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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

GARY PIERCE, Chairman
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA	Docket No. E-01933A-12-0291 **NOTICE OF FILING REDACTED DIRECT TESTIMONY (REVENUE REQUIREMENT) AND EXHIBITS OF KEVIN C. HIGGINS ON BEHALF OF FREEPORT-MCMORAN COPPER & GOLD INC. AND ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION**

Freeport-McMoRan Copper & Gold Inc. and Arizonans for Electric Choice and Competition (collectively "AECC"), hereby submit the Redacted Direct Testimony (Revenue Requirement) and Exhibits of Kevin C. Higgins on behalf of AECC in the above captioned Docket.

For the parties who have signed the Tucson Electric Power Company ("TEP") Protective Agreement, they will be able to view the confidential portion of Mr. Higgins' Testimony by accessing the TEP Rate Case Data Room site.

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PROFESSIONAL CORPORATION
PHOENIX

RESPECTFULLY SUBMITTED this 21st day of December 2012.

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BEFORE THE ARIZONA CORPORATION COMMISSION

In the Matter of the Application of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates And Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of Its Operations Throughout the State of Arizona	)	Docket No. E-01933A-12-0291

REDACTED

Direct Testimony of Kevin C. Higgins

on behalf of

Freeport-McMoRan Copper & Gold Inc. and

Arizonans for Electric Choice & Competition

Revenue Requirement

December 21, 2012

DIRECT TESTIMONY OF KEVIN C. HIGGINS

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EXHIBITS (Continued)

DIRECT TESTIMONY OF KEVIN C. HIGGINS

INTRODUCTION

Q. Please state your name and business address.

A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

Q. By whom are you employed and in what capacity?

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this proceeding?

A. My testimony is being sponsored by Freeport-McMoRan Copper & Gold Inc. and Arizonans for Electric Choice and Competition ("AECC"). AECC is a business coalition that advocates on behalf of retail electric customers in Arizona.[1]

Q. Please describe your professional experience and qualifications.

A. My academic background is in economics, and I have completed all coursework and field examinations toward the Ph.D. in Economics at the University of Utah. In addition, I have served on the adjunct faculties of both the University of Utah and Westminster College, where I taught undergraduate and graduate courses in economics. I joined Energy Strategies in 1995, where I assist

[1] Henceforth in this testimony, Freeport-McMoRan Copper & Gold Inc. and AECC collectively will be referred to as "AECC."

private and public sector clients in the areas of energy-related economic and policy analysis, including evaluation of electric and gas utility rate matters.

Prior to joining Energy Strategies, I held policy positions in state and local government. From 1983 to 1990, I was economist, then assistant director, for the Utah Energy Office, where I helped develop and implement state energy policy. From 1991 to 1994, I was chief of staff to the chairman of the Salt Lake County Commission, where I was responsible for development and implementation of a broad spectrum of public policy at the local government level.

Q. Have you testified before this Commission in other dockets?

A. Yes. I have testified in a number of proceedings before this Commission, including the generic proceeding on retail electric competition (1998),[2] the hearings on the Arizona Public Service Company ("APS") 1999 Settlement Agreement (1999),[3] the hearings on the Tucson Electric Power ("TEP") 1999 Settlement Agreement (1999),[4] the AEPCO transition charge hearings (1999),[5] the Commission's Track A proceeding (2002),[6] the APS adjustment mechanism proceeding (2003),[7] the Arizona ISA proceeding (2003),[8] the APS 2004 rate case (2004),[9] the Trico 2004 rate case (2005),[10] the TEP 2004 rate review (2005),[11] the APS 2006 interim rate proceeding (2006),[12] the APS 2006 rate case (2006),[13]

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[2] Docket No. RE-00000C-94-0165.
[3] Docket Nos. RE-00000C-94-0165, E-01345A-98-0471, and E-01345A-98-0473.
[4] Docket Nos. RE-00000C-94-0165, E-01933A-97-0772, and E-01933A-97-0773.
[5] Docket No. E-01773A-98-0470.
[6] Docket Nos. E-00000A-02-0051; E-01345A-01-0822; E-00000A-01-0630; E-01933A-02-0069; E-01933A-98-0471.
[7] Docket No. E-01345A-02-0403.
[8] Docket No. E-00000A-01-0630.
[9] Docket No. E-01345A-03-0437.
[10] Docket No. E-01461A-04-0607.
[11] Docket No. E-01933A-04-0408.
[12] Docket No. E-01345A-06-0009.

TEP's request to amend Decision No. 62103 (2007),[14] the TEP 2007 rate case (2008),[15] the APS 2008 rate case (2008),[16] the APS 2011 rate case (2011-12),[17] and the TEP 2011 Energy Efficiency Plan (2012).[18]

Q. Have you testified before utility regulatory commissions in other states?

A. Yes. I have testified in approximately 145 other proceedings on the subjects of utility rates and regulatory policy before state utility regulators in Alaska, Arkansas, Colorado, Georgia, Idaho, Illinois, Indiana, Kansas, Kentucky, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, New York, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, Texas, Utah, Virginia, Washington, West Virginia, and Wyoming. I have also participated in various Pricing Processes conducted by the Salt River Project Board and have filed affidavits in proceedings at the Federal Energy Regulatory Commission.

A more detailed description of my qualifications is contained in Appendix A, attached to this testimony.

OVERVIEW AND CONCLUSIONS

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

A. My testimony addresses seven major topics:

(1) TEP's request for a non-fuel rate increase of $127.3 million;

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[13] Docket No. E-01345A-05-0816.
[14] Docket No. E-01933A-05-0650.
[15] Docket No. E-01933A-07-0402.
[16] Docket No. E-01345A-08-0172.
[17] Docket No. E-01345A-11-0224.
[18] Docket No. E-01933A-11-0055.

(2) TEP's proposal to change the structure of the Purchased Power and Fuel Adjustment Charge ("PPFAC");

(3) TEP's proposal for adoption of a Lost Fixed Cost Recovery ("LFCR") mechanism;

(4) TEP's proposal for adoption of an Environmental Compliance Adjustor;

(5) TEP's proposal for an energy efficiency resource plan;

(6) TEP's recommended ratemaking treatment for its net operating loss carryforward as it applies to the Company's accumulated deferred income tax balance; and

(7) TEP's proposal for a solar ownership plan.

In my testimony, I recommend adjustments to TEP's proposals that I believe are necessary to ensure results that are just and reasonable.

Relative to the wide scope of this general rate proceeding, my recommended adjustments are concentrated on a limited number of issues. Absence of comment on my part regarding a particular issue does not signify support (or opposition) toward the Company's filing with respect to the non-discussed issue.

Q. What are the primary conclusions and recommendations presented in your testimony?

A. (1) I recommend that TEP's revenue requirement be reduced by at least **$44.525** million relative to the $127.3 million base rate increase proposed by the Company in its Application. This reduction does not take into account adjustments that may be offered by other parties not addressed in my testimony.

(2) I recommend that TEP's proposal to change the structure of the PPFAC be rejected by the Commission. I also recommend that the Commission reject TEP's proposal to change the definition of Long-Term Energy Sales in the PPFAC Plan of Administration. Moreover, in retaining the PPFAC as an adjustor mechanism, I strongly encourage the Commission to consider adopting a 70/30 risk-sharing mechanism, similar to what was approved by the Wyoming and Utah commissions in 2011.

(3) I recommend that TEP's LFCR mechanism be rejected as proposed. The mechanism should not be considered unless the following modifications are made:

- Larger customers (LGS and LLP) should be excluded from the LFCR program and recovery of their fixed delivery costs addressed through rate design.
- The LFCR calculation should be modified such that it is limited to unbundled delivery service revenues calculated using the unbundled delivery charges stated in TEP's tariff.
- The LFCR mechanism proposed by TEP fails to recognize load growth. The kilowatt-hours used for measuring going-forward lost revenue recovery should be limited to the <u>lesser</u> of energy efficiency improvements attributable to TEP programs or actual net reductions in retail kilowatt-hours sold relative to the retail kilowatt-hours used in setting base rates.

(4) TEP's proposed Environmental Compliance Adjustor is an example of unwarranted single-issue ratemaking, and should be rejected by the Commission.

Before considering an annual rider to recover TEP's environmental upgrade costs, the Commission should consider establishing a review process that subjects these investments to Commission and stakeholder review, including consideration of alternative actions, well in advance of the arrival of the projects as proposed additions to rate base.

(5) TEP proposes to amortize the recovery of energy efficiency expenses over four years. I do not object to the proposed four-year amortization, but I disagree with TEP's proposed ROE premium of 200 basis points on energy efficiency investment, and recommend that the proposed premium be rejected. Further, I recommend that on a going-forward basis, the overall costs of TEP's energy efficiency programs be kept within 3.0 percent of customers' total bills and that the DSMS for non-residential customers be assessed on an equal percentage basis, as proposed in the TEP EE settlement agreement filed in Docket No. E-01933A-11-0055. I recommend that these rate impact and rate design parameters be a condition of any TEP energy efficiency resource plan approved by the Commission.

(6) With respect to the net operating loss carryforward, I recommend that the Commission recognize the accumulated deferred income tax asset as proposed by TEP in setting rates in this case, but also require TEP to establish a regulatory liability when bonus tax depreciation associated with plant included in rate base in this case is applied against future tax years.

(7) I recommend that the Commission deny TEP's request for approval for four consecutive years of solar project investments. It is essential that the Commission retain direct control over approving each year's REST budget. TEP

should not be granted a four-year authorization to build solar projects when the cost consequences to customers from future REST filings remain unknown.

ADJUSTMENTS TO BASE REVENUE INCREASE

Q. What increase in base revenues is TEP recommending in this case?

A. In its Application, TEP is requesting a non-fuel rate increase of $127.3 million, or 15.3 percent, to become effective on or before August 1, 2013.[19]

This requested increase is accompanied by a proposal to remove all fuel and purchased power expense from base rates and shift cost recovery of these items entirely to the PPFAC; currently, the PPFAC serves only as an adjustor mechanism that recovers from, or credits to, customers fuel and purchased power expense to the extent this expense *deviates* from the level set in base rates. As part of its filing, TEP is projecting an increase of fuel and purchased power costs of $23.5 million over the amount currently recovered in base rates.[20] If TEP's proposal to separate all fuel and purchased power expense from base rates is rejected, then TEP is seeking to recover this projected increase of $23.5 million of fuel and purchased power costs through its base rates, resulting in a total base rate increase of $150.8 million per year. However, the incremental fuel and purchased power cost of $23.5 million is already being recovered from customers through the 2012 Forward Component of the PPFAC; thus, the inclusion of these latter

[19] Direct testimony of David G. Hutchens, p. 3.
[20] Calculated as $292,189,698 - $268,253,221; from TEP Responses to STF 9.14.a and STF 9.12.c.

costs in base rates would not represent a net increase in overall rates to customers.[21]

Q. Do you have any recommended adjustments to TEP's proposed base rate increase?

A. Yes. I am recommending a reduction of **$44.525** million to TEP's proposed base rate increase relative to the Company's Application. This recommendation is presented in Exhibit KCH-1 and is summarized in Table KCH-1 and consists of the following adjustments, each of which will be discussed in turn:

[21] The amount recovered by the 2012 Forward Component of the PPFAC is actually $24.3 million. See TEP Response to STF 9.12.c.

Table KCH-1
Summary of AECC Adjustments to TEP Revenue Requirements

	ACC Jurisdictional Adjustment Amount ($000s)
Rate Base Adjustments	
Sahuarita - Nogales Transmission Line Disallowance	($4,375)
2012 Average Rate Base Adjustment	
Post Test Year Capital Additions	($376)
2012 Rate Base Accum. Depr. & ADIT	($7,367)
Revenue Adjustments	
Springerville Third Party Revenue Recognition	($7,240)
Expense Adjustments	
Payroll Expense Adjustment	($1,915)
Overhaul Adjustment	($2,371)
Injuries & Damages Adjustment	($101)
Lime Expense Adjustment	($836)
Incentive Compensation Adjustment	($3,052)
Cost of Capital Adjustments	
Capital Structure Adjustment	($5,632)
Cost of Debt Adjustment	($1,188)
Return on Equity Adjustment	($6,624)
Allowed Return on New TEP Headquarters Building Adj.	($2,389)
REST-Related Adjustment	
Post-Test Year Renewables Adjustment	($1,059)
Total AECC Adjustments	($44,525)

Sahuarita – Nogales Transmission Project

Q. What is the Sahuarita-Nogales transmission project?

A. This project was intended to provide Arizona's first significant transmission link to Mexico, as well as provide additional transmission to Santa Cruz County, a territory that was served by Citizens Utilities, TEP's initial partner in the venture.

Q. How did TEP come to be involved in this project?

A. In 1999, the Commission had approved a settlement agreement that required Citizens to build a second transmission line to serve customers in Santa Cruz County. According to TEP witness Michael J. DeConcini, TEP was concerned that the construction of the new Citizens line "would preclude future transmission projects in the region, including a new link to Mexico,"[22] which TEP had been contemplating as far back as 1991. Accordingly, TEP approached Citizens and proposed a joint transmission project that would provide a second transmission source in Santa Cruz County, as well as provide the major link to Mexico that TEP sought.

In 2000, TEP and Citizens entered into a Memorandum of Understanding ("MOU") to design, site, permit, and build the project. In January 2002, the Commission approved a Certificate of Environmental Compatibility ("CEC") for the project for construction along a western corridor. However, in March 2005, the U.S. Forest Service released a final Environmental Impact Statement indicating that a central corridor was its preference. According to Mr. DeConcini, because that preference "conflicted with the Commission's decision, TEP was left without authorization to build the line along a single route."[23]

Q. What is the current status of the project?

A. According to Mr. DeConcini, TEP and Citizens' successor, UNS Electric, a TEP affiliate, are "leaning toward abandoning the project."[24] Mr. DeConcini cites the difficulties in coming to agreement with the Forest Service on a path for

[22] Direct testimony of Michael J. DeConcini, p. 39, pp. 5-6.
[23] Ibid, p. 39.
[24] Ibid, p. 40.

the line, the high cost of completing the project, and the limited progress in reaching an interconnection agreement with Mexico as contributing factors in moving toward this decision. Moreover, lower-than-projected load growth in the UNS Electric service territory and other, less expensive upgrades to the local transmission system apparently have obviated the need for the project to serve local needs.

Q. What has TEP proposed in this case with respect to recovery of the costs of the Sahuarita-Nogales transmission project?

A. TEP is proposing to establish a regulatory asset that will allow recovery of $8.9 million in Sahuarita-Nogales transmission project development costs over a three-year amortization period. In addition, the unamortized balance would be included in rate base and earn TEP's authorized rate of return. Further, $2.1 million in land costs would be included in rate base, but not included in the three-year amortization.

Q. What is your recommendation to the Commission regarding the recovery of Sahuarita-Nogales transmission project costs from TEP ratepayers?

A. I recommend that the Commission reject TEP's proposal to recover Sahuarita-Nogales transmission project costs from TEP ratepayers. These costs should be disallowed in their entirety. This project, which is on the verge of being abandoned, is not used and useful and does not – and will not – provide any benefits to TEP ratepayers.

In defending the Company's proposal, Mr. DeConcini asserts that TEP's expenditure to develop this project was prudently incurred. He also refers to the Commission's "directive to develop the project."[25]

I disagree with Mr. DeConcini's characterization of prudency. In Decision No. 62011, (November 2, 1999) the Commission directed Citizens to develop the initial project to improve service in Santa Cruz County. The Commission's directive to Citizens to improve service to its customers causes no cost implications for TEP customers. It was later, in furtherance of its objectives to interconnect with Mexico, that TEP interposed in Citizens' efforts to upgrade its local system. However, the subsequent approval of the Sahuarita-Nogales CEC was limited to environmental considerations and neither confers a finding of prudence nor assurance of cost recovery.

Q. Are you familiar with TEP's regulatory circumstances at the time the Company entered into the MOU with Citizens to develop the project?

A. Yes. In 1999, the Commission approved a settlement agreement that was intended to transition TEP to retail electric competition.[26] The MOU with Citizens was signed the very next year. Under the terms of the 1999 Settlement Agreement, TEP's retail rates were capped until January 1, 2009. During that time period, all profits from TEP's off-system sales were retained by the Company and not shared with customers. Moreover, Section 3.1 of the 1999 Settlement Agreement required divestiture of TEP's generation assets by December 31, 2002, which would have resulted in TEP's retail rates being driven

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[25] Ibid, p. 40.
[26] Docket Nos. RE-00000C-94-0165, E-01933A-97-0772, and E-01933A-97-0773.

by the pass-through of market prices upon expiration of the rate cap. Under such circumstances, the profits from off-system sales and purchases from Mexico would have inured solely to TEP shareholders. The divestiture requirement was in force until September 10, 2002, when the Commission's Track A decision directed TEP to cancel its plans for the divestiture of its assets. Thus, at the time TEP entered the MOU with Citizens, the Company's expectation was that all profits from wholesale transactions with Mexico would be retained by shareholders, and not shared at all with customers. The corollary is that TEP clearly undertook its Sahuarita-Nogales venture solely at shareholder risk.

Significantly, even after the Commission's Track A decision, TEP steadfastly maintained that its retail rates after January 1, 2009 would be set by market prices. In September 2005, TEP filed a motion to amend Decision No. 62103 in which the Company sought resolution over whether TEP was entitled to charge market-based rates for generation service under the 1999 settlement agreement.[27] Then, as recently as TEP's last rate case, the Company argued that it was entitled to set retail rates for generation service using a market-based formula tied to the forward market price at Palo Verde.[28] Although others (myself included) disagreed with TEP's interpretation of the requirements of its future pricing structure, if TEP's interpretation had been upheld by the Commission, then it would have followed that all future profits from transactions with Mexico would be retained by shareholders. It was not until May 29, 2008, when TEP entered a settlement agreement in Docket No. E-01933A-05-0650, that TEP

[27] Docket No. E-01933A-05-0650.
[28] Docket No. E-01933A-07-0402. See direct testimony of James S. Pignatelli, esp. pp. 4-7, 14.

finally relinquished its market pricing argument. But by that time, the Sahuarita-Nogales transmission project had already ground to a regulatory standstill. The upshot is that funds expended by TEP in furtherance of interconnection with Mexico should be viewed in the context of TEP's advocacy prior to May 2008 for market pricing of its retail generation service.

In summary, TEP's request to recover costs associated with the Sahuarita-Nogales transmission project should be denied. This project is not used and useful and provides no benefits to TEP customers. Moreover, TEP's pursuit of this project was initiated at a time in which TEP intended that the full benefits of profits from power sales and purchases to and from Mexico would inure to shareholders. Thus, the development costs associated with this project were undertaken solely at shareholder risk.

Q. What is the impact on TEP's jurisdictional revenue requirement from your adjustment?

A. My adjustment to disallow recovery of expenditures related to the Sahuarita-Nogales transmission project is shown in Exhibit KCH-2. This adjustment reduces TEP's ACC jurisdictional revenue requirement by approximately **$4.375** million.

Post-Test Year Adjustments

Q. What is meant by the term "test year" as used in ratemaking?

A. "Test year" refers to a discrete twelve-month period that is used as the basis for setting utility rates in a general rate proceeding. This term is often used interchangeably with the term "test period," although some jurisdictions make a fine distinction between the two, with "test year" referring to the baseline period for which underlying historical financial and operating data must be reported and "test period" referring to the twelve-month period used for setting rates. When this distinction is made, test year and test period can be coterminous, overlapping, or entirely distinct time periods.

Q. What test year is TEP using in its application?

A. Officially, the test year that TEP is using for revenue requirement purposes is Calendar Year 2011. As such, TEP begins its analysis by presenting a Calendar Year 2011 baseline that sets out the Company's twelve-month revenue, expense, and investment levels. These results are then adjusted for ratemaking purposes, which is typical in most general rate proceedings. However, in most ratemaking contexts, the test period analysis that results from such adjustments can be readily described with reference to a discrete time period, e.g., "2011 historical test year with known and measureable changes through 12/31/12," or "2012 projected test period," etc.

TEP's filing defies such a clear description. While the basis of the Company's filing starts with 2011 actual revenues, expenses, and investment, the filing incorporates various revenue, expense, and investment elements that are adjusted for values that either occurred or are projected to occur variously in 2012, 2013, or even 2014, but without adhering to a consistent time frame for all adjustments. The disparate time frames used by TEP for its test period adjustments are highlighted in Table KCH-2, below, which identifies the time period applicable to selected TEP proposed adjustments.

Table KCH-2
Time Frame for Various TEP-Proposed Adjustments

Adjustment	Time Frame For Valuation	Reference
Rate Base	Year ended 2011 plant balances, with capital additions through 2012. Accumulated depreciation calculated for the period Dec. 2012-Sep. 2013 for Post-Test Year Renewables.	Bonavia, p. 14; TEP Rate Base - Post Test Year Renewable Workpaper, Bates No. TEP(0291)007697.
Payroll Expense	Escalated by 3% for 2012, and again by 3% for 2013.	TEP Income - Payroll Expense Workpaper, Bates No. TEP(0291)007252.
Incentive Compensation	Adjustment based on an average of adjusted 2009 through 2011 incentive compensation levels, escalated by 1% for each year 2010 through 2014.	TEP Income - Incentive Compensation Workaper, Bates No. TEP(0291)007213.
Lime Expense	Jan.-Apr. 2012 data for net lime cost per MWh forms the basis of an annual adjustment to 2011 lime expense for Springerville Unit 2.	TEP Income - Lime Expense Workpaper, Bates No. TEP(0291)007230.
Fuel & Purchased Power	Year ending March 31, 2013.	TEP 6. TEP PPFAC DFD-8.xlsx Workpaper.
Retail Sales	Weather normalized and annualized to end of 2011 customer count.	Jones, pp. 6, 10.
Property Tax	The property tax assessment rate for 2013 and the average property tax rate for 2012, applied to adjusted utility plant including Post-Test Year additions.	Kissinger, p. 42.; TEP Income - Property Tax Workpaper, Bates No. TEP(0291)007304.

In my view, TEP's blending of a Calendar Year 2011 test year with adjustments that are from disparate time periods results in a test period that is ill-defined and unsynchronized.

Q. What do you mean by "unsynchronized" test period?

A. A test period is considered to be fully synchronized when all elements used in ratemaking – i.e., rate base, revenues, and expenses – correspond to the very same time period, both with respect to the twelve-month period selected for measurement (e.g., Calendar Year 2011) as well as <u>when</u> during the selected period these values are being measured (i.e., end-of-period values versus average-of-period values). Conversely, a test period is considered to be unsynchronized when all elements used in ratemaking do *not* correspond to the same time period.

Q. In general, is it preferable for test periods to be fully synchronized?

A. Yes. A fully-synchronized test period adheres to what is known as the "matching principle." Measuring rate base, revenues, and expenses over the same twelve-month period and in the same manner (i.e., end-of-period or average-of-period) properly aligns these major ratemaking elements, ensuring the most reasonable basis for measuring whether the utility's rates provide it with a reasonable opportunity to earn its authorized rate of return. In contrast, an unsynchronized test period creates the potential for mismatches among ratemaking elements that distort the proper measurement of the utility's rate of return over the test period.

Q. What is TEP recommending with respect to post-test year plant adjustments?

A. TEP is proposing that two sets of post-test year plant adjustments be recognized for ratemaking purposes, which the Company refers to as "post-test year" and "post-test year renewable." Because the ratemaking treatment of the "post-test year renewable" plant interacts with cost recovery through the Renewable Energy Standard and Tariff ("REST"), I will treat the renewable and non-renewable post-test year plant separately. As proposed, the (non-renewable) post-test year plant adjustments add $22.8 million in total Company net plant[29] associated with facilities that are scheduled to come on line after December 31, 2011, but which are projected to be in service by December 31, 2012.

Q. What is your assessment of TEP's proposal for post-test period plant adjustments?

A. In general, TEP's proposal for post-test period plant additions is problematic in that it attempts to recover a return on (projected) new plant in service that is not synchronized with the underlying test year. One potential problem with this unsynchronized approach is that the cost of new plant added through December 31, 2012 would be recovered in rates that are calculated based on the level of retail sales that existed at the end of 2011, rather than the sales that are projected for 2012, consistent with the proposed recovery of the cost of the new plant. However, in this particular circumstance, TEP's retail load in 2012 appears to be nearly identical to that experienced in 2011, mitigating this potential pitfall.

My concerns about unsynchronized test period notwithstanding, there may be a case for recognizing post-test period plant additions because TEP may not have the ability to pursue the more straightforward option of filing a rate case using a fully-projected (i.e., future) test period, an option that is available to many other utilities in the country. R14-2-103 defines test year as "the one-year *historical* period used in determining rate base, operating income and rate of return." [Emphasis added] R14-2-103 goes on to state that "the end of the test

[29] Source: TEP Rate Base – Post-Test Year Workpaper.

year shall be the most recent practical date available prior to the filing." While I can offer no legal opinion on this language, one possible interpretation is that only historical test periods may be used to set rates in a TEP rate case. For a utility that is adding new capital investment, limiting cost recovery to plant that is in service no later than December 31, 2011 – for a rate effective period starting in 2013 – creates predictable concerns about regulatory lag. The inclusion of post-test period plant is an obvious attempt to address this concern while maintaining the formality of an historical test period.

Q. Given the preceding discussion, do you support TEP's proposed post-test year plant additions adjustment as filed?

A. No, I do not. On balance, I support some recognition of post-test year plant additions, but not as proposed by TEP. I have two specific objections to TEP's proposal for (non-renewable) post-test year plant, which I address through two adjustments. In addition, I have a separate objection to a portion of the renewable plant additions, which I address in a separate discussion in my testimony.

Q. Please proceed. What is your first basis for objecting to TEP's proposal for a post-test year plant adjustment in the form requested by the Company?

A. The first basis is that TEP proposes to recognize its post-test period rate base adjustments as projected end-of-period values rather than average-of-period values.

Q. What does it mean for rate base to be projected to an end-of-period value?

A. It means that for the purpose of setting rates, TEP is proposing to use its forecasted value of the rate base additions on the last day of its proposed measurement period for the plant additions, December 31, 2012.

Q. Please explain your disagreement with TEP regarding the use of end-of-period rate base for the plant additions.

A. The sole justification for using an end-of-period rate base is to address utility concerns about regulatory lag. According to the regulatory lag argument, utilities are challenged to earn their authorized rates of return on investment during periods of system expansion when historical test periods are used for setting rates. One means of reducing regulatory lag is to use a projected test period – or in this instance, an adjustment for projected plant additions – rather than a strictly historical measurement period. An entirely separate means of reducing regulatory lag is to adjust rate base in an historical test period to an end-of-period value, as this will cause the utility's authorized rate of return to be applied to the year-ending value of net plant in service. To this end, TEP already uses end-of-period values for its Calendar Year 2011 test year (in addition to various adjustments that apply 2012 and 2013 values, as noted above).

However, in offering its plant additions adjustment, TEP proposes to combine both a projected measurement period and an end-of-period rate base, thus "doubling up" the attrition mitigation mechanisms. In my experience, jurisdictions seldom allow end-of-period values to be used for a projected (or forecasted) test period or measurement period. In a recent example, in its 2009 general rate case in Wyoming, PacifiCorp attempted to combine an end-of-period rate base with a projected test period. Although the revenue requirement for the case was resolved through stipulation, the Wyoming Commission expressly prohibited PacifiCorp from filing its next rate case using the combination of a future test period and an end of period rate base.

> In the event the Company makes a filing using a forecast test year, the Commission expects it to utilize an average rate base and not an end-of-period rate base. If the Company seeks to use an end-of-period rate base, it must include *in the application* a persuasive demonstration that its use would be appropriate. In addition, if the Company uses a forecast test year in its next application, it must [i] present the application using an average rate base and [ii] submit historical test year data, adjusted for known and measurable changes. In Paragraph 25 of the *Stipulation*, the Company has agreed to submit historical test year data with its next general rate case application for informational purposes.[30] [Italics in original.]

In short, an end-of-period rate base should only be contemplated when applied to an historical test period or measurement period. The proper measurement for a projected rate base is average-of-period value. Since the value of rate base changes each month as new plant is added and existing plant depreciates, determining rate base by averaging each month's value ensures that the asset base upon which the utility will earn a return is reflective of its "typical" value during the course of the test period or measurement period.

Q. What is your recommended change to TEP's post-test year plant additions to address this concern?

A. I recommend that the rate base used for TEP's post-test year plant additions be modified to an average-of-period value over the post-test year measurement period, January 1, 2012 through December 31, 2012. The change is presented in Attachment KCH-3. As part of this adjustment, I have recognized depreciation expense associated with the post-test year plant additions incurred in

[30] Wyoming Public Service Commission, Docket No. 20000-352-ER-09 (Record No. 12310), et al. Final Order at 33.

2012; it is my understanding that TEP inadvertently failed to include this expense.[31] This adjustment reduces the TEP revenue requirement by approximately **$0.376** million relative to TEP's filed case.

Q. What is your second basis for objecting to TEP's proposal for a post-test year adjustment in the form requested by the Company?

A. TEP's recommended inclusion of post-test year plant additions in 2012 fails to recognize that its existing plant will have depreciated in 2012. If new plant is to be recognized in rate base based on 2012 additions, then it is essential to recognize the increase in accumulated depreciation associated with existing plant in that same year. Otherwise, customers will be unfairly disadvantaged by the inconsistent valuation dates used for post-test year plant and existing plant.

Q. What is your recommended change to TEP's accumulated depreciation to address this concern?

A. I recommend that if post test-year plant additions are recognized in rate base, then accumulated depreciation (and accumulated deferred income taxes) associated with existing plant should also be recognized. As I have already adjusted TEP's post-test year plant additions to an average-of-period value, the accumulated depreciation associated with existing plant should also be measured on an average-of-period basis over the post-test year measurement period, January 1, 2012 through December 31, 2012. The change is presented in Exhibit KCH-4. This adjustment reduces the TEP revenue requirement by approximately **$7.367** million relative to TEP's filed case.

[31] TEP Response to AECC 16.4.

Q. How should accumulated depreciation associated with existing plant be treated if post test-year plant additions are recognized using end-of-period 2012 values rather than average-of-period 2012 values?

A. If post test-year plant additions are recognized using end-of-period 2012 values, then accumulated depreciation associated with existing plant should also be recognized using end-of-period 2012 values, in order to remain synchronized.

Springerville Units 3 and 4 Revenues

Q. What has TEP proposed with respect to payments the Company receives for use of common and coal handling facilities at TEP's Springerville Units 3 and 4?

A. As discussed in Mr. DeConcini's testimony, TEP charges the owners of Springerville Units 3 and 4 approximately $14 million for the use of common and coal handling facilities. TEP proposes to split these revenues 50/50 between shareholders and customers.

Q. Do you agree with TEP's approach?

A. No, I do not. TEP customers pay for the costs of Springerville Units 1 and 2. Fees charged to the owners of Springerville Units 3 and 4 for the use of common and coal handling facilities should be dedicated entirely to mitigating the costs charged to customers for the operations of Springerville Units 1 and 2, rather than partially directed to shareholders.

In the period since the last rate case, TEP has had the full benefit of these revenues. TEP is now seeking to increase customer rates by over 15 percent. It is incumbent upon the Commission to ensure that every dollar of the revenues contributed by owners of Springerville Units 3 and 4 for the use of shared facilities are used to mitigate TEP's proposed rate increase.

Q. What is your recommendation to the Commission regarding the treatment of revenues from the owners of Springerville Units 3 and 4 for the use of coal and common facilities?

A. I recommend that 100 percent of the revenues from the owners of Springerville Units 3 and 4 for the use of coal and common facilities be credited to customers. This adjustment is presented in Exhibit KCH-5. This adjustment reduces TEP's ACC jurisdictional revenue requirement by approximately **$7.240** million relative to TEP's filed case.

Payroll Expense

Q. What has TEP proposed regarding payroll expense?

A. Payroll expense is discussed by TEP witness Karen Kissinger. Ms. Kissinger explains:

> The Payroll Expense Adjustment is intended to reflect a normal level of salaries and wages in test year operating expenses. The Payroll Expense Adjustment was computed based on an average of O&M wages for 2010 and 2011, and reflects the known and measurable wage increases of 3.75% effective January 9, 2012 for classified employees, and approximately 1% effective March 19, 2012 for unclassified employees.

Q. Have you reviewed the details of TEP's payroll expense adjustment?

A. Yes, I have. TEP's payroll adjustment escalates the average of TEP's 2010 and 2011 wage expense by 3 percent for 2012, presumably to reflect the 3.75 percent increase for classified employees and approximately 1 percent increase for unclassified employees referenced in Ms. Kissinger's testimony.

However, in deriving the 3 percent average increase, TEP rounded up the blended average of its actual increase from 2.5 percent to 3.0 percent.[32]

In addition, TEP goes on to apply a second 3.0 percent escalator for 2013 to produce the Company's adjusted test year payroll expense in this case.

Q. What is your assessment of TEP's proposal?

A I disagree with TEP arbitrarily "rounding up" the actual 2012 increase from 2.5 percent to 3.0 percent. I also disagree with TEP's inclusion of a second 3.0 percent increase in payroll expense for 2013. The test year in this case is 2011. TEP proposes a pro forma adjustment to payroll expense to include projected cost increases for the twelve-month period beyond the test year. The merit of that adjustment may be arguable in the context of an historical test period, which is nominally being used in this case; however, I have accepted other adjustments to include 2012 projected costs, and am prepared to accept this adjustment as well. However, the second escalator extends TEP's pro forma adjustment twenty-four months beyond the test period. I believe this is far too much of a stretch. Moreover, the use of a 2013 payroll escalator is unmentioned in TEP's direct case and therefore unsupported in its filing.

Q. What is your recommendation to the Commission regarding payroll expense?

A. The 2012 increase in payroll expense should be calculated using the actual 2.5 percent increase rather than rounded up to 3.0 percent, as TEP has done. Further, TEP's use of a second 3.0 percent payroll expense escalator for 2013 should be rejected. I present my adjustment to TEP's proposal in Exhibit KCH-6,

[32] Source: TEP Workpaper "Income – Payroll Expense." See also Exhibit KCH-6, p. 4.

which also includes a conforming adjustment to TEP's payroll tax expense adjustment. My recommended adjustment reduces TEP's ACC jurisdictional revenue requirement by approximately **$1.915** million relative to TEP's filed case.

Generation Overhaul Expense

Q. What has TEP proposed with respect to generation overhaul expense?

A. Generation overhauls occur over multi-year cycles. For this reason, the expense incurred in any one test period may not be reasonably representative of going-forward expense. To address this concern, it is appropriate to normalize generation overhaul expense using a representative time period.

TEP normalizes generation overhaul expense by combining historical data from 2004 through 2011 with projected overhaul expenses extending out to 2020.

Q. Do you agree with TEP's approach?

A. No. I do not agree with TEP's use of projected expenses through 2020. This approach is far too speculative. Rather, it is preferable to normalize generation overhaul expense by using historical data over a multi-year period. I believe the historical period used in TEP's analysis, i.e., 2004 through 2011, is appropriate for this purpose.

Q. What is your recommendation to the Commission regarding generation overhaul expense?

A. I recommend that generation overhaul expense be normalized using the historical period, 2004-2011. This adjustment is presented in Exhibit KCH-7. This adjustment reduces TEP's ACC jurisdictional revenue requirement by approximately **$2.371** million relative to TEP's filed case.

Injuries and Damages Expense

Q. What has TEP proposed with respect to injuries and damages expense?

A. Actual test period injuries and damages expenses were $0.451 million. TEP proposes to adjust this amount upward by $0.678 million to $1.129 million based on the three-year average of this expense from 2009 through 2011.

Q. What is your assessment of TEP's approach?

A. I do not object to normalizing this expense over a multi-year period. However, I believe it is reasonable to extend this period somewhat to better reflect the longer-term trend. Accordingly, I have calculated TEP's injuries and damages expense using the five-year period, 2007 through 2011.

Q. What is your recommendation to the Commission regarding injuries and damages expense?

A. I recommend that injuries and damages expense be normalized using the historical period, 2007-2011. This adjustment is presented in Exhibit KCH-8. This adjustment reduces TEP's ACC jurisdictional revenue requirement by approximately **$0.101** million relative to TEP's filed case.

Lime Expense

Q. What has TEP proposed with respect to lime expense?

A. TEP is proposing an adjustment that increases lime expense for Springerville Unit 2 by $1.246 million on an ACC jurisdictional basis. As stated by TEP witness Dallas Dukes, the adjustment revises test-year lime expense to reflect known and measureable rail and commodity cost increases.[33] TEP calculated its adjustment using the first four months of lime expenses at Springerville Unit 2.

Q. What is your assessment of TEP's adjustment?

A. At a general level, this type of selective adjustment outside the test period is a source of concern in ratemaking. Because the utility has a clear advantage with respect to information concerning its operations, if adjustments that are not synchronous with the test period are permitted, the utility is in a position to select those non-synchronous adjustments that inure to its benefit.

Putting this general concern aside, I still do not support TEP's adjustment as proposed. TEP is proposing a 35.5 percent increase in lime expense at Springerville Unit 2. However, a review of TEP's response to RUCO 8.06 shows that the cost of lime per ton (including freight) has actually increased only 7.65 percent through the first nine months of 2012.[34] The balance of the increase projected by TEP appears to be driven by variability in the sulfur credit TEP receives. The sulfur credit is a reimbursement from the coal mine for coal quality exceeding a given sulfur content and is used to offset the additional lime cost required to scrub the higher-sulfur coal.[35] As TEP has based its justification for the proposed adjustment on the delivered cost of lime, any adjustment approved for lime expense should be strictly limited to changes in this cost. Any cost impacts attributable to variability in the sulfur credit should be excluded. TEP has the burden to demonstrate that its rate increase is reasonable. TEP's direct case

[33] Direct testimony of Dallas J. Dukes, p. 17, lines 17-22.
[34] See Exhibit KCH-9, p. 3.
[35] Source: TEP Response to AECC 17.3.a.

fails to explain or provide any basis for adjusting expenses attributable to the sulfur credit.

Q. What is your recommendation to the Commission regarding lime expense?

A. Because it is a selective adjustment outside the test period, I believe it would be reasonable for the Commission to reject TEP's lime expense adjustment altogether. However, in recognition of the apparent increase in the cost of lime at Springerville Unit 2, I am recommending an adjustment that recognizes the 7.65 percent increase in the delivered cost of lime per ton. This adjustment is presented in Exhibit KCH-9. This adjustment reduces TEP's ACC jurisdictional revenue requirement by approximately **$0.836** million relative to TEP's filed case.

Incentive Compensation

Q. What has TEP proposed with respect to incentive compensation?

A. TEP is proposing to increase the total Company incentive compensation expense by $2.686 million relative to the 2011 test year. The adjustment is comprised of several components, including: (1) an averaging of incentive compensation levels over the 2009-2011 period; (2) an escalator of 1 percent per year applied to each year of the averaging exercise (carried through to 2014); and (3) and the inclusion of approximately $2 million in below-the-line expenses recorded in Account 426, after removal of 50 percent of officers' and directors' incentive compensation.

Q. Do you have any observations concerning TEP's incentive compensation program and the Company's proposal to recover most of these costs in rates?

