SECTION 11
BILLING AND COLLECTION
(continued)

7. The Customer must provide the Company with a current email address for electronic bill delivery. If the electronic bill is electronically sent to the Customer at the email address that the Customer provided to the Company, then the Electronic Bill will be considered properly sent. Further, the Customer will be responsible for updating the Company with any changes to this email address. Failure to do so will not excuse the Customer from timely paying the Company for electric service.

L. Collections

1. All unpaid closed accounts may be referred to a collection agency for collections.

2. If a collection agency referral is warranted for collection of unpaid final bills, Customer will be responsible for associated collection agency fees incurred. If the unpaid bill is referred to a credit bureau, the Company will not be held responsible to notify the Credit Bureau of any payment status.

M. Refunds

Customers will not be eligible for refunds, rebates or other Company program payments if the Customer has a delinquent Company balance.

N. Refund of Credit Balance Following Discontinuance of Service

Upon discontinuance of service, the Company shall refund the Customer any credit balance remaining on the account. With the consent of the Customer (when available), any credit balance remaining on the account that is less than $5.00, shall be donated to a low-income assistance program to be determined by the Company or as may be required by law.

SECTION 12
TERMINATION OF SERVICE

A. Please refer to the Arizona Administrative Code R14-2-211.A.

B. Termination of Service Without Notice

1. Electric service may be disconnected without advance written notice under the following conditions:

   a. The existence of an obvious safety or health hazard to the consumer, the general population or the Company's personnel or facilities;

   b. The Company has evidence of meter tampering or fraud; or

   c. The Company has evidence of unauthorized resale or use of electric service; or

   d. Customer makes payment to avoid/stop disconnection for non-payment with a dishonored or fraudulent payment. The Company will not be required to restore service until the repayment of those funds and all other delinquent amounts are paid by cash, money order, cashier's check, certified funds or verified electronic payment; or

   e. Customer makes payment to reconnect service with a dishonored or fraudulent payment. The Company will not be required to restore service until the repayment of those funds and all other delinquent amounts are paid by cash, money order, cashier's check, certified funds or verified electronic payment; or

   f. Failure of a Customer to comply with the curtailment procedures imposed by the Company during supply shortages.

2. The Company will not be required to restore service until the conditions that led to the termination have been corrected to the satisfaction of the Company.

3. The Company will maintain a record of all terminations of service without notice for a minimum of one (1) year and will be available for inspection by the Commission.

C. Termination of Service With Notice

1. The Company may disconnect service to any Customer for any reason stated below provided that the Company has met the notice requirements described in Subsection 12.E. below:

   a. Customer violation of any of the Company's Rates;

   b. Failure of the Customer to pay a delinquent bill for electric service;

   c. Failure of a prior Customer to pay a delinquent bill for electric service where the prior Customer continues to reside on the premise;

   d. Failure of the Customer to meet agreed-upon deferred payment arrangements;

   e. Failure to meet or maintain the Company's deposit requirements;

   f. Failure of the Customer to provide the Company reasonable safe access to its equipment and property;

SECTION 12
TERMINATION OF SERVICE
(continued)

g. Returned or invalid payments;

h. Customer breach of a written contract for service between the Company and Customer;

i. When necessary for the Company to comply with an order of any governmental agency having such jurisdiction;

j. When a hazard exists that is not imminent, but in the Company's opinion, may cause property damage;

k. Customer facilities that do not comply with Company requirements or specifications;

l. Failure to provide or retain rights-of-way or easements necessary to serve the Customer; or

m. The Company learns of the existence of any condition in Section 3.D., Grounds for Refusal of Service.

2. The Company will maintain a record of all terminations of service with notice for one (1) year and be available for Commission inspection.

D. The Company will not be obligated to renotify the Customer of the termination of service, even if the Customer – after receiving the required termination of service notification – has made payment, yet the payment is returned within three (3) to five (5) business days of receipt for any reason. The original notification will apply.

E. Termination Notice Requirements

1. The Company will not terminate service to any of its Customers without providing advance written notice to the Customer of the Company's intent to disconnect service, except under those conditions specified in Subsection 12.B. where advance written notice is not required.

2. This advance written notice will contain, at a minimum, the following information:

a. The name of the person whose service is to be terminated and the address where service is being rendered.

b. The Company's Rate that was violated and explanation of the violation or the amount of the bill that the Customer has failed to pay in accordance with the payment policy of the Company, if applicable.

c. The date on or after which service may be terminated.

d. A statement advising the Customer to contact the Company at a specific phone number for information regarding any deferred payment or other procedures that the Company may offer or to work out some other mutually agreeable solution to avoid termination of the Customer's service.

SECTION 12
TERMINATION OF SERVICE
(continued)

e. A statement advising the Customer the Company's stated reason(s) for the termination of services may be disputed by contacting the Company at a specific address or phone number, advising the Company of the dispute and making arrangements to discuss the cause for termination with a responsible employee of the Company in advance of the scheduled date of termination. The responsible employee will be empowered to resolve the dispute and the Company will retain the option to terminate service after affording this opportunity for a meeting and concluding that the reasons for termination is just and advising the Customer of his right to file a complaint with the Commission.

