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BEFORE THE ARIZONA CORPORATION COMMISSION

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AZ CORP COMMISSION
DOCKET CONTROL

COMMISSIONERS
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BRENDA BURNS

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.

DOCKET NO. E-01933A-12-0291

STAFF'S NOTICE OF FILING DIRECT TESTIMONY

The Utilities Division ("Staff") of the Arizona Corporation Commission ("Commission") hereby submits the Direct Testimony of Staff witnesses Ralph Smith, S. Keith Berry, Michael J. McGarry, Michael Lewis, Emily Medine and Howard S. Solganick (Public) in the above-referenced matter.

A confidential version of Ralph Smith, Michael McGarry, Michael Lewis, and Emily Medine's Direct Testimony will be provided under seal to the Commissioners, their Assistants, the assigned Administrative Law Judge, and the parties that have signed the Protective Agreement in this case.

RESPECTFULLY SUBMITTED this 21st day of December, 2012.

Arizona Corporation Commission
DOCKETED
DEC 21 2012
DOCKETED BY

Robin R. Mitchell, Staff Attorney
Charles H. Hains, Staff Attorney
Brian E. Smith, Staff Attorney
Legal Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007
(602) 542-3402

...

...

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

Copies of the foregoing were mailed and/or
emailed this 21st day of December, 2012 to:

Bradley S. Carroll
Tucson Electric Power Company
88 E. Broadway Blvd., MS HQE910
P.O. Box 711
Tucson, Arizona 85702
Attorney for Tucson Electric Power
bcarroll@tep.com

Michael W. Patten
ROSHKA DEWULF & PATTEN, PLC
One Arizona Center
400 East Van Buren Street, Suite 800
Phoenix, Arizona 85004
Attorney for Tucson Electric Power
mpatten@rdp-law.com

Lawrence V. Robertson, Jr.
Attorney at Law
P.O. Box 1448
Tubac, Arizona 85646
Attorney for Southern Arizona Homebuilders
Association (SAHBA) and
EnerNOC, Inc. and Southern Arizona Water
Users Association (SAWUA)
TubacLawyer@aol.com

Daniel Pozefsky
Chief Counsel
Residential Utility Consumer Office
1110 West Washington, Suite 220
Phoenix, Arizona 85007
dpozefsky@ruco.gov

C. Webb Crockett
Patrick J. Black
FENNEMORE CRAIG, P.C.
3003 North Central Avenue
Suite 2600
Phoenix, Arizona 85012-2913
Attorneys for Freeport-McMoRan
and AECC
wcrockett@fclaw.com
pblack@fclaw.com

Kevin C. Higgins, Principal
Energy Strategies, LLC
215 South State Street
Suite 200
Salt Lake City, Utah 84111
Consultant to Freeport-McMorRan
and AECC
KHiggins@Energystrat.com

Kurt J. Boehm
Jody M. Kyler
BOEHM, KURTZ & LOWRY
36 East Seventh Street, Suite 1510
Cincinnati, Ohio 45202
Attorneys for Kroger
kboehm@BKLlawfirm.com
jkyler@BKLlawfirm.com

John William Moore, Jr.
MOORE, BENHAM & BEAVER
7321 North 16th Street
Phoenix, Arizona 85020
Attorney for Kroger Co.
jmoore@mbmblaw.com

Stephen J. Baron
J. Kennedy & Associates
570 Colonial Park Drive, Suite 305
Roswell, Georgia 30075
Consultant to Kroger Co.
sbaron@jkenn.com

Thomas L. Mumaw
Melissa Krueger
Pinnacle West Capital Corporation
P.O. Box 53999, MS 8695
Phoenix, Arizona 85072-3999
Thomas.Mumaw@pinnaclewest.com
Melissa.Krueger@pinnaclewest.com

Leland Snook
Zachary J. Fryer
Arizona Public Service Company
P.O. Box 53999, MS 9708
Phoenix, Arizona 85072-3999
Leland.Snook@aps.com
Zachary.Fryer@aps.com

Timothy M. Hogan
ARIZONA CENTER FOR LAW IN THE PUBLIC INTEREST
202 E. McDowell Road, Suite 153
Phoenix, Arizona 85004
Attorneys for SWEEP and Vote Solar Initiative
thogan@aclpi.org

Jeff Schlegel
SWEEP Arizona Representative
1167 W. Smalayuca Drive
Tucson, Arizona 85704-3224
schlegelj@aol.com

Annie C. Lappe
Rick Gilliam
The Vote Solar Initiative
1120 Pearl Street, Suite 200
Boulder, Colorado 80302
annie@votesolar.org
rick@votesolar.org

Nicholas J. Enoch
Jarrett J. Haskovec
LUBIN & ENOCH, P.C.
349 North Fourth Avenue
Phoenix, Arizona 85003
Attorneys for IBEW Local 1116
Nick@lubinandenoch.com
Jarrett@lubinandenoch.com

Travis Ritchie
Sierra Club Environmental Law Program
85 Second St., 2nd Floor
San Francisco, CA 94105
Attorney for Sierra Club
travis.ritchie@sierraclub.org

Terrance A. Spann
General Attorney
Regulatory Law Office (JALS-RL/IP)
Office of the Judge Advocate General
U.S. Army Legal Services Agency
9275 Gunston Road, Suite 1300
Fort Belvoir, VA 22060-5546
terrance.a.spann.civ@mail.mil

Michael M. Grant
GALLAGHER & KENNEDY, P.A.
2575 East Camelback Road
Phoenix, AZ 85016-9225
Attorneys for AIC
mmg@gknet.com

Gary Yaquinto
President and CEO
Arizona Investment Council
2100 North Central Avenue, Suite 210
Phoenix, AZ 85004
gyaquinto@arizonaic.org

Cynthia Zwick
1940 E. Luke Avenue
Phoenix, AZ 85016
czwick@azcaa.org

Court S. Rich
ROSE LAW GROUP, PC
6613 N. Scottsdale Road, Suite 200
Scottsdale, AZ 85250
Attorney for Solar Energy Industries Association (SEIA)

Michael L. Neary
Executive Director
Arizona Solar Energy Industries Association (AriSEIA)
111 W. Renee Dr.
Phoenix, AZ 85027

BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
Chairman
BOB STUMP
Commissioner
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Commissioner

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

PUBLIC

DIRECT

TESTIMONY

OF

RALPH C. SMITH

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

DECEMBER 21, 2012

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EXECUTIVE SUMMARY
TUCSON ELECTRIC POWER COMPANY
DOCKET NO. E-01933A-12-0291
DIRECT TESTIMONY OF STAFF WITNESS RALPH C. SMITH

My testimony addresses the following issues:

- Tucson Electric Power Company's ("TEP" or "Company") proposed revenue requirement.
- Adjusted rate base
- Adjusted net operating income
- Base cost for fuel and purchased power
- Depreciation rates
- Other issues, including the discontinuance of GreenWatts and some of TEP's adjustments that have been accepted by Staff in this case that warrant additional discussion.

My findings and recommendations for each of these areas are as follows:

- The Company's proposed revenue requirement of a base rate increase of $127.762 million is overstated. On original cost rate base ("OCRB") my calculations show a jurisdictional revenue deficiency of $75.837 million. I recommend that TEP be authorized a base rate increase of $76.406 million. This is near the lower end of the two fair value options that have been calculated. On adjusted fair value rate base ("FVRB") under Staff's option 1, which uses a fair value rate of return of 4.63 percent, I show a revenue increase of $75.405 million. Staff is also presenting the Commission with an option 2 for the fair value rate of return for TEP. Under option 2 the fair value rate of return for TEP is 4.86 percent and the jurisdictional revenue deficiency is approximately $84.036 million. The Testimony of Staff witness Dr. S. Keith Berry addresses the determination of the fair value rate of return.

- The base rate increases of $75.405 million (under option 1) and $84.036 million (under option 2) equate to percentage increase of approximately 9.06 percent and 10.10 percent over TEP's adjusted Electric Retail Revenues at current rates, respectively.

- The following adjustments to TEP's proposed original cost and fair value rate base should be made:

	Summary of Staff Adjustments to Rate Base (Thousands of Dollars)	ACC Jurisdictional Original Cost
Adj. No.	Description	Increase (Decrease)
B-1	Sahuarita-Nogales Transmission Line	$ (11,089)
B-2	Cash Working Capital	$ 787
B-3	Remove One-Half of Prepaid D&O Insurance	$ (117)
B-4	Fuel Inventory - Adjustment for San Juan Coal Price	$ (1,590)
B-5	New Headquarters Building	$ (6,578)
	Total of Staff Adjustments	**$ (18,587)**
	TEP Proposed Rate Base	$ 1,519,073
	Rounding	
	Staff Proposed Rate Base	**$ 1,500,486**

- The following adjustments to TEP's proposed revenues, expenses and net operating income should be made:

	Summary of Staff Adjustments to Net Operating Income (Thousands of Dollars)	ACC Jurisdictional	
Adj.	Description	Pre-Tax Revenue or Expense Adjustment	Net Operating Income Increase (Decrease)
C-1	Sahuarita-Nogales Transmission Line Amortization Expense	$ (2,983)	$ 1,803
C-2	Incentive Compensation (PEP) Program Expense	$ (2,094)	$ 1,265
C-3	Overhaul and Outage Expense	$ (2,514)	$ 1,519
C-4	Interest Synchronization	$ -	$ 427
C-5	Base Cost of Fuel and Purchased Power		$ -
C-6	Rate Case Expense	$ (247)	$ 149
C-7	Directors' and Officers' Liability Insurance Expense	$ (289)	$ 175
C-8	Edison Electric Institute and Industry Association Dues	$ (112)	$ 68
C-9	Property Tax Expense	$ (1,460)	$ 882
C-10	Depreciation and Property Taxes on New Headquarters Building Adjustment	$ (309)	$ 187
C-11	Other Operating Revenue: Reimbursed Operating Expenses for Springerville Units 3 and 4	$ (5,569)	$ 3,365
C-12	Springerville Unit 1 Levelized Expense	$ (13)	$ 8
C-13	Day Nite Design Branding/ Marketing/ General Corporate Advertising	$ (13)	$ 8
C-14	Lime Expense	$ 5,076	$ (3,067)
Total of Staff's Adjustments		**$ (10,527)**	**$ 6,789**
	Adjusted Net Operating Income per TEP		$ 52,472
	Adjusted Net Operating Income per Staff		$ 59,261

- The new depreciation rates proposed by TEP presented in Dr. White's Direct Testimony Exhibit REW-1 for production, distribution and general plant and cost of removal should be adopted for use in this case. The new depreciation rates proposed by TEP for production, distribution and general plant were generally developed in a manner that is consistent with the Commission's rules for depreciation rates. As noted above, the depreciation rates for production plant include a component for dismantlement based on TEP's dismantlement studies. The depreciation rates developed by Dr. White include a cost of removal component and include the impacts of plant specific dismantlement studies that were prepared for TEP by other consultants.

- Staff recommends that TEP report to the Commission no later than July 31, 2014, the status of the Springerville Unit 1 leases, and in that report present a proposal for accounting protection of ratepayers, such as tracking as a regulatory liability, if the Springerville Unit 1 costs will be lower than currently reflected in rates under the levelized lease cost treatment. The timing of this report by TEP is intended to allow Staff and other interested parties to review TEP's proposal and bring this matter to the Commission's attention before the leases expire in January 2015.

I. INTRODUCTION

Q. Please state your name, position and business address.

A. Ralph C. Smith. I am a Senior Regulatory Consultant at Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

Q. Please describe Larkin & Associates.

A. Larkin & Associates is a Certified Public Accounting and Regulatory Consulting firm. The firm performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.). Larkin & Associates has extensive experience in the utility regulatory field as expert witnesses in over 600 regulatory proceedings including numerous telephone, water and sewer, gas, and electric matters.

Q. Mr. Smith, please summarize your educational background.

A. I received a Bachelor of Science degree in Business Administration (Accounting Major) with distinction from the University of Michigan - Dearborn, in April 1979. I passed all parts of the Certified Public Accountant ("C.P.A.") examination in my first sitting in 1979, received my CPA license in 1981, and received a certified financial planning certificate in 1983. I also have a Master of Science in Taxation from Walsh College, 1981, and a law degree (J.D.) cum laude from Wayne State University, 1986. In addition, I have attended a variety of continuing education courses in conjunction with maintaining my accountancy license. I am a licensed C.P.A. and attorney in the State of Michigan. I am also a Certified Financial Planner™ professional and a Certified Rate of Return Analyst ("CRRA"). Since 1981, I have been a member of the Michigan Association of Certified Public Accountants. I am also a member of the Michigan Bar Association and the Society of Utility and Regulatory Financial Analysts ("SURFA"). I have also been a member of

the American Bar Association ("ABA"), and the ABA sections on Public Utility Law and Taxation.

Q. Please summarize your professional experience.

A. Subsequent to graduation from the University of Michigan, and after a short period in which I installed a computerized accounting system for a Southfield, Michigan realty management firm, I accepted a position as an auditor with the predecessor CPA firm to Larkin & Associates in July 1979. Before becoming involved in utility regulation where the majority of my time for the past 33 years has been spent, I performed audit, accounting, and tax work for a wide variety of businesses that were clients of the firm.

During my service in the regulatory section of our firm, I have been involved in rate cases and other regulatory matters concerning numerous electric, gas, telephone, water, and sewer utility companies. My present work consists primarily of analyzing rate case and regulatory filings of public utility companies before various regulatory commissions, and, where appropriate, preparing testimony and schedules relating to the issues for presentation before these regulatory agencies.

I have performed work in the field of utility regulation on behalf of industry, state attorneys general, consumer groups, municipalities, and public service commission staffs concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Indiana, Illinois, Kansas, Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Carolina, North Dakota, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Vermont, Virginia,

Washington, Washington D.C., West Virginia and Canada as well as the Federal Energy Regulatory Commission and various state and federal courts of law.

Q. Have you prepared an attachment summarizing your educational background and regulatory experience?

A. Yes. Attachment RCS-1 provides details concerning my experience and qualifications.

Q. On whose behalf are you appearing?

A. I am appearing on behalf of the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff ("Staff").

Q. Have you previously testified before the Arizona Corporation Commission?

A. Yes. I have previously testified before the Commission on a number of occasions. I testified before the Commission in Docket No. E-01345A-06-0009, involving an emergency rate increase request by Arizona Public Service Company ("APS" or "Company"), and APS' Docket Nos. E-01345A-05-0816, E-01345A-05-0826, E-01345A-05-0827, and E-01345A-08-0172 concerning proceedings involving APS base rates and other matters. I testified before the Commission in the Arizona-American Water Company in Docket Nos. W-01303A-09-0343 and SW-01303A-09-0343. I also testified before the Commission in the last UNS Gas, Inc. rate case, Docket No. G-04204A-11-0158, as well as Docket Nos. G-04204A-08-0571, G-04204A-06-0463, G-04204A-06-0013 and G-04204A-05-0831. Additionally, I presented testimony the UNS Electric, Inc. rate case Docket No. E-04204A-06-0783, as well as the Southwest Gas Corporation rate cases G-01551A-07-0504 and G-01551A-10-0458. I also submitted testimony in Docket No. E-01933A-07-0402, Tucson Electric Power's ("TEP") last rate case.

Q. What is the purpose of the testimony you are presenting?

A. The purpose of my testimony is to address the revenue requirement and selected other issues, including new depreciation rates proposed by Tucson Electric Power Company ("TEP" or "Company").

Q. Have you prepared any exhibits to be filed with your testimony?

A. Yes. Attachments RCS-2 through RCS-6 contain the results of my analysis and copies of selected documents that are referenced in my testimony.

II. REVENUE REQUIREMENT

Q. What issues are addressed in your testimony?

A. My testimony addresses the Company's proposed revenue requirement and selected other issues.

A. Summary of Company Proposed and Staff Adjusted Revenue Requirement

Q. What did your review of TEP's filing indicate?

A. As shown on Attachment RCS-2, Schedule A, based on the fair value rate of return ("FVROR") recommended by Staff witness Dr. S. Keith Berry and the adjustments to TEP's rate base and net operating income recommended by myself and other Staff witnesses, I have calculated a jurisdictional base rate revenue requirement deficiency on original cost rate base ("OCRB") of $75.837 million. TEP should be authorized a base rate increase of no more than $76.406 million which is within the range, and near the lower end of the range of the two fair value options calculated by Staff. On adjusted fair value rate base ("FVRB") under Staff's option 1, which uses a FVROR of 4.63 percent, a revenue deficiency of $75.405 million results. Under option 2, the FVROR for TEP is 4.86 percent, and the jurisdictional revenue deficiency is approximately $84.036 million.

Q. What revenue increase does Staff recommend?

A. Staff recommends a revenue increase of no more than $76.406 million on adjusted fair value rate base. As shown on Schedule A, on OCRB my calculations show a jurisdictional revenue deficiency of $75.837 million. I recommend that TEP be authorized a base rate increase of $76.406 million on adjusted FVRB. This is near the bottom of the range of the two fair value options calculated by Staff. Staff's fair value option 1, which uses a FVROR of 4.63 percent, produces a jurisdictional revenue deficiency of $75.405. Under option 2 the fair value rate of return for TEP is 4.86 percent, and the jurisdictional revenue deficiency is approximately $84.036 million.

The base rate increases of $75.405 million (under option 1) and $84.036 million (under option 2) equate to percentage increase of approximately 9.06 percent and 10.10 percent over TEP's adjusted Electric Retail Revenues at current rates, respectively. Attachment RCS-2, Schedule D, shows the development of Staff's recommended fair value rate of return to be applied to FVRB. The testimony of Staff witness Berry also addresses the determination of the fair value rate of return.

B. Return on Fair Value Rate Base

Q. In TEP's last rate case, was the Company awarded an additional revenue increase based on an enhancement to the return on equity represented by an incremental return on FVRB?

A. No. In TEP's last rate case, Docket No. E-01933A-07-0402, the Company's revenue requirement that was approved by the Commission pursuant to a settlement did not include an additional amount of revenue increase based on a fair value increment. Essentially, the Company's revenue increase computed in Docket No. E-01933A-07-0402 was the same on original cost rate base and on fair value rate base, which was consistent

with the Commission's traditional practice for calculating an allowed return on fair value rate base.

Q. Describe the change in the Commission method of calculating operating income as it relates to the calculation of the FVROR.

A. Prior to a 2007 Arizona Court of Appeals decision,[1] the Commission had determined operating income by multiplying the weighted average cost of capital ("WACC") by the OCRB. The resulting product was then divided by the FVRB to determine a FVROR. The Arizona Court of Appeals found that the Commission did not comply with Article 15, Section 14 of the Arizona Constitution when it set rates based on original cost instead of fair value. However, the Court noted: "If the Commission determines that the cost of capital analysis is not the appropriate methodology to determine the rate of return to be applied to the FVRB, the Commission has the discretion to determine the appropriate methodology." The Commission, in Decision No. 70441, adopted a FVROR based on the WACC modified to reflect a 2.00 percent reduction to the cost of equity, but not to the cost of debt. In Decision No. 71308, the Commission calculated the FVROR by subtracting an inflation factor from both the debt and equity components of the WACC. In other cases, particularly where settlements were reached, the FVROR ultimately used was within a range of Staff recommended FVROR options presented in those cases.

[1] *Chaparral City Water* Co *v Ariz Corp. Comm'n*, 1 CA-CC 05-0002 (Ariz. App. Feb. 13, 2007).

Q. Has an Arizona utility recently submitted testimony in another jurisdiction showing that the additional return and revenue requirement produced by applying an additional return amount to the fair value rate base increment are effectively an augmentation to the otherwise awarded return on equity ("ROE")?

A. Yes. As one illustrative example of this, in its most recent Nevada rate cases for its Northern Nevada and Southern Nevada divisions, Southwest Gas Corporation filed rebuttal testimony on August 31, 2012 of Mr. Wood showing how the additional return allowed in its last Arizona rate case that was produced by applying an additional return amount to the fair value rate base increment is effectively an augmentation to the otherwise awarded ROE on original cost rate base. Excerpts from Southwest Gas Corporation's rebuttal testimony and exhibits in Nevada PUC Docket Nos. 12-02019 and 12-04005 that made this presentation are included in Attachment RCS-6. As documented there, Southwest Gas in its most recent Nevada rate case told the Nevada Commission that the 9.5 percent ROE awarded by the Arizona Commission in SWG's last Arizona rate case, with the fair value increment, was equivalent to a 10.3 percent ROE on original cost rate base. Thus, an additional 80 basis points addition to the ROE on original cost rate base was produced in that case by the return allowed on the fair value increment. Southwest Gas' witness on this, Mr. Wood, included in his Nevada rate case rebuttal testimony calculations to translate the additional FV return into the higher ROE, which he explained as follows:

> The equivalent ROE, based on an OCRB methodology, is 10.36 percent. Rebuttal Exhibit No.___(TKW-2) displays the calculation of this equivalent OCRB ROE. First, the fair value rate base (FVRB) was computed as a weighted average of the OCRB and the reconstruction cost new depreciated rate base, using a 50 percent weight for each. The resulting FVRB was established at $1,452,932,391, which is 1.36 times greater than the OCRB of $1,070,115,558. Second, the authorized capital structure for the OCRB was established at 52.3 percent common equity and 47.7

percent long-term debt. Third, the fair value rate of return (FVROR) was calculated. The capital component amounts used to compute the FVROR were composed of the common equity and long-term debt amounts used to finance the OCRB, plus an amount equal to the increment of the FVRB above the OCRB. The cost components were 9.5 percent for common equity, 8.34 percent for long-term debt, and an inflation-adjusted risk-free return of 1.25 percent for the FVRB increment above the OCRB, resulting in a FVROR of 6.92 percent. Finally, the resulting net operating income is computed by multiplying the FVRB by the FVROR, which equates to $100,525,025, and subtracting the interest expense of $42,571,123 results in a net income of $57,953,902. Dividing the net income by the common equity of $559,670,437, results in an ROE of 10.36 percent.

Q. Have you performed a similar calculation for TEP's requested ROE and Staff's recommended ROE in the current TEP rate case?

A. Yes. These calculations are shown on Attachment RCS-2, Schedule D, pages 2-4.

Q. Please explain those calculations.

A. On its Schedule D-1, TEP has requested a return on equity ("ROE") of 10.75 percent, and an overall rate of return of 7.74 percent. On Attachment RCS-2, Schedule D, page 2, following the same format that was recently used by Southwest Gas Corporation in its August 31, 2012 rebuttal filing in its Nevada PUC rate case, I show that TEP's revenue increase request is the equivalent of an ROE on OCRB of 12.45 percent.

Pages 3 and 4 show that the equivalent ROE on Staff FVROR options 1 and 2 to be 9.4 percent and 10.19 percent, respectively. Page 5 shows that the equivalent ROE for Staff's recommended revenue increase is 9.45 percent.

Q. How has Staff used this analysis in the current TEP rate case to calibrate its recommended revenue increase based on FVRB?

A. Because the fair value increment that has been awarded in some Arizona cases and is being requested by TEP in the current case can be translated directly into an equivalent ROE that would be applied to original cost rate base, and this type of conversion has been presented by utilities such as Southwest Gas in its recent non-Arizona rate case proceedings, this highlights additional information on what equivalent ROEs on OCRB would result if a certain FVROR is adopted as the basis for establishing an Arizona utility's revenue requirement. This additional information can be considered by the Commission in reviewing the revenue requirement and calibrating the impact of the Fair Value analysis so it does not result in an excessive ROE.

Q. How has Staff addressed the ruling in the Court of Appeals decision for purposes of the current TEP rate case?

A. In view of the Court of Appeals decision in the Chaparral City case and the recent highlighting of how the FV results translate into an equivalent ROE, Staff has appropriately adjusted the weighted cost of capital to derive two FVROR options for the Commission's consideration to apply to the utility's adjusted FVRB. My testimony in the instant rate case as well as the testimony of Dr. Berry describes Staff's derivation of the two FVROR options. These options for the FVROR to be applied to the FVRB are presented in view of the Court of Appeals decision concerning Chaparral and the Commission's Decision No. 70441 in the Chaparral remand case, as described above.[2] My Attachment RCS-2, Schedule D, page 1, shows the derivation of the two FVROR calculations that were considered by Staff. This includes the two options developed by Dr. Berry which are consistent with Staff calculations of the FVROR from other major

[2] See, e.g., the preceding discussion, including the description of the calculations shown on Schedule A at pages 4-5 of this testimony.

Arizona utility rate cases after the Chaparral remand case. Attachment RCS-2, Schedule D, pages 3 and 4 also shows the equivalent ROE on original cost rate base that would result if the FVROR were used for each of those two FV options. To compute the FV revenue requirement, Staff has selected a FVROR between those two options. My Attachment RCS-2, Schedule A, shows this in column F. Additionally, Attachment RCS-2, on Schedule D, page 5, shows what the equivalent ROE on OCRB would be related to that result.

Q. Please explain how the analysis and recommendations fulfill the guidance for consideration of FVRB that is required by the Arizona constitution as clarified by the courts.

A. My Attachment RCS-2, Schedule A, in columns A through E, on line 9, summarizes the resulting revenue deficiencies that would be produced in the current TEP rate case from TEP's proposals and from Staff's calculation of the revenue requirement on OCRB and on each of the two FVROR options that have been calculated by Staff. Staff's recommendation, which is shown on Schedule A, in column F, falls within the range of FVRORs developed by Staff using various calculation methods, and is near, but not at the low end of that range. Schedule A, columns A through F, on line 10, also shows the equivalent OCRB ROE, calculated as explained above, for each TEP revenue deficiency scenario. I believe that this information and Staff's recommended FVROR in the current TEP rate case that was made after considering these alternatives appropriately fulfills the requirement of the Arizona Constitution that the Commission must set rates on a utility's fair value rate base.

C. Test Year

Q. What test year is being used in this case?

A. TEP's filing is based on the historic test year ended December 31, 2011. Staff's calculations use the same historic test year.

Q. Could you please discuss the test year concept?

A. Yes. In Arizona, a historic test year approach is used. Various adjustments are made to the historic test year amounts to ensure that there is a matching of investment, revenues and expenses. Rate base items, such as plant in service and accumulated depreciation, are based on the actual level as of the end of the historic test year. Under appropriate circumstances, known and measurable adjustments for post-test-year charges may also be recognized. Several rate base items that tend to fluctuate from month to month, such as materials and supplies and prepayments, can be based on either a test year average level, or a year-end level, depending on which alternative produces results that are best representative of normal, ongoing conditions. Since end of test year net plant in service is used, revenues are annualized based on end of test year customer levels. Additionally, certain expenses, such as depreciation and payroll costs, are annualized based on end of test year levels. This is to ensure that the going-forward revenue and expense levels are matched with the investment (net plant-in-service) used to serve those customers.

As time goes forward, changes in the Company's cost structure will occur. For example, rate base will increase as new plant is added to serve new customers, revenue will increase as customers are added, expenses will fluctuate, etc. It is very important to be consistent with a test period approach to ensure that there is a consistent matching between investment, revenues and costs. Any adjustments that reach beyond the end of the historic test year must be very carefully considered before being adopted.

D. Organization of Staff Accounting Schedules

Q. How are Staff's accounting schedules organized?

A. Staff's accounting schedules are presented in Attachment RCS-2. They are organized into summary schedules and adjustment schedules. The summary schedules consist of Schedules A, A-1, B, B.1, C, C.1 and D. Attachment RCS-2 also contains rate base adjustment Schedules B-1 through B-5 and net operating income adjustment Schedules C-1 through C-14. For Schedules A, B, B.1, C and C.1, Attachment RCS-2 presents ACC jurisdictional results. The revenue requirement for TEP is based upon the ACC jurisdictional adjusted results.

Q. What is shown on Schedule A of Attachment RCS-2?

A. Attachment RCS-2 presents the Staff Accounting Schedules and revenue requirement determination. Schedule A presents the overall financial summary, giving effect to all the adjustments I am recommending in my testimony. This schedule presents the change in the Company's gross revenue requirement needed for the Company to have the opportunity to earn Staff's recommended rate of return on Staff's proposed OCRB and FVRB . The rate base and operating income amounts are taken from Schedules B and C, respectively. The overall rate of return on OCRB of 7.00 percent, as presented in the prefiled testimony of Staff witness Berry, is provided on Schedule D for convenience, as are the derivation of Staff's two options for the fair value rate of return.

Columns D and E of Schedule A present Staff's calculation of the base rate revenue deficiency on FVRB using two alternatives for the fair value rate of return.

The operating income deficiency shown on line 5 of Schedule A is obtained by subtracting the operating income available on line 4 (operating income as adjusted) from the required

operating income on line 3. Line 7 represents the gross revenue deficiency, which is obtained by multiplying the income deficiency by the gross revenue conversion factor ("GRCF"). The derivation of the GRCF is shown on Schedule A-1.

Q. How does the GRCF recommended by Staff compare with the GRCF contained in TEP's filing?

A. As shown on Schedule A-1, Staff recommends a GRCF of 1.6590. This is the same as the GRCF of 1.6590 used in TEP's filing. TEP's filing used an uncollectibles rate of 0.2486 percent. Staff's GRCF uses that same uncollectibles rate, as well as the same combined state and federal income tax rate of 39.571 percent.

Q. What is shown on Schedule B?

A. Schedule B presents TEP's proposed adjusted test year Original Cost and RCND rate base and Staff's proposed adjusted test year Original Cost and Fair Value rate base. The beginning rate base amounts presented on Schedule B are taken from the Company's filing for the test year, specifically TEP Schedule B-1. Staff's recommended adjustments to rate base are summarized on Schedule B.1. Each of the adjustments is discussed in this testimony. Staff adjusted rate base results on Attachment RCS-2, Schedule B and the adjustments on Schedule B.1 are shown on an ACC jurisdictional basis.

Schedules B-1 through B-5 provide further support and calculations for the rate base adjustments Staff is recommending.

Q. What is shown on Schedule C?

A. The starting point on Schedule C is TEP's adjusted test year net operating income, as provided on Company Schedule C-1. Staff's recommended adjustments to TEP's adjusted

test year revenues and expenses are summarized on Schedule C.1. Each of the adjustments is discussed in this testimony. Staff adjusted net operating income results on Attachment RCS-2, Schedule C and the adjustments on C.1 are shown on an ACC jurisdictional basis.

Schedules C-1 through C-14 provide further support and calculations for the net operating income adjustments Staff is recommending.

Q. What is shown on Schedule D?

A. Schedule D, page 1 summarizes the capital structure and cost of capital that was proposed by TEP and the capital structure and cost of capital that is recommended by Staff witness Berry. Schedule D, page 1 also presents the derivation of Staff's recommended fair value rate of return for use with the Staff's adjusted fair value rate base. Schedule D, pages 2-5, shows the equivalent ROE on OCRB for TEP's requested increase (on page 2), for Staff calculated FVROR options 1 and 2 (on pages 3 and 4, respectively) and for Staff's recommended revenue increase on FVRB (on page 5).

E. Fair Value Rate Base

Q. How was the fair value basis of rate base determined?

A. As shown on Attachment RCS-2, Schedule B, the fair value rate base was determined by averaging Original Cost and reconstruction cost new depreciated ("RCND") rate base information. For purposes of this presentation, I have used the Company's RCND information as the starting point for the fair value rate base. In this case, each of Staff's adjustments to OCRB also produced the same amount of adjustment to RCND rate base.

III. RATE BASE

Q. Have you prepared a schedule that summarizes Staff's proposed adjustments to rate base?

A. Yes. As noted above, the adjusted rate base is shown on Schedule B and the adjustments to TEP's proposed rate base are shown on Schedule B.1. A comparison of the Company's proposed rate base and Staff's recommended rate base on an Original Cost and Fair Value basis are presented below:

	Summary of Staff Adjustments to Rate Base (Thousands of Dollars)	**ACC Jurisdictional Original Cost**
Adj. No.	Description	Increase (Decrease)
B-1	Sahuarita-Nogales Transmission Line	$ (11,089)
B-2	Cash Working Capital	$ 787
B-3	Remove One-Half of Prepaid D&O Insurance	$ (117)
B-4	Fuel Inventory - Adjustment for San Juan Coal Price	$ (1,590)
B-5	New Headquarters Building	$ (6,578)
	Total of Staff Adjustments	**$ (18,587)**
	TEP Proposed Rate Base	$ 1,519,073
	Rounding	
	Staff Proposed Rate Base	**$ 1,500,486**

B-1 Sahuarita-Nogales Transmission Line

Q. What has TEP requested for the Sahuarita-Nogales Transmission Line?

A. TEP has requested inclusion in rate base of a new regulatory asset of $11.089 million for costs that it recorded for a Sahuarita-Nogales Transmission Line.

Q. What is the "Sahuarita-Nogales Transmission Line"?

A. This was a transmission line project that TEP was considering but which has not been built. It is for a transmission line to Mexico that TEP says it is "leaning toward" abandoning. TEP included about $11 million in rate base as a new "regulatory asset," in

account 182.3. Approximately $2 million of that is for land and land rights, which TEP has recorded in account 105, plant held for future use ("PHFFU") and allocated to the FERC jurisdiction.[3] TEP apparently has no plans to use this land in the near future. The PHFFU amount for this transmission project land should be removed from the ACC jurisdictional rate base because (1) TEP has no plans to use it in the near future and (2) the land and PHFFU for a transmission project such as this is jurisdictionally allocated to the FERC jurisdiction. The remaining $8.95 million reflects various costs TEP incurred to develop the proposed 345KV transmission line plus expenses associated with the state and federal siting processes. TEP is also proposing that all non-land costs incurred for the development of the Sahuarita-Nogales Transmission Line be amortized to expense over 3 years. TEP's proposed amortization expense is addressed in a Staff operating expense adjustment.

Q. What is Staff's position concerning this request by TEP for a new regulatory asset to be included in jurisdictional rate base for the Sahuarita-Nogales Transmission Line project?