A. Yes. First, I note that TEP's incentive compensation grew dramatically in 2009, increasing by over 50 percent (approximately $3.2 million) in that year relative to 2008. This growth is shown in Table KCH-3, below. Second, this marked growth coincides with TEP starting to book a material portion of its incentive compensation as a below-the-line expense in FERC Account 426, most of which is comprised of incentive compensation for officers and directors. The $3.4 million booked into this account in 2009 corresponds to the large majority of the increase in incentive compensation from 2008 to 2009. The majority of TEP's proposed adjustment in this general rate case is comprised of moving incentive compensation costs from this below-the-line account into test year incentive compensation expenses (after removing 50 percent of officers' and directors' incentive compensation).

Table KCH-3

TEP Incentive Compensation
Total Company, 2007-2011

FERC Account	2007	2008	2009	2010	2011
0107					442,221
0426			3,431,608	3,568,178	3,404,253
0500	268,436	218,141	209,027	173,553	83,927
0506	807,375	805,330	838,917	729,383	786,569
0514	441,917	381,207	401,665	375,720	309,913
0566	235,240	185,526	285,237	327,220	587,565
0570	70,665	107,993	130,857	117,544	62,030
0580	186,886	72,714	67,365	54,731	53,316
0588	403,195	305,519	261,603	230,012	215,121
0598	86,162	83,538	51,500	39,812	34,017
0903	411,432	333,667	336,170	247,009	226,452
0920	3,114,420	3,160,220	2,895,148	2,330,391	2,061,087
0935	964				
Total Expense	6,026,692	5,653,855	8,909,097	8,193,553	8,266,471

Data Sources: TEP's Response to AECC Data Request 14.7 & TEP's O&M PEP Summary for Dec 31, 2009 to 2011 (workpaper)

Third, the historical years (2009 and 2010) that TEP has selected for averaging purposes <BEGIN CONFIDENTIAL>[redacted]<END CONFIDENTIAL>.[36]

Fourth, TEP's short-term incentive program emphasizes the Company performance as it impacts four categories of stakeholders: investors, customers, community/environment, and employees. Over the 2009-11 period, the investor

[36] Source: Confidential Attachment to UDR 1.35.

category was given a weighting of 35-40 percent, the customer category was weighted 30-35 percent, and the remaining two categories 15 percent each. [Supplemental Response to UDR 1.35]

Q. Do you support TEP's proposed adjustment for incentive compensation?

A. No, I do not. First, I believe the averaging period selected by TEP over-weights years judged to be of very high performance relative to target. Second, I disagree with the use of escalators applied to past years and rolled forward to 2014. This practice unduly inflates the cost of the program. And third, and most importantly, I disagree with the proportion of incentive compensation expense allocated to customers for recovery. The maximum proportion recoverable in rates should correspond to the weighting assigned to meeting customer-related goals in the program. In the 2011 and 2012 plans, <BEGIN CONFIDENTIAL>[redacted] <END CONFIDENTIAL> I am recommending that 37.5 percent of TEP's incentive compensation program be recoverable from customers.

Q. Why do you propose excluding the weighting assigned to TEP's community/environment program?

A. In my opinion, a significant proportion of the goals in this category are variations of corporate earnings goals. For example, in 2011, one of the major goals in this category was achievement of <BEGIN CONFIDENTIAL>[redacted]

[redacted] <END CONFIDENTIAL>. While TEP is free to reward its employees with incentive compensation if these types of goals are achieved, the proportion of incentive compensation dedicated to reaching these goals should be funded by shareholders and not customers.

Q. Do you have any concerns with TEP's proposal to shift expenses from a below-the-line FERC account into adjusted test period expenses?

A. Yes, I do. The implications of TEP's proposal in this regard are not clearly explained in its filing. However, my concern over this aspect of TEP's proposal is mitigated by the reduced overall level of cost recovery that occurs with my adjustment.

Q. Please summarize your recommended treatment of incentive compensation expense.

A. I recommend that no more than 37.5 percent of TEP's 2011 incentive compensation expense be included in test year revenue requirements. This adjustment is presented in Exhibit KCH-10. This adjustment reduces TEP's ACC jurisdictional revenue requirement by approximately **$3.052** million relative to TEP's filed case.

Capital Structure and Cost of Debt

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

A. TEP is proposing a capital structure of 54 percent debt and 46 percent equity.

Q. Does TEP's proposed capital structure represent either its test year capital structure or its projected capital structure in the subsequent year?

A. No. TEP's capital structure at the end of the 2011 test year was 56.5 percent debt and 43.5 percent equity. At the end of 2012, the Company's projected capital structure is 57.8 percent debt and 42.2 percent equity [Schedule D-1]. Thus, TEP's proposed capital structure represents neither its 2011 test year capital structure nor its projected capital structure at the end of 2012. Rather, TEP is proposing a hypothetical capital structure that assumes a greater proportion of equity for ratemaking purposes than actually exists or is projected to exist in 2012.

Q. Do you agree with TEP's use of a hypothetical capital structure in setting rates?

A. No. TEP's use of a hypothetical capital structure causes the weighted average cost of capital used in ratemaking to be greater than it is in reality. Consequently, when the (hypothetical) weighted average cost of capital is applied to TEP's rate base to determine TEP's return, it causes TEP's revenue requirement to be greater than it would be if the Company's actual capital structure were used for this purpose. In essence, the Company is asking to be awarded an equity return on equity that does not exist. Or, put another way, the Company is seeking a premium return on its actual equity over the nominally stated rate – in *addition* to the extra return provided by the fair value increment.

Q. What is your recommendation to the Commission with respect to capital structure?

A. I recommend that the Company's actual capital structure be used in setting its rates. Because TEP is proposing to incorporate 2012 plant additions in rate base, which I believe should be adjusted to average-of-year values, the appropriate measurement date for TEP's capital structure is average-of-year 2012. I have estimated the average capital structure for 2012 by taking the average of the end-of-year 2011 capital structure and the end-of-year 2012 capital structure. This produces a capital structure of 57.15 percent debt and 42.85 percent equity.

Q. What is the revenue requirement impact of your adjustment to capital structure?

A. This adjustment is presented in Exhibit KCH-11. This adjustment reduces TEP's ACC jurisdictional revenue requirement by approximately **$5.632** million relative to TEP's filed case.

Q. Does your recommendation to use an average-of-year 2012 capital structure also apply to the cost of debt?

A. Yes. Because TEP is seeking a return on 2012 plant additions, it is appropriate to use 2012 debt costs. I estimated average 2012 debt costs by taking the average of the end-of-year 2011 cost of debt and the end-of-year 2012 cost of debt. This results in an average cost of debt of 5.04 percent.

Q. What is the revenue requirement impact of your adjustment to the cost of debt?

A. This adjustment is presented in Exhibit KCH-12. This adjustment reduces TEP's ACC jurisdictional revenue requirement by approximately **$1.118** million relative to TEP's filed case.

Return on Equity

Q. What return on equity is TEP proposing?

A. TEP is proposing a return on equity ("ROE") of 10.75%. This return represents an increase of 50 basis points over the 10.25% ROE approved in Decision No. 70628, issued December 12, 2008, in Docket No. E-01933A-07-0402.

Q. Does AECC support TEP's request?

A. No. Please refer to Exhibit KCH-13, pp. 3-7, which shows the ROEs approved in the country each year since 2008, as compiled by an independent research group, Regulatory Research Associates. The 10.25% ROE that TEP was awarded in 2008 exactly matched the median ROE approved for electric utilities in the United States that year. After rising to 10.5% in 2009, the median approved ROE has declined steadily. In 2011 it was down to 10.15%, and for the first three quarters of 2012, it had fallen to 10.05%. I was personally involved in settling several rate cases in 2012 that resulted in allowed ROEs of 9.8%. Thus, TEP's proposed ROE of 10.75% is moving in exactly the opposite direction of the trend nationally. If TEP's ROE were to be reset at a rate reflective of the national median, as occurred in 2008, it would be in the vicinity of 10.1%.

Q. If TEP's allowed ROE were to be set at the national median of approximately 10.1%, how would TEP's effective return be impacted by the fair value increment?

A. Unlike the vast majority of utilities in the country, the fair value increment provides Arizona utilities with a premium return above the nominal ROE applied to original cost rate base. Thus, even if TEP's nominal ROE were to remain in line with the national median, TEP's effective ROE would actually be somewhat higher, due to the fair value increment.

Q. In offering the preceding discussion of national trends, are you intending to supplant the Commission's consideration of traditional cost-of-capital analysis?

A. No, not at all. I fully expect that Staff, and perhaps RUCO, will file cost-of-capital analyses for the Commission's consideration, along with that filed by TEP. My discussion of national trends is intended to supplement that analysis.

Q. What would be the revenue requirement impact if TEP's ROE were set at 10.1%?

A. The revenue requirement impact of setting TEP's allowed ROE equal to 10.1% is presented in Exhibit KCH-13. It reduces TEP's ACC jurisdictional revenue requirement by approximately **$6.624 million** relative to TEP's filed case. I have incorporated an ROE of 10.1% into AECC's overall revenue requirement recommendations at this time, pending further information being presented into the record by other parties.

Headquarters Building

Q. What has TEP proposed with respect to its new headquarters building?

A. TEP has spent approximately $92 million related to construction of a new headquarters building in downtown Tucson.[37] TEP is proposing to include the cost of the new headquarters in rate base, where it would earn a return at the Company's weighted average cost of capital. TEP would also recover the

[37] Direct testimony of Michael J. DeConcini, p. 26.

depreciation expense and ongoing operations expense in its proposed revenue requirement. Altogether, the total Company annual revenue requirement associated with the new headquarters is approximately $28 million, or $27,000 per year per employee working there.[38]

Q. Do you agree with TEP's proposal for recovery of costs associated with its new headquarters?

A. No, I do not. While corporate facilities are obviously necessary to conduct business, TEP already had corporate facilities, albeit less desirable. I believe it is reasonable to ask whether significant outlays on new corporate headquarters constitutes the type of "investment" that utilities should be incented to make on a par, say, with investments in distribution, generation, and transmission that provide direct benefits or service to customers. In TEP's case, customers are being asked to provide the Company with an equity return on an expensive building that will not provide or deliver a single kilowatt-hour to customers; moreover, the cost of this building is being folded into a proposed 15 percent rate increase. It is fair to ask whether this type of growth in rate base should be encouraged and rewarded.

In my opinion, it is not reasonable for TEP customers to pay the Company a return on these discretionary expenditures that is comparable to the return on investment in an asset that is more necessary to the provision of electric service. Rather, I propose that TEP be allowed to recover its costs and a return on its capital invested in the new headquarters building, but not at the level of return allowed for its other assets in rate base. Instead, recovery of the headquarters

[38] Source: Attachment STF 25.1 "BuildingAllocRateUpdate 2012 05" in TEP Response to STF 25.1.

expenditures plus a carrying charge equal to the cost of long-term debt is a more appropriate cost recovery treatment. I believe this is a proportionate approach that would fully reimburse the Company for its costs plus a reasonable cost of capital without unjustly enriching the Company for having made this expensive discretionary expenditure.

Q. What is the revenue requirement impact of adopting your proposed ratemaking treatment for the new headquarters building?

A. The revenue requirement impact of limiting TEP's allowed ROE to the cost of debt for its headquarters building is presented in Exhibit KCH-14. This adjustment reduces TEP's ACC jurisdictional revenue requirement by approximately **$2.389 million** relative to TEP's filed case.

Inclusion of Renewable Generation Costs in Base Rates

Q. What is TEP proposing with respect to the treatment of post-test year renewable generation plant additions?

A. TEP is proposing to include approximately $17.7 million of post-test year renewable generation net plant in total Company rate base associated with the Company's 5 MW solar PV array project.[39] According to the direct testimony of TEP witness David Hutchens, this plant will be recovered through the REST mechanism until the rates approved in this docket go into effect. At that time, REST rates will be reduced by a commensurate amount.

Q. Do you have any objections to TEP's proposal for inclusion of post-test year renewable generation costs in base rates?

[39] Source: TEP Rate Base – Post-Test Year Renewable Workpaper.

A. Yes. My objection is directed to the cost of the plant additions, as distinct from their post-test year timing. TEP's proposal for inclusion of post-test year renewable generation costs includes costs that exceed the Market Cost of Comparable Conventional Generation ("MCCCG"), as this term is defined in R14-2-1801.K. According to this provision of the REST Rule:

> "Market Cost of Comparable Conventional Generation" means the Affected Utility's energy and capacity cost of producing or procuring the incremental electricity that would be avoided by the resources used to meet the Annual Renewable Energy Requirement, taking into account hourly, seasonal, and long-term supply and demand circumstances. Avoided costs include any avoided transmission and distribution costs and any avoided environmental compliance costs.

The REST is expressly intended to recover the costs of qualifying resources in excess of the MCCCG. R14-2-1808.B.4 provides that the utility's REST filing shall provide "data to demonstrate that the Affected Utility's proposed Tariff is designed to recover only the costs in excess of the Market Cost of Comparable Conventional Generation." As the REST and the accompanying REST Adjustor rate have been created for the very purpose of recovering these above-market costs, it is, in my view, unreasonable to shift the cost recovery for above-market costs into base rates. Rather, base rates should only be used for recovery of renewable generation undertaken to comply with the REST <u>up to</u> the amount of the MCCCG.

Q. Does TEP concede that the cost of its 5 MW solar PV facility exceeds the MCCCG?

A. No. In Data Request AECC 18.1, TEP was asked to identify the portion of the post-test year renewable plant cost recovery requested by TEP that exceeded the market cost of generation, as that term is used in R14-2-1801.K of the Arizona Administrative Code. TEP responded as follows:

> The $18.4 million of Post Test Year Renewables represents the amount of additional plant that TEP will place in service by December 2012. Since TEP will not incur any costs in excess of the market cost of generation for these assets, the market cost of generation as defined in R14-2-1801.K of the Arizona Administrative Code is not applicable.

Q. Do you agree with TEP's contention that the Company will not incur any costs in excess of the MCCCG for these assets?

A. No. TEP's contention is incorrect. In response to AECC Data Request 18.4, TEP provided the revenue requirement for this project that will be recovered through the REST charge. On an annualized basis, this revenue requirement is $2.1 million per year.[40] This information is provided in Exhibit KCH-15. In addition, in response to AECC Data Request 18.5, TEP provided the MCCCG used in the Company's 2013 REST Implementation Plan, which I am providing in Confidential Exhibit KCH-16. Using generous assumptions regarding the capacity factor of the plant (35%), presented in Exhibit KCH-15, p. 4, I estimate that the cost per-kWh in 2013 ($138/MWH) will be more than double the MCCCG in that year.

Q. The renewable generation plant that TEP is seeking to include in the post-test year plant adjustment is utility-owned. Does the REST Rule make any distinctions between utility-owned renewable generation and third-party-owned renewable generation (that may be purchased by utilities) with respect to the treatment of above-market costs?

[40] TEP anticipates that recovery through the REST charge in 2013 will be for eight months, or $1.4 million.

A. No. The purpose of the REST Adjustor is to recover costs that are in excess of the Market Cost of Comparable Conventional Generation. There is absolutely no distinction in the Rule between utility-owned generation and generation that is purchased from third parties. Indeed, there is no logical or equitable reason to make such a distinction. Above-market cost is above-market cost: it does not matter whether it derives from a utility-owned facility or a utility purchase from a third party.

Q. Why is it important for above-market renewable energy costs to continue to be recovered in the REST Adjustor rather than base rates?

A. It is a matter of transparency in public policy. The REST requirement is a mandate and the REST Adjustor clearly identifies the above-market component of the cost of this mandate. If above-market costs are shifted to base rates it would obscure the true costs of the REST requirement to the public, making these costs appear to be less than they actually are. This would not be good public policy. Moreover, the structure of cost recovery in the REST differs from that of base rates; notably, each customer class has a per-meter cap applicable to the REST Adjustor that limits the exposure of any individual customer to the above-market costs of the program. Shifting above-market costs into base rates undermines the protection otherwise afforded by the REST Adjustor caps.

Q. What is your recommendation to the Commission regarding the proper amount of post-test year renewable generation costs that should be recovered in base rates?

A. I recommend that all costs in excess of the Market Cost of Comparable Conventional Generation be excluded from base rates. Prudently-incurred costs in excess of the Market Cost of Comparable Conventional Generation should remain subject to the REST and recovered through the REST Adjustor.

Q. In making your recommendation regarding base rates, are you proposing that TEP cost recovery for the renewable plant additions be denied?

A. No. I am simply making a recommendation regarding the appropriate recovery in base rates. To the extent that the cost in excess of the Market Cost of Comparable Conventional Generation is prudently-incurred, it should be eligible for recovery through the REST Adjustor.

Q. Did you ask TEP to calculate the portion of the post-test year renewable plant in this case that is not in excess of the market cost of generation?

A. Yes. I requested this information in AECC Data Request 18.2. TEP did not provide this calculation, but simply contended that the "Market Cost of Comparable Conventional Generation ("MCCCG") is not applicable to post-test-year capital expenditures for additional plant."

Q. Have you estimated a revenue requirement adjustment in this case from limiting recovery of TEP's renewable generation cost in base rates to an amount that does not exceed the Market Cost of Comparable Conventional Generation?

A. Yes. Based on my calculation that the cost per kWh of the TEP solar PV project is more than twice the cost of the MCCCG, I am recommending that the Commission disallow at least 50 percent of the annual revenue requirement for this project identified by TEP in its response to AECC 18.4, or **$1.059 million**. This adjustment is presented in Exhibit KCH-15.

PROPOSED CHANGES TO THE PPFAC

Q. What changes has TEP proposed to the PPFAC?

A. TEP is proposing three basic changes to the PPFAC:

- Currently the PPFAC recovers the difference between actual fuel and purchased power costs and the power supply costs included in base rates. TEP is proposing to change the basic structure of the PPFAC by eliminating the current base power supply rates and recovering all of those costs through the PPFAC;
- TEP is proposing to adopt 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
- TEP is proposing to expand the list of costs that are recovered through the PPFAC.

TEP is also proposing certain changes to the administration process of the PPFAC Plan of Administration ("POA").

Q. Do you support TEP's proposal to change the basic structure of the PPFAC?

A. No, I do not. The PPFAC was adopted as an adjustor mechanism that would reflect differences in costs between those in base rates and those actually incurred. I believe it is strongly preferable for the PPFAC to remain structured as an adjustor that reflects differentials in fuel and purchased power costs rather than the entirety of these costs.

Q. Why do you believe it is preferable for the PPFAC to remain structured as an adjustor that reflects differentials in fuel and purchased power costs rather than the entirety of these costs?

A. Based on my experience around the country, I believe it is important for regulators to be wary of the slippery slope that accompanies the introduction of adjustor mechanisms, such as the PPFAC, which was adopted in TEP's last general rate case. The introductions of these mechanisms, which are often adopted as part of a larger compromise, are invariably followed in subsequent years by repeated proposals from utilities to alter the mechanism further to the utility's advantage.

TEP's proposal to expand the costs included in the PPFAC is entirely consistent with this pattern. In this same vein, I view the Company's proposal to restructure the PPFAC to include all fuel and purchased power costs (rather than just differences in costs) as a step in the direction of insulating the Company from scrutiny with respect to its fuel and purchased power expenses by advancing the perception that these costs are somehow entirely outside the utility's control. In contrast, by retaining the current structure, the large majority of fuel and purchased power costs remain in base rates, with the expectation that they will be subject to close scrutiny in a general rate case.

Moreover, it is important for the PPFAC solely to reflect differences in costs, because this structure better accommodates a sharing of risks between customers and shareholders. Although a risk-sharing provision is currently lacking from the current PPFAC, I am recommending in this case that such a sharing mechanism be introduced.

Q. Why do you believe a risk-sharing mechanism is an important feature of a fuel adjustor?

A. A risk-sharing mechanism is essential to keep customer and Company interests aligned. Under the current PPFAC, TEP simply passes through 100 percent of changes in base fuel costs and purchased power in between rate cases to customers. This type of 100 percent cost pass-through seriously reduces a utility's incentive to manage its fuel and purchased power costs as well as it would manage them if it remained exposed to the energy cost risk. It is axiomatic that when a firm stands to gain or lose from its cost management decisions, the pursuit of its economic self-interest gives it a powerful incentive to perform well in managing its costs. I strongly recommend against continuing with a PPFAC design that fails to incorporate this natural economic incentive.

Q. But aren't energy costs largely outside a utility's control?

A. Absolutely not. The utility's energy costs are completely out of the customers' control, but not of the utility. Utilities are not mere passive bystanders when it comes to managing power costs. Every hour of every day, utilities need to be managing the dispatch of their systems to achieve minimum costs, subject to the reliability constraints under which they operate. This requires a sophisticated approach to managing utility-owned resources, as well as conducting a large volume of transactions – purchases and sales – throughout the year. The depth and breadth of this around-the-clock dispatch and balancing requirement is so extensive that it is inadvisable for regulators to rely solely on after-the-fact prudence audits to ensure sound utility cost-management performance; rather it is far preferable for the Commission to harness the natural economic self-interest of the company to incentivize the desired behavior of ensuring sound utility cost-management performance.

Q. Are there other aspects of managing fuel and purchased power costs that are important besides optimizing system dispatch?

A. Yes. In addition to hourly dispatch, TEP enters into numerous transactions throughout the course of the year that impact its fuel and purchased power costs, such as short- and long-term purchases and sales and fuel procurement. For example, TEP transacted for more than 2.9 billion kilowatt-hours of long-term, intermediate-term, and short-term power purchases in 2011, valued at over $137 million, consummated with more than 95 counterparties. The Company also made over 3.7 billion kilowatt-hours of long-term, intermediate term, and short-term sales in 2011, worth more than $128 million, also transacted with more than 95 counterparties.[41] It is critical that TEP have the proper incentives for these transactions to produce the greatest possible net benefit to customers. This incentive is most efficiently implemented by a regime in which TEP shares in the benefits and risks of its decisions.

Q. Does TEP hedge a portion of its fuel and purchased power costs?

A. Yes. When a utility hedges its fuel and/or purchased power costs, it is effectively locking in the cost of fuel and/or purchased power that is expected to be consumed in the future. TEP analyzes its hedging opportunities at least three years into the future and executes both non-discretionary (i.e., mechanistic) and

[41] Source: TEP 2011FERC Form 1, pp. 310-11; 326-27.

discretionary hedging transactions. To execute its hedges, TEP uses a variety of hedging products.[42]

So while it is correct that utilities do not control the market price of natural gas, it is nevertheless the case that a utility's *decisions* in executing its natural gas hedging strategy (e.g., timing, magnitude) have a large influence on the cost of gas that it ultimately incurs and the fuel costs that are passed on to customers.

Q. If TEP locks in forward fuel prices at prices that later decline, how are these costs treated for ratemaking purposes?

A. In a general rate case, under the current operation of the PPFAC, if the hedged price exceeds the projected market price, the difference is included as a component of fuel cost for full recovery from customers, subject only to prudency considerations. Conversely, if the hedged price is below the projected market price, this difference is credited against the fuel cost recovered from customers. In between rate cases, these differences are included in the PPFAC, and passed through 100 percent to customers. Under TEP's proposal to change the structure of the PPFAC, hedging costs would not be included in base rates; rather, 100 percent of hedging costs would be included in the PPFAC, along with all fuel and purchased power costs.

Q. If TEP's proposal to restructure the PPFAC is rejected, what hedging costs are included for recovery in this general rate case?

A. If TEP's proposal to restructure the PPFAC is rejected, then the Company will seek to recover in base rates its projected fuel and purchased power costs for the year ending March 2013, which includes approximately $7 million in mark-to-

[42] Source: TEP Response to UDR 1.92.

market costs associated with TEP's hedges; that is, TEP's hedges cost $7 million more than the projected cost of fuel in the measurement year ending March 2013.[43]

Q. How does your proposal to introduce risk sharing in the PPFAC affect the sharing of risks related to TEP's hedging decisions?

A. Under the current arrangement, there is no risk whatsoever to TEP from its hedging decisions: short of a prudency disallowance, 100 percent of the risk from TEP's hedging decisions is borne by customers.

Under my proposal, if TEP's hedges turn out to cost more than was projected at the time of the general rate case, the Company shares in this cost; similarly, if the Company's hedging decisions prove to reduce fuel costs below what was projected in the general rate case, TEP shares in this gain.

Q. Do you believe that the threat of a prudency disallowance is sufficient incentive to fully align utility and customer interests in managing fuel costs in between rate cases?

A. No. In my view, the threat of a finding of imprudence following an after-the-fact audit is not a good substitute for a utility having "skin in the game" when it comes to managing its fuel costs. A finding of imprudence essentially requires a determination that a utility acted <u>unreasonably</u> in its power cost management. In contrast, a risk-sharing mechanism structured such that each and every transaction affects the Company's bottom line, provides an incentive for the Company to get the *best possible deal* from every transaction. Striving to get the best possible deal from every transaction is different from simply not behaving

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[43] Source: Schedule G and H Supporting Workpapers: 6.TEP PPFAC DFD-8.xlsx

unreasonably. Getting the best possible deal is a more exacting and efficient aspiration. A well-crafted sharing mechanism supports this objective.

Q. In the past two years, have other utility commissions in the Western United States considered the question of requiring a sharing mechanism in a power supply adjustor mechanism?

A. Yes. In the past year, both the Wyoming and Utah commissions considered whether to adopt a sharing mechanism for a power cost adjustor mechanism.

Q. Are you personally familiar with these two cases?

A. Yes. I was a witness in both cases.

Q. What determinations did the Wyoming and Utah commissions reach?

A. The Wyoming and Utah commissions each independently determined to adopt 70/30 sharing mechanisms, with 70 percent of the deviations in base fuel costs being assigned to customers and 30 percent assigned to the utility.[44]

Q. In your opinion, does the 70/30 sharing arrangements adopted by the Wyoming and Utah commissions strike a reasonable balance between utility and customer interests?

A. Yes, it does. This sharing ratio places the substantial majority of responsibility for recovering base fuel cost deviations on customers, but it meaningfully aligns utility and customer interests through shared benefits and costs.

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[44] Wyoming Public Service Commission Memorandum Opinion, Findings and Order, February 4, 2011, issued in Docket No. 20000-368-EA-10.
Utah Public Service Commission, Corrected Report and Order, March 3, 2011, issued in Docket No. 09-035-15.

Q. Should this Commission consider adopting the 70/30 sharing provision recently adopted in Wyoming and Utah?

A. Yes. I strongly encourage the Commission to consider adopting the 70/30 sharing proportion that was recently approved in these other two Western states, rather than retaining the current 100/0 approach.

Q. How do you reconcile your advocacy for a sharing mechanism with the fact that APS's 90/10 sharing mechanism was removed in its last general rate case?

A. The removal of APS's 90/10 sharing mechanism occurred as part of a comprehensive settlement agreement that included both a zero-dollar base rate change and a multi-year stay out. Those special conditions, along with other provisions in the APS settlement agreement, warranted a relaxation of the sharing mechanism, at least for the duration of the agreement. There are no features in TEP's general rate case filing that are comparable to the special conditions in the APS settlement agreement. Consequently, the removal of the 90/10 sharing mechanism in the last APS general rate case should not be viewed as precedential in this case.

Similarly, the current TEP PPFAC was adopted as part of a comprehensive settlement agreement in 2008 following the expiration of the TEP rate freeze that had been in effect since a prior 1999 Settlement Agreement. In particular, the 2008 TEP Settlement Agreement that adopted the PPFAC without a sharing provision also adopted a <u>four-year freeze</u> in base rates. This base rate freeze was all the more noteworthy in that it followed a prior freeze in TEP's rates that had extended over nine years, spanning 1999 to 2008, that had resulted from a previous settlement agreement in 1999. The long-term base rate stability that was achieved as part of the 2008 TEP Settlement Agreement was an important factor in justifying the absence of a sharing mechanism in the PPFAC for the same time period. That rate case stay-out period has now expired, and the absence of a risk-sharing mechanism in the PPFAC should expire as well.

Q. What is your assessment of TEP's proposal to adopt PPFAC rates that are differentiated to reflect seasonal differences, on-peak and off-peak differences, and the voltage at which a customer takes service?

A. TEP proposes to reflect these differentials in its restructured PPFAC mechanism, which, as I discussed above, would include all fuel and purchased power expense, not just the differential relative to fuel and purchased power costs in base rates. While I oppose TEP's PPFAC restructuring proposal, I fully support differentiating fuel and purchased power expense by rate schedule to reflect seasonal differences, on-peak and off-peak differences, and the voltage at which a customer takes service. However, it is not necessary to restructure the PPFAC to accomplish this objective. Rather, these differentials should be reflected in the fuel and purchased power costs included in each rate schedule's base rates. Moreover, as I will discuss in my rate design testimony (to be filed January 11, 2013), TEP's proposal to differentiate these costs does not go far enough. For example, utilities typically reflect the lower cost of fuel and purchased power (per delivered kilowatt-hour) for a customer taking service at primary voltage rather than secondary voltage. TEP fails to make this distinction, limiting its recognition of voltage differences for this purpose to Extra-High Voltage (138 kV and above).

Q. What is your position regarding TEP's proposal to expand the list of items eligible for the PPFAC?

A. TEP's proposal to expand the list of items eligible for the PPFAC is an example of the "slippery slope" I noted above. The list of items eligible for inclusion in the PPFAC was the subject of careful negotiation in Docket No. E-01933A-07-0402. I recommend against expanding the list of eligible expenses beyond what the parties agreed to (and the Commission approved) in that docket. Despite their exclusion from the PPFAC, these expenses remain eligible for cost recovery – just not through the adjustor mechanism.

Q. Do you have any concerns with TEP's proposed changes to the PPFAC POA?

A. Yes. TEP's proposed changes to the POA are discussed by Mr. Hutchens on pages 42-44 of his direct testimony. Among the changes proposed by Mr. Hutchens is a change in the definition of Long-Term Energy Sales. Currently, the POA defines Long-Term Energy Sales to be "the portion of load from Total Native Load Energy Sales wholesale customers (currently Salt River Project, Tohono O'odham Utility Authority and Navajo Tribal Utility Authority) that is served by TEP, excluding the load served with Preference Power." All other sales, irrespective of term, are defined to be short-term sales.

TEP is proposing that the definition of Long-Term Energy Sales be expanded to include other long-term energy sales agreements it may enter into the future. Specifically, TEP proposes to redefine Long-Term Energy Sales as any wholesale sales transaction in which the duration is longer than one year.

This proposed change is of serious concern because the revenues from short-term sales are included as a credit against the fuel costs charged to retail customers, whereas the revenues from long-term sales are not. This distinction is acceptable under the current arrangement because the definition of Long-Term Energy Sales is limited to situations in which TEP is providing wholesale service to native load customers, and presumably these customers are already allocated their share of system costs.

However, not all long-term sales arrangements fit this description. In general, all revenues from wholesale sales, irrespective of term, should be credited against fuel and purchased power costs and included in the PPFAC, unless such sales are made on behalf of native load customers who are allocated a share of system costs.

Q. What is your recommendation to the Commission concerning the definition of Long-Term Energy Sales in the PPFAC POA?

A. TEP's proposal to change the definition of Long-Term Energy Sales should be rejected. TEP's proposal, as I understand it, would carve out the margins from all sales longer than one year for the sole benefit of shareholders. This proposition should be totally unacceptable to the Commission. The generating resources that are used to make these sales are paid for by TEP customers. Consequently, in a general rate case, 100 percent of the pro forma margins from long-term sales should be credited to customers (unless the sales are made on behalf of native load customers who are also allocated a share of system costs). Similarly, in between rate cases, 100 percent of the margins from new long-term sales should be included in the PPFAC. If my proposal for risk sharing is adopted, 70 percent of the margins from new long-term sales (in between rate cases) should be credited to customers in the PPFAC and 30 percent to TEP. If my proposal for risk sharing is not adopted, then 100 percent of the margins should be credited to customers in the PPFAC.

LOST FIXED COST RECOVERY MECHANISM

Q. What is TEP proposing with respect to a lost fixed cost recovery mechanism ("LFCR")?

A. The stated intent of TEP's proposed LFCR mechanism is to collect delivery service costs that would have been recovered but for usage lost to energy efficiency and distributed generation systems.[45] When customers as a whole reduce energy usage through energy efficiency or distributed generation, rates would be increased to make up the fixed-cost recovery deemed to have been lost. The adjustment would occur every year and be subject to a 2.0 percent annual rate cap.

In his direct testimony, Mr. Hutchens likens the Company's proposal to the lost fixed-cost recovery mechanism that the Commission approved for APS in Decision No. 73183.[46]

Q. Are you familiar with the fixed-cost recovery mechanism that the Commission approved for APS in Decision No. 73183?

A. Yes. I participated in the negotiations that led to the development of the APS fixed-cost recovery mechanism and testified in support of that mechanism as

[45] Direct testimony of David G. Hutchens, p. 9.
[46] Ibid, p. 10.

part of the overall APS settlement agreement that was approved by the Commission on May 24, 2012.

Q. Do you agree with Mr. Hutchens' contention that TEP's proposed LFCR is similar to the APS fixed-cost recovery mechanism?

A. No. I strongly disagree with this contention. A key component of the APS fixed-cost recovery mechanism is that customers with billing demands greater than 400 kW are entirely excluded from the APS mechanism. Instead, fixed cost recovery for these customers is addressed through rate design. In contrast, TEP's proposal provides no exclusion for larger customers, not even mines. In this important sense, the TEP LFCR proposal and the APS mechanism are fundamentally different. The only exemption from the LFCR proposed by TEP is for residential customers who choose a fixed monthly LFCR charge.

Whereas AECC supported the APS fixed-cost recovery mechanism as part of an overall settlement, AECC is strongly opposed to the TEP LFCR proposal.

Q. Please elaborate on your objections to TEP's proposal.

A. Foremost, as I noted, the TEP proposal fails to exclude larger customers, even though, as demonstrated in the APS case, concerns about fixed cost recovery for these customers can be addressed through rate design. In addition, although TEP purports that the LFCR mechanism is intended to collect delivery service costs that are unrecovered due to energy efficiency and distributed generation, in fact, the math of TEP's proposal reaches well beyond delivery service to include costs associated with generation and transmission. Moreover, TEP's proposal to recover "lost" revenues due to conservation would still increase rates even when overall revenues are increasing due to load growth.

Q. Please explain how concerns about fixed cost recovery for larger customers can be addressed through rate design.

A. The premise for recovery of "lost margins" is to insulate the utility from the loss of fixed-cost recovery when customers conserve energy by participating in utility-sponsored energy efficiency programs. This erosion of fixed-cost recovery may occur because, for many rate schedules, a portion of fixed cost is recovered through the volumetric energy charge. Thus, if energy consumption declines, all other things being equal, fixed cost recovery from conserving customers on these rate schedules declines.

In the last APS rate case, this concern was addressed by designing rates for larger customers that removed fixed-cost recovery from energy charges in favor of customer charges and demand charges. Consequently, very little – if any – fixed cost recovery occurs through the volumetric energy charge.

Q. Doesn't energy conservation also enable a customer to reduce its demand charge?

A. Yes, but it is much more difficult for a customer to reduce its demand charge from conservation in the short term than its energy charge. This is particularly true given the structure of TEP's tariff, because the demand charges for LGS and LLP customers are subject to a ratchet ranging from 50 percent to 66.67 percent. This ratchet means that the demand charge in any given month cannot fall below 50-66.67% of its peak level measured during the preceding eleven months – even if subsequent usage is reduced. Ironically, TEP is proposing to increase its ratchet dramatically to 100 percent in this case, yet completely ignores the implications of this proposed change when designing its LFCR mechanism.

Q. How can TEP address fixed-cost recovery concerns through rate design?

A. The stated purpose of TEP's proposal is to recover delivery service costs that would otherwise be unrecovered when energy conservation or distributed generation occurs. TEP's rates are unbundled; therefore, delivery service rates are already separately stated in the tariff. TEP's proposed delivery service rates consist of customer charges, demand charges, and energy charges. This structure should be changed. The delivery service energy charges should be eliminated and TEP should recover all of its delivery service costs from larger customers through the customer and demand charges. This rate design change would not only address fixed-cost recovery concerns, it would improve rate design. It is well understood that the cost of providing delivery service is driven by customer-related costs and demand-related costs – not energy-related costs. For this reason alone, TEP's delivery service charges should not have an energy-charge component for demand-billed customers.

Q. If the LFCR mechanism is approved, should the calculation of lost fixed-cost revenues be limited to the unbundled rate for delivery service?

A. Yes. As I noted above, the stated purpose of TEP's proposal is the recovery of delivery service costs, yet the calculation of "delivery revenue" for the purpose of determining the LFCR charge appears to include all revenues (minus customer charges and the cost of fuel and purchased power). Thus, it includes generation and transmission-related revenues, thereby overstating the fixed cost of delivery service. This calculation should be modified such that it is limited to the unbundled delivery service revenues based on the unbundled delivery charges stated in TEP's tariff.

Q. Should load growth be taken into account if a LFCR mechanism is adopted?

A. Yes. TEP's proposal focuses on the sales impact of energy efficiency (and distributed generation) in isolation and neglects to consider the effects of overall load growth on fixed cost recovery. In practice, the implementation of energy efficiency programs does not imply that a utility will be unable to fully recover its fixed costs. In general, when load grows above the level of the billing determinants used in setting rates, the fixed-cost recovery that occurs as a function of volumetric sales increases. This inures to the benefit of the utility. In traditional ratemaking, utilities are <u>not</u> required to return this incremental fixed-cost recovery to customers. This incremental fixed-cost recovery can be thought of as "found" margins. If a "lost margins" approach is adopted by the Commission, then "lost margins" should be netted against "found margins." Specifically, I recommend that the kilowatt-hours used for measuring going-forward lost revenue recovery be limited to the <u>lesser</u> of energy efficiency improvements attributable to TEP programs or actual net reductions in retail kilowatt-hours sold relative to the retail kilowatt-hours used in setting base rates.

Q. Please summarize your recommendation to the Commission regarding TEP's LFCR proposal.

A. I recommend that TEP's LFCR mechanism be rejected as proposed. The mechanism should not be considered unless the following modifications are made:

- Larger customers (LGS and LLP) should be excluded from the LFCR program and recovery of their fixed delivery costs addressed through rate design.
- The LFCR calculation should be modified such that it is limited to unbundled delivery service revenues calculated using the unbundled delivery charges stated in TEP's tariff.
- The kilowatt-hours used for measuring going-forward lost revenue recovery should be limited to the lesser of energy efficiency improvements attributable to TEP programs or actual net reductions in retail kilowatt-hours sold relative to the retail kilowatt-hours used in setting base rates.

Q. Mr. Hutchens indicates that if TEP's LFCR proposal is rejected, then the Commission should impose full revenue decoupling. Do you wish to respond?

A. AECC strongly opposes full revenue decoupling.

Q. Are you familiar with the Commission Policy Statements regarding decoupling that were issued December 29, 2010?

A. Yes, I am.

Q. Did AECC participate in the decoupling workshop process that was sponsored by the Commission in 2010?

A. Yes.

Q. What position regarding revenue decoupling did AECC advocate as part of the workshops?

A. AECC consistently recommended <u>against</u> adoption of a decoupling mechanism for <u>any customer class</u>. At the most fundamental level, decoupling is as much a "revenue assurance" mechanism as it is a "conservation enabling" mechanism. As such, it is sure to capture a much wider range of effects than just customer responses to utility-sponsored energy efficiency programs. For example, decoupling provides unwarranted insulation to the utility from the effects of price elasticity. Generally, all sellers of goods face a risk that price increases will reduce sales. But, with decoupling, if customers respond to utility rate hikes by reducing their electricity, fixed charges are increased to compensate the utility for any resultant reduction in per-customer usage. Such an increase reflects an undue transfer of risk from utilities to customers.