3. Where applicable, a copy of the termination notice will be simultaneously forwarded to designated third parties.

F. Timing of Terminations With Notice

1. The Company will give at least a five (5) day advance written notice prior to the termination date.

2. This notice will be considered to be given to the Customer when a copy of the notice is left with the Customer or posted first class via the U.S. Postal Service, addressed to the Customer's last known address.

3. If, after the period of time allowed by the notice has elapsed and the delinquent account has not been paid nor arrangements made with the Company for payment of the bill – or in the case of a violation of the Company's rules the Customer has not satisfied the Company that this violation has ceased – then the Company may terminate service on or after the day specified in the notice without giving further notice.

4. The Company will have the right (but not the obligation) to remove any or all of its property installed on the Customer's premises upon the termination of service. Upon the termination of service the Company may, without liability for injury or damage, dismantle and remove its line extension facilities within two (2) years after termination of service. The Company will give the Customer thirty (30) days written notice before removing its facilities should the Company decide to do so, or else waive any reestablishment charge within the next one (1) year for the same service to the same Customer at the same location.

G. Landlord/Tenant Rule

1. In situations where service is rendered at an address different from the mailing address of the bill or where the Company knows that a landlord/tenant relationship exists and the landlord is the Customer of the Company, and where the landlord as a Customer would otherwise be subject to disconnection of service, the Company may not disconnect service until the following actions have been taken:

a. Where it is feasible to so provide service, the Company, after providing notice as required in these rules, will offer the occupant the opportunity to subscribe for service in his or her own name. If the occupant then declines to so subscribe, the Company may disconnect service pursuant to the rules.

b. The Company will not attempt to recover from a tenant or condition service to a tenant, upon the prepayment of any outstanding bills or other charges due upon the outstanding account of the landlord.

SECTION 13
RECONNECTION OF SERVICE

When service has been discontinued for any of the reasons set forth in these Rules and Regulations, the Company will not be required to restore service until the following conditions have been met by the Customer:

A. Where service was discontinued without notice:

1. The hazardous condition must be removed and the installation will conform to accepted standards.
2. All bills for service and/or applicable investigative costs due the Company by reason of fraudulent or unauthorized use, diversion or tampering must be paid and a deposit to guarantee the payment of future bills may be required.
3. Required arrangements for service must be made.

B. Where service was discontinued with notice:

1. The Customer must make arrangements for the payment of all bills and these arrangements must be satisfactory to the Company.
2. The Customer must furnish a satisfactory guarantee to pay all future bills.
3. The Customer must correct any and all violations of these Rules and Regulations.

SECTION 14
ADMINISTRATIVE AND HEARING REQUIREMENTS

A. Customer Service Complaints

1. The Company will make a full and prompt investigation of all service complaints made by its Customers, either directly or through the Commission.

2. The Company will respond to the complainant and/or the Commission representative within five (5) business days as to the status of the Company's investigation.

3. The Company will notify the complainant and/or the Commission representative of the final disposition of each complaint. Upon request of the complainant or the Commission representative, the Company will report the findings of its investigation in writing.

4. The Company will inform the Customer of his right of appeal to the Commission.

5. The Company will keep a record of all written service complaints received that must contain, at a minimum, the following data:

   a. Name and address of complainant;

   b. Date and nature of the complaint;

   c. Disposition of the complaint; and

   d. A copy of any correspondence between the Company, the Customer, and/or the Commission.

6. This record will be maintained for a minimum period of one (1) year and will be available for inspection by the Commission.

B. Customer Bill Disputes

1. Any utility Customer who disputes a portion of a bill rendered for electric service must pay the undisputed portion of the bill and notify the Company's designated representative that any unpaid amount is in dispute prior to the delinquent date of the bill.

SECTION 14
ADMINISTRATIVE AND HEARING REQUIREMENTS
(continued)

2. Upon receipt of the Customer notice of dispute, the Company will:

   a. Notify the Customer within five (5) business days of the receipt of a written dispute notice.

   b. Initiate a prompt investigation as to the source of the dispute.

   c. Withhold disconnection of service until the investigation is completed and the Customer is informed of the results.

   d. Upon request of the Customer, the Company will report the results of the investigation in writing.

   e. Inform the Customer of his right of appeal to the Commission.

3. Once the Customer has received the results of the Company's investigation, the Customer will submit payment within five (5) business days to the Company for any disputed amounts. Failure to make full payment may be grounds for termination of service.

4. The Company will inform the Customer of his right of appeal to the Commission.

C. Commission resolution of service and bill disputes

1. In the event the Customer and the Company cannot resolve a service or bill dispute the Customer must file a written statement of dissatisfaction with the Commission; by submitting this statement to the Commission, the Customer will be deemed to have filed an informal complaint against the Company.

