215	302	187
Intangible Plant—Software Costs	44	34	43	33
Intangible Plant—Other	83	61	78	57
Electric Plant Held for Future Use	5	5	4	4
Total Plant in Service (1)	4,856	4,453	4,222	3,863
Utility Plant under Capital Leases	$ 583	$ 583	$ 583	$ 583

(1) At December 31, 2010, UniSource Energy's total plant included $65 million of non-regulated plant in service related to BMGS, with $4 million of accumulated depreciation. See Note 2 for information regarding UNS Electric's 2011 purchase of BMGS from UED.

TEP Utility Plant under Capital Leases

All TEP utility plant under capital leases is used in TEP's generation operations and amortized over the primary lease term. See Note 6. In April 2010, TEP terminated the capital lease of Sundt Unit 4 and purchased the related leased assets. At December 31, 2011, the utility plant under capital leases includes Springerville Common Facilities, Springerville Unit 1, and Springerville Coal Handling Facilities. The following table shows the amount of lease expense incurred for TEP's generation-related capital leases:

	Years Ended December 31,		
	2011	2010	2009
	-Millions of Dollars-		
Lease Expense:			
Interest Expense – Included in:			
Capital Leases	$ 40	$ 47	$ 49
Operating Expenses – Fuel	4	4	4
Other Expense	1	2	1
Amortization of Capital Lease Assets – Included in:			
Operating Expenses – Fuel	3	3	2
Operating Expenses – Depreciation and Amortization	14	14	26
Total Lease Expense	$ 62	$ 70	$ 82

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The depreciable lives as of December 31, 2011 were as follows:

Major Class of Utility Plant in Service	TEP	UNS Gas and UNS Electric
Electric Generation Plant	6-59 years	38-42 years
Electric Transmission Plant	20-60 years	20-50 years
Electric Distribution Plant	28-60 years	23-50 years
Gas Distribution Plant	n/a	30-55 years
Gas Transmission Plant	n/a	30-65 years
General Plant	5-31 years	5-40 years
Intangible Plant	3-18 years	5-32 years

See *Utility Plant* in Note 1 and *TEP Capital Lease Obligations* in Note 6.

JOINTLY-OWNED FACILITIES

At December 31, 2011, TEP's interests in jointly-owned generating stations and transmission systems were as follows:

	Ownership Percentage	Plant in Service	Construction Work in Progress	Accumulated Depreciation	Net Book Value
		-Millions of Dollars-			
San Juan Units 1 and 2	50.0%	$ 430	$ 8	$ 219	$ 219
Navajo Station Units 1, 2 and 3	7.5	146	1	99	48
Four Corners Units 4 and 5	7.0	96	2	71	27
Transmission Facilities	7.5 to 95.0	289	9	179	119
Luna Energy Facility	33.3	52	—	1	51
Total		$ 1,013	$ 20	$ 569	$ 464

TEP has financed or provided funds for the above facilities and TEP's share of its operating expenses is reflected in the income statements based on the nature of the expense.

NOTE 6. 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's and TEP's long-term debt in the statements of capitalization.

UNISOURCE ENERGY DEBT- Convertible Senior Notes

In 2005, UniSource Energy issued $150 million of 4.50% Convertible Senior Notes (Convertible Senior Notes) due in 2035. UniSource Energy has the option to redeem the Convertible Senior Notes, in whole or in part, for cash at par plus accrued interest. Investors may require UniSource Energy to repurchase the Convertible Senior Notes, in whole or in part, for cash at par plus accrued interest on March 1 of 2015, 2020, 2025 and 2030, and upon the occurrence of certain fundamental changes, such as a change in control. Each $1,000 of Convertible Senior Notes can be converted into 28.814 shares of UniSource Energy Common Stock at any time, which is equivalent to a conversion price of approximately $34.71 per share of common stock. The conversion rate is subject to adjustments including an adjustment to reduce the conversion price upon the payment of quarterly dividends in excess of $0.19 per share.

In December 2011, UniSource Energy announced that it would redeem $35 million of the $150 million outstanding Convertible Senior Notes on January 12, 2012, at a redemption price of 100% of the principal amount plus accrued interest. In January 2012, holders of approximately $33 million of the Convertible Senior Notes converted their interests into approximately 964,000 shares of UniSource Energy Common Stock. The remaining $2 million of

Convertible Senior Notes were redeemed for cash. After the partial redemption, UniSource Energy had $115 million of Convertible Senior Notes outstanding.

TEP DEBT

Variable Rate Tax-Exempt Bonds (IDBs)

At December 31, 2011, TEP had $215 million in tax-exempt variable rate debt outstanding. At December 31, 2010, TEP had $365 million outstanding. Each series of bonds is supported by a letter of credit issued under the TEP Credit Agreement or separate TEP Letter of Credit and Reimbursement Agreements. The letters of credit are secured by mortgage bonds issued under TEP's 1992 Mortgage.

In November 2011, TEP repurchased $150 million of variable rate IDBs. TEP did not cancel the repurchased bonds, which remained outstanding under their respective indentures but were not reflected as debt on the balance sheet. See 2011 TEP Unsecured Notes below.

In December 2010, TEP issued $37 million of Coconino County, Arizona, tax-exempt pollution control bonds (2010 Coconino Bonds). The 2010 Coconino Bonds are supported by a letter of credit (LOC). The LOC is secured by $37 million of 1992 Mortgage Bonds and expires December 2014. The bonds accrue interest at a variable weekly rate and are due October 2032. These bonds are multi-modal bonds that allow TEP to change the interest feature of the bonds. They are callable at any time at par plus accrued interest and are subject to mandatory redemption under certain circumstances if the LOC is not extended. The average interest rate on TEP's 2010 Coconino Bonds was 0.23% in 2011 and 0.38% in 2010. TEP used the proceeds to redeem a corresponding principal amount of fixed rate Coconino pollution control bonds.

TEP capitalized less than $1 million in costs related to the issuance of these bonds and will amortize the costs to interest expense through October 2032, the term of the bonds.

The following table shows interest rates on TEP's variable rate IDBs which are reset weekly by its remarketing agents:

	Years Ended December 31,		
	2011	2010	2009
Interest Rates on IDBs:			
Average Interest Rate	0.18%	0.26%	0.41%
Range of Average Weekly Rates	0.05% to 0.34%	0.17% to 0.39%	0.25% to 0.79%

In August 2009, TEP entered into an interest rate swap that had the effect of converting $50 million of variable rate IDBs to a fixed rate of 2.4% from September 2009 to September 2014.

Unsecured Fixed Rate IDBs

At December 31, 2011, TEP had $616 million in unsecured fixed rate IDBs. At December 31, 2010, TEP had $638 million outstanding.

In November 2011, TEP redeemed $22 million in unsecured fixed rate IDBs. See 2011 TEP Unsecured Notes below.

In October 2010, TEP issued $100 million of Pima County, Arizona tax-exempt IDBs. The IDBs are unsecured, bear interest at a rate of 5.25%, mature in October 2040, and are callable at par on or after October 1, 2020. Net of an underwriting discount, $99 million of proceeds were deposited in a construction fund with the bond trustee. The proceeds were applied to the construction of certain of TEP's transmission and distribution facilities used to provide electric service in Pima County. TEP drew down $88 million of the proceeds from the construction fund in 2010 and $11 million in 2011.

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

TEP capitalized approximately $1 million in costs related to the issuance of these bonds and will amortize the costs to interest expense through October 2040, the term of the bonds.

2011 TEP Unsecured Notes

In November 2011, TEP issued $250 million of 5.15% Notes due November 2021 at a discount of $0.8 million. The debt is callable anytime before August 15, 2021, with a make-whole premium plus accrued interest. Anytime after August 15, 2021, the debt is callable at par plus accrued interest. TEP used the net proceeds from the sale to 1) repurchase $150 million of variable rate IDBs, 2) redeem $22 million of 6.1% fixed rate IDBs and 3) repay $78 million of outstanding revolving credit facility balances, with any remaining proceeds to be applied to general corporate purposes. The variable rate IDBs were supported by letters of credit (LOCs) issued under TEP's Credit Facility. As a result of the repurchase of the variable rate IDBs, TEP cancelled $155 million of LOCs and reduced its mortgage bonds supporting the LOCs by the same amount.

TEP capitalized $2 million in costs related to the issuance of the notes and will amortize the costs to interest expense through November 2021, the term of the notes.

1992 Mortgage

TEP's 1992 Mortgage 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 $2 billion at December 31, 2011 and December 31, 2010.

TEP CAPITAL LEASE OBLIGATIONS

Springerville Leases

The terms of TEP's capital leases are as follows:

- 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. Instead of extending the leases TEP may exercise a fixed-price purchase provision. The fixed prices for the acquisition of common facilities are: $38 million in 2017 and $68 million in 2021.
- The Springerville Coal Handling Facilities Leases have an initial term to April 2015 but have fixed-rate lease renewal options if certain conditions are satisfied as well as a fixed-price purchase provision of $120 million. The lease provides for one renewal period of six years beginning in April 2015, with additional renewal periods of five or more years through 2035.
- The Springerville Unit 1 Leases have an initial term to January 2015 and provide for renewal periods of three or more years through 2030. TEP has a fair market value purchase option for facilities under the Springerville Unit 1 Lease.

TEP agreed with Tri-State, the owner of Springerville Unit 3, and SRP, the owner of Springerville Unit 4, that if the Springerville Coal Handling Facilities and Common Leases are not renewed, TEP will exercise the purchase options under these contracts. SRP will then be obligated to buy a portion of these facilities and Tri State will then be obligated to either 1) buy a portion of these facilities; or 2) continue making payments to TEP for the use of these facilities.

In December 2011, TEP and the owner participants of the Springerville Unit 1 Leases completed a formal appraisal process to determine the fair market value purchase price, in accordance with the Springerville Unit 1 Leases agreements. Based on that appraisal, TEP would have to pay $159 million in 2015 for the 86% interest not already owned by TEP.

In January 2012, through scheduled lease payments, TEP reduced its capital lease obligations by $74 million.

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Investments in Springerville Lease Debt and Equity

TEP's investments in Springerville Unit 1 lease debt totaled $29 million at December 31, 2011 and $67 million at December 31, 2010. The investments in lease debt mature in 2013. TEP also held an undivided equity ownership interest in the Springerville Unit 1 Leases totaling $37 million at December 31, 2011 and December 31, 2010.

Interest Rate Swaps—Springerville Common Facilities Lease Debt

TEP's interest rate swaps hedge the floating interest rate risk associated with the Springerville Common Facilities Lease Debt. Interest on the lease debt is payable at six-month LIBOR plus a spread. The applicable spread was 1.625% at each of December 31, 2011 and December 31, 2010. The swaps have the effect of fixing the interest rates on the amortizing principal balances as follows:

Outstanding at December 31, 2011	Fixed Ratio	LIBOR Spread
$ 34 million	5.77%	1.625%
$ 22 million	3.18%	1.625%
$ 7 million	3.32%	1.625%

TEP recorded these interest rate swaps as a cash flow hedge for financial reporting purposes. See Note 16.

UNS ELECTRIC SENIOR UNSECURED NOTES

UNS Electric has $100 million of senior unsecured notes; $50 million at 6.5%, due 2015 and $50 million at 7.1%, due 2023. The UNS Electric long-term notes are guaranteed by UES. The 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.

UNS Electric's long-term notes contain certain restrictive covenants, including restrictions on transactions with affiliates, mergers, liens to secure indebtedness, restricted payments and incurrence of indebtedness.

UNS ELECTRIC TERM LOAN CREDIT AGREEMENT AND INTEREST RATE SWAP

In August 2011, UNS Electric entered into a four-year $30 million variable rate term loan credit agreement. UNS Electric used the $30 million in proceeds to repay borrowings under its revolving credit facility. The interest rate currently in effect is three-month LIBOR plus 1.25%. At the same time, UNS Electric entered into a fixed-for-floating interest rate swap in which UNS Electric will pay a fixed rate of 0.97% and receive a three-month LIBOR rate on a $30 million notional amount over a four-year period ending August 10, 2015. The UNS Electric term loan credit agreement, included in Long-Term Debt on the balance sheet, is guaranteed by UES.

The term loan credit agreement contains certain restrictive covenants for UNS Electric and UES. The covenants include restrictions on transactions with affiliates, restricted payments, additional indebtedness, liens and mergers. UNS Electric must meet an interest coverage ratio to issue additional debt. However, UNS Electric may, without meeting these tests, refinance indebtedness and incur short-term debt in an amount not to exceed $5 million. The credit agreement also requires UNS Electric to maintain a maximum leverage ratio, and allows UNS Electric to pay dividends so long as it maintains compliance with the credit agreement.

UNS GAS SENIOR UNSECURED NOTES

In August 2011, UNS Gas issued $50 million of senior guaranteed notes at 5.39%, due August 2026. UNS Gas used the proceeds to pay in full the $50 million of UNS Gas 6.23% notes that matured in August 2011. UNS Gas has another $50 million of notes at 6.23%, due August 2015. The 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.

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

UNS Gas capitalized less than $0.5 million of costs related to the issuance of the notes and will amortize these costs over the life of the notes.

UNS Gas' long-term debt contains certain restrictive covenants, including restrictions on transactions with affiliates, mergers, liens to secure indebtedness, restricted payments and incurrence of indebtedness.

UNISOURCE CREDIT AGREEMENT

In November 2011, UniSource Energy amended its existing credit agreement to extend the expiration date from November 2014 to November 2016.

In November 2010, UniSource Energy amended and restated its existing credit agreement. As amended, the agreement consists of a $125 million revolving credit facility and revolving letter of credit facility. UniSource Energy's obligations under the agreement are secured by a pledge of the capital stock of Millennium, UES and UED.

UniSource Energy capitalized less than $0.5 million related to the 2011 credit agreement amendment and $1 million related to the 2010 credit agreement amendment and restatement and will amortize these costs through November 2016.

Unisource Energy had $57 million outstanding borrowings at December 31, 2011 and $27 million outstanding borrowings at December 31, 2010, under its revolving credit facility. The weighted average interest rate on the revolver was 2.04% at December 31, 2011, and 3.26% at December 31, 2010. We have included the revolver borrowings in Long-Term Debt as UniSource Energy has the ability and the intent to have outstanding borrowings for the next twelve months. As of February 21, 2012, outstanding borrowings under the UniSource Credit Agreement were $52 million.

Interest rates and fees under the UniSource Credit Agreement are based on a pricing grid tied to UniSource Energy's credit ratings. The interest rate currently in effect on borrowings is LIBOR plus 1.75% for Eurodollar loans or Alternate Base Rate plus 0.75% for Alternate Base Rate loans.

The UniSource Credit Agreement contains a number of covenants which restrict UniSource Energy and its subsidiaries, including restrictions on additional indebtedness, liens, mergers and sales of assets. The UniSource Credit Agreement also requires UniSource Energy to meet a minimum cash flow to interest coverage ratio determined on a UniSource Energy standalone basis and not to exceed a maximum leverage ratio determined on a consolidated basis. Under the UniSource Credit Agreement, UniSource Energy may pay dividends so long as it maintains compliance with the agreement.

TEP CREDIT AGREEMENT

In December 2011, TEP reduced its letter of credit facility from $341 million to $186 million, following the repurchase of $150 million of variable rate IDBs and the cancellation of $155 million of LOCs supporting those bonds.

In November 2011, TEP amended its existing credit agreement to extend the expiration date from November 2014 to November 2016.

In November 2010, TEP amended and restated its existing credit agreement, consisting of a $200 million revolving credit and revolving letter of credit facility and a $341 million letter of credit facility to support tax-exempt bonds.

The TEP credit facility is secured by $386 million of mortgage bonds issued under the 1992 Mortgage, which creates a lien on and security interest in most of TEP's utility plant assets.

TEP capitalized $1 million related to the 2011 credit agreement amendment and $4 million related to the 2010 credit agreement amendment and restatement and will amortize these costs through November 2016.

Interest rates and fees under the TEP Credit Agreement are based on a pricing grid tied to TEP's credit ratings. The interest rate currently in effect on borrowings is LIBOR plus 1.125% for Eurodollar loans or Alternate Base Rate plus 0.125% for Alternate Base Rate loans. The margin rate currently in effect on the $186 million letter of credit facility is 1.125%.

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The TEP Credit Agreement contains a number of covenants which restrict TEP and its subsidiaries, including restrictions on liens, mergers and sale of assets. The TEP Credit Agreement also requires TEP not to exceed a maximum leverage ratio. Under the TEP Credit Agreement, TEP may pay dividends to UniSource Energy so long as it maintains compliance with the agreement.

As of December 31, 2011, TEP had $10 million in borrowings and $1 million outstanding in letters of credit under its revolving credit facility. The weighted average interest rate on the revolver was 3.38%, at December 31, 2011. As of December 31, 2010, TEP only had $1 million outstanding in letters of credit under its revolving credit facility. The revolving loan balance was included in Current Liabilities in the UniSource Energy and TEP balance sheets. The outstanding letters of credit are off-balance sheet obligations of TEP. As of February 21, 2012, TEP had $85 million in borrowings and $1 million outstanding in letters of credit under its revolving credit facility.

2010 TEP REIMBURSEMENT AGREEMENT

In December 2010, TEP entered into a four-year $37 million reimbursement agreement (2010 TEP Reimbursement Agreement). A $37 million letter of credit was issued pursuant to the 2010 TEP Reimbursement Agreement. The letter of credit supports $37 million aggregate principal amount of variable rate tax-exempt IDBs that were issued on behalf of TEP in December 2010 (See Variable Rate Tax-Exempt Bonds above).

The 2010 TEP Reimbursement Agreement is secured by $37 million of mortgage bonds issued under TEP's 1992 Mortgage. Fees are payable on the aggregate outstanding amount of the letter of credit at a rate of 1.50% per annum.

The 2010 TEP Reimbursement Agreement contains substantially the same restrictive covenants as the TEP Credit Agreement described above.

UNS GAS/UNS ELECTRIC CREDIT AGREEMENT

In November 2011, UNS Gas and UNS Electric amended their existing unsecured credit agreement to extend the expiration date from November 2014 to November 2016.

In November 2010, UNS Gas and UNS Electric amended and restated their existing unsecured credit agreement. As amended, the UNS Gas/UNS Electric Credit Agreement consists of a $100 million revolving credit and revolving letter of credit facility. The maximum borrowings outstanding at any one time for UNS Gas or UNS Electric under the agreement may not exceed $70 million. UNS Gas and UNS Electric each are liable for only their own individual borrowings under the UNS Gas/UNS Electric Credit Agreement. UES guarantees the obligations of both UNS Gas and UNS Electric. The UNS Gas/UNS Electric Credit Agreement may be used to issue letters of credit, as well as for revolver borrowings. UNS Gas and UNS Electric issue letters of credit, which are off-balance sheet obligations, to support power and gas purchases and hedges.

UNS Gas and UNS Electric capitalized less than $0.5 million of costs related to the 2011 credit agreement amendment and $1 million related to the 2010 credit agreement amendment and restatement, and will amortize these costs through November 2016.

Interest rates and fees under the UNS Electric/UNS Gas Credit Agreement are based on a pricing grid tied to their credit ratings. The interest rate currently in effect on borrowings is LIBOR plus 1.5% for Eurodollar loans or Alternate Base Rate plus 0.5% for Alternate Base Rate loans.

The UNS Electric/UNS Gas Credit Agreement contains a number of covenants which impose restrictions on UNS Gas, UNS Electric and UES, including restrictions on additional indebtedness, liens and mergers. The UNS Electric/UNS Gas Credit Agreement also stipulates a maximum leverage ratio. Under the terms of the UNS Electric/UNS Gas Credit Agreement, UNS Gas and UNS Electric may pay dividends so long as they maintain compliance with the agreement.

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

UNS Electric had $6 million and $13 million in outstanding letters of credit under the UNS Gas/UNS Electric Credit Agreement as of December 31, 2011, and December 31, 2010, respectively, which are not shown on the balance sheet.

UED SECURED TERM LOAN

In July 2011, UED received $63 million from UNS Electric from the sale of BMGS. UED used a portion of those funds to fully repay the $27 million outstanding under its secured term loan.

Other

As of December 31, 2011, UniSource Energy and its subsidiaries were in compliance with the terms of their respective loan, note purchase and credit agreements. No amounts of net income were subject to dividend restrictions.

DEBT MATURITIES

Long-term debt, including term loan payments, revolving credit facilities classified as long-term, and capital lease obligations mature on the following dates:

	TEP Variable Rate IDBs Supported by Letters of Credit (1)	TEP Scheduled Debt Retirements (2)	TEP Capital Lease Obligations	TEP Total	UNS Gas	UNS Electric	UniSource Energy Parent Company (3)	Total
	- Millions of Dollars -							
2012	$ —	$ —	$ 118	$ 118	$ —	$ —	$ —	$ 118
2013	—	—	122	122	—	—	—	122
2014	37	—	195	232	—	—	—	232
2015	—	—	23	23	50	80	—	153
2016	178	—	18	196	—	—	57	253
Total 2012 – 2016	215	—	476	691	50	80	57	878
Thereafter	—	866	61	927	50	50	150	1,177
Less: Imputed Interest	—	—	(107)	(107)	—	—	—	(107)
Total	$ 215	$ 866	$ 430	$1,511	$ 100	$ 130	$ 207	$1,948

(1) TEP's Variable Rate IDBs are backed by $186 million in LOCs issued pursuant to TEP's Credit Agreement which expires in November 2016 and TEP's $37 million Reimbursement Agreement which expires December 2014. Although the Variable Rate IDBs mature between 2018 and 2032, the above table reflects a redemption or repurchase of such bonds in 2014 and 2016 as though the LOCs terminate without replacement upon expiration of the TEP Credit Agreement.

(2) The repayment of TEP Unsecured Notes is not reduced by the approximately $1 million discount.

(3) In January 2012, UniSource Energy redeemed $35 million of its convertible senior notes. Pursuant to the redemption, substantially all of the notes were converted into approximately 1 million shares of UniSource Energy Common Stock.

NOTE 7. STOCKHOLDERS' EQUITY

DIVIDEND LIMITATIONS

UniSource Energy

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. UniSource Energy and each of its subsidiaries were in compliance with debt covenants at December 31, 2011; therefore, TEP and the other subsidiaries were not restricted from paying dividends.

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In February 2012, UniSource Energy declared a first quarter dividend to shareholders of $0.43 per share of UniSource Energy Common Stock. The dividend, totaling approximately $16 million, will be paid on March 22, 2012, to common shareholders of record as of March 12, 2012.

In January 2012, holders of approximately $33 million of the Convertible Senior Notes converted their interests into approximately 964,000 shares of UniSource Energy Common Stock increasing common stock equity by $33 million.

TEP

UniSource Energy is the holder of TEP's common stock. TEP pays dividends from current year earnings; therefore the dividend restriction in the Federal Power Act does not limit TEP's payment of dividends from net income. TEP paid dividends to UniSource Energy of $60 million in both 2010 and 2009. TEP did not pay dividends to UniSource Energy in 2011.

UniSource Energy contributed capital to TEP of $30 million in 2011, $15 million in 2010, and $30 million in 2009.

NOTE 8. INCOME TAXES

A reconciliation of the federal statutory income tax rate to each company's effective income tax rate follows:

	UniSource Energy			TEP		
	Years Ended December 31,					
	2011	2010	2009	2011	2010	2009
	-Millions of Dollars-					
Federal Income Tax Expense at Statutory Rate	$ 62	$ 66	$ 59	$ 48	$ 58	$ 51
State Income Tax Expense, Net of Federal Benefit	8	9	7	6	8	6
Deferred Tax Asset Valuation Allowance	—	8	—	—	—	—
Deferred Tax Asset Write-Off Related to Unregulated Investment	—	3	—	—	—	—
AFUDC Equity	(1)	(1)	(1)	(1)	(1)	(1)
Domestic Production Deduction	—	(3)	(1)	—	(3)	(1)
Federal/State Tax Credits	(3)	(2)	(1)	(2)	(2)	(1)
Other	1	(3)	—	1	—	—
Total Federal and State Income Tax Expense	$ 67	$ 77	$ 63	$ 52	$ 60	$ 54
Effective Tax Rate	38%	41%	37%	38%	36%	37%

In 2010, UniSource Energy recorded a $3 million out-of-period income tax expense. The out-of-period expense related to the write-off of a previously recorded deferred tax asset associated with the excess of tax over book basis difference in a consolidated unregulated investment. Management concluded that this out-of-period adjustment was not material to the current and prior period financial statements.

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Income tax expense included in the income statements consists of the following:

	UniSource Energy			TEP		
	Years Ended December 31,					
	2011	2010	2009	2011	2010	2009
	-Millions of Dollars-					
Current Tax Expense (Benefit)						
Federal	$ (7)	$ 34	$ 6	$ (5)	$ 28	$ 7
State	(2)	7	—	(2)	7	1
Total	(9)	41	6	(7)	35	8
Deferred Tax Expense (Benefit)						
Federal	64	32	47	50	24	38
Federal Investment Tax Credits	(1)	(1)	—	(1)	(1)	—
State	13	5	10	10	2	8
Total	76	36	57	59	25	46
Total Federal and State Income Tax Expense	$ 67	$ 77	$ 63	$ 52	$ 60	$ 54

The significant components of deferred income tax assets and liabilities consist of the following:

	UniSource Energy December 31,		TEP December 31,	
	2011	2010	2011	2010
	-Millions of Dollars-			
Gross Deferred Income Tax Assets				
Capital Lease Obligations	$ 169	$ 192	$ 169	$ 192
Net Operating Loss Carryforwards	81	—	76	—
Customer Advances and Contributions in Aid of Construction	30	43	17	27
Alternative Minimum Tax Credit	43	34	25	16
Accrued Postretirement Benefits	23	24	23	24
Renewable Energy Credit Up-Front Incentive Payments	22	14	18	11
Emission Allowance Inventory	10	11	10	11
Unregulated Investment Losses	9	9	—	—
Other	34	29	29	26
Gross Deferred Income Tax Assets	421	356	367	307
Deferred Tax Assets Valuation Allowance	(7)	(8)	—	—
Gross Deferred Income Tax Liabilities				
Plant—Net	(581)	(465)	(513)	(413)
Capital Lease Assets—Net	(41)	(48)	(41)	(48)
Regulatory Asset—Income Taxes Recoverable Through Future Revenues	(4)	(7)	(3)	(7)
Pensions	(17)	(12)	(18)	(13)
PPFAC	(19)	(1)	(16)	—
Other	(29)	(30)	(17)	(22)
Gross Deferred Income Tax Liabilities	(691)	(563)	(608)	(503)
Net Deferred Income Tax Liabilities	$ (277)	$ (215)	$ (241)	$ (196)

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The balance sheets display the net deferred income tax liability as follows:

	UniSource Energy		TEP	
	December 31,		December 31,	
	2011	2010	2011	2010
	-Millions of Dollars-			
Deferred Income Taxes – Current Assets	$ 23	$ 31	$ 22	$ 32
Deferred Income Taxes – Noncurrent Liabilities	(300)	(246)	(263)	(228)
Net Deferred Income Tax Liability	$ (277)	$ (215)	$ (241)	$ (196)

Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or the entire deferred income tax asset will not be realized. The $9 million unregulated investment loss deferred tax asset includes $7 million of capital loss at December 31, 2011 and $8 million at December 31, 2010. The deferred tax asset can only be used if the company has capital gains to offset the losses. Management believes that it is more likely than not that the company will not be able to generate future capital gains. As a result, UniSource Energy recorded a $7 million valuation allowance against the deferred tax asset as of December 31, 2011 and $8 million at December 31, 2010. Management believes that based on its historical pattern of taxable income, UniSource Energy will produce sufficient income in the future to realize all other deferred income tax assets.

State Tax Rate Change

We record deferred tax assets and liabilities using the income tax rates expected to be in effect when the deferred tax assets and liabilities are realized or settled. In the first quarter of 2011, the Arizona legislature passed a bill reducing the corporate income tax rate from the current rate of 6.968%. The tax rate reduction will be phased in beginning in 2014, with a reduction of approximately 0.5% per year until the income tax rate reaches 4.9% for 2017 and later years. As a result of these tax rate reductions, we reduced the net deferred tax liabilities at UniSource Energy and TEP by $13 million, offset entirely by adjustments to regulatory assets and liabilities. The income tax rate change did not have an impact on UniSource Energy's and TEP's effective tax rate for 2011.

Uncertain Tax Positions

In accordance with accounting rules related to uncertain tax positions, we are required to determine whether it is "more likely than not" that we will sustain an income tax position under examination. Each income tax position is measured to determine the amount of benefit to recognize in the financial statements. The following table shows the changes in unrecognized tax benefits of UniSource Energy and TEP:

	UniSource Energy		TEP	
	December 31,		December 31,	
	2011	2010	2011	2010
	-Millions of Dollars-			
Unrecognized Tax Benefits, beginning of year	$ 41	$ 19	$ 35	$ 19
Additions based on tax positions taken in the current year	9	11	8	8
Reductions based on settlements with tax authorities	(22)	—	(19)	—
Additions based on tax positions taken in the prior year	1	16	—	13
Reductions based on tax positions taken in the prior year	—	(4)	—	(4)
Reductions based on expiration of the statute of limitations	—	(1)	—	(1)
Unrecognized Tax Benefits, end of year	$ 29	$ 41	$ 24	$ 35

Unrecognized tax benefits of $1 million, if recognized, would reduce the effective tax rate at December 31, 2011, and December 31, 2010, for both UniSource Energy and TEP. Included in reductions based on settlements with authorities is $13 million for UniSource Energy and $10 million for TEP related to a change in accounting method filed with the Internal Revenue Service (IRS) in 2011. The remaining balance in unrecognized tax benefits could change in the next twelve months as a result of ongoing IRS audits, but we are unable to determine the amount of the change.

UniSource Energy and TEP recognize interest accrued related to unrecognized tax benefits in Other Interest Expense in the income statements. UniSource Energy and TEP recorded a reduction to interest expense of $1 million in 2011 and 2009. We did not recognize a reduction to interest expense in 2010. The balance of interest payable for UniSource Energy and TEP was $1 million at December 31, 2011 and $2 million at December 31, 2010. We have no penalties accrued in the years presented.