Further, to the extent that customers reduce usage in response to economic conditions or otherwise practice self-funded energy conservation, these behaviors will be captured in the decoupling adjustment and unduly increase rates to customers. In addition, decoupling would also cause rates to be adjusted due to changes in weather-related usage.

Q. Do the Commission Policy Statements provide for any flexibility with respect to the treatment of customer classes?

A. Yes. Policy Statement 11 provides that:

> Broad participation in decoupling is preferred; however, the unique characteristics of each utility may merit different treatment of some customer classes. Utilities should address any proposed distinct treatments and justify why certain customer classes may merit different treatment.

Q. If decoupling is approved by the Commission for TEP in this proceeding, are there customer classes that merit different treatment?

A. Yes. At a minimum, the LGS and LLP rate schedules should be excluded from decoupling. Instead, fixed cost recovery for these customers should be addressed through rate design, as I explained in my discussion of the LFCR proposal.

Q. If larger customers are excluded from a decoupling mechanism, would other customers be forced to bear decoupling-related costs caused by the larger customers?

A. Absolutely not. If a customer group is excluded from the decoupling mechanism, they would neither pay the decoupling charge *nor shift costs to other classes for recovery.* The only decoupling costs that should be recorded by TEP would be those directly attributable to the participating classes. Consequently, no costs would be shifted from non-participants to participants.

ENVIRONMENTAL COMPLIANCE ADJUSTOR

Q. What has TEP proposed with respect to the adoption of an Environmental Compliance Adjustor?

A. As discussed by Mr. Hutchens, TEP is proposing that the Commission approve an Environmental Compliance Adjustor ("ECA"). The ECA would allow TEP to pass through to customers in between rate cases the incremental costs of its qualifying environmental compliance investments, including return on investment, depreciation expense, taxes and associated O&M cost.[47] The ECA would be reset each year.

Q. Do you support adoption of the proposed ECA?

[47] Direct testimony of David G. Hutchens, pp. 26-27.

A. No. If adopted, the ECA would be a vehicle for potentially flowing through hundreds of millions of dollars of costs to TEP customers without the scrutiny of a rate case. It is an example of unwarranted single-issue ratemaking.

Q. What is single-issue ratemaking?

A. Single-issue ratemaking occurs when utility rates are adjusted in response to a change in cost or revenue items considered in isolation. Single-issue ratemaking ignores the multitude of other factors that otherwise influence rates, some of which could, if properly considered, move rates in the opposite direction from the single-issue change.

When regulatory commissions determine the appropriateness of a rate or charge that a utility seeks to impose on its customers the standard practice is to review and consider all relevant factors, rather than just certain factors in isolation. Considering some costs or revenues in isolation might cause a commission to allow a utility to increase rates to recover higher costs in one area without recognizing counterbalancing savings in another area. For example, the proposed ECA would allow TEP to earn a return on its new investment and charge customers for depreciation expenses associated with that new investment without recognizing that its existing rate base would have depreciated to a lower value at the time the ECA is charged to customers. In short, it exacerbates the problems associated with TEP's practice of seeking to set rates using unsynchronized test periods. In my opinion, the proposed ECA is a classic example of an application of single-issue ratemaking that is not in the public interest. The Commission should view such proposals with great wariness. I recommend that it be rejected.

Q. How do you reconcile your recommendation to reject TEP's proposal with the fact that APS has an Environmental Improvement Surcharge?

A. APS's Environmental Improvement Surcharge ("EIS") is limited to recovering the <u>carrying costs</u> on government-mandated environmental controls, rather than the totality of such costs as proposed by TEP. Currently, APS's EIS rate is set at zero. Most significantly, the EIS is capped at the relatively low rate of $.00016 per kWh. In contrast, the ECA proposed by TEP is open ended, making it a far riskier proposition for customers.

Q. Are you aware of any other utilities in the western United States that have in place an open-ended environmental adjustment mechanism of the sort proposed by TEP?

A. No. I have researched the tariffs of the major investor-owned utilities in the western United States. While California utilities have "attrition adjustments," I am not aware of any utility in the West that has in place the type of adjustment mechanism that TEP is seeking.

Q. What about the pressure that many utilities are facing to comply with environmental regulations?

A. I do not dispute that utilities are facing pressure to comply with environmental regulations. However, I do not believe that an annual pass-through mechanism will encourage the most cost-effective compliance actions. Recent experience in the western U.S. shows that environmental upgrade decisions are sometimes modified when utilities are required to consider a broad range of alternatives as part of an approval process required by state utility regulators. For example, PacifiCorp recently changed its plans to invest in environmental upgrades at its Naughton No. 3 coal plant as part of an economic evaluation required by the Wyoming Public Service Commission for new environmental investments. Rather than continue with its previously-announced plans to upgrade the coal facility, PacifiCorp determined, based on the analysis undertaken in response to testimony filed by intervenors, that it would be more cost-effective on a risk-adjusted basis to convert the plant to natural gas.[48] Had an annual pass-through mechanism been available, PacifiCorp may very well have proceeded with its original plans to upgrade its coal facilities. Instead, PacifiCorp was required to present a full range of investment alternatives as part of a public process before any funding could be approved (including through a general rate case).

Before considering an annual rider to recover TEP's environmental upgrade costs, it would be wise for the Commission to require that the efficacy of these investments be subject to a process that will allow for Commission and stakeholder review well in advance of the arrival of the projects as proposed additions to rate base. The examination should be structured to shed light on the expected revenue requirement impact on customers, including potential changes in depreciation expense, which is anticipated from these investments relative to the cost of alternative actions.

Q. Why is it important to consider the impact on future depreciation expense when evaluating environmental upgrades?

[48] Wyoming Public Service Commission, Docket No. 2000-400-EA-11. Order Granting Motion to Withdraw Application, July 19, 2012 at 1.

A. Environmental upgrades are generally depreciated using the same depreciation rate as the existing rate base. Consequently, when environmental projects come into rate base at the current time, the depreciation expense reflects a long asset life. However, asset lives are subject to revision in future depreciation studies as existing plants approach retirement. This means that the depreciation expense for environmental upgrades may be subject to significant upward revision in future rate cases. The upshot is that expensive environmental upgrades applied to plants with relatively short remaining useful lives may have future ratemaking consequences for customers when the plants are retired, an implication that is not readily apparent at the time the environmental investments first come into rates.

ENERGY EFFICIENCY RESOURCE PLAN

Q. What has TEP proposed regarding an energy efficiency resource plan?

A. As discussed in the direct testimony of Mr. Hutchens, TEP is proposing a three-year planning horizon for the Company's energy efficiency programs and the associated DSM surcharge ("DSMS"). According to the proposal, the DSMS rate would be established in advance and would include predictable year-over-year DSMS increases. The proceeds of the DSMS would be used to recover the costs of TEP's expenditures on energy efficiency programs using a capital investment and recovery model is similar to that used for supply-side resources except that the capital invested in energy efficiency programs would be considered a regulatory asset and amortized over a four-year term, and the ROE on this regulatory asset would earn a 200 basis point premium.[49]

Q. What is your assessment of TEP's energy efficiency resource plan proposal?

A. I do not object to amortizing the recovery of energy efficiency expenses over four years; under the current system, energy efficiency investments are evaluated based on life-cycle energy savings (i.e., a multi-year period) but fully expensed in the first year, creating a mismatch between the cost recovery and benefits received. In other words, under the current system, cost recovery is more front-end loaded relative to benefits received than a supply-side resource.

However, I do not agree that an ROE premium of 200 basis points is warranted. TEP justifies the premium by depicting the energy efficiency investment as riskier than supply-side investments, because they have no value outside of the Commission's rules.[50] Yet, the funds to make these investments are also provided differently. The funds for supply-side investments must be provided by the Company in advance, and are eligible for recovery after the investments become used and useful. In contrast, funding for energy efficiency programs is provided by customers contemporaneously through the DSMS. Thus, the energy efficiency investments TEP would be making under its proposal would be funded using customer money. When this aspect of the financing is taken into consideration, it argues for an ROE discount rather than a premium as proposed by TEP. Taken as a whole, TEP's request for an ROE premium should be rejected.

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[49] Direct testimony of David G. Hutchens, pp. 16-18.
[50] Ibid, p. 18.

Q. Do you have any comments concerning the cost of energy efficiency programs to customers?

A. Yes. AECC participated in TEP's 2011-12 Energy Efficiency ("EE") Implementation Plan case, Docket No. E-01933A-11-0055, and strongly opposed the Company's initial requests for significant increases in the DSMS. After working with the Company and other parties, AECC joined in a settlement agreement that resulted in a proposed DSMS rate for non-residential customers of 2.86 percent. Although the settlement agreement was opposed by Staff, it was recommended for approval by Administrative Law Judge Jane Rodda on August 30, 2012 and remains pending before the Commission as of the date of this testimony.

One of the attributes of the TEP EE settlement agreement is that it would set DSMS rates for non-residential customers on an equal percentage basis. An equal percentage approach is fair because it makes the cost of funding EE programs proportionate to each non-Residential customer's bill. Any individual customer's contribution to EE program funding through a surcharge is not a direct purchase of energy or demand, but a contribution to programs and overhead costs. It makes sense for funding of this sort to be proportionate to the customer's energy costs because a proportionate surcharge best reflects the potential benefits the customer might receive as a result of EE programs. It therefore strikes a reasonable balance between the costs charged to customers for EE programs and the potential benefits they might receive. Percentage-of-bill riders are used in Idaho, Utah, Wyoming, and New Mexico.

Another attribute of the TEP EE settlement agreement is that the overall cost of energy efficiency programs is kept within 3.0 percent of customers' total bills. I recommend that on a going-forward basis, the overall costs of TEP energy efficiency programs continue to be kept within 3.0 percent of customers' total bills and that the DSMS for non-residential customers be assessed on an equal percentage basis, as proposed in the TEP EE settlement agreement. I recommend that these rate impact and rate design parameters be a condition of any TEP energy efficiency resource plan approved by the Commission.

NET OPERATING LOSS CARRYFORWARD

Q. Have you reviewed the testimony of TEP witnesses Karen G. Kissinger and James I. Warren regarding TEP's treatment of its net operating loss ("NOL") carryforward as it applies to the Company's accumulated deferred income tax ("ADIT") balance?

A. Yes, I have.

Q. Please describe the ratemaking treatment TEP is seeking with respect to its NOL carryforward.

A. TEP anticipates that it will not be able to fully utilize all of the accelerated depreciation to which it would otherwise be entitled because the Company experienced a net operating loss for federal income tax purposes for the 2011 tax year.[51] The net operating loss is due in large part to the magnitude of certain bonus tax depreciation that is allowable to the Company. TEP is seeking recognition of an ADIT asset associated with this NOL as an addition to rate base.

[51] Direct testimony of Karen G. Kissinger, p. 21.

Q. What are the implications for ratemaking of this treatment?

A. The answer to this question requires a brief background discussion. The bonus tax depreciation that gives rise to this situation is a greatly accelerated tax deduction for depreciation that has been permitted pursuant to several statutes signed into law in recent years to stimulate the economy. Generally, the tax benefits of accelerated depreciation are not passed through directly to ratepayers; instead, according to the conventions of income tax normalization, a utility's ADIT (created because of the timing differences between tax and book depreciation) is viewed as a source of zero-cost capital to the utility as part of the ratemaking process. Consequently, ADIT is booked as a credit against rate base, thereby reducing revenue requirements for customers.

As explained by Ms. Kissinger, because of the net operating loss, there is a portion of TEP's tax depreciation deductions from which the Company has yet to realize a cash benefit. Consequently, TEP proposes to recognize an ADIT asset associated with the NOL. The ADIT asset will be an <u>increase</u> to rate base, offsetting a portion of the ADIT reduction to rate base that would otherwise apply. The upshot is that because of the NOL, the benefit of the ADIT reduction to rate base that would otherwise apply is reduced.

Q. Are you proposing to challenge the recognition of the ADIT asset as proposed by Ms. Kissinger and supported by Mr. Warren?

A. No, I am not. However, the existence of the NOL creates a problem for regulators. One the one hand, Ms. Kissinger argues that it would be unfair for retail customers to receive the rate-base reducing benefits of the ADIT related to accelerated depreciation when the Company has not yet received the benefit of this deduction. On the other hand, TEP will be able to realize the benefit of its 2011 accelerated depreciation deductions in future years, because the tax code permits these deductions to be carried forward to tax years when they can be applied against positive taxable income. If there is not some recognition of this benefit to customers when TEP avails itself of this deduction, then customers will be deprived of the full benefits of the ADIT to which they are entitled. The challenge for regulators is to balance fairness to TEP and to customers in this situation.

Q. What is your recommendation to the Commission to address this problem?

A. I recommend that the Commission recognize the ADIT asset as proposed by TEP in setting rates in this case, but also require TEP to establish a regulatory liability when bonus tax depreciation associated with plant included in rate base in this case is applied against future tax years. As I noted above, the tax benefit from bonus depreciation can be carried forward to future tax years when positive taxable income is realized. For this reason, it makes sense to calculate annually the revenue requirement reduction associated with the increase in accumulated deferred income tax associated with bonus tax depreciation as this benefit is realized by TEP. This revenue requirement reduction should be deferred and booked as a regulatory liability, earn a carrying charge equal to the Company's approved rate of return, and be recognized as a credit to customers in rates at a future date. I believe this approach strikes the desired balance in being fair both to TEP and to customers.

TEP SOLAR OWNERSHIP PLAN

Q. What is TEP requesting regarding its development of solar resources?

A. As discussed in the direct testimony of Mr. Hutchens, TEP is requesting "continued authority" to invest up to $30 million of capital annually in 2014 through 2017 to develop 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 would be submitted as part of TEP's annual REST Implementation Plans.[52] TEP is requesting approval for four consecutive years of project investments because the Company believes that "requiring annual approval of utility-owned projects through the REST process is proving too difficult to achieve as the Company pursues new technologies and a greater number of projects."[53]

Q. Do you recommend adoption of the Company's proposal?

A. No. TEP's proposal overlooks a critical part of the equation: the cost to customers. The cost of TEP's compliance with the REST rules continues to increase. It is essential that the Commission retain direct control over approving each year's REST budget. TEP should not be granted a four-year authorization to build solar projects when the cost consequences to customers from future REST filings remain unknown.

[52] Direct testimony of David G. Hutchens, pp. 30-31.
[53] Ibid, p. 32.

Q. Does this conclude your direct testimony?

A. Yes, it does.

APPENDIX A

KEVIN C. HIGGINS
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Vitae

PROFESSIONAL EXPERIENCE

Principal, Energy Strategies, L.L.C., Salt Lake City, Utah, January 2000 to present. Responsible for energy-related economic and policy analysis, regulatory intervention, and strategic negotiation on behalf of industrial, commercial, and public sector interests. Previously Senior Associate, February 1995 to December 1999.

Adjunct Instructor in Economics, Westminster College, Salt Lake City, Utah, September 1981 to May 1982; September 1987 to May 1995. Taught in the economics and M.B.A. programs. Awarded Adjunct Professor of the Year, Gore School of Business, 1990-91.

Chief of Staff to the Chairman, Salt Lake County Board of Commissioners, Salt Lake City, Utah, January 1991 to January 1995. Senior executive responsibility for all matters of county government, including formulation and execution of public policy, delivery of approximately 140 government services, budget adoption and fiscal management (over $300 million), strategic planning, coordination with elected officials, and communication with consultants and media.

Assistant Director, Utah Energy Office, Utah Department of Natural Resources, Salt Lake City, Utah, August 1985 to January 1991. Directed the agency's resource development section, which provided energy policy analysis to the Governor, implemented state energy development policy, coordinated state energy data collection and dissemination, and managed energy technology demonstration programs. Position responsibilities included policy formulation and implementation, design and administration of energy technology demonstration programs, strategic management of the agency's interventions before the Utah Public Service Commission, budget preparation, and staff development. Supervised a staff of economists, engineers, and policy analysts, and served as lead economist on selected projects.

Utility Economist, Utah Energy Office, January 1985 to August 1985. Provided policy and economic analysis pertaining to energy conservation and resource development, with an emphasis on utility issues. Testified before the state Public Service Commission as an expert witness in cases related to the above.

Acting Assistant Director, Utah Energy Office, June 1984 to January 1985. Same responsibilities as Assistant Director identified above.

Research Economist, Utah Energy Office, October 1983 to June 1984. Provided economic analysis pertaining to renewable energy resource development and utility issues. Experience includes preparation of testimony, development of strategy, and appearance as an expert witness for the Energy Office before the Utah PSC.

Operations Research Assistant, Corporate Modeling and Operations Research Department, Utah Power and Light Company, Salt Lake City, Utah, May 1983 to September 1983. Primary area of responsibility: designing and conducting energy load forecasts.

Instructor in Economics, University of Utah, Salt Lake City, Utah, January 1982 to April 1983. Taught intermediate microeconomics, principles of macroeconomics, and economics as a social science.

Teacher, Vernon-Verona-Sherrill School District, Verona, New York, September 1976 to June 1978.

EDUCATION

Ph.D. Candidate, Economics, University of Utah (coursework and field exams completed, 1981).

> Fields of Specialization: Public Finance, Urban and Regional Economics, Economic Development, International Economics, History of Economic Doctrines.

Bachelor of Science, Education, State University of New York at Plattsburgh, 1976 (cum laude).

Danish International Studies Program, University of Copenhagen, 1975.

SCHOLARSHIPS AND FELLOWSHIPS

University Research Fellow, University of Utah, Salt Lake City, Utah 1982 to 1983.
Research Fellow, Institute of Human Resources Management, University of Utah, 1980 to 1982.
Teaching Fellow, Economics Department, University of Utah, 1978 to 1980.
New York State Regents Scholar, 1972 to 1976.

EXPERT TESTIMONY

"In the Matter of Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates," **Kentucky** Public Service Commission, Case No. 2012-00221. Direct testimony submitted October 3, 2012.

"In the Matter of Application of Louisville Gas & Electric Company for an Adjustment of Its Electric Rates, **Kentucky** Public Service Commission, Case No. 2012-00221. Direct testimony submitted October 3, 2012.

"In the Matter of PacifiCorp's Filing of Revised Tariff Schedules for Electric Service in Oregon," **Oregon** Public Utilities Commission, Docket No. UE-245. Rebuttal testimony submitted August 13, 2012.

"In the Matter of the Application of Tucson Electric Power Company for Approval of Its 2011-2012 Energy Efficiency Implementation Plan," **Arizona** Corporation Commission, Docket No. E-01933A-11-0055. Direct testimony submitted June 15, 2012. Rebuttal testimony submitted July 6, 2012. Cross examined July 11, 2012.

"In the Matter of PacifiCorp, dba Pacific Power 2013 Transition Adjustment Mechanism," **Oregon** Public Utilities Commission, Docket No. UE-245. Reply testimony submitted June 6, 2012.

"In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations," **Utah** Public Service Commission, Docket No. 11-035-200. Direct testimony submitted June 4, 2012.

"In the In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan; In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Certain Accounting Authority," Public Utilities Commission of **Ohio**, Case Nos. 11-346-EL-SSO and11-348-EL-SSO. Direct testimony submitted May 4, 2012. Cross examined May 25, 2012.

"In the Matter of the Application of Rocky Mountain Power for Approval of a General Rate Increase in Its Retail Electric Utility Service Rates in Wyoming of $62.8 Million Per Year or an Average Overall Increase of 10.4 Percent," **Wyoming** Public Service Commission, Docket No. 20000-405-ER-11. Direct testimony submitted April 30, 2012. Settlement testimony submitted June 22, 2012. Cross examined July 16, 2012.

"Application of Entergy Texas, Inc. for Authority to Change Rates and Reconcile Fuel Costs," Public Utility of **Texas**," Docket No. 39896. Direct testimony submitted March 27, 2012. Cross rebuttal testimony submitted April 13, 2012.

"In the Matter of Advice Letter No. 1597 – Electric Filed by Public Service Company of Colorado to Revise Its Colorado PUC No. 7 – Electric Tariff to Implement a General Rate Schedule Adjustment and Other Changes Effective December 23, 2011," **Colorado** Public Utilities Commission, Docket No. 11AL-947E. Answer testimony submitted March 2, 2012. Supplemental testimony submitted April 18, 2012.

"In the Matter of the Rocky Mountain Power Proposed Schedule 94, Energy Balancing Account (EBA) Pilot Program Tariff," **Utah** Public Service Commission. Direct testimony submitted February 23, 2012. Rebuttal testimony submitted March 15, 2012. Supplemental rebuttal testimony submitted March 16, 2012. Cross examined April 24, 2012.

"In the Matter of the Joint Application of Westar Energy, Inc. and Kansas Gas and Electric Company for Approval to Make Certain Changes in Their Charges for Electric Service," **Kansas** Corporation Commission," Docket No. 12-WSEE-112-RTS. Direct testimony submitted January 5, 2012. Cross-Answering testimony submitted January 17, 2012.

"In the Matter of the Petition of Public Service Company of Colorado Pursuant to C.R.S. § 40-6-111(1)(d) for Interim Rate Relief Effective on or before January 21, 2012," **Colorado** Public Utilities Commission, Docket No. 11M-951E. Affidavit submitted December 23, 2011.

"2011 Puget Sound Energy General Rate Case," **Washington** Utilities and Transportation Commission, Docket No. UG-101644. Response testimony submitted December 3, 2011. Cross Answer testimony submitted January 17, 2012. Joint testimony in support of electric rate design stipulation filed January 13, 2012. Joint testimony in support of gas rate design stipulation filed January 17, 2012. Oral testimony in support of stipulations presented February 14, 2012.

"In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return," **Arizona** Corporation Commission, Docket No. E-01345A-11-0224. Direct testimony submitted November 18, 2011 (revenue requirement), December 2, 2011 (cost of service), and January 18, 2012 (settlement agreement). Responsive testimony submitted January 25, 2012 (settlement agreement). Cross examined February 1, 2012.

"In the Matter of the Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina," **North Carolina** Utilities Commission, Docket No. E-7, Sub 989. Direct testimony submitted October 31, 2011.

"In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan," Public Utilities Commission of **Ohio**," Case Nos. 11-346-EL-SSO and 11-348-EL-SSO, et al. Direct testimony in support of Stipulation submitted October 28, 2011.

"Application of Nevada Power Company d/b/a NV Energy, for Authority to Increase Its Annual Revenue Requirement for General Rates Charged to All Classes of Customers, Begin to Recover the Costs of Constructing Harry Allen Combined Cycle, Goodsprings and Other Generating, Transmission and Distribution Plant Additions, and to Reflect Changes in Cost of Service and for Relief Properly Thereto; Application of Nevada Power Company d/b/a/ NV Energy for Approval of New and Revised Depreciation Rates for Its Electrical Operations; Application of Sierra Pacific Power Company d/b/a/ NV Energy for a Determination of the Reasonableness of the Ely Energy Center Project Development Costs and for Authority to Reclassify Those Costs from a Deferred Debit to a Regulatory Asset with an Appropriate Carrying Charge," Public Utilities Commission of **Nevada**, Docket Nos. 11-06006, 11-06007, and 11-06008. Direct testimony submitted October 12, 2011. Cross examined November 2, 2011.

"In the Matter of the Application of Idaho Power Company for Authority to Increase Its Rates and Charges for Electric Service in Idaho," **Idaho** Public Utilities Commission, Case No. IPC-E-11-08. Direct testimony submitted October 7, 2011. Rebuttal testimony submitted November 16, 2011. Cross examined December 5, 2011.

"In the Matter of the Application of Public Service Company of Colorado for an Order Approving Regulatory Treatment of Margins Earned from Certain Renewable Energy Credit and Energy Transactions and Petition for Declaratory Order Clarifying the Meaning of the Phrase) "Transactions Executed" as that Phrase Is Used in the Settlement Agreement Approved in Docket No. 09A-602E," **Colorado** Public Utilities Commission, Docket No. 11A-510E. Answer testimony submitted September 19, 2011. Cross examined October 20, 2011.

"In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan," Public Utilities Commission of **Ohio**," Case Nos. 11-346-EL-SSO and Case No. 11-348-EL-SSO. "In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Certain Accounting Authority," Case Nos. 11-349-EL-AAM and 11-350-EL-AAM. Direct testimony submitted July 25, 2011.

"In the Matter of the Application of Appalachian Power Company for an Adjustment of Electric Base Rates," **Virginia** Corporation Commission, Case No. PUE-2011-00037. Direct testimony submitted July 20, 2011.

"Ameren Illinois Company d/b/a Ameren Illinois, Proposed General Increase in Electric Delivery Service Rates; Ameren Illinois Company d/b/a Ameren Illinois, Proposed General Increase in Natural Gas Rates," **Illinois** Commerce Commission, Docket Nos. 11-0279 and 11-0282. Direct testimony submitted June 29, 2011. Rebuttal testimony submitted August 23, 2011.

"In the Matter of PacifiCorp, dba Pacific Power 2012 Transition Adjustment Mechanism," Public Utility Commission of **Oregon**, Docket No. UE-227. Reply testimony submitted June 24, 2011. Rebuttal testimony submitted August 16, 2011.

"In the Matter of the Application of Rocky Mountain Power to Implement a Permanent Avoided Cost Methodology for Customers That Do Not Qualify for Tariff Schedule 37 – Avoided Cost Purchases from Qualifying Facilities," **Wyoming** Public Service Commission, Docket No. 20000-388-EA-11. Direct testimony submitted May 26, 2011. Cross examined August 2, 2011.

"In the Matter of the Application of Public Service Company of New Mexico for Revision of Its Retail Electric Rates Pursuant to Advice Notice Nos. 397 and 32 (Former TNMP Services), Public Service Company of New Mexico, Applicant," **New Mexico** Public Regulation Commission, Case No. 10-00086-UT. Direct testimony in Opposition to Stipulation submitted April 14, 2011. Cross examined May 12, 2011.

"In the Matter of the Application of Rocky Mountain Power for Authority to Increase Its Retail Electric Utility Service Rates in Wyoming Approximately $97.9 Million Per Year or 17.3 Percent," **Wyoming** Public Service Commission, Docket No. 20000-384-ER-10. Direct testimony submitted April 11, 2011. Cross answer testimony submitted May 6, 2011. Stipulation testimony submitted June 9, 2011. Cross examined June 20, 2011.

"In the Matter of the Application of Rocky Mountain Power for Approval of an Adjustment to the Demand-Side Management Program and Suspend Schedule 191 Rate Surcharges," **Wyoming** Public Service Commission, Docket No. 20000-383-ER-10. Direct testimony submitted March 30, 2011. Cross examined May 11, 2011.

"In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations," **Utah** Public Service Commission, Docket No. 10-035-124. Direct testimony submitted March 9, 2011 (test period); May 26, 2011 (revenue requirement); and June 2, 2011 (cost of service). Rebuttal testimony submitted March 17, 2011 (test period) and June 30, 2011 (revenue requirement). Surrebuttal testimony submitted July 19, 2011 (revenue requirement). Cross examined March 24, 2011 (test period); August 3, 2011 (revenue requirement stipulation); and August 8, 2011 (cost of service stipulation).

"Application of Nevada Power Company d/b/a NV Energy to Establish Interim Base Energy Efficiency Program Rates and Base Energy Efficiency Implementation Rates Pursuant To NRS 704.785 and the Order Issued in Docket No. 09-07016; Application of Sierra Pacific Power Company d/b/a NV Energy to Establish Interim Base Energy Efficiency Program Rates and Base Energy Efficiency Implementation Rates Pursuant to NRS704.785 and the Order Issued in Docket No. 09-07016," Public Utilities Commission of **Nevada,** Docket Nos. 10-10024 and 10-10025. Direct testimony submitted March 8, 2011. Cross examined March 29, 2011.

"2010 Puget Sound Energy Tariff Filing," **Washington** Utilities and Transportation Commission, Docket No. UG-101644. Joint testimony in support of stipulation filed February 11, 2011. Oral testimony in support of stipulation presented March 1, 2011.

"Petition of Duke Energy Indiana, Inc. for Approval to Offer Additional Energy Efficiency Programs; For Approval of Program Cost Recovery, Lost Revenues and Incentives Pursuant to 170 IAC 4-8-5, 170 IAC 4-8-6, and 170 IAC 4-8-7; Authority to Defer Costs Pending Approval and for Authority to Implement Annual Tracking Mechanism," **Indiana** Utility Regulatory Commission, Cause No. 43955. Direct testimony submitted February 9, 2011.

"In the Matter of the Application of Duke Energy Ohio for Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for Standard Service Offer Electric Generation Supply, Accounting Modifications, and Tariffs for Generation Service," Public Utilities Commission of **Ohio**, Case No. 10-2586-EL-SSO. Direct testimony submitted December 21, 2010. Deposed December 22, 2010. Cross examined January 18, 2011.

"In the Matter of the Application of Public Service Company of Colorado for Approval of a Number of Strategic Issues Relating To Its DSM Plan, Including Long-Term Electric Energy Savings Goals and Incentives," **Colorado** Public Utilities Commission, Docket No. 10A-554EG. Answer testimony submitted December 17, 2010. Cross answer testimony submitted February 4, 2011. Cross examined March 2, 2011.

"In the Matter of Appalachian Power Company and Wheeling Power Company," Public Service Commission of **West Virginia**, Case No. 10-0699-E-42T. Direct testimony submitted November 10, 2010. Rebuttal testimony submitted November 23, 2010.

"In the Matter of the Application of Rocky Mountain Power for Alternative Cost Recovery for Major Plant Additions of the Populus to Ben Lomond Transmission Line and Dunlap I Wind Project," **Utah** Public Service Commission, Docket No. 10-035-89. Confidential direct testimony submitted October 26, 2010. Oral testimony in support of stipulation presented December 6, 2010.

"In the Matter of Georgia Power Company's 2010 Rate Case," **Georgia** Public Service Commission, Docket No. 31958. Direct testimony submitted October 22, 2010. Cross examined November 8, 2010.

"In the Matter of the Application of Rocky Mountain Power for Authority to Implement an Energy Cost Adjustment Mechanism," **Wyoming** Public Service Commission, Docket No. 20000-368-EA-10. Direct testimony submitted September 10, 2010. Cross examined November 9, 2010.

"Application of Entergy Texas, Inc. for Authority to Change Rates and Reconcile Fuel Costs," Public Utility Commission of **Texas**, Docket No. 37744. Direct testimony submitted June 9, 2010.

"Portland General Electric General Rate Case Filing," Public Utility Commission of **Oregon**, Docket No. UE-215. Opening testimony submitted June 4, 2010. Joint testimony in support of stipulation submitted August 2, 2010.

"In the Matter of the Application of Duke Energy Ohio, Inc. to Establish and Adjust the Initial Level of its Distribution Reliability Rider," Public Utilities Commission of **Ohio**, Case No. 09-1946-EL-RDR. Direct testimony submitted May 18, 2010.

"In the Matter of PacifiCorp, dba Pacific Power, 2011 Transition Adjustment Mechanism," Public Utility Commission of **Oregon**, Docket No. UE-216. Reply testimony submitted May 12, 2010. Joint testimony in support of stipulation submitted July 26, 2010.

"In the Matter of the Application of Rocky Mountain Power for Alternative Cost Recovery for Major Plant Additions of the Ben Lomond to Terminal Transmission Line and the Dave Johnston Generation Unit 3 Emissions Control Measure," **Utah** Public Service Commission, Docket No. 10-035-13. Direct testimony submitted April 26, 2010.

"In the Matter of a Notice of Inquiry into Energy Efficiency," **Arkansas** Public Service Commission, Docket No. 10-010-U. Direct testimony submitted March 23, 2010. Cross examined October 18, 2010.

"In the Matter of the Application of Entergy Arkansas, Inc. for Approval of Changes in Rates for Retail Electric Service," **Arkansas** Public Service Commission," Docket No. 09-084-U. Direct testimony submitted February 26, 2010.

"In the Matter of the Application of Rocky Mountain Power for Approval of a General Rate Increase of Approximately $70.9 Million per Year or 13.7 Percent," **Wyoming** Public Service Commission, Docket No. 20000-352-ER-09. Direct testimony submitted February 16, 2010. Cross answer testimony submitted March 15, 2010. Direct settlement testimony submitted

March 31, 2010. Cross examined April 23, 2010.

"Amended Petition of Puget Sound Energy, Inc., for an Order Authorizing the Use of the Proceeds from the Sale of Renewable Energy Credits and Carbon Financial Instruments," **Washington** Utilities and Transportation Commission, Docket No. UE-070725. Response testimony submitted January 28, 2010.

"Application of Appalachian Power Company for a 2009 Statutory Review of Rates Pursuant to § 56.585.1 A of the Code of Virginia," **Virginia** Corporation Commission, Case No. PUE-2009-00030. Direct testimony submitted December 28, 2009. Additional direct testimony submitted March 8, 2010. Cross examined April 1, 2010.

"In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for Standard Service Offer Electric Generation Supply, Accounting Modifications with Reconciliation Mechanism and Tariffs for Generation Service," Public Utilities Commission of **Ohio**, Case No. 09-906-EL-SSO. Direct testimony submitted December 4, 2009. Deposed December 10, 2009.

"2009 Puget Sound Energy General Rate Case," **Washington** Utilities and Transportation Commission, Docket Nos. UE-090704 and UG-090705. Response testimony submitted November 17, 2009. Joint testimony in support of stipulation submitted January 8, 2010.

"In the Matter of the Application of Rocky Mountain Power for Approval of Its Proposed Energy Cost Adjustment Mechanism," **Utah** Public Service Commission, Docket No. 09-035-15. Direct Phase I testimony submitted November 16, 2009. Direct Phase II testimony submitted August 4, 2010. Rebuttal Phase II testimony submitted September 15, 2010. Surrebuttal Phase I testimony submitted January 5, 2010. Surrebuttal Phase II testimony submitted October 13, 2010. Cross examined January 12, 2010 (Phase I) and November 2, 2010 (Phase II).

"In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of Its Proposed Electric Service Schedules and Electric Service Regulations," **Utah** Public Service Commission, Docket No. 09-035-23. Direct testimony submitted October 8, 2009. Rebuttal testimony submitted November 12, 2009. Surrebuttal testimony submitted November 30, 2009. Cross examined December 15-16, 2009.

"Re: The Tariff Sheets Filed by Public Service Company of Colorado with Advice Letter No. 1535 – Electric," **Colorado** Public Utilities Commission, Docket No. 09AL-299E. Answer testimony submitted October 2, 2009. Surrebuttal testimony submitted December 18, 2009.

"In the Matter of the Applications of Westar Energy, Inc., and Kansas Gas and Electric Company for Approval to Make Certain Changes in their Charges for Electric Service," **Kansas** Corporation Commission, Docket No. 09-WSEE-925-RTS. Direct testimony submitted September 30, 2009. Cross answer testimony submitted October 16, 2009.

"Central Illinois Light Company d/b/a AmerenCILCO Proposed General Increase in Electric Delivery Service Rates; Central Illinois Public Service Company d/b/a AmerenCIPS Proposed General Increase in Electric Delivery Service Rates; Illinois Power Company d/b/a/ AmerenIP Proposed General Increase in Electric Delivery Service Rates; Central Illinois Light Company d/b/a AmerenCILCO Proposed General Increase in Gas Delivery Service Rates; Central Illinois Public Service Company d/b/a AmerenCIPS Proposed General Increase in Gas Delivery Service Rates; Illinois Power Company d/b/a/ AmerenIP Proposed General Increase in Gas Delivery Service Rates," **Illinois** Commerce Commission, Docket Nos. 09-0306, 09-0307, 09-0308, 09-0309, 09-0310, and 09-0311. Direct testimony submitted September 28, 2009. Rebuttal testimony submitted November 20, 2009.

"In the Matter of the Complaint of Nucor Steel-Indiana, a Division of Nucor Corporation against Duke Energy Indiana, Inc. for Determination of Reasonable and Just Charges and Conditions for Electric Service and Request for Expedited Adjudication," **Indiana** Utility Regulatory Commission, Cause No. 43754. Direct testimony submitted September18, 2009. Rebuttal testimony submitted December 3, 2009. Testimony withdrawn pursuant to settlement agreement.

"In the Matter of PacifiCorp's Filing of Revised Tariff Schedules for Electric Service in Oregon," Public Utility Commission of **Oregon,** Docket No. UE-210. Reply testimony submitted July 24, 2009. Joint testimony in support of stipulation submitted September 25, 2009.

"In The Matter of the Application of Rocky Mountain Power to Establish an Avoided Cost Methodology for Customers That Do Not Qualify for Tariff Schedule 37 – Avoided Cost Purchases from Qualifying Facilities," **Wyoming** Public Service Commission, Docket No. 20000-342-EA-09. Direct testimony submitted July 21, 2009. Cross examined September 1, 2009.

"In the Matter of PacifiCorp, dba Pacific Power, 2010 Transition Adjustment Mechanism," Public Utility Commission of **Oregon,** Docket No. UE-207. Reply testimony submitted July 14, 2009. Joint testimony in support of stipulation submitted September 25, 2009.

"In The Matter of the Application of The Detroit Edison Company for Authority to Increase Its Rates, Amend Its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy," **Michigan** Public Service Commission, Case No. U-15768. Direct testimony submitted July 9, 2009. Rebuttal testimony submitted July 30, 2009.

"In the Matter of the Investigation of Westar Energy, Inc., and Kansas Gas and Electric Company to Consider the Issue of Rate Consolidation and Resulting Rate Design," **Kansas** Corporation Commission," Docket No. 09-WSEE-641-GIE. Direct testimony submitted June 26, 2009. Cross examined August 17, 2009.

"Illinois Commerce Commission on Its Own Motion vs Commonwealth Edison Company, Investigation of Rate Design Pursuant to Section 9-250 of the Public Utilities Act," **Illinois** Commerce Commission, Docket No. 08-0532. Direct testimony submitted May 22, 2009.

"In the Matter of the Application of Duke Energy Kentucky, Inc. for Approval of Energy Efficiency Plan, Including an Energy Efficiency Rider and Portfolio of Energy Efficiency Programs," **Kentucky** Public Service Commission, Case No. 2008-00495. Direct testimony submitted May 11, 2009.

"In the Matter of the Application by Nevada Power Company d/b/a NV Energy, filed Pursuant to NRS§704.110(3) and NRS §704.110(4) for Authority to Increase Its Annual Revenue Requirement for General Rates Charged to All Classes of Customers, Begin to Recover the Costs of Acquiring the Bighorn Power Plant, Constructing the Clark Peakers, Environmental Retrofits and Other Generating, Transmission and Distribution Plant Additions, to Reflect Changes in Cost of Service and for Relief Properly Related Thereto, Public Utilities Commission of **Nevada**, Docket No. 08-12002. Direct testimony submitted April 14, 2009 (revenue requirement) and April 21, 2009 (cost of service/rate design). Cross examined May 6, 2009.