2. Within 30 days of the receipt of a written statement of Customer dissatisfaction related to a service or bill dispute, a designated representative of the Commission will endeavor to resolve the dispute by correspondence or telephone with the Company and the Customer. If resolution of the dispute is not achieved within 20 days of the Commission representative's initial effort, the Commission will hold an informal meeting to arbitrate the resolution of the dispute. This informal meeting will be governed by the following rules:

   a. Each party may be represented by legal counsel, if desired.

   b. All informal meetings may be recorded or held in the presence of a stenographer.

   c. All parties will have the opportunity to present written or oral evidentiary material to support the positions of the individual parties.

   d. All parties and the Commission's representative will be given the opportunity to cross-examine the various parties.

SECTION 14
ADMINISTRATIVE AND HEARING REQUIREMENTS
(continued)

e. The Commission's representative will render a written decision to all parties within five business days after the date of the informal meeting. This written decision of the arbitrator is not binding on any of the parties and the parties may still make a formal complaint to the Commission.

3. The Company may implement its termination procedures if the Customer fails to pay all bills rendered during the resolution of the dispute by the Commission.

4. The Company will maintain a record of written statements of dissatisfaction and their resolution for a minimum of one (1) year and make these records available for Commission inspection.

SECTION 15
TEMPORARY SERVICE OR CYCLICAL USAGE

A. For electric service of a temporary nature [*less than two (2) years*], line extension charges may apply as set forth in the TEP Statement of Charges, in addition to the regular charges for service which will be billed under the applicable rate schedule. Emergency, supplementary, breakdown or other standby service is not considered temporary and is subject to the provisions of Section 16. Permanent or semi-permanent businesses whose characteristics of operation result in infrequent cyclical usage of energy (e.g., asphalt batch plants, lettuce cooling plants) will require separate contracts with the Company to assure full recovery of the Company's annual ownership cost on the total facilities installed to provide service to the Applicant.

SECTION 16
STANDBY SERVICE

A. Emergency, breakdown, supplementary or other standby service will be supplied by the Company at its option only under special contracts specifying the rates, terms and conditions governing such service.

SECTION 17
POWER FACTOR

A. The Company may require the Customer by written notice to either maintain a specified minimum lagging power factor or the Company may after thirty (30) days install power factor corrective equipment and bill the Customer for the total costs of this equipment and installation.

B. In the case of apparatus and devices having low power factor, now in service, which may hereafter be replaced, and all similar equipment hereafter installed or replaced, served under general commercial schedules, the Company may require the Customer to provide, at the Customer's own expense, power factor corrective equipment to increase the power factor of any such devices to not less than ninety (90) percent.

C. If the Customer installs and owns the capacitors needed to supply his reactive power requirements, then the Customer must equip them with suitable disconnecting switches, so installed that the capacitors will be disconnected from the Company's lines whenever the Customer's load is disconnected from the Company's facilities.

D. Gaseous tube installations totaling more than one thousand (1,000) volt-amperes must be equipped with capacitors of sufficient rating to maintain a minimum of ninety percent (90%) lagging power factor.

E. Company installation and removal of metering equipment to measure power factor will be at the discretion of the Company.

TEP Settlement Agreement Issues Matrix

Terms & Conditions	Settlement Agreement	Opposition
I. Recitals	Rates should become effective on July 1, 2013.	None
II. Rate Increase	Non-fuel base rate increase of $76,194,000. • Over adjusted test-year retail revenues. Fuel base rate increase of $31,599,730. • Over current base fuel rates. Annual PPFAC recovery <u>reduction</u> of $52,750,597. PPFAC rate reset on effective date of new rates.	None
II. Rate Increase (Rate Base)	Original Cost Rate Base $1,507,062,648 Fair Value Rate Base $2,268,199,253 RCND Rate Base $3,029,335,858	None
II. Rate Increase (Revenue Requirement)	Total Adjusted Test Year $959,977,525 Total non-fuel $659,724,574 Total fuel $300,252,951	None
III. Bill Impact	Average monthly bill increase of less than $3 for an average residential customer.	None
IV. Cost of Capital	**Actual Capital Structure** 55.97% Long-term debt 0.53% Short-term debt 43.50% Common Equity **Return** 10.0% Return on Equity 5.18% Cost of long-term debt 1.42% Cost of short-term debt **Fair Value** 5.05% Rate of Return (includes 0.68% Rate of Return on fair value rate base increment)	None
V. Depreciation & Amortization Rates	As proposed by TEP.	None