A. Staff's position is that TEP has not justified inclusion of this item as an ACC jurisdictional regulatory asset for various reasons, and, therefore it should be removed from ACC jurisdictional rate base. Had this transmission line been built, the cost would have been included in TEP's transmission plant accounts, and would have become part of the costs of TEP's FERC-regulated transmission tariff. Staff therefore believes that the costs incurred by TEP for this transmission line project are not ACC jurisdictional costs and should not be included in the ACC jurisdictional rate base. Additionally, although TEP has indicated that it is leaning toward abandoning the project, a firm decision to abandon it has apparently not yet been made. When and if TEP does make a definite decision to

[3] In TEP's cost of service study, TEP has identified FERC-regulated costs for its FERC-regulated Open Access Transmission Tariff ("OATT").

abandon this transmission line project, TEP should raise the matter with FERC, and should seek recovery of its costs related to the abandonment of this transmission line project from FERC.

Q. Please explain Staff's adjustment for the Sahuarita-Nogales Transmission Line project.

A. As shown on Schedule B-1, all of the costs that TEP proposed to treat as a new regulatory asset and include in jurisdictional rate base are being removed. This reduces TEP's proposed jurisdictional rate base by $11.089 million.

Q. Is there a related adjustment to operating expenses?

A. Yes. Staff adjustment C-1 removes TEP's proposed amortization expense.

TEP's Requested Working Capital

Q. Have you reviewed the Company's request for a working capital allowance?

A. Yes. The Company's working capital request consists of four separate subcomponents. The subcomponents are:

(1) adjustment to the recorded end-of-test-year balances for Fuel Inventory to reflect the targeted inventory days level, per the recommendation of Staff in Docket No. E-01933A-07-0402 and accepted by the Commission in Decision No. 70628;

(2) a thirteen-month average materials and supplies balance of $56.998 million on a total company basis and $42.837 million on an ACC Jurisdictional basis;

(3) a thirteen-month average prepayments balance of $6.023 million on a total company basis and $4.538 million on an ACC Jurisdictional basis; and

(4) reflection of a measure of Cash Working Capital that was developed through the preparation of a comprehensive lead-lag study.

Q. Is Staff adjusting any of the components of TEP's working capital request?

A. Yes. Staff is adjusting three components of TEP's working capital request.

On Attachment RCS-2, Schedule B-2, Staff has adjusted the results of TEP's lead-lag study for the impact of Staff adjustments to TEP's expenses.

Second, Staff has adjusted TEP's prepayments balance to remove one-half of the prepaid Directors' and Officers' Liability Insurance, as shown on Attachment RCS-2, Schedule B-3.

Third, TEP's request for fuel inventory is adjusted for the price of coal at the San Juan plant which TEP used to compute the inventory. The San Juan coal price adjustment is shown on Attachment RCS-2, Schedule B-4 and is sponsored by Staff witness Emily Medine. This also includes a minor adjustment to remove the cost of ash handling at the Sundt plant from coal inventory cost, as explained by Staff witness Medine.

Each of these adjustments is discussed below.

B-2 Cash Working Capital – Lead Lag Study

Q. What amount of Cash Working Capital has TEP reflected in jurisdictional rate base?

A. As shown on Company Schedule B-5, and reproduced on Attachment RCS-2, Schedule B-2, columns A through D, TEP's proposed jurisdictional rate base reflects a request for working capital of negative $19.358 million.

Q. What is cash working capital?

A. Cash working capital is the cash needed by the Company to cover its day-to-day operations. If the Company's cash expenditures, on an aggregate basis, precede the cash recovery of expenses, investors must provide cash working capital. In that situation a positive cash working capital requirement exists. On the other hand, if revenues are typically received prior to when expenditures are made, on average, then ratepayers provide the cash working capital to the utility, and the negative cash working capital allowance is reflected as a reduction to rate base. In this case, the cash working capital requirement is a reduction to rate base as ratepayers are essentially supplying these funds.

Q. Does TEP have a positive or negative cash working capital requirement?

A. TEP has a negative cash working capital requirement. In other words, as measured by the results of TEP's lead-lag study, ratepayers are providing funding for TEP's operations before TEP pays cash out to employees and vendors.

Q. Did TEP present a lead/lag study in support of its cash working capital requirement?

A. Yes, TEP performed a lead/lag study to calculate the cash working capital requirement in this case. The Company provided its lead/lag study calculations with the workpapers provided in the case.

Q. Has TEP made any revisions to the cash working capital calculation included in its filing?

A. No, none of which I am aware.

Q. Are you recommending any adjustments to TEP's cash working capital request?

A. Yes. As shown on Attachment RCS-2, Schedule B-2, I have reflected the impact of Staff's adjustments to operating expenses.

Q. What is the result of your cash working capital calculation?

A. As shown on Schedule B-2, TEP's filed cash working capital request should be increased by approximately $787,000 on a jurisdictional basis for the impacts of Staff's adjustments to operating expenses.

B-3 Prepaid Directors and Officers' Liability Insurance

Q. Please explain the adjustment for Prepaid Directors' and Officers' Liability Insurance.

A. This adjustment, as shown on Schedule B-3, removes one-half, or $117,007, of the jurisdictional rate base amount for Prepaid Directors' and Officers' Liability Insurance that Southwest identified in its response to data request STF 24.1(a), to reflect a 50-50 sharing of such cost between shareholders and ratepayers. The sharing of this cost is addressed in additional detail in conjunction with a related adjustment to expense, Staff Adjustment C-7, below.

B-4 Fuel Inventory

Q. Please explain the adjustment to TEP's proposed coal inventory for the San Juan coal price.

A. This adjustment reduces TEP's proposed rate base by $1.757 million in total and by $1.590 million on a jurisdictional basis for the use of the more appropriate coal price for the San Juan and Sundt plants as described in Ms. Medine's testimony. Staff witness Emily Medine has identified an adjustment to the price of coal used by TEP to derive its proposed rate base amount for coal inventory at the San Juan plant. As shown on Attachment RCS-2, Schedule B-4, for San Juan coal inventory, TEP used a cost per ton of $63.62, which included non-recurring costs related to a "thermal event" (i.e., a mine fire). This contrasts with Staff witness Medine's recommendation to use $50.52 per ton for the San Juan plant coal inventory.

Q. Does the adjustment to San Juan and Sundt coal inventory costs also reflect the removal of ash handling costs?

A. Yes. The $50.52 per ton price for San Juan plant coal inventory also reflects Ms. Medine's recommendation that ash handling costs be excluded from the coal inventory amount included in rate base. The per-ton costs shown on Schedule B-4 for the San Juan and Sundt coal inventory reflect removal of ash handling costs, as recommended by Ms. Medine.

B-5 UniSource Energy Headquarters Building

Q. What has TEP requested for the new UniSource Energy Headquarters Building?

A. TEP witness DeConcini's Direct Testimony at page 26 indicates that TEP has invested approximately $92 million in a new headquarters building in downtown Tucson. TEP has not proposed pro forma adjustments to remove from rate base any of the cost for the new building; however, TEP has proposed an adjustment for increased rent from affiliates

related to the use of the new building, and an allocation of new building costs to affiliates. TEP also made a pro forma adjustment to remove certain expenses related to its old headquarters building.

Q. What costs are included in the $92 million new headquarters building cost?

A. TEP's workpaper TEP(0291)014816 shows the following components:[4]

	Amount
TEP New HQ - IT	$ 7,363,145
TEP New HQ - Facilities	$ 84,604,455
Total	$ 91,967,600

Q. Does TEP expect operating efficiencies from the new building?

A. TEP witness DeConcini's Direct Testimony at page 27 indicates that the new building allows employees to work more efficiently and effectively on behalf of TEP's customers. He also states that departments that work frequently together are assigned to offices in the same areas of the building, resulting in members of a project team who once were located miles away from each other now being located on the same floor, making it easier to communicate and collaborate while saving travel time and other expenses.

Q. Has TEP provided a diagram of the new building?

A. Yes. TEP's response to STF 16.08(a) provided a confidential diagram on page TEP(0291)027312 showing the amount of gross square footage on each floor of the 9 floor "stacking plan," the occupancy percentage for each floor, and the 248,410 gross square footage associated with the three levels of underground parking.[5] In response to

[4] TEP has represented to Staff counsel that these new headquarters building cost components are not confidential.
[5] TEP has represented to Staff counsel that these new headquarters building gross square footage is not confidential.

STF 26.06, TEP provided additional information on the square footage for each floor of the building and unoccupied space.

Q. What cost per square foot of the various types of building space has TEP provided?

A. TEP's response to STF 16.08(e) states the following amounts as the actual cost per square foot for the various areas in the new headquarters building:

Office	$263/sf
Retail	$178/sf
Parking	$64/sf

Q. How much retail space does the new headquarters building include?

A. TEP's response to STF 16.08(a) indicates that there is 12,000 gross square feet of retail office space, and all of it is currently unoccupied. TEP's response to STF 16.08(c) indicates that:

> The only area of the building with a plan to lease is the retail space. We are currently working with a commercial real estate broker to identify potential tenants. There are currently no leases in place for the retail portion of the headquarters building.

Q. Is the 12,000 gross square feet of retail space in the new headquarters building used and useful in providing electric utility service?

A. No, it is not currently being used for either retailing or for the provision of electric utility service.

Q. Other than the retail space, what has TEP indicated concerning whether it has plans to lease any of the new headquarters building to affiliates or others?

A. TEP's response to STF 16.08(b) indicates that there are no plans to lease or sub-lease portions of the headquarters building to affiliates. The Company's response to STF 16.08(f) indicates that none of the headquarters building is currently being leased or sub-leased to others.

Q. Has TEP reflected downward adjustments to its expenses resulting from such efficiencies?

A. Other than allocating some of the costs of the new headquarters building to its affiliates - UNS Electric ("UNSE"), UNS Gas ("UNSG"), and others based on TEP labor hours worked for such affiliates - Staff does not believe that TEP has reflected pro forma adjustments to decrease expenses for increased efficiencies.

Q. Have TEP's average corporate office space costs per employee increased substantially as a result of the new headquarters building?

A. Yes. As one indicator of the magnitude of the cost of corporate office space per employee, TEP calculates a cost per employee and a facilities cost per hour. As shown in TEP's response to STF 23.1, in 2010 (before the new headquarters building) the cost per employee and facilities cost were [redacted] respectively. In December 2011, with the cost of the new headquarters building included, the cost per employee and facilities cost [redacted]. This is a 77 percent increase in TEP's corporate facility cost per employee.

Q. What other concerns does Staff have about the cost of the new building?

A. Beyond the sheer magnitude of the per employee facilities cost increase, Staff's other concerns about the cost of the new building is that the new building includes substantial amounts of office space that are not currently being used, that the new building includes approximately $2.1 million cost for retail space that is not currently being used, that the building includes a cost of approximately $16 million for underground garage/parking,[6] and that TEP has not adequately substantiated that its proposed charging of new building costs to ratepayers is fair and reasonable.

Q. What adjustments has Staff made for the cost of the new headquarters building?

A. Staff's proposed adjustment for new headquarters building cost is shown on Attachment RCS-2, Schedule B-5, page 1. Staff recommends that all of the cost of the building related to retail space be borne by shareholders. The cost of the 12,000 square feet of retail space, all of which is currently unused, is $2.136 million.[7]

Staff also recommends that the cost related to unused office space be borne by shareholders. As shown on Schedule B-5, page 3, there is approximately 8,540 square feet of vacant office and cubicle space. At TEP's estimate of $263 per square foot for office space, the estimated cost of this vacant office space is approximately $2.246 million.

Staff also recommends that one-half of the cost of the underground garage/parking area not be charged to ratepayers. It is questionable that ratepayers should pay for parking by

[6] See, e.g., TEP's responses to STF 22.06(e) and (h) for the $2.1 million cost of retail space and $16.0 million for parking.
[7] Also see TEP's response to STF 22.06(e).

TEP and affiliate employees in downtown Tucson. In its response to STF 22.06(l)[8] for example, TEP cites the Downtown Tucson Partnership web site for stating that:

> With over 15,000 spaces, parking Downtown is quick and easy. Metered street parking is less expensive than in almost any other city (free on evenings and weekends). Private and public parking lots and garages are also a great deal. You walk farther in a mall parking lot than you do parking anywhere Downtown. With parking Downtown, you're never far from where you need to be. ...

With so much relatively inexpensive parking available in Downtown Tucson that could presumably be used by the TEP employees who are working in the new headquarters building, attempting to charge the full cost of the new headquarters building parking areas to ratepayers should be considered to be not just, fair and reasonable to ratepayers. TEP's response to STF 26.07 identifies the cost of the parking structure as $10.5 million.[9] Accordingly, Staff has excluded $5.25 million or half of the $10.5 million cost for the headquarters parking structure, in deriving the amount for the new headquarters building that is included in Staff's recommended rate base.

As shown on Attachment RCS-2, Schedule B-5, page 1, the amount being excluded from general plant in rate base is $9.632 million, before recognizing TEP's allocation of office building/facilities cost to affiliates. TEP's 12/6/2012 supplemental response to STF 23.1 shows that TEP has allocated approximately 4.5 percent of building cost to affiliates. Conversely, TEP has retained approximately 95.5 percent of the building cost. After recognizing this allocation to affiliates, the adjustment for new headquarters building cost

[8] TEP provided this response as a reason for why none of the headquarters parking needs to be made available to serve the 12,000 gsf of retail space. But by detailing the abundant parking in Downtown Tucson, it also calls into question the need for any additional ratepayer-funded parking.

[9] If an allocation of land costs were included, the cost would be approximately $16.0 million. Also, see TEP's response to STF 22.06(h).

is $9.199 million on a total Company basis and $6.756 million on an ACC jurisdictional basis.

Q. What is shown on pages 2 and 3 of Schedule B-5?

A. Schedule B-5, page 2, shows the office space by floor for the new UniSource Energy headquarters, and the percent occupied for each floor that was identified in TEP's confidential response to STF 16.08(a) and (d). Page 2 also shows, by floor, the amount of space for (1) cubicles, offices, conference rooms and circulation space, (2) ancillary space, and (3) total space per TEP's confidential response to STF 26.06. Schedule B-5, page 3, shows the amount, by floor, of vacant office space, per TEP's confidential response to STF 26.06. Similar information to TEP's response to STF 26.06 was utilized for a detailed tour of the new Downtown Tucson headquarters building conducted on December 4, 2012. The vacant square footage listed on Schedule B-5, page 3, was used to derive the adjustment shown on Schedule B-5, page 1, lines 2-4, for removing cost for unoccupied office space in the new headquarters building.

Q. Are there related adjustments for Property Tax Expense, Depreciation Expense and Accumulated Depreciation?

A. Yes. The related adjustments for Depreciation Expense and Property Tax Expense are shown on Attachment RCS-2, Schedule C-10. The related adjustment for Accumulated Depreciation is shown on Attachment RCS-2, Schedule B-5, page 1, line 13.

IV. ADJUSTMENTS TO OPERATING INCOME

Q. Please describe how you have summarized Staff's proposed adjustments to operating income.

A. Schedule C summarizes Staff's recommended jurisdictional net operating income. Schedule C.1 presents Staff's recommended adjustments to test year revenues and expenses on an Arizona jurisdictional basis. The impact on state and federal income taxes associated with each of the recommended adjustments to operating income is also reflected on Schedule C.1. TEP's proposed adjusted test year net operating income is $52.472 million, whereas Staff's recommended adjusted net operating income is $59.261 million. The recommended adjustments to operating income are discussed below in the same order as they appear on Schedule C.1.

C-1 Sahuarita-Nogales Transmission Line Amortization Expense

Q. Please explain Staff Adjustment C-1.

A. This adjustment removes TEP's requested amortization of cost for the Sahuarita-Nogales Transmission Line project which was not completed and which TEP is considering abandoning. As described above, in conjunction with Staff rate base adjustment B-1, had the transmission line been built, the costs would be under FERC's jurisdiction. TEP should address recovery of costs associated with such a transmission line project with FERC. There is no basis for including such costs in the jurisdictional revenue requirement in the current rate case. The removal of TEP's requested amortization reduces jurisdictional operating expenses by $2.983 million, as shown on Attachment RCS-2, Schedule C-1.

C-2 Incentive Compensation (PEP) Program Expense

Q. What has TEP requested for Incentive Compensation (PEP) Program Expense?

A. As confirmed in TEP's response to STF 12.01, the Company recorded $4,060,814 in 2011 PEP expense, and increased that amount by $2,686,326 in a pro forma adjustment, for a total Company amount of $6,747,140, and a jurisdictional operating expense request of $5,059,311. Page 32 of TEP witness Kissinger's Direct Testimony explains that:

> TEP's Performance Enhancement Plan ("PEP") is based on specific, pre-established goals with awards measured on specific Company performance, and is designed to award non-union employees for their contributions to TEP. The payout is determined based on year-end results and payments are made to employees the following year (usually in the first quarter). The Adjustment produces a pro forma test year expense level reflecting 50% of officers and other senior managements (collectively referred to as "Upper Management") average PEP for the past three years (2009-2011) and 100% of the remaining employees' average PEP for the same past three years.

Ms. Kissinger's Direct Testimony at pages 32-33 cites and apparently relies upon Decision Nos. 70665 (Southwest Gas Corporation) and 69663 (Arizona Public Service Company), although at page 34, she recognizes that there are more recent decisions for both Southwest Gas and APS.

Page 35 of her Direct Testimony indicates that TEP is not requesting recovery of cost related to its Long-Term Incentive (Stock-Based) Compensation and Supplemental Executive Retirement Plan ("SERP"), although she states that TEP reserves the right to request recovery of up to 100 percent of those costs in a future rate case.

Q. Has TEP indicated that its requested Incentive Compensation Expense is a revenue requirement claim by the Company that represents a conscious deviation from the principles and policies established in prior Commission Orders?

A. Yes. TEP's response to UDR 1.63(a) states that: "The only revenue requirement claims that knowingly deviate from the Commission's prior decision for TEP is the 'Incentive Compensation Adjustment.'"

Q. In Commission Decision No. 70628 (December 1, 2008), what percentage of TEP's PEP was removed?

A. In Commission Decision No. 70628, 50 percent of TEP's PEP incentive compensation was removed to provide for an equal sharing of such cost, which provided for an appropriate balance between the benefits attained by both shareholders and ratepayers.

Q. Did you review TEP's short-term incentive program ("PEP") in the context of TEP's current rate case?

A. Yes. A description of the PEP was provided in TEP's response to UDR 1.35, and the confidential 2011 PEP goals provided therein as well as the confidential 2012 PEP goals that were provided in TEP's September 25, 2012 supplemental response to UDR 1.35 (bates TEP(0291)022720-022721) are included in Attachment RCS-4.

Q. Should a 50/50 sharing of the cost of TEP's short-term incentive program continue to apply in the current TEP rate case?

A. Yes. The 50/50 sharing of the cost of TEP's short-term incentive program is also consistent with Staff's treatment of cash-based incentive compensation in other recent rate cases involving energy utilities such as Southwest Gas Corporation (Docket No. G-

01551A-10-0458), Arizona Public Service Company (Docket No. E-01345A-11-0224) and UNS Gas (Docket No. G-04204A-11-0158).

Q. Please explain Staff Adjustment C-2.

A. This adjustment applies a 50/50 sharing to an average of TEP's PEP expense for 2010 and 2011 to determine the PEP expense allowance amount for the test year. As shown on Attachment RCS-2, Schedule C-2, TEP's requested PEP expense is reduced by $2.094 million on a jurisdictional basis. The $2.094 million adjustment includes a reduction to O&M expenses of $1,912,464 and a reduction for related payroll tax expense of $181,975.

C-3 Overhaul and Outage Expense

Q. Please explain Staff Adjustment C-3.

A. This adjustment provides for a normalized allowance for Overhaul and Outage Expense as shown on Attachment RCS-2, Schedule C-3, page 1, of $12.349 million (total Company) and $11.590 million (ACC jurisdictional). It reduces TEP's proposed jurisdictional amount by $2.514 million.

It differs from TEP's proposed adjustment in that it uses historical information, which TEP had also used for 2004 through 2011, and does not utilize projections. TEP's proposed allowance is based in part on projections of future outage and overhaul expenses through 2020. Since it is expected that TEP will have one or more additional rate cases during this period[10], there is no need to utilize for purposes of the current TEP rate case projections of future overhaul costs through such a distant period, such as 2020. Indeed, the potential impact of environmental regulations on some of TEP's coal-fired plants

[10] The period used for recovery of costs of the current rate case by TEP and Staff in the current case is three and four years, respectively, suggesting an expectation that the next TEP rate case will occur in approximately three or four years.

(such as San Juan) has raised some questions about whether such older units would continue to be able to operate economically through an extended future period such as 2020.

Additionally, Staff has tested the accuracy of TEP's prior forecasts of outage and overhaul costs. As shown on Schedule C-3, pages 5 and 6, actual costs have differed markedly from some of TEP's previous budgets/forecasts, calling into question the accuracy of TEP's projections, especially projections extending far into the future beyond the current rate case cycle. Although it appears that some forecast information was utilized as the basis for normalizing outage and overhaul expense in TEP's last rate case, the concern over the accuracy of TEP's projections and the lack of a need to use extensive future projections due to expectations that TEP will be in for one or more rate cases between now and 2020 argues in favor of using historical information in the current case for determining the normalized plant overhaul expense allowance.

Q. Please explain what is shown on the different pages of Schedule C-3 of Attachment RCS-2.

A. Page 1 summarizes the adjustment. It shows for each plant, the test year recorded amounts, TEP's proposed normalized amounts, and TEP's proposed adjustments, in columns A and B on a total Company and ACC jurisdictional basis, respectively. Page 1, columns C and D show Staff's normalized amounts, the recorded amounts, and Staff's adjustments by plant. Column C shows total Company amounts and column D shows ACC jurisdictional amounts. Column E and F show Staff's adjustments, by plant, as differences from TEP's proposed amounts. Column E shows total Company amounts of Staff's adjustments by plant and column F shows ACC jurisdictional amounts. Lines 19-

22 on page 1 summarize the information and show totals for TEP's request, Staff's recommendation and Staff's adjustment.

Page 2 shows the derivation of Staff's recommended normalized amounts by plant. To derive the normalized amounts, actual costs for the period 2004 through 2011 were considered. The costs of major and minor overhauls were evaluated separately.

Page 3 shows a comparative derivation of normalized plant overhaul costs using simple averages. For most plants an average of the full 8 year period is shown. For Luna, which was not operational for the full 8 year period, a four-year average was used.

Page 4 shows additional overhaul cost information for a longer historical period, extending back to 1999. Averages for the 13-year period through 2011 are shown for most plants. A four-year average is shown for Luna. The average overhaul cost shown on page 4 is $11.758 million.

Pages 5 and 6 show comparisons of some of TEP's prior forecasts/budgets for overhaul costs with actual information. A number of TEP's prior forecasts have differed markedly from actual results. These differences can be very large, and cast doubt on the accuracy of TEP's forecasts. The comparisons of TEP's projections with actual are one reason why Staff has recommended in the current TEP rate case that the allowance for normalized overhaul expense be based on actual information. Staff has not utilized TEP's forecasted plant overhaul projections through 2020, which were partially the basis for TEP's requested expense amount.

Q. Please summarize Staff's adjustment to normalize plant outage and overhaul expense.

A. As shown on Schedule C-3, page 1, Staff's adjustment to normalize plant outage and overhaul expense reduces TEP's proposed jurisdictional amount for such expense by $2.514 million.

C-4 Interest Synchronization

Q. What is interest synchronization?

A. Interest synchronization refers to the widely accepted process used in utility ratemaking which involves coordinating the amount of interest deduction that is used to compute income tax expense for ratemaking purposes with the other elements of the ratemaking formula. The interest synchronization process typically involves multiplying the weighted cost of debt (from the recommended cost of capital) by the adjusted rate base in order to derive a "synchronized" amount of interest expense. The synchronized interest is then treated as the amount of interest deduction in computing the income tax expense.

Q. Please explain the adjustment for interest synchronization.

A. The interest synchronization adjustment applies the weighted cost of debt to the calculation of test year income tax expense. After adjustments, as shown on Attachment RCS-2, Schedule B, Staff's proposed rate base differs from that of the Company. Additionally, as shown on Attachment RCS-2, Schedule D, page 1, Staff's proposed cost of capital, which is sponsored by Staff witness Berry, reflects a weighted cost of debt that also differs from TEP's request. This results in an adjustment to the amount of synchronized interest included in the tax calculation. The calculation of the interest synchronization adjustment is shown on Attachment RCS-2, Schedule C-4. This

adjustment decreases income tax expense by the amount shown on Schedule C-4 and increases the Company's achieved operating income by a similar amount.

C-5 Base Cost of Fuel and Purchased Power

Q. What has TEP proposed as the base cost for fuel and purchased power?

A. In its filing, TEP calculated a base cost of fuel and purchased power of $292.190 million by multiplying adjusted test year sales of 9,285,592,991 kWh times a PPFAC rate of $0.031467.[11] TEP's calculation is reproduced on Attachment RCS-2, Schedule C-5. TEP has also requested that all fuel and purchased power cost be removed from its base rates, and instead be recovered in its Purchased Power and Fuel Adjustment Clause ("PPFAC").[12]

Q. What is Staff's proposed base cost of fuel and purchased power?

A. As shown on Schedule C-5, page 1, I have calculated Staff's recommended base cost of fuel and purchased power, which is the amount that would be reflected in TEP's base rates. This adjustment uses the adjusted test year base cost of fuel and purchased power starting with TEP's most current projected average net cost of 3.1495 cents per kWh. This is from TEP's November 7, 2012 PPFAC Report for September 2012. The 3.1495 cents per kWh represents the Company's projected average net fuel costs for the PPFAC period April 2012 through March 2013. Put another way, Schedule C-5 uses, as the starting point, a per-kWh rate of $0.031495, which is from TEP's September 2012 PPFAC Report, filed November 7, 2012, Schedule 2, line 7, and reflects the Projected Average Net Fuel Cost that is applicable for the current period which runs April 1, 2012 through March 31, 2013.

[11] See, e.g., TEP PPFAC adjustment workpaper and TEP's response to STF 9.12. Copies of these items are included in Attachment RCS-3.

[12] See, e.g., TEP witness Hutchens' Direct Testimony; also see TEP witness Jones' Direct Testimony at page 52, lines 24-25. Another witness for Staff is addressing PPFAC rate design issues.

The resultant base cost of fuel and purchased power of $292.450 million on Schedule C-5, column B, line 3, has been reduced by $5.076 million for the adjusted test year jurisdictional amount of sulfur credits. TEP proposes to reflect sulfur credits related to a Springerville coal contract as a reduction to lime expense in account 502. TEP's proposed pro forma adjustment for lime expenses in account 502 is reproduced on Schedule C-5, page 2 and reflects a jurisdictional reduction of $5.076 million for sulfur credits, which TEP has offset against its Springerville lime expense that it records in account 502. Staff proposes to reflect sulfur credits as a reduction to the cost of coal expense in account 501 (which is a PPFAC-includable account). Also, see the direct testimony of Staff witness Emily Medine.

As shown on Schedule C-5, page 1, Staff's adjusted base cost of fuel and purchased power is $287.373 million. The per-kWh base cost of fuel and purchased power Staff recommends is $0.030948.

Q. How are contractual adjustments to the cost of coal typically accounted for by electric utilities with coal-fired generation?

A. In my experience, utilities with coal-fired generation would typically record such contractual coal price adjustments as an adjustment to the coal price, which is recorded in account 151 (coal inventory) and is charged to account 501 (steam fuel expense) when the coal is burned to generate electricity. That is, adjustments to the cost of coal for coal deliveries having heat, ash, or sulfur content qualities that vary from, or are outside of the contract specifications, would typically be accounted for as an adjustment to the cost of the coal. The price discounts for such coal quality deviations are often specified in the coal contract. Coal with a lower BTU (heat content, or with higher ash or sulfur content is considered inferior in quality, other things being equal, and thus has a lower cost. Such

contractual coal price adjustments associated with the receipt of coal with a higher sulfur content would typically be recorded (as a credit or reduction to coal cost) in account 151 (fuel inventory) which then would reduce the steam generation fuel expense recorded in account 501 when the coal is burned. For TEP, Account 501 is a PPFAC-includable account. Coal costs and any price adjustments which affect the cost of coal that are recorded in Account 501, such as these Springerville sulfur credits should be, thus should reduce the costs that are charged to TEP's ratepayers through the PPFAC. However, TEP has instead attempted to record the Springerville sulfur credits as a reduction to its lime expense, which TEP records in Account 502. Account 502 is not included in TEP's PPFAC, so this questionable accounting by TEP can entail both PPFAC and base rate consequences.

Q. What reasons has TEP provided for recording Springerville plant sulfur credits in Account 502, Fuel Handling expense, rather than in Account 501, Steam Fuel Expense?

A. When coal delivered to TEP's Springerville plant exceeds contract specifications for sulfur content, TEP's cost of such coal is reduced by the amount of such "sulfur credits." TEP has provided a confidential March 2009 accounting memorandum, which is attached to Staff witness Medine's testimony as Attachment I, that describes the Company's rationale for recording the Springerville sulfur credits [redacted]

Q. What effect has this accounting by TEP had on coal costs that are charged to ratepayers?

A. Because TEP's PPFAC includes costs and credits that are recorded in account 501, Steam Fuel Expense, but does **not** include the lime expenses that TEP recorded in account 502, TEP's decision to account for the Springerville sulfur credits in account 502 means that TEP has failed to pass these coal cost reductions on to ratepayers through the PPFAC for the periods following the establishment of TEP's PPFAC in its last rate case, Docket No. E-01933A-07-0402. In other words, by not recording the Springerville coal contract related coal price adjustments represented by the sulfur credits as reductions to the cost of coal recorded in the PPFAC-included account 501, TEP failed to pass these coal cost reductions on to ratepayers through the PPFAC for the periods 2009 through the present.

Q. How did TEP account for those sulfur credits prior to 2009?

A. Prior to 2009, TEP accounted for such sulfur credits, which are a contractual adjustment to the cost of coal, as a reduction to coal costs, i.e., as a reduction to the coal costs in account 501.

An explanation provided by TEP on December 14, 2012, which is directly on point to the Company's pre-2009 accounting for Springerville coal contract related sulfur credits stated that:

> Prior to February 2009, sulfur credits were recorded in FERC 501 and offset coal costs. In March 2009, TEP's accounting policy relating the sulfur credits was modified (per accounting memo dated March 2009) to more properly record sulfur credits in FERC account 502 as an offset to lime costs. Prior to 2009, TEP did not have a PPFAC. TEP's PPFAC, which became effective in January 2009, does not allow for the recovery of lime costs.

In order to verify this accounting, Staff has recently requested TEP's sufficiently detailed accounting records for accounts 151, 501 and 502 for 2007 and 2008 so we can see exactly how TEP was accounting for the Springerville sulfur credits in those years. TEP has also been requested to include the journal entries from those years that TEP used to record the Springerville coal related sulfur credits, as well as illustrative Spingerville coal invoices from 2008 which show the reduction to the cost of coal for the sulfur credit. Depending on the timing of when TEP is able to provide such accounting details, Staff may need to address this matter further in surrebuttal.

Q. Is the accounting for such sulfur credits as a reduction to coal costs recorded in account 501 in accordance with the Uniform System of Accounts?

A. Yes. The Uniform System of Accounts ("USOA") provides for Account 501, Fuel, that:

> This account shall include the cost of fuel used in the production of steam for the generation of electricity, including expenses in unloading fuel from the shipping media and handling thereof up to the point where the fuel enters the first boiler plant bunker, hopper, bucket, tank or holder of the boiler-house structure. Records shall be maintained to show the quantity, B.t.u. content and cost of each type of fuel used.
>
> The cost of the fuel shall be charged initially to account 151, Fuel Stock, and cleared to this account on the basis of the fuel used. Fuel handling expenses may be charged to this account as incurred or charged initially to account 152, Fuel Stock Expenses Undistributed. In the latter event, they shall be cleared to this account on the basis of the fuel used. Respective amounts of fuel stock and fuel stock expenses shall be readily available.

For Account 151, Fuel Stock, the USOA provides, among other things that:

> This account shall include the book cost of fuel on hand.
>
> Items:
>
> **1. Invoice price for fuel less any cash or other discounts. ...**
>
> (Emphasis supplied.)

As described in Staff witness Medine's testimony, the sulfur credits are a contractual adjustment (i.e., a discount) to the cost of coal and occur when the sulfur content of the coal exceeds contract specifications. Other things being equal, coal with a higher sulfur content generally has a lower cost than lower sulfur coal. Consequently, other things being equal, coal with a higher sulfur content typically has a discounted price compared to lower sulfur coal. The sulfur credits represent a discount to the invoiced price for the coal. Credits recorded in account 501 for coal price discounts reduce the cost of coal used in the production of steam for the generation of electricity. TEP's attempt to record such sulfur credits in account 502 instead of in account 501, where they had apparently previously been recorded, does not represent standard electric generation industry accounting for a contractual adjustment to the cost of coal.

Q. Was the accounting for Springerville coal contract sulfur credits described in TEP's confidential March 2009 memorandum presented to or authorized by the Commission?

A. No. Staff has found no documentation that the 2009 accounting described by TEP to record such sulfur credits in an account other than account 501 (where they reduce the cost of coal) and to record such credits in account 502 (where TEP has used them as an offset to lime costs) was presented to or authorized by the Commission. TEP's March 25, 2009 memo on "Accounting for Sulfur Credits," which is included with Staff witness Medine's testimony as Attachment I, and which has come to Staff's attention for the first time in the context of the current TEP rate case, states that:

[redacted]

[redacted]

Q. Does Staff agree with TEP's proposal to record the Springerville coal contract related sulfur credits in account 502?

A. No. Staff's position is that the sulfur credits should be and should have continued to be recorded by TEP in account 501 as a reduction to the cost of coal. Staff witness Medine's testimony describes in additional detail how contractual coal price adjustments based on the heat (BTU) and sulfur content of the coal delivered are standard industry practice and represent a contractual adjustment to the cost of such coal. Staff's position is that ratepayers should receive the benefit of the sulfur credits that TEP received pursuant to its Springerville coal contracts for 2009 through 2012. Staff is also concerned that TEP diverted its recording of such Springerville coal contract related sulfur credits out of account 501 – a PPFAC includable account – without Commission authorization.