UniSource Energy and TEP have been audited by the IRS through tax year 2006 and are currently under audit by the IRS for 2008 through 2010. 2007 was not selected for audit. We are unable to determine when the audits will be completed. UniSource Energy and TEP are not currently under audit by any state tax agencies.

NOTE 9. EMPLOYEE BENEFIT PLANS

PENSION BENEFIT PLANS

We maintain noncontributory, defined benefit pension plans for substantially all regular employees and certain affiliate employees. Benefits are based on years of service and the employee's average compensation. We fund the pension plans by contributing at least the minimum amount required under Internal Revenue Service regulations.

We recognize the underfunded status of our defined benefit pension plans as a liability on our balance sheets. The underfunded status is measured as the difference between the fair value of the pension plans' assets and the projected benefit obligation for pension plans. We recognize a regulatory asset to the extent these future costs are probable of recovery in Retail Rates, and expect to recover these costs over the estimated service lives of employees.

Additionally, we provide supplemental retirement benefits to certain employees whose benefits are limited by Internal Revenue Service benefit or compensation limitations. Changes in Supplemental Executive Retirement Plan (SERP) benefit obligations are recognized as a component of accumulated other comprehensive income (AOCI).

Pension Contributions

The Pension Protection Act of 2006 (The Pension Act) established minimum funding targets for pension plans. A plan's funding target is the present value of all benefits accrued or earned as of the beginning of the plan year. While the annual targets are not legally required, benefit payment options are limited for plans that do not meet the targets, and a funding deficiency notice must be sent to all plan participants. Our plans are in compliance with The Pension Act.

In 2012, UniSource Energy expects to contribute $23 million to the pension plans, including $20 million in contributions by TEP.

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. UNS Gas and UNS Electric active employees do not participate in the postretirement medical plan.

In 2009, TEP established a Voluntary Employee Beneficiary Association (VEBA) to fund its other postretirement benefit plan. TEP contributed $2 million in each of 2011 and 2010 and $1 million in 2009 to the VEBA. We record changes in other postretirement obligation, not yet reflected in net periodic benefit cost, as a regulatory asset, as such amounts are probable of future recovery in Retail Rates. TEP's retiree medical plan was amended effective December 31, 2011 to increase the participant contributions for unclassified employees who retire on or after July 1, 2012.

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The pension and other postretirement benefit related amounts (excluding tax balances) included on the UniSource Energy balance sheet are:

	Pension Benefits		Other Postretirement Benefits	
	Years Ended December 31,			
	2011	2010	2011	2010
	-Millions of Dollars-			
Regulatory Pension Asset included in Other Regulatory Assets	$ 106	$ 86	$ 8	$ 8
Accrued Benefit Liability included in Accrued Employee Expenses	(1)	—	(2)	(4)
Accrued Benefit Liability included in Pension and Other Postretirement Benefits	(72)	(63)	(66)	(65)
Accumulated Other Comprehensive Loss (SERP)	2	4	—	—
Net Amount Recognized	$ 35	$ 27	$ (60)	$ (61)

The table above includes accrued pension benefit liabilities for UNS Gas and UNS Electric of approximately $8 million at December 31, 2011, and $6 million at December 31, 2010. The table also includes a postretirement benefit liability of $1 million for UNS Gas and UNS Electric for each period presented.

OBLIGATIONS AND FUNDED STATUS

We measured the actuarial present values of all pension benefit obligations and other postretirement benefit plans at December 31, 2011, and December 31, 2010. The tables below include TEP's, UNS Gas' and UNS Electric's 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,			
	2011	2010	2011	2010
	-Millions of Dollars-			
Change in Projected Benefit Obligation				
Benefit Obligation at Beginning of Year	$ 283	$ 242	$ 73	$ 71
Actuarial (Gain) Loss	22	28	—	(1)
Interest Cost	16	15	4	4
Service Cost	10	8	3	3
Amendments	—	—	(2)	—
Other	—	1	—	—
Benefits Paid	(12)	(11)	(5)	(4)
Projected Benefit Obligation at End of Year	319	283	73	73
Change in Plan Assets				
Fair Value of Plan Assets at Beginning of Year	220	184	4	2
Actual Return on Plan Assets	14	25	—	—
Benefits Paid	(12)	(11)	(5)	(4)
Employer Contributions (1)	23	22	6	6
Fair Value of Plan Assets at End of Year	245	220	5	4
Funded Status at End of Year	$ (74)	$ (63)	$ (68)	$ (69)

(1) TEP made $20 million in pension contributions and $6 million of other postretirement benefits contributions in 2011 and 2010.

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In March 2010, the Patient Protection and Affordable Care Act (PPACA) was signed into law. One provision of PPACA imposes a 40% excise tax on plans in which the aggregate value of employer-sponsored health insurance exceeds a threshold amount starting in 2018. There are uncertainties surrounding implementation and calculation of the excise tax. Our best estimate of the potential impact resulted in an increase in the postretirement benefit obligation of $1 million at December 31, 2011 and $2 million at December 31, 2010.

The table above includes the following for UNS Gas and UNS Electric:

- Pension benefit obligations of $8 million at December 31, 2011, and $6 million at December 31, 2010;
- Plan assets of $10 million December 31, 2011, and $9 million at December 31, 2010; and
- A postretirement benefit liability of $1 million at December 31, 2011 and December 31, 2010.

The following table provides the components of UniSource Energy's regulatory assets and accumulated other comprehensive loss that have not been recognized as components of net periodic benefit cost as of the dates presented:

	Pension Benefits		Other Postretirement Benefits	
	Years Ended December 31,			
	2011	2010	2011	2010
	-Millions of Dollars-			
Net Loss	$ 108	$ 89	$ 11	$ 11
Prior Service Cost (Benefit)	1	1	(3)	(3)

Information for pension plans with Accumulated Benefit Obligations in excess of pension plan assets follows:

	December 31,	
	2011	2010
	-Millions of Dollars-	
Projected Benefit Obligation at End of Year	$ 319	$ 283
Accumulated Benefit Obligation at End of Year	281	243
Fair Value of Plan Assets at End of Year	245	220

At December 31, 2011, and December 31, 2010, all UniSource Energy defined benefit pension plans had accumulated benefit obligations in excess of pension plan assets.

The components of net periodic benefit costs are as follows:

	Pension Benefits			Other Postretirement Benefits		
	Years Ended December 31,					
	2011	2010	2009	2011	2010	2009
	-Millions of Dollars-					
Service Cost	$ 10	$ 8	$ 7	$ 3	$ 3	$ 2
Interest Cost	15	15	14	4	4	4
Expected Return on Plan Assets	(16)	(14)	(11)	—	—	—
Prior Service Cost Amortization	—	—	1	(1)	(2)	(2)
Recognized Actuarial Loss	6	5	7	—	—	1
Net Periodic Benefit Cost	$ 15	$ 14	$ 18	$ 6	$ 5	$ 5

Approximately 19% of the net periodic benefit cost was capitalized as a cost of construction and the remainder was included in current year earnings.

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The changes in plan assets and benefit obligations recognized as regulatory assets or in AOCI are as follows:

	Pension Benefits				
	2011		2010		2009
	Regulatory Asset	AOCI	Regulatory Asset	AOCI	Regulatory Asset
	-Millions of Dollars-				
Current Year Actuarial (Gain) Loss	$ 25	$ (2)	$ 16	$ 1	$ (21)
Amortization of Actuarial (Gain) Loss	(5)	—	(5)	—	(7)
Plan Amendments	—	—	—	—	(1)
Total Recognized (Gain) Loss	$ 20	$ (2)	$ 11	$ 1	$ (29)

	Other Postretirement Benefits		
	2011	2010	2009
	Regulatory Asset	Regulatory Asset	Regulatory Asset
	-Millions of Dollars-		
Prior Service Cost (Credit)	$ (2)	$ —	$ —
Current Year Actuarial (Gain) Loss	—	(1)	1
Amortization of Actuarial Gain (Loss)	—	(1)	(1)
Prior Service (Cost) Amortization	1	2	2
Total Recognized (Gain) Loss	$ (1)	$ —	$ 2

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 $7 million estimated net loss and less than $0.5 million prior service cost from other regulatory assets and less than $0.5 million prior service cost from AOCI into net periodic benefit cost in 2012. The estimated net loss for the defined benefit postretirement plans that will be amortized from other regulatory assets into net periodic benefit cost in 2012 is less than $1 million. The estimated prior service benefit that will be amortized is less than $1 million.

	Pension Benefits		Other Postretirement Benefits	
	2011	2010	2011	2010
Weighted-Average Assumptions Used to Determine Benefit Obligations as of the Measurement Date				
Discount Rate	4.9%-5.0%	5.5% - 5.6%	4.7%	5.2%
Rate of Compensation Increase	3.0%	3.0% – 5.0%	N/A	N/A

	Pension Benefits			Other Postretirement Benefits		
	2011	2010	2009	2011	2010	2009
Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31						
Discount Rate	5.5%-5.6%	6.3%	6.3%	5.2%	6.0%	6.5%
Rate of Compensation Increase	3.0%-5.0%	3.0%–5.0%	3.0% -5.0%	N/A	N/A	N/A
Expected Return on Plan Assets	7.0%	7.5%	8.0%	5.1%	5.6%	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 use a combination of sources in selecting the expected long-term rate-of-return-on-assets assumption, including an investment return model. The model used provides a "best-estimate" range over 20 years from the 25 th percentile to the 75 th percentile. The model used as a guideline for selecting the overall rate-of-return-on-assets assumption is based on forward looking return expectations only. The above method is used for all asset classes.

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2011	December 31, 2010
Assumed Health Care Cost Trend Rates		
Health Care Cost Trend Rate Assumed for Next Year	6.9%	7.9%
Ultimate Health Care Cost Trend Rate Assumed	4.5%	4.5%
Year that the Rate Reaches the Ultimate Trend Rate	2049	2027

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, 2011 amounts:

	One-Percentage-Point Increase	One-Percentage-Point Decrease
	-Millions of Dollars-	
Effect on Total of Service and Interest Cost Components	$ 1	$ (1)
Effect on Postretirement Benefit Obligation	5	(5)

PENSION PLAN AND OTHER POSTRETIREMENT BENEFIT ASSETS

Pension Assets

We calculate the fair value of plan assets on December 31, the measurement date. Pension plan asset allocations, by asset category, were as follows:

	TEP Plan Assets		UNS Gas and UNS Electric Plan Assets	
	December 31, 2011	December 31, 2010	December 31, 2011	December 31, 2010
Asset Category				
Equity Securities	49%	57%	55%	57%
Fixed Income Securities	42	34	34	32
Real Estate	7	7	11	11
Other	2	2	—	—
Total	100%	100%	100%	100%

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following tables set forth the fair value measurements of pension plan assets, by level within the fair value hierarchy:

	Fair Value Measurements of Pension Assets December 31, 2011			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	- Millions of Dollars -			
Asset Category				
Cash Equivalents	$ 1	$ —	$ —	$ 1
Equity Securities:				
U.S. Large Cap	—	61	—	61
U.S. Small Cap	—	13	—	13
Non-U.S.	—	47	—	47
Fixed Income	—	101	—	101
Real Estate	—	7	11	18
Private Equity	—	—	4	4
Total	$ 1	$ 229	$ 15	$ 245

	Fair Value Measurements of Pension Assets December 31, 2010			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	- Millions of Dollars -			
Asset Category				
Cash Equivalents	$ 1	$ —	$ —	$ 1
Equity Securities:				
U.S. Large Cap	—	63	—	63
U.S. Small Cap	—	12	—	12
Non-U.S.	—	51	—	51
Fixed Income	—	75	—	75
Real Estate	—	6	10	16
Private Equity	—	—	2	2
Total	$ 1	$ 207	$ 12	$ 220

Level 1 cash equivalents are based on observable market prices and are comprised of the fair value of commercial paper, money market funds, and certificates of deposit.

Level 2 investments comprise amounts held in commingled equity funds, U.S. bond and real estate funds. Valuations are based on active market quoted prices for assets held by each respective fund.

Level 3 real estate investments were valued using a real estate index value. The real estate index value was developed based on appraisals comprising 85% of real estate assets tracked by the index in 2011, and comprising 94% in 2010.

Level 3 private equity funds are classified as funds-of-funds. They are valued based on individual fund manager valuation models.

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The tables above reflecting the fair value measurements of pension plan assets include Level 2 assets for the UES pension plan of $10 million at December 31, 2011, and $9 million at December 31, 2010.

The following tables set forth a reconciliation of changes in the fair value of pension assets classified as Level 3 in the fair value hierarchy. There were no transfers in or out of Level 3.

	Year Ended December 31, 2011			
	Private Equity	Real Estate	Hedge Fund	Total
	- Millions of Dollars -			
Beginning Balance at January 1, 2011	$ 2	$ 10	$ —	$ 12
Actual Return on Plan Assets:				
Assets Held at Reporting Date	—	1	—	1
Assets Sold During the Period	—	—	—	—
Purchases, Sales, and Settlements	2	—	—	2
Ending Balance at December 31, 2011	$ 4	$ 11	$ —	$ 15

	Year Ended December 31, 2010			
	Private Equity	Real Estate	Hedge Fund	Total
	- Millions of Dollars -			
Beginning Balance at January 1, 2010	$ 1	$ 8	$ 1	$ 10
Actual Return on Plan Assets:				
Assets Held at Reporting Date	—	1	—	1
Assets Sold During the Period	—	—	(1)	(1)
Purchases, Sales, and Settlements	1	1	—	2
Ending Balance at December 31, 2010	$ 2	$ 10	$ —	$ 12

UES has no pension assets classified as Level 3 in the fair value hierarchy.

Pension Plan Investments

Investment Goals

Strategic asset allocation is the principal method for achieving each pension plan's investment objective, while maintaining an appropriate level of risk. We will consider the projected impact on benefit security of any proposed changes to the current asset allocation policy. The expected long-term returns and implications for pension plan sponsor funding will be reviewed in selecting policies to ensure that current asset pools are projected to be adequate to meet the expected liabilities of the pension plans. We expect to use asset allocation policies weighted most heavily to equity and fixed income funds, while maintaining some exposure to real estate and opportunistic funds. Within the fixed income allocation, long-duration funds may be used to partially hedge interest rate risk.

Risk Management

We recognize the difficulty of achieving investment objectives in light of the uncertainties and complexities of the investment markets. We also recognize some risk must be assumed to achieve a pension plan's long-term investment objectives. In establishing risk tolerances, the following factors affecting risk tolerance and risk objectives will be considered: 1) plan status; 2) plan sponsor financial status and profitability; 3) plan features; and 4) workforce characteristics. We have determined that the pension plans can tolerate some interim fluctuations in market value and rates of return in order to achieve long-term objectives. TEP tracks each pension plan's portfolio relative to the benchmark through quarterly investment reviews. The reviews consist of a performance and risk assessment of all investment categories and on the portfolio as a whole. Investment managers for the pension plan may use derivative financial instruments for risk management purposes or as part of their investment strategy. Currency hedges also have been used for defensive purposes.

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Relationship between Plan Assets and Benefit Obligations

The overall health of each plan will be monitored by comparing the value of plan obligations (both Accumulated Benefit Obligation and Projected Benefit Obligation) against the market value of assets and tracking the changes in each. The frequency of this monitoring will depend on the availability of plan data, but will be no less frequent than annually via annual actuarial valuation.

The current target allocation percentages for the major categories of plan assets as of December 31, 2011 follow. Each plan allows a variance of +/- 2% from these targets before funds are automatically rebalanced.

	TEP Plan	UES Plan	VEBA Trust
Fixed Income	41%	33%	38%
U.S. Large Cap	24%	28%	33%
Non-U.S. Developed	15%	17%	9%
Real Estate	8%	11%	—
U.S. Small Cap	5%	5%	7%
Non-U.S. Emerging	5%	6%	11%
Private Equity	2%	—	—
Cash / Treasury Bills	—	—	2%
Total	100%	100%	100%

Pension Fund Descriptions

The funds are manager of manager funds, which allow different fund managers to make investment decisions, with the exception of the private equity fund, which holds a portfolio of investment funds.

Other Postretirement Benefit Assets

As of December 31, 2011, the fair value of VEBA trust assets were $5 million, of which $3 million were fixed income investments and $2 million were equities. As of December 31, 2010, the fair value of VEBA trust assets was $4 million, including $2 million of fixed income investments and approximately $2 million of equity and money market funds. There are no level three assets in the VEBA trust.

ESTIMATED FUTURE BENEFIT PAYMENTS

TEP expects the following benefit payments to be made by the defined benefit pension plans and postretirement plan, which reflect future service, as appropriate.

	Pension Benefits	Other Postretirement Benefits
	-Millions of Dollars-	
2012	$ 13	$ 4
2013	15	5
2014	16	5
2015	17	5
2016	18	5
Years 2017-2021	109	31

UNS Gas and UNS Electric expect annual pension and postretirement benefit payments of approximately $6 million in 2012 through 2016 and $9 million in 2017 through 2021 to be made by the defined benefit pension and postretirement plans.

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DEFINED CONTRIBUTION PLANS

We offer defined contribution savings plans to all eligible 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 which may include a UNS stock fund. We match part of a participant's contributions to the plans. TEP made matching contributions to these plans of $5 million in 2011 and $4 million in each of 2010 and 2009. UNS Gas and UNS Electric made matching contributions of less than $1 million in each of 2011, 2010, and 2009.

NOTE 10. SHARE-BASED COMPENSATION PLAN

In 2011, UniSource Energy shareholders approved the UniSource Energy 2011 Omnibus Stock and Incentive Plan (2011 Plan), a new share-based compensation plan. Under the 2011 Plan, the Compensation Committee of the UniSource Energy Board of Directors (Compensation Committee) may issue various types of share-based compensation, including stock options, restricted shares/units, and performance shares. The total number of shares which may be awarded under the 2011 Plan cannot exceed 1.2 million shares. The 2011 Plan supersedes and replaces the UniSource Energy 2006 Omnibus Stock and Incentive Plan (2006 Plan) and all other prior equity compensation plans (Prior Plans). The Prior Plans, however, remain in effect until all stock options and other awards granted thereunder have been exercised, forfeited, canceled, expired or terminated.

STOCK OPTIONS

No stock options were granted by the Compensation Committee during 2011 or 2010. In 2009, the Compensation Committee granted 248,760 stock options to officers with an exercise price of $26.11.

Stock options are granted 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 is recorded on a straight-line basis over the service period for the total award based on the grant date fair value of the options less estimated forfeitures. For awards granted to retirement eligible officers, compensation expense is recorded immediately. The 2002 stock option award accrues dividend equivalents that are paid in cash on the earlier of the date of separation of service or the date the option expires. Dividend equivalents are recorded as dividends when paid.

The fair value of the 2009 option award was 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 the stock options granted in 2009 was estimated using historical exercise data. The risk-free rate was 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. The expected volatility was based on historical volatility for UniSource Energy's stock for a period equal to the expected term of the award. The expected dividend yield on a share of stock was calculated using the historical dividend yield with the implicit assumption that current dividend yields will continue in the future.

	2009
Expected Term (years)	7
Risk-free Rate	3.4%
Expected Volatility	25.0%
Expected Dividend Yield	3.2%
Weighted-Average Grant-Date Fair Value of Options Granted During the Period	$ 5.53

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

See summary of the stock option activity in the table below:

(Shares in Thousands)	2011		2010		2009	
Stock Options	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Outstanding, Beginning of Year	921	$ 27.96	1,598	$ 24.50	1,635	$ 22.50
Granted	—	—	—	—	249	26.11
Exercised	(319)	25.60	(660)	19.33	(282)	14.46
Forfeited/Expired	(21)	31.92	(17)	37.88	(4)	12.28
Outstanding, End of Year	581	29.11	921	27.96	1,598	24.50
Exercisable, End of Year	508	$ 29.53	654	$ 28.70	1,085	$ 23.06
Aggregate Intrinsic Value of Options Exercised ($000s)	$ 3,690		$ 9,124		$ 4,177	

	At December 31, 2011
Aggregate Intrinsic Value for Options Outstanding ($000s)	$ 4,670
Aggregate Intrinsic Value for Options Exercisable ($000s)	$ 3,892
Weighted Average Remaining Contractual Life of Outstanding Options	5.6 years
Weighted Average Remaining Contractual Life of Exercisable Options	5.4 years

See summary of stock options in the table below:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number of Shares (000s)	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number of Shares (000s)	Weighted-Average Exercise Price
$17.44 - $17.84	20	1.3 years	$ 17.75	20	$ 17.75
$26.11 - $37.88	561	5.7 years	$ 29.51	489	$ 30.01

RESTRICTED STOCK UNITS/AWARDS AND PERFORMANCE SHARES

Restricted Stock Units

Restricted stock and stock units are generally granted 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 is payable in Common Stock. Stock units vest either immediately or over periods ranging from one to three years. The restricted stock units vest immediately upon death, disability, or retirement. In the January following the year the person is no longer a director, Common Stock shares will be issued for the vested stock units. 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.

Common Stock shares totaling 56,705 in 2011, 14,866 in 2010, and 101,765 in 2009 were issued with no additional increase in equity as the expense was previously recognized over the vesting period.

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Compensation Committee granted the following stock units to non-employee directors:

- May 2011—14,655 stock units at a weighted average fair value of $37.53 per share,
- May 2010—15,620 stock units at a weighted average fair value of $31.69 per share,
- May 2009—21,886 stock units at a weighted average fair value of $26.73 per share.

Performance Share Awards

In 2011, the Compensation Committee granted performance share awards to officers. Half of the performance share awards had a grant date fair value, based on a Monte Carlo simulation, of $33.73 per share. Those awards will be paid out in shares of UniSource Energy Common Stock based on a comparison of UniSource Energy's cumulative Total Shareholder Return to the Edison Electric Institute Index during the performance period of January 1, 2011 through December 31, 2013. The remaining half had a grant date fair value of $36.58 per share and will be paid out in shares of UniSource Energy Common Stock based on cumulative net income for the three-year period ending December 31, 2013. The performance shares vest based on the achievement of goals by the end of the performance period; any unearned awards are forfeited. Performance shares are eligible for dividend equivalents during the performance period.

In 2010, the Compensation Committee granted performance share awards to officers. Half of the performance share awards had a grant date fair value, based on a Monte Carlo simulation, of $31.26 per share. Those awards will be paid out in shares of UniSource Energy Common Stock based on a comparison of UniSource Energy's cumulative Total Shareholder Return to the Edison Electric Institute Index during the performance period of January 1, 2010 through December 31, 2012. The remaining half had a grant date fair value of $30.52 per share and will be paid out in shares of UniSource Energy Common Stock based on cumulative net income for the three-year period ending December 31, 2012. The performance shares vest based on the achievement of goals by the end of the performance period; any unearned awards are forfeited. Performance shares are eligible for dividend equivalents during the performance period.

In 2009, the Compensation Committee granted performance share awards to officers at a grant date fair value, based on a Monte Carlo simulation, of $21.62 per share. At December 31, 2011, upon completion of the three-year performance period, 45,642 shares vested based on goal attainment at 75% of targeted UniSource Energy Total Shareholder Return during the performance period compared to the Total Shareholder Return over the same period of an industry or peer group; 23,414 shares were unearned and forfeited. Compensation expense equal to the fair value on the grant date was recognized over the vesting period for the requisite service period.

	Performance Shares		Restricted Stock Units	
	Shares (000s)	Weighted-Average Grant-Date Fair Value	Shares (000s)	Weighted-Average Grant-Date Fair Value
Non-vested at January 1, 2011	156	$ 27.19	16	$ 31.69
Granted	93	35.26	15	37.53
Vested	(46)	23.41	(16)	31.69
Forfeited	(50)	28.29	—	—
Non-vested at December 31, 2011	153	$ 32.85	15	$ 37.53

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS *(Continued)*

SHARE-BASED COMPENSATION EXPENSE (Stock Options, Performance Shares and Restricted Stock Units)

Annually during 2009 through 2011, UniSource Energy recorded share-based compensation expense of $3 million, $2 million of which related to TEP. No share-based compensation was capitalized as part of the cost of an asset. UniSource Energy did not realize a tax deduction from the exercise of share-based payment arrangements in 2011. In each of 2010 and 2009, UniSource Energy realized an actual tax deduction from the exercise of share-based payment arrangements of $3 million.

At December 31, 2011, the total unrecognized compensation cost related to non-vested share-based compensation was $2 million, which will be recorded as compensation expense over the remaining vesting periods through December 2013. The total number of shares awarded but not yet issued, including target performance based shares, under the share-based compensation plans at December 31, 2011, was 0.7 million.

NOTE 11. FAIR VALUE MEASUREMENTS

The following tables set forth, by level within the fair value hierarchy, UniSource Energy's and TEP's assets and liabilities accounted for at fair value on a recurring basis. These assets and liabilities are classified in their entirety based on the lowest level of input significant to the fair value measurement. There were no transfers between Levels 1, 2 or 3 for either reporting period.

	UniSource Energy			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	December 31, 2011 - Millions of Dollars -			
Assets				
Cash Equivalents (1)	$ 23	$ —	$ —	$ 23
Rabbi Trust Investments to support the Deferred Compensation and SERP Plans (2)	—	16	—	16
Energy Contracts (4)	—	—	14	14
Total Assets	23	16	14	53
Liabilities				
Energy Contracts (4)	—	(21)	(24)	(45)
Interest Rate Swaps (5)	—	(12)	—	(12)
Total Liabilities	—	(33)	(24)	(57)
Net Total Assets and (Liabilities)	$ 23	$ (17)	$ (10)	$ (4)

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	UniSource Energy			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	December 31, 2010 - Millions of Dollars -			
Assets				
Cash Equivalents (1)	$ 38	$ —	$ —	$ 38
Rabbi Trust Investments to support the Deferred Compensation and SERP Plans (2)	—	16	—	16
Collateral Posted (3)	—	3	—	3
Energy Contracts (4)	—	—	15	15
Total Assets	38	19	15	72
Liabilities				
Energy Contracts (4)	—	(19)	(25)	(44)
Interest Rate Swaps (5)	—	(10)	—	(10)
Total Liabilities	—	(29)	(25)	(54)
Net Total Assets and (Liabilities)	$ 38	$ (10)	$ (10)	$ 18

	TEP			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	December 31, 2011 - Millions of Dollars -			
Assets				
Cash Equivalents (1)	$ 8	$ —	$ —	$ 8
Rabbi Trust Investments to support the Deferred Compensation and SERP Plans (2)	—	16	—	16
Energy Contracts (4)	—	—	3	3
Total Assets	8	16	3	27
Liabilities				
Energy Contracts (4)	—	(9)	(3)	(12)
Interest Rate Swaps (5)	—	(11)	—	(11)
Total Liabilities	—	(20)	(3)	(23)
Net Total Assets and (Liabilities)	$ 8	$ (4)	$ —	$ 4

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	TEP			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	December 31, 2010 - Millions of Dollars -			
Assets				
Cash Equivalents (1)	$ 21	$ —	$ —	$ 21
Rabbi Trust Investments to support the Deferred Compensation and SERP Plans (2)	—	16	—	16
Energy Contracts (4)	—	—	3	3
Total Assets	21	16	3	40
Liabilities				
Energy Contracts (4)	—	(7)	(2)	(9)
Interest Rate Swaps (5)	—	(10)	—	(10)
Total Liabilities	—	(17)	(2)	(19)
Net Total Assets and (Liabilities)	$ 21	$ (1)	$ 1	$ 21

(1) Cash Equivalents are based on observable market prices and include the fair value of commercial paper, money market funds and certificates of deposit. These amounts are included in Cash and Cash Equivalents and Investments and Other Property—Other on the balance sheets.

(2) Rabbi Trust Investments include amounts held in mutual and money market funds related to deferred compensation and SERP benefits. The valuation is based on quoted prices traded in active markets. These investments are included in Investments and Other Property—Other on the balance sheets.

(3) Collateral provided for energy contracts with counterparties to reduce credit risk exposure. Collateral Posted is included in Current Assets—Other on the UniSource Energy balance sheet.

(4) Energy Contracts include gas swap agreements (Level 2), gas collars (Level 3), forward power purchase and sales contracts (Level 3), and forward power purchase contracts indexed to gas (Level 3), entered into to reduce exposure to energy price risk. These contracts are included in Derivative Instruments on the balance sheets. The valuation techniques are described below. See Note 16.

(5) Interest Rate Swaps are valued based on the 3-month or 6-month LIBOR index or the Securities Industry and Financial Markets Association (SIFMA) Municipal Swap index. These interest rate swaps are included in Derivative Instruments on the balance sheets.

Energy Contracts

We primarily apply the market approach for recurring fair value measurements. When we have observable inputs for substantially the full term of the asset or liability—such as gas swap derivatives valued using New York Mercantile Exchange (NYMEX) pricing, adjusted for basis differences—we categorize the instrument in Level 2. We categorize derivatives in Level 3 using an aggregate pricing service or published prices that represent a consensus reporting of multiple brokers.

For both power and gas prices, TEP and UNS Electric obtain quotes from brokers, major market participants, exchanges or industry publications and rely on our own price experience from active transactions in the market. We primarily use one set of quotations each for power and for gas and then validate those prices using other sources. We believe that the market information provided is reflective of market conditions as of the time and date indicated.

Published prices for energy derivative contracts may not be available due to the nature of contract delivery terms including: delivery periods during non-standard time blocks, delivery during only a few months of a given year when prices are quoted only for the annual average, or delivery at illiquid delivery points. In these cases, we use percentage multipliers to value non-standard time blocks, we apply historical price curve relationships to calendar year quotes, and we include adjustments for transmission and line losses to value contracts at illiquid delivery points. We also consider the impact of counterparty credit risk using current and historical default and recovery rates as well as our own credit risk using market credit default swap data. We review these assumptions quarterly.

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

TEP estimates the fair value of its purchase power call option using an internal pricing model which includes assumptions about market risks such as liquidity, volatility, and contract valuation. This model also considers credit and non-performance risk.

UNS Gas estimates the fair value of its gas collar using the Black-Scholes-Merton option pricing model which includes assumptions about future prices of energy, interest rates, volatility, credit worthiness and credit spread.