"Verified Petition of Duke Energy Indiana, Inc. Requesting the Indiana Utility Regulatory Commission to Approve an Alternative Regulatory Plan Pursuant to the Ind. Code 8-1-2.5, *Et Seq.*, for the Implementation of an Electric Distribution System "SmartGrid" and Advanced Metering Infrastructure, Distribution Automation Investments, and a Distribution Renewable Generation Demonstration Project and Associated Accounting and Rate Recovery Mechanisms, Including a Ratemaking Proposal to Update Distribution Rates Annually and a "Lost Revenue" Recovery Mechanism, in Accordance with Ind. Code 8-1-2-42(a) and 8-1-2.5-1 *Et Seq.* and Preliminary Approval of the Estimated Costs and Scheduled Deployment of the Company's SmartGrid Initiative," **Indiana** Utility Regulatory Commission, Cause No. 43501. Direct testimony submitted February 27, 2009.

"In The Matter of the Application of Duke Energy Ohio for an Increase in Electric Distribution Rates," Public Utilities Commission of **Ohio**, Case No. 08-709-EL-AIR; "In the Matter of the Application of Duke Energy Ohio for Tariff Approval," Case No. 08-710-EL-ATA; "In the Matter of the Application of Duke Energy Ohio for Approval to Change Accounting Methods," Case No. 08-711-EL-AAM. Direct testimony submitted February 26, 2009.

"In The Matter of the Amended Application of Rocky Mountain Power for Approval of a General Rate Increase of Approximately $28.8 Million per Year (6.1 Percent Overall Average

Increase)", **Wyoming** Public Service Commission, Docket No. 20000-333-ER-08. Direct testimony submitted January 30, 2009. Summary of cross answer testimony submitted February 27, 2009. Settlement testimony submitted March 13, 2009. Cross examined March 24, 2009.

"In the Matter of the Application of Dayton Power and Light Company for Approval of Its Electric Security Plan," Public Utilities Commission of **Ohio**, Case No. 08-1094-EL-SSO; "In the Matter of the Application of Dayton Power and Light Company for Approval of Revised Tariffs, Case No. 08-1095-EL-ATA; "In the Matter of the Application of Dayton Power and Light Company for Approval of Certain Accounting Authority Pursuant to Ohio Rev. Code §4905.13," Case No. 08-1096-EL-AAM; In the Matter of the Application of Dayton Power and Light Company for Approval of Its Amended Corporate Separation Plan, Case No. 08-1097-EL-UNC. Direct testimony submitted January 26, 2009. Deposed February 6, 2009. Testimony withdrawn pursuant to stipulation filed February 24, 2009.

"Application of Oncor Electric Delivery Company LLC for Authority to Change Rates," Public Utility Commission of **Texas**, SOAH Docket No. 473-08-3681, PUC Docket No. 35717. Direct testimony submitted November 26, 2008. Cross examined February 3, 2009.

"In the Matter of the Application of Columbus Southern Power Company for Approval of Its Electric Security Plan; An Amendment to Its Corporate Separation Plan; and the Sale of Certain Generating Assets", Public Utilities Commission of **Ohio**, Case No. 08-917-EL-SSO; "In the Matter of the Application of Ohio Power Company for Approval of Its Electric Security Plan; and an Amendment to Its Corporate Separation Plan," Case No. 08-918-EL-SSO. Direct testimony submitted October 31, 2008. Cross examined November 25, 2008.

"Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Base Rates," **Kentucky** Public Service Commission, Case No. 2008-00252. Direct testimony submitted October 28, 2008.

"Application of Kentucky Utilities Company for an Adjustment of Base Rates," **Kentucky** Public Service Commission, Case No. 2008-00251. Direct testimony submitted October 28, 2008.

"In the Matter of the Application of Idaho Power Company for Authority to Increase its Rates and Charges for Electric Service," **Idaho** Public Utilities Commission, Case No. IPC-E-08-10. Direct testimony submitted October 24, 2008. Rebuttal testimony submitted December 3, 2008. Cross examined December 19, 2008.

"In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations," **Utah** Public Service Commission, Docket No. 08-035-38. Direct testimony submitted October 7, 2008 (test period) and February 12, 2009 (revenue requirement). Cross examined October 28, 2008 (test period).

"In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Establish a Standard Service Offer Pursuant to R.C. § 4928.143 in the Form of an Electric Security Plan," Public Utility Commission of **Ohio**, Case No. 08-935-EL-SSO. Direct testimony submitted September 29, 2008. Deposed October 13, 2008. Cross examined October 21, 2008.

"In the Matter of the Application of Westar Energy, Inc. and Kansas Gas and Electric Company for Approval to Make Certain Changes In Their Charges for Electric Service," State Corporation Commission of **Kansas**, Docket No. 08-WSEE-1041-RTS. Direct testimony submitted September 29, 2008. Cross Answer testimony submitted October 8, 2008.

"In the Matter of Appalachian Power Company's Application for Increase in Electric Rates," **Virginia** State Corporation Commission, Case No. PUE-2008-00046. Direct testimony submitted September 26, 2008.

"In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for Standard Service Offer Electric Generation Supply, Accounting Modifications with Reconciliation Mechanism and Tariffs for Generation Service," Public Utility Commission of **Ohio**, Case No. 08-936-EL-SSO. Direct testimony submitted September 9, 2008. Deposed September 16, 2008.

"In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return," **Arizona** Corporation Commission, Docket No. E-01345A-08-0172. Direct testimony submitted August 29, 2008 (interim rates), December 19, 2008 (revenue requirement), January 9, 2009 (cost of service, rate design), and July 1, 2009 (settlement agreement). Reply testimony submitted August 6, 2009 (settlement agreement). Cross examined September 16, 2008 (interim rates) and August 20, 2009 (settlement agreement).

"Verified Joint Petition of Duke Energy Indiana, Inc., Indianapolis Power & Light Company, Northern Indiana Public Service Company and Vectren Energy Delivery of Indiana, Inc. for Approval, if and to the Extent Required, of Certain Changes in Operations That Are Likely To Result from the Midwest Independent System Operator, Inc.'s Implementation of Revisions to Its Open Access Transmission and Energy Markets Tariff to Establish a Co-Optimized, Competitive Market for Energy and Ancillary Services Market; and for Timely Recovery of Costs Associated with Joint Petitioners' Participation in Such Ancillary Services Market," **Indiana** Utility Regulatory Commission, Cause No. 43426. Confidential direct testimony submitted August 6, 2008. Confidential direct testimony in opposition to Settlement Agreement submitted November 12, 2008.

"In The Matter of the Application of The Detroit Edison Company for Authority to Increase Its Rates, Amend Its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy, and for Miscellaneous Accounting Authority," **Michigan** Public Service Commission, Case No. U-15244. Direct testimony submitted July 15, 2008. Rebuttal testimony submitted August 8, 2008.

"Portland General Electric General Rate Case Filing," Public Utility Commission of **Oregon,** Docket No. UE-197. Direct testimony submitted July 9, 2008. Surrebuttal testimony submitted September 15, 2008.

"In the Matter of PacifiCorp, dba Pacific Power, 2009 Transition Adjustment Mechanism, Schedule 200, Cost-Based Supply Service," Public Utility Commission of **Oregon,** Docket No. UE-199. Reply testimony submitted June 23, 2008. Joint testimony in support of stipulation submitted September 4, 2008.

"2008 Puget Sound Energy General Rate Case," **Washington** Utilities and Transportation Commission, Docket Nos. UE-072300 and UG-072301. Response testimony submitted May 30, 2008. Cross-Answer testimony submitted July 3, 2008. Joint testimony in support of partial stipulations submitted July 3, 2008 (gas rate spread/rate design), August 12, 2008 (electric rate spread/rate design), and August 28, 2008 (revenue requirements). Cross examined September 3, 2008.

"Verified Petition of Duke Energy Indiana, Inc. Requesting the Indiana Utility Regulatory Commission to Approve an Alternative Regulatory Plan Pursuant to the Ind. Code 8-1-2.5, Et Seq., for the Offering of Energy Efficiency Conservation, Demand Response, and Demand-Side Management Programs and Associated Rate Treatment Including Incentives Pursuant to a Revised Standard Contract Rider No. 66 in Accordance with Ind. Code 8-1-2.5-1 Et Seq. and 8-1-2-42(a); Authority to Defer Program Costs Associated with Its Energy Efficiency Portfolio of Programs; Authority to Implement New and Enhanced Energy Efficiency Programs in Its Energy Efficiency Portfolio of Programs; and Approval of a Modification of the Fuel Adjustment Clause Earnings and Expense Tests," **Indiana** Utility Regulatory Commission, Cause No. 43374. Confidential direct testimony submitted May 21, 2008 and October 27, 2008. Testimony withdrawn pursuant to stipulation, but re-submitted June 1, 2010. Confidential supplemental direct testimony submitted June 10, 2010. Application withdrawn by Duke Energy Indiana, June 2010.

"Cinergy Corp., Duke Energy Ohio, Inc., Cinergy Power Investments, Inc., Generating Facilities LLCs," **Federal Energy Regulatory Commission**, Docket No. EC-08-78-000. Affidavit filed May 14, 2008.

"Application of Entergy Gulf States, Inc. for Authority to Change Rates and to Reconcile Fuel Costs, Public Utility Commission of **Texas**, Docket No. 34800 [SOAH Docket No. 473-08-0334]. Direct testimony submitted April 11, 2008. Testimony withdrawn pursuant to stipulation.

"Central Illinois Light Company d/b/a AmerenCILCO Proposed General Increase in Electric Delivery Service Rates, Central Illinois Public Service Company d/b/a AmerenCIPS Proposed General Increase in Electric Delivery Service Rates, Illinois Power Company d/b/a/ AmerenIP Proposed General Increase in Electric Delivery Service Rates, Central Illinois Light Company d/b/a AmerenCILCO, Proposed General Increase in Gas Delivery Service Rates, Central Illinois Public Service Company d/b/a AmerenCIPS Proposed General Increase in Gas Delivery Service Rates, Illinois Power Company d/b/a/ AmerenIP Proposed General Increase in Gas Delivery Service Rates," **Illinois** Commerce Commission, Docket Nos. 07-0585, 07-0586, 07-0587, 07-0588, 07-0589, 07-0590. Direct testimony submitted March 14, 2008. Rebuttal testimony submitted April 8, 2008.

"In the Matter of the Application of Public Service Company of Colorado for Authority to Implement an Enhanced Demand Side Management Cost Adjustment Mechanism to Include Current Recovery and Incentives," **Colorado** Public Utilities Commission, Docket No. 07A-420E. Answer testimony submitted March 10, 2008. Cross examined April 25, 2008.

"An Investigation of the Energy and Regulatory Issues in Section 50 of Kentucky's 2007 Energy Act," **Kentucky** Public Service Commission, Administrative Case No. 2007-00477. Direct testimony submitted February 29, 2008. Supplemental direct testimony submitted April 1, 2008. Cross examined April 30, 2008.

"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," **Arizona** Corporation Commission, Docket No. E-01933A-07-0402. Direct testimony submitted February 29, 2008 (revenue requirement), March 14, 2008 (rate design), and June 12, 2008 (settlement agreement). Cross examined July 14, 2008.

"Commonwealth Edison Company Proposed General Increase in Electric Rates," **Illinois** Commerce Commission, Docket No. 07-0566. Direct testimony submitted February 11, 2008. Rebuttal testimony submitted April 8, 2008.

"In the Matter of the Application of Questar Gas Company to File a General Rate Case," **Utah** Public Service Commission, Docket No. 07-057-13. Direct testimony submitted January 28, 2008 (test period), March 31, 2008 (rate of return), April 21, 2008 (revenue requirement), and August 18, 2008 (cost of service, rate spread, rate design). Rebuttal testimony submitted September 22, 2008 (cost of service, rate spread, rate design). Surrebuttal testimony submitted May 12, 2008 (rate of return) and October 7, 2008 (cost of service, rate spread, rate design).

Cross examined February 8, 2008 (test period), May 21, 2008 (rate of return), and October 15, 2008 (cost of service, rate spread, rate design).

"In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations, Consisting of a General Rate Increase of Approximately $161.2 Million Per Year, and for Approval of a New Large Load Surcharge," **Utah** Public Service Commission, Docket No. 07-035-93. Direct testimony submitted January 25, 2008 (test period), April 7, 2008 (revenue requirement), and July 21, 2008 (cost of service, rate design). Rebuttal testimony submitted September 3, 2008 (cost of service, rate design). Surrebuttal testimony submitted May 23, 2008 (revenue requirement) and September 24, 2008 (cost of service, rate design). Cross examined February 7, 2008 (test period).

"In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Increase Rates for Distribution Service, Modify Certain Accounting Practices and for Tariff Approvals," Public Utilities Commission of **Ohio**, Case Nos. 07-551-EL-AIR, 07-552-EL-ATA, 07-553-EL-AAM, and 07-554-EL-UNC. Direct testimony submitted January 10, 2008.

"In the Matter of the Application of Rocky Mountain Power for Authority to Increase Its Retail Electric Utility Service Rates in Wyoming, Consisting of a General Rate Increase of Approximately $36.1 Million per Year, and for Approval of a New Renewable Resource Mechanism and Marginal Cost Pricing Tariff," **Wyoming** Public Service Commission, Docket No. 20000-277-ER-07. Direct testimony submitted January 7, 2008. Cross examined March 6, 2008.

"In the Matter of the Application of Idaho Power Company for Authority to Increase Its Rates and Charges for Electric Service to Electric Customers in the State of Idaho," **Idaho** Public Utilities Commission, Case No. IPC-E-07-8. Direct testimony submitted December 10, 2007. Cross examined January 23, 2008.

"In The Matter of the Application of Consumers Energy Company for Authority to Increase Its Rates for the Generation and Distribution Of Electricity and Other Relief," **Michigan** Public Service Commission, Case No. U-15245. Direct testimony submitted November 6, 2007. Rebuttal testimony submitted November 20, 2007.

"In the Matter of Montana-Dakota Utilities Co., Application for Authority to Establish Increased Rates for Electric Service," **Montana** Public Service Commission, Docket No. D2007.7.79. Direct testimony submitted October 24, 2007.

"In the Matter of the Application of Public Service Company of New Mexico for Revision of its Retail Electric Rates Pursuant to Advice Notice No. 334," **New Mexico** Public Regulation

Commission, Case No. 07-0077-UT. Direct testimony submitted October 22, 2007. Rebuttal testimony submitted November 19, 2007. Cross examined December 12, 2007.

"In The Matter of Georgia Power Company's 2007 Rate Case," **Georgia** Public Service Commission, Docket No. 25060-U. Direct testimony submitted October 22, 2007. Cross examined November 7, 2007.

"In the Matter of the Application of Rocky Mountain Power for an Accounting Order to Defer the Costs Related to the MidAmerican Energy Holdings Company Transaction," **Utah** Public Service Commission, Docket No. 07-035-04; "In the Matter of the Application of Rocky Mountain Power, a Division of PacifiCorp, for a Deferred Accounting Order To Defer the Costs of Loans Made to Grid West, the Regional Transmission Organization," Docket No. 06-035-163; "In the Matter of the Application of Rocky Mountain Power for an Accounting Order for Costs related to the Flooding of the Powerdale Hydro Facility," Docket No. 07-035-14. Direct testimony submitted September 10, 2007. Surrebuttal testimony submitted October 22, 2007. Cross examined October 30, 2007.

"In the Matter of General Adjustment of Electric Rates of East Kentucky Power Cooperative, Inc.," **Kentucky** Public Service Commission, Case No. 2006-00472. Direct testimony submitted July 6, 2007. Supplemental direct testimony submitted March 18, 2008.

"In the Matter of the Application of Sempra Energy Solutions for a Certificate of Convenience and Necessity for Competitive Retail Electric Service," **Arizona** Corporation Commission, Docket No. E-03964A-06-0168. Direct testimony submitted July 3, 2007. Rebuttal testimony submitted January 17, 2008 and February 7, 2007.

"Application of Public Service Company of Oklahoma for a Determination that Additional Electric Generating Capacity Will Be Used and Useful," **Oklahoma** Corporation Commission, Cause No. PUD 200500516; "Application of Public Service Company of Oklahoma for a Determination that Additional Baseload Electric Generating Capacity Will Be Used and Useful," Cause No. PUD 200600030; "In the Matter of the Application of Oklahoma Gas and Electric Company for an Order Granting Pre-Approval to Construct Red Rock Generating Facility and Authorizing a Recovery Rider," Cause No. PUD200700012. Responsive testimony submitted May 21, 2007. Cross examined July 26, 2007.

"Application of Nevada Power Company for Authority to Increase Its Annual Revenue Requirement for General Rates Charged to All Classes of Electric Customers and for Relief Properly Related Thereto," Public Utilities Commission of **Nevada**, Docket No. 06-11022. Direct testimony submitted March 14, 2007 (Phase III – revenue requirements) and March 19, 2007 (Phase IV – rate design). Cross examined April 10, 2007 (Phase III – revenue requirements) and April 16, 2007 (Phase IV – rate design).

"In the Matter of the Application of Entergy Arkansas, Inc. for Approval of Changes in Rates for Retail Electric Service," **Arkansas** Public Service Commission, Docket No. 06-101-U. Direct testimony submitted February 5, 2007. Surrebuttal testimony submitted March 26, 2007.

"Monongahela Power Company and The Potomac Edison Company, both d/b/a Allegheny Power – Rule 42T Application to Increase Electric Rates and Charges," Public Service Commission of **West Virginia**, Case No. 06-0960-E-42T; "Monongahela Power Company and The Potomac Edison Company, both d/b/a Allegheny Power – Information Required for Change of Depreciation Rates Pursuant to Rule 20," Case No. 06-1426-E-D. Direct and rebuttal testimony submitted January 22, 2007.

"In the Matter of the Tariffs of Aquila, Inc., d/b/a Aquila Networks-MPS and Aquila Networks-L&P Increasing Electric Rates for the Services Provided to Customers in the Aquila Networks-MPS and Aquila Networks-L&P Missouri Service Areas," **Missouri** Public Service Commission, Case No. ER-2007-0004. Direct testimony submitted January 18, 2007 (revenue requirements) and January 25, 2007 (revenue apportionment). Supplemental direct testimony submitted February 27, 2007.

"In the Matter of the Filing by Tucson Electric Power Company to Amend Decision No. 62103, **Arizona** Corporation Commission, Docket No. E-01933A-05-0650. Direct testimony submitted January 8, 2007. Surrebuttal testimony filed February 8, 2007. Cross examined March 8, 2007.

"In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area," **Missouri** Public Service Commission, Case No. ER-2007-0002. Direct testimony submitted December 15, 2006 (revenue requirements) and December 29, 2006 (fuel adjustment clause/cost-of-service/rate design). Rebuttal testimony submitted February 5, 2007 (cost-of-service). Surrebuttal testimony submitted February 27, 2007. Cross examined March 21, 2007.

"In the Matter of Application of The Union Light, Heat and Power Company d/b/a Duke Energy Kentucky, Inc. for an Adjustment of Electric Rates," **Kentucky** Public Service Commission, Case No. 2006-00172. Direct testimony submitted September 13, 2006.

"In the Matter of Appalachian Power Company's Application for Increase in Electric Rates," **Virginia** State Corporation Commission, Case No. PUE-2006-00065. Direct testimony submitted September 1, 2006. Cross examined December 7, 2006.

"In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, To Approve Rate Schedules Designed to Develop Such Return, and to Amend Decision No. 67744, **Arizona** Corporation Commission," Docket No. E-01345A-05-0816. Direct testimony submitted August 18, 2006 (revenue requirements) and September 1, 2006 (cost-of-service/rate design). Surrebuttal testimony submitted September 27, 2006. Cross examined November 7, 2006.

"Re: The Tariff Sheets Filed by Public Service Company of Colorado with Advice Letter No 1454 – Electric," **Colorado** Public Utilities Commission, Docket No. 06S-234EG. Answer testimony submitted August 18, 2006.

"Portland General Electric General Rate Case Filing," Public Utility Commission of **Oregon,** Docket No. UE-180. Direct testimony submitted August 9, 2006. Joint testimony regarding stipulation submitted August 22, 2006.

"2006 Puget Sound Energy General Rate Case," **Washington** Utilities and Transportation Commission, Docket Nos. UE-060266 and UG-060267. Response testimony submitted July 19, 2006. Joint testimony regarding stipulation submitted August 23, 2006.

"In the Matter of PacifiCorp, dba Pacific Power & Light Company, Request for a General Rate Increase in the Company's Oregon Annual Revenues," Public Utility Commission of **Oregon**, Docket No. UE-179. Direct testimony submitted July 12, 2006. Joint testimony regarding stipulation submitted August 21, 2006.

"Petition of Metropolitan Edison Company for Approval of a Rate Transition Plan," **Pennsylvania** Public Utilities Commission, Docket Nos. P-00062213 and R-00061366; "Petition of Pennsylvania Electric Company for Approval of a Rate Transition Plan," Docket Nos. P-0062214 and R-00061367; Merger Savings Remand Proceeding, Docket Nos. A-110300F0095 and A-110400F0040. Direct testimony submitted July 10, 2006. Rebuttal testimony submitted August 8, 2006. Surrebuttal testimony submitted August 18, 2006. Cross examined August 30, 2006.

"In the Matter of the Application of PacifiCorp for approval of its Proposed Electric Rate Schedules & Electric Service Regulations," **Utah** Public Service Commission, Docket No. 06-035-21. Direct testimony submitted June 9, 2006 (Test Period). Surrebuttal testimony submitted July 14, 2006.

"Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for the Approval of the Conservation Enabling Tariff Adjustment Option and Accounting Orders," **Utah** Public Service Commission, Docket No. 05-057-T01. Direct testimony submitted May 15, 2006. Rebuttal testimony submitted August 8, 2007. Cross examined September 19, 2007.

"Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, Illinois Power Company d/b/a AmerenIP, Proposed General Increase in Rates for Delivery Service (Tariffs Filed December 27, 2005)," **Illinois** Commerce Commission, Docket Nos. 06-0070, 06-0071, 06-0072. Direct testimony submitted March 26, 2006. Rebuttal testimony submitted June 27, 2006.

"In the Matter of Appalachian Power Company and Wheeling Power Company, both dba American Electric Power," Public Service Commission of **West Virginia**, Case No. 05-1278-E-PC-PW-42T. Direct and rebuttal testimony submitted March 8, 2006.

"In the Matter of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota," **Minnesota** Public Utilities Commission, Docket No. G-002/GR-05-1428. Direct testimony submitted March 2, 2006. Rebuttal testimony submitted March 30, 2006. Cross examined April 25, 2006.

"In the Matter of the Application of Arizona Public Service Company for an Emergency Interim Rate Increase and for an Interim Amendment to Decision No. 67744," **Arizona** Corporation Commission, Docket No. E-01345A-06-0009. Direct testimony submitted February 28, 2006. Cross examined March 23, 2006.

"In the Matter of the Applications of Westar Energy, Inc. and Kansas Gas and Electric Company for Approval to Make Certain Changes in Their Charges for Electric Service," State Corporation Commission of **Kansas**, Case No. 05-WSEE-981-RTS. Direct testimony submitted September 9, 2005. Cross examined October 28, 2005.

"In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Recover Costs Associated with the Construction and Ultimate Operation of an Integrated Combined Cycle Electric Generating Facility," Public Utilities Commission of **Ohio**," Case No. 05-376-EL-UNC. Direct testimony submitted July 15, 2005. Cross examined August 12, 2005.

"In the Matter of the Filing of General Rate Case Information by Tucson Electric Power Company Pursuant to Decision No. 62103," **Arizona** Corporation Commission, Docket No. E-01933A-04-0408. Direct testimony submitted June 24, 2005.

"In the Matter of Application of The Detroit Edison Company to Unbundle and Realign Its Rate Schedules for Jurisdictional Retail Sales of Electricity," **Michigan** Public Service Commission, Case No. U-14399. Direct testimony submitted June 9, 2005. Rebuttal testimony submitted July 1, 2005.

"In the Matter of the Application of Consumers Energy Company for Authority to Increase Its Rates for the Generation and Distribution of Electricity and Other Relief," **Michigan** Public Service Commission, Case No. U-14347. Direct testimony submitted June 3, 2005. Rebuttal testimony submitted June 17, 2005.

"In the Matter of Pacific Power & Light, Request for a General Rate Increase in the Company's Oregon Annual Revenues," Public Utility Commission of **Oregon**, Docket No. UE 170. Direct testimony submitted May 9, 2005. Surrebuttal testimony submitted June 27, 2005. Joint testimony regarding partial stipulations submitted June 2005, July 2005, and August 2005.

"In the Matter of the Application of Trico Electric Cooperative, Inc. for a Rate Increase," **Arizona** Corporation Commission, Docket No. E-01461A-04-0607. Direct testimony submitted April 13, 2005. Surrebuttal testimony submitted May 16, 2005. Cross examined May 26, 2005.

"In the Matter of the Application of PacifiCorp for Approval of its Proposed Electric Service Schedules and Electric Service Regulations," **Utah** Public Service Commission, Docket No. 04-035-42. Direct testimony submitted January 7, 2005.

"In the Matter of the Application by Golden Valley Electric Association, Inc., for Authority to Implement Simplified Rate Filing Procedures and Adjust Rates," Regulatory Commission of **Alaska**, Docket No. U-4-33. Direct testimony submitted November 5, 2004. Cross examined February 8, 2005.

"Advice Letter No. 1411 - Public Service Company of Colorado Electric Phase II General Rate Case," **Colorado** Public Utilities Commission, Docket No. 04S-164E. Direct testimony submitted October 12, 2004. Cross-answer testimony submitted December 13, 2004. Testimony withdrawn January 18, 2005, following Applicant's withdrawal of testimony pertaining to TOU rates.

"In the Matter of Georgia Power Company's 2004 Rate Case," **Georgia** Public Service Commission, Docket No. 18300-U. Direct testimony submitted October 8, 2004. Cross examined October 27, 2004.

"2004 Puget Sound Energy General Rate Case," **Washington** Utilities and Transportation Commission, Docket Nos. UE-040641 and UG-040640. Response testimony submitted September 23, 2004. Cross-answer testimony submitted November 3, 2004. Joint testimony regarding stipulation submitted December 6, 2004.

"In the Matter of the Application of PacifiCorp for an Investigation of Interjurisdictional Issues," **Utah** Public Service Commission, Docket No. 02-035-04. Direct testimony submitted July 15, 2004. Cross examined July 19, 2004.

"In the Matter of an Adjustment of the Gas and Electric Rates, Terms and Conditions of Kentucky Utilities Company," **Kentucky** Public Service Commission, Case No. 2003-00434.

Direct testimony submitted March 23, 2004. Testimony withdrawn pursuant to stipulation entered May 2004.

"In the Matter of an Adjustment of the Gas and Electric Rates, Terms and Conditions of Louisville Gas and Electric Company," **Kentucky** Public Service Commission, Case No. 2003-00433. Direct testimony submitted March 23, 2004. Testimony withdrawn pursuant to stipulation entered May 2004.

"In the Matter of the Application of Idaho Power Company for Authority to Increase Its Interim and Base Rates and Charges for Electric Service," **Idaho** Public Utilities Commission, Case No. IPC-E-03-13. Direct testimony submitted February 20, 2004. Rebuttal testimony submitted March 19, 2004. Cross examined April 1, 2004.

"In the Matter of the Applications of the Ohio Edison Company, the Cleveland Electric Illuminating Company and the Toledo Edison Company for Authority to Continue and Modify Certain Regulatory Accounting Practices and Procedures, for Tariff Approvals and to Establish Rates and Other Charges, Including Regulatory Transition Charges Following the Market Development Period," Public Utilities Commission of **Ohio**, Case No. 03-2144-EL-ATA. Direct testimony submitted February 6, 2004. Cross examined February 18, 2004.

"In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, To Fix a Just and Reasonable Rate of Return Thereon, To Approve Rate Schedules Designed to Develop Such Return, and For Approval of Purchased Power Contract," **Arizona** Corporation Commission, Docket No. E-01345A-03-0437. Direct testimony submitted February 3, 2004. Rebuttal testimony submitted March 30, 2004. Direct testimony regarding stipulation submitted September 27, 2004. Responsive / Clarifying testimony regarding stipulation submitted October 25, 2004. Cross examined November 8-10, 2004 and November 29-December 3, 2004.

"In the Matter of Application of the Detroit Edison Company to Increase Rates, Amend Its Rate Schedules Governing the Distribution and Supply of Electric Energy, etc.," **Michigan** Public Service Commission, Case No. U-13808. Direct testimony submitted December 12, 2003 (interim request) and March 5, 2004 (general rate case).

"In the Matter of PacifiCorp's Filing of Revised Tariff Schedules," Public Utility Commission of **Oregon**, Docket No. UE-147. Joint testimony regarding stipulation submitted August 21, 2003.

"Petition of PSI Energy, Inc. for Authority to Increase Its Rates and Charges for Electric Service, etc.," **Indiana** Utility Regulatory Commission, Cause No. 42359. Direct testimony submitted August 19, 2003. Cross examined November 5, 2003.

"In the Matter of the Application of Consumers Energy Company for a Financing Order Approving the Securitization of Certain of its Qualified Cost," **Michigan** Public Service Commission, Case No. U-13715. Direct testimony submitted April 8, 2003. Cross examined April 23, 2003.

"In the Matter of the Application of Arizona Public Service Company for Approval of Adjustment Mechanisms," **Arizona** Corporation Commission, Docket No. E-01345A-02-0403. Direct testimony submitted February 13, 2003. Surrebuttal testimony submitted March 20, 2003. Cross examined April 8, 2003.

"Re: The Investigation and Suspension of Tariff Sheets Filed by Public Service Company of Colorado, Advice Letter No. 1373 – Electric, Advice Letter No. 593 – Gas, Advice Letter No. 80 – Steam," **Colorado** Public Utilities Commission, Docket No. 02S-315 EG. Direct testimony submitted November 22, 2002. Cross-answer testimony submitted January 24, 2003.

"In the Matter of the Application of The Detroit Edison Company to Implement the Commission's Stranded Cost Recovery Procedure and for Approval of Net Stranded Cost Recovery Charges," **Michigan** Public Service Commission, Case No. U-13350. Direct testimony submitted November 12, 2002.

"Application of South Carolina Electric & Gas Company: Adjustments in the Company's Electric Rate Schedules and Tariffs," Public Service Commission of **South Carolina**, Docket No. 2002-223-E. Direct testimony submitted November 8, 2002. Surrebuttal testimony submitted November 18, 2002. Cross examined November 21, 2002.

"In the Matter of the Application of Questar Gas Company for a General Increase in Rates and Charges," **Utah** Public Service Commission, Docket No. 02-057-02. Direct testimony submitted August 30, 2002. Rebuttal testimony submitted October 4, 2002.

"The Kroger Co. v. Dynegy Power Marketing, Inc.," **Federal Energy Regulatory Commission**, EL02-119-000. Confidential affidavit filed August 13, 2002.

"In the matter of the application of Consumers Energy Company for determination of net stranded costs and for approval of net stranded cost recovery charges," **Michigan** Public Service Commission, Case No. U-13380. Direct testimony submitted August 9, 2002. Rebuttal testimony submitted August 30, 2002. Cross examined September 10, 2002.

"In the Matter of the Application of Public Service Company of Colorado for an Order to Revise Its Incentive Cost Adjustment," **Colorado** Public Utilities Commission, Docket 02A-158E. Direct testimony submitted April 18, 2002.

"In the Matter of the Generic Proceedings Concerning Electric Restructuring Issues," **Arizona** Corporation Commission, Docket No. E-00000A-02-0051, "In the Matter of Arizona Public Service Company's Request for Variance of Certain Requirements of A.A.C. R14-2-1606," Docket No. E-01345A-01-0822, "In the Matter of the Generic Proceeding Concerning the Arizona Independent Scheduling Administrator," Docket No. E-00000A-01-0630, "In the Matter of Tucson Electric Power Company's Application for a Variance of Certain Electric Competition Rules Compliance Dates," Docket No. E-01933A-02-0069, "In the Matter of the Application of Tucson Electric Power Company for Approval of its Stranded Cost Recovery," Docket No. E-01933A-98-0471. Direct testimony submitted March 29, 2002 (APS variance request); May 29, 2002 (APS Track A proceeding/market power issues); and July 28, 2003 (Arizona ISA). Rebuttal testimony submitted August 29, 2003 (Arizona ISA). Cross examined June 21, 2002 (APS Track A proceeding/market power issues) and September 12, 2003 (Arizona ISA).

"In the Matter of Savannah Electric & Power Company's 2001 Rate Case," **Georgia** Public Service Commission, Docket No. 14618-U. Direct testimony submitted March 15, 2002. Cross examined March 28, 2002.

"Nevada Power Company's 2001 Deferred Energy Case," Public Utilities Commission of **Nevada**, PUCN 01-11029. Direct testimony submitted February 7, 2002. Cross examined February 21, 2002.

"2001 Puget Sound Energy Interim Rate Case," **Washington** Utilities and Transportation Commission, Docket Nos. UE-011570 and UE-011571. Direct testimony submitted January 30, 2002. Cross examined February 20, 2002.

"In the Matter of Georgia Power Company's 2001 Rate Case," **Georgia** Public Service Commission, Docket No. 14000-U. Direct testimony submitted October 12, 2001. Cross examined October 24, 2001.

"In the Matter of the Application of PacifiCorp for Approval of Its Proposed Electric Rate Schedules and Electric Service Regulations," **Utah** Public Service Commission, Docket No. 01-35-01. Direct testimony submitted June 15, 2001. Rebuttal testimony submitted August 31, 2001.

"In the Matter of Portland General Electric Company's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 1149," Public Utility Commission of **Oregon**, Docket No. UE-115. Direct testimony submitted February 20, 2001. Rebuttal testimony submitted May 4, 2001. Joint testimony regarding stipulation submitted July 27, 2001.

"In the Matter of the Application of APS Energy Services, Inc. for Declaratory Order or Waiver of the Electric Competition Rules," **Arizona** Corporation Commission, Docket No.E-01933A-00-0486. Direct testimony submitted July 24, 2000.

"In the Matter of the Application of Questar Gas Company for an Increase in Rates and Charges," **Utah** Public Service Commission, Docket No. 99-057-20. Direct testimony submitted April 19, 2000. Rebuttal testimony submitted May 24, 2000. Surrebuttal testimony submitted May 31, 2000. Cross examined June 6 & 8, 2000.

"In the Matter of the Application of Columbus Southern Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues," Public Utility Commission of **Ohio**, Case No. 99-1729-EL-ETP; "In the Matter of the Application of Ohio Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues," Public Utility Commission of **Ohio**, Case No. 99-1730-EL-ETP. Direct testimony prepared, but not submitted pursuant to settlement agreement effected May 2, 2000.

"In the Matter of the Application of FirstEnergy Corp. on Behalf of Ohio Edison Company, The Cleveland Electric Illuminating Company, and the Toledo Edison Company for Approval of Their Transition Plans and for Authorization to Collect Transition Revenues," Public Utility Commission of **Ohio**, Case No. 99-1212-EL-ETP. Direct testimony prepared, but not submitted pursuant to settlement agreement effected April 11, 2000.

"2000 Pricing Process," **Salt River Project** Board of Directors, oral comments provided March 6, 2000 and April 10, 2000.

"Tucson Electric Power Company vs. Cyprus Sierrita Corporation," **Arizona** Corporation Commission, Docket No. E-000001-99-0243. Direct testimony submitted October 25, 1999. Cross examined November 4, 1999.

"Application of Hildale City and Intermountain Municipal Gas Association for an Order Granting Access for Transportation of Interstate Natural Gas over the Pipelines of Questar Gas Company for Hildale, Utah," **Utah** Public Service Commission, Docket No. 98-057-01. Rebuttal testimony submitted August 30, 1999.

"In the Matter of the Application by Arizona Electric Power Cooperative, Inc. for Approval of Its Filing as to Regulatory Assets and Transition Revenues," **Arizona** Corporation Commission, Docket No. E-01773A-98-0470. Direct testimony submitted July 30, 1999. Cross examined February 28, 2000.

"In the Matter of the Application of Tucson Electric Power Company for Approval of its Plan for Stranded Cost Recovery," **Arizona** Corporation Commission, Docket No. E-01933A-98-0471; "In the Matter of the Filing of Tucson Electric Power Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01933A-97-0772; "In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," Docket No.

RE-00000C-94-0165. Direct testimony submitted June 30, 1999. Rebuttal testimony submitted August 6, 1999. Cross examined August 11-13, 1999.

"In the Matter of the Application of Arizona Public Service Company for Approval of its Plan for Stranded Cost Recovery," **Arizona** Corporation Commission, Docket No. E-01345A-98-0473; "In the Matter of the Filing of Arizona Public Service Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01345A-97-0773; "In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," Docket No. RE-00000C-94-0165. Direct testimony submitted June 4, 1999. Rebuttal testimony submitted July 12, 1999. Cross examined July 14, 1999.

"In the Matter of the Application of Tucson Electric Power Company for Approval of its Plan for Stranded Cost Recovery," **Arizona** Corporation Commission, Docket No. E-01933A-98-0471; "In the Matter of the Filing of Tucson Electric Power Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01933A-97-0772; "In the Matter of the Application of Arizona Public Service Company for Approval of its Plan for Stranded Cost Recovery," Docket No. E-01345A-98-0473; "In the Matter of the Filing of Arizona Public Service Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01345A-97-0773; "In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," Docket No. RE-00000C-94-0165. Direct testimony submitted November 30, 1998.

"Hearings on Pricing," **Salt River Project** Board of Directors, written and oral comments provided November 9, 1998.

"Hearings on Customer Choice," **Salt River Project** Board of Directors, written and oral comments provided June 22, 1998; June 29, 1998; July 9, 1998; August 7, 1998; and August 14, 1998.

"In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," **Arizona** Corporation Commission, Docket No. U-0000-94-165. Direct and rebuttal testimony filed January 21, 1998. Second rebuttal testimony filed February 4, 1998. Cross examined February 25, 1998.

"In the Matter of Consolidated Edison Company of New York, Inc.'s Plans for (1) Electric Rate/Restructuring Pursuant to Opinion No. 96-12; and (2) the Formation of a Holding Company Pursuant to PSL, Sections 70, 108, and 110, and Certain Related Transactions," **New York** Public Service Commission, Case 96-E-0897. Direct testimony filed April 9, 1997. Cross examined May 5, 1997.

"In the Matter of the Petition of Sunnyside Cogeneration Associates for Enforcement of Contract Provisions," **Utah** Public Service Commission, Docket No. 96-2018-01; "In the Matter of the Application of Rocky Mountain Power for an Order Approving an Amendment to Its Power

Purchase Agreement with Sunnyside Cogeneration Associates," Docket Nos. 05-035-46, and 07-035-99. Direct testimony submitted July 8, 1996. Oral testimony provided March 18, 2008.

"In the Matter of the Application of PacifiCorp, dba Pacific Power & Light Company, for Approval of Revised Tariff Schedules and an Alternative Form of Regulation Plan," **Wyoming** Public Service Commission, Docket No. 20000-ER-95-99. Direct testimony submitted April 8, 1996.

"In the Matter of the Application of Mountain Fuel Supply Company for an Increase in Rates and Charges," **Utah** Public Service Commission, Case No. 95-057-02. Direct testimony submitted June 19, 1995. Rebuttal testimony submitted July 25, 1995. Surrebuttal testimony submitted August 7, 1995.

"In the Matter of the Investigation of the Reasonableness of the Rates and Tariffs of Mountain Fuel Supply Company," **Utah** Public Service Commission, Case No. 89-057-15. Direct testimony submitted July 1990. Surrebuttal testimony submitted August 1990.