Q. What amounts of Springerville sulfur credits has TEP recorded?

A. Staff witness Medine has compiled the following amounts of TEP recorded Springerville plant sulfur credits from information provided by TEP:

	2009	2010	2011	Total
Sulfur Credit	5,136,186.8	3,874,081.0	4,789,038.0	13,799,306

Q. What amount of Springerville sulfur credits has TEP reflected in its current rate case request?

A. As shown on Attachment RCS-2, Schedule C-5, page 2, during the 2011 test year, TEP recorded $4.789 million of sulfur credits in account 502. TEP also proposed a pro forma adjustment to increase its lime expense for Springerville Generating Station unit 2. TEP's derivation of that adjustment was based on lime costs net of the sulfur credits. After incorporating the impact of TEP's pro forma adjustment, TEP has essentially reflected an adjusted amount for Springerville units 1 and 2 sulfur credits of $5.700 million in total, and $5.076 million on an ACC jurisdictional basis. The components of TEP's test year recorded amount and pro forma adjustment are reproduced on Schedule C-5, page 2.

Q. How has Staff reflected the adjusted test year jurisdictional amount of Springerville coal contract related sulfur credits?

A. Staff has reflected this as a reduction to fuel expense in account 501. Because account 501 is included in TEP's PPFAC, Staff has also reflected this as a reduction to the base cost of fuel and purchased power.

Q. What base cost of fuel and purchased power has Staff reflected at this time in determining TEP's revenue requirement?

A. As shown on Attachment RCS-2, Schedule C-5, page 1, a base cost of fuel and purchased power of $0.030948 per kWh, or $287.373 million, has been used. This is $4.816 million lower than the amount reflected by TEP. The $4.816 million difference is comprised of two components, a $260,000 difference between the per-kWh starting amount for determining the base cost of fuel and a $5.076 million difference for the treatment of sulfur credits as a reduction to the cost of coal. The net of those two amounts produces the adjustment of $4.816 million. As shown in Schedule C-5, page 1, an adjustment has been

made to correspondingly decrease pro forma PPFAC revenue and fuel and purchased power costs by the same amount of $4.816 million.

Q. Has Staff also made an adjustment to Lime Expense, relating to the Springerville coal contract sulfur credits accounting issue that you described above?

A. Yes. As described in a subsequent section of my testimony, Staff has made a corresponding adjustment to Lime Expense, relating to the sulfur credits accounting issue. That Staff adjustment is shown on Attachment RCS-2, Schedule C-14, and increases the jurisdictional adjusted cost of Lime Expense in account 502 by $5.076 million.

C-6 Rate Case Expense

Q. What amount of rate case expense is the Company requesting recovery for in this case?

A. TEP is requesting recovery of $1.415 million for current rate case expenses over 3 years for an annual allowance of $471,667 per year.

Q. Do you agree with the Company's proposed amount of rate case expense for this case?

A. No. The total amount of rate case expense is excessive and would represent an unreasonable burden on ratepayers. Additionally, the amount included in rates for an allowance for rate case expense should be understood to be a normalized amount, not an amortization. Additionally, a four-year normalization period was used in TEP's last rate case. TEP has not exhibited an historical pattern of filing for base rate changes on a three-year interval.

Q. What total amount of rate case expense was allowed in the last TEP rate case?

A. The allowance for rate case expense was based on a total amount of $900,000 for rate case expenses in its prior rate case, Docket No. E-01933A-07-0402, normalized over a period of four years, for an annual allowance of $225,000 per year.[13]

Q. How does the current TEP rate case compare with the last TEP rate case?

A. TEP's last rate case included complex issues involving whether TEP generation would be regulated at market prices or at a cost of service which are not present in the current TEP rate case. TEP has not justified a more than doubling of the annual rate case expense allowance from Docket No. E-01933A-07-0402 of $225,000 to its requested amount of $471,667, which is an increase of 110 percent.

Q. What do you recommend for the allowance for rate case expense for TEP in this proceeding?

A. I recommend an annual allowance of $225,000, based on normalizing a total amount of $900,000 over the same four-year base rate case filing cycle that was used in TEP's last base rate case.

Q. Please summarize your recommended adjustment.

A. I recommend an annual allowance of $225,000 per year, based on holding the total amount of allowed rate case charges to $900,000, normalized over the same four year base rate filing cycle that was used in TEP's last base rate case. Schedule C-6 reduces the Company's proposed annual allowance for current rate case costs by $246,667.

[13] See, e.g., TEP's workpaper TEP(0402)002591 from Docket No. E-01933A-07-0402, a copy of which is included in Attachment RCS-3, attached to my testimony.

Q. May Staff adjust the estimated amount of $900,000 downward if it is determined to include excessive charges for no-bid contracts?

A. Yes. Based on a review to date of confidential documentation provided by TEP, Staff is concerned that the Company's rate case expense for the current case may contain excessive charges resulting from no-bid contracts.[14] Consequently, a downward adjustment may be necessary to the total amount or annual allowance. If Staff determines that such an adjustment is needed, it will be presented in the Staff surrebuttal filing.

C-7 Directors' and Officers' Liability Insurance

Q. Please explain Staff Adjustment C-7.

A. This adjustment removes one-half of the Directors' and Officers' Liability Insurance expense and reduces test year O&M expense by $327,100. The removal of one-half of this expense reflects an equal (i.e., 50/50) sharing of the cost for this insurance between shareholders and ratepayers. The ACC jurisdictional expense reduction is $289,320, as shown on Attachment RCS-2, Schedule C-7.

Q. Why should the cost of the D&O insurance expense be shared between shareholders and ratepayers?

A. This type of insurance coverage usually comes into play when a shareholder sues the officers and directors of a public company, such as TEP's parent UniSource Energy. Thus, it helps protect the officers and directors from the costs of a shareholder lawsuit. Shareholders benefit from payouts under the policy that would reduce the cost not recoverable from ratepayers. On the other hand, ratepayers benefit from this because having such insurance improves the ability of the publicly traded parent corporation to attract and retain qualified directors and officers and enables the directors and officers to

[14] TEP provided details for outside consultant contracts and invoices in its CONFIDENTIAL response to STF 5.34.

make decisions without fear of personal liability. Consequently, it is reasonable for shareholders to bear some of the cost for the D&O Insurance.

Q. Was this adjustment made in TEP's last rate case?

A. To my knowledge it was not.

Q. Did Staff recommend a similar adjustment in Southwest Gas' most recent Arizona rate case and in the most recent UNS Gas rate case?

A. Yes, and a similar adjustment was also made in Southwest Gas' Nevada rate case, Nevada PSC Docket No. 09-04003, and adopted by the Nevada Commission in an order dated October 29, 2009. Southwest's D&O Insurance expense is a "system allocable" expense, meaning that it is incurred at Southwest's corporate headquarters and the cost is allocated to the divisions. Thus, a portion of the same Southwest D&O Insurance expense that was recently disallowed in Nevada was being allocated to Arizona, and was adjusted for 50/50 sharing by Staff in SWG's most recent Arizona rate case, Docket No. G-01551A-10-0458.[15] Staff also recommended a similar adjustment in UNS Gas's most recent rate case, Docket No. G-04204A-11-0158. Similarly, TEP's D&O Insurance Expense represents a cost for insurance coverage for UniSource Energy directors that benefits shareholders and should thus be borne in part by shareholders.

Q. Have other regulatory commissions besides Nevada made a similar adjustment for sharing of D&O Liability Insurance Expense between shareholders and ratepayers?

A. Yes. The Nevada Commission order in Southwest Gas' 2009 rate case, at page 47, paragraph 157, cited two states (Arkansas and California) that have required a sharing of

[15] Southwest Gas' most recent Arizona rate case resulted in a settlement being reached by most of the parties to that case, which incorporated this Staff adjustment. The Commission's Final Order incorporated that adjustment.

D&O Liability Insurance Expense between ratepayers and shareholders on a 50-50 basis.[16] I am aware that at least two other commissions (Connecticut and Florida) have made adjustments for a ratepayer and shareholder sharing of D&O Insurance expense. Connecticut has also required shareholders to share a portion of the cost of D&O Insurance expense, with the shareholder portion varying from 50 percent to 75 percent in different cases.

Q. Have you included an attachment with excerpts from the orders of which you are aware which have made such findings concerning sharing of D&O Insurance Expense between shareholders and ratepayers?

A. Yes. Attachment RCS-5 contains excerpts from such orders that we have currently located.

Q. Please summarize the adjustment to expense for D&O Insurance sharing between shareholders and ratepayers.

A. As shown on Schedule C-7, TEP's proposed test year expense for D&O Insurance of $654,200 should be reduced by $327,100 to reflect an allocation of 50 percent of this expense to shareholders. The ACC jurisdictional adjustment reduces expense by $289,320.

Q. Is there a related adjustment to rate base?

A. Yes. A related adjustment to rate base is shown on Schedule B-3 to remove 50 percent of the prepaid amount for D&O Insurance.

[16] To date, we have not located the Arkansas and California commission orders which required that sharing.

C-8 Edison Electric Institute and Industry Association Dues

Q. Please explain Staff's proposed adjustment for Edison Electric Institute and Industry Association dues.

A. This adjustment is shown on Schedule C-8 and reduces test year expense by $127,121 on a total company basis and $112,438 on an ACC Jurisdictional basis. It reflects the removal of 49.93 percent of Edison Electric Institute ("EEI") core dues, and 6.0 percent of the EEI Utility Air Regulatory Group ("UARG") dues. Staff's adjustment also removes 100 percent of Western Energy Supply and Transmission ("WEST") Association dues.

Q. How does Staff's proposed adjustment for Edison Electric Institute dues compare with TEP's proposed treatment of such dues?

A. As noted above, Staff's adjustment reflects the removal of 49.93 percent of EEI core dues, 6 percent of the EEI UARG dues and 100 percent of the WEST dues. TEP's filing reflected the removal of 21.3 percent of the EEI core dues for Legislative Advocacy, removal of 8.2 percent of Utility Solid Waste Activities Group ("USWAG") dues, removal of none of the EEI UARG dues, and none of the WEST dues.

Q. How did you determine the portion of EEI core dues that should not be charged to ratepayers?

A. I obtained a classification by NARUC category for EEI Core Dues activities for the year ended December 31, 2005. This is shown on Schedule C-8, page 2. EEI Core Dues relating to the following activities should be excluded from rates:

- Legislative Advocacy
- Regulatory Advocacy
- Advertising
- Marketing

- Public Relations

The sum of EEI Core Dues activities for these NARUC categories totals 49.93 percent, as shown on Schedule C-8, page 2.

Q. What is the purpose of the NARUC-designated categorization of EEI expenditures?

A. The purpose of the NARUC-designated categorization of EEI expenditures is to provide regulatory commissions with information that is useful in helping them decide which, if any, of the costs of the association should be approved for inclusion in utility rates. Often, state commissioners review the costs of the association charged or allocated to the utilities in their jurisdiction in accordance with the policies of their commission for treatment of costs directly incurred by the state's utilities for similar activities. Certain expense categories may be viewed by some State commissions as potential vehicles for charging ratepayers with such costs as lobbying, advocacy or promotional activities which may not be to their benefit. The NARUC-designated categories of EEI expenditures are thus intended to be helpful to state utility regulatory commissions.

Q. Was this same percentage for the EEI core dues disallowance used in any other electric utility rate cases?

A. Yes. The Arkansas Public Service Commission in Docket No. 06-101-U, an Entergy Arkansas, Inc. rate case, in Order No. 10 (6/15/07) adopted a similar adjustment to reflect the disallowance of 49.93 percent of EEI core dues. This 49.93 percent disallowance of EEI core dues corresponds to the above-identified activity categories.

Q. What is UARG?

A. UARG is the EEI Utility Air Regulatory Group, which EEI sometimes also refers to as the "Separately Funded Activity" ("SFA") for Environment. This group, like the other EEI

separately funded activities (or "U-groups"), advocates the electric utility industry's views before legislative, regulatory, and judicial bodies.

Q. Did TEP provide information from EEI indicating the non-deductible percentage for UARG?

A. Yes. A letter from EEI dated March 29, 2012, provided on Company workpaper TEP(0291)007234, states that percentages of such activities are non-deductible:

> We have completed the calculation of EEI's actual final expenditures relating to influencing legislation for calendar year 2011. A total of 21.3% of our regular dues was devoted to non-deductible activities in 2011. In addition, 29.1% of the assessment for the SFA for Industry Issues, **6.0% of the assessment for the SFA for Environment,** 8.2% of the assessment for the Utility Solid Waste Activities Group ("USWAG"), and 68.2% of the assessment for the Water Advocacy Coalition (WAC) **were devoted to non-deductible activities in 2011.** These percentages may affect the extent to which your 2011 EEI dues and SFA payments qualify as a deductible business expense.
>
> (Emphasis supplied.)

EEI's letter refers to UARG as the SFA for Environment. EEI's invoices refer to the SFA-Environment by its traditional designation, UARG. Association activities, such as lobbying and influencing legislation, are considered a "non-deductible activity" for federal income tax purposes. According to the EEI guidance, at least 6.0 percent of the UARG dues are related to "non-deductible activity." Consequently, at least 6.0 percent of the UARG dues should be disallowed for ratemaking purposes. I recommend disallowing $8,608 on a total company basis, and $7,614 on an ACC Jurisdictional basis, of EEI UARG dues from the cost of service.

Q. What are the WEST dues?

A. As provided in TEP's response to UDR 1.55a, WEST Associates is a coalition of 10 cooperative, public power and investor-owned electric utilities serving over 12 million customers in 11 Western states. WEST Associates advocates on behalf of the member utilities to ensure that uniquely western issues impacting member companies and their operations are recognized in federal, state and local regulatory matters.

Q. Why did you determine to remove 100 percent of the WEST dues?

A. WEST dues are a discretionary expenditure. Except for organizations related to reliability, these expenditures are not directly essential to the provision of electric service. The cost of membership in organizations should not be reflected in rates unless the Company can demonstrate the cost is necessary for the provision of safe, reliable, and reasonably priced electric service, or that such membership otherwise provides a direct benefit to ratepayers. A web search indicates that WEST sponsors legislative travel. The portion of WEST dues that go for such activities should be disallowed but cannot be ascertained from information provided by TEP. The Company has neither explained nor justified the WEST dues expenditures. Given the discretionary nature of these expenditures, it would be unreasonable to include them in rates without some type of review for cost/benefit and appropriateness. I recommend disallowing $11,632 on a total Company basis, and $10,289 on an ACC Jurisdictional basis, of WEST dues from the cost of service.

C-9 Property Tax Expense

Q. Why is there a concern with how TEP and its affiliates have been deriving Arizona property tax expenses for ratemaking purposes?

A. In the recent UNS Gas rate case, it came to Staff's attention that the combined total amount of Arizona property tax expense being requested in rate cases by TEP and its utility affiliates, UNS Gas and UNS Electric, was consistently exceeding the total amount of property taxes in each year that these three affiliated utilities were paying to the Arizona counties and municipalities that were assessing the property taxes. TEP and its affiliates argue that their ratemaking method for reflecting property taxes should continue to be used, even though the method consistently overcharges ratepayers for Arizona property taxes for the three utilities combined. However, Staff sees no justification for these three utilities continuing to reflect for ratemaking purposes more Arizona property taxes than they are actually paying. Staff believes the property tax estimation method used by TEP and its utility affiliates is flawed because it consistently overstates the combined amount of Arizona property taxes that these three affiliated utilities are assessed and pay.

TEP has also claimed that because a "separate return" basis is used to calculate income tax expense for ratemaking purposes, its Arizona property tax allowances should also be based on "separate company" calculations, even though the Arizona property taxes are assessed for the three affiliated utilities on a combined basis. However, Staff does not view this Arizona property tax issue as being similar to corporate income taxes, which involve the application of complex tax laws.

Q. Has TEP identified any decisions or Commission directives which specifically address the issue of actual property taxes versus "stand alone" property taxes?

A. No. TEP's response to STF 16.10, for example, states that: "TEP is not aware of any decisions or Commission directives which specifically address the issue of actual versus standalone property taxes." As indicated in its response to STF 11.11(c), the TEP-affiliated utilities instead have relied on Decision No. 59951(January 1997) decision on an income tax issue that was addressed for the electric division of Citizens Utilities which addressed an issue of whether a 34 percent or 35 percent income tax rate should be used for computing income taxes for that utility at that time.

Q. Is the property tax issue being addressed in the current TEP rate case the same as an income tax issue that was addressed for the electric division of Citizens Utilities in Decision No. 59951?

A. No. The property tax issue being addressed in the current TEP rate case is basically whether TEP and its affiliates should be allowed to use a method to compute property tax expense for ratemaking purposes that has consistently over-charged Arizona ratepayers for the combined utilities' amounts of actual Arizona property taxes. This has nothing to do with income taxes. Moreover, TEP's response to STF 25.3 states that TEP has not used a 34 percent income tax rate for ratemaking purposes in the last ten years. So the income tax issue that was addressed in 1997 for the electric division of Citizens Utilities in Decision No. 59951 is not on point to the property tax issue being addressed in the current TEP rate case. TEP's response to STF 11.11(c) indicates that actual property tax bills for TEP and its affiliated utilities are computed on a combined basis. The Company does not expect pro forma property tax expense for ratemaking purposes computed on a standalone basis to produce the same results as actual property tax bills.

Q. Since TEP has attempted to justify using a method for determining property tax expenses that has resulted in substantial overstatements of actual property tax expense in each year (2008, 2009, 2010 and 2011) by referring to a "combined" method, did Staff investigate the impacts of the method of TEP's affiliates, such as UNS Electric and UNS Gas?

A. Yes. This was investigated through discovery in the recent UNS Gas rate case and in the current TEP rate case, including confidential information provided in response to STF 5.42, STF 11.10, STF 11.11, STF 16.10, and UDR 1.66 and 1.68. The method has also resulted in large over-estimations of property tax expense for TEP and UNS Gas but not for UNS Electric. TEP's supplemental response to STF 16.10(i) in the current case shows the property tax amounts for TEP, UNS Gas, UNS Electric and the combined 3 utilities using (1) TEP's proposed ratemaking method (labeled on that response as "Standalone") and (2) the actual property tax expense. A copy of that response is included in Attachment RCS-4. The combined property tax amounts for the three affiliated utilities are also summarized below:

Property Taxes - All Three Utilities (TEP, UNSG and UNSE)			
Year	Company Proposed Ratemaking (Standalone)	Actual	Dollar Difference - Over (Under) Actual
2008	$ 31,086,631	$ 30,960,721	$ 125,910
2009	$ 37,295,024	$ 36,510,393	$ 784,631
2010	$ 37,742,465	$ 37,088,968	$ 653,497
2011	$ 39,113,512	$ 39,193,822	$ (80,310)
2012	$ 41,323,323	$ 40,896,821	$ 426,502
Average	$ 37,312,191	$ 36,930,145	$ 382,046
Source: TEP's supplemental response to STF 16.10(i)			

As shown in the above table, in five of the six years reviewed and on average, the Company's proposed ratemaking for property tax expense would over-charge Arizona

ratepayers for Arizona property taxes. Staff sees no justification for a method that consistently over-charges Arizona ratepayers of the three affiliated utilities for Arizona property taxes that are assessed to and paid by these utilities.

Q. What is the Arizona property tax assessment cycle and how does that affect the amounts of Arizona property taxes that TEP pays and records as expense on its books?

A. The Company's response to STF 11.10 describes the dates which govern the property tax assessment, payment and expense recording cycle. For tax year 2012, for example, it shows the following dates:

- Assessment date: January 1, 2011
- Lien date: January 1, 2012
- Expense Recording: 50% in 2012 and 50% in 2013
- Payment Due Dates: October 1, 2012 and March 1, 2013
- Payment Delinquent Dates: November 1, 2012 and May 1, 2013

Q. Has TEP provided actual versus stand-alone property tax information for 2013?

A. Yes. TEP's response to STF 28.1 provides actual versus stand-alone property tax information for 2013 for TEP, as well as for the affiliated utilities, UNS Electric and UNS Gas.

Q. What property tax expense has TEP claimed on a pro forma adjusted basis for the test year?

A. As shown on Attachment RCS-2, Schedule C-9, page 2, TEP has claimed total property tax expense of $39,148,092 on a pro forma adjusted basis. This includes the 2011 test year recorded amount of $32,641,952 and the net result of three pro forma adjustments proposed by TEP for property taxes. TEP's pro forma adjustments reduce property taxes

by $503,492 to reflect costs assigned to the owners of Springerville Units 3 and 4, and increases of recorded property tax expense of $3,657,904 for Springerville Unit 1 and $3,351,728 for a general increase based on TEP's application of the stand-alone ratemaking method described above.

Q. What is Staff's recommended property tax expense adjustment?

A. As shown on Schedule C-9, Staff's recommended adjustment uses the 2013 "actual" basis amounts of property taxes provided by TEP in response to STF 28.1 for TEP in total, as well as corresponding with the Springerville property tax adjustments. The 2013 actual property taxes shown in the response to STF 28.1 are based on assessments of plant in service as of December 31, 2011, and represent the best available estimates of property taxes anticipated to be recorded in 2013. As shown on Schedule C-9, page 1, Staff's adjustment reduces TEP's proposed property tax expense by $1.460 million on an ACC Jurisdictional basis, and consists of three components: (1) an increase of $249,795 for property taxes (on line 1), and decreases of $33,579 and $1,675,816, respectively, corresponding with using actual 2013 amounts for TEP's Springerville Units 3 and 4 Adjustment and Springerville Unit 1 Adjustment for property taxes.[17]

C-10 Property Tax and Depreciation Expense – New Headquarters Building

Q. Please explain Staff adjustment C-10.

A. This adjustment removes property tax expense for structures and buildings on the amount of Staff's jurisdictional adjustment for TEP's new headquarters building plant. As shown on Exhibit RCS-2, Schedule C-10, property taxes are reduced by $130,541. Depreciation expense of $178,000 is also removed at TEP's proposed depreciation rate for structures

[17] Staff's adjustment for Springerville Unit 1 related expenses is addressed in additional detail in conjunction with Staff Adjustment C-11. In that adjustment, the amount shown for 2013 actual Springerville Unit 1 property taxes is added to Springerville Unit 1 expenses, subject to the cap provided by using a levelized cost recovery rate of $25.67 per MW.

and buildings on the amount of Staff's jurisdictional adjustment for TEP's new headquarters building plant.

C-11 Other Operating Revenue: Reimbursed Operating Expenses for Springerville Units 3 and 4

Q. Please explain Staff adjustment C-11.

A. As shown on Attachment RCS-2, Schedule C-11, TEP records Other Operating Revenue to reflect the reimbursement of operating expenses for Springerville fuel handling and common facilities from the owners of Springerville Units 3 and 4. TEP operates the Springerville plant, including Unit 1 (which TEP leases), Unit 2 (which TEP owns), and Units 3 and 4 (which are owned by non-affiliated entities, Tri-State and Salt River Project ("SRP")). The non-affiliates, Tri-State and SRP, pay TEP for TEP's operating expenses related to those units (Springerville 3 and 4), as well as reimburse TEP for costs related to Springerville common and coal handling facilities. TEP proposes to keep approximately $6.961 million of those Springerville operating expense reimbursements annually for its shareholders. TEP reflects its proposed shareholder retention by excluding 50 percent of the reimbursements from Tri-State and SRP for Springerville fuel handing and common facilities use from Other Operating Revenue. Other Operating Revenue would typically be considered as a source of revenue that helps offset the utility's revenue requirement.

Because of the unique history of Springerville, Staff believes that some sharing of the non-affiliated owners' cost reimbursements to TEP with shareholders may be appropriate, but believes that an almost $7 million amount annually for TEP's shareholders for such sharing is excessive. Staff's adjustment, as shown on Schedule C-11, reflects a 90/10 sharing of the Other Operating Revenues related to Tri-State and SRP reimbursements to TEP for Springerville coal handling and common facilities use. TEP's attempt to divert for the benefit of its shareholders $6.961 million of the Springerville operating expense

reimbursements annually is reduced by $5.569 million, by adding that amount back to Other Operating Income. This leaves an annual pre-tax profit amount for TEP shareholders of 10 percent, or $1.392 million, for the Springerville fuel handling and common reimbursements TEP receives from Tri-State and SRP that is not reflected in developing TEP's jurisdictional revenue requirement.

It should also be noted, as also shown on Schedule C-11, that both TEP and Staff have reflected 100 percent of the Other Operating Revenues recorded by TEP for Springerville vehicle use reimbursements by Tri-State and SRP, which correspondingly reduces the revenue requirement borne by TEP's ratepayers.

C-12 Springerville Unit 1 Levelized Expense

Q. Please discuss TEP's lease interests in Springerville Unit 1.

A. As described in the testimony of TEP witnesses Karen Kissinger and Kentton Grant, TEP leases Springerville Unit 1 under seven separate lease agreements. The scheduled lease payments vary from period to period but are fixed by contract and are not tied to any market-based index or variable rate of interest. For financial reporting purposes, TEP accounts for these leases using the interest method of capital lease accounting. TEP records a lease obligation on its balance sheet equal to the net present value of scheduled rent payments and records interest expense on the liability in each reporting period. This method also requires TEP to record a capital lease on its balance sheet and to amortize the asset on a straight-line basis over the term of the lease.

Q. How are Springerville Unit 1 costs reflected in TEP's current rates?

A. In TEP's last rate case, SGS unit 1 was reflected as a non-fuel recovery allowance based on $25.67 per kW per month that reflected a levelized cost of the facility through the

remainder of the primary lease term. The associated leasehold improvements were included in rate base at their depreciated original cost.

Q. How has TEP proposed to reflect Springerville Unit 1 lease costs in the current rate case?

A. In the current rate case, TEP has made an adjustment to increase jurisdictional operating expenses by $41 million. TEP's lease for SGS unit 1 is addressed in TEP witness Grant's testimony at pages 17-32. A similar adjustment was a significant issue in TEP's last rate case. TEP's 2011 TY recorded O&M expense for Springerville Unit 1 was about $71 million, and equates to a cost per kW/month of about $15.54. TEP's pro forma adjustment increases that cost to $25.67/kW/month for a total adjusted expense of $117.055 million before jurisdictional allocation.

TEP's Springerville Unit 1 adjustment is fairly complex and includes numerous pieces, including rent, payroll adjustments, property taxes, and rent/lease cost. The rent is the largest single item and reflects a total increase of $45 million. The total capped expense amount of $117.055 million, as reproduced on Attachment RCS-2, Schedule C-12, page 2, column G, is based on 380 MW x 12 months x the $25.67 levelized cost/kW/month.

Q. Is that generally consistent with how the TEP's Springerville Unit 1 leases were treated in TEP's last rate case?

A. Yes. A similar levelized adjustment that also utilized the $25.67 cost/kW/month and the 380MW that had approximated a levelized cost of the facility through the remainder of the primary lease term was ultimately accepted by Staff and was incorporated into the settlement results in TEP's last rate case that were approved by the Commission in its determination of TEP's revenue requirement in that case. The levelized lease treatment

for Springerville Unit 1 costs from TEP's last rate case that reflected such a settlement, however, were not viewed as being binding upon any ratemaking treatment in the current TEP rate case. Consequently, Staff has re-examined the Springerville Unit 1 issue freshly in the context of the current TEP rate case.

Q. Has Staff accepted TEP's proposed Springerville Unit 1 levelized lease treatment as a cap on Springerville Unit 1 cost recovery for purposes of the current TEP rate case?

A. Yes. The policy reasons and history behind this adjustment from the last TEP rate case were reviewed, as well as TEP's testimony and support in the current rate case. In the current case, TEP is seeking a continuation of the existing ratemaking treatment ordered in the last case, and its adjusted SGS unit 1 operating costs reflect the $25.67/kW/month allowance for SGS 1 and common facilities. Springerville Unit 1 leasehold improvements are included in rate base at their depreciated original cost. Although Staff has accepted the continued use of the $25.67/kW/month allowance as the capped expense allowance for use in the current TEP rate case for Springerville Unit 1 levelized lease costs, the individual expense components of the total $117.055 million allowance for this differ between Staff and TEP. These differences cause a difference in the amount of ACC jurisdictional expense for Springerville Unit 1 between TEP's request and Staff's recommendations.

Q. Please explain Staff adjustment C-12.

A. As shown on Attachment RCS-2, Schedule C-12, both TEP and Staff have reflected an allowance for Springerville Unit 1 expense based on a levelized recovery cap using $25.67 per kW per month, which is the same level that was reflected in TEP's last rate case, Docket No. E-01933A-07-0402 and incorporated into Decision No. 70628 (December 1, 2008). Although both TEP and Staff have reflected the continued levelized ratemaking

cap for Springerville Unit 1 in the current case, the specific levels of certain expenses, such as incentive compensation and Springerville Unit 1 property taxes are different between TEP and Staff. Because different jurisdictional factors are applied to the various expenses which comprise the Springerville Unit 1 expense allowance, the variances between Staff and TEP result in a total Company adjustment of zero and an ACC jurisdictional expense decrease of approximately $13,000 in Staff's adjustment. As shown on Schedule C-12, page 1, the net jurisdictional expense decrease in Staff's adjustment is comprised of a net decrease to jurisdictional O&M expenses of $1.689 million and a net increase in Springerville Unit 1 property tax expense of $1.676 million.

Q. What is shown on Schedule C-12, pages 2 and 3?

A. Schedule C-12, page 2, reproduces TEP's proposed Springerville Unit 1 levelized cost allowance. Page 2 also shows TEP's jurisdictional expense request by account, and the related jurisdictional factors for each account.

Schedule C-12, page 3, shows, in similar detail, the components of Staff's proposed Springerville Unit 1 levelized cost allowance. As shown on page 3, Staff's adjustment reflects removal of 50 percent of the incentive compensation amounts that were included in TEP's proposed Springerville Unit 1 expenses. Fifty percent of the incentive compensation expenses included by TEP in TEP's Springerville Unit 1 expense amounts are removed to reflect conceptual consistency with Staff adjustment C-2, which reflects removal of 50 percent of the annual incentive compensation amounts requested by TEP. Staff's adjustment also uses the amount of Springerville Unit 1 property tax expense, computed on the "actual" method for 2013, as described above in conjunction with Staff adjustment C-9. This reflects consistent treatment of Springerville Unit 1 property taxes in Staff adjustments C-9 and C-12.

Q. What has TEP proposed for Springerville Unit 1 leasehold improvement costs?

A. TEP has included these in rate base at net depreciated original cost, which appears to be consistent with the treatment in TEP's last rate case. The Springerville Unit 1 leasehold improvements are used and useful in the provision of electric utility service, so inclusion in rate base at net depreciated original cost is not objectionable.

TEP has also included an amortization of SGS unit 1 leasehold improvements. This is discussed at Mr. Grant's testimony at pages 32-33. TEP proposes a ten-year amortization for the cost of those leasehold improvements. The remaining life of the lease was used, subject to the following considerations to mitigate the cost impact. For SGS common facilities the lease expires in 2021. However, for SGS unit 1 and the Coal Handling Facilities ("CHF") the leases expire in 2015. In the current case, to help mitigate cost impacts, TEP has proposed a ten-year amortization period for the leasehold improvements, which would extend beyond the current expiration dates of the leases for SGS unit 1 and the CHF.

Q. What is Staff's position on TEP's proposed treatment of the amortization of SGS unit 1 leasehold improvements?

A. In the context of the treatment of the other SGS unit 1 lease costs, and in recognition that TEP's proposed ten-year amortization period for the SGS unit 1 leasehold improvements helps mitigate the cost impacts (versus an alternative of using a shorter amortization period), Staff has accepted TEP's proposed treatment. Again, the treatment of SGS costs, including any remaining unamortized leasehold improvement costs should be reviewed in TEP's next rate case. In the report Staff recommends be filed by TEP in July 2014 concerning the status of SGS unit 1, TEP should also identify the remaining unamortized SGS unit 1 leasehold improvements, and if TEP's ownership arrangement for SGS unit 1

is changing (e.g., if either TEP acquires the unit or enters into a new lease), TEP should also at that time include a discussion of whether the amortization period for SGS leasehold improvement costs should be revised for accounting and/or ratemaking purposes.

Q. You mentioned that the primary Springerville Unit 1 lease is scheduled to expire in January 2015. Is it reasonable to anticipate that Springerville Unit 1 will continue to operate beyond the current January 2015 lease expiration date?

A. Yes. TEP has indicated that Springerville is one of TEP's most efficient generating plants. Although it is unclear at this point what form of ownership or financial/lease arrangement will replace the current leases, it is reasonable to expect that Springerville Unit 1 will continue to operate well beyond the primary lease expiration date of January 2015.

Q. What regulatory concerns does Staff have regarding the Springerville Unit 1 lease expirations?

A. Staff wants to make the Commission aware of a regulatory concern regarding the expirations of Springerville Unit 1 leases.

One option is that TEP will acquire Springerville at the end of the lease. The primary Springerville lease provides for an acquisition price based on the fair market value. TEP witness Grant's direct testimony and exhibits present the status of the potential acquisition. There is currently a dispute between TEP and the lessors over what the fair market value should be. If TEP's view of the fair market value/acquisition price prevails, upon lease expiration and acquisition in January 2015, TEP's revenue requirement related to Springerville could be significantly reduced. However, it is not clear at this point if TEP's view of the acquisition price will prevail and because of the substantial amounts at

stake, another possibility is that extended litigation over the acquisition amount could ensue.