UniSource Energy's and TEP's assessments of the significance of a particular input to the fair value measurements requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

The following tables set forth a reconciliation of changes in the fair value of assets and liabilities classified as Level 3 in the fair value hierarchy:

	Year Ended December 31, 2011	
	UniSource Energy	TEP
	Energy Contracts	
	-Millions of Dollars-	
Balance as of December 31, 2010	$ (10)	$ 1
Gains and (Losses) (Realized/Unrealized) Recorded to:		
Net Regulatory Assets – Derivative Instruments	(9)	2
Other Comprehensive Income	(1)	(1)
Settlements	10	(2)
Balance as of December 31, 2011	$ (10)	$ —
Total gains (losses) attributable to the change in unrealized gains or losses relating to assets/liabilities still held at the end of the period	$ (9)	$ —

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Year Ended December 31, 2010			
	UniSource Energy			TEP
	Energy Contracts	Equity Investments (1)	Total	Energy Contracts
	- Millions of Dollars -			
Balance as of December 31, 2009	$ (13)	$ 6	$ (7)	$ (4)
Gains and (Losses) (Realized/Unrealized) Recorded to:				
Net Regulatory Assets – Derivative Instruments	(9)	—	(9)	9
Other Comprehensive Income	(1)	—	(1)	(1)
Other Expense	—	(6)	(6)	—
Settlements	13	—	13	(3)
Balance as of December 31, 2010	$ (10)	$ —	$ (10)	$ 1
Total gains (losses) attributable to the change in unrealized gains or losses relating to assets/liabilities still held at the end of the period	$ (4)	$ —	$ (4)	$ 5

(1) In December 2010, Millennium reduced to zero the book value of its equity investments classified as Level 3 in the fair value hierarchy.

Financial Instruments Not Carried at Fair Value

The market price received when selling an asset or paid to transfer a liability at the measurement date is the fair value of a financial instrument. We use the following methods and assumptions for estimating the fair value of our financial instruments:

- The carrying amounts of our current assets and liabilities, including Current Maturities of Long-Term Debt, and amounts outstanding under our credit agreements approximate their fair value due to the short-term nature of these instruments; with the exception of $50 million of UNS Gas Senior Unsecured Notes, outstanding at December 31, 2010, with a make-whole provision on a call premium that have a fair value of $51 million. These items have been excluded from the table below.
- Investments in Lease Debt and Equity: TEP calculates the present value of remaining cash flows at the balance sheet date using current market rates for instruments with similar characteristics with respect to credit rating and time-to-maturity. We also incorporate the impact of counterparty credit risk using market credit default swap data. The fair value of TEP's Investment in Lease Equity decreased significantly during the fourth quarter of 2011 based on the recent Springerville Unit 1 appraisal. No impairment was recorded as TEP expects to recover the full carrying value in Retail Rates.
- Long-Term Debt: UniSource Energy and TEP use quoted market prices, where available, or calculate the present value of remaining cash flows at the balance sheet date using current market rates for bonds with similar characteristics with respect to credit rating and time-to-maturity. TEP considers the principal amounts of variable rate debt outstanding to be reasonable estimates of their fair value. We also incorporate the impact of our own credit risk using a credit default swap rate when determining the fair value of long-term debt.

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The use of different estimation methods and/or market assumptions may yield different estimated fair value amounts. The amount recorded on the balance sheet (carrying value) and the estimated fair values of our financial instruments included the following:

	December 31,			
	2011		2010	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	-Millions of Dollars-			
Assets:				
TEP Investment in Lease Debt and Equity	$ 66	$ 50	$ 105	$ 111
Liabilities:				
Long-Term Debt				
TEP	1,080	1,061	1,004	862
UniSource Energy	1,517	1,543	1,353	1,238

TEP intends to hold the $29 million investment in Springerville Lease Debt Securities to maturity. 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.

NOTE 12. 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 EPS is Net Income adjusted for the interest on Convertible Senior Notes (net of tax) that would not be paid if the notes were converted to common shares.

The following table shows the effects of potentially dilutive common stock on the weighted average number of shares:

	Years Ended December 31,		
	2011	2010	2009
	-Thousands of Dollars-		
Numerator:			
Net Income	$ 109,975	$ 112,984	$ 105,901
Income from Assumed Conversion of Convertible Senior Notes	4,390	4,390	4,390
Adjusted Numerator	$ 114,365	$ 117,374	$ 110,291
	-Thousands of Shares-		
Denominator:			
Weighted Average Shares of Common Stock Outstanding:			
Common Shares Issued	36,780	36,200	35,653
Fully Vested Deferred Stock Units	129	123	105
Participating Securities	53	92	100
Total Weighted Average Shares of Common Stock Outstanding and Participating Securities—Basic	36,962	36,415	35,858
Effect of Diluted Securities:			
Convertible Senior Notes	4,281	4,178	4,093
Options and Stock Issuable under Share Based Compensation Plans	366	448	499
Total Shares—Diluted	41,609	41,041	40,450

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table shows the number of stock options excluded from the diluted EPS computation because the stock option's exercise price was greater than the average market price of the Common Stock:

	Years Ended December 31,		
	2011	2010	2009
	-Thousands of Shares-		
Stock Options Excluded from the Diluted EPS Computation	153	212	395

In January 2012, holders of approximately $33 million of Convertible Senior Notes converted their interests into approximately 964,000 shares of UniSource Energy Common Stock. This conversion of convertible notes to common stock will have a minimal impact on diluted EPS as the dilutive effect of the convertible notes has been reflected in the diluted EPS computation.

NOTE 13. MILLENNIUM INVESTMENTS

In 2010, Millennium recorded impairment losses of $10 million reducing the book value of its unconsolidated equity and cost method investments to zero. Millennium received notification of valuation changes and ownership percentage reductions as projects lost viability and funding failed. In addition, Millennium sold a wholly-owned subsidiary, and recorded a gain of less than $1 million. Gains and losses were included in Other Income or Other Expense on UniSource Energy's income statements. Millennium also wrote off $3 million of Deferred Tax Assets related to its investments.

In 2009, Millennium sold an equity investment and recorded a $6 million gain on the sale which is included in Other Income on UniSource Energy's income statements. Millennium received an upfront payment of $5 million in 2009 and a $15 million, three-year, 6%, secured note receivable due in June 2012. Principal on the note is due at maturity; interest on the note is due annually on December 31. The $15 million note is included in Current Asset – Other on UniSource Energy's balance sheet.

NOTE 14. RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

The following recently issued accounting standards are not yet reflected in the financial statements:

- The Financial Accounting Standards Board (FASB) issued authoritative guidance that will eliminate the current option to report other comprehensive income in the statement of changes in equity. An entity can elect to present items of net income and other comprehensive income in one continuous statement, or in two separate but consecutive statements. We will be required to comply in the first quarter of 2012 and plan to present a separate statement of other comprehensive income.

- The FASB issued authoritative guidance that changed some fair value measurement principles and disclosure requirements. The most significant disclosure change is expansion of required information for unobservable inputs. We will be required to comply in the first quarter of 2012, and we do not expect this pronouncement to have a material impact on the valuation techniques used to estimate the fair value of assets and liabilities.

- The FASB issued authoritative guidance that will require entities to disclose both gross and net information about instruments and transactions eligible for offset in the statement of financial position as well as instruments and transactions subject to an agreement similar to a master netting arrangement. In addition, the standard requires disclosure of collateral received and posted in connection with master netting arrangements. We will be required to comply in the first quarter of 2013.

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 15. SUPPLEMENTAL CASH FLOW INFORMATION

A reconciliation of net income to net cash flows from operating activities follows:

	UniSource Energy		
	Years Ended December 31,		
	2011	2010	2009
	-Thousands of Dollars-		
Net Income	$ 109,975	$ 112,984	$ 105,901
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities			
Depreciation Expense	133,832	128,215	144,960
Amortization Expense	30,983	28,094	31,058
Depreciation and Amortization Recorded to Fuel and Other O&M Expense	6,140	5,432	4,929
Amortization of Deferred Debt-Related Costs included in Interest Expense	3,985	3,753	4,171
Provision for Retail Customer Bad Debts	2,072	3,724	3,583
Use of Renewable Energy Credits for Compliance	5,695	4,745	—
California Power Exchange Provision for Wholesale Revenue Refunds Refunds	—	—	4,172
Deferred Income Taxes	75,588	28,142	57,452
Deferred Tax Valuation Allowance	(73)	7,510	—
Pension and Postretirement Expense	21,202	19,688	23,594
Pension and Postretirement Funding	(28,775)	(27,742)	(30,078)
Share Based Compensation Expense	2,599	2,751	2,779
Excess Tax Benefit from Stock Options Exercised	—	(3,338)	(3,256)
Allowance for Equity Funds Used During Construction	(4,496)	(4,232)	(4,113)
CTC Revenue Refunded	(35,958)	(10,095)	(12,726)
Decrease to Reflect PPFAC/PGA Recovery	(4,932)	(29,622)	(14,553)
Gain on Settlement of El Paso Electric Dispute	(7,391)	—	—
Loss/(Gain) on Millennium's Investments	—	9,936	(4,730)
Changes in Assets and Liabilities which Provided (Used) Cash Exclusive of Changes Shown Separately			
Accounts Receivable	2,743	(8,851)	6,458
Materials and Fuel Inventory	(20,864)	21,744	(24,621)
Accounts Payable	7,397	2,661	(8,243)
Income Taxes	(2,739)	24,470	11,443
Interest Accrued	14,344	14,354	15,956
Current Regulatory Liabilities	2,644	2,788	10,009
Taxes Other Than Income Taxes	2,857	2,442	(48)
Other	20,492	7,367	23,213
Net Cash Flows – Operating Activities	$ 337,320	$ 346,920	$ 347,310

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	TEP		
	Years Ended December 31,		
	2011	2010	2009
	-Thousands of Dollars-		
Net Income	$ 85,334	$ 108,260	$ 90,688
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities			
Depreciation Expense	104,894	99,510	116,970
Amortization Expense	34,650	32,196	35,931
Depreciation and Amortization Recorded to Fuel and Other O&M Expense	4,509	3,855	3,439
Amortization of Deferred Debt-Related Costs included in Interest Expense	2,378	2,146	2,364
Provision for Retail Customer Bad Debts	1,447	2,506	2,342
Use of Renewable Energy Credits for Compliance	5,190	4,245	—
California Power Exchange Provision for Wholesale Revenue Refunds Refunds	—	—	4,172
Deferred Income Taxes	59,309	24,897	45,678
Pension and Postretirement Expense	18,816	17,454	21,294
Pension and Postretirement Funding	(25,878)	(25,672)	(28,330)
Share Based Compensation Expense	2,027	2,131	2,121
Allowance for Equity Funds used During Construction	(3,842)	(3,567)	(3,516)
CTC Revenue Refunded	(35,958)	(10,095)	(12,726)
Decrease to Reflect PPFAC Recovery	(6,165)	(21,541)	(18,186)
Gain on Settlement of El Paso Electric Dispute	(7,391)	—	—
Changes in Assets and Liabilities which Provided (Used) Cash Exclusive of Changes Shown Separately			
Accounts Receivable	4,809	(5,156)	(951)
Materials and Fuel Inventory	(19,789)	20,920	(23,794)
Accounts Payable	13,166	(447)	(10,456)
Income Taxes	(5,582)	20,203	(2,714)
Interest Accrued	14,268	14,431	16,142
Current Regulatory Liabilities	303	2,500	10,555
Taxes Other Than Income Taxes	2,282	1,469	725
Other	19,517	12,238	16,316
Net Cash Flows – Operating Activities	$ 268,294	$ 302,483	$ 268,064

Proceeds from the issuance of the 2010 Coconino Bonds were deposited with a trustee and were used in 2010 to redeem $37 million of pollution control bonds. TEP had no cash receipts or payments as a result of this transaction.

Proceeds from the issuance of $100 million of Pima County tax-exempt IDBs were deposited in a construction fund with a trustee. TEP drew down funds as qualified expenditures were incurred. The $11 million remaining in the construction fund at December 31, 2010 affected recognized assets and liabilities but did not result in cash receipts or payments. TEP drew down the remaining funds in the construction fund by March 2011.

Proceeds from the issuance of $95 million of unsecured fixed rate IDBs in 2009 were deposited with a trustee and were used in 2009, to redeem approximately $95 million of unsecured fixed rate IDBs. TEP had no cash receipts or payments as a result of this transaction.

Other non-cash investing and financing activities that affected recognized assets and liabilities but did not result in cash receipts or payments were as follows:

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Years Ended December 31,		
	2011	2010	2009
	-Thousands of Dollars-		
(Decrease)/Increase to Utility Plant Accruals (1)	$ (2,154)	$ 8,514	$ 1,082
Net Cost of Removal of Interim Retirements (2)	31,626	4,592	43,381
Capital Lease Obligations (3)	15,162	16,630	17,984
Asset Retirement Obligations (4)	7,638	(1,872)	—
UED Secured Term Loan Prepayments (5)	—	3,188	3,625

(1) The non-cash additions to Utility Plant represent accruals for capital expenditures.

(2) The non-cash net cost of removal of interim retirements represents an accrual for future asset retirement obligations that does not impact earnings.

(3) The non-cash change in capital lease obligations represents interest accrued for accounting purposes in excess of interest payments.

(4) The non-cash additions to asset retirement obligations and related capitalized assets represent revision of estimated asset retirement cost due to changes in timing and amount of expected future asset retirement obligations.

(5) The non-cash UED Secured Term Loan prepayment represents deposits applied to $30 million of loan principal.

NOTE 16. ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

FINANCIAL IMPACT OF DERIVATIVES

Cash Flow Hedges

At December 31, 2011, UniSource Energy and TEP had liabilities related to their cash flow hedges of $14 million and $12 million at December 31, 2010.

The net after-tax unrealized gains and losses on derivative activities reported in AOCI were as follows:

	UniSource Energy			TEP		
	Years Ended December 31,					
	2011	2010	2009	2011	2010	2009
	-Millions of Dollars-					
Net After-Tax Unrealized Losses	$ 4	$ 6	$ —	$ 4	$ 6	$ —

Regulatory Treatment of Commodity Derivatives

The following table discloses unrealized gains and losses on energy contracts that are recoverable through the PPFAC or PGA on the balance sheet as a regulatory asset or a regulatory liability rather than as a component of AOCI or in the income statements.

	UniSource Energy			TEP		
	Years Ended December 31,					
	2011	2010	2009	2011	2010	2009
	-Millions of Dollars-					
Increase (Decrease) to Regulatory Assets	$ 2	$ —	$ (29)	$ 2	$ (4)	$ (11)

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The fair value of derivative assets and liabilities were as follows:

	UniSource Energy		TEP	
	December 31, 2011	December 31, 2010	December 31, 2011	December 31, 2010
	-Millions of Dollars-			
Assets	$ 14	$ 15	$ 3	$ 3
Liabilities	(43)	(42)	(9)	(7)
Net Assets (Liabilities)	$ (29)	$ (27)	$ (6)	$ (4)

The realized losses on settled gas swaps that are fully recoverable through the PPFAC or PGA were as follows:

	UniSource Energy			TEP		
	Years Ended December 31,					
	2011	2010	2009	2011	2010	2009
	-Millions of Dollars-					
Realized Losses on Gas Swaps	$ 19	$ 23	$ 51	$ 7	$ 9	$ 29

At December 31, 2011, UniSource Energy and TEP had contracts that will settle through the third quarter of 2015.

Other Commodity Derivatives

The settlement of forward purchased power and sales contracts that do not result in physical delivery were reflected in the financial statements of UniSource Energy and TEP as follows:

	2011	2010	2009
	-Millions of Dollars-		
Recorded in Wholesale Sales:			
Forward Power Sales	$ 10	$ 27	$ 20
Forward Power Purchases	(15)	(34)	(18)
Total Sales and Purchases Not Resulting in Physical Delivery	$ (5)	$ (7)	$ 2

DERIVATIVE VOLUMES

At December 31, 2011, UniSource Energy had gas swaps totaling 14,856 Billion British thermal units (GBtu) and power contracts totaling 3,147 Gigawatt-hours (GWh) while TEP had gas swaps totaling 6,855 GBtu and power contracts totaling 815 GWh. At December 31, 2010, UniSource Energy had gas swaps totaling 14,973 GBtu and power contracts totaling 4,807 GWh while TEP had gas swaps totaling 6,424 GBtu and power contracts totaling 1,144 GWh. We account for gas swaps and power contracts as derivatives.

CREDIT RISK ADJUSTMENT

When the fair value of our derivative contracts is reflected as an asset, the counterparty owes us and this creates credit risk. We also consider the impact of our own credit risk on instruments that are in a net liability position. The impact of counterparty credit risk and our own credit risk on the fair value of derivative asset contracts was less than $0.5 million at December 31, 2011, and December 31, 2010.

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 non-performance by counterparties pursuant to the terms of their contractual obligations. We 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.

We have contractual agreements for energy procurement and hedging activities that contain certain provisions requiring each company to post collateral under certain circumstances. These circumstances include: exposures

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

in excess of unsecured credit limits provided to TEP, UNS Gas or UNS Electric; credit rating downgrades; or a failure to meet certain financial ratios. In the event that such credit events were to occur, we would have to provide certain credit enhancements in the form of cash or letters of credit to fully collateralize our exposure to these counterparties.

The following table shows the sum of the fair value of all derivative instruments under contracts with credit-risk related contingent features that are in a net liability position at December 31, 2011. It also shows cash collateral and letters of credit posted, and additional collateral to be posted if credit-risk related contingent features were triggered.

	TEP	UniSource Energy
	December 31, 2011	
	-Millions of Dollars-	
Net Liability Position	$ 16	$ 64
Cash Collateral Posted	—	—
Letters of Credit	1	6
Additional Collateral to Post if Contingent Features Triggered	16	61

As of December 31, 2011, TEP had $17 million of credit exposure to other counterparties' creditworthiness related to its wholesale marketing and gas hedging activities; and UNS Electric had $1 million of such exposure related to its supply and hedging contracts. TEP had four counterparties which individually comprise greater than 10% of the total credit exposure and UNS Electric had one. At December 31, 2011, UNS Gas had no exposure to other counterparties' creditworthiness.

NOTE 17. 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 while UNS Gas' sales generally peak during the winter. 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 Amounts)			
2011				
Operating Revenue	$ 344,766	$ 369,673	$ 450,948	$ 344,128
Operating Income	44,820	71,289	123,760	41,803
Net Income	13,472	28,604	59,712	8,187
Basic EPS	0.37	0.77	1.61	0.22
Diluted EPS	0.35	0.71	1.46	0.22
2010				
Operating Revenue	$ 318,849	$ 339,114	$ 438,830	$ 357,173
Operating Income	52,955	72,301	123,524	48,334
Net Income	20,178	25,889	55,665	11,252
Basic EPS	0.56	0.71	1.52	0.31
Diluted EPS	0.52	0.66	1.38	0.30

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.

UNISOURCE ENERGY, TEP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Concluded)

	TEP			
	First	Second	Third	Fourth
	-Thousands of Dollars-			
2011				
Operating Revenue	$ 239,588	$ 295,233	$ 369,846	$ 251,719
Operating Income	27,792	62,497	111,479	27,613
Net Income	4,704	25,157	53,912	1,561
2010				
Operating Revenue	$ 231,083	$ 274,694	$ 354,638	$ 264,852
Operating Income	38,248	63,901	116,055	35,827
Net Income	10,490	27,941	59,704	10,125

The following tables reflect the quarterly impact of revisions recorded in the second and third quarters of 2011 (See Note 1):

	2010 Three Months Ended							
	March 31,		June 30,		September 30,		December 31,	
	As Reported	As Revised	As Reported	As Revised	As Reported	As Revised	As Reported	As Revised
	-Thousands of Dollars- (Except Per Share Amounts)							
	UniSource Energy							
Income Statement								
Net Income	$ 19,972	$ 20,178	$ 25,886	$ 25,889	$ 54,883	$ 55,665	$ 11,082	$ 11,252
Basic EPS	0.55	0.56	0.71	0.71	1.50	1.52	0.30	0.31
Diluted EPS	0.52	0.52	0.66	0.66	1.36	1.38	0.29	0.30
	TEP							
Income Statement								
Net Income	$ 10,349	$ 10,490	$ 27,938	$ 27,941	$ 58,993	$ 59,704	$ 9,999	$ 10,125

Schedule II—Valuation and Qualifying Accounts – UniSource Energy

Description Year Ended December 31,	Beginning Balance	Additions-Charged to Income	Deductions	Ending Balance
	-Millions of Dollars-			
Reserve for Uncollectible Accounts (1)				
2011	$ 13	$ 5	$ 2	$ 16
2010	$ 13	$ 4	$ 4	$ 13
2009	$ 27	$ 4	$ 18	$ 13
Deferred Tax Assets Valuation Allowance (2)				
2011	$ 8	$ —	$ 1	$ 7
2010	$ —	$ 8	$ —	$ 8
2009	$ —	$ —	$ —	$ —
Other (3)				
2011	$ 4			$ 6
2010	$ 2			$ 4
2009	$ 4			$ 2

(1) TEP, UNS Gas and UNS Electric record additions to the Reserve for Uncollectible Accounts based on historical experience and any specific customer collection issues identified. Deductions principally reflect amounts charged off as uncollectible, less amounts recovered. Amounts include reserves for trade receivables, wholesale sales and in-kind transmission imbalances.

(2) Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or the entire deferred income tax asset will not be realized. Management believes that it is more likely than not that we will not be able to generate future capital gains to offset the capital losses related to an unregulated investment loss deferred tax asset. As a result, an $8 million valuation allowance was recorded against the deferred tax asset as of December 31, 2010.

(3) Principally reserves for sales tax audits, litigation and damages billable to third parties.

Schedule II—Valuation and Qualifying Accounts—TEP

Description Year Ended December 31,	Beginning Balance	Additions-Charged to Income	Deductions	Ending Balance
	-Millions of Dollars-			
Reserve for Uncollectible Accounts (1)				
2011	$ 11	$ 4	$ 1	$ 14
2010	$ 11	$ 3	$ 3	$ 11
2009	$ 24	$ 2	$ 15	$ 11
Other (2)				
2011	$ 3			$ 4
2010	$ —			$ 3
2009	$ 4			$ —

(1) TEP records additions to the Reserve for Uncollectible Accounts based on historical experience and any specific customer collection issues identified. Deductions principally reflect amounts charged off as uncollectible, less amounts recovered. Amounts include reserves for trade receivables, wholesales sales and in-kind transmission imbalances.

(2) Principally reserves for sales tax audits, litigation and damages billable to third parties.

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 13(a) – 15(e) or Rule 15(d) – 15(e) under the Securities Exchange Act of 1934, as amended (the Exchange Act), as of December 31, 2011. 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 2011, that has materially affected, or is reasonably likely to materially affect, UniSource Energy or TEP's internal control over financial reporting.

UniSource Energy's and TEP's Management's Reports on Internal Control Over Financial Reporting Under 404 of Sarbanes-Oxley appear as the first two reports under Item 8 in UniSource Energy's and TEP's 2011 Annual Report on Form 10-K, the Report of Independent Registered Public Accounting Firm for UniSource Energy appears as the third report under Item 8, and the Report of Independent Registered Public Accounting Firm for TEP appears as the fourth report under Item 8.

ITEM 9B. – OTHER INFORMATION

None.

PART III

ITEM 10. – DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE OF THE REGISTRANTS

Directors – UniSource Energy

Name	Age	Board Committee*	Director Since
Paul J. Bonavia	60	None	2009
Lawrence J. Aldrich	59	2,3,5	2000
Barbara M. Baumann	56	1,2,4	2005
Larry W. Bickle	66	3,4,5	1998
Harold W. Burlingame	71	2,3,5	1998
Robert A. Elliott	56	1,2,3,4,5	2003
Daniel W.L. Fessler	70	1,3,5	2005
Louise L. Francesconi	59	1,2,4	2008
Warren Y. Jobe	71	1,2,4	2001
Ramiro G. Peru	56	1,2,4	2008
Gregory A. Pivirotto	59	1,3,4	2008
Joaquin Ruiz	59	2,3,5	2005

* Board Committees

(1) Audit

(2) Compensation

(3) Corporate Governance and Nominating

(4) Finance

(5) Environmental, Safety and Security

Paul J. Bonavia Mr. Bonavia has served as Chairman and Chief Executive Officer of UniSource Energy and TEP since January 2009; he also served as President from January 2009 to December 2011. Prior to joining UniSource Energy, Mr. Bonavia served as President of the Utilities Group of Xcel Energy. Mr. Bonavia previously served as President of Xcel Energy's Commercial Enterprises business unit and President of the company's Energy Markets unit.

Lawrence J. Aldrich President and Chief Executive Officer of University Physicians Healthcare from 2009-2010. President of Aldrich Capital Company since January 2007; Chief Operating Officer of The Critical Path Institute from 2005-2007; General Partner of Valley Ventures, LP from September 2002 to December 2005; Managing Director and Founder of Tucson Ventures, LLC, from February 2000 to September 2002.

Barbara M. Baumann President and Owner of Cross Creek Energy Corporation since 2003; Executive Vice President of Associated Energy Managers, LLC from 2000 to 2003; former Vice President of Amoco Production Company; Director of SM Energy Company since 2002; member of the Board of Trustees of the Putnam Mutual Funds since 2010.

Larry W. Bickle Director of SM Energy Company since 1994; Retired private equity investor; Managing Director of Haddington Ventures, LLC from 1997 to 2007. Non-executive Chairman of Quantum Natural Gas Strategies, LLC since 2008.

Harold W. Burlingame Executive Vice President of AT&T from 1986-2001; Senior Executive Advisor for ATT Wireless from 2001-2005; Chairman of ORC Worldwide from 2004-2010; President of IRC Foundation since December 2010; Director of Cornerstone On Demand since 2006.

Robert A. Elliott President and owner of The Elliott Accounting Group since 1983; Director and Corporate Secretary of Southern Arizona Community Bank from 1998-2010; Television Analyst/Pre- game Show Co-host for Fox Sports Arizona from 1998-2009; Chairman of the Board of

	Tucson Metropolitan Chamber of Commerce from 2002 to 2003; Chairman of the Board of Tucson Urban League from 2003 to 2004; Chairman of the Board of the Tucson Airport Authority from January 2006 to January 2007; Director of AAA since 2007; Director of the NBA Retired Players Association since 2010; and Director of the University of Arizona Foundation.
Daniel W.L. Fessler	President of the California Public Utility Commission from 1991-1996; Professor Emeritus of the University of California since 1994; Of counsel for the law firm of Holland & Knight from 2003-2007; Partner in the law firm of LeBoeuf, Lamb, Greene & MacRae LLP from 1997 to 2003; previously served on the UniSource Energy and TEP boards of directors from 1998 to 2003; Managing Principal of Clear Energy Solutions, LLC since December 2004.
Louise L. Francesconi	Retired President of Raytheon Missile Systems; Director of Stryker Corporation since July 2006; Chairman of the Board of Trustees for TMC Healthcare; Director of Global Solar Energy, Inc. since 2008.
Warren Y. Jobe	Certified Public Accountant (licensed, but not practicing); Senior Vice President of Southern Company from 1998 to 2001; Executive Vice President and Chief Financial Officer of Georgia Power Company from 1987-1998; Director of WellPoint Health Networks, Inc. from 2003 to December 2004; Director of WellPoint, Inc. since December 2004; Trustee of RidgeWorth Funds since 2004. Director of Home Banc Corp. from 2005-2009.
Ramiro G. Peru	Executive Vice President and Chief Financial Officer of Swift Corporation, a trucking company, from June 2007 to December 2007; Executive Vice President and Chief Financial Officer of Phelps Dodge Corporation from October 2004 to March 2007; Senior Vice President and Chief Financial Officer of Phelps Dodge Corporation from May 1999 to September 2004; Director of WellPoint Health Networks, Inc. from 2003 to December 2004; Director of WellPoint, Inc. since December 2004; Director of Southern Peru Copper Corporation from 2002 to 2004.
Gregory A. Pivirotto	President and Chief Executive Officer and Director of University Medical Center Corporation from 1994-2010; Certified Public Accountant since 1978; Director of Arizona Hospital & Healthcare Association from 1997 to 2005. Director of Tucson Airport Authority since 2008; Member of the Advisory Board of Harris Bank since 2010.
Joaquin Ruiz	Professor of Geosciences, University of Arizona since 1983; Dean, College of Science, University of Arizona since 2000; Executive Dean of the University of Arizona College of Letters, Arts and Science since 2009.

Directors – TEP

Name	Age	Director Since
Paul J. Bonavia	60	2009
Michael J. DeConcini	47	2009
David G. Hutchens	45	2011
Kevin P. Larson	55	2009

Paul J. Bonavia	Mr. Bonavia has served as Chairman and Chief Executive Officer of UniSource Energy and TEP since January 2009; he also served as President from January 2009 to December 2011. Prior to joining UniSource Energy, Mr. Bonavia served as President of the Utilities Group of Xcel Energy. Mr. Bonavia previously served as President of Xcel Energy's Commercial Enterprises business unit and President of the company's Energy Markets unit.
Michael J. DeConcini	Mr. DeConcini has served as Senior Vice President, Operations of UniSource Energy since May 2010 and Senior Vice President and Chief Operating Officer of TEP from May

	2009 to December 2011 when his title at TEP was changed to Senior Vice President, Operations. Mr. DeConcini joined TEP in 1988 and 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.
David G. Hutchens	Mr. Hutchens has served as President of UniSource Energy and TEP since December 2011. In March 2011, Mr. Hutchens was named Executive Vice President of UniSource Energy and TEP. In May 2009, Mr. Hutchens was named Vice President of Energy Efficiency and Resource Planning. In January 2007, Mr. Hutchens was elected Vice President of Wholesale Energy at UniSource Energy and TEP. Mr. Hutchens joined TEP in 1995.
Kevin P. Larson	Mr. Larson has served as Senior Vice President and Chief Financial Officer of UniSource Energy and TEP since September 2005. Mr. Larson is also Treasurer of UniSource Energy. Mr. Larson joined TEP in 1985 and thereafter held various positions in its finance department and investment subsidiaries. He was elected Treasurer in August 1994 and Vice President in March 1997. In October 2000, he was elected Vice President and Chief Financial Officer.