"In the Matter of the Review of the Rates of Utah Power and Light Company pursuant to The Order in Case No. 87-035-27," **Utah** Public Service Commission, Case No. 89-035-10. Rebuttal testimony submitted November 15, 1989. Cross examined December 1, 1989 (rate schedule changes for state facilities).

"In the Matter of the Application of Utah Power & Light Company and PC/UP&L Merging Corp. (to be renamed PacifiCorp) for an Order Authorizing the Merger of Utah Power & Light Company and PacifiCorp into PC/UP&L Merging Corp. and Authorizing the Issuance of Securities, Adoption of Tariffs, and Transfer of Certificates of Public Convenience and Necessity and Authorities in Connection Therewith," **Utah** Public Service Commission, Case No. 87-035-27; Direct testimony submitted April 11, 1988. Cross examined May 12, 1988 (economic impact of UP&L merger with PacifiCorp).

"In the Matter of the Application of Mountain Fuel Supply Company for Approval of Interruptible Industrial Transportation Rates," **Utah** Public Service Commission, Case No. 86-057-07. Direct testimony submitted January 15, 1988. Cross examined March 30, 1988.

"In the Matter of the Application of Utah Power and Light Company for an Order Approving a Power Purchase Agreement," **Utah** Public Service Commission, Case No. 87-035-18. Oral testimony delivered July 8, 1987.

"Cogeneration: Small Power Production," **Federal Energy Regulatory Commission**, Docket No. RM87-12-000. Statement on behalf of State of Utah delivered March 27, 1987, in San Francisco.

"In the Matter of the Investigation of Rates for Backup, Maintenance, Supplementary, and Standby Power for Utah Power and Light Company," **Utah** Public Service Commission, Case No. 86-035-13. Direct testimony submitted January 5, 1987. Case settled by stipulation approved August 1987.

"In the Matter of the Application of Sunnyside Cogeneration Associates for Approval of the Cogeneration Power Purchase Agreement," **Utah** Public Service Commission, Case No. 86-2018-01. Rebuttal testimony submitted July 16, 1986. Cross examined July 17, 1986.

"In the Matter of the Investigation of Demand-Side Alternatives to Capacity Expansion for Electric Utilities," **Utah** Public Service Commission, Case No. 84-999-20. Direct testimony submitted June 17, 1985. Rebuttal testimony submitted July 29, 1985. Cross examined August 19, 1985.

"In the Matter of the Implementation of Rules Governing Cogeneration and Small Power Production in Utah," **Utah** Public Service Commission, Case No. 80-999-06, pp. 1293-1318. Direct testimony submitted January 13, 1984 (avoided costs), May 9, 1986 (security for levelized contracts) and November 17, 1986 (avoided costs). Cross-examined February 29, 1984 (avoided costs), April 11, 1985 (standard form contracts), May 22-23, 1986 (security for levelized contracts) and December 16-17, 1986 (avoided costs).

OTHER RELATED ACTIVITY

Participant, Wyoming Load Growth Collaborative, March 2008 to January 2009.

Participant, Oregon Direct Access Task Force (UM 1081), May 2003 to November 2003.

Participant, Michigan Stranded Cost Collaborative, March 2003 to March 2004.

Member, Arizona Electric Competition Advisory Group, December 2002 to present.

Board of Directors, ex-officio, Desert STAR RTO, September 1999 to February 2002.

Member, Advisory Committee, Desert STAR RTO, September 1999 to February 2002. Acting Chairman, October 2000 to February 2002.

Board of Directors, Arizona Independent Scheduling Administrator Association, October 1998 to present.

Acting Chairman, Operating Committee, Arizona Independent Scheduling Administrator Association, October 1998 to June 1999.

Member, Desert Star ISO Investigation Working Groups: Operations, Pricing, and Governance, April 1997 to December 1999. Legal & Negotiating Committee, April 1999 to December 1999.

Participant, Independent System Operator and Spot Market Working Group, Arizona Corporation Commission, April 1997 to September 1997.

Participant, Unbundled Services and Standard Offer Working Group, Arizona Corporation Commission, April 1997 to October 1997.

Participant, Customer Selection Working Group, Arizona Corporation Commission, March 1997 to September 1997.

Member, Stranded Cost Working Group, Arizona Corporation Commission, March 1997 to September 1997.

Member, Electric System Reliability & Safety Working Group, Arizona Corporation Commission, November 1996 to September 1998.

Chairman, Salt Palace Renovation and Expansion Committee, Salt Lake County/State of Utah/Salt Lake City, multi-government entity responsible for implementation of planning, design, finance, and construction of an $85 million renovation of the Salt Palace Convention Center, Salt Lake City, Utah, May 1991 to December 1994.

State of Utah Representative, Committee on Regional Electric Power Cooperation, a joint effort of the Western Interstate Energy Board and the Western Conference of Public Service Commissioners, January 1987 to December 1990.

Member, Utah Governor's Economic Coordinating Committee, January 1987 to December 1990.

Chairman, Standard Contract Task Force, established by Utah Public Service Commission to address contractual problems relating to qualifying facility sales under PURPA, March 1986 to December 1990.

Chairman, Load Management and Energy Conservation Task Force, Utah Public Service Commission, August 1985 to December 1990.

Alternate Delegate for Utah, Western Interstate Energy Board, Denver, Colorado, August 1985 to December 1990.

Articles Editor, Economic Forum, September 1980 to August 1981.

EXHIBIT KCH-1

Summary of AECC Revenue Requirement Adjustments

Test Year Ended December 31, 2011
(Thousands of Dollars)

As Adjusted by AECC

Line No.	Description	ACC Jurisdiction: Original Cost		RCND		Fair Value (FV)		Line No.
1	Adjusted Rate Base	$1,433,676	(a)&(b)	$2,891,415	(a)&(b)	$2,162,546		1
2	Adjusted Operating Income	62,461	(c)	$62,461	(c)	$62,461		2
3	Current Rate of Return (Ln. 2 ÷ Ln. 1)	4.36%		2.16%		2.89%		3
4	Required Operating Income on OCRB @ WACC	$103,342		$103,342		$103,342		4
5	Required Return on FV Increment	$11,370		$11,370		$11,370		5
6	Required Operating Income	$114,713		$114,713		$114,713		6
7	Weighted Average Cost of Capital	7.21%	(d)	7.21%		7.21%		7
8	Fair Value Adjustment	0.79%		-3.24%		-1.90%		8
9	Required Rate of Return (Ln. 6 ÷ Ln. 1)	8.00%	(d)	3.97%		5.30%		9
10	Operating Income Deficiency (Ln. 6 - Ln. 2)	$52,252		$52,252		$52,252		10
11	Gross Revenue Conversion Factor	1.6590	(e)	1.6590	(e)	1.6590	(e)	11
12	Increase in Gross Revenue Requirement (Ln. 10 x Ln. 11)	$86,683		$86,683		$86,683		12
13	AECC Recommended Return on Headquarters Adjustment	($2,389)	(f)	($2,389)		($2,389)		13
14	AECC Recommended Post-Test Year Renewables Adjustment	($1,059)	(g)	($1,059)		($1,059)		14
15	Net Increase in Gross Revenue Requirement (Ln. 12 + Ln. 13 + Ln. 14)	$83,235		$83,235		$83,235		15
16	Adjusted Present Retail Revenues	$836,938	(h)	$836,938		$836,938		16
17	Percent Change from Present Revs. (Ln. 15 ÷ Ln. 16)	9.95%		9.95%		9.95%		17
18	TEP Claimed Revenue Deficiency	$127,760		$127,760		$127,760		18
19	TEP Percent Change from Present Revs. (Ln. 18 ÷ Ln. 16)	15.27%		15.27%		15.27%		19
20	AECC Change from TEP Claimed Revenue Deficiency (Ln. 15 - Ln. 18)	($44,525)		($44,525)		($44,525)		20
21	AECC Percent Change from TEP Claimed Revenue Deficiency (Ln. 17 - Ln. 19)	-5.32%		-5.32%		-5.32%		21

Supporting Schedules/Exhibits
(a) TEP Schedule B-1
(b) AECC Exhibit KCH-1, p. 7
(c) AECC Exhibit KCH-1, p. 4
(d) TEP Schedule D-1
(e) TEP Schedule C-3
(f) AECC Exhibit KCH-14, p. 1
(g) AECC Exhibit KCH-15, p. 1
(h) TEP Schedule C-3

Summary of AECC Revenue Requirement Adjustments

Test Year Ended December 31, 2011
(Thousands of Dollars)

As Filed by TEP

Line No.	Description	ACC Jurisdiction: Original Cost (OCRB)		RCND		Fair Value (FV)		Line No.
1	Adjusted Rate Base	$1,519,073	(a)	$3,041,359	(a)	$2,280,216		1
2	Adjusted Operating Income	$52,471	(b)	$52,471	(b)	$52,471		2
3	Current Rate of Return (Ln. 2 ÷ Ln. 1)	3.45%		1.73%		2.30%		3
4	Required Operating Income on OCRB @ WACC	$117,610		$117,610		$117,610		4
5	Required Return on FV Increment	$11,874		$11,874		$11,874		5
6	Required Operating Income	$129,484		$129,484		$129,484		6
7	Weighted Average Cost of Capital (WACC)	7.74%	(c)	7.74%		7.74%		7
8	Fair Value Adjustment	0.78%		-3.48%		-2.06%		8
9	Required Rate of Return (Ln. 6 ÷ Ln. 1)	8.52%	(c)	4.26%		5.68%		9
10	Operating Income Deficiency (Ln. 6 - Ln. 2)	$77,012		$77,012		$77,012		10
11	Gross Revenue Conversion Factor	1.6590	(d)	1.6590	(d)	1.6590	(d)	11
12	Increase in Gross Revenue Requirement (Ln. 10 x Ln. 11)	$127,760		$127,760		$127,760		12
13	Adjusted Present Retail Revenues	$836,938	(e)	$836,938		$836,938		13
14	Percent Change from Present Revs. (Ln. 12 ÷ Ln. 13)	15.27%		15.27%		15.27%		14

Supporting Schedules
(a) TEP Schedule B-1
(b) TEP Schedule C-1
(c) TEP Schedule D-1
(d) TEP Schedule C-3
(e) TEP Schedule H-1

Summary of AECC Proposed Cost of Capital

Test Year Ended December 31, 2011
(Thousands of Dollars)

Line No.	Capital Source		Capitalization Amount	Capitalization Percent	Cost Rate	Weighted Cost of Capital	Line No.
	AECC Proposed	(a)					
1	Short-Term Debt		N/A	N/A	N/A	N/A	1
2	Long-Term Debt - Net		1,123,303	57.15%	5.04%	2.88%	2
3	Common Stock Equity		842,232	42.85%	10.10%	4.33%	3
4	Total Capital		$1,965,535	100.00%		7.21%	4
	TEP Proposed - End of Test Period	(b)					
5	Short-Term Debt		N/A	N/A	N/A	N/A	5
6	Long-Term Debt - Net		$1,061,389	54.00%	5.18%	2.80%	6
7	Common Stock Equity		904,146	46.00%	10.75%	4.94%	7
8	Total Capital		$1,965,535	100.00%		7.74%	8

Supporting Schedules/Exhibits
(a) AECC Exhibits KCH-11, KCH-12, KCH-13
(b) TEP Schedule D-1, p. 1 of 2

Summary of AECC Revenue Requirement Adjustments

Operating Revenues and Expenses

Test Year Ended December 31, 2011
(Thousands of Dollars)

Line No.	Description	TEP Total Company (a) Unadjusted	TEP Total Company (a) Pro Forma Adjustments	TEP Total Company (a) Total Adjusted	AECC Total Company (b) Pro Forma Adjustments	AECC Total Company (b) Total Adjusted	TEP ACC Jurisdictional (a) ACC Jurisdiction Unadjusted	TEP ACC Jurisdictional (a) Pro Forma Adjustments	TEP ACC Jurisdictional (a) ACC Jurisdiction Adjusted	AECC ACC Jurisdictional (b) Pro Forma Adjustments	AECC ACC Jurisdictional (b) ACC Jurisdiction Adjusted	Line No.
	Operating Revenues											
1	Electric Retail Revenues	586,647	($41,898)	$544,749	$19	$544,768	$586,647	($41,898)	544,749	$19	$544,768	1
2	PPFAC Revenue	270,650	$21,539	292,189	(19)	292,170	$270,650	$21,539	292,189	(19)	292,170	2
3	Sales for Resale	128,262	(128,262)	(0)	0	(0)	0	0	0	0	0	3
4	Other Operating Revenue	185,621	($141,240)	44,381	6,961	51,342	163,092	(133,910)	29,182	6,961	36,143	4
5	Total Operating Revenues	1,171,180	(289,861)	881,319	6,961	888,280	1,020,388	(154,269)	866,120	6,961	873,081	5
	Operating Expenses											
6	Fuel Expense	294,358	(2,169)	292,190	(19)	$292,171	260,917	31,272	292,190	(19)	292,171	6
7	Purchased Power - Demand	4,658	(4,658)	0	0	0	0	0	0	0	0	7
8	Purchased Power - Energy	132,885	(132,885)	0	0	0	0	0	0	0	0	8
9	Transmission	(674)	674	(0)	0	(0)	0	0	0	0	0	9
10	Fuel, Purchased Power and Transmission	431,227	(139,038)	292,189	(19)	292,170	260,917	31,272	292,190	(19)	292,171	10
11	Other Operations and Maintenance Expense	388,322	(50,449)	337,874	(12,035)	325,838	339,649	42,339	381,989	(10,590)	371,399	11
12	Depreciation	122,429	(2,848)	119,580	681	120,261	100,508	(3,197)	97,310	573	97,883	12
13	Taxes Other than Income Taxes	40,251	5,183	45,434	(423)	45,011	30,980	4,161	35,141	(316)	34,825	13
14	Income Taxes	55,790	(42,986)	12,804	7,979	20,783	30,583	(23,564)	7,018	7,323	14,342	14
15	Total Operating Expenses	1,038,019	(230,138)	807,881	(3,816)	804,064	762,637	51,011	813,649	(3,029)	810,620	15
16	Operating Income	133,161	($59,723)	$73,438	$10,777	$84,215	257,751	(205,280)	$52,471	$9,990	$62,461	16
	Other Income and Deductions											
17	Allowance for Equity Funds	3,841										
18	Other - Net	(2,801)										
19	Total Other Income and Deductions	1,040										
20	Income Before Interest Expense	134,201										
	Interest Expense											
21	Interest on Long-Term Debt	39,918										
22	Interest on Short-Term Debt	689										
23	Other Interest Expense	10,334										
24	Allowance for Borrowed Funds	(2,074)										
25	Total Interest Expense	48,867										
26	Income Before Cumulative Effect of Accounting Change	85,334										
27	Cumulative Effect of Accounting Change - Net of Tax	0										
28	Net Income Available for Common Stock	$85,334										

Supporting Schedules/Exhibits/Data Source
(a) TEP Schedule C-1 and TEP Rev. Req't Model
(b) AECC Exhibit KCH-1, p. 7

Summary of AECC Revenue Requirement Adjustments

Test Year Ended December 31, 2011
(Thousands of Dollars)

Line No.		Sahuarita - Nogales Transmission Line Disallowance		2012 Average Rate Base Adjustment - Post Test Year Capital Additions		2012 Average Rate Base Adjustment - 2011 R.B. Acc. Depr. & ADIT Roll-Forward		Line No.
		Total Company (a)	ACC Jurisdictional (b)	Total Company (c)	ACC Jurisdictional (d)	Total Company (e)	ACC Jurisdictional (f)	
1	Operating Revenues							1
2	Electric Retail Revenues	0	0	0	0	0	0	2
3	PPFAC Revenue	0	0	0	0	0	0	3
4	Sales for Resale	0	0	0	0	0	0	4
5	Other Operating Revenue	0	0	0	0	0	0	5
6	Total Operating Revenues	0	0	0	0	0	0	6
7	Operating Expenses							7
8	Fuel Expense	0	0	0	0	0	0	8
9	Purchased Power - Demand	0	0	0	0	0	0	9
10	Purchased Power - Energy	0	0	0	0	0	0	10
	Transmission	0	0	0	0	0	0	
11	Fuel, Purchased Power and Transmission	0	0	0	0	0	0	11
12	Other Operations & Maintenance Expense	(2,983)	(3,023)	0	0	0	0	12
13	Depreciation and Amortization	0	0	681	573	0	0	13
14	Taxes Other than Income	0	(3)	0	0	0	0	14
15	Income Taxes	1,317	1,330	(165)	(131)	835	665	15
16	Total Operating Expenses	(1,665)	(1,696)	516	442	835	665	16
17	Operating Income	1,665	1,696	(516)	(442)	(835)	(665)	17
18	Rate Base - Original Cost	(12,359)	(12,043)	(9,425)	(8,648)	(75,354)	(60,069)	18
19	Rate Base - RCND	(13,912)	(13,211)	(9,184)	(8,467)	(147,924)	(118,348)	19

Line No.		Springerville Third Party Revenue Adjustment		Payroll Expense Adjustment		Generation Overhaul Expense Adjustment		Line No.
		Total Company (g)	ACC Jurisdictional (h)	Total Company (i)	ACC Jurisdictional (j)	Total Company (k)	ACC Jurisdictional (l)	
1	Operating Revenues							1
2	Electric Retail Revenues	0	0	19	19	0	0	2
3	PPFAC Revenue	0	0	(19)	(19)	0	0	3
4	Sales for Resale	0	0	0	0	0	0	4
5	Other Operating Revenue	6,961	6,961	0	0	0	0	5
6	Total Operating Revenues	6,961	6,961	0	(0)	0	0	6
7	Operating Expenses							7
8	Fuel Expense	0	0	(19)	(19)	0	0	8
9	Purchased Power - Demand	0	0	0	0	0	0	9
10	Purchased Power - Energy	0	0	0	0	0	0	10
	Transmission	0	0	0	0	0	0	
11	Fuel, Purchased Power and Transmission	0	0	(19)	(19)	0	0	11
12	Other Operations & Maintenance Expense	0	0	(2,028)	(1,695)	(2,432)	(2,275)	12
13	Depreciation and Amortization	0	0	0	0	0	0	13
14	Taxes Other than Income	0	0	(154)	(114)	0	0	14
15	Income Taxes	2,785	2,778	880	731	973	908	15
16	Total Operating Expenses	2,785	2,778	(1,320)	(1,097)	(1,459)	(1,366)	16
17	Operating Income	4,176	4,183	1,320	1,097	1,459	1,366	17
18	Rate Base - Original Cost	(2,775)	(2,085)	(877)	(659)	(969)	(728)	18
19	Rate Base - RCND	(6,040)	(4,539)	(1,909)	(1,435)	(2,110)	(1,586)	19

Supporting Exhibits
(a) & (b) AECC Exhibit KCH-2, p. 1
(c) & (d) AECC Exhibit KCH-3, p. 1
(e) & (f) AECC Exhibit KCH-4, p. 1
(g) & (h) AECC Exhibit KCH-5, p. 1
(i) & (j) AECC Exhibit KCH-6, p. 1
(k) & (l) AECC Exhibit KCH-7, p. 1

Summary of AECC Revenue Requirement Adjustments

Test Year Ended December 31, 2011
(Thousands of Dollars)

Line No.		Injuries & Damages Expense Adjustment		Lime Expense Adjustment		Incentive Compensation Expense Adjustment		Line No.
		Total Company (a)	ACC Jurisdictional (b)	Total Company (c)	ACC Jurisdictional (d)	Total Company (e)	ACC Jurisdictional (f)	
1	Operating Revenues							1
2	Electric Retail Revenues	0	0	0	0	0	0	2
3	PPFAC Revenue	0	0	0	0	0	0	3
4	Sales for Resale	0	0	0	0	0	0	4
5	Other Operating Revenue	0	0	0	0	0	0	5
6	Total Operating Revenues	0	0	0	0	0	0	6
7	Operating Expenses							7
8	Fuel Expense	0	0	0	0	0	0	8
9	Purchased Power - Demand	0	0	0	0	0	0	9
10	Purchased Power - Energy	0	0	0	0	0	0	10
	Transmission	0	0	0	0	0	0	
11	Fuel, Purchased Power and Transmission	0	0	0	0	0	0	11
12	Other Operations & Maintenance Expense	(109)	(96)	(901)	(800)	(3,583)	(2,701)	12
13	Depreciation and Amortization	0	0	0	0	0	0	13
14	Taxes Other than Income	0	0	0	0	(269)	(200)	14
15	Income Taxes	44	38	361	319	1,541	1,161	15
16	Total Operating Expenses	(65)	(58)	(540)	(480)	(2,311)	(1,740)	16
17	Operating Income	65	58	540	480	2,311	1,740	17
18	Rate Base - Original Cost	(43)	(33)	(359)	(270)	(1,535)	(1,154)	18
19	Rate Base - RCND	(95)	(71)	(782)	(588)	(3,342)	(2,512)	19

Line No.		Capital Structure Adjustment		Cost of Debt Adjustment		Return on Equity Adjustment		Line No.
		Total Company (g)	ACC Jurisdictional (h)	Total Company (i)	ACC Jurisdictional (j)	Total Company (k)	ACC Jurisdictional (l)	
1	Operating Revenues							1
2	Electric Retail Revenues	0	0	0	0	0	0	2
3	PPFAC Revenue	0	0	0	0	0	0	3
4	Sales for Resale	0	0	0	0	0	0	4
5	Other Operating Revenue	0	0	0	0	0	0	5
6	Total Operating Revenues	0	0	0	0	0	0	6
7	Operating Expenses							7
8	Fuel Expense	0	0	0	0	0	0	8
9	Purchased Power - Demand	0	0	0	0	0	0	9
10	Purchased Power - Energy	0	0	0	0	0	0	10
	Transmission	0	0	0	0	0	0	
11	Fuel, Purchased Power and Transmission	0	0	0	0	0	0	11
12	Other Operations & Maintenance Expense	0	0	0	0	0	0	12
13	Depreciation and Amortization	0	0	0	0	0	0	13
14	Taxes Other than Income	0	0	0	0	0	0	14
15	Income Taxes	(1,183)	(932)	592	457	0	0	15
16	Total Operating Expenses	(1,183)	(932)	592	457	0	0	16
17	Operating Income	1,183	932	(592)	(457)	0	0	17
18	Rate Base - Original Cost	776	583	(388)	(291)	0	0	18
19	Rate Base - RCND	2,164	1,625	(1,082)	(813)	0	0	19

Supporting Exhibits
(a) & (b) AECC Exhibit KCH-8, p. 1
(c) & (d) AECC Exhibit KCH-9, p. 1
(e) & (f) AECC Exhibit KCH-10, p. 1
(g) & (h) AECC Exhibit KCH-11, p. 1
(i) & (j) AECC Exhibit KCH-12, p. 1
(k) & (l) AECC Exhibit KCH-13, p. 1

Summary of AECC Revenue Requirement Adjustments

Test Year Ended December 31, 2011
(Thousands of Dollars)

Line No.		Blank Total Company (a)	Blank ACC Jurisdictional (b)	Blank Total Company (c)	Blank ACC Jurisdictional (d)	Total Adjustments Total Company (e)	Total Adjustments ACC Jurisdictional (f)	Line No.
1	Operating Revenues							1
2	Electric Retail Revenues	0	0	0	0	19	19	2
3	PPFAC Revenue	0	0	0	0	(19)	(19)	3
4	Sales for Resale	0	0	0	0	0	0	4
5	Other Operating Revenue	0	0	0	0	6,961	6,961	5
6	Total Operating Revenues	0	0	0	0	6,961	6,961	6
7	Operating Expenses							7
8	Fuel Expense	0	0	0	0	(19)	(19)	8
9	Purchased Power - Demand	0	0	0	0	0	0	9
10	Purchased Power - Energy	0	0	0	0	0	0	10
	Transmission	0	0	0	0	0	0	
11	Fuel, Purchased Power and Transmission	0	0	0	0	(19)	(19)	11
12	Other Operations & Maintenance Expense	0	0	0	0	(12,035)	(10,590)	12
13	Depreciation and Amortization	0	0	0	0	681	573	13
14	Taxes Other than Income	0	0	0	0	(423)	(316)	14
15	Income Taxes	0	0	0	0	7,979	7,323	15
16	Total Operating Expenses	0	0	0	0	(3,816)	(3,029)	16
17	Operating Income	0	0	0	0	10,777	9,990	17
18	Rate Base - Original Cost	0	0	0	0	(103,308)	(85,397)	18
19	Rate Base - RCND	0	0	0	0	(184,216)	(149,944)	19

EXHIBIT KCH-2

AECC Sahuarita - Nogales Transmission Line Disallowance Adjustment

Line No.		Total Company AECC Transmission Line Adjustment (a)	Jurisdictional AECC Transmission Line Adjustment (b)		Line No.
1	Operating Revenues				1
2	Electric Retail Non-Fuel Revenue	0	0		2
3	PPFAC Revenue	0	0		3
4	Sales for Resale	0	0		4
5	Other Operating Revenue	0	0		5
6	Total Operating Revenues	0	0		6
7	Operating Expenses				7
8	Fuel Expense	0	0		8
9	Purchased Power - Demand	0	0		9
10	Purchased Power - Energy	0	0		10
11	Transmission	0	0		11
12	Fuel, Purchased Power and Transmission	0	0		12
13	Other Operations & Maintenance Expense	(2,983)	(3,023)		13
14	Depreciation and Amortization	0	0		14
15	Taxes Other than Income	0	(3)		15
16	Income Taxes	1,317	1,330		16
17	Total Operating Expenses	(1,665)	(1,696)		17
18	Operating Income	1,665	1,696		18
19	Rate Base - Original Cost	(12,359)	(12,043)		19
20	Rate Base - RCND	(13,912)	(13,211)		20
21	Gross Revenue Conversion Factor		1.6590	(c)	21
22	Operating Income Revenue Requirement Impact (-Ln. 18 x Ln. 21)		(2,813)		22
23	OCRB Revenue Requirement Impact (Ln. 19 x WACC x Ln. 21)		(1,547)		23
24	FV Increment Rev. Req't Impact (Avg[Ln. 19, Ln. 20] - Ln. 19 x 1.56% x Ln. 21)		(15)		24
25	Total Revenue Requirement Impact (Ln. 22 + Ln. 23 + Ln. 24)		(4,375)		25

Supporting Schedules/Data Source
(a) & (b) TEP Rev Req Model - AECC WP
(c) TEP Schedule C-3

AECC Sahuarita-Nogales Transmission Line Disallowance Adjustment

Description	FERC Account	TEP Proposed Total Company Test Year Amount[1]	AECC Recommended Total Company Test Year Amount	AECC Recommended Total Company Adjustment
Regulatory Asset (OCRB)	182.3	$11,088,732	$0	($11,088,732)
Regulatory Asset (RCND)	182.3	$11,088,732	$0	($11,088,732)
Regulatory Asset Amortization Expense	407.3	$2,982,638	$0	($2,982,638)

1. Data Sources: TEP Rate Base - Sahuarita-Nogales Transmission Line Workpaper, Bates No. TEP(0291)007709 and TEP Income - Sahuarita-Nogales Transmission Line Amortization Workpaper, Bates No. TEP(0291)007504.

EXHIBIT KCH-3

AECC Post-Test Year Capital Additions Adjustment

Line No.		Total Company AECC Post TY Capital Adds. Adjustment (a)	Jurisdictional AECC Post TY Capital Adds. Adjustment (b)		Line No.
1	Operating Revenues				1
2	Electric Retail Non-Fuel Revenue	0	0		2
3	PPFAC Revenue	0	0		3
4	Sales for Resale	0	0		4
5	Other Operating Revenue	0	0		5
6	Total Operating Revenues	0	0		6
7	Operating Expenses				7
8	Fuel Expense	0	0		8
9	Purchased Power - Demand	0	0		9
10	Purchased Power - Energy	0	0		10
11	Transmission	0	0		11
12	Fuel, Purchased Power and Transmission	0	0		12
13	Other Operations & Maintenance Expense	0	0		13
14	Depreciation and Amortization	681	573		14
15	Taxes Other than Income	0	0		15
16	Income Taxes	(165)	(131)		16
17	Total Operating Expenses	516	442		17
18	Operating Income	(516)	(442)		18
19	Rate Base - Original Cost	(9,425)	(8,648)		19
20	Rate Base - RCND	(9,184)	(8,467)		20
21	Gross Revenue Conversion Factor		1.6590	(c)	21
22	Operating Income Revenue Requirement Impact (-Ln. 18 x Ln. 21)		732		22
23	OCRB Revenue Requirement Impact (Ln. 19 x WACC x Ln. 21)		(1,111)		23
24	FV Increment Rev. Req't Impact (Avg[Ln. 19, Ln. 20] - Ln. 19 x 1.56% x Ln. 21)		2		24
25	Total Revenue Requirement Impact (Ln. 22 + Ln. 23 + Ln. 24)		$\boxed{(376)}$		25

Supporting Schedules/Data Source
(a) & (b) TEP Rev Req Model - AECC WP
(c) TEP Schedule C-3

AECC Post-Test Year Capital Additions Adjustment

Average 2012 Rate Base

		PLANT IN SERVICE			ACCUMULATED DEPRECIATION		
Description	FERC Account	TEP Proposed Total Company Test Year Amount[1]	AECC Recommended Total Company Test Year Amount [2]	AECC Recommended Total Company Adjustment	TEP Proposed Total Company Test Year Amount[1]	AECC Recommended Total Company Test Year Amount [2]	AECC Recommended Total Company Adjustment
INTANGIBLE PLANT							
Miscellaneous Intangible Plant	303	$1,891,041	1,304,259	($586,782)	$7,879	$56,162	$48,283
STEAM PRODUCTION PLANT							
Structures & Improvements	311	$230,262	1,605,925	$1,375,663	$324	$44,318	$43,994
Boiler Plant Equipment	312	$13,462,910	2,967,609	($10,495,301)	$18,175	$41,643	$23,468
Turbogenerator Units	314	($148,026)	1,578,915	$1,726,941	($232)	$14,045	$14,277
Accessory Electric Equipment	315	$633,092	577,648	($55,444)	$1,024	$4,805	$3,781
Miscellaneous Power Plant Equipment	316	$0	319,064	$319,064	$0	$1,699	$1,699
OTHER PRODUCTION PLANT							
Structures & Improvements	341	$0	16,825	$16,825	$0	$242	$242
Prime Movers	343	$29,998	-	($29,998)	$64	$0	($64)
Generators	344	($1,441,039)	114,001	$1,555,040	($2,017)	$983	$3,000
TRANSMISSION PLANT							
Station Equipment	353	$0	102,654	$102,654	$0	$441	$441
DISTRIBUTION PLANT							
Structures & Improvements	361	$0	7,982	$7,982	$0	$66	$66
Station Equipment	362	$1,742,938	263,191	($1,479,747)	$1,111	$1,754	$643
Poles, Towers, & Fixtures	364	$2,564,583	1,190,969	($1,373,614)	$1,859	$9,245	$7,386
Overhead Conductors & Devices	365	$580,314	624,800	$44,486	$394	$4,718	$4,324
Underground Conduit	366	($11,711)	28,617	$40,328	($7)	$146	$153
Underground Conductors & Devices	367	($199,369)	637,880	$837,249	($155)	$4,284	$4,439
Line Transformers	368	$1,449,344	229,441	($1,219,903)	$1,262	$1,806	$544
Services	369	$0	9,033	$9,033	$0	$42	$42
Street Lighting & Signal Systems	373	$0	6,811	$6,811	$0	$47	$47
GENERAL PLANT							
Structures & Improvements	390	$304,474	386,189	$81,715	$335	$4,348	$4,013
Office Furniture & Equipment	391	($432,364)	641,087	$1,073,451	($2,378)	$25,638	$28,016
Transportation Equipment	392	$377,348	177,251	($200,097)	$665	$5,089	$4,424
Stores Equipment	393	$0	45,840	$45,840	$3,724	$1,195	($2,529)
Tools, Shop, & Garage Equipment	394	$0	30,143	$30,143	$0	$559	$559
Laboratory Equipment	395	$0	1,907	$1,907	$0	$27	$27
Power Operated Equipment	396		126,098	$126,098	$0	$3,927	$3,927
Communication Equipment	397	$1,802,086	401,200	($1,400,886)	$0	$6,006	$6,006
Miscellaneous Equipment	398	$0	16,762	$16,762	$0	$335	$335
TOTAL		$22,835,881	13,412,102	($9,423,779)	$32,027	$233,570	$201,543

1. Data Source: TEP Rate Base - Post Test Year Workpaper, Bates No. TEP(0291)007698.

2. Note: AECC's recommended amounts are 13 mo. average balances from Dec. 2011-Dec. 2012, derived from the Attachment to TEP's Response to AECC 16.1.

AECC Post-Test Year Capital Additions Adjustment

2012 Depreciation Expense

Description	FERC Account	TEP Proposed Total Company Test Year Amount[1]	AECC Recommended Total Company Test Year Amount [2]	AECC Recommended Total Company Adjustment
INTANGIBLE PLANT				
Miscellaneous Intangible Plant	303	$0	$206,050	$206,050
STEAM PRODUCTION PLANT				
Structures & Improvements	311	$0	$97,787	$97,787
Boiler Plant Equipment	312	$0	$126,729	$126,729
Turbogenerator Units	314	$0	$44,773	$44,773
Accessory Electric Equipment	315	$0	$16,564	$16,564
Miscellaneous Power Plant Equipment	316	$0	$6,749	$6,749
OTHER PRODUCTION PLANT				
Structures & Improvements	341	$0	$546	$546
Generators	344	$0	$2,041	$2,041
TRANSMISSION PLANT				
Station Equipment	353	$0	$1,753	$1,753
DISTRIBUTION PLANT				
Structures & Improvements	361	$0	$163	$163
Station Equipment	362	$0	$4,848	$4,848
Poles, Towers, & Fixtures	364	$0	$24,460	$24,460
Overhead Conductors & Devices	365	$0	$12,159	$12,159
Underground Conduit	366	$0	$469	$469
Underground Conductors & Devices	367	$0	$13,790	$13,790
Line Transformers	368	$0	$5,140	$5,140
Services	369	$0	$159	$159
Street Lighting & Signal Systems	373	$0	$141	$141
GENERAL PLANT				
Structures & Improvements	390	$0	$10,655	$10,655
Office Furniture & Equipment	391	$0	$57,623	$57,623
Transportation Equipment	392	$0	$10,566	$10,566
Stores Equipment	393	$0	$3,072	$3,072
Tools, Shop, & Garage Equipment	394	$0	$1,738	$1,738
Laboratory Equipment	395	$0	$106	$106
Power Operated Equipment	396	$0	$8,168	$8,168
Communication Equipment	397	$0	$23,547	$23,547
Miscellaneous Equipment	398	$0	$759	$759
TOTAL		$0	$680,555	$680,555

1. Note: TEP inadvertently omitted depreciation expense for Post-Test Year Plant. (See TEP's Response to AECC 16.4.)
2. Note: AECC's recommended amounts are equal to depreciation expense for calendar year 2012, from the Attachment to TEP's Response to AECC 16.1

EXHIBIT KCH-4

AECC 2012 Average Rate Base Adjustment - 2011 Rate Base Accum. Depr. & ADIT Roll-Forward

Line No.		Total Company AECC Acc. Depr./ADIT Roll-Forward Adjustment (a)	Jurisdictional AECC Acc. Depr./ADIT Roll-Forward Adjustment (b)		Line No.
1	Operating Revenues				1
2	Electric Retail Non-Fuel Revenue	0	0		2
3	PPFAC Revenue	0	0		3
4	Sales for Resale	0	0		4
5	Other Operating Revenue	0	0		5
6	Total Operating Revenues	0	0		6
7	Operating Expenses				7
8	Fuel Expense	0	0		8
9	Purchased Power - Demand	0	0		9
10	Purchased Power - Energy	0	0		10
11	Transmission	0	0		11
12	Fuel, Purchased Power and Transmission	0	0		12
13	Other Operations & Maintenance Expense	0	0		13
14	Depreciation and Amortization	0	0		14
15	Taxes Other than Income	0	0		15
16	Income Taxes	835	665		16
17	Total Operating Expenses	835	665		17
18	Operating Income	(835)	(665)		18
19	Rate Base - Original Cost	(75,354)	(60,069)		19
20	Rate Base - RCND	(147,924)	(118,348)		20
21	Gross Revenue Conversion Factor		1.6590	(c)	21
22	Operating Income Revenue Requirement Impact (-Ln. 18 x Ln. 21)		1,102		22
23	OCRB Revenue Requirement Impact (Ln. 19 x WACC x Ln. 21)		(7,715)		23
24	FV Increment Rev. Req't Impact (Avg[Ln. 19, Ln. 20] - Ln. 19 x 1.56% x Ln. 21)		(754)		24
25	Total Revenue Requirement Impact (Ln. 22 + Ln. 23 + Ln. 24)		(7,367)		25

Supporting Schedules/Data Source
(a) & (b) TEP Rev Req Model - AECC WP
(c) TEP Schedule C-3

AECC 2012 Average Rate Base Adjustment

Accumulated Depreciation (2011 Rate Base Roll-Forward)

Description	FERC Account	TEP Proposed Total Company Test Year Amount[1]	AECC Recommended Total Company Test Year Amount[2]	AECC Recommended Total Company Adjustment
INTANGIBLE PLANT				
Misc Intangible Plant	303	$78,125,315	$84,156,086	$6,030,771
PRODUCTION PLANT				
Land and Land Rights	310	$3,873,608	$3,910,058	$36,451
Structures and Improvements	311	$97,310,310	$99,970,939	$2,660,630
Boiler Plant Equipment	312	$487,376,460	$502,754,165	$15,377,705
Turbogenerator Unit	314	$140,327,737	$145,789,774	$5,462,037
Accessory Electric Plant	315	$59,653,927	$61,768,248	$2,114,322
Misc Power Plant Equipment	316	$13,815,202	$14,112,445	$297,242
San Juan & IRV04 Acquisition Adjustment	115	$2,480,617	$2,355,521	($125,096)
OTHER PRODUCTION PLANT				
Structures & Improvements	341	$2,686,374	$2,912,148	$225,774
Fuel Holders, Products, and Accessories	342	$2,193,323	$2,416,706	$223,383
Prime Movers	343	-$535,720	-$313,848	$221,872
Generators	344	$33,416,584	$34,956,921	$1,540,337
Accessory Electric Equipment	345	$3,036,543	$3,097,933	$61,391
Misc Power Plant Equipment	346	$1,807,179	$1,937,414	$130,235
TRANSMISSION BELOW 138Kv				
Land and Land Rights	350	$5,319,698	$5,371,964	$52,266
Structures & Improvements	352	$4,721,072	$4,781,161	$60,089
Station Equipment	353	$77,962,080	$79,774,798	$1,812,718
Towers and Fixtures	354	$9,315,541	$9,372,651	$57,110
Poles & Fixtures	355	$8,929,613	$9,210,671	$281,059
Overhead Conductors & Devices	356	$12,613,263	$12,787,302	$174,039
Roads & Trails	359	$408,694	$410,180	$1,486
TRANSMISSION ABOVE 138Kv				
Land and Land Rights	350	$13,774,997	$13,926,035	$151,038
Structures & Improvements	352	$8,485,210	$8,557,845	$72,636
Station Equipment	353	$90,114,806	$91,548,043	$1,433,237
Towers and Fixtures	354	$115,221,655	$116,045,615	$823,960
Poles & Fixtures	355	$1,083,579	$1,093,260	$9,681
Overhead Conductors & Devices	356	$63,605,446	$64,025,851	$420,404
Roads & Trails	359	$4,180,924	$4,197,181	$16,257
DISTRIBUTION				
Land & Land Rights	360	$3,543,270	$3,611,427	$68,158
Structures & Improvements	361	$2,695,883	$2,806,298	$110,415
Station Equipment	362	$50,104,994	$51,346,567	$1,241,573
Poles, Towers, and Fixtures	364	$60,196,748	$61,780,976	$1,584,228
Overhead Conductors & Devices	365	$62,605,980	$64,048,087	$1,442,107
Underground Conduit	366	$26,088,537	$26,519,659	$431,123
Underground Conductors & Devices	367	$118,179,291	$121,039,770	$2,860,479
Line Transformer	68 L	$133,503,655	$136,553,288	$3,049,632
Services	369	$44,508,190	$45,550,985	$1,042,796
Meters	370	$17,200,665	$18,014,383	$813,718
Street Lighting & Signal Systems	373	$5,385,561	$5,499,412	$113,851
GENERAL				
Structures & Improvements	390	$22,232,587	$23,797,775	$1,565,188
Office Furniture & Equipment	391	$27,213,038	$30,042,606	$2,829,568
Transportation Equipment	392	$12,912,010	$14,282,213	$1,370,203
Stores Equipment	393	$462,167	$532,330	$70,163
Tools, shop and Garage Equipment	394	$2,612,996	$2,778,766	$165,770
Laboratory Equipment	395	$2,440,557	$2,590,156	$149,599
Power Operated Equipment	396	$1,299,477	$1,483,535	$184,058
Communication Equipment	397	$14,885,137	$16,328,377	$1,443,240
Misc Equipment	398	$2,435,799	$2,552,540	$116,741
TOTAL	Total	$1,951,810,576	$2,012,086,220	$60,275,643

1. Note: TEP amounts are unadjusted Dec. 2011 accumulated depreciation balances plus TEP's Delayed Plant adjustments.
2. Note: AECC's recommended amounts are 13 mo. average accumulated depreciation balances for Dec. 2011-Dec. 2012, derived from the Attachment to TEP's Response to AECC 10.1.