As described above, because the primary SGS Unit 1 leases run through January 2015 and the outcome after that date is subject to significant uncertainties, Staff has concluded that continuation of the use of the $25.67 per kW per month Springerville Unit 1 levelized cap ratemaking treatment is reasonable through that date. However, if TEP's base rates established in the current case are going to continue to be in effect beyond January 2015, Staff recommends that TEP report to the Commission no later than July 31, 2014, concerning the status of the Springerville Unit 1 leases, and the status of TEP's acquisition of Unit 1. Staff recommends that, in that report, TEP present a proposal for accounting protection of ratepayers, such as tracking as a regulatory liability, if the Springerville Unit 1 costs will be lower than the approximately $117.055 million (total Company basis) amount currently reflected in rates under the levelized lease cost treatment. The timing of this report by TEP is intended to allow Staff and other interested parties to review TEP's proposal and bring this matter to the Commission's attention before the leases expire in January 2015.

Staff also recommends that TEP's situation with respect to Springerville Unit 1 and common facilities be reviewed again in the context of TEP's next rate case.

C-13 Day Nite Design Branding/ Marketing/ General Corporate Advertising

Q. Please explain the adjustment for branding, marketing and general corporate advertising expenses.

A. As shown on Attachment RCS-2, Schedule C-13, during the test year, TEP recorded some expenses in account 930, which TEP's response to STF 26.10 indicates are for expenses

paid to Day Nite Design for branding, marketing and general corporate advertising expenses, for which TEP is requesting recovery in rates. This Staff adjustment removes $14,756 of such expenses on a total Company basis and $13,052 on an ACC jurisdictional basis because such expenses are discretionary, but unnecessary for the provision of safe and reliable electric utility service.

C-14 Lime Expense

Q. Please explain Staff's adjustment to Lime Expense.

A. As described in a previous section of my testimony,[18] Staff has made a corresponding adjustment to Lime Expense that relates to the sulfur credits accounting issue. TEP proposes to reflect sulfur credits as a reduction to lime expense in account 502. TEP reduced Lime Expense, on a pro forma adjusted basis, by $5,699,539 as shown on Schedule C-14 and on Schedule C-5, page 2. Staff has reflected sulfur credits as a contractual reduction to the cost of coal expense in account 501 (which is a PPFAC-includable account), in accordance with the USOA and standard accounting for electric utilities with coal-fired generation. Also, see the direct testimony of Staff witness Emily Medine concerning the sulfur credits that reduce TEP's cost of coal when the delivered coal has a higher sulfur content than the base levels specified in the contract. Staff's adjustment to reflect that sulfur credits are a reduction to the cost of coal that is recorded in account 501, rather than a reduction to Lime Expense (which TEP records in account 502), is shown on Attachment RCS-2, Schedule C-14, and increases the jurisdictional adjusted cost of Lime Expense in account 502 by $5.076 million.

[18] See previous testimony discussion under C-5, Base Cost of Fuel and Purchased Power, of an issue involving the accounting for sulfur credits.

V. DEPRECIATION RATES

Q. Please discuss the new depreciation rates that TEP has proposed.

A. The development of new depreciation rates is addressed in the testimony of TEP witness, Dr. White, who sponsors the Company's 2012 Depreciation Rate Study. The tables presented at pages 10-11 of Dr. White's testimony summarizes the overall changes, as follows:

	Accrual Rate			2012 Annualized Accrual		
Function	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Steam Production	3.95%	3.21%	-0.74%	$64,456,192	$52,351,592	($12,104,600)
Other Production	3.63%	3.40%	-0.23%	6,151,449	5,754,061	(397,388)
Distribution	1.82%	1.81%	-0.01%	22,334,266	22,287,648	(46,618)
General Plant	4.87%	5.48%	0.61%	14,268,048	16,046,523	1,778,475
Net Salvage (Dist.)	0.28%	0.27%	-0.01%	3,445,167	3,322,125	(123,042)
Total	3.32%	3.00%	-0.32%	$110,655,122	$99,761,949	($10,893,173)

As shown in the above table, the new depreciation rates proposed by TEP witness White decrease depreciation expense on Distribution, Steam Production, and Other Production by approximately $10.893 million. The change in annualized accruals includes a reduction of $7.861 million attributable to amortization of a $246.684 million depreciation reserve imbalance. The remaining change is attributable to service life and net salvage statistics recommended in the 2012 study.

Q. What Commission rules address the treatment of depreciation?

A. The Commission's rules at R14-02-102 address the treatment of depreciation. The current version of the rules appears to have been adopted effective April 9, 1992. This pre-dates the adoption of Statement of Financial Accounting Standards No. 143, "Accounting for

Asset Retirement Obligations" which has resulted in revisions for financial reporting purposes, among other things, of the presentation of cost of removal information. I discussed SFAS No. 143 in detail in my testimony in TEP's last rate case.

Q. Did TEP file a new depreciation study in the current rate case?

A. Yes. Exhibit REW-1 attached to Dr. White's testimony is the 2012 Depreciation Rate Study for TEP.

Q. Please discuss the Company's proposed depreciation rates and how they were derived.

A. The new depreciation rates proposed by TEP are summarized in Company witness Dr. White's testimony and are shown in detail in his Exhibit REW-1. The Company's proposed rates were developed using a depreciation system composed of the straight-line method, vintage group procedure and remaining life technique.

Q. Before discussing specific issues associated with TEP's proposed depreciation rates, could you please provide your understanding of some basic depreciation terminology?

A. Yes, of course.

Q. What is depreciation?

A. The Commission's rules at R14-2-102(A)(3) define "depreciation" as "an accounting process which will permit the recovery of the original cost of an asset less its net salvage over the service life."

Q. What is net salvage?

A. The Commission's rules at R14-2-102(A)(5) define "net salvage" as "the salvage value of property less the cost of removal."

Q. What is "salvage value"?

A. The Commission's rules at R14-2-102(A)(5) define "salvage value" as:

> [T]he amount received for assets retired, less any expenses incurred in selling or preparing the assets for sale; or if retained, the amount at which the material recoverable is chargeable to materials and supplies, or other appropriate accounts.

Q. What is the "cost of removal"?

A. The Commission's rules at R14-2-102(A)(5) define the "cost of removal" as "the cost of demolishing, dismantling, removing, tearing down, or abandoning of physical assets, including the cost of transportation and handling incidental thereto."

Q. What is depreciation expense?

A. Depreciation expense is a charge to operating expense to reflect the recovery of depreciable utility plant. Depreciation rates are applied to a utility's depreciable utility plant to determine the amount of depreciation expense. Public utility depreciation expense is typically straight-line over the service life which results in an equal share of the cost of assets being assigned or allocated to expense each year over the service life of the assets. A service life is the period of time during which depreciable plant and equipment is in service. [19]

[19] National Association of Regulatory Utility Commissioners Public Utility Depreciation Practices, August, 1996. ("NARUC Depreciation Manual"), p. 321. Also, Commission Rule R14-2-102, which defines "service life" as "the period between the date an asset is first devoted to public service and the date of its retirement from service."

Q. What is depreciable utility plant?

A. Public utilities record their plant investment activity in the individual plant accounts set-forth in the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts ("USOA"). Plant additions, retirements and balances are maintained by plant account. An annual addition is the original cost of plant added to the account during the year. A retirement is recorded in the plant account by removing the original cost of a prior addition when such plant is removed from service. The plant balance is what is left at the end of an accounting period after accounting for additions and retirements.

Q. How is the annual depreciation expense calculated?

A. Annual depreciation expense, called an accrual, is calculated by applying a depreciation rate to plant balances.

Q. Is the depreciation accrual a cash expense?

A. No. Depreciation is considered a non-cash expense.

Q. Please explain the distinction between a cash and non-cash expense.

A. Depreciation expense is considered a non-cash accrual. This contrasts with payroll expense, for example, which involves the current outlay of cash. Depreciation expense does not involve a specific payment during the test-year. Both depreciation and payroll are included as expenses in the income statement and revenue requirement, but no cash flows out of the company for depreciation expense. Instead of reducing the cash account, depreciation expense is recorded on the income statement as an expense and is simultaneously recorded on the balance sheet in the accumulated depreciation account; which is shown as an offset to plant in service. The following accounting entries illustrate the difference:

		Amount
Account	Description	Dr. (Cr.)
403	Depreciation Expense	$ 1,000
108	Accumulated Depreciation	$ (1,000)
	To record depreciation	
various	Payroll Expense	$ 1,000
131	Cash	$ (1,000)
	To record payroll expense	

Q. What is the Accumulated Depreciation account?

A. Accumulated Depreciation, Account 108 in the USOA, is a record of the previously recorded depreciation expense. At any point in time, the accumulated depreciation account represents the net accumulated amount of the original cost of assets and net salvage that has been recovered to date. From a regulatory perspective, Accumulated Depreciation can be considered a measure of the depreciation recovered from ratepayers. Commission Rule R14-2-102 defines "accumulated depreciation" as "the sum of the annual provision for depreciation from the time that the asset is first devoted to public service."

Q. How does depreciation expense impact a utility's revenue requirement?

A. Annual depreciation expense is a cost that is included in a public utility's revenue requirement. Because public utilities tend to be capital intensive, depreciation expense can be a significant component of the utility's revenue requirement.

Q. What is the objective of depreciation expense?

A. From a regulatory perspective, the objective of public utility depreciation is straight-line capital recovery. This is accomplished by allocating the original cost of assets to expense over the lives of those assets through the application of depreciation rates to plant

balances. Additionally, many state regulatory commissions, including the ACC, have allowed utilities to recover through the commission-authorized depreciation rates, the utility's estimated future cost of removal, which is part of the net salvage component of the depreciation rates.

Q. Please illustrate how depreciation rates are developed.

A. The following calculation shows a straight-line whole-life depreciation rate assuming a 10-year average service life and a $1 million plant investment, and the whole life method. Each year the 10 percent depreciation rate would be applied to plant in service to produce an annual depreciation expense and an entry to accumulated depreciation:

Straight-Line Whole-Life Depreciation Rate
Assuming $1 Million Investment and a 10-Year Life
Depreciation Rate: 100% / 10 Years = 10% Per Year

Year	Annual Depreciation Expense	End-of-Year Accumulated Depreciation
1	$ 100,000	$ (100,000)
2	$ 100,000	$ (200,000)
3	$ 100,000	$ (300,000)
4	$ 100,000	$ (400,000)
5	$ 100,000	$ (500,000)
6	$ 100,000	$ (600,000)
7	$ 100,000	$ (700,000)
8	$ 100,000	$ (800,000)
9	$ 100,000	$ (900,000)
10	$ 100,000	$ (1,000,000)
TOTAL	$ 1,000,000	

Q. What happens at the end of an asset's life under this scenario?

A. All things equal, at the end of 10 years, the plant balance will be 100 percent (or $1 million), and the accumulated depreciation balance will also be 100 percent (also $1 million). This equality is important to understanding issues relating to the cost of removal/negative net salvage.

Q. What is negative net salvage?

A. Negative net salvage is the difference between any salvage value and the cost of removal of the asset after completion of its service life. If the cost of removal exceeds the salvage amount, this produces negative net salvage. In this testimony I will use the terms negative net salvage and net cost of removal interchangeably. The ratemaking treatment of negative net salvage was raised by a Staff witness (Mr. Majoros) as a major issue affecting utility depreciation rates in a previous APS rate case, Docket No. E-01345A-03-0437. Negative net salvage can have a significant impact on a utility's depreciation rates and revenue requirement.

Q. What happens if estimated future negative net salvage is included in the calculation?

A. Assume a negative 55 percent (-55%) net salvage ratio. The above whole-life example with a 55 percent value for negative net salvage is as follows:

Straight-Line Whole-Life Depreciation Rate
Assuming $1 Million Investment, a 10-Year Life
And Negative Net Salvage of 55%
Depreciation Rate: [100% - (-55%)] / 10 Years = 15.5% Per Year

Year	Annual Depreciation Expense	End-of-Year Accumulated Depreciation	Annual Negative Net Salvage Charge	FAS 143 Regulatory Liability
1	$ 100,000	$ (100,000)	$ 55,000	$ (55,000)
2	$ 100,000	$ (200,000)	$ 55,000	$ (110,000)
3	$ 100,000	$ (300,000)	$ 55,000	$ (165,000)
4	$ 100,000	$ (400,000)	$ 55,000	$ (220,000)
5	$ 100,000	$ (500,000)	$ 55,000	$ (275,000)
6	$ 100,000	$ (600,000)	$ 55,000	$ (330,000)
7	$ 100,000	$ (700,000)	$ 55,000	$ (385,000)
8	$ 100,000	$ (800,000)	$ 55,000	$ (440,000)
9	$ 100,000	$ (900,000)	$ 55,000	$ (495,000)
10	$ 100,000	$ (1,000,000)	$ 55,000	$ (550,000)
TOTAL	$ 1,000,000		$ 550,000	

In this example, negative net salvage increases the resulting whole-life depreciation rate from 10 percent to 15.5 percent, i.e., by 55 percent. This increase results from the inclusion of estimated future net cost of removal, including estimated future inflation.

Q. Please explain the "FAS 143 Regulatory Liability" column in the above example.

A. Because the Company has no current legal obligation to pay the estimated future inflated cost of removal (negative net salvage) amounts (i.e., has no asset retirement obligation), the excess amounts recovered through depreciation rates are accumulated in a regulatory liability account for financial reporting purposes, pursuant to Statement of Financial Accounting Standards No. 143 ("SFAS 143"). I will explain certain provisions in SFAS 143 that require such treatment in more detail later in my testimony.

Q. Why does negative net salvage increase the depreciation rate?

A. It increases the depreciation rate because negative salvage is, in effect, added to the original cost of the plant. Instead of 100 percent (which represents the original cost of assets), the numerator becomes 155 percent. This is equivalent to capitalizing or adding the estimated cost of removal to the original cost of the asset. In the above example, instead of recovering the original plant cost of $1 million, the depreciation rates would recover $1.55 million.

Q. What happens at the end of a plant asset's life under this scenario?

A. The plant balance will be 100 percent but the sum of the accumulated depreciation balance and the regulatory liability account will be 155 percent. Consequently, unlike the "zero net salvage scenario" shown above, when negative net salvage is included in a depreciation rate, there will not be an equality of plant and reserve at the end of an asset's life because the Company will have charged more depreciation than it paid for the original cost of the asset. Under these circumstances, equality will only be achieved if the Company actually spends additional money at the end of the asset's life.

Q. Is the Company required to pre-collect from ratepayers estimated future amounts of money that it might spend at the end of plant useful life?

A. Where there is no legal requirement to incur cost of removal, TEP has no current legal liability to spend money for estimated future cost of removal. The Commission rules at R14-2-102(B)(3) require: "The cost of depreciable plant adjusted for net salvage shall be distributed in a rational and systematic manner over the estimated service life of the plant." As discussed above, the Commission's rules define "net salvage" to include the cost of removal. Consequently, I conclude that the Commission's rules require cost of removal to be included in the utility's depreciation rates.

Q. If the Company does incur an obligation at the end of an asset's service life that requires spending money for removal, can the Company take the money out of accumulated depreciation?

A. No. Accumulated Depreciation is an unfunded account. Even though the Company collected money from ratepayers for future removal cost that had been included in past depreciation rates, it will have already spent that money on whatever it chose in the past: salaries, dividends, etc.

Q. Please explain the concept of remaining life depreciation.

A. The remaining life technique is similar to the whole-life technique, but it incorporates accumulated depreciation into the numerator of the equation, and the denominator becomes the remaining life rather that the whole life of the asset.

Q. What happens when accumulated depreciation is incorporated into the numerator of the basic depreciation calculation?

A. If the 10-year asset is 3 years old, its remaining life would be 7 years (10 – 3 = 7). The accumulated depreciation account would be 30 percent of the original cost because the 10 percent depreciation rate would have been applied for three years (3 x 10% = 30%). The remaining life depreciation rate would then be 10 percent, calculated as follows:

Straight-Line Remaining-Life Depreciation Rate
Assuming $1 Million Investment and a 10-Year Life
Depreciation Rate: [100% - 30%] / [10 - 3 Years] = 10% Per Year

Year	Annual Depreciation Expense	End-of-Year Accumulated Depreciation
3		$ (300,000)
4	$ 100,000	$ (400,000)
5	$ 100,000	$ (500,000)
6	$ 100,000	$ (600,000)
7	$ 100,000	$ (700,000)
8	$ 100,000	$ (800,000)
9	$ 100,000	$ (900,000)
10	$ 100,000	$ (1,000,000)
TOTAL	$ 700,000	

Under the example with the assumed 55 percent negative net salvage, and a 7-year remaining life, the results would be a 15.5 percent depreciation rate, as shown below:

Straight-Line Remaining-Life Depreciation Rate
Assuming $1 Million Investment, a 10-Year Life
And Negative Net Salvage of 55%
Depreciation Rate: [(100% - (-55%)) - (3 x 15.5%)] / [10 - 3 Years] = 15.5% Per Year
Depreciation Rate: [(108.5%)] / [7 Years] = 15.5% Per Year

Year	Annual Depreciation Expense	End-of-Year Accumulated Depreciation	Annual Negative Net Salvage Charge	FAS 143 Regulatory Liability
3		$ (300,000)		$ (165,000)
4	$ 100,000	$ (400,000)	$ 55,000	$ (220,000)
5	$ 100,000	$ (500,000)	$ 55,000	$ (275,000)
6	$ 100,000	$ (600,000)	$ 55,000	$ (330,000)
7	$ 100,000	$ (700,000)	$ 55,000	$ (385,000)
8	$ 100,000	$ (800,000)	$ 55,000	$ (440,000)
9	$ 100,000	$ (900,000)	$ 55,000	$ (495,000)
10	$ 100,000	$ (1,000,000)	$ 55,000	$ (550,000)
TOTAL	$ 700,000		$ 385,000	

Q. Why would the whole-life depreciation rate in the example with negative net salvage and the remaining life depreciation rate in the negative net salvage example both be 15.5 percent?

A. In these examples, the remaining life depreciation rate and the whole-life depreciation rates are the same (15.5 percent) because I have assumed that the accumulated depreciation account is in balance. In other words, based on a continuation of the fundamental parameters, i.e., the 10-year service life and the negative 55 percent net salvage ratio, exactly the right amount of depreciation has been charged and collected in the past.

Q. What would happen if either of these fundamental parameters were to change?

A. If either the service life or net salvage parameter changes during the life of the plant, the accumulated depreciation account will be out of balance, and the remaining life rate will be either higher or lower than the whole-life rate depending on the direction of the imbalance. That is because the Company will have collected either too much depreciation or not enough depreciation in the past, given the current estimates of lives or future net salvage. The difference between the actual amount recovered, as included in the book

depreciation reserve, and a theoretical estimate of what should be in the book reserve, is called a "reserve imbalance." The remaining life technique is often used to deal with such reserve imbalances.

Q. Since the last revision to the Commission's rules regarding the treatment of depreciation, has a significant accounting pronouncement been issued?

A. Yes. As noted above, it appears that the Commission's rules concerning the treatment of depreciation were last revised and became effective April 9, 1992. Since that date, generally accepted accounting principles ("GAAP"), specifically SFAS 143, highlight the amounts associated with estimated future cost of removal for which no current legal obligation exists and require that they be reported as Regulatory Liabilities for financial reporting purposes. A regulatory liability can be viewed as an amount owed to ratepayers.

Q. What is SFAS 143?

A. The Financial Accounting Standards Board ("FASB") is a standards-setting body for the public accounting profession. In June 2001, the FASB promulgated Statement of Financial Accounting Standards No. 143 ("FAS 143"). This pronouncement addresses the appropriate accounting for long-lived assets. It is effective for all fiscal years beginning after June 15, 2002. However, earlier application was encouraged. Pursuant to SFAS 143, all companies, both unregulated (e.g., Walmart) and regulated (e.g., TEP) must review all of their long-lived assets to determine whether or not they have actual legal obligations to remove retired assets. For some plant and equipment, companies have a legal obligation to remove the asset at the end of the service life. These legal obligations for future removal are called asset retirement obligations ("AROs"). For other assets, no such obligation exists.

If a company does have an ARO, the fair value of the future retirement cost, which is determined using net present value techniques, is considered to be part of the original cost of the asset. That ARO is therefore capitalized (included in the original cost) and depreciated over the life of the asset. In essence, if a Company incurs a legal liability to spend money to remove an asset at the end of its life, that liability is part of the cost of the asset.

In contrast, if a company does not have such legal obligations, the future cost of removal will not be capitalized as part of the asset cost and will not be included in depreciation expense. Only the initial cost of the asset (which does not include estimated inflated future cost of removal for which no current liability exists) will be depreciated.

At the end of the asset's life, for assets without AROs, the accumulated depreciation account will equal the plant balance. In other words, under SFAS 143, there is symmetry between assets with and without AROs. In both cases, the accumulated depreciation will equal the original cost of the asset at the end of its life.

Q How are AROs recorded for accounting purposes?

A. As stated above, AROs are capitalized as a cost of the related asset and simultaneously recorded as a liability for those companies with a legal obligation to remove a retired asset. To illustrate, assuming an ARO of $500, the $500 would be debited (i.e., added) to plant and simultaneously credited (i.e., added) to the regulatory liability account. Each year, as the liability increases due to inflation, the increase is charged to accretion expense and credited to the liability, but the asset value remains the same. In other words, just as the original cost of the asset does not increase, neither does the capitalized asset retirement cost.

Q. What happens if a company does not have an asset retirement obligation pursuant to SFAS 143?

A. If a company does not have such obligations, the estimated future inflated cost of removal is not considered as a cost of the asset, and therefore it will not be included in the company's depreciation expense on its general purpose financial statements. SFAS 143, therefore, unbundles net salvage from depreciation rates. It does this in two ways: (1) by incorporating the net present value of an ARO in the cost of the asset, or (2) by excluding non-AROs from the depreciation rate calculations.

Q. What is the accounting impact of SFAS 143 for electric utilities?

A. Under GAAP, electric utilities are required to review all of their assets to determine if they have any AROs. If a utility has any AROs, they are capitalized. Paragraph B73 of SFAS 143 provides an exception for regulated utilities, which allows them to continue to incorporate net salvage factors ("non-legal AROs") in depreciation rates even if they do not have AROs. Utilities are also required to determine the amount of any prior cost of removal collections relating to non-AROs that is now included in their accumulated depreciation accounts, and reclassify these and any such future charges as a regulatory liability in their financial statements. In other words, even with the paragraph B73 exception, SFAS 143 provides transparency through reporting disclosure requirements.

Q. What is the impact of SFAS 143 on electric regulatory accounting?

A. FERC addressed SFAS 143 in Docket RM02-7-000 which resulted in Order No. 631. FERC Order 631 essentially adopts SFAS 143 and integrates it into the Uniform System of Accounts. Utilities are required to review their long-lived assets to determine if they have any AROs. Where utilities do not have AROs, any charges for such amounts must be separately identified. FERC Order 631 defines cost of removal allowances for which

there is no legal asset retirement obligation, as "non-legal retirement obligations." Past and future "non-legal AROs" must be specifically identified and accounted for separately in the depreciation studies, depreciation expense and the accumulated depreciation account. In Order 631, FERC maintains the transparency resulting from the "separation principle" for non-legal AROs that was established in paragraph B73 of SFAS 143. Paragraph 38 of Order 631 explains FERC's new requirements for non-legal AROs:

> Instead, we will require jurisdictional entities to maintain separate subsidiary records for cost of removal for non-legal retirement obligations that are included as specific identifiable allowances recorded in accumulated depreciation in order to separately identify such information to facilitate external reporting and for regulatory analysis, and rate setting purposes. Therefore, the Commission is amending the instructions of accounts 108 and 110 in Parts 101, 201 and account 31, Accrued depreciation - Carrier property, in Part 352 to require jurisdictional entities to maintain separate subsidiary records for the purpose of identifying the amount of specific allowances collected in rates for non-legal retirement obligations included in the depreciation accruals.

Q. Does FERC provide any additional insight as to the interpretation of these new rules?

A. Yes, at paragraph 39 of the order, FERC states:

> Jurisdictional entities must identify and quantify in separate subsidiary records the amounts, if any, of previous and current accumulated removal costs for other than legal retirement obligations recorded as part of the depreciation accrual in accounts 108 and 110 for public utilities and licensees, account 108 for natural gas companies, and account 31 for oil pipeline companies. If jurisdictional entities do not have the required records to separately identify such prior accruals for specific identifiable allowances collected in rates for non-legal asset retirement obligations recorded in accumulated depreciation, the Commission will require that the jurisdictional entities separately identify and quantify prospectively

> the amount of current accruals for specific allowances collected in rates for non-legal retirement obligations.

Q. Does FERC make any policy calls concerning the appropriate treatment of the disposition of prior and future collections contained in these separate allowances?

A. No. As indicated at paragraph 64 of the Order, FERC declined to make such calls on a policy basis. Rather, FERC will resolve the appropriate treatment of the dispositions of prior and future collections on a case-by-case basis.

Q. Did FERC's Order require anything new or more with respect to its requirement for detailed depreciation studies?

A. No. At paragraph 65 of the Order, FERC states that:

> ... this rule requires nothing new and nothing more with respect to the requirement for a detailed study. Complex depreciation and negative salvage studies are routinely filed or otherwise made available for review in rate proceedings. When utilities perform depreciation studies, a certain amount of detail is expected. It is incumbent upon the utility to provide sufficient detail to support depreciation rates, cost of removal, and salvage estimates in rates.

Additionally, footnote 45 states:

> When an electric utility files for a change in its jurisdictional rates, the Commission requires detailed studies in support of changes in annual depreciation rates if they are different from those supporting the utility's prior approved jurisdictional rate.

Thus, FERC recognizes distinctions between legal and non-legal AROs just as SFAS 143 recognizes those distinctions. On a going-forward basis, jurisdictional entities must be prepared to specifically identify and justify any non-legal AROs that they propose to include in rates.

Q. Has TEP implemented SFAS 143?

A. Yes. The Company has implemented SFAS 143. I have previously described how TEP implemented SFAS 143 with respect to cost of removal that had been recorded in Accumulated Depreciation by TEP with respect to its generation assets. For TEP's transmission, distribution and general plant assets, consistent with adopting this accounting principle for financial reporting purposes, TEP reclassified prior year removal costs of approximately $80 million previously included in accumulated depreciation to the liability for asset retirements and removals in its Balance Sheets.

Q. How does TEP report on its financial statements the component of depreciation rates for net cost of removal that is not associated with a legal obligation that requires application of the accounting requirement for asset retirement obligations?

A. TEP reports that component of accumulated cost of removal as a regulatory liability on its GAAP-basis financial statements. As described on page K-67 of TEP's 2011 SEC Form 10-K (Exhibit KGK-1 to Ms. Kissinger's direct testimony):

> TEP has various transmission and distribution lines that operate under leases and rights of way that contain end dates and restorative clauses. TEP operates its transmission and distribution lines as if they will be operated in perpetuity and would continue to be used or sold without land remediation. As such there are no legal obligations that require application of the accounting requirement for asset retirement obligations. Nevertheless, included in the revenue requirement underlying the Company's electric service Retail Rates is a component of depreciation expense intended to enable TEP to accrue the future costs of retiring assets for which no legal obligations exists. The accumulated balance of such accruals, less actual removal costs incurred, net of salvage proceeds realized, is reported as a regulatory liability.

When initially adopting SFAS 143, companies such as TEP, reclassified for financial statement reporting purposes their accumulated cost of removal for which there is no

current legal obligation for removal, from Accumulated Depreciation and reported this as a Regulatory Liability.

Q. Are the "costs of removal" that were reclassified as a regulatory liability for financial reporting purposes the result of TEP's past depreciation rates?

A. Essentially, yes. Similar to most utilities, TEP's past depreciation rates have included negative net salvage. This has resulted in TEP pre-collecting from ratepayers estimated future costs of removal for non-legal AROs, which under SFAS 143, have been reclassified for financial reporting purposes as a regulatory liability.

Plant and equipment are retired from service at the end of their useful lives. Sometimes the retired plant and equipment may be physically removed and can be resold for value. This is called gross salvage. The cost of removal net of the value received for the salvage constitutes net salvage. In more technical terms, gross salvage is the amount recorded for the property retired due to the sale, reimbursement, or reuse of the property. Cost of removal is the cost incurred in connection with the retirement from service and the disposition of depreciable plant. As discussed above, net salvage is the difference between gross salvage and cost of removal.

Q. Are net salvage ratios included in the Company's depreciation rate calculations?

A. Yes. Substantial negative net salvage ratios are included in several of TEP's depreciation rates. The inclusion of negative future net salvage ratios in TEP's proposed depreciation rates result in depreciation rates that are significantly higher in many instances than if no cost of removal had been included. As noted above, the inclusion of net salvage in depreciation rates appears to be consistent with past practices of the utility and Commission, and appears to be required by Commission rule R14-2-102(B)(3).

Q. Do TEP's proposed depreciation rates include estimated future removal costs?

A. Yes. As noted above, TEP's proposed depreciation rates include estimated future removal costs, including estimated future inflation. TEP has done this by including negative net salvage ratios in the development of depreciation rates for many, but not all, of its depreciable plant assets. TEP has also incorporated the results of dismantlement studies for production plant.[20]

Q. Please comment on the incorporation of the results of plant specific dismantlement studies.

A. TEP has included dismantlement costs for fossil generation in the development of its proposed depreciation rates. TEP has based its costs on dismantlement studies for each plant for which such costs are being requested. The decommissioning studies supporting the dismantlement cost estimates are discussed in TEP witness Mansfield's testimony at pages 6-7. Having plant specific dismantlement studies may produce better cost estimates than attempting to use a percentage negative net salvage/cost of removal. The results of the dismantlement studies are reflected in Dr. White's depreciation study and appear to have been reasonably incorporated into the new depreciation rates proposed by TEP.

Q. Where does TEP develop its estimated future costs of removal that are included in its proposed depreciation rates?

A. These are developed in Dr. White's Attachment REW-1, on Statement E (average net salvage), Statement H (present and proposed parameters) of those attachments. As explained on page 10 of the depreciation study:

> Average net salvage rates for an account or plant function are derived from a direct dollar weighting of a) historical retirements

[20] See, e.g., TEP Exhibit REW-1, Statement G, Dismantlement Costs, Steam and Other Production

with the historical (or realized) net salvage rates and b) future retirements (i.e., surviving plant) with the estimated future net salvage rate. Average net salvage rates will change, therefore, as additional years of retirement and net salvage activity become available and as the weighting of future net salvage estimates changes from the installation of subsequent plant additions.

Q. What remaining useful lives does TEP's depreciation study reflect for production plant?

A. The following table lists TEP's steam and other production plant, shows the TEP ownership share and the remaining lives that are reflected in TEP's depreciation study:

Generating Source	Unit No.	Date in Service	Fuel Type	MW	Operating Agent	TEP's Share %	TEP's Share MW	TEP Expected Remaining Life at 12/31/2012 (In Years)
Springerville Station	1	1985	Coal	401	TEP	100.0	401	
Springerville Station	2	1990	Coal	403	TEP	100.0	403	36.57
San Juan Station	1	1976	Coal	340	PNM	50.0	170	23.72
San Juan Station	2	1973	Coal	340	PNM	50.0	170	20.90
Navajo Station	1	1974	Coal	750	SRP	7.5	56	21.84
Navajo Station	2	1975	Coal	750	SRP	7.5	56	22.77
Navajo Station	3	1976	Coal	750	SRP	7.5	56	23.71
Four Corners Station	4	1969	Coal	784	APS	7.0	55	17.10
Four Corners Station	5	1970	Coal	784	APS	7.0	55	18.05
Luna Energy Facility	1	2006	Gas	555	PNM	33.0	185	37.52
Sundt Station	1	1958	Gas/Oil	81	TEP	100.0	81	5.46/6.45
Sundt Station	2	1960	Gas/Oil	81	TEP	100.0	81	5.46/8.41
Sundt Station	3	1962	Gas/Oil	104	TEP	100.0	104	10.36
Sundt Station	4	1967	Coal/Gas	156	TEP	100.0	156	34.74
Sundt Combustion Turbines		1972-1973	Gas	50	TEP	100.0	50	5.46
DeMoss Petrie		1972	Gas/Oil	75	TEP	100.0	75	32.97
North Loop		2001	Gas	95	TEP	100.0	95	15.54
Solar Electric Generation		2002-2010	Solar	13	TEP	100.0	13	17.06
Total TEP Capacity							2,262	
Source: TEP Exhibit REW-1, page 4, and Statement H								

As shown in the above table, TEP continues to be heavily dependent upon coal-fired generation. With more stringent environmental regulations expected to be imposed in the future, some of TEP's older coal-fired generation may be at risk of becoming uneconomical when the cost of installing additional environmental controls are

considered. It is unclear whether TEP's remaining life estimates for its coal-fired generation fleet are overly optimistic in view of environmental controls that may be imposed, which could render some of the units uneconomic. As the requirements for environmental controls have become more stringent, it has not been uncommon in the electric generation industry to see utility announcements of plant retirements. Currently, as summarized in the above table, TEP has not reflected imminent retirements for its older coal-fired generating units in its depreciation study. TEP's generating plans are subject to review in the Integrated Resource Planning process. Should TEP realize that any of its coal-fired generating units are being rendered uneconomic due to environmental costs or other factors, TEP should inform the Commission promptly of this and provide its analysis. The remaining useful lives used by TEP for such generation should also continue to be reviewed in each TEP rate case.