EXHIBIT
TEP-6

TEP Settlement Agreement Issues Matrix

Terms & Conditions	Settlement Agreement	Opposition
VI. Purchased Power & Fuel Adjustment Clause	Average retail base fuel rate $0.032335/ kWh. PPFAC rate (credit) negative $0.001388/kWh. • Includes: one-time $3 million sulfur credit & $9.7 million San Juan fuel cost deferral. PPFAC modifications • Includes recovery of: broker fees; lime costs; sulfur credits & 100% of proceeds from SO_2 allowances. Defer reset of PPFAC rate from April 1, 2013 until effective date of new rates.	None
VII. Energy Efficiency Resource Plan	TEP will invest in cost-effective EE Programs & Measures, after the EE Programs & Measures and annual budgets have been approved by the Commission. Amortize investments over 5 years. Rate of return on investments (WACC approved in rate case). Recovery through DSM surcharge. Proposed DSM surcharge $0.0004443/kWh • Will be recovered from non-residential customers on a percentage of bill basis. Current DSM surcharge $0.001249/kWh TEP will resume funding of EE Programs previously approved by the Commission on March 1, 2013.	None* *In its pre-filed Settlement Testimony, TEP included an option based on the Existing EE Rules cost recovery methodology for comparison to EERP and for possible adoption in the event the Commission does not adopt the EERP.
VIII. Lost Fixed Cost Recovery (LFCR)	Recovery of certain costs attributable to reductions in kWh sales from EE & DG. • Portion of distribution & transmission costs. LFCR charge • Excludes large light & power; water pumping and lighting customers. • Fixed-rate option available to residential customers. 1% year-over-year cap. First LFCR charge will not be effective until 7/1/14, 2014; customer outreach program to begin by 2/14.	SWEEP – supports full decoupling instead of LFCR Sierra Club – supports SWEEP's position

TEP Settlement Agreement Issues Matrix

Terms & Conditions	Settlement Agreement	Opposition
IX. Environmental Compliance Adjustor (ECA) Surcharge	Recover government-mandated environmental compliance costs once environmental controls are placed in service. Capital Carrying Costs recovered through ECA surcharge. ECA rate capped at 0.25% of retail revenue ($0.00025 per kWh).	None
X. Springerville Unit 1	Lease agreement for SGS Unit 1 expires January 2015 TEP to file report w/ Commission by July 31, 2014 including: • SGS Unit 1 purchase or capacity rights commitments; • Power purchase or other replacement generating resource commitments; • Commitments regarding Coal Handling Facilities leases; and • Estimated non-fuel revenue requirement.	None
XI. Procurement	Staff's proposed modifications except for Risk Manager proposal.	None
XII. Low Income Programs	Lifeline bill impact generally reflective of average monthly dollar increase of a standard residential customer. PPFAC and DSM rates apply to Lifeline customers. TEP to make $150,000 annual contribution to ACAA for low-income utility bill assistance in lieu of interest from the LIFE Fund.	None
XIII. Nogales Transmission Line	TEP to seek recovery of costs related to transmission line from FERC before requesting recovery from ACC.	None
XIV. San Juan Thermal Event	Defer recovery of estimated $9.7 million of costs related to thermal event at the San Juan mine until insurance settlement is completed. Net costs recovered through the PPFAC.	None

TEP Settlement Agreement Issues Matrix

Terms & Conditions	Settlement Agreement	Opposition
XV. Rate Design	Consolidation and simplification of rate offerings. Lower percentage rate impact on small commercial customers than the other customer classes. Increase monthly customer charges. Revisions to Tariffs and Statement of Charges. Rate design portion of Settlement Agreement to remain open until July 1, 2014 to allow possible tariff adjustments to correct unanticipated rate impacts inconsistent with the public interest, provided that any such tariff changes will not reduce TEP's non-fuel revenue requirement.	SWEEP – opposes increase in monthly residential customer charge Sierra Club – supports SWEEP's position
XVI. Rules and Regulations	Revisions agreed to between TEP and ACC Staff.	None
XVII. Green Watts Tariff and Statement of Charges	Eliminate Green Watts Tariff. Revised Statement of Charges.	None
XVIII. Quality of Service	Within 180 days of approval of Settlement Agreement: • TEP will initiate a study to determine effectiveness and cost of converting (upgrading) certain circuits. • TEP will meet with Staff to review certain system reliability and efficiency issues.	None
XIX. Compliance Matters	Eliminate certain non-essential reporting requirements.	None

TEP Settlement Agreement Issues Matrix

Terns & Conditions	Settlement Agreements	Opposition
XXX. Additional Settlement Provisions	TEP will propose similar treatment of retail space at the Company headquarters in next rate case. TEP will make a filing proposing that the Commission open a docket to address accounting treatment for Net Operating Losses. TEP will apply any excess generation depreciation reserves to early retirement of production assets; in next rate case amortized any excess remaining reserves over 15 years. TEP will, over the next three years, meet with Staff and RUCO annually to review planned capital expenditures. TEP will file proposed tariffs for interruptible, partial requirement service and residential critical peak rates by August 30, 2013. TEP will propose a rate for 138kV or higher customers in next rate case.	None

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 1 of 4

July 2, 2012

EXHIBIT
ADMITTED
TEP-7

BEFORE THE ARIZONA CORPORATION COMMISSION

<u>COMMISSIONERS</u>
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 1 of 4

July 2, 2012

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-____ **APPLICATION**

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 $95.82 (a 12.5% 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

[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 $95.82.

---

[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

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

Paul J. Bonavia

on Behalf of

Tucson Electric Power Company

July 2, 2012

TABLE OF CONTENTS

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. <u>CHALLENGES</u>.

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.

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

TABLE OF CONTENTS

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.