AECC 2012 Average Rate Base Adjustment
Derivation of AECC Accumulated Depreciation Adjustment
Continued on Next Page

	Dec-11 Unadjusted Accumulated Depreciation	Delayed Plant Accumulated Depreciation Adjustments	Adjusted Accumulated Depreciation Balance	Jan-2012	Feb-2012	Mar-2012	Apr-2012	May-2012	Jun-2012
INTANGIBLE PLANT									
E303 Misc Intangible Plant	78,170,532	-45,217	78,125,315	1,006,635	1,006,635	1,006,635	1,006,635	1,006,635	1,006,635
Total Intangibles	78,170,532	-45,217	78,125,315	1,006,635	1,006,635	1,006,635	1,006,635	1,006,635	1,006,635
PRODUCTION PLANT									
E310 Land and Land Rights	3,873,608		3,873,608	6,075	6,075	6,075	6,075	6,075	6,075
E311 Structures and Improvements	97,318,486	-8,176	97,310,310	443,438	443,438	443,438	443,438	443,438	443,438
E312 Boiler Plant Equipment	487,390,173	-13,713	487,376,460	2,562,951	2,562,951	2,562,951	2,562,951	2,562,951	2,562,951
E314 Turbogenerator Unit	140,328,732	-995	140,327,737	910,340	910,340	910,340	910,340	910,340	910,340
E315 Accessory Electric Plant	59,651,530	2,397	59,653,927	352,387	352,387	352,387	352,387	352,387	352,387
E316 Misc Power Plant Equipment	13,815,076	126	13,815,202	49,540	49,540	49,540	49,540	49,540	49,540
San Juan & IRV04 Acquisition Adjustment	2,480,617		2,480,617	-20,849	-20,849	-20,849	-20,849	-20,849	-20,849
Total Production	804,858,221	-20,361	804,837,860	4,303,882	4,303,882	4,303,882	4,303,882	4,303,882	4,303,882
OTHER PRODUCTION PLANT									
E341 Structures & Improvements	2,686,283	91	2,686,374	37,629	37,629	37,629	37,629	37,629	37,629
E342 Fuel Holders, Products, and Accessories	2,193,323		2,193,323	37,231	37,231	37,231	37,231	37,231	37,231
E343 Privet Movers	-535,228	-492	-535,720	36,979	36,979	36,979	36,979	36,979	36,979
E344 Generators	33,414,678	1,906	33,416,584	256,723	256,723	256,723	256,723	256,723	256,723
E345 Accessory Electric Equipment	3,036,453	90	3,036,543	10,232	10,232	10,232	10,232	10,232	10,232
E346 Misc Power Plant Equipment	1,807,179		1,807,179	21,706	21,706	21,706	21,706	21,706	21,706
Total Other Production	42,602,688	1,595	42,604,283	400,499	400,499	400,499	400,499	400,499	400,499
TRANSMISSION BELOW 138Kv									
E350 Land and Land Rights	5,319,698		5,319,698	8,711	8,711	8,711	8,711	8,711	8,711
E352 Structures & Improvements	4,721,072		4,721,072	10,015	10,015	10,015	10,015	10,015	10,015
E353 Station Equipment	77,962,080		77,962,080	302,120	302,120	302,120	302,120	302,120	302,120
E354 Towers and Fixtures	9,315,541		9,315,541	9,518	9,518	9,518	9,518	9,518	9,518
E355 Poles & Fixtures	8,929,613		8,929,613	46,843	46,843	46,843	46,843	46,843	46,843
E356 Overhead Conductors & Devices	12,613,263		12,613,263	29,007	29,007	29,007	29,007	29,007	29,007
E359 Roads & Trails	408,694		408,694	248	248	248	248	248	248
Total Transmission	119,269,961	0	119,269,961	406,461	406,461	406,461	406,461	406,461	406,461
TRANSMISSION ABOVE 138Kv									
E350 Land and Land Rights	13,774,997		13,774,997	25,173	25,173	25,173	25,173	25,173	25,173
E352 Structures & Improvements	8,485,210		8,485,210	12,106	12,106	12,106	12,106	12,106	12,106
E353 Station Equipment	90,114,806		90,114,806	238,873	238,873	238,873	238,873	238,873	238,873
E354 Towers and Fixtures	115,221,655		115,221,655	137,327	137,327	137,327	137,327	137,327	137,327
E355 Poles & Fixtures	1,083,579		1,083,579	1,614	1,614	1,614	1,614	1,614	1,614
E356 Overhead Conductors & Devices	63,605,446		63,605,446	70,067	70,067	70,067	70,067	70,067	70,067
E359 Roads & Trails	4,180,924		4,180,924	2,709	2,709	2,709	2,709	2,709	2,709
Total Transmission	296,466,617	0	296,466,617	487,869	487,869	487,869	487,869	487,869	487,869
DISTRIBUTION									
E360 Land & Land Rights	3,543,231	39	3,543,270	11,360	11,360	11,360	11,360	11,360	11,360
E361 Structures & Improvements	2,695,456	427	2,695,883	18,402	18,402	18,402	18,402	18,402	18,402
E362 Station Equipment	50,099,867	5,127	50,104,994	206,929	206,929	206,929	206,929	206,929	206,929
E364 Poles, Towers, and Fixtures	60,197,534	-786	60,196,748	264,038	264,038	264,038	264,038	264,038	264,038
E365 Overhead Conductors & Devices	62,604,103	1,877	62,605,980	240,351	240,351	240,351	240,351	240,351	240,351
E366 Underground Conduit	26,087,940	597	26,088,537	71,854	71,854	71,854	71,854	71,854	71,854
E367 Underground Conductors & Devices	118,153,966	25,325	118,179,291	476,746	476,746	476,746	476,746	476,746	476,746
E368 Line Transformer	133,500,807	2,848	133,503,655	508,272	508,272	508,272	508,272	508,272	508,272
E369 Services	44,508,262	-72	44,508,190	173,799	173,799	173,799	173,799	173,799	173,799
E370 Meters	17,200,724	-59	17,200,665	135,620	135,620	135,620	135,620	135,620	135,620
E373 Street Lighting & Signal Systems	5,385,650	-89	5,385,561	18,975	18,975	18,975	18,975	18,975	18,975
Total Distribution	523,977,539	35,234	524,012,773	2,126,346	2,126,346	2,126,346	2,126,346	2,126,346	2,126,346
GENERAL									
E390 Structures & Improvements	22,229,810	2,777	22,232,587	260,865	260,865	260,865	260,865	260,865	260,865
E391 Office Furniture & Equipment	27,202,227	10,811	27,213,038	471,595	471,595	471,595	471,595	471,595	471,595
E392 Transportation Equipment	12,911,631	379	12,912,010	228,367	228,367	228,367	228,367	228,367	228,367
E393 Stores Equipment	461,240	927	462,167	11,694	11,694	11,694	11,694	11,694	11,694
E394 Tools, shop and Garage Equipment	2,611,889	1,107	2,612,996	27,628	27,628	27,628	27,628	27,628	27,628
E395 Laboratory Equipment	2,440,549	8	2,440,557	24,933	24,933	24,933	24,933	24,933	24,933
E396 Power Operated Equipment	1,299,054	423	1,299,477	30,676	30,676	30,676	30,676	30,676	30,676
E397 Communication Equipment	14,870,121	15,016	14,885,137	240,540	240,540	240,540	240,540	240,540	240,540
E398 Misc Equipment	2,435,782	17	2,435,799	19,457	19,457	19,457	19,457	19,457	19,457
Total General	86,462,304	31,465	86,493,769	1,315,755	1,315,755	1,315,755	1,315,755	1,315,755	1,315,755
Grand Total	1,951,807,860	2,716	1,951,810,576	10,047,447	10,047,447	10,047,447	10,047,447	10,047,447	10,047,447

Note: Software not included in the 2011 proforma, were included in 2012 calculations totaling $69k additional depreciation.
Data Source: Derived from the Attachment to TEP's Response to AECC 10.1 Projected AD Balances. Depreciation associated with Post-Test Year Plant, including Renewables (from the Attachment to TEP's Response to AECC 16.1) was removed from the monthly amounts to isolate existing 2011 plant.

AECC 2012 Average Rate Base Adjustment
Derivation of AECC Accumulated Depreciation Adjustment

	Jul-2012	Aug-2012	Sep-2012	Oct-2012	Nov-2012	Dec-2012	Ending Accumulated Depreciation Balances	2011 Plant 13 Month Average Accumulated Depreciation	AECC Adjustment to 2011 Accumulated Depreciation
INTANGIBLE PLANT									
E303 Misc Intangible Plant	1,006,635	1,006,635	1,005,843	1,000,873	1,000,873	1,000,873	90,186,857	84,156,086	6,030,771
Total Intangibles	1,006,635	1,006,635	1,005,843	1,000,873	1,000,873	1,000,873	90,186,857	84,156,086	6,030,771
PRODUCTION PLANT									
E310 Land and Land Rights	6,075	6,075	6,075	6,075	6,075	6,075	3,946,509	3,910,058	36,451
E311 Structures and Improvements	443,438	443,438	443,438	443,438	443,438	443,438	102,631,569	99,970,939	2,660,630
E312 Boiler Plant Equipment	2,562,951	2,562,951	2,562,951	2,562,951	2,562,951	2,562,951	518,131,871	502,754,165	15,377,705
E314 Turbogenerator Unit	910,340	910,340	910,340	910,340	910,340	910,340	151,251,812	145,789,774	5,462,037
E315 Accessory Electric Plant	352,387	352,387	352,387	352,387	352,387	352,387	63,882,570	61,768,248	2,114,322
E316 Misc Power Plant Equipment	49,540	49,540	49,540	49,540	49,540	49,540	14,409,687	14,112,445	297,242
San Juan & IRV04 Acquisition Adjustment	-20,849	-20,849	-20,849	-20,849	-20,849	-20,849	2,230,425	2,355,521	-125,096
Total Production	4,303,882	4,303,882	4,303,882	4,303,882	4,303,882	4,303,882	856,484,443	830,661,151	25,823,292
OTHER PRODUCTION PLANT									
E341 Structures & Improvements	37,629	37,629	37,629	37,629	37,629	37,629	3,137,922	2,912,148	225,774
E342 Fuel Holders, Products, and Accessories	37,231	37,231	37,231	37,231	37,231	37,231	2,640,090	2,416,706	223,383
E343 Privet Movers	36,979	36,979	36,979	36,979	36,979	36,979	-91,975	-313,848	221,872
E344 Generators	256,723	256,723	256,723	256,723	256,723	256,723	36,497,259	34,956,921	1,540,337
E345 Accessory Electric Equipment	10,232	10,232	10,232	10,232	10,232	10,232	3,159,324	3,097,933	61,391
E346 Misc Power Plant Equipment	21,706	21,706	21,706	21,706	21,706	21,706	2,067,648	1,937,414	130,235
Total Other Production	400,499	400,499	400,499	400,499	400,499	400,499	47,410,268	45,007,275	2,402,992
TRANSMISSION BELOW 138Kv									
E350 Land and Land Rights	8,711	8,711	8,711	8,711	8,711	8,711	5,424,230	5,371,964	52,266
E352 Structures & Improvements	10,015	10,015	10,015	10,015	10,015	10,015	4,841,250	4,781,161	60,089
E353 Station Equipment	302,120	302,120	302,120	302,120	302,120	302,120	81,587,516	79,774,798	1,812,718
E354 Towers and Fixtures	9,518	9,518	9,518	9,518	9,518	9,518	9,429,762	9,372,651	57,110
E355 Poles & Fixtures	46,843	46,843	46,843	46,843	46,843	46,843	9,491,730	9,210,671	281,059
E356 Overhead Conductors & Devices	29,007	29,007	29,007	29,007	29,007	29,007	12,961,341	12,787,302	174,039
E359 Roads & Trails	248	248	248	248	248	248	411,667	410,180	1,486
Total Transmission	406,461	406,461	406,461	406,461	406,461	406,461	124,147,495	121,708,728	2,438,767
TRANSMISSION ABOVE 138Kv									
E350 Land and Land Rights	25,173	25,173	25,173	25,173	25,173	25,173	14,077,074	13,926,035	151,038
E352 Structures & Improvements	12,106	12,106	12,106	12,106	12,106	12,106	8,630,481	8,557,845	72,636
E353 Station Equipment	238,873	238,873	238,873	238,873	238,873	238,873	92,981,281	91,548,043	1,433,237
E354 Towers and Fixtures	137,327	137,327	137,327	137,327	137,327	137,327	116,869,575	116,045,615	823,960
E355 Poles & Fixtures	1,614	1,614	1,614	1,614	1,614	1,614	1,102,941	1,093,260	9,681
E356 Overhead Conductors & Devices	70,067	70,067	70,067	70,067	70,067	70,067	64,446,255	64,025,851	420,404
E359 Roads & Trails	2,709	2,709	2,709	2,709	2,709	2,709	4,213,438	4,197,181	16,257
Total Transmission	487,869	487,869	487,869	487,869	487,869	487,869	302,321,043	299,393,830	2,927,213
DISTRIBUTION									
E360 Land & Land Rights	11,360	11,360	11,360	11,360	11,360	11,360	3,679,585	3,611,427	68,158
E361 Structures & Improvements	18,402	18,402	18,402	18,402	18,402	18,402	2,916,712	2,806,298	110,415
E362 Station Equipment	206,929	206,929	206,929	206,929	206,929	206,929	52,588,140	51,346,567	1,241,573
E364 Poles, Towers, and Fixtures	264,038	264,038	264,038	264,038	264,038	264,038	63,365,204	61,780,976	1,584,228
E365 Overhead Conductors & Devices	240,351	240,351	240,351	240,351	240,351	240,351	65,490,194	64,048,087	1,442,107
E366 Underground Conduit	71,854	71,854	71,854	71,854	71,854	71,854	26,950,782	26,519,659	431,123
E367 Underground Conductors & Devices	476,746	476,746	476,746	476,746	476,746	476,746	123,900,249	121,039,770	2,860,479
E368 Line Transformer	508,272	508,272	508,272	508,272	508,272	508,272	139,602,920	136,553,288	3,049,632
E369 Services	173,799	173,799	173,799	173,799	173,799	173,799	46,593,781	45,550,985	1,042,796
E370 Meters	135,620	135,620	135,620	135,620	135,620	135,620	18,828,100	18,014,383	813,718
E373 Street Lighting & Signal Systems	18,975	18,975	18,975	18,975	18,975	18,975	5,613,264	5,499,412	113,851
Total Distribution	2,126,346	2,126,346	2,126,346	2,126,346	2,126,346	2,126,346	549,528,930	536,770,851	12,758,079
GENERAL									
E390 Structures & Improvements	260,865	260,865	260,865	260,865	260,865	260,865	25,362,963	23,797,775	1,565,188
E391 Office Furniture & Equipment	471,595	471,595	471,595	471,595	471,595	471,595	32,872,174	30,042,606	2,829,568
E392 Transportation Equipment	228,367	228,367	228,367	228,367	228,367	228,367	15,652,416	14,282,213	1,370,203
E393 Stores Equipment	11,694	11,694	11,694	11,694	11,694	11,694	602,493	532,330	70,163
E394 Tools, shop and Garage Equipment	27,628	27,628	27,628	27,628	27,628	27,628	2,944,535	2,778,766	165,770
E395 Laboratory Equipment	24,933	24,933	24,933	24,933	24,933	24,933	2,739,755	2,590,156	149,599
E396 Power Operated Equipment	30,676	30,676	30,676	30,676	30,676	30,676	1,667,592	1,483,535	184,058
E397 Communication Equipment	240,540	240,540	240,540	240,540	240,540	240,540	17,771,617	16,328,377	1,443,240
E398 Misc Equipment	19,457	19,457	19,457	19,457	19,457	19,457	2,669,281	2,552,540	116,741
Total General	1,315,755	1,315,755	1,315,755	1,315,755	1,315,755	1,315,755	102,282,826	94,388,298	7,894,529
Grand Total	10,047,447	10,047,447	10,046,655	10,041,685	10,041,685	10,041,685	2,072,361,863	2,012,086,220	60,275,643

AECC 2012 Average Rate Base Adjustment
Derivation of AECC 2012 Average ADIT Adjustment

FERC Account / Sch. M Item	Dec-2011	Jan-2012	Feb-2012	Mar-2012	Apr-2012	May-2012	Jun-2012	Jul-2012	Aug-2012	Sep-2012	Oct-2012	Nov-2012	Dec-2012	13 Mo. Average	AECC Adjustment[1]
190	**132,295,845**	**132,772,107**	**132,809,443**	**132,432,580**	**132,442,781**	**133,504,093**	**133,518,417**	**133,985,972**	**134,673,676**	**156,023,718**	**158,574,863**	**157,839,603**	**158,890,091**	**140,751,015**	**9,125,202**
AZ NOL Carryforward		1,256,587	1,278,955	1,278,955	1,278,955	1,278,955	1,071,800	946,489	791,445	4,874,887	5,097,287	5,003,800	5,126,890		
AZ Tax Credits Carryforward		530,444	568,640	529,130	539,811	602,920	682,159	750,445	834,933	1,503,655	1,555,549	1,533,735	1,563,588		
CIAC		13,268,854	13,249,065	13,186,116	13,198,809	13,313,114	13,615,069	13,872,982	14,192,093	13,412,067	13,438,810	13,427,568	13,442,953		
Customer Advances		3,527,888	3,527,888	3,527,888	3,527,888	3,527,888	3,527,888	3,527,888	3,527,888	3,524,196	3,524,196	3,524,196	3,524,196		
Delayed Plant Adj. NOL		2,722,576	2,722,576	2,722,576	2,722,576	2,722,576	2,722,576	2,722,576	2,722,576	2,722,576	2,722,576	2,722,576	2,722,576		
FED & NM NOL Carryforward		82,542,505	82,539,066	82,262,831	82,250,135	83,138,337	82,989,991	83,266,370	83,717,534	101,407,196	103,659,858	103,050,067	103,933,697		
FED AMT Credit		24,473,169	24,473,169	24,473,169	24,473,169	24,473,169	24,473,169	24,473,169	24,473,169	24,123,152	24,123,152	24,123,152	24,123,152		
Fuel Inventory		598,244	598,244	598,244	598,244	598,244	598,244	598,244	598,244	647,250	647,250	647,250	647,250		
Microwave Equipment		690,631	690,631	692,462	691,984	687,680	676,311	666,600	654,585	647,531	644,976	646,050	644,580		
Post Test Year Plant NOL	3,161,209	3,161,209	3,161,209	3,161,209	3,161,209	3,161,209	3,161,209	3,161,209	3,161,209	3,161,209	3,161,209	3,161,209	3,161,209	3,161,209	-
282	**(511,051,505)**	**(512,418,519)**	**(511,625,511)**	**(509,102,908)**	**(509,611,576)**	**(514,192,176)**	**(523,581,504)**	**(532,078,512)**	**(542,591,696)**	**(568,644,252)**	**(572,436,320)**	**(570,842,298)**	**(573,023,755)**	**(534,707,733)**	**(23,656,228)**
481(a) Capitalized Interest		(7,160,279)	(7,160,279)	(7,160,279)	(7,160,279)	(7,160,279)	(6,418,086)	(5,914,780)	(5,292,049)	(4,526,457)	(4,404,778)	(4,455,926)	(4,385,928)		
Delayed Plant Adjustment		(2,722,576)	(2,722,576)	(2,722,576)	(2,722,576)	(2,722,576)	(2,722,576)	(2,722,576)	(2,722,576)	(2,722,576)	(2,722,576)	(2,722,576)	(2,722,576)		
Plant		(499,374,456)	(498,581,448)	(496,058,845)	(496,567,513)	(501,148,112)	(511,279,633)	(520,279,947)	(531,415,861)	(558,234,011)	(562,147,757)	(560,502,587)	(562,754,042)		
Post Test Year Plant	(3,161,209)	(3,161,209)	(3,161,209)	(3,161,209)	(3,161,209)	(3,161,209)	(3,161,209)	(3,161,209)	(3,161,209)	(3,161,209)	(3,161,209)	(3,161,209)	(3,161,209)	(3,161,209)	-
283		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**		
No Ratemaking Sch M Items		0	0	0	0	0	0	0	0	0	0	0	0		
Grand Total		**(379,646,412)**	**(378,816,068)**	**(376,670,328)**	**(377,168,796)**	**(380,688,082)**	**(390,063,087)**	**(398,092,539)**	**(407,918,020)**	**(412,620,534)**	**(413,861,457)**	**(413,002,696)**	**(414,133,664)**		

Data Source: Attachment to AECC 17.4 - Ratemaking ADIT 2012

1. Note: AECC's Adjustment to Acct 190 is a goal-sought number to achieve Acct. 190 13 mo. average balance including the effects of AECC's 2012 Average Rate Base Adjustment and Post-Test Year 2012 Average Rate Base Adjustment.

EXHIBIT KCH-5

AECC Springerville Third Party Revenue Adjustment

Line No.		Total Company AECC Springerville Revenue Adjustment (a)	Jurisdictional AECC Springerville Revenue Adjustment (b)		Line No.
1	Operating Revenues				1
2	Electric Retail Non-Fuel Revenue	0	0		2
3	PPFAC Revenue	0	0		3
4	Sales for Resale	0	0		4
5	Other Operating Revenue	6,961	6,961		5
6	Total Operating Revenues	6,961	6,961		6
7	Operating Expenses				7
8	Fuel Expense	0	0		8
9	Purchased Power - Demand	0	0		9
10	Purchased Power - Energy	0	0		10
11	Transmission	0	0		11
12	Fuel, Purchased Power and Transmission	0	0		12
13	Other Operations & Maintenance Expense	0	0		13
14	Depreciation and Amortization	0	0		14
15	Taxes Other than Income	0	0		15
16	Income Taxes	2,785	2,778		16
17	Total Operating Expenses	2,785	2,778		17
18	Operating Income	4,176	4,183		18
19	Rate Base - Original Cost	(2,775)	(2,085)		19
20	Rate Base - RCND	(6,040)	(4,539)		20
21	Gross Revenue Conversion Factor		1.6590	(c)	21
22	Operating Income Revenue Requirement Impact (-Ln. 18 x Ln. 21)		(6,940)		22
23	OCRB Revenue Requirement Impact (Ln. 19 x WACC x Ln. 21)		(268)		23
24	FV Increment Rev. Req't Impact (Avg[Ln. 19, Ln. 20] - Ln. 19 x 1.56% x Ln. 21)		(32)		24
25	Total Revenue Requirement Impact (Ln. 22 + Ln. 23 + Ln. 24)		$\boxed{(7,240)}$		25

<u>Supporting Schedules/Data Source</u>
(a) & (b) TEP Rev Req Model - AECC WP
(c) TEP Schedule C-3

AECC Springerville Third Party Revenue Adjustment

Description	FERC Account	TEP Proposed Total Company Test Year Amount[1]	AECC Recommended Total Company Test Year Amount[2]	AECC Recommended Total Company Adjustment
Rent from Electric Property	454	$6,961,004	$13,922,008	$6,961,004

1. Data Source: TEP Income - Springerville Units 3 and 4 Workpaper, Bates No. TEP(0291)007544.

2. Note: TEP proposes to credit ratepayers with 50% of the revenues from Tri-State and SRP for the Springerville Common and Coal Handling Facilities leases. AECC recommends that ratepayers be credited with 100% of these revenues.

EXHIBIT KCH-6

AECC Payroll Expense Adjustment

Line No.		Total Company: AECC Payroll Expense Adjustment (a)	Jurisdictional: AECC Payroll Expense Adjustment (b)		Line No.
1	Operating Revenues				1
2	Electric Retail Non-Fuel Revenue	19	19		2
3	PPFAC Revenue	(19)	(19)		3
4	Sales for Resale	0	0		4
5	Other Operating Revenue	0	0		5
6	Total Operating Revenues	0	(0)		6
7	Operating Expenses				7
8	Fuel Expense	(19)	(19)		8
9	Purchased Power - Demand	0	0		9
10	Purchased Power - Energy	0	0		10
11	Transmission	0	0		11
12	Fuel, Purchased Power and Transmission	(19)	(19)		12
13	Other Operations & Maintenance Expense	(2,028)	(1,695)		13
14	Depreciation and Amortization	0	0		14
15	Taxes Other than Income	(154)	(114)		15
16	Income Taxes	880	731		16
17	Total Operating Expenses	(1,320)	(1,097)		17
18	Operating Income	1,320	1,097		18
19	Rate Base - Original Cost	(877)	(659)		19
20	Rate Base - RCND	(1,909)	(1,435)		20
21	Gross Revenue Conversion Factor		1.6590	(c)	21
22	Operating Income Revenue Requirement Impact (-Ln. 18 x Ln. 21)		(1,820)		22
23	OCRB Revenue Requirement Impact (Ln. 19 x WACC x Ln. 21)		(85)		23
24	FV Increment Rev. Req't Impact (Avg[Ln. 19, Ln. 20] - Ln. 19 x 1.56% x Ln. 21)		(10)		24
25	Total Revenue Requirement Impact (Ln. 22 + Ln. 23 + Ln. 24)		$\boxed{(1,915)}$		25

Supporting Schedules/Data Source
(a) & (b) TEP Rev Req Model - AECC WP
(c) TEP Schedule C-3

AECC Payroll Expense and Payroll Tax Expense Adjustments

Description	FERC Account	Unadjusted Total Company Test Year Amount[1,2]	TEP Proposed Total Company Test Year Amount[1,2]	AECC Recommended Total Company Test Year Amount	AECC Recommended Total Company Adjustment
O&M Payroll Expense	Various	$ 68,355,320	$ 60,467,976	$ 58,421,788	$ (2,046,188)
Taxes Other Than Income	408	$ 9,481,829	$ 9,742,755	$ 9,588,941	$ (153,814)
Total		$ 77,837,149	$ 70,210,731	$ 68,010,730	$ (2,200,001)
Detail of Payroll Expense Adjustment by FERC Account:					
Steam Prod Oper-Supervision	500				($181)
Steam Prod Oper-Supervision	500				($189,417)
Fuel - Steam	501				($18,568)
Steam Expenses	502				($354)
Steam Expenses	502				($202,550)
Electric Expenses	505				($118)
Electric Expenses	505				($62,445)
Steam Prod-Misc Expense	506				($85)
Steam Prod-Misc Expense	506				($60,570)
Maint-Supervision & Engr	510				($69)
Maint-Supervision & Engr	510				($74,633)
Maint of Structures	511				$83
Maint of Structures	511				($17,464)
Maint of Boiler Plant	512				($146)
Maint of Boiler Plant	512				($167,019)
Steam Prod-Mnt Elec Plnt	513				($32)
Steam Prod-Mnt Elec Plnt	513				($48,517)
Steam Prod-Mnt Misc Plnt	514				$38
Steam Prod-Mnt Misc Plnt	514				($63,383)
Other Prod Oper-Supervision	546				($945)
Misc Other Pw Gen Exp	549				($134)
Maint of Structures	552				($687)
Maint Gen & Elec Plant	553				($2,498)
Maint of Misc Oth Pwr Gen Plant	554				($601)
Sys Cntrol/Load Dispatch	556				($29,965)
Prod Expense-Other	557				($9,757)
Trans-Oper Supv & Engr	560				($21,437)
Trans-Load Dispatch	561				($30)
Trans-Misc Oper Expense	566				($1,589)
Trans-Maint Supv & Engr	568				($5,102)
Trans-Maint of Structures	569				($4)
Trans-Maint Stn Equip	570				($54,027)
Trans-Maint of OH Lines	571				($10,436)
Trans-Maint Misc Trans Plnt	573				($3)

AECC Payroll Expense and Payroll Tax Expense Adjustments

Description	FERC Account	Unadjusted Total Company Test Year Amount[1,2]	TEP Proposed Total Company Test Year Amount[1,2]	AECC Recommended Total Company Test Year Amount	AECC Recommended Total Company Adjustment
Dist-Oper Supv & Engr	580				($20,988)
Dist-Load Dispatching	581				($11,158)
Dist-Station Expenses	582				($1,578)
Dist-Overhead Line Exp	583				($9,120)
Dist-Underground Line Exp	584				($3,213)
Dist-Light/Signal Exp	585				($117)
Dist-Meter Expenses	586				($26,330)
Dist-Customer Install Exp	587				($2,997)
Dist-Misc Expense	588				($45)
Dist-Misc Expense	588				($81,900)
Dist-Maint Supv & Engr	590				($14,300)
Dist-Maint Stn Equip	592				($12,572)
Dist-Maint of OH Lines	593				($15,689)
Dist-Maint of UG Lines	594				($1,740)
Dist-Mnt Line Transformers	595				($6,787)
Dist-Maint of Meters	597				($2,613)
Dist-Maint Misc Plant	598				($1,229)
Cust Rec/Collection Exp	903				($167,968)
Customer Assistance Exp	908				($23,161)
Informational/Instrct Adv Exp	909				($769)
A&G Salaries	920				($205)
A&G Salaries	920				($471,475)
Injuries & Damages	925				$613
Injuries & Damages	925				($13,649)
Pensions & Benefits	926				($41,432)
General Advertising Exp	930				($10,817)
Load Dispatch-Reliability	5611				($24,017)
Load Dispatch-Monitor and Operation	5612				($24,405)
Load Dispatch-Transmission Service	5613				($13,882)
Fuel - Steam	501				($0)
Total					($2,046,188)

Data Sources:

1. **TEP Income - Payroll Expense Adjustment Workpaper**
2. **TEP Income - Payroll Tax Expense Adjustment Workpaper**

AECC Payroll Expense Adjustment
Calculation of 2.5% 2012 Increase

Empl Class	12/31/11 Annual Rt	03/23/12 Annual Rt
Classified Total	48,316,882	50,234,338
Unclassified Total	56,933,329	57,706,892
Executive Total	3,439,788	3,471,907
Grand Total	108,689,998	111,413,137
	Average Wage increase in 2012	2.5%

Data Source: TEP Income - Payroll Expense Workpaper, Payroll Increase tab.

Derivation of AECC Payroll Expense And Payroll Tax Expense Adjustment by FERC Account

Payroll by Function — **Total PR**

UNS Corporate Structure
DEC-11 USD
14-MAR-2012 13:37:09

No specific Comp requested

	------- 12 Months DEC-11	% O&M Distribution by FERC			AECC Distribute Payroll Adjustment
Production	**Payroll**	**Distribution**	**Account**	**Description**	
0500 Steam Prod Oper-Supervision	6,043.00	0.01%	0500	Steam Prod Oper-Supervision	(181)
0500 Steam Prod Oper-Supervision	6,327,686.73	9.26%	0500	Steam Prod Oper-Supervision	(189,417)
0501 Fuel - Steam	620,274.68	0.91%	0501	Fuel - Steam	(18,568)
0502 Steam Expenses	11,811.00	0.02%	0502	Steam Expenses	(354)
0502 Steam Expenses	6,766,429.94	9.90%	0502	Steam Expenses	(202,550)
0505 Electric Expenses	3,941.00	0.01%	0505	Electric Expenses	(118)
0505 Electric Expenses	2,086,038.33	3.05%	0505	Electric Expenses	(62,445)
0506 Steam Prod-Misc Expense	2,839.00	0.00%	0506	Steam Prod-Misc Expense	(85)
0506 Steam Prod-Misc Expense	2,023,418.04	2.96%	0506	Steam Prod-Misc Expense	(60,570)
0510 Maint-Supervision & Engr	2,311.00	0.00%	0510	Maint-Supervision & Engr	(69)
0510 Maint-Supervision & Engr	2,493,192.45	3.65%	0510	Maint-Supervision & Engr	(74,633)
0511 Maint of Structures	(2,774.43)	0.00%	0511	Maint of Structures	83
0511 Maint of Structures	583,396.42	0.85%	0511	Maint of Structures	(17,464)
0512 Maint of Boiler Plant	4,890.30	0.01%	0512	Maint of Boiler Plant	(146)
0512 Maint of Boiler Plant	5,579,457.97	8.16%	0512	Maint of Boiler Plant	(167,019)
0513 Steam Prod-Mnt Elec Plnt	1,055.00	0.00%	0513	Steam Prod-Mnt Elec Plnt	(32)
0513 Steam Prod-Mnt Elec Plnt	1,620,772.17	2.37%	0513	Steam Prod-Mnt Elec Plnt	(48,517)
0514 Steam Prod-Mnt Misc Plnt	(1,275.54)	0.00%	0514	Steam Prod-Mnt Misc Plnt	38
0514 Steam Prod-Mnt Misc Plnt	2,117,389.32	3.10%	0514	Steam Prod-Mnt Misc Plnt	(63,383)
0546 Other Prod Oper-Supervision	31,576.45	0.05%	0546	Other Prod Oper-Supervision	(945)
0549 Misc Other Pw Gen Exp	4,487.64	0.01%	0549	Misc Other Pw Gen Exp	(134)
0552 Maint of Structures	22,966.26	0.03%	0552	Maint of Structures	(687)
0553 Maint Gen & Elec Plant	83,445.51	0.12%	0553	Maint Gen & Elec Plant	(2,498)
0554 Maint of Misc Oth Pwr Gen Plant	20,075.16	0.03%	0554	Maint of Misc Oth Pwr Gen Plant	(601)
0556 Sys Cntrol/Load Dispatch	1,001,009.51	1.46%	0556	Sys Cntrol/Load Dispatch	(29,965)
0557 Prod Expense-Other	325,951.22	0.48%	0557	Prod Expense-Other	(9,757)
0560 Trans-Oper Supv & Engr	716,142.32	1.05%	0560	Trans-Oper Supv & Engr	(21,437)
0561 Trans-Load Dispatch	998.82	0.00%	0561	Trans-Load Dispatch	(30)
0566 Trans-Misc Oper Expense	53,081.24	0.08%	0566	Trans-Misc Oper Expense	(1,589)
0568 Trans-Maint Supv & Engr	170,429.33	0.25%	0568	Trans-Maint Supv & Engr	(5,102)
0569 Trans-Maint of Structures	129.48	0.00%	0569	Trans-Maint of Structures	(4)
0570 Trans-Maint Stn Equip	1,804,849.82	2.64%	0570	Trans-Maint Stn Equip	(54,027)
0571 Trans-Maint of OH Lines	348,628.31	0.51%	0571	Trans-Maint of OH Lines	(10,436)
0573 Trans-Maint Misc Trans Plnt	116.34	0.00%	0573	Trans-Maint Misc Trans Plnt	(3)
0580 Dist-Oper Supv & Engr	701,119.53	1.03%	0580	Dist-Oper Supv & Engr	(20,988)
0581 Dist-Load Dispatching	372,755.08	0.55%	0581	Dist-Load Dispatching	(11,158)
0582 Dist-Station Expenses	52,712.58	0.08%	0582	Dist-Station Expenses	(1,578)
0583 Dist-Overhead Line Exp	304,680.18	0.45%	0583	Dist-Overhead Line Exp	(9,120)
0584 Dist-Underground Line Exp	107,325.28	0.16%	0584	Dist-Underground Line Exp	(3,213)
0585 Dist-Light/Signal Exp	3,905.04	0.01%	0585	Dist-Light/Signal Exp	(117)
0586 Dist-Meter Expenses	879,575.35	1.29%	0586	Dist-Meter Expenses	(26,330)
0587 Dist-Customer Install Exp	100,132.07	0.15%	0587	Dist-Customer Install Exp	(2,997)
0588 Dist-Misc Expense	1,515.83	0.00%	0588	Dist-Misc Expense	(45)

Derivation of AECC Payroll Expense And Payroll Tax Expense Adjustment by FERC Account

Payroll by Function	**Total PR** UNS Corporate Structure DEC-11 USD 14-MAR-2012 13:37:09				
No specific Comp requested					
	—— 12 Months DEC-11 ————	% O&M Distribution by FERC			AECC Distribute Payroll Adjustment
0588 Dist-Misc Expense	2,735,979.58	4.00%	0588	Dist-Misc Expense	(81,900)
0590 Dist-Maint Supv & Engr	477,696.30	0.70%	0590	Dist-Maint Supv & Engr	(14,300)
0592 Dist-Maint Stn Equip	419,982.85	0.61%	0592	Dist-Maint Stn Equip	(12,572)
0593 Dist-Maint of OH Lines	524,103.02	0.77%	0593	Dist-Maint of OH Lines	(15,689)
0594 Dist-Maint of UG Lines	58,113.27	0.09%	0594	Dist-Maint of UG Lines	(1,740)
0595 Dist-Mnt Line Transformers	226,722.15	0.33%	0595	Dist-Mnt Line Transformers	(6,787)
0597 Dist-Maint of Meters	87,299.93	0.13%	0597	Dist-Maint of Meters	(2,613)
0598 Dist-Maint Misc Plant	41,044.95	0.06%	0598	Dist-Maint Misc Plant	(1,229)
0903 Cust Rec/Collection Exp	5,611,162.69	8.21%	0903	Cust Rec/Collection Exp	(167,968)
0908 Customer Assistance Exp	773,723.28	1.13%	0908	Customer Assistance Exp	(23,161)
0909 Informational/Instrct Adv Exp	25,700.40	0.04%	0909	Informational/Instrct Adv Exp	(769)
0920 A&G Salaries	6,837.40	0.01%	0920	A&G Salaries	(205)
0920 A&G Salaries	15,750,178.88	23.04%	0920	A&G Salaries	(471,475)
0925 Injuries & Damages	(20,477.33)	-0.03%	0925	Injuries & Damages	613
0925 Injuries & Damages	455,949.45	0.67%	0925	Injuries & Damages	(13,649)
0926 Pensions & Benefits	1,384,084.70	2.02%	0926	Pensions & Benefits	(41,432)
0930 General Advertising Exp	361,358.05	0.53%	0930	General Advertising Exp	(10,817)
5611 Load Dispatch-Reliability	802,316.71	1.17%	5611	Load Dispatch-Reliability	(24,017)
5612 Load Dispatch-Monitor and Operation Transmiss	815,273.06	1.19%	5612	Load Dispatch-Monitor and Operation Transmiss	(24,405)
5613 Load Dispatch-Transmission Service and Schedu	463,752.28	0.68%	5613	Load Dispatch-Transmission Service and Schedu	(13,882)
0501 Fuel - Steam	14.00	0.00%	0501	Fuel - Steam	(0)
Transmission					-
0561 Trans-Load Dispatch	0.00	0.00%			-
0566 Trans-Misc Oper Expense	0.00	0.00%			-
Distribution					-
Customer Accounting					-
Customer Service & Information					-
Administration & General					-
0930 General Advertising Exp	0.00				-