Q. Should the depreciation rates proposed by TEP be adopted for use in this case?

A. Yes. The depreciation rates proposed by TEP presented in Dr. White's Attachment REW-1 should be adopted for use in this case. Those depreciation rates proposed by TEP were developed in a manner that is generally consistent with the Commission's rules for depreciation rates. My review of the details provided in Dr. White's Attachment REW-1 and other information indicates that those new rates proposed by TEP are consistent with industry accepted depreciation practices. The net change in percentage terms resulting from TEP's proposed new depreciation rates is a decrease of 0.32 percent (from a current composite of 3.32 percent to 3.00 percent under the new proposed rates). TEP's proposed rates for Steam Production Plant show a decrease of approximately $12.1 million, or 0.74 percent versus current rates. TEP's proposed depreciation rates for General Plant show an increase of approximately $1.778 million, or 0.61 percent. For all categories of plant

studied (production, distribution, general plant and net salvage), TEP shows a net decrease of approximately $10.893 million.

VI. OTHER ISSUES

Q. Are there certain other issues which did not result in Staff making adjustments to TEP's proposed rate base or net operating income that you wish to discuss?

A. Yes.

A. Post-Test Year Plant

Q. How is inclusion of post-test year plant in rate base an issue in the current TEP rate case?

A. As described below in more detail, TEP has proposed to include approximately $40 million in rate base for solar and other post-test year plant additions. Some of this amount relates to projects that would be placed into service, at various points in time before new base rates resulting from this proceeding are anticipated to become effective.

Q. Is the inclusion of post-test-year plant in rate base an exceptional ratemaking treatment and up to the discretion of the Commission?

A. Yes, it is. Staff's understanding is, in specific instances, the Commission has allowed a utility to include CWIP, or alternatively post-test year plant additions, in rate base, but the Commission's general practice has been to not allow CWIP to be included in rate base. That said, the inclusion of CWIP in rate base is an exceptional ratemaking treatment.

Q. Please elaborate on how including CWIP or post-test-year plant in rate base is an exceptional ratemaking treatment.

A. CWIP, as the title designates, is not plant that is completed and providing service to ratepayers during the test year. During the test year, it is not used or useful in providing electric service to a utility's customers. The ratemaking process is predicated on an examination of the operations of a utility to insure that the assets upon which ratepayers are required to provide the utility with a rate of return are prudently incurred and are both used and useful in providing services on a current basis. Facilities in the process of being built are not used or useful. The ratemaking process therefore excludes CWIP from rate base until such projects are completed and providing service to ratepayers in the context of a test year that is being used for determining the utility's revenue requirement. In the current TEP rate case, the test year is the twelve months ending December 31, 2011, and the construction projects the Company seeks to include in rate base were not providing service during that period. The Company claims that the construction projects it is requesting for inclusion in rate base will be in service by December 31, 2012, before the time rates in this proceeding take effect.

Q. What post-test year plant additions is TEP requesting?

A. In its filing, TEP has requested post-test year plant additions for plant it anticipates will be placed into service by December 31, 2012.

Q. What is Staff's position on the inclusion of post-test-year plant in rate base for TEP?

A. I am advised that Staff has made a policy decision to recommend allowing the inclusion of post test year plant in rate base in this proceeding.

Q. What policy guidance are you following concerning the amount of post-test year plant additions that Staff proposes be included in rate base?

A. Staff has determined in the current TEP base rate case that post-test-year plant additions that can be verified as having been placed into service by December 31, 2012 should be included in rate base as post-test-year plant.

Q. What rate base adjustments have you made to TEP's proposed miscellaneous post-test year plant additions based on that guidance?

A. TEP's proposed post test year plant additions are for items that TEP had recorded in CWIP as of December 31, 2011, the end of the test year, for which TEP projects will be in service by December 31, 2012. The sample of projects reviewed by Staff engineers and engineering consultants confirmed that such plant is being placed into service by that date. Consequently, Staff has accepted TEP's adjustment for post test year plant. The amounts of post-test-year plant that TEP has requested that are in service or projected to be in service by December 31, 2012 have therefore been included in rate base as plant in service by Staff.

B. Accumulated Deferred Income Taxes – Impact of Net Operating Loss Carryforward Attributable to Tax Depreciation

Q. Has the amount of Accumulated Deferred Income Taxes ("ADIT") reflected by TEP as an offset to rate base been impacted by a tax Net Operating Loss ("NOL")?

A. Yes. For the 2011 test year, TEP had an NOL carry-forward, which is an ADIT debit balance item that effectively increases rate base (or could be viewed as limiting the ADIT credit balance for depreciation which but for the NOL carryforward would have been a larger reduction to rate base). TEP has also included in rate base debit balance ADIT for Alternative Minimum Tax (AMT). TEP claims that its NOL carry forward resulted from use of accelerated tax deprecation (including bonus tax depreciation) and, therefore, TEP

needs to include the NOL carryforward-related ADIT in rate base (or not reduce rate base for that portion of the depreciation related ADIT) until it actually is applied on an income tax return to reduce taxes. TEP points out that in two other small utility rate cases it appears the Commission reflected the full ADIT rate base deduction for accelerated tax depreciation without regard to whether the utility's tax depreciation had created an NOL carryforward. TEP claims that the treatment utilized in those two small utility rate cases could result in a normalization violation.

Q. Have you seen similar situations arise in other recent rate cases?

A. Yes. It has not been unusual for utilities to have NOLs in recent years. In many instances, some portion or all of the NOLs can be attributed to the tax depreciation claimed. Extra large deductions have been available for bonus tax depreciation in 2010 and 2011 and the opportunity for taking 50% bonus tax depreciation on qualifying plant investments continues in 2012.

Q. How has the ADIT related to the utility NOL carryforward resulting from tax depreciation generally been addressed?

A. Based on my experience, it has generally been addressed by limiting the ADIT deduction to tax depreciation deductions that have actually been used to reduce the utility's income taxes. In other words, rate base was not reduced by the impact of the NOL carryforward that resulted from tax depreciation. Normalization requirements appear to support TEP's proposed treatment as well as the treatment that I have seen for NOL carryforward impacts resulting from tax depreciation impacts on ADIT in other rate cases.

Q. Is Staff proposing a different treatment for the impact of the NOL carryforward attributable to tax depreciation for TEP in the current case?

A. No. The treatment of the ADIT relating to the NOL carryforward proposed by TEP appears to be reasonable in the context of the current rate case.

C. Green Watts

Q. What has TEP proposed for the Green Watts program?

A. TEP proposes to discontinue Green Watts. Its solar programs, Community Solar Program, would essentially replace it. As explained on page 48 of TEP witness Craig Jones Direct Testimony, GreenWatts is a voluntary contribution program that allowed customers to support the development of clean energy including solar resources. TEP has been applying revenues from GreenWatts to the cost of building, operating and maintaining new solar power sources. With the REST rules now in effect, TEP believes that the GreenWatts program is redundant, requiring separate administration and accounting. TEP believes that the cost burden to continue this program outweighs its effectiveness to support solar development, in light of other programs. TEP witness Craig indicates at page 48 of his Direct Testimony that TEP's Community Solar Program is designed specifically for customers who want to support solar development in the community without having to put a system on their personal residence. He states that the Community Solar Program not only accomplishes all of the goals of the GreenWatts program, but provides other benefits that GreenWatts does not provide.

Q. Has the number of customers participating in GreenWatts, and the monthly revenue from GreenWatts declined?

A. Yes. TEPs' response to STF 1.066 shows GreenWatts participation and revenues for the period January 2009 through July 2012. As of January 2009, there were 48 commercial

customers and 2,176 residential customers participating in GreenWatts for monthly GreenWatts revenue to TEP of $9,176. As of July 2012, there were 39 commercial customers and 1,745 residential customers participating in GreenWatts, for monthly GreenWatts revenue to TEP of approximately $7,093.

Q. Does Staff oppose TEP's discontinuing Green Watts if it is replaced by one of TEP's solar programs?

A. No.

Q. If there is a remaining balance of customer-provided Green Watts funds when the program is discontinued by TEP, how should those funds be accounted for and applied?

A. It appears from the discovery received, including TEP's response to STF 11.03, that to date TEP has over-collected Green Watts revenue from ratepayers and has a "regulatory liability" for the net over-collections which appear to be continuing. If there is any remaining balance of customer-provided GreenWatts funds when the program is discontinued by TEP, those funds should be accounted for as a regulatory liability by TEP, and should be applied to the solar program that replaces GreenWatts.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

Attachment RCS-1
QUALIFICATIONS OF RALPH C. SMITH

Accomplishments

Mr. Smith's professional credentials include being a Certified Financial Planner™ professional, a Certified Rate of Return Analyst, a licensed Certified Public Accountant and attorney. He functions as project manager on consulting projects involving utility regulation, regulatory policy and ratemaking and utility management. His involvement in public utility regulation has included project management and in-depth analyses of numerous issues involving telephone, electric, gas, and water and sewer utilities.

Mr. Smith has performed work in the field of utility regulation on behalf of industry, public service commission staffs, state attorney generals, municipalities, and consumer groups concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Carolina, North Dakota, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Vermont, Virginia, Washington, Washington DC, West Virginia, Canada, Federal Energy Regulatory Commission and various state and federal courts of law. He has presented expert testimony in regulatory hearings on behalf of utility commission staffs and intervenors on several occasions.

Project manager in Larkin & Associates' review, on behalf of the Georgia Commission Staff, of the budget and planning activities of Georgia Power Company; supervised 13 professionals; coordinated over 200 interviews with Company budget center managers and executives; organized and edited voluminous audit report; presented testimony before the Commission. Functional areas covered included fossil plant O&M, headquarters and district operations, internal audit, legal, affiliated transactions, and responsibility reporting. All of our findings and recommendations were accepted by the Commission.

Key team member in the firm's management audit of the Anchorage Water and Wastewater Utility on behalf of the Alaska Commission Staff, which assessed the effectiveness of the Utility's operations in several areas; responsible for in-depth investigation and report writing in areas involving information systems, finance and accounting, affiliated relationships and transactions, and use of outside contractors. Testified before the Alaska Commission concerning certain areas of the audit report. AWWU concurred with each of Mr. Smith's 40 plus recommendations for improvement.

Co-consultant in the analysis of the issues surrounding gas transportation performed for the law firm of Cravath, Swaine & Moore in conjunction with the case of Reynolds Metals Co. vs. the Columbia Gas System, Inc.; drafted in-depth report concerning the regulatory treatment at both state and federal levels of issues such as flexible pricing and mandatory gas transportation.

Lead consultant and expert witness in the analysis of the rate increase request of the City of Austin - Electric Utility on behalf of the residential consumers. Among the numerous ratemaking issues addressed were the economies of the Utility's employment of outside services; provided both written and oral testimony outlining recommendations and their bases. Most of Mr. Smith's recommendations were adopted by the City Council and Utility in a settlement.

Key team member performing an analysis of the rate stabilization plan submitted by the Southern Bell Telephone & Telegraph Company to the Florida PSC; performed comprehensive analysis of the Company's projections and budgets which were used as the basis for establishing rates.

Lead consultant in analyzing Southwestern Bell Telephone separations in Missouri; sponsored the complex technical analysis and calculations upon which the firm's testimony in that case was based. He has also assisted in analyzing changes in depreciation methodology for setting telephone rates.

Lead consultant in the review of gas cost recovery reconciliation applications of Michigan Gas Utilities Company, Michigan Consolidated Gas Company, and Consumers Power Company. Drafted recommendations regarding the appropriate rate of interest to be applied to any over or under collections and the proper procedures and allocation methodology to be used to distribute any refunds to customer classes.

Lead consultant in the review of Consumers Power Company's gas cost recovery refund plan. Addressed appropriate interest rate and compounding procedures and proper allocation methodology.

Project manager in the review of the request by Central Maine Power Company for an increase in rates. The major area addressed was the propriety of the Company's ratemaking attrition adjustment in relation to its corporate budgets and projections.

Project manager in an engagement designed to address the impacts of the Tax Reform Act of 1986 on gas distribution utility operations of the Northern States Power Company. Analyzed the reduction in the corporate tax rate, uncollectibles reserve, ACRS, unbilled revenues, customer advances, CIAC, and timing of TRA-related impacts associated with the Company's tax liability.

Project manager and expert witness in the determination of the impacts of the Tax Reform Act of 1986 on the operations of Connecticut Natural Gas Company on behalf of the Connecticut Department of Public Utility Control - Prosecutorial Division, Connecticut Attorney General, and Connecticut Department of Consumer Counsel.

Lead Consultant for The Minnesota Department of Public Service ("DPS") to review the Minnesota Incentive Plan ("Incentive Plan") proposal presented by Northwestern Bell Telephone Company ("NWB") doing business as U S West Communications ("USWC"). Objective was to express an opinion as to whether current rates addressed by the plan were appropriate from a Minnesota intrastate revenue requirements and accounting perspective, and to assist in developing recommended modifications to NWB's proposed Plan.

Performed a variety of analytical and review tasks related to our work effort on this project. Obtained and reviewed data and performed other procedures as necessary (1) to obtain an understanding of the Company's Incentive Plan filing package as it relates to rate base, operating income, revenue requirements, and plan operation, and (2) to formulate an opinion concerning the reasonableness of current rates and of amounts included within the Company's Incentive Plan filing. These procedures included requesting and reviewing extensive discovery, visiting the Company's offices to review data, issuing follow-up information requests in many instances, telephone and on-site discussions with Company representatives, and frequent discussions with counsel and DPS Staff assigned to the project.

Lead Consultant in the regulatory analysis of Jersey Central Power & Light Company for the Department of the Public Advocate, Division of Rate Counsel. Tasks performed included on-site review and audit of Company, identification and analysis of specific issues, preparation of data requests, testimony, and cross examination questions. Testified in Hearings.

Assisted the NARUC Committee on Management Analysis with drafting the Consultant Standards for Management Audits.

Presented training seminars covering public utility accounting, tax reform, ratemaking, affiliated transaction auditing, rate case management, and regulatory policy in Maine, Georgia, Kentucky, and Pennsylvania. Seminars were presented to commission staffs and consumer interest groups.

Previous Positions

With Larkin, Chapski and Co., the predecessor firm to Larkin & Associates, was involved primarily in utility regulatory consulting, and also in tax planning and tax research for businesses and individuals, tax return preparation and review, and independent audit, review and preparation of financial statements.

Installed computerized accounting system for a realty management firm.

Education

Bachelor of Science in Administration in Accounting, with distinction, University of Michigan, Dearborn, 1979.

Master of Science in Taxation, Walsh College, Michigan, 1981. Master's thesis dealt with investment tax credit and property tax on various assets.

Juris Doctor, cum laude, Wayne State University Law School, Detroit, Michigan, 1986. Recipient of American Jurisprudence Award for academic excellence.

Continuing education required to maintain CPA license and CFP® certificate.

Passed all parts of CPA examination in first sitting, 1979. Received CPA certificate in 1981 and Certified Financial Planning certificate in 1983. Admitted to Michigan and Federal bars in 1986.

Michigan Bar Association.

American Bar Association, sections on public utility law and taxation.

Partial list of utility cases participated in:

79-228-EL-FAC	Cincinnati Gas & Electric Company (Ohio PUC)
79-231-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
79-535-EL-AIR	East Ohio Gas Company (Ohio PUC)
80-235-EL-FAC	Ohio Edison Company (Ohio PUC)
80-240-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
U-1933*	Tucson Electric Power Company (Arizona Corp. Commission)
U-6794	Michigan Consolidated Gas Co. --16 Refunds (Michigan PSC)
81-0035TP	Southern Bell Telephone Company (Florida PSC)
81-0095TP	General Telephone Company of Florida (Florida PSC)
81-308-EL-EFC	Dayton Power & Light Co.- Fuel Adjustment Clause (Ohio PUC)
810136-EU	Gulf Power Company (Florida PSC)
GR-81-342	Northern States Power Co. -- E-002/Minnesota (Minnesota PUC)
Tr-81-208	Southwestern Bell Telephone Company (Missouri PSC))
U-6949	Detroit Edison Company (Michigan PSC)
8400	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
18328	Alabama Gas Corporation (Alabama PSC)
18416	Alabama Power Company (Alabama PSC)
820100-EU	Florida Power Corporation (Florida PSC)
8624	Kentucky Utilities (Kentucky PSC)
8648	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
U-7236	Detroit Edison - Burlington Northern Refund (Michigan PSC)
U6633-R	Detroit Edison - MRCS Program (Michigan PSC)
U-6797-R	Consumers Power Company -MRCS Program (Michigan PSC)
U-5510-R	Consumers Power Company - Energy conservation Finance Program (Michigan PSC)
82-240E	South Carolina Electric & Gas Company (South Carolina PSC)
7350	Generic Working Capital Hearing (Michigan PSC)
RH-1-83	Westcoast Transmission Co., (National Energy Board of Canada)
820294-TP	Southern Bell Telephone & Telegraph Co. (Florida PSC)
82-165-EL-EFC (Subfile A)	Toledo Edison Company(Ohio PUC)
82-168-EL-EFC	Cleveland Electric Illuminating Company (Ohio PUC)
830012-EU	Tampa Electric Company (Florida PSC)
U-7065	The Detroit Edison Company - Fermi II (Michigan PSC)
8738	Columbia Gas of Kentucky, Inc. (Kentucky PSC)
ER-83-206	Arkansas Power & Light Company (Missouri PSC)
U-4758	The Detroit Edison Company – Refunds (Michigan PSC)
8836	Kentucky American Water Company (Kentucky PSC)
8839	Western Kentucky Gas Company (Kentucky PSC)
83-07-15	Connecticut Light & Power Co. (Connecticut DPU)
81-0485-WS	Palm Coast Utility Corporation (Florida PSC)
U-7650	Consumers Power Co. (Michigan PSC)
83-662	Continental Telephone Company of California, (Nevada PSC)
U-6488-R	Detroit Edison Co., FAC & PIPAC Reconciliation (Michigan PSC)
U-15684	Louisiana Power & Light Company (Louisiana PSC)
7395 & U-7397	Campaign Ballot Proposals (Michigan PSC)
820013-WS	Seacoast Utilities (Florida PSC)
U-7660	Detroit Edison Company (Michigan PSC)
83-1039	CP National Corporation (Nevada PSC)
U-7802	Michigan Gas Utilities Company (Michigan PSC)
83-1226	Sierra Pacific Power Company (Nevada PSC)
830465-EI	Florida Power & Light Company (Florida PSC)
U-7777	Michigan Consolidated Gas Company (Michigan PSC)
U-7779	Consumers Power Company (Michigan PSC)

U-7480-R	Michigan Consolidated Gas Company (Michigan PSC)
U-7488-R	Consumers Power Company – Gas (Michigan PSC)
U-7484-R	Michigan Gas Utilities Company (Michigan PSC)
U-7550-R	Detroit Edison Company (Michigan PSC)
U-7477-R**	Indiana & Michigan Electric Company (Michigan PSC)
18978	Continental Telephone Co. of the South Alabama (Alabama PSC)
R-842583	Duquesne Light Company (Pennsylvania PUC)
R-842740	Pennsylvania Power Company (Pennsylvania PUC)
850050-EI	Tampa Electric Company (Florida PSC)
16091	Louisiana Power & Light Company (Louisiana PSC)
19297	Continental Telephone Co. of the South Alabama (Alabama PSC)
76-18788AA &76-18793AA	Detroit Edison - Refund - Appeal of U-4807 (Ingham County, Michigan Circuit Court)
85-53476AA & 85-534785AA	Detroit Edison Refund - Appeal of U-4758 (Ingham County, Michigan Circuit Court)
U-8091/U-8239	Consumers Power Company - Gas Refunds (Michigan PSC)
TR-85-179**	United Telephone Company of Missouri (Missouri PSC)
85-212	Central Maine Power Company (Maine PSC)
ER-85646001 & ER-85647001	New England Power Company (FERC)
850782-EI & 850783-EI	Florida Power & Light Company (Florida PSC)
R-860378	Duquesne Light Company (Pennsylvania PUC)
R-850267	Pennsylvania Power Company (Pennsylvania PUC)
851007-WU & 840419-SU	Florida Cities Water Company (Florida PSC)
G-002/GR-86-160	Northern States Power Company (Minnesota PSC)
7195 (Interim)	Gulf States Utilities Company (Texas PUC)
87-01-03	Connecticut Natural Gas Company (Connecticut PUC))
87-01-02	Southern New England Telephone Company (Connecticut Department of Public Utility Control)
3673-	Georgia Power Company (Georgia PSC)
29484	Long Island Lighting Co. (New York Dept. of Public Service)
U-8924	Consumers Power Company – Gas (Michigan PSC)
Docket No. 1	Austin Electric Utility (City of Austin, Texas)
Docket E-2, Sub 527	Carolina Power & Light Company (North Carolina PUC)
870853	Pennsylvania Gas and Water Company (Pennsylvania PUC)
880069**	Southern Bell Telephone Company (Florida PSC)
U-1954-88-102 T E-1032-88-102	Citizens Utilities Rural Company, Inc. & Citizens Utilities Company, Kingman Telephone Division (Arizona CC)
89-0033	Illinois Bell Telephone Company (Illinois CC)
U-89-2688-T	Puget Sound Power & Light Company (Washington UTC))
R-891364	Philadelphia Electric Company (Pennsylvania PUC)
F.C. 889	Potomac Electric Power Company (District of Columbia PSC)
Case No. 88/546*	Niagara Mohawk Power Corporation, et al Plaintiffs, v. Gulf+Western, Inc. et al, defendants (Supreme Court County of Onondaga, State of New York)
87-11628*	Duquesne Light Company, et al, plaintiffs, against Gulf+ Western, Inc. et al, defendants (Court of the Common Pleas of Allegheny County, Pennsylvania Civil Division)
890319-EI	Florida Power & Light Company (Florida PSC)
891345-EI	Gulf Power Company (Florida PSC)
ER 8811 0912J	Jersey Central Power & Light Company (BPU)
6531	Hawaiian Electric Company (Hawaii PUCs)

R0901595	Equitable Gas Company (Pennsylvania Consumer Counsel)
90-10	Artesian Water Company (Delaware PSC)
89-12-05	Southern New England Telephone Company (Connecticut PUC)
900329-WS	Southern States Utilities, Inc. (Florida PSC)
90-12-018	Southern California Edison Company (California PUC)
90-E-1185	Long Island Lighting Company (New York DPS)
R-911966	Pennsylvania Gas & Water Company (Pennsylvania PUC)
I.90-07-037, Phase II	(Investigation of OPEBs) Department of the Navy and all Other Federal Executive Agencies (California PUC)
U-1551-90-322	Southwest Gas Corporation (Arizona CC)
U-1656-91-134	Sun City Water Company (Arizona RUCO)
U-2013-91-133	Havasu Water Company (Arizona RUCO)
91-174***	Central Maine Power Company (Department of the Navy and all Other Federal Executive Agencies)
U-1551-89-102 & U-1551-89-103	Southwest Gas Corporation - Rebuttal and PGA Audit (Arizona Corporation Commission)
Docket No. 6998	Hawaiian Electric Company (Hawaii PUC)
TC-91-040A and TC-91-040B	Intrastate Access Charge Methodology, Pool and Rates Local Exchange Carriers Association and South Dakota Independent Telephone Coalition
9911030-WS & 911-67-WS	General Development Utilities - Port Malabar and West Coast Divisions (Florida PSC)
922180	The Peoples Natural Gas Company (Pennsylvania PUC)
7233 and 7243	Hawaiian Nonpension Postretirement Benefits (Hawaiian PUC)
R-00922314 & M-920313C006	Metropolitan Edison Company (Pennsylvania PUC)
R00922428	Pennsylvania American Water Company (Pennsylvania PUC)
E-1032-92-083 & U-1656-92-183	Citizens Utilities Company, Agua Fria Water Division (Arizona Corporation Commission)
92-09-19	Southern New England Telephone Company (Connecticut PUC)
E-1032-92-073	Citizens Utilities Company (Electric Division), (Arizona CC)
UE-92-1262	Puget Sound Power and Light Company (Washington UTC))
92-345	Central Maine Power Company (Maine PUC)
R-932667	Pennsylvania Gas & Water Company (Pennsylvania PUC)
U-93-60**	Matanuska Telephone Association, Inc. (Alaska PUC)
U-93-50**	Anchorage Telephone Utility (Alaska PUC)
U-93-64	PTI Communications (Alaska PUC)
7700	Hawaiian Electric Company, Inc. (Hawaii PUC)
E-1032-93-111 & U-1032-93-193	Citizens Utilities Company - Gas Division (Arizona Corporation Commission)
R-00932670	Pennsylvania American Water Company (Pennsylvania PUC)
U-1514-93-169/ E-1032-93-169	Sale of Assets CC&N from Contel of the West, Inc. to Citizens Utilities Company (Arizona Corporation Commission)
7766	Hawaiian Electric Company, Inc. (Hawaii PUC)
93-2006- GA-AIR*	The East Ohio Gas Company (Ohio PUC)
94-E-0334	Consolidated Edison Company (New York DPS)
94-0270	Inter-State Water Company (Illinois Commerce Commission)
94-0097	Citizens Utilities Company, Kauai Electric Division (Hawaii PUC)
PU-314-94-688	Application for Transfer of Local Exchanges (North Dakota PSC)
94-12-005-Phase I	Pacific Gas & Electric Company (California PUC)
R-953297	UGI Utilities, Inc. - Gas Division (Pennsylvania PUC)
95-03-01	Southern New England Telephone Company (Connecticut PUC)
95-0342	Consumer Illinois Water, Kankakee Water District (Illinois CC)
94-996-EL-AIR	Ohio Power Company (Ohio PUC)
95-1000-E	South Carolina Electric & Gas Company (South Carolina PSC)

Non-Docketed Staff Investigation	Citizens Utility Company - Arizona Telephone Operations (Arizona Corporation Commission)
E-1032-95-473	Citizens Utility Co. - Northern Arizona Gas Division (Arizona CC)
E-1032-95-433	Citizens Utility Co. - Arizona Electric Division (Arizona CC)
	Collaborative Ratemaking Process Columbia Gas of Pennsylvania (Pennsylvania PUC)
GR-96-285	Missouri Gas Energy (Missouri PSC)
94-10-45	Southern New England Telephone Company (Connecticut PUC)
A.96-08-001 et al.	California Utilities' Applications to Identify Sunk Costs of Non- Nuclear Generation Assets, & Transition Costs for Electric Utility Restructuring, & Consolidated Proceedings (California PUC)
96-324	Bell Atlantic - Delaware, Inc. (Delaware PSC)
96-08-070, et al.	Pacific Gas & Electric Co., Southern California Edison Co. and San Diego Gas & Electric Company (California PUC)
97-05-12	Connecticut Light & Power (Connecticut PUC)
R-00973953	Application of PECO Energy Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code (Pennsylvania PUC)
97-65	Application of Delmarva Power &Light Co. for Application of a Cost Accounting Manual and a Code of Conduct (Delaware PSC)
16705	Entergy Gulf States, Inc. (Cities Steering Committee)
E-1072-97-067	Southwestern Telephone Co. (Arizona Corporation Commission)
Non-Docketed Staff Investigation	Delaware - Estimate Impact of Universal Services Issues (Delaware PSC)
PU-314-97-12	US West Communications, Inc. Cost Studies (North Dakota PSC)
97-0351	Consumer Illinois Water Company (Illinois CC)
97-8001	Investigation of Issues to be Considered as a Result of Restructuring of Electric Industry (Nevada PSC)
U-0000-94-165	Generic Docket to Consider Competition in the Provision of Retail Electric Service (Arizona Corporation Commission)
98-05-006-Phase I	San Diego Gas & Electric Co., Section 386 costs (California PUC)
9355-U	Georgia Power Company Rate Case (Georgia PUC)
97-12-020 - Phase I	Pacific Gas & Electric Company (California PUC)
U-98-56, U-98-60, U-98-65, U-98-67	Investigation of 1998 Intrastate Access charge filings (Alaska PUC)
(U-99-66, U-99-65, U-99-56, U-99-52)	Investigation of 1999 Intrastate Access Charge filing (Alaska PUC)
Phase II of 97-SCCC-149-GIT	Southwestern Bell Telephone Company Cost Studies (Kansas CC)
PU-314-97-465	US West Universal Service Cost Model (North Dakota PSC)
Non-docketed Assistance	Bell Atlantic - Delaware, Inc., Review of New Telecomm. and Tariff Filings (Delaware PSC)
Contract Dispute	City of Zeeland, MI - Water Contract with the City of Holland, MI (Before an arbitration panel)
Non-docketed Project	City of Danville, IL - Valuation of Water System (Danville, IL)
Non-docketed Project	Village of University Park, IL - Valuation of Water and Sewer System (Village of University Park, Illinois)

E-1032-95-417	Citizens Utility Co., Maricopa Water/Wastewater Companies et al. (Arizona Corporation Commission)
T-1051B-99-0497	Proposed Merger of the Parent Corporation of Qwest Communications Corporation, LCI International Telecom Corp., and US West Communications, Inc. (Arizona CC)
T-01051B-99-0105	US West Communications, Inc. Rate Case (Arizona CC)
A00-07-043	Pacific Gas & Electric - 2001 Attrition (California PUC)
T-01051B-99-0499	US West/Quest Broadband Asset Transfer (Arizona CC)
99-419/420	US West, Inc. Toll and Access Rebalancing (North Dakota PSC)
PU314-99-119	US West, Inc. Residential Rate Increase and Cost Study Review (North Dakota PSC
98-0252	Ameritech - Illinois, Review of Alternative Regulation Plan (Illinois CUB)
00-108	Delmarva Billing System Investigation (Delaware PSC)
U-00-28	Matanuska Telephone Association (Alaska PUC)
Non-Docketed	Management Audit and Market Power Mitigation Analysis of the Merged Gas System Operation of Pacific Enterprises and Enova Corporation (California PUC)
00-11-038	Southern California Edison (California PUC)
00-11-056	Pacific Gas & Electric (California PUC)
00-10-028	The Utility Reform Network for Modification of Resolution E-3527 (California PUC)
98-479	Delmarva Power & Light Application for Approval of its Electric and Fuel Adjustments Costs (Delaware PSC)
99-457	Delaware Electric Cooperative Restructuring Filing (Delaware PSC)
99-582	Delmarva Power & Light dba Conectiv Power Delivery Analysis of Code of Conduct and Cost Accounting Manual (Delaware PSC)
99-03-04	United Illuminating Company Recovery of Stranded Costs (Connecticut OCC)
99-03-36	Connecticut Light & Power (Connecticut OCC)
Civil Action No. 98-1117	West Penn Power Company vs. PA PUC (Pennsylvania PSC)
Case No. 12604	Upper Peninsula Power Company (Michigan AG)
Case No. 12613	Wisconsin Public Service Commission (Michigan AG)
41651	Northern Indiana Public Service Co Overearnings investigation (Indiana UCC)
13605-U	Savannah Electric & Power Company – FCR (Georgia PSC)
14000-U	Georgia Power Company Rate Case/M&S Review (Georgia PSC)
13196-U	Savannah Electric & Power Company Natural Gas Procurement and Risk Management/Hedging Proposal, Docket No. 13196-U (Georgia PSC)
Non-Docketed	Georgia Power Company & Savannah Electric & Power FPR Company Fuel Procurement Audit (Georgia PSC)
Non-Docketed	Transition Costs of Nevada Vertically Integrated Utilities (US Department of Navy)
Application No. 99-01-016, Phase I	Post-Transition Ratemaking Mechanisms for the Electric Industry Restructuring (US Department of Navy)
99-02-05	Connecticut Light & Power (Connecticut OCC)
01-05-19-RE03	Yankee Gas Service Application for a Rate Increase, Phase I-2002-IERM (Connecticut OCC)
G-01551A-00-0309	Southwest Gas Corporation, Application to amend its rate Schedules (Arizona CC)
00-07-043	Pacific Gas & Electric Company Attrition & Application for a rate increase (California PUC)

97-12-020	
Phase II	Pacific Gas & Electric Company Rate Case (California PUC)
01-10-10	United Illuminating Company (Connecticut OCC)
13711-U	Georgia Power FCR (Georgia PSC)
02-001	Verizon Delaware § 271(Delaware DPA)
02-BLVT-377-AUD	Blue Valley Telephone Company Audit/General Rate Investigation (Kansas CC)
02-S&TT-390-AUD	S&T Telephone Cooperative Audit/General Rate Investigation (Kansas CC)
01-SFLT-879-AUD	Sunflower Telephone Company Inc., Audit/General Rate Investigation (Kansas CC)
01-BSTT-878-AUD	Bluestem Telephone Company, Inc. Audit/General Rate Investigation (Kansas CC)
P404, 407, 520, 413 426, 427, 430, 421/ CI-00-712	Sherburne County Rural Telephone Company, dba as Connections, Etc. (Minnesota DOC)
U-01-85	ACS of Alaska, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-34	ACS of Anchorage, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-83	ACS of Fairbanks, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-87	ACS of the Northland, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
96-324, Phase II	Verizon Delaware, Inc. UNE Rate Filing (Delaware PSC)
03-WHST-503-AUD	Wheat State Telephone Company (Kansas CC)
04-GNBT-130-AUD	Golden Belt Telephone Association (Kansas CC)
Docket 6914	Shoreham Telephone Company, Inc. (Vermont BPU)
Docket No. E-01345A-06-009	Arizona Public Service Company (Arizona Corporation Commission)
Case No. 05-1278-E-PC-PW-42T	Appalachian Power Company and Wheeling Power Company both d/b/a American Electric Power (West Virginia PSC)
Docket No. 04-0113	Hawaiian Electric Company (Hawaii PUC)
Case No. U-14347	Consumers Energy Company (Michigan PSC)
Case No. 05-725-EL-UNC	Cincinnati Gas & Electric Company (PUC of Ohio)
Docket No. 21229-U	Savannah Electric & Power Company (Georgia PSC)
Docket No. 19142-U	Georgia Power Company (Georgia PSC)
Docket No. 03-07-01RE01	Connecticut Light & Power Company (CT DPUC)
Docket No. 19042-U	Savannah Electric & Power Company (Georgia PSC)
Docket No. 2004-178-E	South Carolina Electric & Gas Company (South Carolina PSC)
Docket No. 03-07-02	Connecticut Light & Power Company (CT DPUC)
Docket No. EX02060363, Phases I&II	Rockland Electric Company (NJ BPU)
Docket No. U-00-88	ENSTAR Natural Gas Company and Alaska Pipeline Company (Regulatory Commission of Alaska)
Phase 1-2002 IERM, Docket No. U-02-075	Interior Telephone Company, Inc. (Regulatory Commission of Alaska)
Docket No. 05-SCNT-1048-AUD	South Central Telephone Company (Kansas CC)
Docket No. 05-TRCT-607-KSF	Tri-County Telephone Company (Kansas CC)
Docket No. 05-KOKT-060-AUD	Kan Okla Telephone Company (Kansas CC)
Docket No. 2002-747	Northland Telephone Company of Maine (Maine PUC)
Docket No. 2003-34	Sidney Telephone Company (Maine PUC)