Executive Officers of UniSource Energy and TEP

See *Item 1. Business, Executive Officers of the Registrants.*

Information required by Items 401, 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 2012 Annual Meeting of Shareholders, which will be filed with the SEC not later than 120 days after December 31, 2011, 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 2012 Annual Meeting of Shareholders, which will be filed with the SEC not later than 120 days after December 31, 2011, which information is incorporated herein by reference.

ITEM 12. – SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

General

At February 21, 2012, UniSource Energy had outstanding 38.0 million shares of Common Stock. At February 21, 2012, the number of shares of Common Stock beneficially owned by all directors and officers of UniSource Energy as a group amounted to approximately 3% of the outstanding Common Stock.

At February 21, 2012, 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 2012 Annual Meeting of Shareholders, which will be filed with the SEC not later than 120 days after December 31, 2011, 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 will be contained in UniSource Energy's Proxy Statement relating to the 2012 Annual Meeting of Shareholders, which will be filed with the SEC not later than 120 days after December 31, 2011, 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 2012 Annual Meeting of Shareholders, which will be filed with the SEC not later than 120 days after December 31, 2011, 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 2012 Annual Meeting of Shareholders, which will be filed with the SEC not later than 120 days after December 31, 2011, 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 2012 Annual Meeting of Shareholders, which will be filed with the SEC not later than 120 days after December 31, 2011, which information is incorporated herein by reference.

PART IV

ITEM 15. – EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

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(3). Exhibits
Reference is made to the Exhibit Index commencing on page 162.

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 27, 2012

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 27, 2012	/s/ Paul J. Bonavia* Paul J. Bonavia Chairman of the Board and Principal Executive Officer
Date: February 27, 2012	/s/ Kevin P. Larson Kevin P. Larson Principal Financial Officer
Date: February 27, 2012	/s/ Karen G. Kissinger* Karen G. Kissinger Principal Accounting Officer
Date: February 27, 2012	/s/ Lawrence J. Aldrich* Lawrence J. Aldrich Director
Date: February 27, 2012	/s/ Barbara M. Baumann* Barbara M. Baumann Director
Date: February 27, 2012	/s/ Larry W. Bickle* Larry W. Bickle Director
Date: February 27, 2012	/s/ Harold W. Burlingame* Harold W. Burlingame Director
Date: February 27, 2012	/s/ Robert A. Elliott* Robert A. Elliott Director

Date: February 27, 2012	/s/ Daniel W.L. Fessler* Daniel W.L. Fessler Director
Date: February 27, 2012	/s/ Louise L. Francesconi* Louise L. Francesconi Director
Date: February 27, 2012	/s/ Warren Y. Jobe* Warren Y. Jobe Director
Date: February 27, 2012	/s/ Ramiro Peru* Ramiro Peru Director
Date: February 27, 2012	/s/ Gregory A. Pivirotto* Gregory A. Pivirotto Director
Date: February 27, 2012	/s/ Joaquin Ruiz* Joaquin Ruiz Director
Date: February 27, 2012	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 27, 2012

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 27, 2012	/s/ Paul J. Bonavia* Paul J. Bonavia Chairman of the Board and Principal Executive Officer
Date: February 27, 2012	/s/ Kevin P. Larson Kevin P. Larson Principal Financial Officer and Director
Date: February 27, 2012	/s/ Karen G. Kissinger* Karen G. Kissinger Principal Accounting Officer
Date: February 27, 2012	/s/ Michael J. DeConcini* Michael J. DeConcini Director
Date: February 27, 2012	/s/ David G. Hutchens* David G. Hutchens Director
Date: February 27, 2012	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. (Form 10-K for the year ended December 31,1997, File No. 13739 – Exhibit. 2(a)).
*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 the year ended December 31, 1996, File No. 1-5924-Exhibit No 3(a)).
*3(a)(1)	—	TEP Articles of Amendment filed with the ACC on September 3, 2009 (Form 10-K for the year ended December 31, 2010, File No. 1-1379 – Exhibit 3(a))
*3(b)	—	Bylaws of TEP, as amended as of August 31, 2009 (Form 10-Q for the quarter ended September 30, 2009, File No. 13739 – Exhibit 3.1).
*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)	—	Revised and restated bylaws of UniSource Energy, as revised and restated December 14, 2011 (Form 8-K, dated December 15, 2011, File No. 13739 – Exhibit 3.1)
4(a)	—	Reserved.
*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)).

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*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(e)(7)	—	Third Supplemental Indenture of Trust, dated as of December 7, 2011, between the Apache County Authority and U.S. Bank Trust National Association, as successor trustee, relating to Industrial Development Bonds 1983 Series B (Tucson Electric Power Company Springerville Project)
*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(f)(7)	—	Third Supplemental Indenture of Trust, dated as of December 7, 2011, between the Apache County Authority and U.S. Bank Trust National Association, as successor trustee, relating to Industrial Development Bonds 1983 Series C (Tucson Electric Power Company Springerville Project)
4(g)	—	Reserved
*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(i)(9)	—	Supplemental Indenture No. 8 creating a series of bonds designated First Mortgage Bonds, Collateral Series G, dated as of June 1, 2008. (Form 8-K dated June 25, 2008, File Nos. 1-5924 and 1-13739 – Exhibit 4(b)).
*4(i)(10)	—	Supplemental Indenture No. 9 dated as of July 3, 2008, (Form 10-K for the year ended December 31, 2009, File No. 1-3739, Exhibit 4(i)(10)).
*4(i)(11)	—	Supplemental Indenture No. 10 creating a series of bonds designated as First Mortgage Bonds, Collateral Series H, dated as of March 1, 2010. (Form 8-K dated March 5, 2010, File No. 1-13739, Exhibit 4(b)).
*4(i)(12)	—	Supplemental Indenture No.11, dated as of November 1, 2010, between Tucson Electric Power Company and The Bank of New York Mellon, as trustee. (Form 8-K dated November 15, 2010, File No. 1-13739, Exhibit 4.5).
*4(i)(13)	—	Supplemental Indenture No. 12, dated as of December 1, 2010, between TEP and the Bank of New York Mellon, creating a series of bonds designated First Mortgage Bonds, Collateral Series J. (Form 8-K dated December 17, 2010, File No. 1-13739, Exhibit 4(b)).

4(i)(14)	—	Supplemental Indenture No.13, dated as of November 1, 2011, between Tucson Electric Power Company and The Bank of New York Mellon, amending terms of bonds designated First Mortgage Bonds, Collateral Series I.
*4(j)(1)	—	Indenture of Trust, dated as of June 1, 2008, between The Industrial Development Authority of the County of Pima and U.S. Bank Trust National Association authorizing Industrial Development Revenue Bonds, 2008 Series B (Tucson Electric Power Company Project). (Form 8-K dated June 25, 2008, File Nos. 1-5924 and 1-13739 — Exhibit 4(a)).
*4(j)(2)	—	Loan Agreement, dated as of June 1, 2008, between The Industrial Development Authority of the County of Pima and TEP relating to Industrial Development Revenue Bonds, 2008 Series B (Tucson Electric Power Company Project). (Form 8-K dated June 25, 2008, File Nos. 1-5924 and 1-13739 — Exhibit 4(b)).
*4(k)(1)	—	Indenture of Trust, dated as of December 1, 2010, between the Coconino County, Arizona Pollution Control Corporation and U.S. Bank Trust National Association authorizing Pollution Control Bonds, 2010 Series A (Tucson Electric Power Company Navajo Project). (Form 8-K dated December 17, 2010, File No. 1-13739, Exhibit 4(c)).
*4(k)(2)	—	Loan Agreement, dated as of December 1, 2010, between the Coconino County, Arizona Pollution Control Corporation and TEP relating to Pollution Control Bonds, 2010 Series A (Tucson Electric Power Company Navajo Project). (Form 8-K dated December 17, 2010, File No. 1-13739, Exhibit 4(d)).
*4(l)(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(l)(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(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 B (Tucson Electric Power Company Project). (Form 10-Q for the quarter ended March 31, 1998, File No. 1-5924 — Exhibit 4(c)).
*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 B (Tucson Electric Power Company Project). (Form 10-Q for the quarter ended March 31, 1998, File No. 1-5924 — Exhibit 4(d)).
*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 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(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 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(o)(1)	—	Second Amended and Restated Credit Agreement, dated as of November 9, 2010, among Tucson Electric Power Company, Union Bank, N.A., as Administrative Agent, and a group of lenders. (Form 8-K dated November 15, 2010, File No. 1-13739, Exhibit 4.3).
4(o)(2)	-	Amendment No. 1 to Second Amended and Restated Credit Agreement, dated as of November 18, 2011, among Tucson Electric Power Company, Union Bank, N.A., as Administrative Agent, and a group of lenders.

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*4(p)(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(p)(2)	—	Note Purchase Agreement, dated as of May 4, 2011, among UNS Gas, Inc., UniSource Energy Services, Inc., and a group of purchasers, (Form 8-K dated August 12, 2011, File 1-13739 — Exhibit 4.1).
*4(q)(1)	—	Note Purchase and Guaranty Agreement dated August 5, 2008, among UNS Electric, Inc., and UniSource Energy Services, Inc., and certain institutional investors. (Form 10-Q for the quarter ended June 30, 2008, File Nos. 1-5924 and 1-13739 — Exhibit 4).
*4(r)(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(s)(1)	—	Second Amended and Restated Credit Agreement, dated as of November 9, 2010, among UniSource Energy Corporation, Union Bank, N.A., as Administrative Agent, and a group of lenders. (Form 8-K dated November 15, 2010, File No. 1-13739, Exhibit 4.1).
4(s)(2)	—	Amendment No. 1 to Second Amended and Restated Credit Agreement, dated as of November 18, 2011, among UniSource Energy Corporation, Union Bank, N.A., as Administrative Agent, and a group of lenders.
*4(t)(1)	—	Second Amended and Restated Credit Agreement, dated as of November 9, 2010, among UNS Electric, Inc., UNS Gas, Inc., UniSource Energy Services, Inc., Union Bank, N.A., as Administrative Agent, and a group of lenders. (Form 8-K dated November 15, 2010, File No. 1-13739, Exhibit 4.4).
4(t)(2)	—	Amendment No. 1 to Second Amended and Restated Credit Agreement, dated as of November 18, 2011, among UNS Electric, Inc., UNS Gas, Inc., UniSource Energy Services, Inc., Union Bank, N.A., as Administrative Agent, and a group of lenders.
*4(u)(1)	—	Reimbursement Agreement, dated as of December 14, 2010, among TEP, as Borrower, the financial institutions from time to time, parties thereto and JPMorgan Chase Bank, N.A., as Administrative Agent and as Issuing Bank. (Form 8-K dated December 17, 2010, File No. 1-13739, Exhibit 4(a)).
*4(v)(1)	—	Second Amended and Restated Pledge Agreement, dated as of November 9, 2010, among UniSource Energy Corporation, Union Bank, N.A., as Administrative Agent, and a group of lenders. (Form 8-K dated November 15, 2010, File No. 1-13739, Exhibit 4.2).
*4(w)(1)	—	Indenture of Trust, dated as of March 1, 2008, between The Industrial Development Authority of the County of Pima and U.S. Bank Trust National Association authorizing Industrial Development Revenue Bonds, 2008 Series A (Tucson Electric Power Company Project). (Form 8-K dated March 19, 2008, File Nos. 1-5924 and 1-13739 — Exhibit 4(a)).
*4(w)(2)	—	Loan Agreement, dated as of March 1, 2008, between the Industrial Development Authority of the County of Pima and TEP relating to Industrial Development Revenue Bonds, 2008 Series A (Tucson Electric Power Company Project). (Form 8-K dated March 19, 2008, File Nos. 1-5924 and 1-13739 — Exhibit 4(b)).
*4(x)(1)	—	Indenture of Trust, dated as of October 1, 2009, between The Industrial Development Authority of the County of Pima and U.S. Bank Trust National Association authorizing Pollution Control Revenue Bonds, 2009 Series A (Tucson Electric Power Company Navajo Project). (Form 8-K dated October 13, 2009, File No. 1-13739- Exhibit 4(A)).

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*4(x)(2)	—	Loan Agreement, dated as of October 1, 2009, between The Industrial Development Authority of the County of Pima and TEP relating to Pollution Control Revenue Bonds, 2009 Series A (Tucson Electric Power Company San Juan Project). (Form 8-K dated October 13, 2009, File No. 1-13739- Exhibit 4(B)).
*4(x)(3)	—	Indenture of Trust, dated as of October 1, 2009, between Coconino County, Arizona Pollution Control Corporation and U.S. Bank Trust National Association authorizing Pollution Control Revenue Bonds, 2009 Series A (Tucson Electric Power Company Navajo Project). (Form 8-K dated October 13, 2009, File No. 1-13739- Exhibit 4(C)).
*4(x)(4)	—	Loan Agreement, dated as of October 1, 2009, between Coconino County, Arizona Pollution Control Corporation and TEP relating to Pollution Control Revenue Bonds, 2009 Series A (Tucson Electric Power Company Navajo Project). (Form 8-K dated October 13, 2009, File No. 1-13739- Exhibit 4(D)).
*4(y)(1)	—	Indenture of Trust, dated as of October 1, 2010, between the Industrial Development Authority of the County of Pima and U.S. Bank Trust National Association, authorizing Industrial Development Revenue Bonds, 2010 Series A (Tucson Electric Power Company Project). (Form 8-K dated October 8, 2010, File No. 1-13739 Exhibit 4(a)).
*4(y)(2)	—	Loan Agreement, dated as of October 1, 2010, between the Industrial Development Authority of the County of Pima and TEP, relating to Industrial Development Revenue Bonds, 2010 Series A (Tucson Electric Power Company Project). (Form 8-K dated October 8, 2010, File No. 1-13739 Exhibit 4(b)).
*4(z)(1)	—	Credit Agreement, dated as of August 10, 2011, among UNS Electric, Inc., UniSource Energy Services, Inc., and Union Bank, N.A., as Administrative Agent (Form 8-K dated August 12, 2011, File 1-13739 — Exhibit 4.2).
*4(aa)(1)	—	Indenture, dated November 1, 2011, between Tucson Electric Power Company and U.S. Bank National Association, as trustee, authorizing 5.15% Notes due 2021 (Form 8-K dated November 8, 2011, File 1-13739 — Exhibit 4.1).
*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)).

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*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. (Form 10-Q for the quarter ended June 30, 2003, File No. 1-5924 – Exhibit 10(a)).
*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. (Form 10-Q for the quarter ended June 30, 2003, File No. 1-5924 – Exhibit 10(b)).
*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. (Form 10-Q for the quarter ended June 30, 2003, File No. 1-5924 – Exhibit 10(c)).

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*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. (Form 10-Q for the quarter ended June 30, 2003, File No. 1-5924 – Exhibit 10(d)).
*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. (Form 10-Q for the quarter ended June 30, 2003, File No. 1-5924 – Exhibit 10(e)).
*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. (Form 10-Q for the quarter ended June 30, 2003, File No. 1-5924 – Exhibit 10(f)).
*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. (Form 8-K dated June 12, 2006, File No. 1-5924 – Exhibit 10.1).
*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. (Form 8-K dated June 12, 2006, File No. 1-5924 – Exhibit 10.2).
*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. (Form 8-K dated June 12, 2006, File No. 1-5924 – Exhibit 10.3).
*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. (Form 8-K dated June 12, 2006, File No. 1-5924 – Exhibit 10.4).
*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. (Form 8-K dated June 12, 2006, File No. 1-5924 – Exhibit 10.5).
*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. (Form 8-K dated June 12, 2006, File No. 1-5924 – Exhibit 10.6).

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*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(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(m)	—	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). (Form 10-K for the year ended December 31, 2004, File No. 1-5924 – Exhibit 10(q)).
+*10(n)	—	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(o)	—	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)	—	UniSource Energy 2006 Omnibus Stock and Incentive Plan. (Form S-8 dated January 31, 2007, File No. 333-140353).
+*10(q)	—	Stock Option Agreement between UniSource Energy and Raymond S. Heyman dated as of September 15, 2005 (Form 10-K for the year ended December 31, 2007, File No. 1-13739, Exhibit 10(r)).
+*10(r)	—	Management and Directors Deferred Compensation Plan II of UniSource Energy. (Form S-8 dated December 30, 2008, File No. 333-156491).
+*10(s)	—	Letter of Employment dated as of December 9, 2008, between UniSource Energy and Paul J. Bonavia. (Form 8-K dated December 15, 2008, File No. 1-13739).
+*10(t)	—	Amended and Restated Officer Change in Control Agreement, dated as of October 9, 2009, between TEP and Michael J. DeConcini (including a schedule of other officers who are covered by substantially identical agreements) (Form 8-K dated October 13, 2009, File No. 1-13739 – Exhibit 10(A)).
+*10(u)	—	Employment Agreement, dated May 4, 2009, between UniSource Energy and Paul J. Bonavia. (Form 10-Q for the quarter ended March 31, 2009, File No. 13739 – Exhibit 4).
+*10(v)	—	UniSource Energy Corporation 2011 Omnibus Stock and Incentive Plan. (Form 8-K dated May 10, 2011, File 1-13739 – Exhibit 10.1).

12(a)	—	Computation of Ratio of Earnings to Fixed Charges – UniSource Energy.
12(b)	—	Computation of Ratio of Earnings to Fixed Charges – TEP.
21	—	Subsidiaries of the Registrants.
23(a)	—	Consent of Independent Registered Public Accounting Firm – UniSource Energy.
23(b)	—	Consent of Independent Registered Public Accounting Firm – TEP.
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 Paul J. Bonavia.
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 Paul J. Bonavia.
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).
#*101	—	The following materials from UniSource Energy's and TEP's Annual Report on Form 10-K for the fiscal year ended December 31, 2011, formatted in XBRL (Extensible Business Reporting Language):

(a) UniSource Energy's and TEP's (i) Consolidated Statements of Income, (ii) Consolidated Statements of Cash Flows, (iii) Consolidated Balance Sheets, (iv) Consolidated Statements of Capitalization, (v) Consolidated Statements of Changes in Stockholders' Equity and Comprehensive Income; and

(b) Notes to Consolidated Financial Statements.

These exhibits are deemed furnished and not filed pursuant to Rule 406T of Regulation S-T.

(*) 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 Securities Exchange Act of 1934, as amended.

Exhibit 4(e)(7)

THIRD SUPPLEMENTAL INDENTURE OF TRUST

THIS THIRD SUPPLEMENTAL INDENTURE OF TRUST, dated December 7, 2011 (this "Third Supplemental Indenture"), between THE INDUSTRIAL DEVELOPMENT AUTHORITY OF THE COUNTY OF APACHE, a political subdivision of the State of Arizona created and existing under and by virtue of the Constitution and laws of the State of Arizona (hereinafter called the "Authority"), and U.S. Bank Trust National Association, a national banking association, as successor trustee (hereinafter called the "Trustee"), being an amendment and supplement to the Indenture of Trust, dated as of December 1, 1983, as heretofore supplemented (the "Indenture"), between the Authority and the Trustee pursuant to which the Authority issued The Industrial Development Authority of the County of Apache Industrial Development Revenue Bonds, 1983 Series B (Tucson Electric Power Company Springerville Project) (the "Bonds").

WITNESSETH:

WHEREAS, the Authority is authorized and empowered under Title 35, Chapter 5, Arizona Revised Statutes, as amended (the "Act"), to issue its bonds in accordance with the Act and to make secured or unsecured loans for the purpose of financing or refinancing the acquisition, construction, improvement or equipping of projects consisting of land, any building or other improvement, and all real and personal properties, including but not limited to machinery and equipment, whether or not now in existence or under construction, whether located within or without Apache County, which shall be suitable for, among other things, facilities for the furnishing of electric energy, gas or water, air and water pollution control facilities and sewage and solid waste disposal facilities, and to charge and collect interest on such loans and pledge the proceeds of loan agreements as security for the payment of the principal of and interest on bonds, or designated issues of bonds, issued by the Authority; and

WHEREAS, the Authority has entered into a Loan Agreement, dated as of December 1, 1983, as heretofore supplemented (the "Loan Agreement"), with Tucson Electric Power Company, an Arizona corporation (the "Company"); and

WHEREAS, pursuant to the Indenture, the Authority has heretofore issued and sold the Bonds for the purpose of financing the Company's share of the costs of the acquisition, construction, improvement and equipping of certain facilities, including facilities relating to the Company's Springerville Generating Station located in Apache County, Arizona as more fully described in Exhibit A to the Loan Agreement; and

WHEREAS, the Authority has been requested by the Company to amend and supplement the Indenture as hereinafter set forth in order to provide for cancellation of the Letter of Credit at any time all of the Outstanding Bonds are Company Bonds registered in the name of the Company; and

WHEREAS, pursuant to Section 12.03 of the Indenture, the Authority has requested that the Trustee enter into this Third Supplemental Indenture; and

WHEREAS, pursuant to Section 12.05 of the Indenture, the Company and the Bank have consented to this Third Supplemental Indenture; and

WHEREAS, there has been delivered to the Authority and the Trustee a Approving Opinion of Bond Counsel stating that the amendments set forth in this Third Supplemental Indenture are authorized or permitted by the Act and comply with terms of the Act, are authorized or permitted by the Indenture and comply with the terms of the Indenture, will, upon the execution and delivery hereof, be valid and binding upon the Authority in accordance with the terms hereof and will not adversely affect the exemption from federal income taxation of interest on the Bonds.

NOW, THEREFORE, for and in consideration of these premises and the mutual covenants herein contained and the sum of one dollar lawful money of the United States of America, to the Authority duly paid by the Trustee at or before the execution and delivery of these presents, and for other good and valuable consideration the receipt and sufficiency of which are hereby acknowledged, the parties hereto covenant and agree as follows:

Section 1. **Definitions** . Unless otherwise specifically provided herein to the contrary, the capitalized terms in this Third Supplemental Indenture, including, without limitation, the capitalized terms set forth in the Recitals hereto, shall have the meanings provided for such terms in the Indenture.

Section 2. **Amendment of Subsection 4.05(b)** . Subsection 4.05(b) of the Indenture is hereby amended by addition of the following sentence at the end thereof;

> If at any time all of the Bonds Outstanding shall be Company Bonds registered in the name of the Company and an Authorized Company Representative shall have so directed the Trustee, the entity acting as Trustee and Agent shall promptly surrender any Letter of Credit then in effect to the Bank for cancellation.

Section 3. **Counterparts** . This Third Supplemental Indenture may be executed in any number of counterparts, each of which, when executed and delivered, shall be an original; but such counterparts shall together constitute but one and the same instrument.

Section 4. **Effective Date** . The amendments set forth in this Third Supplemental Indenture shall be deemed to be effective as of the date that: (i) all Outstanding Bonds are registered in the name of the Company, as evidenced by a certificate of the Registrar delivered to the Authority and (ii) the Company, as Owner of all Outstanding Bonds and as authorized by Section 13.05 of the Indenture, delivers its written consent to this Third Supplemental Indenture pursuant to Section 12.03 of the Indenture, such written consent to be delivered to the Authority and the Trustee.

Section 5. **Provisions of Indenture Not Otherwise Modified** . Except as specifically amended by this Third Supplemental Indenture, the Indenture is hereby ratified, approved and confirmed and remains in full force and effect.

IN WITNESS WHEREOF, The Industrial Development Authority of the County of Apache has caused this Third Supplemental Indenture to be executed by its President, and U.S. Bank Trust National Association has caused this Third Supplemental Indenture to be executed on its behalf by one of its Vice Presidents, all as of the day and year first above written.

THE INDUSTRIAL DEVELOPMENT
AUTHORITY OF THE COUNTY OF APACHE

By: /s/ John Lang, President
Title: Authorized Officer

U.S. BANK TRUST NATIONAL
ASSOCIATION, as TRUSTEE

By: /s/ Patrick Crowley
Title: Vice President

Signature Page to Third Supplemental Indenture of Trust

Exhibit 4(f)(7)

THIRD SUPPLEMENTAL INDENTURE OF TRUST

THIS THIRD SUPPLEMENTAL INDENTURE OF TRUST, dated December 7, 2011 (this "Third Supplemental Indenture"), between THE INDUSTRIAL DEVELOPMENT AUTHORITY OF THE COUNTY OF APACHE, a political subdivision of the State of Arizona created and existing under and by virtue of the Constitution and laws of the State of Arizona (hereinafter called the "Authority"), and U.S. Bank Trust National Association, a national banking association, as successor trustee (hereinafter called the "Trustee"), being an amendment and supplement to the Indenture of Trust, dated as of December 1, 1983, as heretofore supplemented (the "Indenture"), between the Authority and the Trustee pursuant to which the Authority issued The Industrial Development Authority of the County of Apache Industrial Development Revenue Bonds, 1983 Series C (Tucson Electric Power Company Springerville Project) (the "Bonds").

WITNESSETH:

WHEREAS, the Authority is authorized and empowered under Title 35, Chapter 5, Arizona Revised Statutes, as amended (the "Act"), to issue its bonds in accordance with the Act and to make secured or unsecured loans for the purpose of financing or refinancing the acquisition, construction, improvement or equipping of projects consisting of land, any building or other improvement, and all real and personal properties, including but not limited to machinery and equipment, whether or not now in existence or under construction, whether located within or without Apache County, which shall be suitable for, among other things, facilities for the furnishing of electric energy, gas or water, air and water pollution control facilities and sewage and solid waste disposal facilities, and to charge and collect interest on such loans and pledge the proceeds of loan agreements as security for the payment of the principal of and interest on bonds, or designated issues of bonds, issued by the Authority; and

WHEREAS, the Authority has entered into a Loan Agreement, dated as of December 1, 1983, as heretofore supplemented (the "Loan Agreement"), with Tucson Electric Power Company, an Arizona corporation (the "Company"); and

WHEREAS, pursuant to the Indenture, the Authority has heretofore issued and sold the Bonds for the purpose of financing the Company's share of the costs of the acquisition, construction, improvement and equipping of certain facilities, including facilities relating to the Company's Springerville Generating Station located in Apache County, Arizona as more fully described in Exhibit A to the Loan Agreement; and

WHEREAS, the Authority has been requested by the Company to amend and supplement the Indenture as hereinafter set forth in order to provide for cancellation of the Letter of Credit at any time all of the Outstanding Bonds are Company Bonds registered in the name of the Company; and

WHEREAS, pursuant to Section 12.03 of the Indenture, the Authority has requested that the Trustee enter into this Third Supplemental Indenture; and

WHEREAS, pursuant to Section 12.05 of the Indenture, the Company and the Bank have consented to this Third Supplemental Indenture; and

WHEREAS, there has been delivered to the Authority and the Trustee a Approving Opinion of Bond Counsel stating that the amendments set forth in this Third Supplemental Indenture are authorized or permitted by the Act and comply with terms of the Act, are authorized or permitted by the Indenture and comply with the terms of the Indenture, will, upon the execution and delivery hereof, be valid and binding upon the Authority in accordance with the terms hereof and will not adversely affect the exemption from federal income taxation of interest on the Bonds.

NOW, THEREFORE, for and in consideration of these premises and the mutual covenants herein contained and the sum of one dollar lawful money of the United States of America, to the Authority duly paid by the Trustee at or before the execution and delivery of these presents, and for other good and valuable consideration the receipt and sufficiency of which are hereby acknowledged, the parties hereto covenant and agree as follows:

Section 1. **Definitions** . Unless otherwise specifically provided herein to the contrary, the capitalized terms in this Third Supplemental Indenture, including, without limitation, the capitalized terms set forth in the Recitals hereto, shall have the meanings provided for such terms in the Indenture.

Section 2. **Amendment of Subsection 4.05(b)** . Subsection 4.05(b) of the Indenture is hereby amended by addition of the following sentence at the end thereof;

If at any time all of the Bonds Outstanding shall be Company Bonds registered in the name of the Company and an Authorized Company Representative shall have so directed the Trustee, the entity acting as Trustee and Agent shall promptly surrender any Letter of Credit then in effect to the Bank for cancellation.

Section 3. **Counterparts** . This Third Supplemental Indenture may be executed in any number of counterparts, each of which, when executed and delivered, shall be an original; but such counterparts shall together constitute but one and the same instrument.

Section 4. **Effective Date** . The amendments set forth in this Third Supplemental Indenture shall be deemed to be effective as of the date that: (i) all Outstanding Bonds are registered in the name of the Company, as evidenced by a certificate of the Registrar delivered to the Authority and (ii) the Company, as Owner of all Outstanding Bonds and as authorized by Section 13.05 of the Indenture, delivers its written consent to this Third Supplemental Indenture pursuant to Section 12.03 of the Indenture, such written consent to be delivered to the Authority and the Trustee.

Section 5. **Provisions of Indenture Not Otherwise Modified** . Except as specifically amended by this Third Supplemental Indenture, the Indenture is hereby ratified, approved and confirmed and remains in full force and effect.

IN WITNESS WHEREOF, The Industrial Development Authority of the County of Apache has caused this Third Supplemental Indenture to be executed by its President, and U.S. Bank Trust National Association has caused this Third Supplemental Indenture to be executed on its behalf by one of its Vice Presidents, all as of the day and year first above written.

THE INDUSTRIAL DEVELOPMENT
AUTHORITY OF THE COUNTY OF APACHE

By: /s/ John Lang, President
Title: Authorized Officer

U.S. BANK TRUST NATIONAL
ASSOCIATION, as TRUSTEE

By: /s/ Patrick Crowley
Title: Vice President

Signature Page to Third Supplemental Indenture of Trust

Exhibit 4(i)(14)

Supplemental Indenture No. 13

TUCSON ELECTRIC POWER COMPANY

to

THE BANK OF NEW YORK MELLON,

Trustee

Dated as of November 1, 2011

Supplemental to Indenture of Mortgage and Deed of Trust,
dated as of December 1, 1992

Amending Terms of Bonds Designated
First Mortgage Bonds, Collateral Series I
This instrument constitutes a mortgage, a deed of trust and a security agreement.