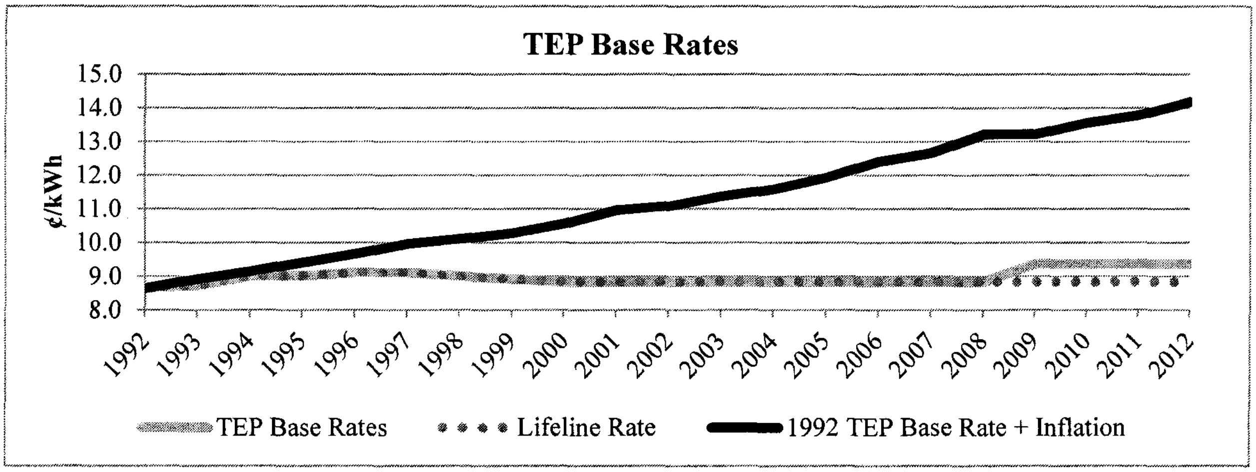
It is clear from the record that the prudently incurred cost increases TEP has endured during the rate freeze without the benefit of increased sales have rendered its current rates inadequate and do not afford the Company a reasonable opportunity to earn its authorized rate of return. TEP's rate increase 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?

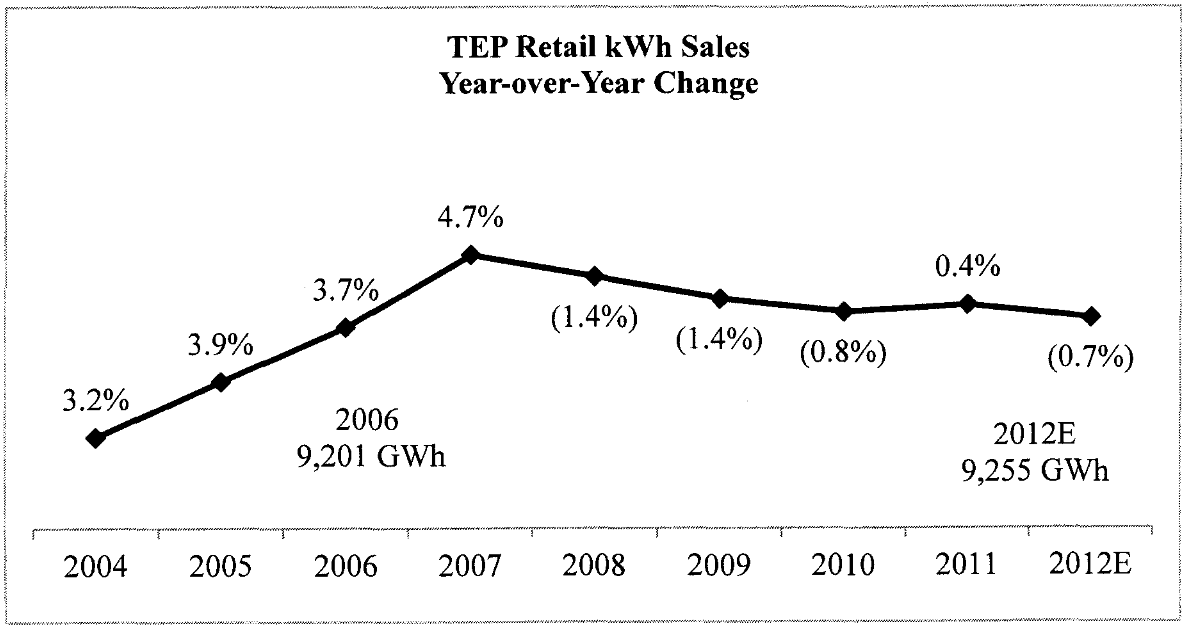
A. TEP's base rates have increased three times and decreased three times over the last 20 years. Despite the rising cost of goods and services, including those tracked by the Consumer Price Index ("CPI"), TEP's base rates, in real dollars, are lower than they were in 1992, as shown in the following chart.



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. <u>LOST FIXED COST RECOVERY MECHANISM.</u>

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.