Docket No. 2003-35	Maine Telephone Company (Maine PUC)
Docket No. 2003-36	China Telephone Company (Maine PUC)
Docket No. 2003-37	Standish Telephone Company (Maine PUC)
Docket Nos. U-04-022, U-04-023	Anchorage Water and Wastewater Utility (Regulatory Commission of Alaska)
Case 05-116-U/06-055-U	Entergy Arkansas, Inc. EFC (Arkansas Public Service Commission)
Case 04-137-U	Southwest Power Pool RTO (Arkansas Public Service Commission)
Case No. 7109/7160	Vermont Gas Systems (Department of Public Service)
Case No. ER-2006-0315	Empire District Electric Company (Missouri PSC)
Case No. ER-2006-0314	Kansas City Power & Light Company (Missouri PSC)
Docket No. U-05-043,44	Golden Heart Utilities/College Park Utilities (Regulatory Commission of Alaska)
A-122250F5000	Equitable Resources, Inc. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)
E-01345A-05-0816	Arizona Public Service Company (Arizona CC)
Docket No. 05-304	Delmarva Power & Light Company (Delaware PSC)
05-806-EL-UNC	Cincinnati Gas & Electric Company (Ohio PUC)
U-06-45	Anchorage Water Utility (Regulatory Commission of Alaska)
03-93-EL-ATA, 06-1068-EL-UNC	Duke Energy Ohio (Ohio PUC)
PUE-2006-00065	Appalachian Power Company (Virginia Corporation Commission)
G-04204A-06-0463 et. al	UNS Gas, Inc. (Arizona CC)
Docket No. 2006-0386	Hawaiian Electric Company, Inc (Hawaii PUC)
E-01933A-07-0402	Tucson Electric Power Company (Arizona CC)
G-01551A-07-0504	Southwest Gas Corporation (Arizona CC)
Docket No.UE-072300	Puget Sound Energy, Inc. (Washington UTC)
PUE-2008-00009	Virginia-American Water Company (Virginia SCC)
PUE-2008-00046	Appalachian Power Company (Virginia SCC)
E-01345A-08-0172	Arizona Public Service Company (Arizona CC)
A-2008-2063737	Babcock & Brown Infrastructure Fund North America, LP. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)
08-1783-G-42T	Hope Gas, Inc., dba Dominion Hope (West Virginia PSC)
08-1761-G-PC	Hope Gas, Inc., dba Dominion Hope, Dominion Resources, Inc., and Peoples Hope Gas Companies (West Virginia PSC)
Docket No. 2008-0085	Hawaiian Electric Company, Inc. (Hawaii PUC)
Docket No. 2008-0266	Young Brothers, Limited (Hawaii PUC)
G-04024A-08-0571	UNS Gas, Inc. (Arizona CC)
Docket No. 09-29	Tidewater Utilities, Inc. (Delaware PSC)
Docket No. UE-090704	Puget Sound Energy, Inc. (Washington UTC)
09-0878-G-42T	Mountaineer Gas Company (West Virginia PSC)
2009-UA-0014	Mississippi Power Company (Mississippi PSC)
Docket No. 09-0319	Illinois-American Water Company (Illinois CC)
Docket No. 09-414	Delmarva Power & Light Company (Delaware PSC)
R-2009-2132019	Aqua Pennsylvania, Inc. (Pennsylvania PUC)
Docket Nos. U-09-069, U-09-070	ENSTAR Natural Gas Company (Regulatory Commission of Alaska)
Docket Nos. U-04-023, U-04-024	Anchorage Water and Wastewater Utility - Remand (Regulatory Commission of Alaska)
W-01303A-09-0343 & SW-01303A-09-0343	Arizona-American Water Company (Arizona CC)
09-872-EL-FAC & 09-873-EL-FAC	Financial Audits of the FAC of the Columbus Southern Power Company and the Ohio Power Company - Audit I (Ohio PUC)
2010-00036	Kentucky-American Water Company (Kentucky PSC)
E-04100A-09-0496	Southwest Transmission Cooperative, Inc. (Arizona CC)
E-01773A-09-0496	Arizona Electric Power Cooperative, Inc. (Arizona CC)

R-2010-2166208, R-2010-2166210, R-2010-2166212, & R-2010-2166214	Pennsylvania-American Water Company (Pennsylvania PUC)
PSC Docket No. 09-0602	Central Illinois Light Company D/B/A AmerenCILCO; Central Illinois Public Service Company D/B/A AmerenCIPS; Illinois Power Company D/B/A AmerenIP (Illinois CC)
10-0713-E-PC	Allegheny Power and FirstEnergy Corp. (West Virginia PSC)
Docket No. 31958	Georgia Power Company (Georgia PSC)
Docket No. 10-0467	Commonwealth Edison Company (Illinois CC)
PSC Docket No. 10-237	Delmarva Power & Light Company (Delaware PSC)
U-10-51	Cook Inlet Natural Gas Storage Alaska, LLC (Regulatory Commission of Alaska)
10-0699-E-42T	Appalachian Power Company and Wheeling Power Company (West Virginia PSC)
10-0920-W-42T	West Virginia-American Water Company (West Virginia PSC)
A.10-07-007	California-American Water Company (California PUC)
A-2010-2210326	TWP Acquisition (Pennsylvania PUC)
08-1012-EL-FAC	Financial, Management, and Performance Audit of the FAC for Dayton Power and Light – Audit 1 (Ohio PUC)
10-268-EL FAC et al.	Financial Audit of the FAC of the Columbus Southern Power Company and the Ohio Power Company – Audit II (Ohio PUC)
Docket No. 2010-0080	Hawaiian Electric Company, Inc. (Hawaii PUC)
G-01551A-10-0458	Southwest Gas Corporation (Arizona CC)
10-KCPE-415-RTS	Kansas City Power & Light Company – Remand (Kansas CC)
PUE-2011-00037	Virginia Appalachian Power Company (Commonwealth of Virginia SCC)
R-2011-2232243	Pennsylvania-American Water (Pennsylvania PUC)
U-11-100	Power Purchase Agreement between Chugach Association, Inc. and Fire Island Wind, LLC (Regulatory Commission of Alaska)
A.10-12-005	San Diego Gas & Electric Company (California PUC)
PSC Docket No. 11-207	Artesian Water Company, Inc. (Delaware PSC)
Cause No. 44022	Indiana-American Water Company, Inc. (Indiana Utility Regulatory Commission)
PSC Docket No. 10-247	Management Audit of Tidewater Utilities, Inc. Affiliate Transactions (Delaware Public Service Commission)
G-04204A-11-0158	UNS Gas, Inc. (Arizona Corporation Commission)
E-01345A-11-0224	Arizona Public Service Company (Arizona CC)
UE-111048 & UE-11049	Puget Sound Energy, Inc. (Washington Utilities and Transportation Commission)
Docket No. 11-0721	Commonwealth Edison Company (Illinois CC)
11AL-947E	Public Service Company of Colorado (Colorado PSC)
U-11-77 & U-11-78	Golden Heart Utilities, Inc. and College Utilities Corporation (The Regulatory Commission of Alaska)
Docket No. 11-0767	Illinois-American Water Company (Illinois CC)

Tucson Electric Power Company
Docket No. E-01933A-12-0291
Attachment RCS-2
Staff Accounting Schedules
Accompanying the Direct Testimony of Ralph C. Smith

****TEP Confidential Information has been Redacted****

Schedule	Description	Confidential	No. of Pages	Page No.
	Revenue Requirement Summary Schedules			
A	Calculation of Revenue Deficiency (Sufficiency)	No	1	2
A-1	Gross Revenue Conversion Factor	No	1	3
B	Adjusted Rate Base - ACC Jurisdictional	No	1	4
B.1	Summary of Adjustments to Rate Base - ACC Jurisdictional	No	1	5
C	Adjusted Net Operating Income - ACC Jurisdictional	No	1	6
C.1	Summary of Net Operating Income Adjustments - ACC Jurisdictional	No	3	7-9
D	Capital Structure and Cost Rates	No	5	10-14
	Rate Base Adjustments			
B-1	Sahuarita-Nogales Transmission Line	No	1	15
B-2	Cash Working Capital	No	1	16
B-3	Remove One-Half of Prepaid D&O Insurance	No	1	17
B-4	Fuel Inventory - Adjustment for San Juan Coal Price	No	1	18
B-5	New Headquarters Building	Yes	3	19-21
	Net Operating Income Adjustments			
C-1	Sahuarita-Nogales Transmission Line Amortization Expense	No	1	22
C-2	Incentive Compensation (PEP) Program Expense	No	1	23
C-3	Overhaul and Outage Expense	No	6	24-29
C-4	Interest Synchronization	No	1	30
C-5	Base Cost of Fuel and Purchased Power	No	2	31-32
C-6	Rate Case Expense	No	1	33
C-7	Directors' and Officers' Liability Insurance Expense	No	1	34
C-8	Edison Electric Institute and Industry Association Dues	No	2	35-36
C-9	Property Tax Expense	No	2	37-38
C-10	Depreciation and Property Taxes on New Headquarters Building Adjustment	No	1	39
C-11	Other Operating Revenue: Reimbursed Operating Expenses for Springerville Units 3 and 4	No	1	40
C-12	Springerville Unit 1 Levelized Expense	No	3	41-43
C-13	Day Nite Design Branding/ Marketing/ General Corporate Advertising	No	1	44
C-14	Lime Expense	No	1	45
	Total Pages, Including Content Listing		45	

Tucson Electric Power Company
Computation of Increase in Gross Revenue Requirement
ACC Jurisdictional
Test Year Ended December 31, 2011
(Thousands of Dollars)

Docket No. E-01933A-12-0291
Schedule A
Page 1 of 1

Line No.	Description	Reference	TEP Proposed Original Cost (A)	TEP Proposed Fair Value (B)	Staff Calculated Original Cost (C)	Staff Calculated Fair Value Option 1 (D)	Staff Calculated Fair Value Option 2 (E)	Staff Recommended Fair Value (F)
1	Adjusted Rate Base	Sch. B (ACC)	$ 1,519,073	$ 2,280,216	$ 1,500,486	$ 2,261,629	$ 2,261,629	$ 2,261,629
2	Rate of Return	Sch. D	7.74%	5.68%	7.00%	4.63%	4.86%	4.66%
3	Operating Income Required for Rate of Return		$ 117,610	$ 129,484	$ 104,973	$ 104,713	$ 109,915	$ 105,316
4	Net Operating Income Available	Sch. C (ACC)	$ 52,472	$ 52,472	$ 59,261	$ 59,261	$ 59,261	$ 59,261
5	Operating Income Excess/Deficiency		$ 65,138	$ 77,012	$ 45,712	$ 45,452	$ 50,654	$ 46,055
6	Gross Revenue Conversion Factor	Sch. A-1	1.6590	1.6590	1.6590	1.6590	1.6590	1.6590
7	Base Rate Revenue Deficiency		$ 108,063	$ 127,763	$ 75,837	$ 75,405	$ 84,036	$ 76,406
8	Base Rate Revenue Deficiency for Adjusted FVRB	[a]	$ 19,699					
9	Total Base Rate Revenue Deficiency		$ 127,762	$ 127,763	$ 75,837	$ 75,405	$ 84,036	$ 76,406
10	Equivalent OCRB ROE	Sch. D	12.45%	12.45%	9.40%	9.40%	10.19%	9.45%
			Sch,D, p.2, L19	Sch,D, p.2, L19	Sch,D, p.1,L7	Sch,D, p.3, L19	Sch,D, p.4, L19	Sch,D, p.5, L19
	Revenue Increase and Estimated Percentage Rate Increase (Decrease)							
11	Electric Retail Revenues - Current Rates	Sch. C (ACC)	$ 836,938	$ 836,938	$ 832,122	$ 832,122	$ 832,122	$ 832,122
12	With Proposed Base Rate Increase	L9 + L11	$ 964,700	$ 964,701	$ 907,959	$ 907,527	$ 916,158	$ 908,528
13	Percent Retail Revenue Increase		15.3%	15.3%	9.11%	9.06%	10.10%	9.18%

Notes and Source

Cols. A & B taken from TEP filing, Schedule A-1

[a]:

14	Adjusted OCRB Rate Base		$ 1,519,073	Col.A, L.1
15	Adjusted FVRB		$ 2,280,216	Col.B, L.1
16	Difference from OCRB		$ 761,143	
17	Return on FV Increment		1.56%	2012 TEP Rev Req Model.xls, Cover, numbered Line 16
18	Operating Income Required on FVRB Increment		$ 11,874	
19	Gross Revenue Conversion Factor	Sch. A-1	1.6590	Also see, 2012 TEP Rev Req Model.xls, Cover, numbered Line 21
20	Base Revenue Deficiency for Adjusted FVRB	Col.A, L.8	$ 19,699	
21	Revenue Deficiency on OCRB	Col.A, L.7	$ 108,063	
22	Revenue Deficiency Claimed by TEP	Col.A, L.9	$ 127,762	Also see, 2012 TEP Rev Req Model.xls, Cover, numbered Line 22

Tucson Electric Power Company
Computation of Gross Revenue Conversion Factor

Docket No. E-01933A-12-0291
Schedule A-1
Page 1 of 1

Test Year Ended December 31, 2011

Line No.	Description	Company Proposed (A)	Staff Proposed (B)
1	Gross Revenue	100.00%	100.00%
2	Less: Uncollectible Revenue	0.24860%	0.24860%
3	Taxable Income as a Percent	99.75%	99.75%
4	Less: Federal and State Income Taxes	39.47%	39.47%
5	Change in Net Operating Income	60.28%	60.28%
6	Gross Revenue Conversion Factor	1.6590	1.6590

Notes and Source

Col.A: TEP Filing, Schedule C-3

7	Combined State and Federal Income Tax Rate	39.571%	39.571%

Components of Revenue Requirement Increase or (Decrease)

		Amount	Percent
8	Net Income	$ 46,057	60.2789%
9	Federal and State Income Taxes	$ 30,159	39.4725%
10	Uncollectibles	$ 190	0.2486%
11	Total Revenue Increase	$ 76,406	100.0000%
12	From Schedule A, Column F	$ 76,406	

Tucson Electric Power Company
Original Cost and RCND Adjusted Rate Base
ACC Jurisdiction

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

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Schedule B
Page 1 of 1

Line No.	Description	Original Cost As Adjusted by TEP (A)	Original Cost Staff Adjustments (B)	Original Cost As Adjusted by Staff (C)	RCND As Adjusted by TEP (D)	RCND Staff Adjustments (E)	RCND As Adjusted by Staff (F)
1	Gross Utility Plant in Service	$ 3,199,453	$ (6,756)	$ 3,192,697	$ 6,655,502	$ (6,756)	$ 6,648,746
2	Less: Accumulated Depreciation	$ (1,411,639)	$ 178	$ (1,411,461)	$ (3,005,492)	$ 178	$ (3,005,314)
3	Net Utility Plant in Service	$ 1,787,814	$ (6,578)	$ 1,781,236	$ 3,650,010	$ (6,578)	$ 3,643,432
4	Plant Held for Future Use	$ -	$ -	$ -	$ -	$ -	$ -
5	Total Net Utility Plant	$ 1,787,814	$ (6,578)	$ 1,781,236	$ 3,650,010	$ (6,578)	$ 3,643,432
6	Customer Advances for Construction	$ (8,924)	$ -	$ (8,924)	$ (13,182)	$ -	$ (13,182)
							$ -
7	Customer Deposits	$ (23,743)	$ -	$ (23,743)	$ (23,743)	$ -	$ (23,743)
8	Deferred Credit - Contributed Plant and Retirement Obligations	$ (15,832)	$ -	$ (15,832)	$ (15,773)	$ -	$ (15,773)
9	Accumulated Deferred Income Taxes	$ (284,654)	$ -	$ (284,654)	$ (620,365)	$ -	$ (620,365)
10	Total Deductions	$ (333,153)	$ -	$ (333,153)	$ (673,063)	$ -	$ (673,063)
11	Allowance for Working Capital	$ 53,323	$ (920)	$ 52,403	$ 53,323	$ (920)	$ 52,403
							$ -
12	Regulatory Assets	$ 11,089	$ (11,089)	$ 0	$ 11,089	$ (11,089)	$ 0
13	Regulatory Liabilities	$ -	$ -	$ -	$ -	$ -	$ -
14	Total Rate Base	$ 1,519,073	$ (18,587)	$ 1,500,486	$ 3,041,359	$ (18,587)	$ 3,022,772

Notes and Source
Cols. A and D: TEP filing, Schedule B-1

	Fair Value Calculation (Per Company)			
15	Original Cost	$	1,519,073	
16	RCND	$	3,041,359	
17	Total	$	4,560,432	
18	Average (Fair Value)	$	2,280,216	See Sch. A
	Fair Value Calculation (Per Staff)			
19	Original Cost	$	1,500,486	
20	RCND	$	3,022,772	
21	Total	$	4,523,258	
22	Average (Fair Value)	$	2,261,629	See Sch. A

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Tucson Electric Power Company
Summary of Rate Base Adjustments
ACC Jurisdiction

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

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Schedule B.1
Page 1 of 1

Line No.	Description	Staff Adjustments	Sahuarita-Nogales Transmission Line B-1	Cash Working Capital B-2	Remove One-Half of Prepaid D&O Insurance B-3	Fuel Inventory - Adjustment for San Juan Coal Price B-4	New Headquarters Building B-5
1	Gross Utility Plant in Service	$ (6,756)	$ -				$ (6,756)
2	Less: Accumulated Depreciation	$ 178	$ -				$ 178
3	Net Utility Plant in Service	$ (6,578)	$ -	$ -	$ -	$ -	$ (6,578)
4	Plant Held for Future Use	$ -					
5	Total Net Utility Plant	$ (6,578)	$ -	$ -	$ -	$ -	$ (6,578)
6	Customer Advances for Construction	$ -					
7	Customer Deposits	$ -					
8	Deferred Credit - Contributed Plant & Retirement Oblig.	$ -					
9	Accumulated Deferred Income Taxes	$ -					
10	Total Deductions	$ -	$ -	$ -	$ -	$ -	$ -
11	Allowance for Working Capital	$ (920)		$ 787	$ (117)	$ (1,590)	
12	Regulatory Assets	$ (11,089)	$ (11,089)				
13	Regulatory Liabilities	$ -					
14	Total Rate Base	$ (18,587)	$ (11,089)	$ 787	$ (117)	$ (1,590)	$ (6,578)

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Tucson Electric Power Company
Adjusted Net Operating Income
ACC Jurisdictional

Docket No. E-01933A-12-0291
Schedule C
Page 1 of 1

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

Line No.	Description	As Adjusted by TEP (A)	Staff Adjustments (B)	As Adjusted by Staff (C)
	Operating Revenues			
1	Electric Retail Revenues	$ 836,938	$ (4,816)	$ 832,122
2	Sales for Resale	$ -	$ -	$ -
3	Other Operating Revenues	$ 29,182	$ 5,569	$ 34,751
4	Total Operating Revenues	$ 866,120	$ 753	$ 866,873
	Operating Expenses			
5	Fuel, Purchased Power and Transmission	$ 292,190	$ (4,816)	$ 287,374
6	Other O&M Expenses	$ 381,989	$ (4,865)	$ 377,124
7	Depreciation & Amortization	$ 97,310	$ (178)	$ 97,132
8	Taxes Other Than Income Taxes	$ 35,141	$ 85	$ 35,226
9	Income Taxes	$ 7,018	$ 3,738	$ 10,756
10	Total Operating Expenses	$ 813,648	$ (6,036)	$ 807,612
11	Net Operating Income	$ 52,472	$ 6,789	$ 59,261

Notes and Source

Col. A: TEP Schedule C-1
Col. B: Staff Schedule C.1

Tucson Electric Power Company
Summary of Net Operating Income Adjustments
ACC Jurisdiction

Docket No. E-01933A-12-0291
Schedule C.1
Page 1 of 3

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

Line No.	Description	Staff Adjustments	Sahuarita-Nogales Transmission Line Amortization Expense	Incentive Compensation (PEP) Program Expense	Overhaul and Outage Expense	Interest Synchronization
			C-1	C-2	C-3	C-4
	Operating Revenues					
1	Electric Retail Revenues	$ (4,816)			$ -	
2	Sales for Resale	$ -				
3	Other Operating Revenues	$ 5,569	$ -			
4	Total Operating Revenues	$ 753	$ -	$ -	$ -	$ -
	Operating Expenses					
5	Fuel, Purchased Power and Transmission	$ (4,816)				
6	Other O&M Expenses	$ (4,865)	$ (2,983)	$ (2,094)	$ (2,514)	
7	Depreciation & Amortization	$ (178)				
8	Taxes Other Than Income Taxes	$ 85				
9	PRE-TAX OPERATING EXPENSES	$ (9,774)	$ (2,983)	$ (2,094)	$ (2,514)	$ -
10	PRE-TAX OPERATING INCOME	$ 10,527	$ 2,983	$ 2,094	$ 2,514	$ -
11	Income Taxes	$ 3,738	$ 1,180	$ 829	$ 995	$ (427)
12	TOTAL OPERATING EXPENSES	$ (6,036)	$ (1,803)	$ (1,265)	$ (1,519)	$ (427)
13	OPERATING INCOME	$ 6,789	$ 1,803	$ 1,265	$ 1,519	$ 427

Notes and Source

Combined Effective Tax Rate* 39.571%

* Per TEP filing, Schedule C-3

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Tucson Electric Power Company
Summary of Net Operating Income Adjustments
ACC Jurisdiction

Docket No. E-01933A-12-0291
Schedule C.1
Page 2 of 3

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

Line No.	Description	Base Cost of Fuel and Purchased Power	Rate Case Expense	Directors' and Officers' Liability Insurance Expense	Edison Electric Institute and Industry Association Dues	Property Tax Expense	Depreciation and Property Taxes on New Headquarters Building Adjustment
		C-5	C-6	C-7	C-8	C-9	C-10
	Operating Revenues						
1	Electric Retail Revenues	$ (4,816)					
2	Sales for Resale						
3	Other Operating Revenues						
4	Total Operating Revenues	$ (4,816)	$ -	$ -	$ -	$ -	$ -
	Operating Expenses						
5	Fuel, Purchased Power and Transmission	$ (4,816)					
6	Other O&M Expenses		$ (247)	$ (289)	$ (112)		
7	Depreciation & Amortization						$ (178)
8	Taxes Other Than Income Taxes					$ (1,460)	$ (131)
9	PRE-TAX OPERATING EXPENSES	$ (4,816)	$ (247)	$ (289)	$ (112)	$ (1,460)	$ (309)
10	PRE-TAX OPERATING INCOME	$ -	$ 247	$ 289	$ 112	$ 1,460	$ 309
11	Income Taxes	$ -	$ 98	$ 114	$ 44	$ 578	$ 122
12	TOTAL OPERATING EXPENSES	$ (4,816)	$ (149)	$ (175)	$ (68)	$ (882)	$ (187)
13	OPERATING INCOME	$ -	$ 149	$ 175	$ 68	$ 882	$ 187

Notes and Source

Combined Effective Tax Rate* 39.571%

* Per TEP filing, Schedule C-3

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Tucson Electric Power Company
Summary of Net Operating Income Adjustments
ACC Jurisdiction

Docket No. E-01933A-12-0291
Schedule C.1
Page 3 of 3

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

Line No.	Description	Other Operating Revenue: Reimbursed Operating Expenses for Springerville Units 3 and 4 C-11	Springerville Unit 1 Levelized Expense C-12	Day Nite Design Branding/ Marketing/ General Corporate Advertising C-13	Lime Expense C-14
	Operating Revenues				
1	Electric Retail Revenues				
2	Sales for Resale				
3	Other Operating Revenues	$ 5,569			
4	Total Operating Revenues	$ 5,569	$ -	$ -	$ -
	Operating Expenses				
5	Fuel, Purchased Power and Transmission				
6	Other O&M Expenses		$ (1,689)	$ (13)	$ 5,076
7	Depreciation & Amortization				
8	Taxes Other Than Income Taxes		$ 1,676		
9	PRE-TAX OPERATING EXPENSES	$ -	$ (13)	$ (13)	$ 5,076
10	PRE-TAX OPERATING INCOME	$ 5,569	$ 13	$ 13	$ (5,076)
11	Income Taxes	$ 2,204	$ 5	$ 5	$ (2,009)
12	TOTAL OPERATING EXPENSES	$ 2,204	$ (8)	$ (8)	$ 3,067
13	OPERATING INCOME	$ 3,365	$ 8	$ 8	$ (3,067)

Notes and Source

Combined Effective Tax Rate* 39.571%

* Per TEP filing, Schedule C-3

Tucson Electric Power Company
Capital Structure & Cost Rates

Docket No. E-01933A-12-0291
Schedule D
Page 1 of 5

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

Line No.	Capital Source		Capitalization Amount (A)	Percent (B)	Cost Rate (C)	Weighted Avg. Cost of Capital (D)
	I. TEP - Proposed					
1	Short-Term Debt		$ -	0.00%	0.00%	0.00%
2	Long-Term Debt		$ 1,061,389	54.00%	5.18%	2.80%
3	Common Stock Equity		$ 904,146	46.00%	10.75%	4.94%
4	Total Capital		$ 1,965,535	100.00%		7.74%
	II. ACC Staff - Proposed for OCRB [b]	**Total**	**Supporting OCRB**			
5	Short-Term Debt	$ 10,000	$ 7,913	0.53%	1.42%	0.01%
6	Long-Term Debt	$ 1,061,389	$ 839,831	55.97%	5.18%	2.90%
7	Common Stock Equity	$ 824,943	$ 652,742	43.50%	9.400% [b]	4.09%
8	Total Capital	$ 1,896,332	$ 1,500,486	100.00%		7.00%
9	Staff Adjusted Original Cost Rate Base	Sch B	$ 1,500,486			
10	Difference					-0.7462%
11	Weighted Cost of Debt					2.91%
	III. ACC Staff - Proposed Cost of Capital for Fair Value Rate Base - Option 1					
12	Short-Term Debt		$ 7,913	0.35%	1.42%	0.00%
13	Long-Term Debt		$ 839,831	37.13%	5.18%	1.92%
14	Common Stock Equity		$ 652,742	28.86%	9.400% [b]	2.71%
15	Capital financing OCRB		$ 1,500,486			
16	Appreciation above OCRB not recognized on utility's books		$ 761,143	33.65%	0% [a]	0.00%
17	Total capital supporting FVRB		$ 2,261,629	100.00%		4.63%
	IV. ACC Staff - Proposed Cost of Capital for Fair Value Rate Base - Option 2					
18	Short-Term Debt		$ 7,913	0.35%	1.42%	0.00%
19	Long-Term Debt		$ 839,831	37.13%	5.18%	1.92%
20	Common Stock Equity		$ 652,742	28.86%	9.40% [b]	2.71%
21	Capital financing OCRB		$ 1,500,486			
22	Appreciation above OCRB not recognized on utility's books		$ 761,143	33.65%	0.68% [c]	0.23%
23	Total capital supporting FVRB		$ 2,261,629	100.00%		4.86%

Notes and Source

Lines 1-4 taken from UNS Electric Inc. filing, Schedule D-1

Lines 12-16, Col.A:

24	Fair Value Rate Base	$ 2,261,629	Schedule A
25	Original Cost Rate Base	$ 1,500,486	Schedule A
26	Difference	$ 761,143	

Difference is appreciation of Fair Value over Original Cost that is not recognized on the utility's books.

[a] The appreciation of Fair Value over Original Cost has not been recognized on the utility's books. Such off-book appreciation has not been financed by debt or equity capital recorded on the utility's books. The appreciation over Original Cost book value is therefore recognized for cost of capital purposes at zero cost.

[b] Per Staff witness Keith Berry, Exhibit SKB-2

[c] Per Staff witness Keith Berry - midpoint of 0% and real risk-free rate of return of 1.36%

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Tucson Electric Power Company
Equivalent Original Cost Rate Base Return on Equity - Staff FVROR Option 1

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

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Schedule D
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Line No.	Capital Source	Reference	Amount (A)	Percent (B)	Cost Rate (C)	Rate Of Return (D)
	I. Staff Adjusted Fair Value Rate Base					
1	Original Cost Rate Base (OCRB)	Sch. B	$ 1,500,486			
2	Reconstruction Cost new Depreciated (RCND)	Sch. B	$ 3,022,772			
3	Fair Value Rate Base (FVRB)	Sch. B	$ 2,261,629			
4	FVRB/OCRB Multiple	L.3 / L.1	1.50726			
	II. Staff Proposed Capital Structure for OCRB - Per Staff Witness S. Keith Berry					WACC
5	Short-Term Debt	L.1 and Sch.D, p.1	$ 7,913	0.53%	1.42%	0.01%
6	Long-Term Debt		$ 839,831	55.97%	5.18%	2.90%
7	Common Stock Equity		$ 652,742	43.50%	9.40%	4.09%
8	Total Capital Supporting OCRB		$ 1,500,486	100.00%		7.00%
	III. Staff Fair Value Rate of Return Option 1					FVROR
9	Short-Term Debt	Col.A, L5	$ 7,913	0.35%	1.42%	0.00%
10	Long-Term Debt	Col.A, L6	$ 839,831	37.13%	5.18%	1.92%
11	Common Stock Equity	Col.A, L7	$ 652,742	28.86%	9.40%	2.71%
12	FVRB Increment Above Original Cost	L3 - L1	$ 761,143	33.65%	0.00%	0.00%
13	Total Capital Supporting OCRB Plus FVRB Increment		$ 2,261,629	100.00%		4.64%
	IV. Net Income and Net Equivalent OCRB Proposed ROE					
14	Net Operating Income (FVROR x FVRB)		$ 104,973 =	$ 2,261,629 x	4.64%	
	Interest Expense (Debt x Debt Cost):					
15	Short Term Debt		$ (112) =	$ 7,913 x	1.42%	
16	Long Term Debt		$ (43,503) =	$ 839,831 x	5.18%	
17	Net Income		$ 61,358			
18	Common Equity Supporting OCRB	Line 7	$ 652,742			
19	Equivalent ROE on OCRB - Staff FVROR Option 1	L17 /L18	9.40%			

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Tucson Electric Power Company
Equivalent Original Cost Rate Base Return on Equity - Staff FVROR Option 2

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

Line No.	Capital Source	Reference	Amount (A)	Percent (B)	Cost Rate (C)	Rate Of Return (D)
	I. Staff Adjusted Fair Value Rate Base					
1	Original Cost Rate Base (OCRB)	Sch. B	$ 1,500,486			
2	Reconstruction Cost new Depreciated (RCND)	Sch. B	$ 3,022,772			
3	Fair Value Rate Base (FVRB)	Sch. B	$ 2,261,629			
4	FVRB/OCRB Multiple	L.3 / L.1	1.50726			
	II. Staff Proposed Capital Structure for OCRB - Per Staff Witness S. Keith Berry					WACC
5	Short-Term Debt	L.1 and Sch.D, p.1	$ 7,913	0.53%	1.42%	0.01%
6	Long-Term Debt		$ 839,831	55.97%	5.18%	2.90%
7	Common Stock Equity		$ 652,742	43.50%	9.40%	4.09%
8	Total Capital Supporting OCRB		$ 1,500,486	100.00%		7.00%
	III. Staff Fair Value Rate of Return Option 2					FVROR
9	Short-Term Debt	Col.A, L5	$ 7,913	0.35%	1.42%	0.00%
10	Long-Term Debt	Col.A, L6	$ 839,831	37.13%	5.18%	1.92%
11	Common Stock Equity	Col.A, L7	$ 652,742	28.86%	9.40%	2.71%
12	FVRB Increment Above Original Cost	L3 - L1	$ 761,143	33.65%	0.68%	0.23%
13	Total Capital Supporting OCRB Plus FVRB Increment		$ 2,261,629	100.00%		4.87%
	IV. Net Income and Net Equivalent OCRB Proposed ROE					
14	Net Operating Income (FVROR x FVRB)		$ 110,149 =	$ 2,261,629 x	4.87%	
	Interest Expense (Debt x Debt Cost):					
15	Short Term Debt		$ (112) =	$ 7,913 x	1.42%	
16	Long Term Debt		$ (43,503) =	$ 839,831 x	5.18%	
17	Net Income		$ 66,534			
18	Common Equity Supporting OCRB	Line 7	$ 652,742			
19	Equivalent ROE on OCRB - Staff FVROR Option 2	L17 /L18	10.19%			

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Tucson Electric Power Company
Equivalent Original Cost Rate Base Return on Equity - Staff FVROR Recommendation