SUPPLEMENTAL INDENTURE NO. 13 , dated as of November 1, 2011, between TUCSON ELECTRIC POWER COMPANY (hereinafter sometimes called the "Company"), a corporation organized and existing under the laws of the State of Arizona, having its principal office at One South Church Avenue, in the City of Tucson, Arizona, as trustor, and THE BANK OF NEW YORK MELLON , formerly known as The Bank of New York (successor in trust to Bank of Montreal Trust Company), a banking corporation organized and existing under the laws of the State of New York and having its principal office at 101 Barclay Street, in the Borough of Manhattan, The City of New York, New York, as trustee (hereinafter sometimes called the "Trustee"), under the Indenture of Mortgage and Deed of Trust, dated as of December 1, 1992, between the Company and the Trustee (hereinafter called the "Original Indenture"), as heretofore amended and supplemented, this Supplemental Indenture No. 13 being supplemental thereto (the Original Indenture as heretofore amended and supplemented, and as supplemented hereby, and as it may from time to time be further supplemented, modified, altered or amended by any supplemental indenture entered into in accordance with and pursuant to the provisions thereof, is hereinafter called the "Indenture").

RECITALS OF THE COMPANY

WHEREAS, on November 9, 2010, the Company issued a series of Bonds designated "First Mortgage Bonds, Collateral Series I" limited in aggregate principal amount (except as contemplated in *clause (b)* of *Section 2* of *Article II* of the Original Indenture) to $540,588,000, such series of Bonds and such Bonds to be hereinafter sometimes called, respectively, "Series 10" and "Series 10 Bonds"; and

WHEREAS, all terms of Series 10 Bonds have been established in a Supplemental Indenture No. 11, dated as of November 1, 2010 (the "Supplemental Indenture No. 11"); and

WHEREAS, the Holder of all Series 10 Bonds is Union Bank, N.A., in its capacity as Administrative Agent under the Second Amended and Restated Credit Agreement, dated as of November 9, 2010, among the Company, the Lenders party thereto, the Issuing Banks party thereto, the Co-Syndication Agents party thereto, the Co-Documentation Agents party thereto and the Administrative Agent, as amended, amended and restated, supplemented or otherwise modified from time to time (the "Credit Agreement"); and

WHEREAS, the Company is amending the Credit Agreement to, among other things, extend the term thereof, and desires to amend the Series 10 Bonds to extend their stated maturity; and

WHEREAS, Section 2 of Article XIII of the Indenture provides that with the consent of the Holder of each Outstanding Bond directly affected, the Company and the Trustee may enter into an indenture supplemental to the Indenture for the purpose of adding any provisions to, or changing in any manner or eliminating any of the provisions of the Indenture, including, but not limited to, changing the stated maturity of the principal of any such Bond; and

WHEREAS, the Administrative Agent, as Holder of all Series 10 Bonds, has consented to all changes described in this Supplemental Indenture No. 13; and

WHEREAS, as provided in Article II, Section 6 of the Indenture, upon surrender for exchange of the existing Series 10 Bonds by the Administrative Agent, the Company shall execute, the Trustee shall authenticate, and the Company shall deliver to the Administrative Agent replacement Series 10 Bonds in substitution and exchange for (but not payment of) the surrendered Series 10 Bonds, and the Trustee shall cancel the surrendered Series 10 Bonds and deliver proof of cancellation to the Company; and

WHEREAS, effective June 3, 1999, The Bank of New York succeeded to all of the corporate trust business of Bank of Montreal Trust Company, and, as a consequence, The Bank of New York, being otherwise qualified and eligible under *Article XII* of the Original Indenture, became the successor trustee under the Indenture without further act on the part of the parties thereto, as contemplated by *Section 11* of *Article XII* of the Original Indenture; and

WHEREAS, effective July 1, 2008, The Bank of New York changed its name to The Bank of New York Mellon.

ARTICLE I

ADDITIONAL DEFINITIONS

Section 1. **Applicability of Article**.

For all purposes of this Supplemental Indenture No. 13, except as otherwise expressly provided or unless the context otherwise requires, the terms defined herein shall have the meanings herein specified and include the plural as well as the singular. All terms that are not defined herein but are defined in the Supplemental Indenture No. 11 or in the Indenture shall have the meanings set forth in the Supplemental Indenture No. 11 or in the Indenture, respectively.

ARTICLE II

AMENDMENT OF TERMS OF SERIES 10 BONDS

This Supplemental Indenture No. 13 is being delivered to effect the following changes to the Supplemental Indenture No. 11 and the Series 10 Bonds:

1. clause (d) of Article II of the Supplemental Indenture No. 11 is hereby amended to read as follows:

   "(d) the Series 10 Bonds shall mature on December 9, 2016;"; and

2. the form of Series 10 Bonds is hereby amended to read as set forth in Exhibit A attached hereto.

ARTICLE III

MISCELLANEOUS PROVISIONS

This Supplemental Indenture No. 13 is a supplement to the Original Indenture. As heretofore supplemented and further supplemented by this Supplemental Indenture No. 13, the Original Indenture is in all respects ratified, approved and confirmed, and the Original Indenture as heretofore supplemented and this Supplemental Indenture No. 13 shall together constitute one and the same instrument.

Upon the effectiveness of this Supplemental Indenture No. 13, each reference in the Supplemental Indenture No. 11 to "this Supplemental Indenture No. 11", "hereunder", "hereof", "herein" or words of like import referring to the Supplemental Indenture No. 11 shall mean and be a reference to the Supplemental Indenture No. 11, as amended by this Supplemental Indenture No. 13. Except as specifically amended above, the Supplemental Indenture No. 11 shall continue to be in full force and effect and is hereby in all respects ratified, approved and confirmed.

The Trustee makes no representation as to the validity or sufficiency of this Supplemental Indenture No. 13. The statements and recitals herein are deemed to be those of the Company and not of the Trustee.

IN WITNESS WHEREOF, Tucson Electric Power Company has caused its corporate name to be hereunto affixed, and this instrument to be signed by one of its Vice Presidents, and its corporate seal to be hereunto affixed and attested by its Secretary or one of its Assistant Secretaries for and on its behalf; and The Bank of New York Mellon, as trustee, in evidence of its acceptance of the trust hereby created, has caused its corporate name to be hereunto affixed, and this instrument to be signed by one of its authorized signatories and its corporate seal to be hereunto affixed and attested by one of its authorized signatories, for and on its behalf, all as of the day and year first above written.

TUCSON ELECTRIC POWER COMPANY

By /s/ Kentton C. Grant
Kentton C. Grant
Vice President and Treasurer

Attest:

/s/ Linda H. Kennedy
Linda H. Kennedy
Secretary

[SEAL]

THE BANK OF NEW YORK MELLON,
Trustee

By /s/ Francine Kincaid
Authorized Signatory

Attest:

/s/ Scott Klein
Authorized Signatory

[SEAL]

STATE OF ARIZONA)
) ss.:
COUNTY OF PIMA)

This instrument was acknowledged before me this 17th day of November, 2011 by Kentton C. Grant, as Vice President and Treasurer, and Linda H. Kennedy, as Secretary, of TUCSON ELECTRIC POWER COMPANY, an Arizona corporation, known to me to be the individuals who executed this instrument, and known to me to be a Vice President and Treasurer and the Secretary, respectively, of said corporation, and who personally acknowledged before me and stated that they executed said instrument on behalf of said corporation for the purposes and consideration therein expressed.

/s/ Aniza Ortiz
NOTARY PUBLIC

Aniza Ortiz
Notary Public – Arizona
Pima County
My Commission Expires
May 26, 2014

STATE OF NEW YORK)
) ss.:
COUNTY OF NEW YORK)

This instrument was acknowledged before me this 16th day of November, 2011 by Francine Kincaid, as Authorized Signatory, and Scott Klein, as Authorized Signatory, of THE BANK OF NEW YORK MELLON, a New York banking corporation, known to me to be the individuals who executed this instrument, and known to me to be Authorized Signatories of said corporation, and who personally acknowledged before me and stated that they executed said instrument on behalf of said corporation for the purposes and consideration therein expressed.

/s/ Joann Labarbera
NOTARY PUBLIC

Joann Labarbera
Notary Public, State of New York
No. 01LA5023752
Qualified in New York County
Commission Expires June 8, 2014

Exhibit A

[Form of Bond]
This bond is non-transferable,
except to a successor Administrative Agent under the
Credit Agreement referred to herein.

No. _________ $

TUCSON ELECTRIC POWER COMPANY

FIRST MORTGAGE BOND, COLLATERAL SERIES I

DUE DECEMBER 9, 2016

TUCSON ELECTRIC POWER COMPANY, a corporation of the State of Arizona (hereinafter sometimes called the "Company"), for value received, promises to pay to as Administrative Agent under the Credit Agreement hereinafter referred to or registered assigns, the principal sum of

DOLLARS

on December 9, 2016 in coin or currency of the United States of America which at the time of payment shall be legal tender for the payment of public and private debts, at the office or agency of the Company in The City of New York, or in the City of Tucson, Arizona, upon presentation hereof, and quarterly, on the last Business Day (as defined in Supplemental Indenture No. 11 hereinafter referred to) of March, June, September and December in each year, commencing December 31, 2010 (each an "Interest Payment Date"), and at Maturity (as defined in Supplemental Indenture No. 11 hereinafter referred to), to pay interest thereon in like coin or currency at the rate specified below, from the Interest Payment Date next preceding the date of this bond (unless this bond be dated on an Interest Payment Date, in which case from the date hereof; or unless this bond be dated prior to the first Interest Payment Date, in which case from and including the date of the first authentication and delivery of the bonds of this series), until the Company's obligation with respect to such principal sum shall be discharged.

During the period from and including the date of the first authentication and delivery of the bonds of this series (which date was November 9, 2010) to and including the day next preceding the first Interest Payment Date, the bonds of this series shall bear interest at the rate of eight per centum (8%) per annum; thereafter, the bonds of this series shall bear interest at a rate equal to the Alternate Base Rate (as defined in Supplemental Indenture No. 11 hereinafter referred to) from time to time in effect plus 500 basis points. Interest on the bonds of this series during any period for which payment is made shall be computed in accordance with the Credit Agreement.

This bond is one of an issue of bonds of the Company, issued and to be issued in one or more series under and equally and ratably secured (except as any sinking, amortization, improvement, renewal or other fund, established in accordance with the provisions of the indenture hereinafter mentioned, may afford additional security for the bonds of any particular series) by the Indenture of Mortgage and Deed of Trust, dated as of December 1, 1992 (the "Original Indenture"), from the Company to The Bank of New York Mellon, formerly known as The Bank of New York (successor in trust to Bank of Montreal Trust Company), as trustee (the "Trustee"), as supplemented by thirteen supplemental indentures including Supplemental Indenture No. 11, dated as of November 1, 2010, establishing the bonds of this series, as amended by Supplemental Indenture No. 13, dated as of November 1, 2011 (the Original Indenture, as so supplemented, and such Supplemental Indenture No. 11, as so amended, being hereinafter called the "Indenture" and "Supplemental Indenture No. 11", respectively), to which Indenture reference is hereby made for a description of the property mortgaged and pledged, the nature and extent of the security provided by the Indenture, the rights and limitations of rights of the Company, the Trustee and the holders of said bonds with respect to the security provided by the Indenture, the powers, duties and immunities of the Trustee, the terms and conditions upon which such bonds are and are to be secured, and the circumstances under which additional bonds may be issued. The acceptance of this bond shall be deemed to constitute the consent and agreement by the holder hereof to all of the terms and provisions of the Indenture. This bond is one of a series of bonds designated as the First Mortgage Bonds, Collateral Series I, of the Company.

The Indenture permits, with certain exceptions as therein provided, the Trustee to enter into one or more supplemental indentures for the purpose of adding any provisions to, or changing in any manner or eliminating any of the provisions of, the Indenture with the consent of the holders of not less than sixty per centum (60%) in aggregate principal amount of the bonds of all series then outstanding under the Indenture, considered as one class; provided, however, that if there shall be bonds of more than one series outstanding under the Indenture and if a proposed supplemental indenture shall directly affect the rights of the holders of bonds of one or more, but less than all, of such series, then the consent only of the holders of bonds in aggregate principal amount of the outstanding bonds of all series so directly affected, considered as one class, shall be required; and provided, further, that if the bonds of any series shall have been issued in more than one tranche and if the proposed supplemental indenture shall directly affect the rights of the holder of bonds of one or more, but less than all, of such tranches, then the consent only of the holders of bonds in aggregate principal amount of the outstanding bonds of all tranches so directly affected, considered as one class, shall be required; and provided, further, that the Indenture permits the Trustee to enter into one or more supplemental indentures for limited purposes without the consent of any holders of bonds. Any such consent by the holder of this bond shall be conclusive and binding upon such holder and upon all future holders of this bond and of any bond issued upon the registration of transfer hereof or in exchange therefor or in lieu hereof, whether or not notation of such consent is made upon this bond.

The Company has issued and delivered the bonds of this series to Union Bank, N.A., as Administrative Agent (the "Administrative Agent") under the Second Amended and Restated Credit Agreement, dated as of November 9, 2010, among the Company, the Lenders party thereto, the Issuing Banks party thereto, the Co-Syndication Agents party thereto, the Co-Documentation Agents party thereto and Union Bank, N.A. (formerly known as Union Bank of

California, N.A.), as Administrative Agent, as amended, amended and restated, supplemented or otherwise modified from time to time (the "Credit Agreement"), in order to provide collateral security for the obligation of the Company thereunder to pay the Obligations (as defined in Supplemental Indenture No. 11).

Upon the occurrence of an Event of Default under the Credit Agreement, and further upon such additional conditions as are set forth in subdivision (h) of Article II of Supplemental Indenture No. 11, then all bonds of this series shall be redeemed immediately at the principal amount thereof plus accrued interest to the date of redemption.

The obligation of the Company to pay interest on the bonds of this series on any Interest Payment Date prior to Maturity (a) shall be deemed to have been satisfied and discharged in full in the event that all amounts then due in respect of the Obligations shall have been paid or (b) shall be deemed to remain unsatisfied in an amount equal to the aggregate amount then due in respect of the Obligations and remaining unpaid (not in excess, however, of the amount otherwise then due in respect of interest on the bonds of this series).

The obligation of the Company to pay the principal of and accrued interest on the bonds of this series at or after Maturity (x) shall be deemed to have been satisfied and discharged in full in the event that all amounts then due in respect of the Obligations shall have been paid and no Letter of Credit (as defined in Supplemental Indenture No. 11) shall remain outstanding or (y) shall be deemed to remain unsatisfied in an amount equal to the aggregate amount then due in respect of the Obligations and remaining unpaid plus the aggregate stated amount of the outstanding Letters of Credit (not in excess, however, of the amount otherwise then due in respect of principal of and accrued interest on the bonds of this series).

The principal of this bond and the interest accrued hereon may become or be declared due and payable before the stated maturity hereof, on the conditions, in the manner and at the times set forth in the Indenture, upon the happening of a default as therein provided.

This bond is non-transferable except as required to effect transfer to any successor administrative agent under the Credit Agreement, any such transfer to be made at the office or agency of the Company in The City of New York, upon surrender and cancellation of this bond, and upon any such transfer a new bond of this series, for the same aggregate principal amount and having the same stated maturity date, will be issued to the transferee in exchange herefor. Prior to due presentment for registration of transfer, the Company and the Trustee may deem and treat the person in whose name this bond is registered as the absolute owner hereof for the purpose of receiving payment and for all other purposes. This bond, alone or with other bonds of this series, may in like manner be exchanged at such office or agency for one or more bonds of this series of the same aggregate principal amount and having the same stated maturity date and interest rate, all as provided in the Indenture.

No recourse shall be had for the payment of the principal of or interest on this bond, or for any claim based hereon or otherwise in respect hereof or of the Indenture, against any incorporator, shareholder, director or officer, as such, past, present or future, of the Company or of any predecessor or successor corporation, either directly or through the Company or any predecessor or successor corporation, whether by virtue of any constitution, statute or rule of law, or by the enforcement of any assessment or penalty or by any legal or equitable proceeding or otherwise howsoever (including, without limiting the generality of the foregoing, any proceeding to enforce any claimed liability of shareholders of the Company, based upon any theory of disregarding the corporate entity of the Company or upon any theory that the Company was acting as the agent or instrumentality of the shareholders); all such liability being, by the acceptance hereof and as a part of the consideration for the issuance hereof, expressly waived and released by every holder hereof, and being likewise waived and released by the terms of the Indenture under which this bond is issued, as more fully provided in said Indenture.

This bond shall not be valid or become obligatory for any purpose until the certificate of authentication hereon shall have been signed by The Bank of New York Mellon, or its successor, as Trustee under the Indenture.

IN WITNESS WHEREOF, the Company has caused this bond to be signed in its name by the manual or facsimile signature of its President or one of its Vice Presidents, and its corporate seal, or a facsimile thereof, to be impressed or imprinted hereon and attested by the manual or facsimile signature of its Secretary or one of its Assistant Secretaries.

Dated: , 20

TUCSON ELECTRIC POWER COMPANY

By:____________________________________

Attest:

____

[FORM OF TRUSTEE'S CERTIFICATE OF AUTHENTICATION]

This is one of the bonds, of the series designated therein, described in the within-mentioned Indenture.

Dated: , 20

The Bank of New York Mellon,
Trustee

By:____

Exhibit 4(o)(2)

[Execution Version]

AMENDMENT NO. 1
TO
CREDIT AGREEMENT

This AMENDMENT NO. 1, dated as of November 18, 2011 (this " ***Amendment*** "), is made by and among TUCSON ELECTRIC POWER COMPANY, an Arizona corporation (the " ***Borrower*** "), the lenders listed on the signature pages of this Amendment as "Lenders" (such lenders, together with their respective permitted assignees from time to time, being referred to herein, collectively, as the " ***Lenders*** "), THE BANK OF NEW YORK MELLON, JPMORGAN CHASE BANK, N.A., WELLS FARGO BANK, NATIONAL ASSOCIATION, UNION BANK, N.A. and U.S. BANK NATIONAL ASSOCIATION, as issuing banks (collectively, in such capacities, the " ***Issuing Banks*** "), and UNION BANK, N.A. (formerly known as Union Bank of California, N.A.), as administrative agent (in such capacity, the " ***Administrative Agent*** ").

PRELIMINARY STATEMENT:

The Borrower, the Lenders, the Issuing Banks, JPMorgan Chase Bank, N.A., SunTrust Bank and Wells Fargo Bank, National Association, as Co-Syndication Agents, Bank of America, N.A. and U.S. Bank National Association, as Co-Documentation Agents, and the Administrative Agent previously entered into that certain Second Amended and Restated Credit Agreement, dated as of November 9, 2010 (the " ***Existing Agreement*** ", as amended by this Amendment, the " ***Amended Agreement*** ", and as the Amended Agreement may hereafter be amended, restated, supplemented or otherwise modified from time to time, the " ***Credit Agreement*** "). The Borrower desires to amend the Existing Agreement to (a) extend the Final Maturity Date to November 9, 2016, (b) reduce the Applicable Margin and the Commitment Fee Rate, and (c) make certain other modifications thereto, and the Lenders, the Issuing Banks and the Administrative Agent have agreed to such amendments on the terms and conditions set forth herein. The parties therefore agree as follows (capitalized terms used but not defined herein having the meanings assigned to such terms in the Existing Agreement):

SECTION 1. Amendments to Existing Agreement. The Existing Agreement is, effective as of the date hereof and subject to the satisfaction of the conditions precedent set forth in Section 2 hereof, hereby amended as follows:

(a) ***Bond Delivery Agreement*** . The definition of " Bond Delivery Agreement " contained in Section 1.01 of the Existing Agreement is hereby amended and restated in its entirety to read as follows:

" Bond Delivery Agreement " means the Amended and Restated Bond Delivery Agreement, dated as of the Amendment No. 1 Effective Date, between the Borrower and the Administrative Agent, substantially in the form of Exhibit F, executed and delivered pursuant to the terms of Amendment No. 1 in connection with the issuance of the Collateral Mortgage Bonds.

(b) ***Collateral Mortgage Bonds*** . The definition of " Collateral Mortgage Bonds " contained in Section 1.01 of the Existing Agreement is hereby amended and restated in its entirety to read as follows:

" Collateral Mortgage Bonds " means the First Mortgage Bonds, Collateral Series I, substantially in the form attached to the Thirteenth Supplemental Indenture.

(c) ***Disclosure Documents*** . The definition of " Disclosure Documents " contained in Section 1.01 of the Existing Agreement is hereby amended and restated in its entirety to read as follows:

" Disclosure Documents " means (i) the Annual Report on Form 10-K of the Borrower for the fiscal year ended December 31, 2010, as filed with the SEC, (ii) the Quarterly Reports on Form 10-Q of the Borrower for the fiscal quarters ended March 31, 2011, June 30, 2011 and September 30, 2011, as filed with the SEC, and (iii) the Current Reports on Form 8-K of the Borrower as filed with the SEC on February 25, 2011 and May 11, 2011.

(d) ***Final Maturity Date*** . The definition of " Final Maturity Date " contained in Section 1.01 of the Existing Agreement is hereby amended and restated in its entirety to read as follows:

" Final Maturity Date " means November 9, 2016.

(e) ***Security Documents*** . The definition of " Security Documents " contained in Section 1.01 of the Existing Agreement is hereby amended by deleting the phrase "the Eleventh Supplemental Indenture, the Collateral Mortgage Bonds and the Bond Delivery Agreement" in its entirety and substituting therefor the new phrase "the Eleventh Supplemental Indenture, the Thirteenth Supplemental Indenture, the Collateral Mortgage Bonds and the Bond Delivery Agreement".

(f) ***Transactions*** . The definition of " Transactions " contained in Section 1.01 of the Existing Agreement is hereby amended by deleting the phrase "under the Eleventh Supplemental Indenture" in its entirety and substituting therefor the new phrase "under the Thirteenth Supplemental Indenture".

(g) ***Additional Definitions*** . The following new definitions are hereby added to Section 1.01 of the Existing Agreement in appropriate alphabetical order:

" Amendment No. 1 " means Amendment No. 1, dated as of November 18, 2011, among the Borrower, the Issuing Banks, the Lenders and the Administrative Agent, which Amendment No. 1 amended this Agreement pursuant to the terms thereof.

" Amendment No. 1 Effective Date " means November 18, 2011.

" Thirteenth Supplemental Indenture " means Supplemental Indenture No. 13 under the Mortgage Indenture, substantially in the form of Exhibit G.

(h) ***Letters of Credit*** . Section 2.04(a)(ii) of the Existing Agreement is hereby amended by deleting the last sentence thereof in its entirety and substituting therefor the following new sentence: "On the Amendment No. 1 Effective Date, upon the satisfaction (or waiver in accordance with Section 9.02) of the conditions precedent specified in Section 2 of Amendment No. 1, each of the Existing Revenue Bond Letters of Credit shall be amended by the applicable Issuing Bank to extend the stated expiration date thereof to November 2, 2016 (which date is five (5) Business Days prior to the Final Maturity Date)."

(i) ***Financial Condition*** . Section 3.04(a) of the Existing Agreement is hereby amended by (i) deleting each reference to the date "December 31, 2009" in its entirety and substituting therefor in each case the new date "December 31, 2010" and (ii) deleting the phrase "to and including the Effective Date" in its entirety and substituting therefor the new phrase "to and including the Amendment No. 1 Effective Date".

(j) ***No Material Adverse Change*** . Section 3.04(b) of the Existing Agreement is hereby amended by deleting the phrase "since December 31, 2009" in its entirety and substituting therefor the new phrase "since December 31, 2010".

(k) ***Secured Indebtedness*** . Section 3.04(c) of the Existing Agreement is hereby amended by (i) deleting the phrase "As of the Effective Date" in its entirety and substituting therefor the new phrase "As of the Amendment No. 1 Effective Date" and (ii) deleting the amount "$540,588,000" in its entirety and substituting therefor the new amount "$577,741,000".

(l) ***Security Documents*** . Section 3.12(a) of the Existing Agreement is hereby amended by deleting the phrase "As of the Effective Date" in its entirety and substituting therefor the new phrase "As of the Amendment No. 1 Effective Date".

(m) ***Solvency*** . Section 3.14 of the Existing Agreement is hereby amended by deleting the phrase "On the Effective Date" in its entirety and substituting therefor the new phrase "On the Amendment No. 1 Effective Date".

(n) ***Pricing Schedule*** . Schedule 1.01 of the Existing Agreement is hereby replaced in its entirety with Schedule A attached hereto.

(o) ***Commitment Schedule*** . Schedule 2.01 of the Existing Agreement is hereby replaced in its entirety with Schedule B attached hereto.

(p) ***Additional Exhibits*** . Exhibit A hereto is hereby added as Exhibit F to the Existing Agreement. Exhibit B hereto is hereby added as Exhibit G to the Existing Agreement.

SECTION 2. Conditions of Effectiveness . This Amendment shall become effective as of the date first written above (the " ***Effective Date*** ") when, and only when, (a) the Administrative Agent shall have received all fees (including, without limitation, all upfront fees) payable by the Borrower pursuant to that certain proposal letter agreement, dated October 5, 2011, among Union Bank, the Borrower, UniSource Energy, UNS Gas and UNS Electric (the " ***Proposal Letter*** "), together with, to the extent invoiced, reimbursement or payment of all reasonable fees and out-of-pocket disbursements of counsel to the Administrative Agent and other out-of-pocket expenses of the Administrative Agent required to be reimbursed or paid by the Borrower pursuant to the Proposal Letter, (b) all requisite Governmental Authorities (including, without limitation, the ACC and all other regulatory authorities) and third parties shall have approved or consented to the execution, delivery and performance by the Borrower of this Amendment, the Amended Agreement, the other Loan Documents executed and delivered in connection herewith and the transactions contemplated hereby and thereby (collectively, the " ***Transactions*** ") to the extent required (and the Administrative Agent shall have received copies of all such approvals and consents, which shall be in form and substance satisfactory to the Administrative Agent and the Lenders, certified by an authorized officer of the Borrower as being true, correct and complete copies thereof and as being in full force and effect), no stay of any applicable regulatory approval shall have been issued and there shall be no litigation or governmental, administrative or judicial action, actual or threatened, that could reasonably be expected to restrain, prevent or impose burdensome conditions on this Amendment, the Amended Agreement, any of the other Loan Documents or the Transactions, and (c) the Administrative Agent shall have received: (i) counterparts of this Amendment executed by all of the parties hereto (in sufficient quantity for each party to have a fully executed original), and (ii) all of the following documents, each document being dated the Effective Date unless otherwise specified below, in form and substance satisfactory to the Administrative Agent and in the number of originals or photostatic copies reasonably requested by the Administrative Agent:

(A) a favorable written opinion (addressed to the Administrative Agent, the Issuing Banks and the Lenders) of each of (1) Morgan, Lewis & Bockius LLP, New York counsel for the Borrower, (2) Todd C. Hixon, Esq., General Counsel for the Borrower, and (3) Rodey, Dickason, Sloan, Akin & Robb, PA, special New Mexico counsel for the Borrower, in each case covering such customary matters relating to this Amendment, the Amended Agreement, the other Loan Documents executed and delivered in connection herewith, the Mortgage Indenture, the Lien of the Mortgage Indenture and the Transactions as the Administrative Agent shall reasonably request, and the Borrower hereby requests such counsel to deliver such opinions;

(B) counterparts of the Bond Delivery Agreement (as defined in the Amended Agreement) signed on behalf of the Borrower and any other parties thereto, together with (1) the Collateral Mortgage Bonds (as defined in the Amended Agreement) in an aggregate principal amount not less than $540,588,000 and reflecting a maturity date of December 9, 2016, duly issued and authenticated under the Mortgage Indenture (and (I) the Administrative Agent, the Issuing Banks and the Lenders hereby consent to the amendment and restatement of the existing Collateral Mortgage Bonds to reflect such maturity date and (II) in connection therewith, the Issuing Banks and the Lenders hereby authorize and direct the Administrative Agent to execute and deliver a Bondholder Consent substantially in the form of Exhibit C hereto) (such Collateral Mortgage Bonds being delivered in exchange for the Mortgage Bonds of the same series and amount held by the Administrative Agent which reflect a May 1, 2015 maturity date); (2) a duly executed copy of the Thirteenth Supplemental Indenture (as defined in the Amended Agreement) and all other documents, instruments and filings relating to the issuance and authentication of the Collateral Mortgage Bonds (as defined in the Amended Agreement) under the Mortgage Indenture; (3) copies of any amendments or supplements, entered into at any time after November 9, 2010, to the Mortgage Indenture, the Revenue Bond Indentures, the Revenue Bond Loan Agreements and all related agreements with respect to the Revenue Bonds, certified by an authorized officer of the Borrower as being a true, correct and complete copy thereof and as being in full force and effect; (4) all documents, instruments and filings creating or perfecting the Lien of the Mortgage Indenture; and (5) all other documents and instruments required by law or reasonably requested by the Administrative Agent to be filed, registered or recorded to create or perfect the Liens intended to be created under the Security Documents;

(C) such documents and certificates as the Administrative Agent or its counsel may reasonably request relating to the organization, existence and good standing of the Borrower, the authorization of the Transactions and any other legal matters relating to the Borrower, this Amendment, the Amended Agreement, the other Loan Documents executed and delivered in connection herewith, the Mortgage Indenture, the Lien of the Mortgage Indenture or the Transactions, all in form and substance satisfactory to the Administrative Agent and its counsel;

(D) a certificate (the statements in which shall be true), signed by an Authorized Officer, certifying that:

(1) the representations and warranties of the Borrower set forth in this Amendment, the Amended Agreement and the other Loan Documents are true and correct on and as of the Effective Date with the same effect as though made on and as of such date, except to the extent such representations and warranties expressly relate to an earlier date (in which case such representations and warranties were true and correct as of such earlier date);

(2) both before and after giving effect to this Amendment, no Default has occurred and is continuing;

(3) the Borrower and its Subsidiaries do not have any indebtedness or preferred stock outstanding other than (x) the Obligations, (y) the Indebtedness described in the most recent financial statements of the Borrower and its Consolidated Subsidiaries referenced in Section 3.04(a) of the Amended Agreement and (z) $250 million of 5.15% Notes due November 15, 2021, issued by the Borrower on November 8, 2011; and

(4) the Capital Stock of the Borrower (to the extent owned by UniSource Energy, which owns all Capital Stock of the Borrower) is free and clear of any Liens.