Total Operations	51,671,303.01				

Maintenance - Electric					
Production					
Transmission					
5691 Maintenance of Computer Hardware	0.00	0.00%			
Distribution					
Production					
Administrative & General					
0935 Maint General Plant	0.00	0.00%			

Total Maintenance	16,684,017.34				

Total Operations & Maintenance	68,355,320.35	45.35%		Total Adjustment	(2,046,188)
				Effective Payroll Tax Rate	7.5%
				Payroll Tax Expense Adjustment	(153,814)

Data Sources:
1. TEP Income - Payroll Expense Adjustment Workpaper
2. TEP Income - Payroll Tax Expense Adjustment Workpaper

EXHIBIT KCH-7

AECC Generation Overhaul Expense Adjustment

Line No.		Total Company AECC Generation Overhaul Adjustment (a)		Jurisdictional AECC Generation Overhaul Adjustment (b)		Line No.
1	**Operating Revenues**					1
2	Electric Retail Non-Fuel Revenue	0		0		2
3	PPFAC Revenue	0		0		3
4	Sales for Resale	0		0		4
5	Other Operating Revenue	0		0		5
6	Total Operating Revenues	0		0		6
7	**Operating Expenses**					7
8	Fuel Expense	0		0		8
9	Purchased Power - Demand	0		0		9
10	Purchased Power - Energy	0		0		10
11	Transmission	0		0		11
12	Fuel, Purchased Power and Transmission	0		0		12
13	Other Operations & Maintenance Expense	(2,432)		(2,275)		13
14	Depreciation and Amortization	0		0		14
15	Taxes Other than Income	0		0		15
16	Income Taxes	973		908		16
17	Total Operating Expenses	(1,459)		(1,366)		17
18	Operating Income	1,459		1,366		18
19	Rate Base - Original Cost	(969)		(728)		19
20	Rate Base - RCND	(2,110)		(1,586)		20
21	Gross Revenue Conversion Factor			1.6590	(c)	21
22	Operating Income Revenue Requirement Impact (-Ln. 18 x Ln. 21)			(2,267)		22
23	OCRB Revenue Requirement Impact (Ln. 19 x WACC x Ln. 21)			(94)		23
24	FV Increment Rev. Req't Impact (Avg[Ln. 19, Ln. 20] - Ln. 19 x 1.56% x Ln. 21)			(11)		24
25	Total Revenue Requirement Impact (Ln. 22 + Ln. 23 + Ln. 24)			(2,371)		25

<u>Supporting Schedules/Data Source</u>
(a) & (b) TEP Rev Req Model - AECC WP
(c) TEP Schedule C-3

AECC Outage and Overhaul Expense Adjustment

(Excluding Springerville Unit 1)

Description	FERC Account	Unadjusted Total Company Test Year Amount[1]	TEP Proposed Total Company Test Year Amount[1]	AECC Recommended Total Company Test Year Amount	AECC Recommended Total Company Adjustment
Outage and Overhaul Expense	512	$13,758,000	$15,028,001	$12,596,445	($2,431,556)

1. Data Source: TEP Income - Overhaul and Outage Workpaper, Bates No. TEP(0291)007244.

Derivation of AECC Generation Overhaul Expense Adjustment

Plant	2004	2005	2006	2007	2008	2009	2010	2011	8-Yr Avg
Four Corners Unit 4	$1,232,000	$122,000		$372,000		$232,000	$1,810,000		$471,000
Four Corners Unit 5		$230,000	$351,000		$1,619,000	$389,000		$1,012,000	$450,125
Navajo Unit 1		$1,500,000			$1,231,000			$3,210,000	$742,625
Navajo Unit 2	$1,334,000			$532,000			$3,486,000		$669,000
Navajo Unit 3			$516,000			$3,503,000			$502,375
San Juan Unit 1	$1,800,000		$1,798,000		$6,923,000			$6,667,000	$2,148,500
San Juan Unit 2		$1,700,000		$1,802,000		$7,455,000			$1,369,625
Luna Unit 1			Apr. Start-up			$1,363,000			$237,043
Luna Unit 2			Apr. Start-up		$954,000			$869,000	$317,043
Springerville Unit 1	[redacted]								[redacted]
Springerville Unit 2		$5,000,000		$2,951,000	$5,943,000		$5,408,915		$2,412,864
Irvington Unit 1		$1,010,000			$2,442,000		$655,000	$79,000	$523,250
Irvington Unit 2	$1,197,000					$957,620	$2,018,000	$729,000	$612,703
Irvington Unit 3	$1,796,000			$1,000,000	$2,639,000		$850,000		$785,625
Irvington Unit 4	$257,000		$4,810,000			$5,770,330			$1,354,666
Total Excl. SGS 1	$7,616,000	$9,562,000	$7,475,000	$6,657,000	$21,751,000	$19,669,950	$14,227,915	$12,566,000	$12,596,445

Data Source: For 2004-2011, TEP Income - Overhaul and Outage Workpaper, Bates No. TEP(0291)007244.
Data Source: For 2004-2011 corrections, TEP Response to STF 9.06.

EXHIBIT KCH-8

AECC Injuries & Damages Expense Adjustment

Line No.		Total Company AECC Injuries & Damages Adjustment (a)	Jurisdictional AECC Injuries & Damages Adjustment (b)		Line No.
1	Operating Revenues				1
2	Electric Retail Non-Fuel Revenue	0	0		2
3	PPFAC Revenue	0	0		3
4	Sales for Resale	0	0		4
5	Other Operating Revenue	0	0		5
6	Total Operating Revenues	0	0		6
7	Operating Expenses				7
8	Fuel Expense	0	0		8
9	Purchased Power - Demand	0	0		9
10	Purchased Power - Energy	0	0		10
11	Transmission	0	0		11
12	Fuel, Purchased Power and Transmission	0	0		12
13	Other Operations & Maintenance Expense	(109)	(96)		13
14	Depreciation and Amortization	0	0		14
15	Taxes Other than Income	0	0		15
16	Income Taxes	44	38		16
17	Total Operating Expenses	(65)	(58)		17
18	Operating Income	65	58		18
19	Rate Base - Original Cost	(43)	(33)		19
20	Rate Base - RCND	(95)	(71)		20
21	Gross Revenue Conversion Factor		1.6590	(c)	21
22	Operating Income Revenue Requirement Impact (-Ln. 18 x Ln. 21)		(96)		22
23	OCRB Revenue Requirement Impact (Ln. 19 x WACC x Ln. 21)		(4)		23
24	FV Increment Rev. Req't Impact (Avg[Ln. 19, Ln. 20] - Ln. 19 x 1.56% x Ln. 21)		(0)		24
25	Total Revenue Requirement Impact (Ln. 22 + Ln. 23 + Ln. 24)		(101)		25

Supporting Schedules/Data Source
(a) & (b) TEP Rev Req Model - AECC WP
(c) TEP Schedule C-3

AECC Injuries & Damages Expense Adjustment

Description	FERC Account	Unadjusted Total Company Test Year Amount[1]	TEP Proposed Total Company Test Year Amount[1]	AECC Recommended Total Company Test Year Amount	AECC Recommended Total Company Adjustment
Injuries and Damages	925	$451,455	$1,128,981	$1,019,975	($109,005)

1. Data Source: TEP Income - Injuries & Damages Workpaper, Bates No. TEP(0291)007224.

Derivation of AECC Injuries & Damages Expense Adjustment

GL Account	Description	2007	2008	2009	2010	2011	TEP 3-Yr Avg	AECC 5-Yr Avg
50250	Workers' Compensation	$406,739	$332,829	$279,032	$439,950	$479,631	$399,538	$387,636
78040	Workers' Compensation	($278,264)	($103,985)	($71,315)	($30,477)	$24,699	($25,698)	($91,869)
78100	Injuries & Damages	$786,842	$568,774	$902,807	$1,415,491	($52,875)	$755,141	$724,208
	Total	$915,317	$797,618	$1,110,523	$1,824,964	$451,455	$1,128,981	$1,019,975

Data Source: For 2007-2008, TEP Response to AECC DR No. 15.5.
Data Source: For 2009-2011, TEP Income - Injuries & Damages Workpaper, Bates No. TEP(0291)007224.

EXHIBIT KCH-9

AECC Lime Expense Adjustment

Line No.		Total Company AECC Lime Expense Adjustment (a)	Jurisdictional AECC Lime Expense Adjustment (b)		Line No.
1	Operating Revenues				1
2	Electric Retail Non-Fuel Revenue	0	0		2
3	PPFAC Revenue	0	0		3
4	Sales for Resale	0	0		4
5	Other Operating Revenue	0	0		5
6	Total Operating Revenues	0	0		6
7	Operating Expenses				7
8	Fuel Expense	0	0		8
9	Purchased Power - Demand	0	0		9
10	Purchased Power - Energy	0	0		10
11	Transmission	0	0		11
12	Fuel, Purchased Power and Transmission	0	0		12
13	Other Operations & Maintenance Expense	(901)	(800)		13
14	Depreciation and Amortization	0	0		14
15	Taxes Other than Income	0	0		15
16	Income Taxes	361	319		16
17	Total Operating Expenses	(540)	(480)		17
18	Operating Income	540	480		18
19	Rate Base - Original Cost	(359)	(270)		19
20	Rate Base - RCND	(782)	(588)		20
21	Gross Revenue Conversion Factor		1.6590	(c)	21
22	Operating Income Revenue Requirement Impact (-Ln. 18 x Ln. 21)		(797)		22
23	OCRB Revenue Requirement Impact (Ln. 19 x WACC x Ln. 21)		(35)		23
24	FV Increment Rev. Req't Impact (Avg[Ln. 19, Ln. 20] - Ln. 19 x 1.56% x Ln. 21)		(4)		24
25	Total Revenue Requirement Impact (Ln. 22 + Ln. 23 + Ln. 24)		(836)		25

Supporting Schedules/Data Source
(a) & (b) TEP Rev Req Model - AECC WP
(c) TEP Schedule C-3

AECC SGS Unit 2 Lime Expense Adjustment

Description	FERC Account	TEP Proposed Total Company Test Year Amount[1]	AECC Recommended Total Company Test Year Amount[2]	AECC Recommended Total Company Adjustment
Steam Expenses	502	$1,398,994	$498,014	($900,980)

1. Data Source: TEP Income - Lime Expense Workpaper TEP(0291)007229.
2. Note: AECC's Adjustment used 2012 data through Sep., from TEP's Response to RUCO 8.06, and is based on the average percentage increase in lime cost per ton in 2012 over 2011. This percentage increase was applied to SGS Unit 2's 2011 lime cost, excluding the effect of sulfur credit.

Derivation of AECC SGS Unit 2 Lime Expense Adjustment

SGS Lime Summary for 2011-2012

Actual data 2011	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Total
Lime Cost (product, freight, fuel surcharge, tax LESS add'l lime reimbursed to U12 from U34)	1,309,533	730,258	1,367,613	845,973	1,113,841	974,987	1,008,956	1,232,465	989,364	713,135	807,962	1,056,414	12,150,501
Add'l Lime reimbursed to U12 from U34 (Note: this amount has already been deducted from the lime cost above and is included here as a FYI)	(299,531)	(286,088)	(270,564)	(307,341)	(313,192)	(255,990)	(334,828)	(322,056)	(297,473)	(171,506)	(238,609)	(320,258)	(3,417,436)
Monthly lime cost per ton	128.59	129.29	129.38	129.38	129.38	129.38	130.10	133.84	134.16	134.16	134.16	134.16	
AECC Estimated Monthly Tons	10,183.79	5,648.22	10,570.51	6,538.67	8,609.07	7,535.84	7,755.23	9,208.50	7,374.51	5,315.56	6,022.38	7,874.28	92,636.55
Sulfur Credit	-	(587,008)	(603,416)	(673,544)	(237,807)	(711,411)	(394,186)	(420,171)	(380,972)	(80,432)	(279,245)	(420,846)	(4,789,038)
Gross Generation	550,674	524,974	495,553	539,275	574,309	466,649	586,914	557,653	531,105	301,505	413,735	559,704	6,102,050
Net Lime (Lime cost less lime credit less add'l lime reimbursed from U3&4)	1,309,533	143,250	764,197	172,429	876,034	263,576	614,770	812,294	608,392	632,703	528,717	635,568	7,361,463
Cost per MWh	2.38	0.27	1.54	0.32	1.53	0.56	1.05	1.46	1.15	2.10	1.28	1.14	1.21

Actual data 2012	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	
Lime Cost (product, freight, fuel surcharge, tax LESS add'l lime reimbursed to U12 from U34)	634,048	1,935,884	1,374,806	1,233,063	1,193,982	1,413,620	1,016,163	1,270,043	1,016,552	-	-	-	11,088,160
Add'l Lime reimbursed to U12 from U34 (Note: this amount has already been deducted from the lime cost above and is included here as a FYI)	(330,184)	(328,496)	(330,374)	(307,691)	(374,274)	(306,980)	(339,137)	(363,652)	(314,082)				
Monthly lime cost per ton	136.13	140.83	140.58	140.58	140.58	141.42	141.42	143.90	143.74				1,269
AECC Estimated Monthly Tons	4,657.66	13,746.25	9,779.53	8,771.25	8,493.26	9,995.90	7,185.43	8,825.87	7,072.16				78,527.30
Sulfur Credit	(453,821)	(317,250)	(337,746)	(477,949)	(329,199)	(285,429)	(355,276)	(2,925)	(449,680)				(3,009,275)
Gross Generation	564,728	554,055	558,005	520,258	573,361	508,455	569,382	598,828	498,909				4,945,981
Net Lime (Lime cost less lime sulfur credit)	180,227	1,618,634	1,037,060	755,114	864,783	1,128,191	660,887	1,267,118	566,872	-	-	-	8,078,885
Cost per MWh	0.32	2.92	1.86	1.45	1.51	2.22	1.16	2.12	1.14	-	-	-	1.63

Per Carolyn Rice:		
Unit 1 Gross Production 2011	2,834,067	46%
Unit 2 Gross Production 2011	3,267,977	54%
	6,102,044	

AECC ADJUSTMENT TO 2011	
Average Lime Cost Per Ton 2011	$131.1631
Average Lime Cost Per Ton 2012	$141.2013
% Increase Per Ton	7.65%
$ Increase	$498,014

Data Source: Attachment to TEP's Response to RUCO 8.06.

EXHIBIT KCH-10

AECC Incentive Compensation Expense Adjustment

Line No.		Total Company AECC Incentive Compensation Adjustment (a)	Jurisdictional AECC Incentive Compensation Adjustment (b)		Line No.
1	Operating Revenues				1
2	Electric Retail Non-Fuel Revenue	0	0		2
3	PPFAC Revenue	0	0		3
4	Sales for Resale	0	0		4
5	Other Operating Revenue	0	0		5
6	Total Operating Revenues	0	0		6
7	Operating Expenses				7
8	Fuel Expense	0	0		8
9	Purchased Power - Demand	0	0		9
10	Purchased Power - Energy	0	0		10
11	Transmission	0	0		11
12	Fuel, Purchased Power and Transmission	0	0		12
13	Other Operations & Maintenance Expense	(3,583)	(2,701)		13
14	Depreciation and Amortization	0	0		14
15	Taxes Other than Income	(269)	(200)		15
16	Income Taxes	1,541	1,161		16
17	Total Operating Expenses	(2,311)	(1,740)		17
18	Operating Income	2,311	1,740		18
19	Rate Base - Original Cost	(1,535)	(1,154)		19
20	Rate Base - RCND	(3,342)	(2,512)		20
21	Gross Revenue Conversion Factor		1.6590	(c)	21
22	Operating Income Revenue Requirement Impact (-Ln. 18 x Ln. 21)		(2,887)		22
23	OCRB Revenue Requirement Impact (Ln. 19 x WACC x Ln. 21)		(148)		23
24	FV Increment Rev. Req't Impact (Avg[Ln. 19, Ln. 20] - Ln. 19 x 1.56% x Ln. 21)		(18)		24
25	Total Revenue Requirement Impact (Ln. 22 + Ln. 23 + Ln. 24)		$\boxed{(3,052)}$		25

Supporting Schedules/Data Source
(a) & (b) TEP Rev Req Model - AECC WP
(c) TEP Schedule C-3

AECC Incentive Compensation Expense Adjustment

Description	FERC Account	Unadjusted Total Company Test Year Amount[1]	TEP Proposed Total Company Test Year Amount[1]	AECC Recommended Total Company Test Year Amount	AECC Recommended Total Company Adjustment
Operation Supervision & Engineering	500	83,927	$139,446	$59,835	($79,610)
Miscellaneous Steam Power Expenses	506	786,569	$1,306,901	$560,782	($746,119)
Maintenance Miscellaneous Steam Plant	514	309,913	$514,928	$220,952	($293,977)
Miscellaneous Transmission Expenses	566	587,565	$976,252	$418,903	($557,350)
Maintenance of Station Equipment	570	62,030	$103,063	$44,224	($58,839)
Operation Supervision & Engineering	580	53,316	$88,585	$38,011	($50,574)
Miscellaneous Distribution Expenses	588	215,121	$357,427	$153,370	($204,058)
Maintenance of Misc. Distribution Plant	598	34,017	$56,519	$24,252	($32,266)
Customer Records & Collection Expenses	903	226,452	$376,256	$161,448	($214,807)
Administrative & General Salaries	920	2,061,087	$2,357,032	$1,011,380	($1,345,652)
Total O&M Incentive Comp. Adjustment		4,419,997	$6,276,410	$2,693,158	($3,583,252)
FICA Tax @ 7.5%	408	331,500	470,731	201,987	($268,744)
Total		4,751,497	6,747,141	2,895,145	($3,851,996)

1. Data Source: TEP Income - Incentive Compensation Workpaper, Bates No. TEP(0291)007213-007214.

DERIVATION OF AECC RECOMMENDED SHORT-TERM INCENTIVE COMPENSATION EXPENSE

	Total per Query	Adjusted Incentive Compensation	Distribution by FERC	AECC Recommended Share @ 37.5%
Total Incentive Compensation	Year	Year	Year	Year
FERC	2011	2011	2011	2011
0107	442,221			
0426	3,404,253	3,404,253		
0500	83,927	83,927	159,561	59,835
0506	786,569	786,569	1,495,419	560,782
0514	309,913	309,913	589,204	220,952
0566	587,565	587,565	1,117,074	418,903
0570	62,030	62,030	117,931	44,224
0580	53,316	53,316	101,364	38,011
0588	215,121	215,121	408,986	153,370
0598	34,017	34,017	64,673	24,252
0903	226,452	226,452	430,529	161,448
0920	2,061,087	1,418,591	2,697,014	1,011,380
Grand Total	8,266,471	7,181,754	7,181,754	2,693,158

Adjustments:	
FERC 107 Construction Work in Progress	(442,221)
FERC 0920 Capitalized through A&G Load	(642,496)
0% of Officers and Directors Incentive Compensation	-
	7,181,754
FERC 0920 - Total	2,061,087
Less: FERC 0920 Amount Capitalized through A&G Load	31.17%
	(642,496)
*Net FERC 0920	1,418,591
Officers and Directors - Per HR	
Officers	1,776,332
Directors	1,083,328
	2,859,660
Benefit sharing between Ratepayers and Shareholders	0%
Adjusted Officers and Directors Incentive Compensation	0
Total FERC 0426	3,404,253
Net FERC 0426 excluding 0% Officers and Directors	3,404,253
Reclass Adjustment:	
Incentive Compensation recorded below the line in FERC 426	3,404,253
Exclude: 0% of Officers and Directors Benefit Sharing with Shareholders	0
Balance of incentive compensation in FERC 426	3,404,253
Test Year Amount reclassed to Revenue Requirements	3,404,253

Data Source: TEP Income - Incentive Compensation Workpaper, Bates No. TEP(0291)007213-007214.

EXHIBIT KCH-11

AECC Capital Structure Adjustment

Line No.		Total Company: AECC Capital Structure Adjustment (a)	Jurisdictional: AECC Incentive Compensation Adjustment (b)		Line No.
1	Operating Revenues				1
2	Electric Retail Non-Fuel Revenue	0	0		2
3	PPFAC Revenue	0	0		3
4	Sales for Resale	0	0		4
5	Other Operating Revenue	0	0		5
6	Total Operating Revenues	0	0		6
7	Operating Expenses				7
8	Fuel Expense	0	0		8
9	Purchased Power - Demand	0	0		9
10	Purchased Power - Energy	0	0		10
11	Transmission	0	0		11
12	Fuel, Purchased Power and Transmission	0	0		12
13	Other Operations & Maintenance Expense	0	0		13
14	Depreciation and Amortization	0	0		14
15	Taxes Other than Income	0	0		15
16	Income Taxes	(1,183)	(932)		16
17	Total Operating Expenses	(1,183)	(932)		17
18	Operating Income	1,183	932		18
19	Rate Base - Original Cost	776	583		19
20	Rate Base - RCND	2,164	1,625		20
21	Gross Revenue Conversion Factor		1.6590	(c)	21
22	Operating Income Revenue Requirement Impact (-Ln. 18 x Ln. 21)		(1,547)		22
23	TEP As-Filed OCRB Rate Base (KCH-1, p. 2, Ln. 1)		1,519,073		23
24	Total AECC OCRB Rate Base Adjustments before Cap. Str. Adjustment		(85,397)		24
25	Total Adjusted OCRB Rate Base before Debt Adjustment (Ln. 23 + Ln. 24)		1,433,676		25
26	Weighted Cost of Capital before Capital Structure Adjustment		7.74%		26
27	Total Adjusted OCRB Rate Base after Cap. Str. Adjustment (Ln. 19 + Ln. 25)		1,434,258		27
28	Weighted Cost of Capital after Capital Structure Adjustment		7.57%		28
29	OCRB Revenue Req't Impact ([(Ln. 27 x Ln. 28) - (Ln. 25 x Ln. 26)] x Ln. 21)		(4,099)		29
30	FV Increment Rev. Req't Impact (Avg[Ln. 19, Ln. 20] - Ln. 19 x 1.56% x Ln. 21)		13		30
31	Total Revenue Requirement Impact (Ln. 22 + Ln. 29 + Ln. 30)		$\boxed{(5,632)}$		31
			(5,632)		

Supporting Schedules/Data Source
(a) & (b) TEP Rev Req Model - AECC WP
(c) TEP Schedule C-3

AECC Capital Structure Adjustment

Description	Capitalization Percent
2011 Test Year Actual Common Stock Equity Component[1]	43.50%
2012 Projected Common Stock Equity Component[1]	42.20%
2012 Average Common Stock Equity Component	**42.85%**
2012 Average Long-Term Debt Component	**57.15%**

1. Data Source: TEP Schedule D-1.

EXHIBIT KCH-12

AECC Cost of Debt Adjustment

Line No.		Total Company: AECC Capital Structure Adjustment (a)	Jurisdictional: AECC Incentive Compensation Adjustment (b)		Line No.
1	Operating Revenues				1
2	Electric Retail Non-Fuel Revenue	0	0		2
3	PPFAC Revenue	0	0		3
4	Sales for Resale	0	0		4
5	Other Operating Revenue	0	0		5
6	Total Operating Revenues	0	0		6
7	Operating Expenses				7
8	Fuel Expense	0	0		8
9	Purchased Power - Demand	0	0		9
10	Purchased Power - Energy	0	0		10
11	Transmission	0	0		11
12	Fuel, Purchased Power and Transmission	0	0		12
13	Other Operations & Maintenance Expense	0	0		13
14	Depreciation and Amortization	0	0		14
15	Taxes Other than Income	0	0		15
16	Income Taxes	592	457		16
17	Total Operating Expenses	592	457		17
18	Operating Income	(592)	(457)		18
19	Rate Base - Original Cost	(388)	(291)		19
20	Rate Base - RCND	(1,082)	(813)		20
21	Gross Revenue Conversion Factor		1.6590	(c)	21
22	Operating Income Revenue Requirement Impact (-Ln. 18 x Ln. 21)		759		22
23	TEP As-Filed OCRB Rate Base (KCH-1, p. 2, Ln. 1)		1,519,073		23
24	Total AECC OCRB Rate Base Adjustments before Debt Adjustment		(84,815)		24
25	Total Adjusted OCRB Rate Base before Debt Adjustment (Ln. 23 + Ln. 24)		1,434,258		25
26	Weighted Cost of Capital before Debt Adjustment		7.57%		26
27	Total Adjusted OCRB Rate Base after Debt Adjustment (Ln. 19 + Ln. 25)		1,433,967		27
28	Weighted Cost of Capital after Debt Adjustment		7.49%		28
29	OCRB Revenue Req't Impact ([(Ln. 27 x Ln. 28) - (Ln. 25 x Ln. 26)] x Ln. 21)		(1,940)		29
30	FV Increment Rev. Req't Impact (Avg[Ln. 19, Ln. 20] - Ln. 19 x 1.56% x Ln. 21)		(7)		30
31	Total Revenue Requirement Impact (Ln. 22 + Ln. 29 + Ln. 30)		$\boxed{(1,188)}$		31
			(1,188)		

Supporting Schedules/Data Source
(a) & (b) TEP Rev Req Model - AECC WP
(c) TEP Schedule C-3

AECC Cost of Debt Adjustment

Description	Cost Rate
2011 Test Year Actual Long-Term Debt - Net Component[1]	5.22%
2012 Projected Long-Term Debt - Net Component[1]	4.87%
2012 Average Long-Term Debt - Net Component	**5.04%**

1. Data Source: TEP Schedule D-1.

EXHIBIT KCH-13

AECC Return on Equity Adjustment

Line No.		Total Company AECC Capital Structure Adjustment (a)	Jurisdictional AECC Incentive Compensation Adjustment (b)		Line No.
1	Operating Revenues				1
2	Electric Retail Non-Fuel Revenue	0	0		2
3	PPFAC Revenue	0	0		3
4	Sales for Resale	0	0		4
5	Other Operating Revenue	0	0		5
6	Total Operating Revenues	0	0		6
7	Operating Expenses				7
8	Fuel Expense	0	0		8
9	Purchased Power - Demand	0	0		9
10	Purchased Power - Energy	0	0		10
11	Transmission	0	0		11
12	Fuel, Purchased Power and Transmission	0	0		12
13	Other Operations & Maintenance Expense	0	0		13
14	Depreciation and Amortization	0	0		14
15	Taxes Other than Income	0	0		15
16	Income Taxes	0	0		16
17	Total Operating Expenses	0	0		17
18	Operating Income	0	0		18
19	Rate Base - Original Cost	0	0		19
20	Rate Base - RCND	0	0		20
21	Gross Revenue Conversion Factor		1.6590	(c)	21
22	Operating Income Revenue Requirement Impact (-Ln. 18 x Ln. 21)		0		22
23	TEP As-Filed OCRB Rate Base (KCH-1, p. 2, Ln. 1)		1,519,073		23
24	Total AECC OCRB Rate Base Adjustments before ROE Adjustment		(85,106)		24
25	Total Adjusted OCRB Rate Base before ROE Adjustment (Ln. 23 + Ln. 24)		1,433,967		25
26	Weighted Cost of Capital before ROE Adjustment		7.49%		26
27	Total Adjusted OCRB Rate Base after ROE Adjustment (Ln. 19 + Ln. 25)		1,433,967		27
28	Weighted Cost of Capital after ROE Adjustment		7.21%		28
29	OCRB Revenue Req't Impact ([(Ln. 27 x Ln. 28) - (Ln. 25 x Ln. 26)] x Ln. 21)		(6,624)		29
30	FV Increment Rev. Req't Impact (Avg[Ln. 19, Ln. 20] - Ln. 19 x 1.56% x Ln. 21)		0		30
31	Total Revenue Requirement Impact (Ln. 22 + Ln. 29 + Ln. 30)		$\boxed{(6,624)}$		31
			(6,624)		

Supporting Schedules/Data Source
(a) & (b) TEP Rev Req Model - AECC WP
(c) TEP Schedule C-3

AECC Return on Equity Adjustment

Description	Cost Rate
2011 Median Awarded Return on Equity	10.15%
2012 Qtr 1 - Qtr 3 Median Awarded Return on Equity	10.05%
AECC Recommended Maximum Allowed ROE Component	**10.10%**

1. Data Source: SNL 2011 and Q1-Q3 2012 Major Electric Rate Case Summaries.

2008 Major Electric Rate Case Summary from Regulatory Research Associates

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
1/8/2008	Northern States Power-Wisconsin (WI)	9.67	10.75	52.51	12/08-A	39.4
1/17/2008	Wisconsin Electric Power (WI)	9.26	10.75	54.36	12/08-A/P	148.4 (Z)
1/28/2008	Connecticut Light & Power (CT)	7.72	9.4	48.99	12/06-YE	97.9 (D,Z)
1/30/2008	Potomac Electric Power (DC)	7.96	10	46.55	2/07-A	28.3 (D,5)
1/31/2008	Central Vermont Public Service (VT)	8.5	10.21 (R)	50.02	12/06-A	6.4 (B)
2/6/2008	Interstate Power & Light (IA)	---	11.7 (6)	---	---	---
2/28/2008	Idaho Power (ID)	8.1	---	---	---	32.1 (B)
2/29/2008	Fitchburg Gas & Electric (MA)	8.38	10.25	42.8	12/06-YE	2.1 (D)
3/12/2008	PacifiCorp (WY)	8.29	10.25	50.8	08/08	23 (B,7)
3/25/2008	Consolidated Edison of New York (NY)	7.34	9.1	47.98	3/09-A	425.3 (D)
3/31/2008	Virginia Electric Power (VA)	---	12.12 (8)	---	---	---
4/22/2008	MDU Resources (MT)	8.58	10.25	50.67	12/06-A	4.1 (B,Z)
4/24/2008	Public Service Co. of New Mexico (NM)	8.24	10.1	51.37	9/06-YE	34.4
5/1/2008	Hawaiian Electric Company (HI)	8.66	10.7	55.79	12/05-A	44.9 (Bp,I)
5/27/2008	UNS Electric (AZ)	9.02	10	48.85	6/06-YE	4
5/30/2008	Idaho Power (ID)	--- (9)	---	---	---	8.9
6/10/2008	Consumers Energy (MI)	6.93	10.7	41.75 *	12/08-A	221 (I)
6/16/2008	MidAmerican Energy (IA)	---	11.7 (B,10	---	---	---
6/27/2008	Appalachian Power (WV)	7.65	10.5	41.54	12/07-YE	106.1 (B)
6/27/2008	Sierra Pacific Power (NV)	8.41	10.6 (11)	43.49 (11)	6/07-YE	87.1
6/30/2008	Oncor Electric Delivery (TX)	---	---	---	12/06	--- (D,12)
7/1/2008	Central Maine Power (ME)	---	---	---	---	-20.3
7/2/2008	NorthWestern Corporation (MT)	--- (14)	---	---	---	10 (B,I)
7/10/2008	Otter Tail Corporation (MN)	8.33	10.43	50	12/06-A	3.8 (I)
7/16/2008	Orange and Rockland Utilities (NY)	7.69	9.4	48	6/09-A	15.6 (B,D)
7/30/2008	Empire District Electric (MO)	8.92	10.8	50.78	6/07-YE	22
7/31/2008	San Diego Gas & Electric (CA)	--- (15)	--- (15)	--- (15)	12/08-A	234 (B,Z)
8/11/2008	PacifiCorp (UT)	8.29	10.25	50.4	12/08-A	39.4 (R)
8/26/2008	Southwestern Public Service (NM)	8.27	10.18	51.23	12/06-YE	13.1
8/27/2008	MidAmerican Energy (IA)	---	11.7 (B,16	--- (B,16)	---	---
9/10/2008	Commonwealth Edison (IL)	8.36	10.3	45.04	12/06-YE	273.6 (D)
9/24/2008	Central Illinois Light (IL)	8.01	10.65	46.5	12/06-YE	-2.8 (D)
9/24/2008	Central Illinois Public Service (IL)	8.2	10.65	47.91	12/06-YE	22 (D)
9/24/2008	Illinois Power (IL)	8.68	10.65	51.76	12/06-YE	103.9 (D)
9/30/2008	Avista Corp. (ID)	8.45	10.2	47.94	12/07-A	23.2 (B)
10/8/2008	PacifiCorp (WA)	8.06	---	---	---	20.4 (B)
10/8/2008	Puget Sound Energy (WA)	8.25	10.15	46	9/07-A	130.2 (B)
11/13/2008	NorthWestern Corporation (MT)	8.25 (17)	10 (17)	50 (17)	---	---
11/17/2008	Appalachian Power (VA)	7.69	10.2	---	12/07	167.9 (I,B)
12/1/2008	Tucson Electric Power (AZ)	8.03	10.25	42.5	12/06-YE	136.8 (B)
12/17/2008	Duke Energy Ohio (OH)	---	---	---	---	98 (B,Gn,E,Z)
12/18/2008	Madison Gas and Electric (WI)	---	---	---	12/09	-2.7
12/23/2008	Detroit Edison (MI)	7.16	11	40.68 *	12/09-A	83.6
12/29/2008	Portland General Electric (OR)	8.33	10.1 (Bp)	50	12/09-A	121
12/29/2008	Avista Corporation (WA)	8.22	10.2	46.3	12/07-A	32.5 (B)
12/30/2008	Wisconsin Power and Light (WI)	---	---	---	12/09	0 (B)
12/30/2008	Wisconsin Public Service (WI)	---	---	53.41	12/09	48 (B,18)
12/31/2008	Northern States Power (ND)	8.8	10.75	51.77	12/08	12.8 (I,B)
2008	**YEAR AVERAGES/TOTAL**	**8.25**	**10.46**	**48.41**		**2,899.4**
	MEDIAN	**8.27**	**10.25**	**48.99**		
	OBSERVATIONS	**35**	**37**	**33**		**42**

FOOTNOTES

A- Average

B- Order followed stipulation or settlement by the parties. Decision particulars not necessarily precedent-setting or specifically adopted by the regulatory body.

Bp- Order followed partial stipulation or settlement by the parties. Decision particulars not necessarily precedent-setting or specifically adopted by the regulatory body.

D- Applies to electric delivery only

DC- Date certain

E- Estimated

Hy- Hypothetical capital structure utilized.

I- Interim rates implemented prior to the issuance of final order, normally under bond and subject to refund.

M- "Make-whole" increase based on return on equity or overall return of previous case

P- Partial inclusion of CWIP in rate base without AFUDC offset to income

R- Revised

Tr- Applies to electric transmission only

YE- Year-end

Z- Rate change implemented in multiple steps.

* Capital structure includes cost-free items or tax credit balances at the overall rate of return.

(1) Rate increase effective retroactive to 1/1/07.

(2) Rate increase effective retroactive to 6/16/07.

(3) Represents initial revenue requirement for the newly established company.

(4) Rate increase results from a limited issue reopening of a case initially decided on 1/19/07.

(5) Rate increase effective 2/20/08.

(6) ROE applies only to a proposed 200-MW wind generation facility, and is applicable over the 25-year depreciable life of the project.

(7) Rate increase effective 5/1/08.

(8) ROE applies only to a proposed 585-MW coal generation facility, is applicable for AFUDC and CWIP purposes and over the first 12 years of the plant's commercial operation, and includes a 100-basis-point incentive premium.

(9) The 8.1% ROR utilized in the company's case decided on 2/28/08, was incorporated into this proceeding.

(10) ROE applies only to a proposed 108-MW wind generation facility, and is applicable over the 20-year depreciable life of the project.

(11) 500-basis-point premium for demand-side management investments.

(12) Case abated by Commission at company request.

(13) Rate reduction ordered in conjunction with the authorization of a new five-year alternative regulation plan.

(14) Order noted that an ROR of 7.04% is implied in the approved settlement.