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

Line No.	Capital Source	Reference	Amount (A)	Percent (B)	Cost Rate (C)	Rate Of Return (D)
	I. Staff Adjusted Fair Value Rate Base					
1	Original Cost Rate Base (OCRB)	Sch. B	$ 1,500,486			
2	Reconstruction Cost new Depreciated (RCND)	Sch. B	$ 3,022,772			
3	Fair Value Rate Base (FVRB)	Sch. B	$ 2,261,629			
4	FVRB/OCRB Multiple	L.3 / L.1	1.50726			
	II. Staff Proposed Capital Structure for OCRB - Per Staff Witness S. Keith Berry					WACC
5	Short-Term Debt	L.1 and Sch.D, p.1	$ 7,913	0.53%	1.42%	0.01%
6	Long-Term Debt		$ 839,831	55.97%	5.18%	2.90%
7	Common Stock Equity		$ 652,742	43.50%	9.40%	4.09%
8	Total Capital Supporting OCRB		$ 1,500,486	100.00%		7.00%
	III. Staff Fair Value Rate of Return Recommendation - Point Between FVROR Options 1 and 2					FVROR
9	Short-Term Debt	Col.A, L5	$ 7,913	0.35%	1.42%	0.00%
10	Long-Term Debt	Col.A, L6	$ 839,831	37.13%	5.18%	1.92%
11	Common Stock Equity	Col.A, L7	$ 652,742	28.86%	9.40%	2.71%
12	FVRB Increment Above Original Cost	L3 - L1	$ 761,143	33.65%	0.0450%	0.02%
13	Total Capital Supporting OCRB Plus FVRB Increment		$ 2,261,629	100.00%		4.66%
	IV. Net Income and Net Equivalent OCRB Proposed ROE					
14	Net Operating Income (FVROR x FVRB)		$ 105,316 =	$ 2,261,629 x	4.66%	
	Interest Expense (Debt x Debt Cost):					
15	Short Term Debt		$ (112) =	$ 7,913 x	1.42%	
16	Long Term Debt		$ (43,503) =	$ 839,831 x	5.18%	
17	Net Income		$ 61,701			
18	Common Equity Supporting OCRB	Line 7	$ 652,742			
19	Equivalent ROE on OCRB - Staff FVROR Option 2	L17 /L18	9.45%			

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Tucson Electric Power Company
Sahuarita-Nogales Transmission Line

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Test Year Ended December 31, 2011

Line No.	Description	Total Company Amount (A)	ACC Jurisdictional Amount (B)
1	Regulatory Assets -Per Company	$ 11,088,732	$ 11,088,732
2	Regulatory Assets -Per Staff	$ -	$ -
3	Staff Adjustment	$ (11,088,732)	$ (11,088,732)

Notes and Source

Line 1: Company Adjustment Rate Base - Sahuarita-Nogales Transmission Line,
Bates No. TEP(0291)007710

Tucson Electric Power Company
Cash Working Capital

Test Year Ended December 31, 2011

Docket No. E-01933A-12-0291
Schedule B-2
Page 1 of 1

Line No.	Description	Total Company Expense Amount - Per Company (A)	ACC Jurisdictional Expense Amount - Per Company (B)=(A)* 75.31% [1]	Lead/Lag Factor (C)	ACC CWC Required - Per Company (D)=(B)*(C)	Staff Expense Adjustments (E)	Staff Adjusted Expenses Amount (F)=(B)+(E)	ACC CWC Required- Per Staff (G)=(C)*(F)	Staff CWC Adjustment (H)=(G)-(D)
1	Salaries and Wages	$ 71,991,108	$ 54,216,503	0.0713	$ 3,865,637		$ 54,216,503	$ 3,865,637	$ -
2	Incentive Pay	$ 6,247,890	$ 4,705,286	(0.6110)	$ (2,874,930)	$ (2,094,439)	$ 2,610,847	$ (1,595,227)	$ 1,279,702
3	Fuel Expense	$ 285,386,416	$ 214,924,510	0.0191	$ 4,105,058	$ (4,816,000)	$ 210,108,510	$ 4,013,073	$ (91,986)
4	Lease Expense	$ 101,812,888	$ 76,675,286	(0.1585)	$ (12,153,033)		$ 76,675,286	$ (12,153,033)	$ -
5	Remote Generating Plant O&M	$ 47,385,627	$ 35,686,116	0.1188	$ 4,239,511		$ 35,686,116	$ 4,239,511	$ -
6	Office Supplies and Expenses	$ 9,594,745	$ 7,225,802	0.0658	$ 475,458		$ 7,225,802	$ 475,458	$ -
7	Outside Services	$ 10,520,391	$ 7,922,906	(0.0220)	$ (174,304)		$ 7,922,906	$ (174,304)	$ -
8	Property Insurance	$ 2,271,746	$ 1,710,852	0.0999	$ 170,914		$ 1,710,852	$ 170,914	$ -
9	Injuries and Damages	$ 2,278,506	$ 1,715,943	0.1363	$ 233,883	$ (289,320)	$ 1,426,623	$ 194,449	$ (39,434)
10	Pensions and Benefits	$ 17,449,591	$ 13,141,287	0.0642	$ 843,671		$ 13,141,287	$ 843,671	$ -
11	Miscellaneous General Expenses	$ 4,285,497	$ 3,227,408	0.1054	$ 340,169		$ 3,227,408	$ 340,169	$ -
12	Rents	$ 375,864	$ 283,063	0.2109	$ 59,698		$ 283,063	$ 59,698	$ -
13	Property Taxes	$ 39,148,092	$ 29,482,428	(0.4858)	$ (14,322,564)	$ 85,400	$ 29,567,828	$ (14,364,051)	$ (41,487)
14	Payroll Taxes	$ 7,830,466	$ 5,897,124	0.0546	$ 321,983		$ 5,897,124	$ 321,983	$ -
15	Current Income Taxes [2]	$ -	$ -	(0.0701)	$ -		$ -	$ -	$ -
16	Other Taxes	$ 46,168	$ 34,769	(0.1504)	$ (5,229)		$ 34,769	$ (5,229)	$ -
17	Interest on Customer Deposits	$ (2,439)	$ (1,837)	(0.4001)	$ 735		$ (1,837)	$ 735	$ -
18	Other Operations and Maintenance	$ 63,312,707	$ 47,680,800	0.0671	$ 3,199,382	$ (2,481,300)	$ 45,199,499	$ 3,032,886	$ (166,495)
19	Total Operating Expenses	$ 669,935,263	$ 504,528,247		$ (11,673,962)	$ (9,595,659)	$ 494,932,587	$ (10,733,662)	$ 940,300
20	Interest on Long-Term Debt	$ 54,838,713	$ 41,299,035	(0.14)	$ (5,624,929)	$ 1,124,120	$ 42,423,155	$ (5,778,034)	$ (153,105)
21	Revenue Taxes and Assessments	$ 85,440,494	$ 64,345,236	(0.03)	$ (2,059,048)		$ 64,345,236	$ (2,059,048)	$ -
22	Total Other Case Working Capital Elements	$ 140,279,207	$ 105,644,271		$ (7,683,976)	$ 1,124,120	$ 106,768,391	$ (7,837,081)	$ (153,105)
23	Total Cash Working Capital	$ 810,214,470	$ 610,172,518		$ (19,357,938)	$ (8,471,539)	$ 601,700,978	$ (18,570,744)	$ 787,195
24	Staff Cash Working Capital (rounded to $1,000)								$ 787,000

Notes and Source

[1]: ACC jurisdictional Factor is from Company Filing, 2012 TEP Rev Req Model.xls, tab Rate Base-Orig Cost
Cols. A and C: Company Filing, 2012 TEP Rev Req Model.xls, tab Summary
[2] Because TEP has a tax net operating loss carryforward, TEP's income tax expenses for the current rate case are treated as deferred income taxes

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Tucson Electric Power Company
Remove One-Half of Prepaid D&O Insurance

Test Year Ended December 31, 2011

Docket No. E-01933A-12-0291
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Page 1 of 1

Line No.	Description	Account	Total Amount	One Half	Staff Adjustment
		(A)	(B)	(C)	(D)
1	Prepaid D&O Insurance	14010	$ 310,572	$ 155,286	$ (155,286)
2	ACC Jurisdictional Allocation		75.35%	75.35%	75.35%
3	Adjustment to Jurisdictional Rate Base		$ 234,014	$ 117,007	$ (117,007)

Notes and Source

Cols A and B: TEP response to STF 24.1(a)

Line 2: [2012 TEP Rev Req Model.xlsm]Rate Base-Orig Cost
column: ACC Ratio as Filed
FERC Account 165

Check:

4	TEP Adjusted ACC Jurisdictional Prepayments	$ 4,537,991
5	TEP Adjusted Total Prepayments	$ 6,022,956
6	Jurisdictional Factor	75.35%

Line 3: Line 1 x Line 2

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Tucson Electric Power Company
Fuel Inventory - Adjustment for San Juan Coal Price

Docket No. E-01933A-12-0291
Schedule B-4
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Test Year Ended December 31, 2011

Line No.	Account	Description	TEP Adjusted Test Year Amount (A)	Staff Adjusted Test Year Amount (B)	Staff Adjustment (C)
		San Juan Coal Inventory			
1		Target Inventory in Tons	133,218	133,218	133,218
2		Per Ton Cost Used for Inventory	$ 63.62	$ 50.52	$ (13.10)
3	12000	Pro forma Inventory Cost	$ 8,475,749	$ 6,730,593	$ (1,745,156)
		Sundt Coal Inventory			
4		Target Inventory in Tons	32,685	32,685	32,685
5		Per Ton Cost Used for Inventory	$ 79.57	$ 79.22	$ (0.35)
6	12000	Pro forma Inventory Cost	$ 2,600,833	$ 2,589,393	$ (11,440)
		Coal Inventory Adjustment			
7	151	Subtotal Coal Inventory Cost Adjustment		Line 3 + Line 6	$ (1,756,596)
8		Jurisdictional Factor			90.54%
9	151	ACC jurisdictional adjustment			$ (1,590,364)

Notes and Source

Col.A: TEP workpaper TEP(0291(007720)
Per Ton Coal Cost is derived from TEP pro forma inventory cost and target inventory tons

Col.B: Staff witness Emily Medine

Line 8: ACC jurisdictional allocation factor taken from TEP's "2012 Rev Req Model" workpapers and TEP workpaper TEP(0291)007717

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Tucson Electric Power Company
New Headquarters Building

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Schedule B-5
Page 1 of 3

Test Year Ended December 31, 2011

Line No.	Description	Calculations	Staff Adjustment	Reference
1	**Remove Cost of Retail Space**		$ (2,136,000)	Line 15
	Remove Cost of Unoccupied Office Space:			
2	Vacant Office Space (sf)	8,540		Page 3
3	Cost / Sq Ft for Office Space	$ 263		Line 14, Note [d]
4	Remove Cost of Unoccupied Office Space		$ (2,246,000)	
	Allocate Cost of Parking Garage			
5	Estimated Total Cost	$ 10,500,000		STF 26.07
6	Allocation to Ratepayers - 50%	$ 5,250,000		
7	Allocation to TEP Shareholders - 50%		$ (5,250,000)	
	Adjustment to General Plant			
8	Adjustment to TEP Total Company Rate Base for Headquarters Building Cost		$ (9,632,000)	
9	Building Cost Retained by TEP (not allocated to affiliates)		95.5%	
10	Adjustment to TEP Total Company Rate Base for Headquarters Disallowance		$ (9,199,000)	
11	Jurisdictional factor		73.44%	
12	Jurisdictional adjustment for headquarters building cost		$ (6,756,000)	
	Adjustment to Accumulated Depreciation on General Plant			
13	Jurisdictional adjustment for headquarters building cost		$ 178,000	Schedule C-10

Notes and Source

UniSource Energy Headquarters Building - Cost for Sections of Building

	Part of Headquarters Build	Gross Square Feet		Cost/ Sq Ft		Derived Approximate Total Cost	Portion of Total Cost
14	Office	281,280	[a], [b]	$ 263	[c]	$ 73,976,640	80.34%
15	Retail	12,000	[a]	$ 178	[c]	$ 2,136,000	2.32%
16	Parking	249,410	[a], [b]	$ 64	[c]	$ 15,962,240	17.34%
17	Total					$ 92,074,880	100.00%

[a] STF 16.08(a)
[b] Also see CONFIDENTIAL TEP (0291)027312 (In an email dated December 19, 2012, TEP stated "Staff may refer to the cost, square footage, cost per square foot, and the amount of occupied space in its testimony as TEP will no longer consider it confidential.")
[c] STF 16.08(e)
[d] Also see TEP's responses to STF 16.08 and STF 26.07

Line 9: TEP's 12/6/2012 supplemental response to STF 23.1 shows the portion of building costs based on TEP labor hours allocated to affiliate was 4.5%; conversely, the building costs retained by TEP are 95.5%.

Line 11: General Plant (from TEP 2012 Rev Req Model.xls)

18	ACC Jurisdictional	$ 160,622,433
19	Total Company	$ 218,699,653
20	Jurisdictional factor	73.44%

Tucson Electric Power Company
New Headquarters Building
Unoccupied Office Space - Gross Square Footage from Response to STF 16.08
Test Year Ended December 31, 2011

Docket No. E-01933A-12-0291
Schedule B-5
Page 2 of 3

CONFIDENTIAL

UniSource Headquarters
Occupied and Unoccupied Space and Space Per Occupant

Line No.	Floor	Space GSF	Occupied Percent	Occupied Space	Unoccupied Space
	(A)	(B)	(C)	(D)	(E)
1	9	28,750	87%	25,013	3,738
2	8	28,750	75%	21,563	7,188
3	7	28,750	86%	24,725	4,025
4	6	28,750	94%	27,025	1,725
5	5	28,750	87%	25,013	3,738
6	4	37,410	95%	35,540	1,871
7	3	40,660	59%	23,989	16,671
8	2	31,730	79%	25,067	6,663
9	1	27,730	100%	27,730	-
10	Total	281,280		235,663	45,617
11	Unoccupied space as percent of total space				16.2%

Notes and Source

Source: TEP response to STF 16.08(a) and (d)
Breakout of Total Space per On Site Building Tour Documentation and response to STF 26.6 [Note A]:

	Floor	Cubicles, Offices Conference Rooms Circulation Space	Ancillary Space	Total Space (gsf)
		(F)	(G)	(H)
		[BEGIN CONFIDENTIAL]		
12	9			
13	8			
14	7			
15	6			
16	5			
17	4			
18	3			
19	2			
20	1			
21	Total			

[END CONFIDENTIAL]

[A] A copy of such documentation is presented in Attachment RCS-4

Tucson Electric Power Company
New Headquarters Building
Vacant Space - From Confidential On Site Building Tour Documentation
Test Year Ended December 31, 2011

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Schedule B-5
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CONFIDENTIAL

UniSource Headquarters
Vacant Office and Cubicle Space
[BEGIN CONFIDENTIAL]

Line No.		Floor	Vacant Space (Square Feet)
		(A)	(B)
1		9	[redacted]
2		8	
3		7	
4		6	
5		5	
6		4	
7		3	
8		2	
9		1	
			[END CONFIDENTIAL]
10	Total		8,540

Notes and Source
TEP's Confidential response to STF 26.06

Tucson Electric Power Company
Sahuarita-Nogales Transmission Line Amortization Expense

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Schedule C-1
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Test Year Ended December 31, 2011

Line No.	Description	Total Company Amount (A)	ACC Jurisdictional Amount (B)
1	Regulatory Asset Amortization Expense - Per Company	$ 2,982,638	$ 2,982,638
2	Regulatory Asset Amortization Expense - Per Staff	$ -	$ -
3	Staff Adjustment	$ (2,982,638)	$ (2,982,638)

Notes and Source:

Line 1: Company Adjustment Income-Sahuarita-Nogales Transmission Line Amortization,
Bates No. TEP(0291)007504

Tucson Electric Power Company
Incentive Compensation (PEP) Program Expense

Docket No. E-01933A-12-0291
Schedule C-2
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Test Year Ended December 31, 2011

Line No.	Description	2011 Recorded Total Company	Company Pro Forma Adjustments Total Company	Company Requested Total Company	Staff Recommended Total Company	Staff Adjustments Total Company	ACC Juris. Factor	Staff Adjustments ACC Juris.
		(A)	(B)	(C) = (A) +(B)	(D)=P	(E) = (D)-(C)	(F)	(G)=(E)*(F)
	FERC							
1	0500	$ 83,927	$ 55,519	$ 139,446	$ 124,339	$ (15,107)	0.89067	$ (13,455)
2	0506	$ 786,569	$ 520,332	$ 1,306,901	$ 732,067	$ (574,834)	0.89067	$ (511,988)
3	0514	$ 309,913	$ 205,015	$ 514,928	$ 331,100	$ (183,828)	0.89067	$ (163,730)
4	0566	$ 587,565	$ 388,687	$ 976,252	$ 441,759	$ (534,493)	0.00000	$ -
5	0570	$ 62,030	$ 41,033	$ 103,063	$ 86,719	$ (16,344)	0.00000	$ -
6	0580	$ 53,316	$ 35,269	$ 88,585	$ 52,177	$ (36,408)	1.00000	$ (36,408)
7	0588	$ 215,121	$ 142,306	$ 357,427	$ 214,960	$ (142,467)	1.00000	$ (142,467)
8	0598	$ 34,017	$ 22,502	$ 56,519	$ 35,654	$ (20,865)	1.00000	$ (20,865)
9	0903	$ 226,452	$ 149,804	$ 376,256	$ 228,640	$ (147,616)	1.00000	$ (147,616)
10	0920	$ 1,418,591	$ 938,441	$ 2,357,032	$ 1,366,711	$ (990,321)	0.88449	$ (875,934)
11	O&M Expense	$ 3,777,501	$ 2,498,908	$ 6,276,409	$ 3,614,126	$ (2,662,283)		$ (1,912,464)
12	0408 FICA Tax	$ 283,313	$ 187,418	$ 470,731	$ 225,205	$ (245,526)	0.74117	$ (181,975)
13	Total Expense	$ 4,060,814	$ 2,686,326	$ 6,747,140	$ 3,839,331	$ (2,907,809)		$ (2,094,439)

Notes and Source

Col. A: TEP response to UDR 1.36b
Col. B: TEP Income Statement Pro Forma Adjustment, Income - Incentive Compensation.pdf, Bates No. TEP(0291)007212
Col. F: ACC Jurisdictional Factors from TEP Income - Incentive Compensation.pdf, Bates No. TEP(0291)007212:

	FERC	Total Company	ACC	ACC Factor
		(H)	(I)	(J)
14	0500	$ 55,519	$ 49,449	0.89067
15	0506	$ 520,332	$ 463,445	0.89067
16	0514	$ 205,015	$ 182,601	0.89067
17	0566	$ 388,687	$ -	0.00000
18	0570	$ 41,033	$ -	0.00000
19	0580	$ 35,269	$ 35,269	1.00000
20	0588	$ 142,306	$ 142,306	1.00000
21	0598	$ 22,502	$ 22,502	1.00000
22	0903	$ 149,804	$ 149,804	1.00000
23	0920	$ 938,441	$ 830,046	0.88449
24	0408	$ 187,418	$ 138,908	0.74117
25	Total	$ 2,686,326	$ 2,014,330	

Col. D: Staff Recommended Incentive (PEP) Expense - Based on 50/50 Allocation of a Two-Year Average from UDR 1.36

	FERC	2011	2010	Two Year Average	Staff Recommended: 50/50 Sharing	Staff Recommended: Reallocate Account 426 To O&M Expense	Staff Recommended: Total Company
		(K)	(L)	(M)	(N)	(O)	(P)
26	0426 [Note A]	$ 3,404,253	$ 3,568,178	$ 3,486,216	$ 1,743,108		
27	0500	$ 83,927	$ 173,553	$ 128,740	$ 64,370	$ 59,969	$ 124,339
28	0506	$ 786,569	$ 729,383	$ 757,976	$ 378,988	$ 353,079	$ 732,067
29	0514	$ 309,913	$ 375,720	$ 342,817	$ 171,409	$ 159,691	$ 331,100
30	0566	$ 587,565	$ 327,220	$ 457,393	$ 228,697	$ 213,062	$ 441,759
31	0570	$ 62,030	$ 117,544	$ 89,787	$ 44,894	$ 41,825	$ 86,719
32	0580	$ 53,316	$ 54,731	$ 54,024	$ 27,012	$ 25,165	$ 52,177
33	0588	$ 215,121	$ 230,012	$ 222,567	$ 111,284	$ 103,676	$ 214,960
34	0598	$ 34,017	$ 39,812	$ 36,915	$ 18,458	$ 17,196	$ 35,654
35	0903	$ 226,452	$ 247,009	$ 236,731	$ 118,366	$ 110,274	$ 228,640
36	0920	$ 1,418,591	$ 1,411,569	$ 1,415,080	$ 707,540	$ 659,171	$ 1,366,711
37	O&M Expense	$ 7,181,754	$ 7,274,731	$ 7,228,246	$ 3,614,126	$ 1,743,108	$ 3,614,126
38	0408	$ 431,394	$ 438,848	$ 450,410	$ 225,205		$ 225,205
39	Total	$ 7,613,148	$ 7,713,579	$ 7,678,656	$ 3,839,331		$ 3,839,331
40	Sum of O&M Expense Excluding Account 426 Amounts			$ 3,742,030	$ 1,871,018		

Cols. K and L: UDR 1.36
[A] In years 2010 and 2011, TEP recorded approximately 49.0% and 47.4%, respectively, of its PEP Incentive Compensation Expense below-the-line.

Tucson Electric Power Company
Overhaul and Outage Expense

Test Year Ended December 31, 2011

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Line No.	Description	Amount Per Company		Amount Per Staff		Staff Adjustments	
		Total Company	ACC Jurisdictional	Total Company	ACC Jurisdictional	Total Company	ACC Jurisdictional
		(A)	(B)=(A) * 0.93848	(C)	(D)=(C)*0.93848	(E)=(C)-(A)	(F)=(E)*0.93848
	Four Corners						
1	Estimated Recurring Expense	$ 1,108,013	$ 1,039,848	$ 921,125	$ 864,457	$ (186,888)	$ (175,391)
2	Test Year Outage Amount	$ 1,012,000	$ 949,742	$ 1,012,000	$ 949,742	$ -	$ -
3	Adjustment	$ 96,013	$ 90,106	$ (90,875)	$ (85,284)	$ (186,888)	$ (175,391)
	Navajo						
4	Estimated Recurring Expense	$ 2,133,721	$ 2,002,454	$ 1,914,000	$ 1,796,251	$ (219,721)	$ (206,204)
5	Test Year Outage Amount	$ 3,210,000	$ 3,012,521	$ 3,210,000	$ 3,012,521	$ -	$ -
6	Adjustment	$ (1,076,279)	$ (1,010,066)	$ (1,296,000)	$ (1,216,270)	$ (219,721)	$ (206,204)
	San Juan						
7	Estimated Recurring Expense	$ 5,784,261	$ 5,428,413	$ 3,518,125	$ 3,301,690	$ (2,266,136)	$ (2,126,723)
8	Test Year Outage Amount	$ 6,667,000	$ 6,256,846	$ 6,667,000	$ 6,256,846	$ -	$ -
9	Adjustment	$ (882,739)	$ (828,433)	$ (3,148,875)	$ (2,955,156)	$ (2,266,136)	$ (2,126,723)
	Luna						
10	Estimated Recurring Expense	$ 591,308	$ 554,931	$ 398,250	$ 373,750	$ (193,058)	$ (181,181)
11	Test Year Outage Amount	$ 869,000	$ 815,539	$ 869,000	$ 815,539	$ -	$ -
12	Adjustment	$ (277,692)	$ (260,608)	$ (470,750)	$ (441,789)	$ (193,058)	$ (181,181)
	Springville Excluding Unit 1						
13	Estimated Recurring Expense	$ 2,779,583	$ 2,608,583	$ 2,412,864	$ 2,264,425	$ (366,719)	$ (344,158)
14	Test Year Outage Amount	$ -	$ -	$ -	$ -	$ -	$ -
15	Adjustment	$ 2,779,583	$ 2,608,583	$ 2,412,864	$ 2,264,425	$ (366,719)	$ (344,158)
	Irvington						
16	Estimated Recurring Expense	$ 2,631,115	$ 2,469,249	$ 3,184,869	$ 2,988,936	$ 553,754	$ 519,687
17	Test Year Outage Amount	$ 2,000,000	$ 1,876,960	$ 2,000,000	$ 1,876,960	$ -	$ -
18	Adjustment	$ 631,115	$ 592,289	$ 1,184,869	$ 1,111,976	$ 553,754	$ 519,687
19	Total Adjustment	$ 1,270,001	$ 1,191,871	$ (1,408,767)	$ (1,322,100)	$ (2,678,768)	$ (2,513,970)
	Total Allowance						
20	Estimated Recurring Expense	$ 15,028,001	$ 14,103,478	$ 12,349,233	$ 11,589,508	$ (2,678,768)	$ (2,513,970)
21	Test Year Outage Amount	$ 13,758,000	$ 12,911,608	$ 13,758,000	$ 12,911,608	$ -	$ -
22	Total Adjustment	$ 1,270,001	$ 1,191,871	$ (1,408,767)	$ (1,322,100)	$ (2,678,768)	$ (2,513,970)

Notes and Source:
Col. A: TEP adjustment Income-Overhaul and Outage.xls
Col.C: see pages 2 and 3 of this Schedule

Tucson Electric Power Company
Overhaul and Outage - Major and Minor Method

Test Year Ended December 31, 2011

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Outage Type (Major or Minor)

Line No.	Plant	2004	2005	2006	2007	2008	2009	2010	2011
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
1	Four Corners unit 4	Major	Minor		Minor		Minor	Major	
2	*Four Corners unit 5*		Minor	Minor		Major	Minor		Minor
3	Navajo unit 1		Major			Minor			Major
4	Navajo unit 2	Major			Minor			Major	
5	Navajo unit 3			Minor			Major		
6	San Juan unit1	Minor		Minor		Major			Minor
7	San Juan unit 2		Minor		Minor		Major		
8	Luna 1						Minor		
9	Luna 2					Minor			Minor
10	Springerville unit 1								
11	*Springerville unit 2*		Major		Minor	Major		Major	
12	Irvington unit 1		Minor			Minor		Major	Major
13	Irvington unit 2	Major					Minor	Major	Major
14	Irvington unit 3	Major			Minor	Minor		Minor	
15	Irvington unit 4	Minor		Minor			Major		

Frequency %		Frequency # of Years Between Outage	
Major	Minor	Major	Minor
0.25	0.38	4.00	2.67
0.13	0.50	8.00	2.00
0.25	0.13	4.00	8.00
0.25	0.13	4.00	8.00
0.13	0.13	8.00	8.00
0.13	0.38	8.00	2.67
0.13	0.25	8.00	4.00
-	0.13	-	8.00
-	0.25	-	4.00
-	-	-	-
0.38	0.13	2.67	8.00
0.25	0.25	4.00	4.00
0.38	0.13	2.67	8.00
0.13	0.38	8.00	2.67
0.13	0.25	8.00	4.00

Outage Cost ($ 000's)

Actual Cost

	Plant	2004	2005	2006	2007	2008	2009	2010	2011	# of majors scheduled	# of minors scheduled	Average Major $'s	Average Minor $'s
16	Four Corners unit 4	$ 1,232	$ 122		$ 372		$ 232	$ 1,810	$ -	2	3	$ 1,521	$ 242
17	Four Corners unit 5		$ 230	$ 351		$ 1,619	$ 389	$ -	$ 1,012	1	4	$ 1,619	$ 496
18	Total Four Corners	$ 1,232	$ 352	$ 351	$ 372	$ 1,619	$ 621	$ 1,810	$ 1,012			$ 3,140	$ 738
19	Navajo unit 1		$ 1,500			$ 1,231	$ -	$ -	$ 3,210	2	1	$ 2,355	$ 1,231
20	Navajo unit 2	$ 1,334			$ 532		$ -	$ 3,486	$ -	2	1	$ 2,410	$ 532
21	Navajo unit 3			$ 516			$ 3,503	$ -	$ -	1	1	$ 3,503	$ 516
22	Total Navajo	$ 1,334	$ 1,500	$ 516	$ 532	$ 1,231	$ 3,503	$ 3,486	$ 3,210			$ 8,268	$ 2,279
23	San Juan unit1	$ 1,800		$ 1,798		$ 6,923	$ -	$ -	$ 6,667	1	3	$ 6,923	$ 3,422
24	San Juan unit 2		$ 1,700		$ 1,802		$ 7,455		$ -	1	2	$ 7,455	$ 1,751
25	Total San Juan	$ 1,800	$ 1,700	$ 1,798	$ 1,802	$ 6,923	$ 7,455	$ -	$ 6,667			$ 14,378	$ 5,173
26	Luna 1						$ 1,363	$ -		-	1	$ -	$ 1,363
27	Luna 2					$ 954		$ -	$ 869	-	2	$ -	$ 912
28	Total Luna	$ -	$ -	$ -	$ -	$ 954	$ 1,363	$ -	$ 869			$ -	$ 2,275
29	Springerville unit 1									-	-	$ -	$ -
30	Springerville unit 2		$ 5,000		$ 2,951	$ 5,943	$ -	$ 5,409	$ -	3	1	$ 5,451	$ 2,951
31	Total Springerville	$ -	$ 5,000	$ -	$ 2,951	$ 5,943	$ -	$ 5,409	$ -			$ 5,451	$ 2,951
32	*Irvington unit 1*		$ 1,010			$ 2,442		$ 375	$ 1,000	2	2	$ 688	$ 1,726
33	Irvington unit 2	$ 1,197					$ 958	$ 375	$ 1,000	3	1	$ 857	$ 958
34	Irvington unit 3	$ 1,796			$ 1,000	$ 2,639		$ 850		1	3	$ 1,796	$ 1,496
35	Irvington unit 4	$ 257		$ 4,810			$ 5,770			1	2	$ 5,770	$ 2,534
36	Total Irvington	$ 3,250	$ 1,010	$ 4,810	$ 1,000	$ 5,081	$ 6,728	$ 1,600	$ 2,000			$ 9,111	$ 6,713
37	Total Cost Per Year	$ 7,616	$ 9,562	$ 7,475	$ 6,657	$ 21,751	$ 19,670	$ 12,305	$ 13,758			$ 40,348	$ 20,128
38	Total Cost 8 Years	$ 98,794											

Annualized cost		
Major	Minor	Total
$ 380	$ 91	$ 471
$ 202	$ 248	$ 450
$ 583	$ 339	$ 921
$ 589	$ 154	$ 743
$ 603	$ 67	$ 669
$ 438	$ 65	$ 502
$ 1,629	$ 285	$ 1,914
$ 865	$ 1,283	$ 2,149
$ 932	$ 438	$ 1,370
$ 1,797	$ 1,721	$ 3,518
$ -	$ 170	$ 170
$ -	$ 228	$ 228
$ -	$ 398	$ 398
$ -	$ -	$ -
$ 2,044	$ 369	$ 2,413
$ 2,044	$ 369	$ 2,413
$ 172	$ 432	$ 603
$ 322	$ 120	$ 441
$ 225	$ 561	$ 786
$ 721	$ 633	$ 1,355
$ 1,439	$ 1,746	$ 3,185
$ 7,492	$ 4,857	$ 12,349

Notes and Source:
Cols. A to I, lines 1 to 36: TEP adjustment Income-Overhaul and Outage.xls

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Tucson Electric Power Company
Overhaul and Outage - Average Method

Test Year Ended December 31, 2011

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Outage Cost ($ 000's)

Line No.	Plant	Actual Cost 2004	2005	2006	2007	2008	2009	2010	2011	8 Year Total	8 Year Average	
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	
1	Four Corners unit 4	$ 1,232	$ 122		$ 372		$ 232	$ 1,810	$ -	3,768	471	
2	Four Corners unit 5		$ 230	$ 351		$ 1,619	$ 389	$ -	$ 1,012	3,601	450	
3	Total Four Corners	$ 1,232	$ 352	$ 351	$ 372	$ 1,619	$ 621	$ 1,810	$ 1,012			
4	Navajo unit 1		$ 1,500			$ 1,231	$ -	$ -	$ 3,210	5,941	743	
5	Navajo unit 2	$ 1,334			$ 532		$ -	$ 3,486	$ -	5,352	669	
6	Navajo unit 3			$ 516			$ 3,503	$ -	$ -	4,019	502	
7	Total Navajo	$ 1,334	$ 1,500	$ 516	$ 532	$ 1,231	$ 3,503	$ 3,486	$ 3,210			
8	San Juan unit1	$ 1,800		$ 1,798		$ 6,923	$ -	$ -	$ 6,667	17,188	2,149	
9	San Juan unit 2		$ 1,700		$ 1,802		$ 7,455		$ -	10,957	1,370	
10	Total San Juan	$ 1,800	$ 1,700	$ 1,798	$ 1,802	$ 6,923	$ 7,455	$ -	$ 6,667			
11	Luna 1 (Note a)						$ 1,363	$ -		1,363	341	[a]
12	Luna 2 (Note a)					$ 954		$ -	$ 869	1,823	456	[a]
13	Total Luna	$ -	$ -	$ -	$ -	$ 954	$ 1,363	$ -	$ 869			
14	Springerville unit 1									-	-	
15	Springerville unit 2		$ 5,000		$ 2,951	$ 5,943	$ -	$ 5,409	$ -	19,303	2,413	
16	Total Springerville	$ -	$ 5,000	$ -	$ 2,951	$ 5,943	$ -	$ 5,409	$ -			
17	Irvington unit 1		$ 1,010			$ 2,442		$ 375	$ 1,000	4,827	603	
18	Irvington unit 2	$ 1,197					$ 958	$ 375	$ 1,000	3,530	441	
19	Irvington unit 3	$ 1,796			$ 1,000	$ 2,639		$ 850		6,285	786	
20	Irvington unit 4	$ 257		$ 4,810			$ 5,770			10,837	1,355	
21	Total Irvington	$ 3,250	$ 1,010	$ 4,810	$ 1,000	$ 5,081	$ 6,728	$ 1,600	$ 2,000			
22	Total Cost Per Year	$ 7,616	$ 9,562	$ 7,475	$ 6,657	$ 21,751	$ 19,670	$ 12,305	$ 13,758			
23	Total Cost 8 Years	$ 98,794								98,794	12,747	