SECTION 3. Representations and Warranties of the Borrower . The Borrower represents and warrants to the Administrative Agent, the Lenders and the Issuing Banks that: .

(a) ***Authorization; Enforceability*** . The Transactions are within the Borrower's organizational powers and have been duly authorized by all necessary corporate and, if required, stockholder action. This Amendment has been duly executed and delivered by the Borrower, and each of this Amendment and the Amended Agreement constitutes, and each other Loan Document to which the Borrower is a party required to be executed and delivered pursuant to the terms of this Amendment, when executed and delivered by the Borrower (and, in the case of the Collateral Mortgage Bonds (as defined in the Amended Agreement), authenticated by the trustee therefor), will constitute, a legal, valid and binding obligation of the Borrower, enforceable against the Borrower in accordance with its terms, subject to applicable bankruptcy, insolvency, reorganization, moratorium or other laws affecting creditors' rights generally and subject to general principles of equity, regardless of whether considered in a proceeding in equity or at law.

(b) ***Governmental Approvals; No Conflicts*** . The Transactions (i) do not require any consent or approval of, registration or filing with, or any other action by, any Governmental Authority, except for (A) such approvals of the ACC that have been obtained and are in full force and effect and (B) filings necessary to perfect Liens created under the Loan Documents (all of which filings have been made), (ii) will not violate any Requirement of Law, (iii) will not violate or result in a default under any indenture, agreement or other instrument binding upon the Borrower or any of its Consolidated Subsidiaries or its assets, or give rise to a right thereunder to require any payment to be made by the Borrower or any of its Consolidated Subsidiaries, and (iv) will not result in the creation or imposition of any Lien on any asset of the Borrower or any of its Consolidated Subsidiaries, except Liens created under the Loan Documents or under the Mortgage Indenture.

(c) ***Litigation*** . There are no actions, suits or proceedings by or before any arbitrator or Governmental Authority pending against or, to the knowledge of the Borrower, threatened against or affecting the Borrower or any of its Consolidated Subsidiaries that in any manner draws into question the validity or enforceability of this Amendment or the Amended Agreement or that otherwise involve this Amendment, the Amended Agreement, any of the other Loan Documents, the Mortgage Indenture or the Transactions.

(d) ***No Default*** . No Default has occurred and is continuing or would occur as a result of the execution, delivery or performance of this Amendment.

SECTION 4. Reference to and Effect on the Existing Agreement. (a) Upon the effectiveness of this Amendment: (i) each reference in the Existing Agreement to "this Agreement", "hereunder", "hereof" or words of like import referring to the Existing Agreement shall mean and be a reference to the Amended Agreement; and (ii) each reference in any other Loan Document to "the Credit Agreement", "thereunder", "thereof" or words of like import referring to the Existing Agreement shall mean and be a reference to the Amended Agreement. This Amendment shall constitute a "Loan Document" for all purposes under the Credit Agreement.

(b) Except as specifically amended above, the Existing Agreement shall continue to be in full force and effect and is hereby in all respects ratified and confirmed. Without limiting the generality of the foregoing, the Security Documents and all of the Collateral described therein do and shall continue to secure the payment of all Obligations.

(c) The execution, delivery and effectiveness of this Amendment shall not, except as expressly provided herein, operate as a waiver of any right, power or remedy of the Lenders, the Administrative Agent or the Issuing Banks under the Existing Agreement or any other Loan Document, nor constitute a waiver of any provision of the Existing Agreement or any other Loan Document.

SECTION 5. Costs and Expenses . The Borrower agrees to pay, promptly after delivery to the Borrower of a reasonably detailed statement therefor, all reasonable out-of-pocket expenses incurred by the Administrative Agent in connection with the preparation, negotiation, syndication, execution and delivery of this Amendment and the other instruments and documents to be delivered hereunder, including, without limitation, the reasonable fees, charges and disbursements of counsel to the Administrative Agent with respect thereto and with respect to advising the Administrative Agent as to its rights and responsibilities hereunder and thereunder, and all out-of-pocket expenses incurred by the Administrative Agent, any Issuing Bank or any Lender (including, without limitation, the fees, charges and disbursements of any counsel for the Administrative Agent, any Issuing Bank or any Lender) in connection with the enforcement (whether through negotiations, legal proceedings or otherwise) of this Amendment.

SECTION 6. Execution in Counterparts . This Amendment may be executed in counterparts (and by different parties hereto on different counterparts), each of which shall constitute an original but all of which when taken together shall constitute a single contract. Delivery of an executed signature page to this Amendment by facsimile or other electronic transmission (including, without limitation, by Adobe portable document format file (also known as a "PDF" file)) shall be as effective as delivery of a manually signed counterpart of this Amendment.

SECTION 7. Governing Law . This Amendment shall be governed by, and construed in accordance with, the laws of the State of the New York.

SECTION 8. Miscellaneous. This Amendment shall be subject to the provisions of Sections 9.05, 9.07, 9.10, 9.11 and 9.12 of the Existing Agreement, each of which is incorporated by reference herein, *mutatis mutandis* .

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IN WITNESS WHEREOF, the parties hereto have caused this Amendment to be executed by their respective officers thereunto duly authorized, as of the date first above written.

TUCSON ELECTRIC POWER COMPANY

By: /s/ Kentton C. Grant
Name: Kentton C. Grant
Title: Vice President and Treasurer

UNION BANK, N.A ., as Administrative Agent, as an Issuing Bank and as a Lender

By: /s/ Jeffrey P. Fesenmaier
Name: Jeffrey P. Fesenmaier
Title: Vice President

THE BANK OF NEW YORK MELLON, as
an Issuing Bank and as a Lender

By: /s/ Mark W. Rogers
Name: Mark W. Rogers
Title: Vice President

JPMORGAN CHASE BANK, N.A. , as an Issuing Bank and as a Lender

By: /s/ Nancy R. Barwig
Name: Nancy R. Barwig
Title: Credit Executive

WELLS FARGO BANK, NATIONAL ASSOCIATION , as an Issuing Bank and as a Lender

By: /s/ Yann Blindert
Name: Yann Blindert
Title: Director

U.S. BANK NATIONAL ASSOCIATION , as
an Issuing Bank and as a Lender

By: /s/ Raymond J. Palmer
Name: Raymond J. Palmer
Title: Senior Vice President

SUNTRUST BANK , as a Lender

By: /s/ Andrew Johnson
Name: Andrew Johnson
Title: Director

BANK OF AMERICA, N.A. , as a Lender

By: /s/ Kevin P. Bertelsen
Name: Kevin P. Bertelsen
Title: Managing Director

COBANK, ACB, as a Lender

By: /s/ John H. Kemper
Name: John H. Kemper
Title: Vice President

COMERICA BANK , as a Lender

By: /s/ Fatima Arshad
Name: Fatima Arshad
Title: Vice President

COMPASS BANK , an Alabama Banking

Corporation, as a Lender

By: /s/ Izaro Urreiztieta
Name: Izaro Urreiztieta
Title: Senior Vice President

SCOTIABANC INC. , as a Lender

By: /s/ J.F. Todd
Name: J.F. Todd
Title: Managing Director

Amendment No. 1 to TEP Second Amended and Restated Credit Agreement

THE BANK OF NOVA SCOTIA , as a Lender

By: /s/ Thane Rettew
Name: Thane Rattew
Title: Managing Director

Amendment No. 1 to TEP Second Amended and Restated Credit Agreement

Bank Hapoalim B.M., as a Lender

By: /s/ Helen H. Gateson
Name: Helen H. Gateson
Title: Vice President

By: /s/ Frederic S. Becker
Name: Frederic S. Becker
Title: Senior Vice President

CREDIT SUISSE AG, CAYMAN ISLANDS BRANCH, as a Lender

By: /s/ Shaheen Malik
Name: Shaheen Malik
Title: Vice President

By: /s/ Rahul Parmar
Name: Rahul Parmar
Title: Associate

NATIONAL BANK OF ARIZONA , as a Lender

By: /s/ Reid Clark
Name: Reid Clark
Title: Vice President

SCHEDULE A
to Amendment No. 1 to Credit Agreement

SCHEDULE 1.01

PRICING SCHEDULE

The "Applicable Margin" and the "Commitment Fee Rate" for any day (a) from and after the Effective Date through (but not including) the Amendment No. 1 Effective Date, are the respective annual percentage rates set forth in Table A below in the applicable row under the column corresponding to the Status that exists on such day, and (b) from and after the Amendment No. 1 Effective Date, are the respective annual percentages rates set forth in Table B below in the applicable row under the column corresponding to the Status that exists on such day:

TABLE A

	Level 1 ≥ A-/A3	Level 2 BBB+/Baa1	Level 3 BBB/Baa2	Level 4 BBB-/Baa3	Level 5 BB+/Ba1	Level 6 ≤ BB/Ba2
Applicable Margin — Eurodollar Loans	1.625%	1.875%	2.125%	2.50%	3.00%	3.50%
Applicable Margin — ABR Loans	0.625%	0.875%	1.125%	1.50%	2.00%	2.50%
Commitment Fee Rate	0.175%	0.225%	0.350%	0.450%	0.600%	0.750%

TABLE B

	Level 1 ≥ A-/A3	Level 2 BBB+/Baa1	Level 3 BBB/Baa2	Level 4 BBB-/Baa3	Level 5 BB+/Ba1	Level 6 ≤ BB/Ba2
Applicable Margin — Eurodollar Loans	1.00%	1.125%	1.25%	1.50%	1.75%	2.00%
Applicable Margin — ABR Loans	0.00%	0.125%	0.25%	0.50%	0.75%	1.00%
Commitment Fee Rate	0.125%	0.175%	0.20%	0.25%	0.30%	0.35%

For purposes of this Pricing Schedule, the following terms have the following meanings:

" ***Level 1 Status*** " exists at any date if, at such date, the Index Debt is rated either A- or higher by S&P *or* A3 or higher by Moody's.

" ***Level 2 Status*** " exists at any date if, at such date (i) the Index Debt is rated either BBB+ or higher by S&P *or* Baa1 or higher by Moody's and (ii) Level 1 Status does not exist.

" ***Level 3 Status*** " exists at any date if, at such date (i) the Index Debt is rated either BBB or higher by S&P *or* Baa2 or higher by Moody's and (ii) neither Level 1 Status nor Level 2 Status exists.

" ***Level 4 Status*** " exists at any date if, at such date (i) the Index Debt is rated either BBB- or higher by S&P *or* Baa3 or higher by Moody's and (ii) none of Level 1 Status, Level 2 Status or Level 3 Status exists.

" ***Level 5 Status*** " exists at any date if, at such date (i) the Index Debt is rated either BB+ or higher by S&P *or* Ba1 or higher by Moody's and (ii) none of Level 1 Status, Level 2 Status, Level 3 Status or Level 4 Status exists.

" ***Level 6 Status*** " exists at any date if, at such date, no other Status exists.

" ***Status*** " refers to the determination of which of Level 1 Status, Level 2 Status, Level 3 Status, Level 4 Status, Level 5 Status or Level 6 Status exists at any date.

Notwithstanding the foregoing, if the Index Debt is split-rated and the ratings differential is two or more ratings levels, the Status shall be determined assuming that (a) the higher rating is equal to the midpoint of the two ratings (e.g., for a split rating of BBB+/Baa3, BBB is the midpoint and will be deemed to be the higher rating, and for a split rating of BB/Baa1, Baa3 is the midpoint and will be deemed to be the higher rating) or (b) if there is no exact midpoint, the higher rating is equal to the higher of the two middle intermediate ratings (e.g., for a split rating of BBB+/Ba1, BBB is the higher of the two middle intermediate ratings and will be deemed to be the higher rating, and for a split rating of BB/Baa2, Baa3 is the higher of the two middle intermediate ratings and will be deemed to be the higher rating).

If at any time the Index Debt is unrated by both Moody's and S&P, Level 6 Status shall exist; *provided* that if the reason that there is no such Moody's rating or S&P rating results from Moody's or S&P, as the case may be, ceasing to issue debt ratings generally, then the Borrower and the Administrative Agent may select another nationally-recognized rating agency to substitute for Moody's or S&P, as applicable, for purposes of this Pricing Schedule (and all references herein to Moody's or S&P, as applicable, shall refer to such substitute rating agency), and until a substitute nationally-recognized rating agency is so selected the Status shall be determined by reference to the rating most recently in effect prior to such cessation; and *provided* , *further* , that if the Index Debt is rated by only one of Moody's or S&P, the Status shall be determined by reference to the rating of such Rating Agency.

The Applicable Margin and Commitment Fee Rate shall be increased or decreased in accordance with the foregoing Pricing Schedule upon any change in the applicable ratings of the Index Debt. The ratings of the Index Debt in effect at any date is that in effect at the close of business on such date.

[SCHEDULE B
to Amendment No. 1 to Credit Agreement]

SCHEDULE 2.01

Commitments

Lender	Revolving Commitment	Revenue Bond Commitment	Aggregate Commitment
Union Bank, N.A.	$ 20,750,422.15	$ 35,336,625.04	$ 56,087,047.19
JPMorgan Chase Bank, N.A.	$ 18,498,408.45	$ 31,501,591.55	$ 50,000,000.00
SunTrust Bank	$ 18,498,408.45	$ 31,501,591.55	$ 50,000,000.00
Wells Fargo Bank, National Association	$ 18,498,408.45	$ 31,501,591.55	$ 50,000,000.00
Bank of America, N.A.	$ 16,648,567.60	$ 28,351,432.40	$ 45,000,000.00
U.S. Bank National Association	$ 16,648,567.60	$ 28,351,432.40	$ 45,000,000.00
CoBank, ACB	$ 14,798,726.76	$ 25,201,273.24	$ 40,000,000.00
Compass Bank, an Alabama Banking Corporation	$ 14,798,726.76	$ 25,201,273.24	$ 40,000,000.00
National Bank of Arizona	$ 11,099,045.07	$ 18,900,954.93	$ 30,000,000.00
Bank Hapoalim B.M.	$ 9,249,204.22	$ 15,750,795.78	$ 25,000,000.00
Comerica Bank	$ 9,249,204.22	$ 15,750,795.78	$ 25,000,000.00
Scotiabanc Inc.	$ 9,249,204.22	$ 15,750,795.78	$ 25,000,000.00
The Bank of Nova Scotia	$ 9,249,204.22	$ 15,750,795.78	$ 25,000,000.00
The Bank of New York Mellon	$ 9,249,204.22	$ 15,750,795.78	$ 25,000,000.00
Credit Suisse AG, Cayman Islands Branch	$ 3,514,697.60	$ 5,985,302.40	$ 9,500,000.00
Total Commitments	$ 200,000,000.00	$ 340,587,047.19	$ 540,587,047.19

EXHIBIT A
to Amendment No. 1 to Credit Agreement

FORM OF BOND DELIVERY AGREEMENT

[See Attached]

Amended and Restated Bond Delivery Agreement

TUCSON ELECTRIC POWER COMPANY
to
UNION BANK, N.A.,
as Administrative Agent

Dated as of November , 2011

Relating to
First Mortgage Bonds, Collateral Series I

THIS AMENDED AND RESTATED BOND DELIVERY AGREEMENT, dated as of November , 2011, is between TUCSON ELECTRIC POWER COMPANY, an Arizona corporation (the "Company"), and UNION BANK, N.A. (formerly known as Union Bank of California, N.A.), as administrative agent (in such capacity, together with its successors and assigns in such capacity, the "Administrative Agent") under the Second Amended and Restated Credit Agreement, dated as of November 9, 2010, among the Company, the Lenders party thereto, the Issuing Banks party thereto, JPMorgan Chase Bank, N.A., SunTrust Bank and Wells Fargo Bank, National Association, as Co-Syndication Agents, Bank of America, N.A. and U.S. Bank National Association, as Co-Documentation Agents, and Union Bank, N.A. (formerly known as Union Bank of California, N.A.), as Administrative Agent, as amended, amended and restated, supplemented or otherwise modified from time to time (the "Credit Agreement").

WHEREAS, the Company has entered into the Credit Agreement and has requested the issuance of the Revenue Bond Letters of Credit and may from time to time borrow Loans and request the issuance of additional Letters of Credit (such terms and all other capitalized terms used herein without definition having the meanings assigned to them in the Credit Agreement) in accordance with the provisions of the Credit Agreement; and

WHEREAS, the Company has established its First Mortgage Bonds, Collateral Series I, in the aggregate principal amount of up to $540,588,000.00 (the "Series 10 Bonds"), issued under and in accordance with, and secured by, the Indenture of Mortgage and Deed of Trust, dated as of December 1, 1992, between the Company and The Bank of New York Mellon, formerly known as The Bank of New York (successor in trust to Bank of Montreal Trust Company), as trustee (the "Trustee"), as amended and supplemented and as further supplemented by Supplemental Indenture No. 11, dated as of November 1, 2010, as amended by Supplemental Indenture No. 13, dated as of November 1, 2011 (such Indenture, as so amended and supplemented, and such Supplemental Indenture, as so amended, being hereinafter sometimes called the "General First Mortgage" and "Supplemental Indenture No. 11", respectively); and

WHEREAS, the Company has issued and delivered to the Administrative Agent, for its benefit and the benefit of the Lenders and the Issuing Banks, the Series 10 Bonds in order to provide collateral security for the obligation of the Company under the Credit Agreement to pay the Obligations; and

WHEREAS, on the date hereof, the Company is amending the Credit Agreement to, among other things, extend the term thereof; and

WHEREAS, with the consent of the Administrative Agent, the Issuing Banks and the Lenders, the Company and the Trustee are entering into the Supplemental Indenture No. 13, dated as of November 1, 2011, to amend the Series 10 Bonds to extend their stated maturity; and

WHEREAS, the Company and the Administrative Agent previously entered into that certain Bond Delivery Agreement, dated as of November 9, 2010 (the "Existing Bond Delivery Agreement"), and the parties hereto desire to amend and restate the Existing Bond Delivery Agreement on the terms and conditions set forth herein.

NOW, THEREFORE, in consideration of the premises, of the agreements of the Lenders and Issuing Banks in the Credit Agreement, and of other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Company and the Administrative Agent hereby agree that the Existing Bond Delivery Agreement is amended and restated in its entirety, without novation, as follows:

ARTICLE I

SERIES 10 BONDS

SECTION 1.1. Delivery of Series 10 Bonds.

In order to provide collateral security for the obligation of the Company to pay the Obligations, as aforesaid, the Company hereby delivers to the Administrative Agent Series 10 Bonds in the aggregate principal amount of $540,588,000.00, maturing on December 9, 2016 and bearing interest as provided in Supplemental Indenture No. 11, in substitution and exchange for (but not payment of) the Series 10 Bonds previously issued and held by the Administrative Agent. The obligation of the Company to pay the principal of and interest on the Series 10 Bonds shall be deemed to have been satisfied and discharged in full or in part, as the case may be, to the extent of the payment by the Company of the Obligations, all as set forth in subdivision (u) of Article II of Supplemental Indenture No. 11 and in the Series 10 Bonds.

The Series 10 Bonds are registered in the name of the Administrative Agent and shall be owned and held by the Administrative Agent, subject to the provisions of this Agreement, for its benefit and the benefit of the Lenders and the Issuing Banks, and the Company shall have no interest therein. The Administrative Agent shall be entitled to exercise all rights of bondholders under the General First Mortgage with respect to the Series 10 Bonds.

The Administrative Agent hereby acknowledges receipt of the Series 10 Bonds.

SECTION 1.2. Payments on Series 10 Bonds.

Any payments received by the Administrative Agent on account of the principal of or interest on the Series 10 Bonds shall be distributed by the Administrative Agent in accordance with the applicable provisions of the Credit Agreement, and the Company hereby consents to such distribution.

ARTICLE II

NO TRANSFER OF BONDS; SURRENDER OF BONDS

SECTION 2.1. No Transfer of Bonds.

The Administrative Agent shall not sell, assign or otherwise transfer any Series 10 Bonds delivered to it under this Agreement except to a successor administrative agent under the Credit Agreement. The Company may take such actions as it shall deem necessary, desirable or appropriate to effect compliance with such restrictions on transfer, including the issuance of stop-transfer instructions to the trustee under the General First Mortgage or any other transfer agent thereunder.

SECTION 2.2. Surrender of Bonds.

(a) The Administrative Agent shall forthwith surrender to or upon the order of the Company all Series 10 Bonds held by it at the first time at which the Aggregate Commitments shall have been terminated, no Letter of Credit shall be outstanding and all Obligations shall have been paid in full.

(b) Upon any permanent reduction in the Revolving Commitments or the Revenue Bond Commitments pursuant to Section 2.07(b) of the Credit Agreement, the Administrative Agent shall forthwith surrender to or upon the order of the Company Series 10 Bonds in an aggregate principal amount equal to the excess of the aggregate principal amount of the Series 10 Bonds held by the Administrative Agent over the sum of (i) the greater at such time of the total Revolving Commitments and the total Revolving Credit Exposure plus (ii) the greater at such time of the total Revenue Bond Commitments and the total Revenue Bond Credit Exposure, provided that the Administrative Agent shall have received, in accordance with Section 6 of Article II of the General First Mortgage, replacement Series 10 Bonds in an aggregate principal amount equal to the sum of clauses (i) and (ii) above.

This Agreement shall be governed by and construed in accordance with the law of the State of New York.

[R EMAINDER OF P AGE I NTENTIONALLY L EFT B LANK]

IN WITNESS WHEREOF, the Company and the Administrative Agent have caused this Agreement to be executed and delivered as of the date first above written.

TUCSON ELECTRIC POWER COMPANY

By_______________________________
Name: Kentton C. Grant
Title: Vice President

UNION BANK, N.A.,
as Administrative Agent

By_______________________________
Vice President

Signature Page to Amended and Restated Bond Delivery Agreement

EXHIBIT B
to Amendment No. 1 to Credit Agreement

FORM OF THIRTEENTH SUPPLEMENTAL INDENTURE

[See Attached]

Supplemental Indenture No. 13

TUCSON ELECTRIC POWER COMPANY

to

THE BANK OF NEW YORK MELLON,

Trustee

Dated as of November 1, 2011

Supplemental to Indenture of Mortgage and Deed of Trust,
dated as of December 1, 1992

Amending Terms of Bonds Designated
First Mortgage Bonds, Collateral Series I

This instrument constitutes a mortgage, a deed of trust and a security agreement.

SUPPLEMENTAL INDENTURE NO. 13 , dated as of November 1, 2011, between TUCSON ELECTRIC POWER COMPANY (hereinafter sometimes called the "Company"), a corporation organized and existing under the laws of the State of Arizona, having its principal office at One South Church Avenue, in the City of Tucson, Arizona, as trustor, and THE BANK OF NEW YORK MELLON , formerly known as The Bank of New York (successor in trust to Bank of Montreal Trust Company), a banking corporation organized and existing under the laws of the State of New York and having its principal office at 101 Barclay Street, in the Borough of Manhattan, The City of New York, New York, as trustee (hereinafter sometimes called the "Trustee"), under the Indenture of Mortgage and Deed of Trust, dated as of December 1, 1992, between the Company and the Trustee (hereinafter called the "Original Indenture"), as heretofore amended and supplemented, this Supplemental Indenture No. 13 being supplemental thereto (the Original Indenture as heretofore amended and supplemented, and as supplemented hereby, and as it may from time to time be further supplemented, modified, altered or amended by any supplemental indenture entered into in accordance with and pursuant to the provisions thereof, is hereinafter called the "Indenture").

RECITALS OF THE COMPANY

WHEREAS , on November 9, 2010, the Company issued a series of Bonds designated "First Mortgage Bonds, Collateral Series I" limited in aggregate principal amount (except as contemplated in *clause (b)* of *Section 2* of *Article II* of the Original Indenture) to $540,588,000, such series of Bonds and such Bonds to be hereinafter sometimes called, respectively, "Series 10" and "Series 10 Bonds"; and

WHEREAS , all terms of Series 10 Bonds have been established in a Supplemental Indenture No. 11, dated as of November 1, 2010 (the "Supplemental Indenture No. 11"); and

WHEREAS , the Holder of all Series 10 Bonds is Union Bank, N.A., in its capacity as Administrative Agent under the Second Amended and Restated Credit Agreement, dated as of November 9, 2010, among the Company, the Lenders party thereto, the Issuing Banks party thereto, the Co-Syndication Agents party thereto, the Co-Documentation Agents party thereto and the Administrative Agent, as amended, amended and restated, supplemented or otherwise modified from time to time (the "Credit Agreement"); and

WHEREAS , the Company is amending the Credit Agreement to, among other things, extend the term thereof, and desires to amend the Series 10 Bonds to extend their stated maturity; and

WHEREAS , Section 2 of Article XIII of the Indenture provides that with the consent of the Holder of each Outstanding Bond directly affected, the Company and the Trustee may enter into an indenture supplemental to the Indenture for the purpose of adding any provisions to, or changing in any manner or eliminating any of the provisions of the Indenture, including, but not limited to, changing the stated maturity of the principal of any such Bond; and

WHEREAS , the Administrative Agent, as Holder of all Series 10 Bonds, has consented to all changes described in this Supplemental Indenture No. 13; and

WHEREAS, as provided in Article II, Section 6 of the Indenture, upon surrender for exchange of the existing Series 10 Bonds by the Administrative Agent, the Company shall execute, the Trustee shall authenticate, and the Company shall deliver to the Administrative Agent replacement Series 10 Bonds in substitution and exchange for (but not payment of) the surrendered Series 10 Bonds, and the Trustee shall cancel the surrendered Series 10 Bonds and deliver proof of cancellation to the Company; and

WHEREAS, effective June 3, 1999, The Bank of New York succeeded to all of the corporate trust business of Bank of Montreal Trust Company, and, as a consequence, The Bank of New York, being otherwise qualified and eligible under *Article XII* of the Original Indenture, became the successor trustee under the Indenture without further act on the part of the parties thereto, as contemplated by *Section 11* of *Article XII* of the Original Indenture; and

WHEREAS, effective July 1, 2008, The Bank of New York changed its name to The Bank of New York Mellon.

ARTICLE I

ADDITIONAL DEFINITIONS

SECTION 1. **APPLICABILITY OF ARTICLE.**

For all purposes of this Supplemental Indenture No. 13, except as otherwise expressly provided or unless the context otherwise requires, the terms defined herein shall have the meanings herein specified and include the plural as well as the singular. All terms that are not defined herein but are defined in the Supplemental Indenture No. 11 or in the Indenture shall have the meanings set forth in the Supplemental Indenture No. 11 or in the Indenture, respectively.

ARTICLE II

AMENDMENT OF TERMS OF SERIES 10 BONDS

This Supplemental Indenture No. 13 is being delivered to effect the following changes to the Supplemental Indenture No. 11 and the Series 10 Bonds:

1. clause (d) of Article II of the Supplemental Indenture No. 11 is hereby amended to read as follows:

   "(d) the Series 10 Bonds shall mature on December 9, 2016;"; and

2. the form of Series 10 Bonds is hereby amended to read as set forth in Exhibit A attached hereto.

ARTICLE III

MISCELLANEOUS PROVISIONS

This Supplemental Indenture No. 13 is a supplement to the Original Indenture. As heretofore supplemented and further supplemented by this Supplemental Indenture No. 13, the Original Indenture is in all respects ratified, approved and confirmed, and the Original Indenture as heretofore supplemented and this Supplemental Indenture No. 13 shall together constitute one and the same instrument.

Upon the effectiveness of this Supplemental Indenture No. 13, each reference in the Supplemental Indenture No. 11 to "this Supplemental Indenture No. 11", "hereunder", "hereof", "herein" or words of like import referring to the Supplemental Indenture No. 11 shall mean and be a reference to the Supplemental Indenture No. 11, as amended by this Supplemental Indenture No. 13. Except as specifically amended above, the Supplemental Indenture No. 11 shall continue to be in full force and effect and is hereby in all respects ratified, approved and confirmed.

The Trustee makes no representation as to the validity or sufficiency of this Supplemental Indenture No. 13. The statements and recitals herein are deemed to be those of the Company and not of the Trustee.

IN WITNESS WHEREOF, Tucson Electric Power Company has caused its corporate name to be hereunto affixed, and this instrument to be signed by one of its Vice Presidents, and its corporate seal to be hereunto affixed and attested by its Secretary or one of its Assistant Secretaries for and on its behalf; and The Bank of New York Mellon, as trustee, in evidence of its acceptance of the trust hereby created, has caused its corporate name to be hereunto affixed, and this instrument to be signed by one of its authorized signatories and its corporate seal to be hereunto affixed and attested by one of its authorized signatories, for and on its behalf, all as of the day and year first above written.

TUCSON ELECTRIC POWER COMPANY

By______________________________
Kentton C. Grant
Vice President and Treasurer

Attest:

____
Linda H. Kennedy
Secretary

THE BANK OF NEW YORK MELLON,
Trustee

By______________________________
Authorized Signatory

Attest:

____
Authorized Signatory

STATE OF ARIZONA	)	
	)	ss.:
COUNTY OF PIMA	)	

This instrument was acknowledged before me this 17th day of November, 2011 by Kentton C. Grant, as Vice President and Treasurer, and Linda H. Kennedy, as Secretary, of TUCSON ELECTRIC POWER COMPANY, an Arizona corporation, known to me to be the individuals who executed this instrument, and known to me to be a Vice President and Treasurer and the Secretary, respectively, of said corporation, and who personally acknowledged before me and stated that they executed said instrument on behalf of said corporation for the purposes and consideration therein expressed.

____
NOTARY PUBLIC

STATE OF NEW YORK)
) ss.:
COUNTY OF NEW YORK)

This instrument was acknowledged before me this 16th day of November, 2011 by Francine Kincaid, as Authorized Signatory, and Scott Klein, as Authorized Signatory, of THE BANK OF NEW YORK MELLON, a New York banking corporation, known to me to be the individuals who executed this instrument, and known to me to be Authorized Signatories of said corporation, and who personally acknowledged before me and stated that they executed said instrument on behalf of said corporation for the purposes and consideration therein expressed.

NOTARY PUBLIC

Exhibit A

[Form of Bond]
This bond is non-transferable,
except to a successor Administrative Agent under the
Credit Agreement referred to herein.