(15) Rate of return was not an issue in this proceeding. The authorized rate change incorporated the 10.7% return on equity (49% of

2009 Major Electric Rate Case Summary from Regulatory Research Associates

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
1/14/2009	Public Service Oklahoma (OK)	8.31	10.5	44.1	2/08-YE	59.3 (1)
1/21/2009	Westar Energy (KS)	---	---	---	---	65 (B)
1/21/2009	Kansas Gas & Electric (KS)	---	---	---	---	65 (B)
1/21/2009	Cleveland Electric Illuminating (OH)	8.48	10.5 (E)	49	2/08-DC	29.2 (D)
1/21/2009	Ohio Edison (OH)	8.48	10.5 (E)	49	2/08-DC	68.9 (D)
1/21/2009	Toledo Edison (OH)	8.48	10.5 (E)	49	2/08-DC	38.5 (D)
1/30/2009	Idaho Power (ID)	8.18	10.5	49.27	12/08-YE	27 (R)
2/4/2009	United Illuminating (CT)	7.59	8.75	50	12/07-A	6.8 (D,R,2)
2/4/2009	Interstate Power & Light (IA)	---	10.1 (3)	---	---	---
2/5/2009	Kentucky Utilities (KY)	---	---	---	---	-8.9 (B)
2/5/2009	Louisville Gas & Electric (KY)	---	---	---	---	-13.2 (B)
2/10/2009	Union Electric (MO)	8.34	10.76	52.01	3/08-YE	161.7
3/4/2009	Indiana Michigan Power (IN)	7.62	10.5	45.8 *	9/07-YE	19.1 (4)
3/11/2009	Entergy Texas (TX)	---	---	---	3/07	30.5 (B,I,5)
3/17/2009	Southern California Edison (CA)	---	---	---	12/09-A	308.1 (6)
4/2/2009	Entergy New Orleans (LA)	---	11.1	---	12/08-YE	-24.7 (B,7)
4/16/2009	PacifiCorp (ID)	---	---	---	---	4.4 (B)
4/21/2009	PacifiCorp (UT)	8.36	10.61	51	12/09-A	45 (B)
4/24/2009	Consolidated Edison of New York (NY)	7.79	10	48	3/10-A	523.4 (D)
4/30/2009	Tampa Electric (FL)	8.29 (R)	11.25	47.49 *(R)	12/09-A	147.7 (Z,R)
5/4/2009	Minnesota Power (MN)	8.45	10.74	54.79	6/09-A	20.4 (I,R)
5/20/2009	Oklahoma Gas & Electric (AR)	6.43	10.25	36.04 *	12/07-YE	13.3 (B)
5/20/2009	NorthWestern Corp. (MT)	8.38	10.25	50	---	--- (8)
5/20/2009	PacifiCorp (WY)	---	---	---	---	18 (B)
5/28/2009	Public Service New Mexico (NM)	8.77	10.5	50.47	3/08-YE	77.1 (B,Z)
5/29/2009	Idaho Power (ID)	---	---	---	---	10.5 (9)
6/2/2009	Southwestern Public Service (TX)	---	---	---	12/07	57.4 (B,I)
6/9/2009	Public Service Co. of Colorado (CO)	---	---	---	---	112.2 (B)
6/10/2009	Kansas City Power & Light (MO)	---	---	---	12/07-YE	95 (B)
6/10/2009	KCP&L Greater Missouri Oper-L&P (MO)	---	---	---	12/07-YE	15 (B)
6/10/2009	KCP&L Greater Missouri Oper-MPS (MO)	---	---	---	12/07-YE	48 (B)
6/22/2009	Central Hudson Gas & Electric (NY)	7.28	10	47	6/10-A	39.6 (D)
6/24/2009	Nevada Power (NV)	8.66 (10)	10.8 (10)	44.15	6/08-YE	222.7 (Z)
7/8/2009	Duke Energy Ohio (OH)	8.61	10.63 (E)	51.59 (E)	12/08-DC	55.3 (D,B)
7/14/2009	Southwestern Public Service (NM)	---	---	---	---	14.2 (B)
7/17/2009	Avista Corp. (ID)	8.55	10.5	50	9/08-A	12.5 (B)
7/24/2009	Kansas City Power & Light (KS)	---	---	---	12/07-YE	59 (B)
7/24/2009	Oklahoma Gas & Electric (OK)	---	---	---	9/08-YE	48.3 (B)
8/21/2009	Texas-New Mexico Power (TX)	---	---	---	40976	12.7 (B)
8/31/2009	Oncor Electric Delivery (TX)	8.28	10.25	40	12/07-YE	115.1 (D)
10/14/2009	Cleco Power (LA)	8.52	10.7	51	6/09-A	173.3 (B)
10/23/2009	Northern States Power-Minnesota (MN)	8.83	10.88	52.47	12/09-A	91.4 (I)
11/2/2009	Consumers Energy (MI)	6.98	10.7	40.51	12/09-A	139.4 (I)
11/3/2009	Sierra Pacific Power (CA)	8.51	10.7	43.71	12/09-A	5.5 (B)
11/24/2009	Southwestern Electric Power (AR)	6.01	10.25	33.99 *	12/08-YE	17.8 (B)
11/25/2009	Otter Tail Power (ND)	8.62	10.75	53.3	12/07-A	3.1 (I,Z,B)
11/30/2009	Massachusetts El./Nantucket El. (MA)	7.85	10.35	43.15	12/08-YE	43.9 (D)
12/7/2009	Duke Energy Carolinas (NC)	8.38	10.7	52.5	12/08-YE	315.2 (B)
12/10/2009	El Paso Electric (NM)	---	---	---	12/08-YE	5.5 (B)
12/16/2009	Arizona Public Service (AZ)	8.58	11	53.79	12/07-YE	344.7 (B)
12/16/2009	Upper Peninsula Power (MI)	7.83	10.9	49.52 *	12/10	6.5 (B)
12/16/2009	PacifiCorp (WA)	8.06	---	---	---	13.5 (B)
12/18/2009	Wisconsin Electric Power (WI)	8.96	10.4	53.02	12/10-A	85.8
12/18/2009	Wisconsin Power and Light (WI)	9.81	10.4	50.38	12/10-A	58.6
12/22/2009	Avista Corp. (WA)	8.25	10.2	46.5	9/08-A	12.1 (Bp)
12/22/2009	Madison Gas and Electric (WI)	8.67	10.4	55.34	12/10-A	11.9
12/22/2009	Northern States Power-Wisconsin (WI)	8.93	10.4	52.3	12/10-A	6.4
12/22/2009	Wisconsin Public Service (WI)	---	---	---	12/10	18.2
12/24/2009	Public Service of Colorado (CO)	8.72	10.5	58.56	12/08-A	237.9 (B,Z,11)
12/30/2009	Delmarva Power & Light (MD)	7.96	10	49.87	12/08-A	7.5 (D)
2009	**YEAR AVERAGES/TOTAL**	**8.23**	**10.48**	**48.61**		**4,197.3**
	MEDIAN	**8.38**	**10.5**	**49.87**		
	OBSERVATIONS	**38**	**39**	**37**		**58**

FOOTNOTES

A- Average

B- Order followed stipulation or settlement by the parties. Decision particulars not necessarily precedent-setting or specifically adopted by the regulatory body.

Bp- Order followed partial stipulation or settlement by the parties. Decision particulars not necessarily precedent-setting or specifically adopted by the regulatory body.

D- Applies to electric delivery only

DC- Date certain

E- Estimated

I- Interim rates implemented prior to the issuance of final order, normally under bond and subject to refund.

M- "Make-whole" increase based on return on equity or overall return of previous case

R- Revised

YE- Year-end

Z- Rate change implemented in multiple steps.

* Capital structure includes cost-free items or tax credit balances at the overall rate of return.

(1) Recovery of an additional $22.1 million authorized through adjustment mechanisms.

(2) Second-year distribution rate increase of about $19 million authorized based on a 7.76% ROR.

(3) Adopted ROE applies only to the company's proposed 649-MW, coal-fired Sutherland Unit 4 plant. The company subsequently cancelled plans to construct the plant.

(4) Commission decision modified a settlement. Recovery of an additional $22.5 million authorized through tracking mechanisms.

(5) Indicated rate increase includes a $46.7 million base rate increase offset by a net $16.2 million decrease in revenues collected under certain riders.

(6) Indicated rate increase is retroactive to January 1, 2009 and reflects the one-time refund of a $72.5 million overcollection of post-retirement benefits other than pension costs. Additional rate increases of $205.3 million and $219 million authorized for 2010 and 2011, respectively. Rate of return was not an issue in this case.

(7) Rate changes effective June 1, 2009.

(8) Authorized return parameters apply only to the 120-150 MW, gas-fired Mill Creek generating plant.

(9) Rate increase associated with implementation of advanced metering infrastructure. Return parameters are those adopted in the company's previous rate case.

2010 Major Electric Rate Case Summary from Regulatory Research Associates

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
1/11/2010	Detroit Edison (MI)	7.02	11	39.48 *	6/10-A	217.4 (I)
1/12/2010	Northern States Power (SD)	8.32	---	---	---	10.9 (B)
1/19/2010	Interstate Power & Light (IA)	8.91	10.8	49.52	12/08-A	83.7 (I)
1/22/2010	Portland General Electric (OR)	---	---	---	---	9.8 (B)
1/26/2010	PacifiCorp (OR)	8.08	10.13	51	12/10-A	41.5 (B)
1/27/2010	Westar Energy (KS)	8.49	10.4	50.13	---	8.5 (B)
1/27/2010	Kansas Gas & Elec. (KS)	8.49	10.4	50.13	---	8.5 (B)
1/27/2010	Duke Energy Carolinas (SC)	8.41	10.7 (1)	53	12/08-YE	74.1 (B)
2/9/2010	Narragansett Electric (RI)	7.2	9.8	42.75 (Hy)	12/08-A	23.5 (D)
2/18/2010	PacifiCorp (UT)	8.34	10.6	51	6/10-A	32.4
2/24/2010	Idaho Power (OR)	8.06	10.18	49.8	12/08	5 (B)
3/2/2010	Potomac Electric Power (DC)	8.01	9.63	46.18	12/08-A	19.8 (D)
3/4/2010	Kentucky Utilities (VA)	7.85	10.5	53.62	12/08-A	10.6 (I,B)
3/5/2010	Florida Power (FL)	7.88	10.5	46.76 *	12/10-A	126.2 (I,2)
3/11/2010	Virginia Electric and Power (VA)	---	11.9 (3)	---	41251	0 (I,B)
3/11/2010	Virginia Electric and Power (VA)	7.81 (E)	12.3 (4)	47.71	---	71 (I,B,4)
3/11/2010	Virginia Electric and Power (VA)	7.81 (E)	12.3 (5)	47.71	---	64 (I,B,5)
3/17/2010	Florida Power & Light (FL)	6.65	10	47 *	12/10-A	75.5
3/26/2010	Consolidated Edison of New York (NY)	7.76	10.15	48	3/11-A	1,127.60 (D,B,Z)
4/2/2010	Puget Sound Energy (WA)	8.1	10.1	46 (Hy)	12/08-A	74.1 (R)
4/16/2010	Southwestern Electric Power (TX)	---	---	---	3/09	25 (B)
4/29/2010	Central Illinois Light (IL)	8.05	9.9	43.61	12/08-YE	4.9 (D,R)
4/29/2010	Central Illinois Public Service (IL)	8.02	10.06	48.67	12/08-YE	23.7 (D,R)
4/29/2010	Illinois Power (IL)	8.97	10.26	43.55	12/08-YE	28.2 (D,R)
5/12/2010	Atlantic City Electric (NJ)	8.69	10.3	49.1	12/09-YE	20 (D,B)
5/12/2010	Rockland Electric (NJ)	8.21	10.3	49.85	12/09-YE	9.8 (D,B)
5/14/2010	PacifiCorp (WY)	8.33	---	---	---	35.5 (B,Z)
5/26/2010	MDU Resources (WY)	8.25	10	49.77	12/08-YE	2.7
5/28/2010	Union Electric (MO)	8.06	10.1	51.26	3/09-YE	229.6
6/7/2010	Public Service Electric & Gas (NJ)	8.21	10.3	51.2	12/09-YE	73.5 (D,B)
6/15/2010	PacifiCorp (UT)	---	---	---	---	30.8 (B,6)
6/18/2010	Central Hudson Gas & Electric (NY)	7.43	10	48	6/11-A	30.2 (D,B,Z)
6/23/2010	Entergy Arkansas (AR)	5.04	10.2	29.32 *	6/09-YE	63.7 (B,R)
6/23/2010	Empire District Electric (KS)	---	---	---	---	2.8 (B)
6/25/2010	Monongahela Power/Potomac Ed. (WV)	8.71	---	---	12/08-A	60 (B,Z)
6/28/2010	Kentucky Power (KY)	---	10.5	---	9/09-YE	63.7 (B)
6/28/2010	Public Service of New Hampshire (NH)	7.51	9.67	52.4	---	57.4 (D,I,B)
6/30/2010	Connecticut Light & Power (CT)	7.68	9.4	49.2	6/09-DC	101.9 (D,Z)
7/1/2010	Wisconsin Electric Power (MI)	6.99	10.25	47.61 *	12/10-A	23.5 (I)
7/15/2010	South Carolina Electric & Gas (SC)	8.56	10.7	52.96	9/09-YE	101.2 (B,Z)
7/15/2010	Appalachian Power (VA)	7.85	10.53	41.53	12/08-YE	61.5
7/30/2010	Maui Electric (HI)	8.67	10.7	54.89	12/07-A	13.2 (B,I)
7/30/2010	Kentucky Utilities (KY)	---	---	---	10/09-YE	98 (B)
7/30/2010	Louisville Gas & Electric (KY)	---	---	---	10/09-YE	74 (B)
7/30/2010	El Paso Electric (TX)	---	---	---	41069	17.2 (B,7)
8/4/2010	Black Hills Colorado Electric Utility (CO)	9.32	10.5	52	41099	17.9 (B)
8/6/2010	Potomac Electric Power (MD)	8.18	9.83	48.87	12/09-A	7.8
8/11/2010	Black Hills Power (SD)	8.26	---	---	6/09-A	22 (B,I)
8/18/2010	Empire District Electric (MO)	---	---	---	6/09-YE	46.8 (B)
8/25/2010	Northern Indiana Public Service (IN)	7.29	9.9	49.95 *	12/07-YE	-48.9
9/14/2010	Hawaiian Electric (HI)	8.62	10.7	55.1	12/07-A	77.5 (B,I)
9/16/2010	New York State Electric & Gas (NY)	7.48	10	48	8/11-A	88.7 (D,B,Z,8)
9/16/2010	Rochester Gas and Electric (NY)	8.47	10	48	8/11-A	54.2 (D,B,Z,8)
9/21/2010	Avista Corp. (ID)	---	---	---	41252	21.3 (B)
9/30/2010	UNS Electric (AZ)	8.28	9.75	45.76	12/08-YE	7.4
9/30/2010	South Carolina Electric & Gas (SC)	---	---	---	---	47.3 (9)
10/14/2010	Indiana Michigan Power (MI)	7.53	10.35	44.14 *	12/10-A	35.7 (B,I)
10/28/2010	Hawaii Electric Light (HI)	8.33	10.7	51.19	12/06-A	24.6 (B,I)
11/2/2010	Minnesota Power (MN)	8.18	10.38	54.29	12/10-A	67.5 (I)
11/4/2010	Consumers Energy (MI)	6.98	10.7	41.59 *	6/11-A	145.7 (I)
11/19/2010	Avista Corp. (WA)	7.91	10.2	46.5	12/09-A	29.5 (B)
11/22/2010	Kansas City Power & Light (KS)	8.37	10	49.66	9/09-YE	21.8
12/1/2010	Entergy Texas (TX)	8.52	10.13	---	41069	68 (B,I,Z)
12/6/2010	Baltimore Gas & Electric (MD)	8.06	9.86	51.93	7/10-A	31
12/9/2010	NorthWestern Corp. (MT)	7.8	10	48	12/08-A	6.5 (D,B,I,E)
12/15/2010	Interstate Power & Light (IA)	---	10	---	12/09-A	114.5 (I,10)
12/13/2010	Dominion North Carolina Power (NC)	8.22	10.7	51	12/08-YE	3.1 (B)
12/14/2010	PacifiCorp (OR)	8.08	10.13	51	12/11-A	84.6 (B)
12/17/2010	Portland General Electric (OR)	8.03	10	50	12/11-A	100.2 (B)
12/20/2010	Sierra Pacific Power (NV)	8.06	10.6	44.11	12/09-YE	13.1
12/21/2010	Upper Peninsula Power (MI)	7.12	10.3	50.42 *	---	8.9 (B)
12/21/2010	PECO Energy (PA)	---	---	---	41253	225 (D,B)
12/21/2010	PPL Electric Utilities (PA)	---	---	---	41253	77.5 (D,B)
12/21/2010	PacifiCorp (UT)	---	---	---	---	33.3 (B,11)
12/27/2010	PacifiCorp (ID)	7.98	9.9	52.1	12/09-A	13.8
12/29/2010	Georgia Power (GA)	---	11.15	---	---	562.3 (B)
12/30/2010	Georgia Power (GA)	---	---	---	41254	223 (12)
2010	**YEAR AVERAGES/TOTAL**	**7.99**	**10.34**	**48.45**		**5,567.7**
	MEDIAN	**8.06**	**10.25**	**49.36**		
	OBSERVATIONS	**59**	**59**	**54**		**77**

FOOTNOTES

A- Average

B- Order followed stipulation or settlement by the parties. Decision particulars not necessarily precedent-setting or specifically adopted by the regulatory body.

Bp- Order followed partial stipulation or settlement by the parties. Decision particulars not necessarily precedent-setting or specifically adopted by the regulatory body.

CWIP- Construction work in progress

D- Applies to electric delivery only

DC- Date certain

E- Estimated

Hy- Hypothetical capital structure

I- Interim rates implemented prior to the issuance of final order, normally under bond and subject to refund.

M- "Make-whole" rate change based on return on equity or overall return authorized in previous case.

R- Revised

YE- Year-end

Z- Rate change implemented in multiple steps.

* Capital structure includes cost-free items or tax credit balances at the overall rate of return.

(1) While the authorized rate increase is based on a 10.7% ROE, the settlement specifies that the company is permitted to earn up to an 11% ROE.

(2) The permanent rate increase includes a $126.2 million increase that was authorized by the PSC on 5/19/09 in a separate proceeding related to the repowering of the Bartow generating plant. The company had also requested recovery of the Bartow repowering costs in this base rate proceeding. In addition, the $126.2 million Bartow-related increase, when adjusted for 2010 billing determinants, increases to $132.1 million.

(3) Authorized 11.9% ROE includes an 11.3% base ROE and a 60-basis-point management efficiency premium.

(4) Parameters apply to rider for the Virginia City Hybrid Energy Center, and the specified ROE includes an 11.3% base equity return and a 100-basis-point premium.

(5) Parameters apply to rider for the Bear Garden generation facility, and the specified ROE includes an 11.3% base equity return and a 100-basis-point premium.

(6) Case is a limited-issue proceeding involving PacifiCorp's incremental investment in a transmission line and an environmental upgrade project.

(7) The rate increase is effective retroactive to 7/1/10.

(8) The 2010 rate increase is effective retroactive to 8/25/10.

(9) Authorized rate increase represents a current cash return on incremental V.C. Summer nuclear plant CWIP. The increase incorporates a previously authorized 11% ROE and incremental CWIP of $399.1 million as of June 30, 2010.

2011 Major Electric Rate Case Summary from Regulatory Research Associates

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
1/5/2011	Public Service Co. of Oklahoma (OK)	8.17	10.15	45.84	2/10-YE	30.3 (B)
1/12/2011	Madison Gas and Electric (WI)	8.77	10.3	58.06	12/11-A	8
1/13/2011	Wisconsin Public Service (WI)	7.86	10.3	51.65	12/11-A	21
1/18/2011	Delmarva Power & Light (DE)	7.61	10	47.52	3/09-A	16.4 (I,D)
1/20/2011	Niagara Mohawk Power (NY)	6.51	9.3	48	12/11-A	119.3 (D)
1/20/2011	Texas-New Mexico Power (TX)	9.9	10.13	45	3/10-YE	8.3 (D,B,Hy,1)
1/31/2011	Western Massachusetts Electric (MA)	7.63	9.6	50.7	12/09-YE	16.8 (D)
2/3/2011	CenterPoint Energy Houston Elec. (TX)	8.21	10	45	12/09-YE	14.7 (D,Hy,2)
2/24/2011	Duquesne Light (PA)	---	---	---	3/11	45.7 (D,B)
2/25/2011	Hawaiian Electric (HI)	8.16	10	55.81	12/09-A	66.4 (I,B)
3/22/2011	Virginia Electric and Power (VA)	8.76	12.3	49.37	3/12-A	44.7 (I,3)
3/22/2011	Virginia Electric and Power (VA)	8.76	12.3	49.37	3/12-A	13.8 (I,4)
3/25/2011	Southwestern Public Service (TX)	---	---	---	12/09	52.5 (B,Z)
3/25/2011	PacifiCorp (WA)	7.81	9.8	49.1 Hy	12/09-A	33.5
3/30/2011	Appalachian Pwr./Wheeling Pwr. (WV)	7.36	10	42.2	12/09-A	119.1 (B)
4/12/2011	Kansas City Power & Light (MO)	8.58	10	46.3	12/09-YE	34.8
4/25/2011	Otter Tail Power (MN)	8.61	10.74	51.7	12/09-A	5 (I)
4/26/2011	Unitil Energy Systems (NH)	8.39	9.67	45.45	---	6.6 (D,I,B,Z)
4/27/2011	Southern Indiana Gas & Electric (IN)	7.29	10.4	43.46 *	6/09-YE	28.6
5/4/2011	KCP&L Greater Missouri Op. (MPS) (MO)	8.41	10	46.58	12/09-YE	35.7 (R)
5/4/2011	KCP&L Greater Missouri Op. (L&P) (MO)	8.41	10	46.58	12/09-YE	29.8 (R,Z)
5/13/2011	Pacific Gas and Electric (CA)	---	---	---	12/11-A	698 (B,Z)
5/24/2011	Commonwealth Edison (IL)	8.51	10.5	47.28	12/09-YE	155.7 (D)
6/1/2011	Empire District Electric (MO)	---	---	---	6/09	18.7 (B)
6/8/2011	MDU Resources (ND)	8.74	10.75	53.34	12/10	7.6 (B)
6/16/2011	Orange and Rockland Utilities (NY)	7.22	9.2	48	6/12-A	26.6 (D)
6/17/2011	Oklahoma Gas & Electric (AR)	5.93	9.95	34.9 *	12/09-YE	8.8 (B)
7/8/2011	Delmarva Power & Light (MD)	---	---	---	12/10	12.2 (D,B)
7/13/2011	Union Electric (MO)	8.13	10.2	52.24	3/10-YE	173.2
8/1/2011	Fitchburg Gas & Electric (MA)	7.93	9.2	42.88	12/09-YE	3.3 (D)
8/2/2011	MDU Resources (MT)	---	---	---	---	2.6 (B)
8/8/2011	Public Service Co. of New Mexico (NM)	8.41	10	51.28	6/10-YE	72.1 (B)
8/11/2011	PacifiCorp (UT)	7.94	10	51.9	6/12	117 (B)
8/12/2011	Interstate Power and Light (MN)	8.11	10.35	47.74	12/09-A	8.4 (I,R)
8/19/2011	Oncor Electric Delivery (TX)	8.14	10.25	40	6/10-YE	136.7 (D,Hy,B)
9/22/2011	PacifiCorp (WY)	8	10	52.3	12/11-A	61.3 (B)
9/30/2011	Avista Corp. (ID)	---	---	---	12/10	2.8 (B)
9/30/2011	South Carolina Electric & Gas (SC)	---	---	---	6/11-YE	52.8 (5)
10/6/2011	Wisconsin Electric Power (WI)	---	---	---	12/12	0 (6)
10/12/2011	Kentucky Utilities (VA)	7.24	10.3	53.37	12/10-A	6.6 (B)
10/20/2011	Detroit Edison (MI)	6.59	10.5	40.26 *	3/12-A	187.5 (R)
11/30/2011	Appalachian Power (VA)	7.82	10.9	42.69	12/10-YE	55.1
11/30/2011	Virginia Electric and Power (VA)	---	10.9	---	---	--- (7)
12/14/2011	Columbus Southern Power (OH)	7.78	10	50.64 (E)	5/11-DC	0 (D,B)
12/14/2011	Ohio Power (OH)	7.97	10.3	53.79 (E)	5/11-DC	0 (D,B)
12/16/2011	Avista Corp. (WA)	---	---	---	---	20 (B)
12/20/2011	Upper Peninsula Power (MI)	6.25	10.2	45.74 *	12/12	4 (B)
12/21/2011	Northern Indiana Public Service (IN)	6.98	10.2	46.53 *	6/10-YE	7 (B)
12/22/2011	Black Hills Colorado Elec. Utility Co. (CO)	8.53	9.9	49.1	12/10-A	10.5
12/22/2011	Northern States Power-Wisconsin (WI)	8.52	10.4	52.59	12/12-A	12.2
12/23/2011	Nevada Power (NV)	8.17 (8)	10.19 (8)	44.38	12/10-YE	158.6
12/28/2011	Georgia Power (GA)	---	---	---	12/12	35.6 (9)
12/28/2011	Southwestern Public Service (NM)	---	---	---	---	13.5 (B)
12/30/2011	Idaho Power (ID)	7.86	---	---	12/11	34 (B)
2011	**YEAR AVERAGES/TOTAL**	**7.95**	**10.22**	**47.97**		**2,853.5**
	MEDIAN	**8.11**	**10.15**	**47.87**		
	OBSERVATIONS	**41**	**41**	**40**		**53**

FOOTNOTES

A- Average

B- Order followed stipulation or settlement by the parties. Decision particulars not necessarily precedent-setting or specifically adopted by the regulatory body.

CWIP- Construction work in progress

D- Applies to electric delivery only

DC- Date certain

E- Estimated

Hy- Hypothetical capital structure utilized

I- Interim rates implemented prior to the issuance of final order, normally under bond and subject to refund.

M- "Make-whole" rate change based on return on equity or overall return authorized in previous case.

YE- Year-end

Z- Rate change implemented in multiple steps.

* Capital structure includes cost-free items or tax credit balances at the overall rate of return.

(1) The approved stipulation also calls for a $2 million transmission rate increase based on the same return parameters as the $8.3 million distribution increase. Consequently, the aggregate increase was $10.3 million.

(2) Commission decision also required a $12.2 million transmission rate decrease. Thus, in aggregate, rates were increased by $2.5 million.

(3) Proceeding is annual update to Rider S, through which the company is permitted to recognize incremental investment in Virginia City Hybrid Energy Center. The requested ROE is equal to the 11.3% base ROE adopted by the Commission in the company's most recent base rate case, plus a 100-basis-point adder as approved by the Commission, when it granted the company a certificate of convenience and necessity for the plant. The ROE premium is to remain effective through the first 10 years of the plant's useful life.

(4) Proceeding is annual update to Rider R, through which the company is permitted to recognize incremental investment in Bear Garden generation facility. The requested ROE is equal to the 11.3% base ROE adopted by the Commission in the company's most recent base rate case, plus a 100-basis-point adder as approved by the Commission, when it granted the company a certificate of convenience and necessity for the plant. The ROE premium is to remain effective through the first 10 years of the plant's useful life.

(5) Authorized rate increase represents a current cash return on incremental V.C. Summer nuclear plant CWIP. The increase incorporates a previously authorized 11% ROE and incremental CWIP of $436.7 million as of 6/30/11.

(6) Company requested no change in base rates for 2012 if the Commission adopted certain company proposals. The Commission adopted the proposals.

(7) Commission determined that for the company's next biennial review period, which will cover 2011 and 2012, a 10.9% ROE will apply. This ROE includes a 10.4% base ROE and a 50-basis point premium for achieving certain voluntary renewable portfolio targets.

(8) Reflects blended returns after consideration of incentives. Without incentives, a 10% ROE and an 8.09% ROR were authorized.

(9) The authorized $35.6 million rate increase represents the recovery of a cash return on incremental 2012 CWIP and a preliminary true-up of the cash return on 2011 CWIP for Plant Vogtle Units 3 and 4 under the company's legislatively enabled nuclear construction cost recovery tariff. The requested and

Q1-Q3 2012 Major Electric Rate Case Summary from Regulatory Research Associates

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
1/3/2012	Appalachian Power (VA)	---	11.4	---	2/13-YE	26.1 (B,1)
1/10/2012	PacifiCorp (ID)	---	---	---	12/10	34 (B,Z)
1/25/2012	Duke Energy Carolinas (SC)	8.1	10.5	53	12/10-YE	92.8 (B)
1/27/2012	Duke Energy Carolinas (NC)	8.11	10.5	53	12/10-YE	368 (B,2)
2/2/2012	Virginia Electric and Power (VA)	8.77	11.4	53.25	3/13-A	34.1 (3)
2/15/2012	Indiana Michigan Power (MI)	6.84	10.2	42.07 *	12/12-A	14.6 (B)
2/23/2012	Idaho Power (OR)	7.76	9.9	49.9	12/11-A	1.8 (B)
2/22/2012	Florida Power (FL)	---	---	---	---	150 (B,4)
2/27/2012	Gulf Power (FL)	6.39	10.25	38.5 *	12/12-A	68.1 (I,Z)
2/29/2012	Northern States Power-Minnesota (ND)	---	10.4	---	12/11	15.7 (B,I,Z)
3/16/2012	Virginia Electric and Power (VA)	9.03	12.4	53.25	3/13-A	6.4 (5)
3/20/2012	Virginia Electric and Power (VA)	8.48	11.4	53.25	3/13-A	-4.3 (6)
3/21/2012	NorthWestern Corp. (MT)	---	---	---	A	39.1 (I,Z,7)
3/23/2012	Virginia Electric and Power (VA)	8.48	11.4	53.25	3/13-A	46.8 (8)
3/29/2012	Northern States Power-Minnesota (MN)	8.32	10.37	52.56	12/11-A	72.9 (B,I,Z)
3/30/2012	PacifiCorp (WA)	7.74	---	---	12/10	4.5 (B)
4/4/2012	Hawaii Electric Light Company (HI)	8.31	10	55.91	12/10-A	4.5 (I,B)
4/18/2012	Westar Energy/Kansas Gas & Elec. (KS)	---	---	---	3/11	50 (B,9)
4/26/2012	Public Service Co. of Colorado (CO)	8.08	10	56	---	234.4 (B,Z)
5/2/2012	Maui Electric Company (HI)	8.15	10	56.86	12/10-A	4.7 (I,B)
5/7/2012	Puget Sound Energy (WA)	7.8	9.8	48 (Hy)	12/10-A	63.3
5/15/2012	Arizona Public Service (AZ)	8.33	10	53.94	12/10-YE	0 (B)
5/18/2012	El Paso Electric (TX)	---	---	---	9/11	-15 (B)
5/29/2012	Commonwealth Edison (IL)	8.16	10.05	46.17	12/10-YE	-168.6 (D)
6/7/2012	Consumers Energy (MI)	6.7	10.3	42.07 *	9/12-A	118.5 (I)
6/14/2012	Orange and Rockland Utilities (NY)	7.61	9.4	48	6/13-A	19.4 (B,D,10)
6/15/2012	Wisconsin Power and Light (WI)	---	10.4	49.31	12/13-A	0 (11)
6/18/2012	Cheyenne Light, Fuel and Power (WY)	7.99	9.6	54	8/11-YE	2.7 (B)
6/19/2012	Northern State Power-Minnesota (SD)	7.79	9.25	53.04	12/10-A	8 (I)
6/26/2012	Wisconsin Electric Power (MI)	6.35	10.1	43.51 *	12/12-A	9.2 (I)
6/29/2012	Hawaiian Electric Company (HI)	8.11	10	56.29	12/11-A	43.1 (I,B,12)
6/29/2012	Idaho Power (ID)	---	---	---	12/12	58.1 (13)
7/9/2012	Oklahoma Gas & Electric (OK)	---	10.2	---	12/10-YE	4.3 (B)
7/16/2012	PacifiCorp (WY)	7.67	9.8	52.1	3/13-A	50 (B,Z)
7/20/2012	Delmarva Power & Light (MD)	7.56	9.81	50.06	12/11-A	11.3 (D)
7/20/2012	Potomac Electric Power (MD)	7.96	9.31	50.13	12/11-A	18.1 (D)
9/13/2012	Entergy Texas (TX)	8.27	9.8	49.92	6/11-YE	27.7
9/19/2012	Ameren Illinois (IL)	8.86	10.05	51.49	12/10-YE	-48.1 (D,14)
9/19/2012	PacifiCorp (UT)	7.68	9.8	52.1	5/13	154 (B,Z)
9/20/2012	Idaho Power (OR)	7.76	---	---	12/11-A	3 (15)
9/26/2012	Potomac Electric Power (DC)	8.03	9.5	49.23	9/11-A	24 (D)
9/26/2012	South Carolina Electric & Gas (SC)	8.75	---	54.28	6/12-YE	52.1 (16)
	2012 YEAR AVERAGES/TOTAL	**7.94**	**10.22**	**50.79**		**1,699.3**
	MEDIAN	**8.06**	**10.05**	**52.1**		
	OBSERVATIONS	**32**	**33**	**31**		**42**

FOOTNOTES

A- Average

B- Order followed stipulation or settlement by the parties. Decision particulars not necessarily precedent-setting or specifically adopted by the regulatory body.

CWIP- Construction work in progress

D- Applies to electric delivery only

E- Estimated

Hy- Hypothetical capital structure utilized

I- Interim rates implemented prior to the issuance of final order, normally under bond and subject to refund.

YE- Year-end

Z- Rate change implemented in multiple steps.

* Capital structure includes cost-free items or tax credit balances at the overall rate of return.

(1) Rate increase authorized through a generation rider/adjustment clause.

(2) The approved/stipulated $368 million base rate increase includes $51 million that the company is to defer until its next rate case, representing a cash return on construction work in progress.

(3) Increase authorized through a surcharge, Rider W, which reflects in rates the investment in the Warren County Power Station and associated transmission facilities.

(4) PSC adopted a settlement that addresses base rates and issues related to the company's nuclear plants. Effective January 2013, the company is to increase base rates by $150 million, and base rates would then be frozen through 2016, except as otherwise provide for by the settlement.

(5) Increase authorized through a surcharge (Rider B) related to generation conversion project investments.

(6) Rate change approved through surcharge (Rider R) related to the Bear Garden Generating Station.

(7) Case is a limited-issue rate proceeding, covering NorthWestern's incremental investment in the Dave Gates (formerly Mill Creek) generating facility.

(8) Increase authorized through a surcharge, Rider S, associated with the Virginia City Hybrid Energy Center.

(9) Authorized base rate increase is $104.3 million after the transfer to base rates, from a rider, of $54.3 million of certain environmental compliance costs.

(10) Approved Joint Proposal includes three-year rate plan specifying $19.4 million, $8.8 million, and $15.2 million rate increases, based upon 9.4%, 9.5%, and 9.6% ROEs, respectively. A levelized plan was adopted, whereby rates in each of the three years are to be increased by $15.2 million.

(11) PSC adopted the company's proposal to freeze base rates for 2013 and 2014.

(12) Rate increase excludes amounts being recovered through the company's alternative regulation framework.

(13) The rate increase reflects the recovery of the company's investment in the Langley Gulch natural gas-fired combined cycle plant. The rate request and authorization are premised upon the 7.86% overall return authorized in the company's last rate case that was decided on 12/30/11.

(14) This proceeding is a formula rate plan (FRP) filing made pursuant to legislation that requires the state's large electric utilities to invest specific amounts in their transmission and distribution systems, with recovery of these investments to occur in annual FRP proceedings, subject to Commission approval.

(15) The rate increase reflects the recovery of the company's investment in the Langley Gulch natural gas-fired combined cycle plant. The rate request and authorization are premised upon the 9.9% ROE and 7.757% ROR authorized in the company's last rate case that was decided on 2/23/12.

EXHIBIT KCH-14

AECC New Corporate Headquarters Building Return Adjustment

Description	FERC Account	ACC Jurisdiction Average 2012 Net Book Value[1]	ACC Jurisdiction Return at AECC Recommended WACC[2] 7.2082%	ACC Jurisdiction Return at 2012 Average Cost of Debt[3] 5.0400%	ACC Jurisdiction Headquarters Return Adjustment -2.1682%
Software-LN-Downtown Bldg	303	38,778	2,795	1,954	(841)
Land-Downtown	389	6,249,252	450,459	314,962	(135,497)
Str&Impr-EN-Downtown	390	50,659,615	3,651,651	2,553,245	(1,098,407)
Computer Eq-Downtown	391	9,196,259	662,886	463,491	(199,394)
Comm Eq-AZ-Downtown	397	244,600	17,631	12,328	(5,303)
Misc Eq-Downtown	398	35,645	2,569	1,797	(773)
Total		**66,424,148**	**4,787,992**	**3,347,777**	**(1,440,215)**

ACC Jurisdiction Return Adjustmei	**($1,440,215)**
Gross Revenue Conversion Factor	**1.6590**
Revenue Requirement Impact	**($2,389,251)**

1. Data Source: Average 2012 Rate Base Balance derived from Attachment to TEP's Response to AECC 11.8(c) (Confidential)
2. Note: AECC recommended WACC, based on average 2012 capital structure, cost of debt, and AECC recommended ROE. See AECC Exhibit KCH-1, p. 3.
3. Note: AECC recommended cost of debt based on the average of TEP's cost of long term debt on 12/31/11 (actual) and 12/31/12 (projected), reported in TEP Schedule D.

EXHIBIT KCH-15

AECC Adjustment to Remove Renewable Plant Revenue Requirement Above the Market Cost of Comparable Conventional Generation

Line No.	Description	Amount
1	TEP Annual Revenue Requirement for Post-Test Year Renewable Generation	$2,117,908
2	AECC Recommended Disallowance for Costs Above MCCCG (%)	50.0%
3	AECC Recommended Disallowance	($1,058,954)

**TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
AECC'S EIGHTEENTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
December 18, 2012**

AECC 18.2

Post-Test Year Plant – Renewables - Assume that the ACC determines that only that portion of the S18.4 million that is not in excess of the market cost of generation is eligible for inclusion in base rates. What is that amount for the ACC jurisdiction? Please provide any workpapers responsive to this request in Excel format with formulas intact.

RESPONSE:

Please see TEP's response to AECC 18.1. Market Cost of Comparable Conventional Generation ("MCCCG") is not applicable to post-test-year capital expenditures for additional plant.

RESPONDENT:

Pricing (David Lewis) and Carmine Tilghman

WITNESS:

David Hutchens

TEP Solar Project
In Service By December 2012
Revenue Requirement

Assumptions	
5,000	System Size kW
$ 4,044	Cost per kW
$ 20,220,500	Original Cost
20	Asset Life
50,000	O&M First Year
3%	O&M Escalation Factor
40%	Income Tax Rate
7.74%	Nominal Return
10.99%	Pre-tax Return
6.64%	After-tax Return
	Capital Structure:
54.00%	Debt
46.00%	Equity
	Cost of Capital:
5.18%	Debt
10.75%	Equity
0.00%	AZ PTC benefit to ratepayers
1	In Service Period (1 = End of Year, 2 = Start of Year)
2012	In Service Year

Book depreciation	$	84,252	
Tax depreciation	$	10,312,455	
Net book basis (end of year)	$	20,136,248	
Tax basis (end of year)	$	6,874,970	
ADIT (end of year) ((book basis minus tax basis) times tax rate)	$	477,450	
Long-term debt balance (end of year)	$	4,977,276	
LT Debt Interest			
Rate Base, end of year			
Gross plant	$	20,220,500	
Accum. deprec	$	(84,252)	
ADIT	$	(5,459,535)	
Unamortized ITC	$	(5,459,535)	
Rate Base, end of year	$	9,217,178	
Revenue Requirement			
Carrying Costs	$	1,012,628	
Book depreciation	$	1,011,025	
Property tax expense	$	-	
O & M	$	50,000	
Lease Expense	$	44,255	
AZ PTC benefit to ratepayers	$	-	
Gross Revenue Requirement	$	2,117,908	(1)
	$	**1,411,938.97**	(2)

1) This is the gross yearly Revenue Requirement recoverable through REST

2) This is the amount recoverable through REST assuming new rates go in to affect September 2012. (As filed in 2013 REST Budget)

Source: TEP Attachment AECC 18.4.xlsx

Derivation of Post-Test Year Renewable Plant Unit Cost

Line No.	Description	Amount
1	TEP Annual Revenue Requirement for Post-Test Year Renewable Generation	$2,117,908
2	Size of System (MW)	5.0
3	Assumed Capacity Factor (%)	35.0%
4	TEP Post-Test Year Renewable Generation Cost per Unit ($/MWh)	$138.15

Source: TEP Attachment AECC 18.4.xlsx

CONFIDENTIAL EXHIBIT KCH-16

**TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
AECC'S EIGHTEENTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
December 18, 2012**

AECC 18.5

Post-Test Year Plant – Renewables - What is the market cost of generation, as defined in Arizona Administrative Code R14-2-1801.K, that TEP used for its 2013 REST filing?

RESPONSE:

THE FILE LISTED BELOW CONTAINS CONFIDENTIAL INFORMATION AND IS BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.

Please see AECC 18.5-Confidential.pdf, Bates Nos. TEP\030175-030176, for the requested information.

RESPONDENT:

Pricing (David Lewis) and Carmine Tilghman

WITNESS:

David Hutchens

The following Confidential information can be found in Exhibit 6 of TEP's 2013 Renewable Implementation Plan.

MCCCG ($/MWh)	2012	2013	2014	2015	2016
Solar PV					
AZ Wind					
Biomass			REDACTED		
NM Wind					
Solar CSP					

Source: TEP Attachment AECC 18.5-Confidential.pdf