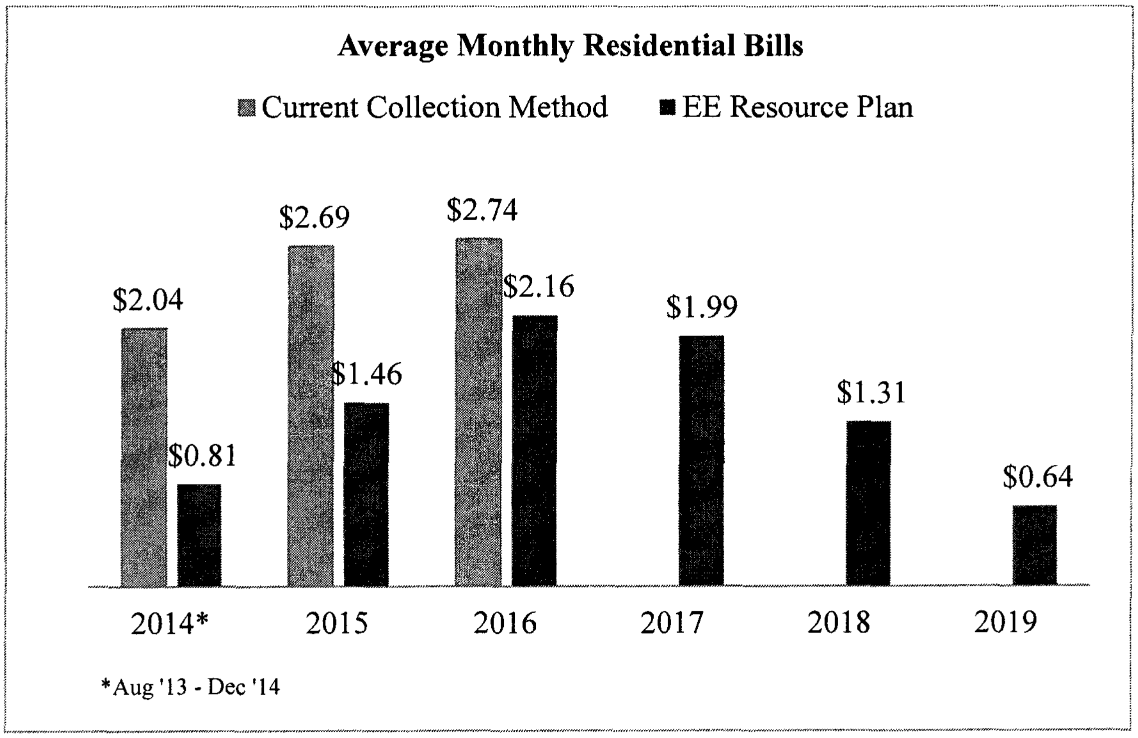
Q. What rate of return on EE investments is TEP requesting?

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. The Environmental Compliance Adjustor.

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. TEP's Solar Ownership Plan (Bright Tucson Solar Build-Out Plan).

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. <u>Post-Test Year Plant.</u>

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. <u>PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE.</u>

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. <u>Consolidation of Base Power Supply Rates into the PPFAC.</u>

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. Changes to the Plan of Administration.

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.

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

TABLE OF CONTENTS

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

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

---

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. GROWTH.

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.

BEFORE THE ARIZONA CORPORATION COMMISSION

<u>COMMISSIONERS</u>
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

TABLE OF CONTENTS

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.

[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:

[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. Operating Costs.

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)	% Total	Balance (in millions)	% Total
	12/31/2006	12/31/2006	12/31/2011	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,

---

[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	Proposed Debt % of	Cost of Debt		Reduction in Revenue
Rate Base ($000)	Capital Structure	Authorized	Proposed	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?

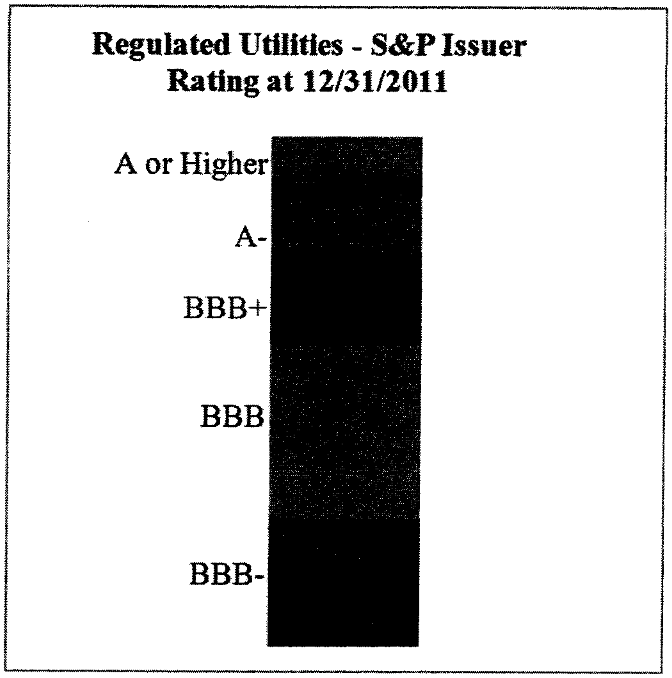
A. It is critical that the Company maintain, and hopefully improve, its credit ratings during this period when significant external financing is anticipated. Both the access to this anticipated new capital and the cost of new capital become more favorable with higher credit ratings, while also decreasing 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.