No. $

TUCSON ELECTRIC POWER COMPANY

FIRST MORTGAGE BOND, COLLATERAL SERIES I

DUE DECEMBER 9, 2016

TUCSON ELECTRIC POWER COMPANY, a corporation of the State of Arizona (hereinafter sometimes called the "Company"), for value received, promises to pay to as Administrative Agent under the Credit Agreement hereinafter referred to or registered assigns, the principal sum of

DOLLARS

on December 9, 2016 in coin or currency of the United States of America which at the time of payment shall be legal tender for the payment of public and private debts, at the office or agency of the Company in The City of New York, or in the City of Tucson, Arizona, upon presentation hereof, and quarterly, on the last Business Day (as defined in Supplemental Indenture No. 11 hereinafter referred to) of March, June, September and December in each year, commencing December 31, 2010 (each an "Interest Payment Date"), and at Maturity (as defined in Supplemental Indenture No. 11 hereinafter referred to), to pay interest thereon in like coin or currency at the rate specified below, from the Interest Payment Date next preceding the date of this bond (unless this bond be dated on an Interest Payment Date, in which case from the date hereof; or unless this bond be dated prior to the first Interest Payment Date, in which case from and including the date of the first authentication and delivery of the bonds of this series), until the Company's obligation with respect to such principal sum shall be discharged.

During the period from and including the date of the first authentication and delivery of the bonds of this series (which date was November 9, 2010) to and including the day next preceding the first Interest Payment Date, the bonds of this series shall bear interest at the rate of eight per centum (8%) per annum; thereafter, the bonds of this series shall bear interest at a rate equal to the Alternate Base Rate (as defined in Supplemental Indenture No. 11 hereinafter referred to) from time to time in effect plus 500 basis points. Interest on the bonds of this series during any period for which payment is made shall be computed in accordance with the Credit Agreement.

This bond is one of an issue of bonds of the Company, issued and to be issued in one or more series under and equally and ratably secured (except as any sinking, amortization, improvement, renewal or other fund, established in accordance with the provisions of the indenture hereinafter mentioned, may afford additional security for the bonds of any particular series) by the Indenture of Mortgage and Deed of Trust, dated as of December 1, 1992 (the "Original Indenture"), from the Company to The Bank of New York Mellon, formerly known as The Bank of New York (successor in trust to Bank of Montreal Trust Company), as trustee (the "Trustee"), as supplemented by thirteen supplemental indentures including Supplemental Indenture No. 11, dated as of November 1, 2010, establishing the bonds of this series, as amended by Supplemental Indenture No. 13, dated as of November 1, 2011 (the Original Indenture, as so supplemented, and such Supplemental Indenture No. 11, as so amended, being hereinafter called the "Indenture" and "Supplemental Indenture No. 11", respectively), to which Indenture reference is hereby made for a description of the property mortgaged and pledged, the nature and extent of the security provided by the Indenture, the rights and limitations of rights of the Company, the Trustee and the holders of said bonds with respect to the security provided by the Indenture, the powers, duties and immunities of the Trustee, the terms and conditions upon which such bonds are and are to be secured, and the circumstances under which additional bonds may be issued. *The acceptance of this bond shall be deemed to constitute the consent and* agreement by the holder hereof to all of the terms and provisions of the Indenture. This bond is one of a series of bonds designated as the First Mortgage Bonds, Collateral Series I, of the Company.

The Indenture permits, with certain exceptions as therein provided, the Trustee to enter into one or more supplemental indentures for the purpose of adding any provisions to, or changing in any manner or eliminating any of the provisions of, the Indenture with the consent of the holders of not less than sixty per centum (60%) in aggregate principal amount of the bonds of all series then outstanding under the Indenture, considered as one class; provided, however, that if there shall be bonds of more than one series outstanding under the Indenture and if a proposed supplemental indenture shall directly affect the rights of the holders of bonds of one or more, but less than all, of such series, then the consent only of the holders of bonds in aggregate principal amount of the outstanding bonds of all series so directly affected, considered as one class, shall be required; and provided, further, that if the bonds of any series shall have been issued in more than one tranche and if the proposed supplemental indenture shall directly affect the rights of the holder of bonds of one or more, but less than all, of such tranches, then the consent only of the holders of bonds in aggregate principal amount of the outstanding bonds of all tranches so directly affected, considered as one class, shall be required; and provided, further, that the Indenture permits the Trustee to enter into one or more supplemental indentures for limited purposes without the consent of any holders of bonds. Any such consent by the holder of this bond shall be conclusive and binding upon such holder and upon all future holders of this bond and of any bond issued upon the registration of transfer hereof or in exchange therefor or in lieu hereof, whether or not notation of such consent is made upon this bond.

The Company has issued and delivered the bonds of this series to Union Bank, N.A., as Administrative Agent (the "Administrative Agent") under the Second Amended and Restated Credit Agreement, dated as of November 9, 2010, among the Company, the Lenders party thereto, the Issuing Banks party thereto, the Co-Syndication Agents party thereto, the Co-

Documentation Agents party thereto and Union Bank, N.A. (formerly known as Union Bank of California, N.A.), as Administrative Agent, as amended, amended and restated, supplemented or otherwise modified from time to time (the "Credit Agreement"), in order to provide collateral security for the obligation of the Company thereunder to pay the Obligations (as defined in Supplemental Indenture No. 11).

Upon the occurrence of an Event of Default under the Credit Agreement, and further upon such additional conditions as are set forth in subdivision (h) of Article II of Supplemental Indenture No. 11, then all bonds of this series shall be redeemed immediately at the principal amount thereof plus accrued interest to the date of redemption.

The obligation of the Company to pay interest on the bonds of this series on any Interest Payment Date prior to Maturity (a) shall be deemed to have been satisfied and discharged in full in the event that all amounts then due in respect of the Obligations shall have been paid or (b) shall be deemed to remain unsatisfied in an amount equal to the aggregate amount then due in respect of the Obligations and remaining unpaid (not in excess, however, of the amount otherwise then due in respect of interest on the bonds of this series).

The obligation of the Company to pay the principal of and accrued interest on the bonds of this series at or after Maturity (x) shall be deemed to have been satisfied and discharged in full in the event that all amounts then due in respect of the Obligations shall have been paid and no Letter of Credit (as defined in Supplemental Indenture No. 11) shall remain outstanding or (y) shall be deemed to remain unsatisfied in an amount equal to the aggregate amount then due in respect of the Obligations and remaining unpaid plus the aggregate stated amount of the outstanding Letters of Credit (not in excess, however, of the amount otherwise then due in respect of principal of and accrued interest on the bonds of this series).

The principal of this bond and the interest accrued hereon may become or be declared due and payable before the stated maturity hereof, on the conditions, in the manner and at the times set forth in the Indenture, upon the happening of a default as therein provided.

This bond is non-transferable except as required to effect transfer to any successor administrative agent under the Credit Agreement, any such transfer to be made at the office or agency of the Company in The City of New York, upon surrender and cancellation of this bond, and upon any such transfer a new bond of this series, for the same aggregate principal amount and having the same stated maturity date, will be issued to the transferee in exchange herefor. Prior to due presentment for registration of transfer, the Company and the Trustee may deem and treat the person in whose name this bond is registered as the absolute owner hereof for the purpose of receiving payment and for all other purposes. This bond, alone or with other bonds of this series, may in like manner be exchanged at such office or agency for one or more bonds of this series of the same aggregate principal amount and having the same stated maturity date and interest rate, all as provided in the Indenture.

No recourse shall be had for the payment of the principal of or interest on this bond, or for any claim based hereon or otherwise in respect hereof or of the Indenture, against any incorporator, shareholder, director or officer, as such, past, present or future, of the Company or of any predecessor or successor corporation, either directly or through the Company or any predecessor or successor corporation, whether by virtue of any constitution, statute or rule of law, or by the enforcement of any assessment or penalty or by any legal or equitable proceeding or otherwise howsoever (including, without limiting the generality of the foregoing, any proceeding to enforce any claimed liability of shareholders of the Company, based upon any theory of disregarding the corporate entity of the Company or upon any theory that the Company was acting as the agent or instrumentality of the shareholders); all such liability being, by the acceptance hereof and as a part of the consideration for the issuance hereof, expressly waived and released by every holder hereof, and being likewise waived and released by the terms of the Indenture under which this bond is issued, as more fully provided in said Indenture.

This bond shall not be valid or become obligatory for any purpose until the certificate of authentication hereon shall have been signed by The Bank of New York Mellon, or its successor, as Trustee under the Indenture.

IN WITNESS WHEREOF, the Company has caused this bond to be signed in its name by the manual or facsimile signature of its President or one of its Vice Presidents, and its corporate seal, or a facsimile thereof, to be impressed or imprinted hereon and attested by the manual or facsimile signature of its Secretary or one of its Assistant Secretaries.

Dated: , 20

TUCSON ELECTRIC POWER COMPANY

By:____

Attest:

____

[FORM OF TRUSTEE'S CERTIFICATE OF AUTHENTICATION]

This is one of the bonds, of the series designated therein, described in the within-mentioned Indenture.

Dated: , 20

The Bank of New York Mellon,
Trustee

By:______________________________

EXHIBIT C
to Amendment No. 1 to Credit Agreement

FORM OF BONDHOLDER CONSENT

[See Attached]

BONDHOLDER CONSENT

UNION BANK, N.A., as Administrative Agent (the " **Administrative Agent** ") under the Second Amended and Restated Credit Agreement, dated as of November 9, 2010, among Tucson Electric Power Company (the " **Company** "), the Lenders party thereto, the Issuing Banks party thereto, the Co-Syndication Agents party thereto, the Co-Documentation Agents party thereto and Union Bank, N.A., as Administrative Agent, as amended, restated, supplemented or otherwise modified from time to time, being the registered holder of $540,588,000 in aggregate principal amount of First Mortgage Bonds, Collateral Series I (the " **Bonds** "), of the Company, DOES HEREBY CONSENT, AS SUCH HOLDER, to the changes of the terms of the Bonds in the Supplemental Indenture No. 13, dated as of November 1, 2011, to the Indenture of Mortgage and Deed of Trust, dated as of December 1, 1992, between the Company and The Bank of New York Mellon (successor in trust to Bank of Montreal Trust Company), as trustee, as amended and supplemented.

Dated: November 18, 2011

UNION BANK, N.A.,
as Administrative Agent

By______________________________
Name:
Title:

Exhibit 4(s)(2)

[Execution Version]

AMENDMENT NO. 1
TO
CREDIT AGREEMENT

This AMENDMENT NO. 1, dated as of November 18, 2011 (this " ***Amendment*** "), is made by and among UNISOURCE ENERGY CORPORATION, an Arizona corporation (the " ***Borrower*** "), the lenders listed on the signature pages of this Amendment as "Lenders" (such lenders, together with their respective permitted assignees from time to time, being referred to herein, collectively, as the " ***Lenders*** "), JPMORGAN CHASE BANK, N.A., WELLS FARGO BANK, NATIONAL ASSOCIATION and UNION BANK, N.A., as issuing banks (collectively, in such capacities, the " ***Issuing Banks*** "), and UNION BANK, N.A. (formerly known as Union Bank of California, N.A.), as administrative agent (in such capacity, the " ***Administrative Agent*** ").

PRELIMINARY STATEMENT :

The Borrower, the Lenders, the Issuing Banks, JPMorgan Chase Bank, N.A., SunTrust Bank and Wells Fargo Bank, National Association, as Co-Syndication Agents, Bank of America, N.A. and U.S. Bank National Association, as Co-Documentation Agents, and the Administrative Agent previously entered into that certain Second Amended and Restated Credit Agreement, dated as of November 9, 2010 (the " ***Existing Agreement*** ", as amended by this Amendment, the " ***Amended Agreement*** ", and as the Amended Agreement may hereafter be amended, restated, supplemented or otherwise modified from time to time, the " ***Credit Agreement*** "). The Borrower desires to amend the Existing Agreement to (a) extend the Final Maturity Date to November 9, 2016, (b) reduce the Applicable Margin and the Commitment Fee Rate, and (c) make certain other modifications thereto, and the Lenders, the Issuing Banks and the Administrative Agent have agreed to such amendments on the terms and conditions set forth herein. The parties therefore agree as follows (capitalized terms used but not defined herein having the meanings assigned to such terms in the Existing Agreement):

SECTION 1. Amendments to Existing Agreement . The Existing Agreement is, effective as of the date hereof and subject to the satisfaction of the conditions precedent set forth in Section 2 hereof, hereby amended as follows:

(a) ***Disclosure Documents*** . The definition of " Disclosure Documents " contained in Section 1.01 of the Existing Agreement is hereby amended and restated in its entirety to read as follows:

" Disclosure Documents " means (a) the Annual Report on Form 10-K of the Borrower for the fiscal year ended December 31, 2010, as filed with the SEC, (b) the Quarterly Reports on Form 10-Q of the Borrower for the fiscal quarters ended March 31, 2011, June 30, 2011 and September 30, 2011, as filed with the SEC, and (c) the Current Reports on Form 8-K of the Borrower as filed with the SEC on February 25, 2011, March 21, 2011, May 11, 2011 and August 12, 2011.

(b) ***Final Maturity Date*** . The definition of " Final Maturity Date " contained in Section 1.01 of the Existing Agreement is hereby amended and restated in its entirety to read as follows:

" Final Maturity Date " means November 9, 2016.

(c) ***Additional Definitions*** . The following new definitions are hereby added to Section 1.01 of the Existing Agreement in appropriate alphabetical order:

" Amendment No. 1 " shall mean Amendment No. 1, dated as of November 18, 2011, among the Borrower, the Issuing Banks, the Lenders and the Administrative Agent, which Amendment No. 1 amended this Agreement pursuant to the terms thereof.

" Amendment No. 1 Effective Date " shall mean November 18, 2011.

(d) ***Financial Condition*** . Section 3.04(a) of the Existing Agreement is hereby amended by (i) deleting each reference to the date "December 31, 2009" in its entirety and substituting therefor in each case the new date "December 31, 2010" and (ii) deleting the phrase "to and including the Effective Date" in its entirety and substituting therefor the new phrase "to and including the Amendment No. 1 Effective Date".

(e) ***No Material Adverse Change*** . Section 3.04(b) of the Existing Agreement is hereby amended by deleting the date "December 31, 2009" in its entirety and substituting therefor the new date "December 31, 2010".

(f) ***Pricing Schedule*** . Schedule 1.01 of the Existing Agreement is hereby replaced in its entirety with Schedule A attached hereto.

SECTION 2. Conditions of Effectiveness . This Amendment shall become effective as of the date first written above (the " ***Effective Date*** ") when, and only when, (a) the Administrative Agent shall have received all fees (including, without limitation, all upfront fees) payable by the Borrower pursuant to that certain proposal letter agreement, dated October 5, 2011, among Union Bank, the Borrower, TEP, UNS Gas and UNS Electric (the " ***Proposal Letter*** "), together with, to the extent invoiced, reimbursement or payment of all reasonable fees and out-of-pocket disbursements of counsel to the Administrative Agent and other out-of-pocket expenses of the Administrative Agent required to be reimbursed or paid by the Borrower pursuant to the Proposal Letter, (b) all requisite Governmental Authorities and third parties, if any, shall have approved or consented to the execution, delivery and performance by the Borrower of this Amendment and the Amended Agreement and the transactions contemplated thereby (collectively, the " ***Transactions*** ") to the extent required and material (and the Administrative Agent shall have received copies, certified by an Authorized Officer to be true, correct and complete and in full force and effect, of all such approvals and consents, which shall be in form and substance satisfactory to the Administrative Agent and the Lenders), no stay of any applicable regulatory approval shall have been issued and there shall be no litigation or governmental, administrative or judicial action, actual or threatened, that could reasonably be expected to restrain, prevent or impose burdensome conditions on this Amendment, the Amended Agreement, any of the other Loan Documents or the Transactions, and (c) the Administrative Agent shall have received: (i) counterparts of this Amendment executed by all of the parties hereto (in sufficient quantity for each party to have a fully executed original), and (ii) all of the following documents, each document being dated the Effective Date unless otherwise specified below, in form and substance satisfactory to the Administrative Agent and in the number of originals or photostatic copies reasonably requested by the Administrative Agent:

(A) a favorable written opinion (addressed to the Administrative Agent, the Issuing Banks and the Lenders) of (1) Morgan, Lewis & Bockius LLP, New York counsel for the Borrower, and (2) Todd C. Hixon, Esq., General Counsel for the Borrower, in each case covering such customary matters relating to this Amendment, the Amended Agreement and the Transactions as the Administrative Agent shall reasonably request, and the Borrower hereby requests such counsel to deliver such opinions;

(B) such documents and certificates as the Administrative Agent or its counsel may reasonably request relating to the organization, existence and good standing of the Borrower, the authorization of the Transactions, and any other legal matters relating to the Borrower, this Amendment, the Amended Agreement or the Transactions, all in form and substance satisfactory to the Administrative Agent and its counsel;

(C) a certificate (the statements in which shall be true), signed by an Authorized Officer, certifying that:

(1) the representations and warranties of the Borrower set forth in this Amendment, the Amended Agreement and the other Loan Documents are true and correct on and as of the Effective Date with the same effect as though made on and as of such date, except to the extent such representations and warranties expressly relate to an earlier date (in which case such representations and warranties were true and correct as of such earlier date); and

(2) both before and after giving effect to this Amendment, no Default has occurred and is continuing;

(D) a certificate, signed by an Authorized Officer, confirming compliance with the conditions set forth in this Section 2; and

(E) copies of all amendments to the TEP Loan Documents (including, without limitation, Amendment No. 1, dated as of the date hereof, to the TEP Credit Agreement), certified by an Authorized Officer as complete and correct and in full force and effect.

SECTION 3. Representations and Warranties of the Borrower . The Borrower represents and warrants to the Administrative Agent, the Lenders and the Issuing Banks that:

(a) *Authorization; Enforceability* . The Transactions are within the Borrower's corporate powers and have been duly authorized by all necessary corporate and, if required, stockholder action. This Amendment has been duly executed and delivered by the Borrower, and each of this Amendment and the Amended Agreement constitutes a legal, valid and binding obligation of the Borrower, enforceable against the Borrower in accordance with its terms, subject to applicable bankruptcy, insolvency, reorganization, moratorium or other laws affecting creditors' rights generally and subject to general principles of equity, regardless of whether considered in a proceeding in equity or at law.

(b) *Government Approvals; No Conflicts* . The Transactions (i) do not require any consent or approval of, registration or filing with, or any other action by, any Governmental Authority, except such as have been obtained or made and are in full force and effect, (ii) will not violate any Requirement of Law, (iii) will not violate or result in a default under any indenture, agreement or other instrument binding upon the Borrower or any Subsidiary or its assets, or give rise to a right thereunder to require any payment to be made by the Borrower or any Subsidiary, and (iv) will not result in the creation or imposition of any Lien on any asset of the Borrower or any Subsidiary, except Liens created under the Loan Documents.

(c) *Litigation* . There are no actions, suits or proceedings by or before any arbitrator or Governmental Authority pending against or, to the knowledge of the Borrower, threatened against or affecting the Borrower or any Subsidiary that in any manner draws into question the validity or enforceability of this Amendment or the Amended Agreement or that otherwise involve this Amendment, the Amended Agreement or the Transactions.

(d) *No Default* . No Default has occurred and is continuing or would occur as a result of the execution, delivery or performance of this Amendment.

SECTION 4. Reference to and Effect on the Existing Agreement . (a) Upon the effectiveness of this Amendment: (i) each reference in the Existing Agreement to "this Agreement", "hereunder", "hereof" or words of like import referring to the Existing Agreement shall mean and be a reference to the Amended Agreement; and (ii) each reference in any other Loan Document to "the Credit Agreement", "thereunder", "thereof" or words of like import referring to the Existing Agreement shall mean and be a reference to the Amended Agreement. This Amendment shall constitute a "Loan Document" for all purposes under the Credit Agreement.

(b) Except as specifically amended above, the Existing Agreement shall continue to be in full force and effect and is hereby in all respects ratified and confirmed. Without limiting the generality of the foregoing, the Security Documents and all of the Collateral described therein do and shall continue to secure the payment of all Obligations.

(c) The execution, delivery and effectiveness of this Amendment shall not, except as expressly provided herein, operate as a waiver of any right, power or remedy of the Lenders, the Administrative Agent or the Issuing Banks under the Existing Agreement or any other Loan Document, nor constitute a waiver of any provision of the Existing Agreement or any other Loan Document.

SECTION 5. Costs and Expenses . The Borrower agrees to pay on demand all reasonable out-of-pocket expenses of the Administrative Agent in connection with the preparation, negotiation, syndication, execution and delivery of this Amendment and the other instruments and documents to be delivered hereunder, including, without limitation, the reasonable fees, charges and disbursements of counsel to the Administrative Agent with respect thereto and with respect to advising the Administrative Agent as to its rights and responsibilities hereunder and thereunder, and all out-of-pocket expenses incurred by the Administrative Agent, any Issuing Bank or any Lender (including, without limitation, the fees, charges and disbursements of any counsel for the Administrative Agent, any Issuing Bank or any Lender) in connection with the enforcement (whether through negotiations, legal proceedings or otherwise) of this Amendment.

SECTION 6. Execution in Counterparts . This Amendment may be executed in counterparts (and by different parties hereto on different counterparts), each of which shall constitute an original but all of which when taken together shall constitute a single contract. Delivery of an executed signature page to this Amendment by facsimile or other electronic transmission (including, without limitation, by Adobe portable document format file (also known as a "PDF" file)) shall be as effective as delivery of a manually signed counterpart of this Amendment.

SECTION 7. Governing Law . This Amendment shall be governed by, and construed in accordance with, the laws of the State of the New York.

SECTION 8. Miscellaneous. This Amendment shall be subject to the provisions of Sections 9.05, 9.07, 9.09, 9.10 and 9.11 of the Existing Agreement, each of which is incorporated by reference herein, *mutatis mutandis* .

[REMAINDER OF PAGE INTENTIONALLY LEFT BLANK]

IN WITNESS WHEREOF, the parties hereto have caused this Amendment to be executed by their respective officers thereunto duly authorized, as of the date first above written.

UNISOURCE ENERGY CORPORATION

By: /s/ Kentton C. Grant
Name: Kentton C. Grant
Title: Vice President, Finance & Rates

UNION BANK, N.A ., as Administrative Agent, as an Issuing Bank and as a Lender

By: /s/ Jeffrey P. Fesenmaier
Name: Jeffrey P. Fesenmaier
Title: Vice President

JPMORGAN CHASE BANK, N.A. , as an
Issuing Bank and as a Lender

By: /s/ Nancy R. Barwig
Name: Nancy R. Barwig
Title: Credit Executive

Amendment No. 1 to UniSource Second Amended and Restated Credit Agreement

WELLS FARGO BANK, NATIONAL ASSOCIATION , as
an Issuing Bank and as a Lender

By: Yann Blindert
Name: Yann Blindert
Title: Director

Amendment No. 1 to UniSource Second Amended and Restated Credit Agreement

SUNTRUST BANK , as a Lender

By: /s/ Andrew Johnson
Name: Andrew Johnson
Title: Director

Amendment No. 1 to UniSource Second Amended and Restated Credit Agreement

BANK OF AMERICA, N.A., as a Lender

By: /s/ Kevin P. Bertelsen
Name: Kevin P. Bertelsen
Title: Managing Director

U.S. BANK NATIONAL ASSOCIATION , as a Lender

By: /s/ Raymond J. Palmer
Name: Raymond J. Palmer
Title: Senior Vice President

Amendment No. 1 to UniSource Second Amended and Restated Credit Agreement

CREDIT SUISSE AG, CAYMAN ISLANDS BRANCH, as a Lender

By: /s/ Shaheen Malik
Name: Shaheen Malik
Title: Vice President

By: /s/ Rahul Parmar
Name: Rahul Parmar
Title: Associate

THE BANK OF NEW YORK MELLON , as
a Lender

By: /s/ Mark W. Rogers
Name: Mark W. Rogers
Title: Vice President

SCHEDULE A
to Amendment No. 1 to Credit Agreement

SCHEDULE 1.01

PRICING SCHEDULE

The "Applicable Margin" and the "Commitment Fee Rate" for any day (a) from and after the Effective Date through (but not including) the Amendment No. 1 Effective Date, are the respective annual percentage rates set forth in Table A below in the applicable row under the column corresponding to the Status that exists on such day, and (b) from and after the Amendment No. 1 Effective Date, are the respective annual percentages rates set forth in Table B below in the applicable row under the column corresponding to the Status that exists on such day:

TABLE A

	Level 1 ≥ A-/A3	Level 2 BBB+/Baa1	Level 3 BBB/Baa2	Level 4 BBB-/Baa3	Level 5 BB+/Ba1	Level 6 ≤ BB/Ba2
Applicable Margin — Eurodollar Loans	1.625%	1.875%	2.125%	2.50%	3.00%	3.50%
Applicable Margin — ABR Loans	0.625%	0.875%	1.125%	1.50%	2.00%	2.50%
Commitment Fee Rate	0.175%	0.225%	0.350%	0.450%	0.600%	0.750%

TABLE B

	Level 1 ≥ A-/A3	Level 2 BBB+/Baa1	Level 3 BBB/Baa2	Level 4 BBB-/Baa3	Level 5 BB+/Ba1	Level 6 ≤ BB/Ba2
Applicable Margin — Eurodollar Loans	1.00%	1.125%	1.25%	1.50%	1.75%	2.00%
Applicable Margin — ABR Loans	0.00%	0.125%	0.25%	0.50%	0.75%	1.00%
Commitment Fee Rate	0.125%	0.175%	0.20%	0.25%	0.30%	0.35%

For purposes of this Pricing Schedule, the following terms have the following meanings:

" ***Level 1 Status*** " exists at any date if, at such date, the Index Debt is rated A- or higher by S&P *and* A3 or higher by Moody's.

" ***Level 2 Status*** " exists at any date if, at such date (i) the Index Debt is rated BBB+ or higher by S&P *and* Baa1 or higher by Moody's and (ii) Level 1 Status does not exist.

" ***Level 3 Status*** " exists at any date if, at such date (i) the Index Debt is rated BBB or higher by S&P *and* Baa2 or higher by Moody's and (ii) neither Level 1 Status nor Level 2 Status exists.

" ***Level 4 Status*** " exists at any date if, at such date (i) the Index Debt is rated BBB- or higher by S&P *and* Baa3 or higher by Moody's and (ii) none of Level 1 Status, Level 2 Status or Level 3 Status exists.

" ***Level 5 Status*** " exists at any date if, at such date (i) the Index Debt is rated BB+ or higher by S&P *and* Ba1 or higher by Moody's and (ii) none of Level 1 Status, Level 2 Status, Level 3 Status or Level 4 Status exists.

" ***Level 6 Status*** " exists at any date if, at such date, no other Status exists.

" ***Status*** " refers to the determination of which of Level 1 Status, Level 2 Status, Level 3 Status, Level 4 Status, Level 5 Status or Level 6 Status exists at any date.

Notwithstanding the foregoing, if the Index Debt is split-rated and the ratings differential is two or more ratings levels, the Status shall be determined assuming that (a) the lower rating is equal to the midpoint of the two ratings (e.g., for a split rating of BBB+/Baa3, BBB is the midpoint and will be deemed to be the lower rating, and for a split rating of BB/Baa1, Baa3 is the midpoint and will be deemed to be the lower rating) or (b) if there is no exact midpoint, the lower rating is equal to the lower of the two middle intermediate ratings (e.g., for a split rating of BBB+/Ba1, BBB- is the lower of the two middle intermediate ratings and will be deemed to be the lower rating, and for a split rating of BB/Baa2, Ba1 is the lower of the two middle intermediate ratings and will be deemed to be the lower rating).

If at any time the Index Debt is unrated by both Moody's and S&P, Level 6 Status shall exist; *provided* that if the reason that there is no such Moody's rating or S&P rating results from Moody's or S&P, as the case may be, ceasing to issue debt ratings generally, then the Borrower and the Administrative Agent may select another nationally-recognized rating agency to substitute for Moody's or S&P, as applicable, for purposes of this Pricing Schedule (and all references herein to Moody's or S&P, as applicable, shall refer to such substitute rating agency), and until a substitute nationally-recognized rating agency is so selected the Status shall be determined by reference to the rating most recently in effect prior to such cessation; and *provided* , *further* , that if the Index Debt is rated by only one of Moody's or S&P, the Status shall be determined by reference to the rating of such Rating Agency.

The Applicable Margin and Commitment Fee Rate shall be increased or decreased in accordance with the foregoing Pricing Schedule upon any change in the applicable ratings of the Index Debt. The ratings of the Index Debt in effect at any date is that in effect at the close of business on such date.

Exhibit 4(t)(2)

[Execution Version]

AMENDMENT NO. 1
TO
CREDIT AGREEMENT

This AMENDMENT NO. 1, dated as of November 18, 2011 (this " ***Amendment*** "), is made by and among UNS ELECTRIC, INC., an Arizona corporation (" ***UNS Electric*** "), and UNS GAS, INC., an Arizona corporation (" ***UNS Gas*** ", and together with UNS Electric being referred to herein, individually, as a " ***Borrower*** " and, collectively, as the " ***Borrowers*** "), UNISOURCE ENERGY SERVICES, INC., an Arizona corporation (the " ***Guarantor*** "), the lenders listed on the signature pages of this Amendment as "Lenders" (such lenders, together with their respective permitted assignees from time to time, being referred to herein, collectively, as the " ***Lenders*** "), JPMORGAN CHASE BANK, N.A., WELLS FARGO BANK, NATIONAL ASSOCIATION and UNION BANK, N.A., as issuing banks (collectively, in such capacities, the " ***Issuing Banks*** "), and UNION BANK, N.A. (formerly known as Union Bank of California, N.A.), as administrative agent (in such capacity, the " ***Administrative Agent*** ").

PRELIMINARY STATEMENT :

The Borrowers, the Guarantor, the Lenders and the Administrative Agent previously entered into that certain Second Amended and Restated Credit Agreement, dated as of November 9, 2010 (the " ***Existing Agreement*** ", as amended by this Amendment, the " ***Amended Agreement*** ", and as the Amended Agreement may hereafter be amended, restated, supplemented or otherwise modified from time to time, the " ***Credit Agreement*** "). The Borrowers desire to amend the Existing Agreement to (a) extend the Final Maturity Date to November 9, 2016, (b) reduce the Applicable Margin and the Commitment Fee Rate, and (c) make certain other modifications thereto, and the Lenders, the Issuing Banks and the Administrative Agent have agreed to such amendments on the terms and conditions set forth herein. The parties therefore agree as follows (capitalized terms used but not defined herein having the meanings assigned to such terms in the Existing Agreement):

SECTION 1. Amendments to Existing Agreement . The Existing Agreement is, effective as of the date hereof and subject to the satisfaction of the conditions precedent set forth in Section 2 hereof, hereby amended as follows:

(a) ***Disclosure Documents*** . The definition of " *Disclosure Documents* " contained in Section 1.01 of the Existing Agreement is hereby amended and restated in its entirety to read as follows:

> " ***Disclosure Documents*** " means (a) the Annual Report on Form 10-K of UniSource Energy for the fiscal year ended December 31, 2010, as filed with the SEC, (b) the Quarterly Reports on Form 10-Q of UniSource Energy for the fiscal quarters ended March 31, 2011, June 30, 2011 and September 30, 2011, as filed with the SEC, and (c) the Current Reports on Form 8-K of UniSource Energy as filed with the SEC on May 11, 2011 and August 12, 2011.

(b) ***Final Maturity Date*** . The definition of " *Final Maturity Date* " contained in Section 1.01 of the Existing Agreement is hereby amended and restated in its entirety to read as follows:

" ***Final Maturity Date*** " means November 9, 2016.

(c) ***Additional Definitions*** . The following new definitions are hereby added to Section 1.01 of the Existing Agreement in appropriate alphabetical order:

" ***Amendment No. 1*** " shall mean Amendment No. 1, dated as of November 18, 2011, among the Borrowers, the Guarantor, the Issuing Banks, the Lenders and the Administrative Agent, which Amendment No. 1 amended this Agreement pursuant to the terms thereof.

" ***Amendment No. 1 Effective Date*** " shall mean November 18, 2011.

(d) ***Disclosure; No Material Adverse Change; Etc*** . Section 7.01(c) of the Existing Agreement is hereby amended by (i) deleting the date "December 31, 2009" in its entirety set forth in subsection (ii) thereof and substituting therefor the new date "December 31, 2010" and (ii) deleting the phrase "prior to the Closing Date" in its entirety set forth in subsection (iii) thereof and substituting therefor the new phrase "prior to the Amendment No. 1 Effective Date".

(e) ***Financial Condition*** . Section 7.01(d) of the Existing Agreement is hereby amended by (i) deleting each reference to the date "December 31, 2009" in its entirety and substituting therefor in each case the new date "December 31, 2010" and (ii) deleting the phrase "to and including the date hereof" in its entirety and substituting therefor the new phrase "to and including the Amendment No. 1 Effective Date".

(f) ***Organization and Ownership of Shares of Subsidiaries of each Obligor.*** Section 7.01(e)(i) of the Existing Agreement is hereby amended by deleting the phrase "As of the Closing Date" in its entirety and substituting therefor the new phrase "As of the Amendment No. 1 Effective Date".

(g) ***Pricing Schedule*** . Schedule 1.01 of the Existing Agreement is hereby replaced in its entirety with Schedule A attached hereto.

SECTION 2. ***Conditions of Effectiveness*** . This Amendment shall become effective as of the date first written above (the " ***Effective Date*** ") when, and only when, (a) the Administrative Agent shall have received all fees (including, without limitation, all upfront fees) payable by the Borrowers pursuant to that certain proposal letter agreement, dated October 5, 2011, among Union Bank, the Borrowers, UniSource Energy and Tucson Electric Power Company (the " ***Proposal Letter*** "), together with, to the extent invoiced, reimbursement or payment of all reasonable fees and out-of-pocket disbursements of counsel to the Administrative Agent and other out-of-pocket expenses of the Administrative Agent required to be reimbursed or paid by the Borrowers pursuant to the Proposal Letter, (b) all requisite Governmental Authorities and third parties, if any, shall have approved or consented to the execution, delivery and performance by the Obligors of this Amendment and the Amended Agreement and the transactions contemplated thereby (collectively, the " ***Transactions*** ") to the extent required and material (and the Administrative Agent shall have received copies, certified by an Authorized Officer of the applicable Obligor to be true, correct and complete and in full force and effect, of all such approvals and consents, which shall be in form and substance satisfactory to the Administrative Agent and the Lenders), no stay of any applicable regulatory approval shall have been issued and there shall be no litigation or governmental, administrative or judicial action, actual or, to the knowledge of the Obligors, threatened, that could reasonably be expected to restrain, prevent or impose burdensome conditions on this Amendment, the Amended Agreement, any of the other Loan Documents or the Transactions, and (c) the Administrative Agent shall have received: (i) counterparts of this Amendment executed by all of the parties hereto (in sufficient quantity for each party to have a fully executed original), and (ii) all of the following documents, each document being dated the Effective Date unless otherwise specified below, in form and substance satisfactory to the Administrative Agent and in the number of originals or photostatic copies reasonably requested by the Administrative Agent:

(A) a favorable written opinion (addressed to the Administrative Agent, the Issuing Banks and the Lenders) of (1) Morgan, Lewis & Bockius LLP, New York counsel for the Obligors, and (2) Todd C. Hixon, Esq., General Counsel for the Guarantor and counsel for the Borrowers, in each case covering such customary matters relating to this Amendment, the Amended Agreement and the Transactions as the Administrative Agent shall reasonably request, and the Obligors hereby request such counsel to deliver such opinions;

(B) such documents and certificates as the Administrative Agent or its counsel may reasonably request relating to the organization, existence and good standing of the Obligors, the authorization of the Transactions, and any other legal matters relating to the Obligors, this Amendment, the Amended Agreement or the Transactions, all in form and substance satisfactory to the Administrative Agent and its counsel;

(C) a certificate (the statements in which shall be true), signed by an Authorized Officer of each Obligor, certifying that:

(1) the representations and warranties of the Obligors set forth in this Amendment, the Amended Agreement and the other Loan Documents are true and correct on and as of the Effective Date with the same effect as though made on and as of such date, except to the extent such representations and warranties expressly relate to an earlier date (in which case such representations and warranties were true and correct as of such earlier date); and

(2) both before and after giving effect to this Amendment, no Default or Event of Default has occurred and is continuing; and

(D) a certificate, signed by an Authorized Officer of each Obligor, confirming compliance with the conditions set forth in this Section 2.

SECTION 3. Representations and Warranties of the Obligors . Each Obligor represents and warrants to the Administrative Agent, each Lender and each Issuing Bank that:

(a) *Authorization; Enforceability* . Such Obligor has the corporate power and authority to execute and deliver this Amendment and to perform the provisions of this Amendment and the Amended Agreement. This Amendment has been duly authorized by all necessary corporate action on the part of such Obligor, and each of this Amendment and the Amended Agreement constitutes a legal, valid and binding obligation of such Obligor enforceable against such Obligor in accordance with its terms, except as such enforceability may be limited by (i) applicable bankruptcy, insolvency, reorganization, moratorium or other similar laws affecting the enforcement of creditors' rights generally and (ii) general principles of equity (regardless of whether such enforceability is considered in a proceeding in equity or at law). This Amendment and has been duly executed and delivered by such Obligor.

(b) *Governmental Authorizations* . No consent, approval or authorization of, or registration, filing or declaration with, any Governmental Authority is required in connection with the execution, delivery or performance by such Obligor of this Amendment, except for the ACC Order, which ACC Order has been obtained and is in full force and effect.

(c) *Compliance with Laws, Other Instruments, etc.* The execution and delivery by such Obligor of this Amendment, and the performance by such Obligor of this Amendment and the Amended Agreement, will not (i) contravene, result in any breach of, or constitute a default under, or result in the creation of any Lien in respect of any Property of such Obligor or any of its Subsidiaries under, any indenture, mortgage, deed of trust, loan, purchase or credit agreement, lease, corporate charter or by-laws, or any other agreement or instrument to which such Obligor or any such Subsidiary is bound or by which such Obligor or any such Subsidiary or any of their respective Properties may be bound or affected, (ii) conflict with or result in a breach of any of the terms, conditions or provisions of any order, judgment, decree, or ruling of any court, arbitrator or Governmental Authority applicable to such Obligor or any of its Subsidiaries or (iii) violate any provision of any Governmental Rule applicable to such Obligor or any of its Subsidiaries.

(d) *Litigation* . There are no actions, suits or proceedings pending or, to the knowledge of such Obligor, threatened against or affecting such Obligor or any of its Subsidiaries or any Property of such Obligor or any of its Subsidiaries in any court or before any arbitrator of any kind or before or by any Governmental Authority that involve this Amendment, the Amended Agreement or the Transactions.

(e) *No Default* . No Default or Event of Default has occurred and is continuing or would occur as a result of the execution, delivery or performance of this Amendment.

SECTION 4. Reference to and Effect on the Existing Agreement . (a) Upon the effectiveness of this Amendment: (i) each reference in the Existing Agreement to "this Agreement", "hereunder", "hereof" or words of like import referring to the Existing Agreement shall mean and be a reference to the Amended Agreement; and (ii) each reference in any other Loan Document to "the Credit Agreement", "thereunder", "thereof" or words of like import referring to the Existing Agreement shall mean and be a reference to the Amended Agreement. This Amendment shall constitute a "Loan Document" for all purposes under the Credit Agreement.

(b) Except as specifically amended above, the Existing Agreement shall continue to be in full force and effect and is hereby in all respects ratified and confirmed.

(c) The execution, delivery and effectiveness of this Amendment shall not, except as expressly provided herein, operate as a waiver of any right, power or remedy of the Lenders, the Administrative Agent or the Issuing Banks under the Existing Agreement or any other Loan Document, nor constitute a waiver of any provision of the Existing Agreement or any other Loan Document.

SECTION 5. Costs and Expenses . The Borrowers agree to pay, promptly after delivery to the Borrowers of a reasonably detailed statement therefor, all reasonable costs and expenses of the Administrative Agent in connection with the preparation, negotiation, syndication, execution and delivery of this Amendment and the other instruments and documents to be delivered hereunder, including, without limitation, the reasonable fees and disbursements of counsel to the Administrative Agent with respect thereto and with respect to advising the Administrative Agent as to its rights and responsibilities hereunder and thereunder, and all costs and expenses of the Administrative Agent, the Issuing Banks and each Lender (including, without limitation, the fees and disbursements of counsel to the Administrative Agent, counsel for each Issuing Bank and counsel for each Lender) in connection with the enforcement (whether through negotiations, legal proceedings or otherwise) of this Amendment and the other documents to be delivered hereunder.

SECTION 6. Execution in Counterparts . This Amendment may be executed in counterparts (and by different parties hereto on different counterparts), each of which shall constitute an original but all of which when taken together shall constitute a single contract. Delivery of an executed signature page to this Amendment by facsimile or other electronic transmission (including, without limitation, by Adobe portable document format file (also known as a "PDF" file)) shall be as effective as delivery of a manually signed counterpart of this Amendment.

SECTION 7. Governing Law . This Amendment shall be governed by, and construed in accordance with, the laws of the State of the New York.

SECTION 8. Miscellaneous. This Amendment shall be subject to the provisions of Sections 12.09, 12.10, 12.11 and 12.13 of the Existing Agreement, each of which is incorporated by reference herein, *mutatis mutandis* .

[REMAINDER OF PAGE INTENTIONALLY LEFT BLANK]

IN WITNESS WHEREOF, the parties hereto have caused this Amendment to be executed by their respective officers thereunto duly authorized, as of the date first above written.

UNS ELECTRIC, INC. , as a Borrower

By: /s/ Kentton C. Grant
Name: Kentton C. Grant
Title: Vice President

UNS GAS, INC. , as a Borrower

By: /s/ Kentton C. Grant
Name: Kentton C. Grant
Title: Vice President

UNISOURCE ENERGY SERVICES, INC ., as Guarantor

By: /s/ Kentton C. Grant
Name: Kentton C. Grant
Title: Vice President and Treasurer

UNION BANK, N.A ., as Administrative Agent and as an Issuing Bank

By: /s/ Jeffrey P. Fesenmaier
Name: Jeffrey P. Fesenmaier
Title: Vice President

WELLS FARGO BANK, NATIONAL ASSOCIATION, as an Issuing Bank

By: /s/ Yann Blindert
Name: Yann Blindert
Title: Director

JPMORGAN CHASE BANK, N.A. , as an Issuing Bank

By: /s/ Nancy R. Barwig
Name: Nancy R. Barwig
Title: Credit Executive

Lender

UNION BANK, N.A .

By: /s/ Jeffrey P. Fesenmaier
Name: Jeffrey P. Fesenmaier
Title: Vice President

Lender

WELLS FARGO BANK, NATIONAL ASSOCIATION

By: /s/ Yann Blindert
Name: Yann Blindert
Title: Director

Amendment No. 1 to UNS Gas/UNS Electric Second Amended and Restated Credit Agreement

Lender

JPMORGAN CHASE BANK, N.A.

By: /s/ Nancy R. Barwig
Name: Nancy R. Barwig
Title: Credit Executive

Lender

SUNTRUST BANK

By: /s/ Andrew Johnson
Name: Andrew Johnson
Title: Director

Lender

BANK OF AMERICA, N.A.

By: /s/ Kevin P. Bertelsen
Name: Kevin P. Bertelsen
Title: Managing Director

Lender

U.S. BANK NATIONAL ASSOCIATION

By: /s/ Raymond J. Palmer
Name: Raymond J. Palmer
Title: Senior Vice President

Lender

CREDIT SUISSE AG, CAYMAN ISLANDS BRANCH

By: /s/ Shaheen Malik
Name: Shaheen Malik
Title: Vice President

By: /s/ Rahul Parmer
Name: Rahul Parmer
Title: Associate

Lender

THE BANK OF NEW YORK MELLON

By: /s/ Mark W. Rogers
Name: Mark W. Rogers
Title: Vice President

SCHEDULE A
to Amendment No. 1 to Credit Agreement

SCHEDULE 1.01

PRICING SCHEDULE

The "Applicable Margin" and the "Commitment Fee Rate" for any day for any Borrower (a) from and after the Closing Date through (but not including) the Amendment No. 1 Effective Date, are the respective annual percentage rates set forth in Table A below in the applicable row under the column corresponding to the Status that exists on such day for such Borrower, which Status shall be determined based on the applicable ratings of such Borrower's Index Debt on such day, and (b) from and after the Amendment No. 1 Effective Date, are the respective annual percentages rates set forth in Table B below in the applicable row under the column corresponding to the Status that exists on such day for such Borrower, which Status shall be determined based on the applicable ratings of such Borrower's Index Debt on such day:

TABLE A

	Level 1 ≥ A-/A3	Level 2 BBB+/Baa1	Level 3 BBB/Baa2	Level 4 BBB-/Baa3	Level 5 BB+/Ba1	Level 6 ≤ BB/Ba2
Applicable Margin — Eurodollar Loans	1.625%	1.875%	2.125%	2.50%	3.00%	3.50%
Applicable Margin — ABR Loans	0.625%	0.875%	1.125%	1.50%	2.00%	2.50%
Commitment Fee Rate	0.175%	0.225%	0.350%	0.450%	0.600%	0.750%

TABLE B

	Level 1 ≥ A-/A3	Level 2 BBB+/Baa1	Level 3 BBB/Baa2	Level 4 BBB-/Baa3	Level 5 BB+/Ba1	Level 6 ≤ BB/Ba2
Applicable Margin — Eurodollar Loans	1.00%	1.125%	1.25%	1.50%	1.75%	2.00%
Applicable Margin — ABR Loans	0.00%	0.125%	0.25%	0.50%	0.75%	1.00%
Commitment Fee Rate	0.125%	0.175%	0.20%	0.25%	0.30%	0.35%

For purposes of this Pricing Schedule, the following terms have the following meanings:

" ***Level 1 Status*** " exists at any date if, at such date, the Index Debt is rated either A- or higher by S&P *or* A3 or higher by Moody's.

" ***Level 2 Status*** " exists at any date if, at such date (i) the Index Debt is rated either BBB+ or higher by S&P *or* Baa1 or higher by Moody's and (ii) Level 1 Status does not exist.

" ***Level 3 Status*** " exists at any date if, at such date (i) the Index Debt is rated either BBB or higher by S&P *or* Baa2 or higher by Moody's and (ii) neither Level 1 Status nor Level 2 Status exists.

" ***Level 4 Status*** " exists at any date if, at such date (i) the Index Debt is rated either BBB- or higher by S&P *or* Baa3 or higher by Moody's and (ii) none of Level 1 Status, Level 2 Status or Level 3 Status exists.

" ***Level 5 Status*** " exists at any date if, at such date (i) the Index Debt is rated either BB+ or higher by S&P *or* Ba1 or higher by Moody's and (ii) none of Level 1 Status, Level 2 Status, Level 3 Status or Level 4 Status exists.

" ***Level 6 Status*** " exists at any date if, at such date, no other Status exists.

" ***Status*** " refers to the determination of which of Level 1 Status, Level 2 Status, Level 3 Status, Level 4 Status, Level 5 Status or Level 6 Status exists at any date.

Notwithstanding the foregoing, if the Index Debt is split-rated and the ratings differential is two or more ratings levels, the Status shall be determined assuming that (a) the higher rating is equal to the midpoint of the two ratings (e.g., for a split rating of BBB+/Baa3, BBB is the midpoint and will be deemed to be the higher rating, and for a split rating of BB/Baa1, Baa3 is the midpoint and will be deemed to be the higher rating) or (b) if there is no exact midpoint, the higher rating is equal to the higher of the two middle intermediate ratings (e.g., for a split rating of BBB+/Ba1, BBB is the higher of the two middle intermediate ratings and will be deemed to be the higher rating, and for a split rating of BB/Baa2, Ba3 is the higher of the two middle intermediate ratings and will be deemed to be the higher rating).

If at any time the Index Debt is unrated by both Moody's and S&P, Level 6 Status shall exist; *provided* that if the reason that there is no such Moody's rating or S&P rating results from Moody's or S&P, as the case may be, ceasing to issue debt ratings generally, then the Borrowers and the Administrative Agent may select another nationally-recognized rating agency to substitute for Moody's or S&P, as applicable, for purposes of this Pricing Schedule (and all references herein to Moody's or S&P, as applicable, shall refer to such substitute rating agency), and until a substitute nationally-recognized rating agency is so selected the Status shall be determined by reference to the rating most recently in effect prior to such cessation; and *provided* , *further* , that if the Index Debt is rated by only one of Moody's or S&P, the Status shall be determined by reference to the rating of such Rating Agency.

The Applicable Margin and Commitment Fee Rate applicable to any Borrower (and, accordingly, the Status of such Borrower at any date) shall be based on the applicable ratings in effect from time to time on such Borrower's Index Debt. The Applicable Margin and Commitment Fee Rate applicable to each Borrower shall be increased or decreased in accordance with the foregoing Pricing Schedule upon any change in the applicable ratings of the Index Debt of such Borrower. The ratings of the Index Debt in effect at any date is that in effect at the close of business on such date.

UniSource Energy Corporation
Computation of Ratio of Earnings to Fixed Charges

	12 Months Ended					
	Dec 31, 2011	Dec. 31, 2010*	Dec. 31, 2009*	Dec. 31, 2008*	Dec. 31, 2007*	Dec. 31, 2006*
	- Thousands of Dollars -					
Fixed Charges:						
Interest on Long-Term Debt	$ 73,217	$ 65,020	$ 58,134	$ 70,227	$ 73,095	$ 75,039
Other Interest (1)	2,535	1,651	3,468	1,837	5,480	7,922
Interest on Capital Lease Obligations	44,874	52,540	53,682	57,272	64,499	72,586
Estimated Interest Portion of Rental Expense	926	240	345	188	258	326
Total Fixed Charges	$ 121,552	$ 119,451	$ 115,629	$ 129,524	$ 143,332	$ 155,873
Net Income	$ 109,975	$ 112,984	$ 105,901	$ 16,955	$ 60,712	$ 68,524
Add:						
Discontinued Operations Loss-Net of Tax	—	—	—	—	—	1,796
Net Income from Continuing Operations	109,975	112,984	105,901	16,955	60,712	70,320
Add (Deduct):						
(Income) Losses from Equity Investees	—	5,570	1,834	713	340	(210)
Income Taxes	66,951	76,921	63,232	18,747	40,274	42,143
Total Fixed Charges	121,552	119,451	115,629	129,524	143,332	155,873
Total Earnings before Taxes and Fixed Charges	$ 298,478	$ 314,926	$ 286,596	$ 165,939	$ 244,658	$ 268,126
Ratio of Earnings to Fixed Charges	2.456	2.636	2.479	1.281	1.707	1.720

* As revised. See Note 1 to the financial statements for more information.

(1) Excludes recognition of Allowance for Borrowed Funds Used During Construction.

Exhibit 12b

Tucson Electric Power Company
Computation of Ratio of Earnings to Fixed Charges

	12 Months Ended					
	Dec. 31, 2011	Dec. 31, 2010*	Dec. 31, 2009*	Dec. 31, 2008*	Dec. 31, 2007*	Dec. 31, 2006*
			- Thousands of Dollars -			
Fixed Charges:						
Interest on Long-Term Debt	$ 49,858	$ 42,378	$ 36,226	$ 47,456	$ 50,230	$ 51,422
Other Interest (1)	1,127	433	1,571	1,367	4,538	6,436
Interest on Capital Lease Obligations	44,874	52,534	53,670	57,252	64,477	72,556
Estimated Interest Portion of Rental Expense	795	72	106	130	160	188
Total Fixed Charges	$ 96,654	$ 95,417	$ 91,573	$106,205	$119,405	$130,602
Net Income	$ 85,334	$108,260	$ 90,688	$ 7,206	$ 55,591	$ 67,306
Add (Deduct):						
(Income) Losses from Equity Investees	—	—	—	(1,381)	—	(320)
Income Taxes	52,000	59,936	54,220	12,729	36,940	42,845
Total Fixed Charges	96,654	95,417	91,573	106,205	119,405	130,602
Total Earnings before Taxes and Fixed Charges	$233,988	$263,613	$236,481	$124,759	$211,936	$240,433
Ratio of Earnings to Fixed Charges	2.421	2.763	2.582	1.175	1.775	1.841

* As revised. See Note 1 to the financial statements for more information.

(1) Excludes recognition of Allowance for Borrowed Funds Used During Construction.

UniSource Energy Corporation Subsidiaries

Subsidiary	State or Other Jurisdiction of Incorporation or Organization
Tucson Electric Power Company (TEP)	Arizona
TEP Subsidiaries:	
San Carlos Resources Inc.	Arizona
Escavada Company.	Arizona
UniSource Energy Services, Inc. (UES)	Arizona
UES Subsidiaries:	
UNS Electric, Inc.	Arizona
UNS Gas, Inc.	Arizona

Exhibit 23a

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-8 (Nos. 333-43765, 333-43767, 333-43769, 333-53309, 333-53333, 333-99317,333-140353, 333-156491 and 333-175001) and on Form S-3 (No. 333-159244) of UniSource Energy Corporation of our report dated February 27, 2012 relating to the financial statements, financial statement schedule and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/PricewaterhouseCoopers LLP
PricewaterhouseCoopers LLP
Phoenix, Arizona
February 27, 2012

Exhibit 23b

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-159244-01) of Tucson Electric Power Company of our report dated February 27, 2012 relating to the financial statements and financial statement schedule, which appears in this Form 10-K.

/s/PricewaterhouseCoopers LLP
PricewaterhouseCoopers LLP
Phoenix, Arizona
February 27, 2012

Exhibit 24(a)

Power of Attorney

KNOW ALL MEN BY THESE PRESENTS, that the undersigned Principal Executive Officer, Principal Financial Officer, Principal Accounting Officer, officers and/or directors of UniSource Energy Corporation, an Arizona corporation, which corporation proposes to file with the Securities and Exchange Commission an Annual Report on Form 10-K for the year ended December 31, 2011, under the Securities Exchange Act of 1934, as amended, does each for himself and not for one another, hereby constitute and appoint Kevin P. Larson, Todd C. Hixon, and Karen G. Kissinger and each of them, his true and lawful attorneys, in his name, place and stead, to sign his name to said proposed Annual Report on Form 10-K and any and all amendments thereto, and to cause the same to be filed with the Securities and Exchange Commission, it being intended to grant and hereby granting to said attorneys, and each of them, full power and authority to do and perform any act and thing necessary and proper to be done in the premises as fully and to all intents and purposes as the undersigned could do if personally present; and each of the undersigned for himself hereby ratifies and confirms all that said attorneys, or any one of them, shall lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, each of the undersigned has hereunto set their hand as of the 27 th of February 2012.

/s/ Paul J. Bonavia

Paul J. Bonavia
Principal Executive Officer
and Chairman of the Board of
Directors

/s/ Robert A. Elliott

Robert A. Elliott, Director

/s/ Kevin P. Larson

Kevin P. Larson
Principal Financial Officer

/s/ Daniel W.L. Fessler

Daniel W.L. Fessler, Director

/s/ Karen G. Kissinger

Karen G. Kissinger
Principal Accounting Officer

/s/ Louise L. Francesconi

Louise L. Francesconi, Director

/s/ Lawrence J. Aldrich

Lawrence J. Aldrich, Director

/s/ Warren Y. Jobe

Warren Y. Jobe, Director

/s/ Barbara M. Baumann

Barbara M. Baumann, Director

/s/ Ramiro G. Peru

Ramiro G. Peru, Director

/s/ Larry W. Bickle

Larry W. Bickle, Director

/s/ Gregory A. Pivirotto

Gregory A. Pivirotto, Director

/s/ Harold W. Burlingame

Harold W. Burlingame, Director

/s/ Joaquin Ruiz

Joaquin Ruiz, Director

Exhibit 24(b)

Power of Attorney

KNOW ALL MEN BY THESE PRESENTS, that the undersigned Principal Executive Officer, Principal Financial Officer, Principal Accounting Officer, officers and/or directors of Tucson Electric Power Company, an Arizona corporation, which corporation proposes to file with the Securities and Exchange Commission an Annual Report on Form 10-K for the year ended December 31, 2011, under the Securities Exchange Act of 1934, as amended, does each for himself and not for one another, hereby constitute and appoint Kevin P. Larson, Todd C. Hixon, and Karen G. Kissinger and each of them, his true and lawful attorneys, in his name, place and stead, to sign his name to said proposed Annual Report on Form 10-K and any and all amendments thereto, and to cause the same to be filed with the Securities and Exchange Commission, it being intended to grant and hereby granting to said attorneys, and each of them, full power and authority to do and perform any act and thing necessary and proper to be done in the premises as fully and to all intents and purposes as the undersigned could do if personally present; and each of the undersigned for himself hereby ratifies and confirms all that said attorneys, or any one of them, shall lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, each of the undersigned has hereunto set their hand as of the 27 th day of February, 2012.

/s/ Paul J. Bonavia
Paul J. Bonavia
Principal Executive Officer
and Chairman of the Board of
Directors

/s/ Kevin P. Larson
Kevin P. Larson
Principal Financial Officer and Director

/s/ Karen G. Kissinger
Karen G. Kissinger
Principal Accounting Officer

/s/ Michael J. DeConcini
Michael J. DeConcini
Director

/s/ David G. Hutchens
David G. Hutchens
Director

Exhibit 31(a)

CERTIFICATION
Pursuant to Section 302 of the Sarbanes-Oxley Act

I, Paul J. Bonavia, certify that:

1. I have reviewed this annual report on Form 10-K for the year ended December 31, 2011, of UniSource Energy Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    c. evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2012

/s/ Paul J. Bonavia
Paul J. Bonavia
Chairman and Principal Executive Officer

Exhibit 31(b)

CERTIFICATION
Pursuant to Section 302 of the Sarbanes-Oxley Act

I, Kevin P. Larson, certify that:

1. I have reviewed this annual report on Form 10-K for the year ended December 31, 2011, of UniSource Energy Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    c. evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2012

/s/ Kevin P. Larson
Kevin P. Larson
Senior Vice President, Treasurer and Principal Financial Officer

CERTIFICATION
Pursuant to Section 302 of the Sarbanes-Oxley Act

I, Paul J. Bonavia, certify that:

1. I have reviewed this annual report on Form 10-K for the year ended December 31, 2011, of Tucson Electric Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a – 15(f) and 15d – 15(f)) for the registrant and have:

   a. designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c. evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2012

/s/ Paul J. Bonavia
Paul J. Bonavia
Chairman and Principal Executive Officer

Exhibit 31(d)

CERTIFICATION
Pursuant to Section 302 of the Sarbanes-Oxley Act

I, Kevin P. Larson, certify that:

1. I have reviewed this annual report on Form 10-K for the year ended December 31, 2011 of Tucson Electric Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a – 15(f) and 15d – 15(f)) for the registrant and have:

    a. designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    c. evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2012

/s/ Kevin P. Larson
Kevin P. Larson
Senior Vice President and Principal Financial Officer

Exhibit 32

UNISOURCE ENERGY CORPORATION

TUCSON ELECTRIC POWER COMPANY

STATEMENTS OF CORPORATE OFFICERS
(Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002)

Each of the undersigned, Paul J. Bonavia, Chairman of the Board and Principal Executive Officer of UniSource Energy Corporation and Tucson Electric Power Company (each a "Company"), and Kevin P. Larson, Senior Vice President and Principal Financial Officer of each Company, hereby certifies, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that each Company's Annual Report on Form 10-K for the year ended December 31, 2011, fully complies with the requirements of Section 13 (a) or 15(d) of the Securities Exchange Act of 1934, as amended, and that the information contained therein fairly presents, in all material respects, the financial condition and results of operations of such Company.

February 27, 2012

/s/ Paul J. Bonavia
Paul J. Bonavia
Chairman of the Board and
Principal Executive Officer
UniSource Energy Corporation
Tucson Electric Power Company

/s/ Kevin P. Larson
Kevin P. Larson
Senior Vice President and
Principal Financial Officer
UniSource Energy Corporation
Tucson Electric Power Company