---

[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

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

Table Of Contents

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.

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

Each user of the information contained herein must make its own study and evaluation of each security it may consider purchasing, holding or selling. NO WARRANTY, EXPRESS OR IMPLIED, AS TO THE ACCURACY, TIMELINESS, COMPLETENESS, MERCHANTABILITY OR FITNESS FOR ANY PARTICULAR PURPOSE OF ANY SUCH RATING OR OTHER OPINION OR INFORMATION IS GIVEN OR MADE BY MOODY'S IN ANY FORM OR MANNER WHATSOEVER.

MIS, a wholly-owned credit rating agency subsidiary of Moody's Corporation ("MCO"), hereby discloses that most issuers of debt securities (including corporate and municipal bonds, debentures, notes and commercial paper) and preferred stock rated by MIS have, prior to assignment of any rating, agreed to pay to MIS for appraisal and rating services rendered by it fees ranging from $1,500 to approximately $2,500,000. MCO and MIS also maintain policies and procedures to address the independence of MIS's ratings and rating processes. Information regarding certain affiliations that may exist between directors of MCO and rated entities, and between entities who hold ratings from MIS and have also publicly reported to the SEC an ownership interest in MCO of more than 5%, is posted annually at www.moodys.com under the heading "Shareholder Relations — Corporate Governance — Director and Shareholder Affiliation Policy."

Any publication into Australia of this document is by MOODY'S affiliate, Moody's Investors Service Pty Limited ABN 61 003 399 657, which holds Australian Financial Services License no. 336969. This document is intended to be provided only to "wholesale clients" within the meaning of section 761G of the Corporations Act 2001. By continuing to access this document from within Australia, you represent to MOODY'S that you are, or are accessing the document as a representative of, a "wholesale client" and that neither you nor the entity you represent will directly or indirectly disseminate this document or its contents to "retail clients" within the meaning of section 761G of the Corporations Act 2001.

Notwithstanding the foregoing, credit ratings assigned on and after October 1, 2010 by Moody's Japan K.K. ("MJKK") are MJKK's current opinions of the relative future credit risk of entities, credit commitments, or debt or debt-like securities. In such a case, "MIS" in the foregoing statements shall be deemed to be replaced with "MJKK". MJKK is a wholly-owned 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 or 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-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 User's Guide.

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.

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.

REGULATORY DISCLOSURES

The Global Scale Credit Ratings on this press release that are issued by one of Moody's affiliates outside the EU are endorsed by Moody's Investors Service Ltd., One Canada Square, Canary Wharf, London E 14 5FA, UK, in accordance with Art.4 paragraph 3 of the Regulation (EC) No 1060/2009 on Credit Rating Agencies. Further information on the EU endorsement status and on the Moody's office that has issued a particular Credit Rating is available on www.moodys.com.

For ratings issued on a program, series or category/class of debt, this announcement provides relevant regulatory disclosures in relation to each rating of a subsequently issued bond or note of the same series or category/class of debt or pursuant to a program for which the ratings are derived exclusively from existing ratings in accordance with Moody's rating practices. For ratings issued on a support provider, this announcement provides relevant regulatory disclosures in relation to the rating action on the support provider and in relation to each particular rating action for securities that derive their credit ratings from the support provider's credit rating. For provisional ratings, this announcement provides relevant regulatory disclosures in relation to the provisional rating assigned, and in relation to a definitive rating that may be assigned subsequent to the final issuance of the debt, in each case where the transaction structure and terms have not changed prior to the assignment of the definitive rating in a manner that would have affected the rating. For further information please see the ratings tab on the issuer/entity page for the respective issuer on www.moodys.com.

Information sources used to prepare the rating are the following : parties involved in the ratings, parties not involved in the ratings, public information, confidential and proprietary Moody's Investors Service information, and confidential and proprietary Moody's Analytics information.

Moody's considers the quality of information available on the rated entity, obligation or credit satisfactory for the purposes of issuing a rating.

Moody's adopts all necessary measures so that the information it uses in assigning a rating is of sufficient quality and from sources Moody's considers to be reliable including, when appropriate, independent third-party sources. However, Moody's is not an auditor and cannot in every instance independently verify or validate information received in the rating process.

Please see the ratings disclosure page on www.moodys.com for general disclosure on potential conflicts of interests.

Please see the ratings disclosure page on www.moodys.com for information on (A) MCO's major shareholders (above 5%) and for (B) further information regarding certain affiliations that may exist between directors of MCO and rated entities as well as (C) the names of entities that hold ratings from MIS that have also publicly reported to the SEC an ownership interest in MCO of more than 5%. A member of the board of directors of this rated entity may also be a member of the board of directors of a shareholder of Moody's Corporation; however, Moody's has not independently verified this matter.

Please see Moody's Rating Symbols and Definitions on the Rating Process page on www.moodys.com for further information on the meaning of each rating category and the definition of default and recovery.

Please see ratings tab on the issuer/entity page on www.moodys.com for the last rating action and the rating history.

The date on which some ratings were first released goes back to a time before Moody's ratings were fully digitized and accurate data may not be available. Consequently, Moody's provides a date that it believes is the most reliable and accurate based on the information that is available to it. Please see the ratings disclosure page on our website www.moodys.com for further information.

Please see www.moodys.com for any updates on changes to the lead rating analyst and to the Moody's legal entity that has issued the rating.

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

MOODY'S
INVESTORS SERVICE

CREDIT RATINGS ISSUED BY MOODY'S INVESTORS SERVICE, INC. ("MIS") AND ITS AFFILIATES ARE MOODY'S CURRENT OPINIONS OF THE RELATIVE FUTURE CREDIT RISK OF ENTITIES, CREDIT COMMITMENTS, OR DEBT OR DEBT-LIKE SECURITIES, AND CREDIT RATINGS AND RESEARCH PUBLICATIONS PUBLISHED BY MOODY'S ("MOODY'S PUBLICATIONS") MAY INCLUDE MOODY'S CURRENT OPINIONS OF THE RELATIVE FUTURE CREDIT RISK OF ENTITIES, CREDIT COMMITMENTS, OR DEBT OR DEBT-LIKE SECURITIES. MOODY'S DEFINES CREDIT RISK AS THE RISK THAT AN ENTITY MAY NOT MEET ITS CONTRACTUAL, FINANCIAL OBLIGATIONS AS THEY COME DUE AND ANY ESTIMATED FINANCIAL LOSS IN THE EVENT OF DEFAULT. CREDIT RATINGS DO NOT ADDRESS ANY OTHER RISK, INCLUDING BUT NOT LIMITED TO: LIQUIDITY RISK, MARKET VALUE RISK, OR PRICE VOLATILITY. CREDIT RATINGS AND MOODY'S OPINIONS INCLUDED IN MOODY'S PUBLICATIONS ARE NOT STATEMENTS OF CURRENT OR HISTORICAL FACT. CREDIT RATINGS AND MOODY'S PUBLICATIONS DO NOT CONSTITUTE OR PROVIDE INVESTMENT OR FINANCIAL ADVICE, AND CREDIT RATINGS AND MOODY'S PUBLICATIONS ARE NOT AND DO NOT PROVIDE RECOMMENDATIONS TO PURCHASE, SELL, OR HOLD PARTICULAR SECURITIES. NEITHER CREDIT RATINGS NOR MOODY'S PUBLICATIONS COMMENT ON THE SUITABILITY OF AN INVESTMENT FOR ANY PARTICULAR INVESTOR. MOODY'S ISSUES ITS CREDIT RATINGS AND PUBLISHES MOODY'S PUBLICATIONS WITH THE EXPECTATION AND UNDERSTANDING THAT EACH INVESTOR WILL MAKE ITS OWN STUDY AND EVALUATION OF EACH SECURITY THAT IS UNDER CONSIDERATION FOR PURCHASE, HOLDING, OR SALE.

 All information contained herein is obtained by MOODY'S from sources believed by it to be accurate and reliable. Because of the possibility of human or mechanical error as well as other factors, however, all information contained herein is provided "AS IS" without warranty of any kind. MOODY'S adopts all necessary measures so that the information it uses in assigning a credit rating is of sufficient quality and from sources Moody's considers to be reliable, including, when appropriate, independent third-party sources. However, MOODY'S is not an auditor and cannot in every instance independently verify or validate information received in the rating process. Under no circumstances shall MOODY'S have any liability to any person or entity for (a) any loss or damage in whole or in part caused by, resulting from, or relating to, any error (negligent or otherwise) or other circumstance or contingency within or outside the control of MOODY'S or any of its directors, officers, employees or agents in connection with the procurement, collection, compilation, analysis, interpretation, communication, publication or delivery of any such information, or (b) any direct, indirect, special, consequential, compensatory or incidental damages whatsoever (including without limitation, lost profits), even if MOODY'S is advised in advance of the possibility of such damages, resulting from the use of or inability to use, any such information. The ratings, financial reporting analysis, projections, and other observations, if any, constituting part of the information contained herein are, and must be construed solely as, statements of opinion and not statements of fact or recommendations to purchase, sell or hold any securities. Each user of the information contained herein must make its own study and evaluation of each security it may consider purchasing, holding or selling. NO WARRANTY, EXPRESS OR IMPLIED, AS TO THE ACCURACY, TIMELINESS, COMPLETENESS, MERCHANTABILITY OR FITNESS FOR ANY PARTICULAR PURPOSE OF ANY SUCH RATING OR OTHER OPINION OR INFORMATION IS GIVEN OR MADE BY MOODY'S IN ANY FORM OR MANNER WHATSOEVER.