Notes and Source:
Cols. A to I, lines 1 to 21: TEP adjustment Income-Overhaul and Outage.xls
[a]: Four-Year Average used for Luna

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Outage Cost ($ 000's)

Line No.	Plant	Actual Cost 1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	13 Year Total	13 Year Average
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
1	Four Corners unit 4	$ -	$ 987	$ -	$ -	$ 94	$ 1,232	$ 122		$ 372		$ 232	$ 1,810	$ -	4,849	373
2	Four Corners unit 5	$ 315	$ -	$ -	$ 772	$ 152		$ 230	$ 351		$ 1,619	$ 389	$ -	$ 1,012	4,840	372
3	Total Four Corners	$ 315	$ 987	$ -	$ 772	$ 246	$ 1,232	$ 352	$ 351	$ 372	$ 1,619	$ 621	$ 1,810	$ 1,012		-
4	Navajo unit 1	$ 1,551	$ -	$ 282	$ -	$ 393		$ 1,500			$ 1,231	$ -	$ -	$ 3,210	8,167	628
5	Navajo unit 2	$ -	$ 495	$ -	$ 293	$ -	$ 1,334			$ 532		$ -	$ 3,486	$ -	6,140	472
6	Navajo unit 3	$ 508	$ -	$ 281	$ -	$ 2,115			$ 516			$ 3,503	$ -	$ -	6,923	533
7	Total Navajo	$ 2,059	$ 495	$ 563	$ 293	$ 2,508	$ 1,334	$ 1,500	$ 516	$ 532	$ 1,231	$ 3,503	$ 3,486	$ 3,210		-
8	San Juan unit1	$ -	$ 1,916	$ -	$ 3,579	$ -	$ 1,800		$ 1,798		$ 6,923	$ -	$ -	$ 6,667	22,683	1,745
9	San Juan unit 2	$ 1,753	$ -	$ 4,216	$ -	$ 2,075		$ 1,700		$ 1,802		$ 7,455		$ -	19,001	1,462
10	Total San Juan	$ 1,753	$ 1,916	$ 4,216	$ 3,579	$ 2,075	$ 1,800	$ 1,700	$ 1,798	$ 1,802	$ 6,923	$ 7,455	$ -	$ 6,667		-
11	Luna 1 (Note a)	$ -	$ -	$ -	$ -	$ -						$ 1,363	$ -		1,363	341 [a]
12	Luna 2 (Note a)	$ -	$ -	$ -	$ -	$ -					$ 954		$ -	$ 869	1,823	456 [a]
13	Total Luna	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 954	$ 1,363	$ -	$ 869		-
14	Springerville unit 1	$ 989	$ 5,300	$ -	$ 3,505	$ -									9,794	753
15	Springerville unit 2	$ 4,719	$ -	$ 1,927	$ -	$ 3,620		$ 5,000		$ 2,951	$ 5,943	$ -	$ 5,409	$ -	29,569	2,275
16	Total Springerville	$ 5,708	$ 5,300	$ 1,927	$ 3,505	$ 3,620	$ -	$ 5,000	$ -	$ 2,951	$ 5,943	$ -	$ 5,409	$ -		-
17	Irvington unit 1	$ -	$ -	$ -	$ -	$ -		$ 1,010			$ 2,442		$ 375	$ 1,000	4,827	371
18	Irvington unit 2	$ -	$ -	$ -	$ -	$ 28	$ 1,197					$ 958	$ 375	$ 1,000	3,558	274
19	Irvington unit 3	$ -	$ -	$ 1,624	$ -	$ 184	$ 1,796			$ 1,000	$ 2,639		$ 850		8,093	623
20	Irvington unit 4	$ 287	$ -	$ 421	$ -	$ 2,517	$ 257		$ 4,810			$ 5,770			14,062	1,082
21	Total Irvington	$ 287	$ -	$ 2,045	$ -	$ 2,729	$ 3,250	$ 1,010	$ 4,810	$ 1,000	$ 5,081	$ 6,728	$ 1,600	$ 2,000		
22	Total Cost Per Year	$ 10,122	$ 8,698	$ 8,751	$ 8,149	$ 11,178	$ 7,616	$ 9,562	$ 7,475	$ 6,657	$ 21,751	$ 19,670	$ 12,305	$ 13,758		
23	Total Cost 13 Years	$ 145,692													145,692	11,758

Notes and Source:
Cols. B to F: Company response to STF 9.01
Cols. G to N: TEP adjustment Income-Overhaul and Outage.xls
[a]: Four-Year Average used for Luna

Tucson Electric Power Company
Overhaul and Outage - Company Projected vs. Actual in Dollars

Test Year Ended December 31, 2011

Outage Cost ($ 000's)

Line No.	Plant	2005	2006	2007	2008	2009	2010	2011	Reference
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	
	Actual								
1	Four Corners	$ 352	$ 351	$ 372	$ 1,619	$ 621	$ 1,810	$ 1,012	
2	Navajo	$ 1,500	$ 516	$ 532	$ 1,231	$ 3,503	$ 3,486	$ 3,210	
3	San Juan	$ 1,700	$ 1,798	$ 1,802	$ 6,923	$ 7,455	$ -	$ 6,667	
	2004 Forecast								
4	Four Corners	$ 313	$ -	$ -	$ -	$ -	$ -	$ -	
5	Navajo	$ 1,138	$ 420	$ 420	$ 420	$ 1,157	$ 1,157	$ 1,157	
6	San Juan	$ -	$ -	$ 2,041	$ 2,000	$ -	$ -	$ -	
	2005 Forecast								
7	Four Corners		$ 150						
8	Navajo		$ 420	$ 420	$ 420	$ 1,240	$ 1,240	$ 1,240	
9	San Juan		$ 2,146	$ 2,191	$ 2,532	$ 5,683			
	2006 Forecast								
10	Four Corners			$ 372	$ 1,701	$ 372	$ 1,700	$ 372	
11	Navajo			$ 532	$ 533	$ 1,500	$ 1,500	$ 1,500	
12	San Juan			$ 1,802	$ 1,798	$ 4,400	$ 4,397	$ 1,800	
	2007 Forecast								
13	Four Corners				$ 1,334				
14	Navajo				$ 521	$ 837	$ 837	$ 837	
15	San Juan				$ 3,966	$ 4,154	$ 2,258	$ 2,242	
	2008 Forecast								
16	Four Corners					$ 341			
17	Navajo					$ 1,921	$ 1,599	$ 1,599	
18	San Juan					$ 4,991	$ 2,890	$ 2,807	
	2004 Variance: Forecast - Actual								
19	Four Corners	$ **(39)**	$ **(351)**	$ **(372)**	$ **(1,619)**	$ **(621)**	$ **(1,810)**	$ **(1,012)**	L4 - L1
20	Navajo	$ **(362)**	$ **(96)**	$ **(112)**	$ **(811)**	$ **(2,346)**	$ **(2,329)**	$ **(2,053)**	L5 - L2
21	San Juan	$ **(1,700)**	$ **(1,798)**	$ **239**	$ **(4,923)**	$ **(7,455)**	$ -	$ **(6,667)**	L6 - L3
	2005 Variance: Forecast - Actual								
22	Four Corners		$ **(201)**	$ **(372)**	$ **(1,619)**	$ **(621)**	$ **(1,810)**	$ **(1,012)**	L7 - L1
23	Navajo		$ **(96)**	$ **(112)**	$ **(811)**	$ **(2,263)**	$ **(2,246)**	$ **(1,970)**	L8 - L2
24	San Juan		$ **348**	$ **389**	$ **(4,391)**	$ **(1,772)**	$ -	$ **(6,667)**	L9 - L3
	2006 Variance: Forecast - Actual								
25	Four Corners			$ -	$ **82**	$ **(249)**	$ **(110)**	$ **(640)**	L10 - L1
26	Navajo			$ -	$ **(698)**	$ **(2,003)**	$ **(1,986)**	$ **(1,710)**	L11 - L2
27	San Juan			$ -	$ **(5,125)**	$ **(3,055)**	$ **4,397**	$ **(4,867)**	L12 - L3
	2007 Variance: Forecast - Actual								
28	Four Corners				$ **(285)**	$ **(621)**	$ **(1,810)**	$ **(1,012)**	L13 - L1
29	Navajo				$ **(710)**	$ **(2,666)**	$ **(2,649)**	$ **(2,373)**	L14 - L2
30	San Juan				$ **(2,957)**	$ **(3,301)**	$ **2,258**	$ **(4,425)**	L15 - L3
	2008 Variance: Forecast - Actual								
31	Four Corners					$ **(280)**	$ **(1,810)**	$ **(1,012)**	L16 - L1
32	Navajo					$ **(1,582)**	$ **(1,887)**	$ **(1,611)**	L17 - L2
33	San Juan					$ **(2,464)**	$ **2,890**	$ **(3,860)**	L18 - L3

Notes and Source:

Lines 1-3:TEP adjustment Income-Overhaul and Outage.xls

Line 4-18: Company response to STF 9.02

Lines 19-33: Differences between actuals and Company forecasted.

Tucson Electric Power Company
Overhaul and Outage - Company Projected vs. Actual in Percentage

Test Year Ended December 31, 2011

Outage Cost ($ 000's)

Line No.	Plant	2005	2006	2007	2008	2009	2010	2011	Reference
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	
	Actual								
1	Four Corners	$ 352	$ 351	$ 372	$ 1,619	$ 621	$ 1,810	$ 1,012	
2	Navajo	$ 1,500	$ 516	$ 532	$ 1,231	$ 3,503	$ 3,486	$ 3,210	
3	San Juan	$ 1,700	$ 1,798	$ 1,802	$ 6,923	$ 7,455	$ -	$ 6,667	
	2004 Forecast								
4	Four Corners	$ 313	$ -	$ -	$ -	$ -	$ -	$ -	
5	Navajo	$ 1,138	$ 420	$ 420	$ 420	$ 1,157	$ 1,157	$ 1,157	
6	San Juan	$ -	$ -	$ 2,041	$ 2,000	$ -	$ -	$ -	
	2005 Forecast								
7	Four Corners		$ 150						
8	Navajo		$ 420	$ 420	$ 420	$ 1,240	$ 1,240	$ 1,240	
9	San Juan		$ 2,146	$ 2,191	$ 2,532	$ 5,683			
	2006 Forecast								
10	Four Corners			$ 372	$ 1,701	$ 372	$ 1,700	$ 372	
11	Navajo			$ 532	$ 533	$ 1,500	$ 1,500	$ 1,500	
12	San Juan			$ 1,802	$ 1,798	$ 4,400	$ 4,397	$ 1,800	
	2007 Forecast								
13	Four Corners				$ 1,334				
14	Navajo				$ 521	$ 837	$ 837	$ 837	
15	San Juan				$ 3,966	$ 4,154	$ 2,258	$ 2,242	
	2008 Forecast								
16	Four Corners					$ 341			
17	Navajo					$ 1,921	$ 1,599	$ 1,599	
18	San Juan					$ 4,991	$ 2,890	$ 2,807	
	2004 Variance: (Forecast -Actual)/Actual								
19	Four Corners	**-11.08%**	**-100.00%**	**-100.00%**	**-100.00%**	**-100.00%**	**-100.00%**	**-100.00%**	(L4 - L1) /L1
20	Navajo	**-24.13%**	**-18.60%**	**-21.05%**	**-65.88%**	**-66.97%**	**-66.81%**	**-63.96%**	(L5 - L2) /L2
21	San Juan	**-100.00%**	**-100.00%**	**13.26%**	**-71.11%**	**-100.00%**	**0.00%**	**-100.00%**	(L6 - L3) /L3
	2005 Variance: (Forecast -Actual)/Actual								
22	Four Corners		**-57.26%**	**-100.00%**	**-100.00%**	**-100.00%**	**-100.00%**	**-100.00%**	(L7 - L1)/L1
23	Navajo		**-18.60%**	**-21.05%**	**-65.88%**	**-64.60%**	**-64.43%**	**-61.37%**	(L8 - L2)/L2
24	San Juan		**19.35%**	**21.59%**	**-63.43%**	**-23.77%**	**0.00%**	**-100.00%**	(L9 - L3)/L3
	2006 Variance: (Forecast -Actual)/Actual								
25	Four Corners			**0.00%**	**5.06%**	**-40.10%**	**-6.08%**	**-63.24%**	(L10 - L1)/L1
26	Navajo			**0.00%**	**-56.70%**	**-57.18%**	**-56.97%**	**-53.27%**	(L11 - L2)/L2
27	San Juan			**0.00%**	**-74.03%**	**-40.98%**	**0.00%**	**-73.00%**	(L12 - L3)/L3
	2007 Variance: (Forecast -Actual)/Actual								
28	Four Corners				**-17.60%**	**-100.00%**	**-100.00%**	**-100.00%**	(L13 - L1)/L1
29	Navajo				**-57.68%**	**-76.11%**	**-75.99%**	**-73.93%**	(L14 - L2)/L2
30	San Juan				**-42.71%**	**-44.28%**	**0.00%**	**-66.37%**	(L15 - L3)/L3
	2008 Variance: (Forecast -Actual)/Actual								
31	Four Corners					**-45.09%**	**-100.00%**	**-100.00%**	(L16 - L1)/L1
32	Navajo					**-45.16%**	**-54.13%**	**-50.19%**	(L17 - L2)/L2
33	San Juan					**-33.05%**	**0.00%**	**-57.90%**	(L18 - L3)/L3

Notes and Source:

Lines 1-3:TEP adjustment Income-Overhaul and Outage.xls

Line 4-18: Company response to STF 9.07

Lines 19-33: Differences between actuals and Company forecasted.

Tucson Electric Power Company
Interest Synchronization

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

Docket No. E-01933A-12-0291
Schedule C-4
Page 1 of 1

Line No.	Description	Tax Rate	Per Company Amount (A)	Per Staff Amount (B)	Reference
1	Adjusted Rate Base -ACC		$ 1,519,073	$ 1,500,486	Schedule B
2	Weighted Cost of Debt		2.80%	2.91%	Schedule D
3	Synchronized Interest Deduction		$ 42,492	C $ 43,616	L1 x L2
4	Increase (Decrease) in Deductible Interest			$ 1,124	L3, B-A
5	State Income Taxes	4.57%		$ (51)	Schedule A-1
6	Federal Taxable Income			$ 1,073	
7	Federal Income Taxes	35.00%		$ (376)	Schedule A-1
8	Increase (Decrease) to Income Tax Expense			$ (427)	L5 +L7

Tucson Electric Power Company
Base Cost of Fuel and Purchased Power

Test Year Ended December 31, 2011

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Schedule C-5
Page 1 of 2

Line No.	Description	TEP Requested (A)	Staff Adjusted (B)	Staff Adjustment (C)
1	Adjusted kWh Sales, per TEP	9,285,592,991	9,285,592,991	
2	Base cost for fuel and purchased power per kWh	$ 0.031467	$ 0.031495	
3	Annualized fuel and purchased power cost before sulfur credits issue	$ 292,189,698	$ 292,449,751	$ 260,053
4	Staff adjustment to reflect sulfur credits as a reduction to coal expense in account 501		$ (5,076,413)	$ (5,076,413)
5	Staff adjusted fuel and purchased power cost	$ 292,189,698	$ 287,373,338	$ (4,816,360)
6	Adjusted kWh Sales, per TEP		9,285,592,991	
7	Staff adjusted base cost of fuel and purchased power per kWh		$ 0.030948	

	Staff Adjustments, stated in thousands of dollars	Amount ($000)
8	Adjustment to PPFAC revenue	$ (4,816)
9	Adjustment to fuel and purchased power cost	$ (4,816)
10	Net impact to pre-tax income	$ -

Notes and Source

Col.A: TEP workpaper, Income, PPFAC Adjustment, and TEP's response to STF 9.12

Col.B: TEP's September 2012 PPFAC Report, filed November 7, 2012, Schedule 2, line 7, Projected Average Net Fuel Cost For current period which runs April 1, 2012 through March 31, 2013

Line 4: See page 2 of this Schedule and Schedule C-14

Tucson Electric Power Company
TEP Requested Pro Forma Lime Expense and Sulfur Credit
Springerville

Docket No. E-01933A-12-0291
Schedule C-5
Page 2 of 2

Line No.	Description				Lime Expense Net of Sulfur Credit (A)		Sulfur Credit (B)		Lime Expense Without Netting Sulfur Credit (C)	
1	Test Year Recorded - Springerville Lime Expense (net of lime cost reimbursed by SGS 3 and 4)				$ 12,150,501	[A]			$ 12,150,501	[A]
2	Lime reimbursed to SGS units 1 and 2 by owners of units 3 and 4 - info only			$ (3,417,436)		[A]				
3	Sulfur Credit				$ (4,789,038)	[A]	**$ (4,789,038)**	[A]		
4	Net 2011 Recorded Expense Including Sulfur Credit				$ 7,361,463					
	TEP Pro Forma Increase for SGS Unit 2:									
5	Total Percentage Increase in Net Lime Cost		35.50%							
6	SGS Unit 2 Percent of total SGS 1 and 2 Generation		54%							
7	Calculated Net Increase	L4 x L5 x L6		$ 1,399,575						
8	Per TEP			$ 1,398,994	[A]					
9	Rounding Difference			$ 581						
	Implied Components of TEP Pro Forma Lime Expense Increase:									
10	Lime Expense for SGS Unit 2	L1 x L5 x L6			$ 2,310,076	[B]			$ 2,310,076	[B]
11	Sulfur Credit	L3 x L5 x L6			$ (910,501)	[B]	**$ (910,501)**	[B]		
12	Rounding	L9			$ 581					
13	TEP Pro Forma Adjustment for Lime Expense for SGS Unit 2			Account 502	$ 1,398,994	[A]				
	TEP Request for Lime Expense After Pro Forma Adjustment									
14	Lime Expense for SGS Units 1 and 2				$ 14,460,577				$ 14,460,577	
15	Sulfur Credit				$ (5,699,539)		**$ (5,699,539)**	**[C]**		
16	Pro Forma Lime Expense Requested by TEP Net of Sulfur Credit - Total Company				$ 8,761,038					
17	Jurisdictional Factor				89.0671%		89.0671%		89.0671%	
18	Pro Forma Lime Expense Requested by TEP Net of Sulfur Credit - ACC Jurisdictional				$ 7,803,200		**$ (5,076,413)**	**[C]**	$ 12,879,613	

Notes and Source

[A] TEP workpapers TEP(0291)007229 - 007230
Dukes' Prefiled Testimony page 17: "The Lime Expense Adjustment revises test-year lime expense associated with Springerville Unit 2 reflecting known and measureable rail and commodity cost increases."

[B] Calculated

[C] Should the Sulfur Credit be in Account 501 as a reduction to the cost of coal burned?

Line 17: Jurisdictional Factor

		Amount	Reference
19	ACC Jurisdictional	$ 1,246,043	TEP workpaper TEP(0291)007229
20	Total Company	$ 1,398,994	TEP workpaper TEP(0291)007229
21	ACC Jurisdictional Percent	89.0671%	[B]

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Tucson Electric Power Company
Rate Case Expense

Docket No. E-01933A-12-0291
Schedule C-6
Page 1 of 1

Test Year Ended December 31, 2011

Line No.	Description	TEP Requested (A)	Staff Adjusted (B)	Staff Adjustment (C)
1	Allowance for Rate Case Expense for Current Rate Case	$ 471,667	$ 225,000	$ (246,667)

Notes and Source

Col.A: TEP workpaper TEP(0291)007486

TEP Requested Rate Case Expense:

		TEP Requested Current Case (D)	TEP Requested Last Case (E)	Dollar Increase (F)	Percent Increase (F)
2	Outside Legal	$ 620,000	$ 500,000	$ 120,000	24.0%
3	Depreciation Study	$ 365,000	$ 90,000	$ 275,000	305.6%
4	Rate Design Study	$ 175,000		$ 175,000	N/A
5	Fair Market Value Study		$ 150,000	$ (150,000)	-100.0%
6	Tax Adjustment Study	$ 140,000		$ 140,000	N/A
7	Cost of Equity Study	$ 115,000	$ 75,000	$ 40,000	53.3%
8	Other		$ 85,000	$ (85,000)	-100.0%
9	Total	$ 1,415,000	$ 900,000	$ 515,000	57.2%
10	Amortized Over Period, in Years	3	$ 4		
11	Adjusted Annual Rate Case Expense	$ 471,667	$ 225,000	$ 246,667	109.6%

		Staff Adjusted (G)	
	Staff Recommended Allowance for Current Rate Case Expense		
12	Limit total amount to last rate case cost	$ 900,000	Col.E., line 9, total allowance
13	Normalized Over 4 Years	4	
14	Staff Recommended Allowance for Current Rate Case Expense	$ 225,000	

Col.D: TEP workpaper TEP(0291)007486

Col.E: TEP workpaper TEP(0402)002591 from last rate case, Docket No. E-01933A-07-0402

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Tucson Electric Power Company
Directors' and Officers' Liability Insurance Expense

Docket No. E-01933A-12-0291
Schedule C-7
Page 1 of 1

Test Year Ended December 31, 2011

Line No.	Description	Company Recorded Expense (A)	Sharing Percentage (B)	Staff Adjustment (C)
1	Directors' and Officers' Liability Insurance Expense	$ 654,200	50%	$ (327,100)
2	ACC Jurisdictional Allocation	88.45%		88.45%
3	Adjustment to Jurisdictional Rate Base	$ 578,640		$ (289,320)

Notes and Source

Line 1: Col. A: Response to UDR 1.60 and STF 24.1(c)
FERC Account 925

Line 2: [2012 TEP Rev Req Model.xlsm]Rate Base-Orig Cost column: ACC Ratio as Filed
FERC Account 925

Check:

4	TEP Adjusted ACC Jurisdictional Property Ins. Expense	$ 2,995,079
5	TEP Adjusted Total Property Insurance Expense	$ 3,386,204
6	Jurisdictional Factor	88.45%

Line 3: Line 1 x Line 2
Line 3, Col.A: also see, response to STF 24.1(d)

Tucson Electric Power Company
Edison Electric Institute and Industry Association Dues

Docket No. E-01933A-12-0291
Schedule C-8
Page 1 of 2

Test Year Ended December 31, 2011

Line No.	Description	Test Year Amount (A)	Company Adjustment (B)	Company Adjusted Amount (C)	Staff Adjustment to Total Company Amount (D)	ACC Jurisdictional Staff Adjustment (E)	
	Edison Electric Institute Dues						
1	Regular Dues	$ 347,085	$ (73,929)	$ 273,156	$ (106,881)	$ (94,536)	a
2	UARG	$ 143,470	$ -	$ 143,470	$ (8,608)	$ (7,614)	b
3	USWAG	$ 28,800	$ (2,362)	$ 26,438	$ -	$ -	
4	Total Test Year EEI Dues	$ 519,355	$ (76,291)	$ 443,064	$ (115,489)	$ (102,150)	
5	WEST Dues	$ 11,632	$ -	$ 11,632	$ (11,632)	$ (10,289)	c
6	Association Dues Expense Adjusted	$ 530,987	$ (76,291)	$ 454,696	$ (127,121)	$ (112,438)	

Notes and Source

Col. A, line 1: Amount taken from TEP's response to UDR 1.64
Col. A, line 3: Amount taken from TEP's Adjustment, Income - Membership Dues.pdf
a: Staff adjustment for Regular Dues based on a disallowance percentage of 49.93% (see page 2)

	Regular Dues	Staff Adjustment	
7	Regular Dues	$ 347,085	
8	Disallowed Donation	$ 15,000	[e]
9	Regular Dues excluding Donation	$ 332,085	
10	Regular Dues disallowance percentage	49.93%	
11	Staff adjustment to Regular Dues Excluding Donation	$ 165,810	
12	Staff Total Adjustment to Regular Dues	$ 180,810	
13	Less: Company adjustment	$ (73,929)	
14	Staff adjustment to Regular Dues	$ 106,881	
15	ACC Jurisdictional Allocation Factor	88.45%	[d]
16	Staff Adjustment - ACC Jurisdictional Amount	$ 94,536	

b: **2011 UARG Provided in UDR 1.55**

17	TEP's Total Dues for UARG in 2011	$ 143,470	
18	Disallowance Percentage	6.00%	[f]
19	Staff Adjustment for UARG Dues	$ 8,608	
20	ACC Jurisdictional Allocation Factor	88.45%	[d]
21	Staff Adjustment - ACC Jurisdictional Amount	$ 7,614	

c: **2011 WEST Dues Provided in UDR 1.55**

22	Total WEST Dues	$ 11,632	
23	Staff Recommended Disallowance Percentage	100.00%	
24	Staff Disallowed for Total Company	$ 11,632	
25	ACC Jurisdictional Allocation Factor	88.45%	[d]
26	Staff Adjustment - ACC Jurisdictional Amount	$ 10,289	

d: ACC jurisdictional allocation factor taken from TEP's "2012 Rev Req Model" workpapers
e: Data from TEP's response to STF 11.01 c
f: letter from EEI dated March 29, 2012, provided on Company workpaper TEP(0291)007234

Edison Electric Institute
Schedule of Expenses by NARUC Category
For Core Dues Activities
For the Year Ended December 31, 2005

Docket No. E-01933A-12-0291
Schedule C-8
Page 2 of 2

NARUC Operating Expense Category	% of Dues	Recommended Disallowance
Legislative Advocacy	20.38%	20.38%
Legislative Policy Research	6.02%	
Regulatory Advocacy	16.49%	16.49%
Regulatory Policy Research	13.99%	
Advertising	1.67%	1.67%
Marketing	3.68%	3.68%
Utility Operations and Engineering	11.31%	
Finance, Legal, Planning and Customer Service	18.75%	
Public Relations	7.71%	7.71%
Total Expenses	100.00%	49.93%

Comments:

* The above percentages represent expenses associated with EEI's core dues activities, based on the operating expense categories established by NARUC. Core expenses are those expenses paid for by shareholder-owned electric utilities' dues.

* The legislative advocacy percent will differ slightly for IRS reporting requirements. For 2005, the lobbying % for IRS reporting is 19.4%.

* Administrative expenses are included in the percentages listed above. Approximately 11% of EEI's core dues expenses are administrative.

Tucson Electric Power Company
Property Tax Expense

Test Year Ended December 31, 2011

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Schedule C-9
Page 1 of 2

Line No.	Description	TEP Proposed (A)	Staff Adjusted (B)	Staff Total Adjustment (C) = B-A	Jurisdictional Allocation (D)	Staff Juris Adj. (E)
1	Property Tax Expense	$ 39,148,092	$ 39,468,588	$ 320,496	77.94% [a]	$ 249,795
2	Springerville Units 3 and 4 Adjustment	$ 503,492	$ 466,149	$ (37,343)	89.92% [b]	$ (33,579)
3	Springerville Unit 1 Adjustment	$ (3,657,904)	$ (5,521,578)	$ (1,863,674)	89.92% [b]	$ (1,675,816)
4	Adjusted Property Tax Expense excluding Springerville adjustments	$ 35,993,680	$ 34,413,159	$ (1,580,521)		$ (1,459,600)
5	Staff Jurisdictional Adjustment					$ (1,459,600)

Notes and Source:

Col A: Per Company's workpaper showing calculation of Property Tax Expense
Adjustment Bates No. TEP(0291)007307
Also see TEP's [2012 Rev Rev Model.xlsm]

Col.B: Response to STF 28.1(a), (d) and (e)

	Jurisdictional factors for property tax expense	TEP Proposed Jurisdictional (F)	TEP Proposed Total Company (G)	Jurisdictional Factor (H)	Applied (I)
6	Taxes Other Than Income Taxes				
7	Property Tax - Steam Production	$ 15,733,923	$ 17,498,464	89.92% [b]	Col.D, L2 & L3
8	Property Tax - Other Production	$ -	$ -		
		$ -			
9	Property Tax - Transmission (EHV)	$ -	$ 2,183,476	0.00%	
10	Property Tax - Transmission (Non-EHV)	$ -	$ 4,059,323	0.00%	
11	Property Tax - Distribution	$ 13,059,052	$ 13,059,052	100.00%	
12	Property Tax - General	$ 1,719,601	$ 2,347,777	73.24%	
13	Total Company Adjusted Property Tax Expense	$ 30,512,576	$ 39,148,092	77.94% [a]	Col.D, L1

Tucson Electric Power Company
Property Tax Expense

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Schedule C-9
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Test Year Ended December 31, 2011

Line No.	Description	TEP Per Books	TEP Property Tax Adjustments: Springerville Units 3 & 4	TEP Property Tax Adjustments: Springerville Unit 1	TEP Property Tax Adjustments: Property Tax	TEP Total Adjustments	TEP Adjusted Total Company
		(A)	(B)	(C)	(D)	(E)	(F)
	Property Tax Expense						
1	Taxes Other Than Income Taxes						
2	Property Tax - Steam Production	$ 14,937,797	$ (503,492)	$ 3,657,904	$ (593,745)	$ 2,560,667	$ 17,498,464
3	Property Tax - Other Production	$ -				$ -	$ -
4	Property Tax - Transmission (EHV)	$ 1,761,061			$ 422,415	$ 422,415	$ 2,183,476
5	Property Tax - Transmission (Non-EHV)	$ 3,794,350			$ 264,973	$ 264,973	$ 4,059,323
6	Property Tax - Distribution	$ 11,364,646			$ 1,694,406	$ 1,694,406	$ 13,059,052
7	Property Tax - General	$ 784,098			$ 1,563,679	$ 1,563,679	$ 2,347,777
8	Total Company Adjusted Property Tax Expense	$ 32,641,952	$ (503,492)	$ 3,657,904	$ 3,351,728	$ 6,506,140	$ 39,148,092
9	2011 actual recorded property tax expense	$ 32,641,952					

Notes and Source
TEP's [2012 Rev Rev Model.xlsm]

Tucson Electric Power Company
Depreciation and Property Taxes on New Headquarters Building Adjustment

Test Year Ended December 31, 2011

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Schedule C-10
Page 1 of 1

Line No.	Description	Staff Adjustment	Reference
	I. Depreciation Expense		
1	Jurisdictional adjustment for new headquarters plant	$ (6,756,000)	Schedule B-5
2	Depreciation rate for Buildings	2.64%	Note A
3	Adjustment to Depreciation Expense	$ (178,000)	Line 1 x Line 2
	II. Property Tax Expense		
4	Total adjustment for new headquarters plant	$ (9,199,000)	Schedule B-5
5	Full Cash Value ADOR Valuation Factor for Plant Placed Into Service in 2011	97.14%	Note B
6	Assessment Ratio	0.195	Note C
7	Property Tax Rate	9.6120%	Note C
8	Adjustment to Property Tax Expense	$ (167,489)	L4 x L5 x L6 x L7
9	Jurisdictional Factor	77.94%	Note D
10	Adjustment to Jurisdictional Property Tax Expense	$ (130,541)	L8 x L9

Notes and Source

Depreciation Expense - Lines 1 - 3:
FERC Account 390.00 Structures and Buildings

[A] TEP Ex. REW-1, page 17, proposed new depreciation rate for account 390.00 structures and buildings
[B] See, e.g., TEP's property tax adjustment workpapers, TEP(0291)007306 et seq, General Plant
Tax Year 2013, Calendar Year Plant at December 31, 2011
ADOR factor for improvements to real property
[C] TEP response to STF 28.1(a)
[D] Schedule C-9

Tucson Electric Power Company
Other Operating Revenue: Reimbursed Operating Expenses for Springerville Units 3 and 4

Test Year Ended December 31, 2011

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Schedule C-11
Page 1 of 1

Line No.	Description	Amount Per Company (A)	Amount Per Staff (B)	Staff Adjustment (C)=(B)-(A)
1	Fuel Handling Facilities Use - Tri-State	$ 3,785,000	$ 3,785,000	
2	Common Facilities Use - Tri-State	$ 3,176,004	$ 3,176,004	
3	Fuel Handling Facilities Use - SRP	$ 3,785,000	$ 3,785,000	
4	Common Facilities Use - Tri-SRP	$ 3,176,004	$ 3,176,004	
5	Total Leases Reimbursement - Other Operating Revenue	$ 13,922,008	$ 13,922,008	
6	Percent Other Operating Revenue Applied to TEP Revenue Requirement	50%	90%	
7	Other Operating Revenue Applied to TEP Revenue Requirement	$ 6,961,004	$ 12,529,807	$ 5,568,803
8	Vehicle Usage - Tri-State	$ 1,093,262	$ 1,093,262	
9	Vehicle Usage - SRP	$ 1,093,262	$ 1,093,262	
10	Total Vehicle Reimbursement	$ 2,186,524	$ 2,186,524	
11	Percent Other Operating Revenue Applied to TEP Revenue Requirement	100%	100%	
12	Other Operating Revenue Applied to TEP Revenue Requirement	$ 2,186,524	$ 2,186,524	$ -
13	Other Operating Revenue Applied to TEP Revenue Requirement	$ 9,147,528	$ 14,716,331	$ 5,568,803

Notes and Source:

Col. A: TEP Company filing, Bates No. TEP(0291)007544

	Other Operating Revenue Retained by TEP Shareholders			Reference
14	Percent	50%	10%	1 - Line 6
15	Amount	$ 6,961,004	$ 1,392,201	L5 - L7

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Tucson Electric Power Company
Springerville Unit 1 - Levelized Expense Allowance

Test Year Ended December 31, 2011

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Schedule C-12
Page 1 of 3

Line No.	FERC	Total Company Adjusted - Per Company (A)	Total Company Adjusted - Per Staff (B)	ACC Jurisdictional Allocator (C)	Jurisdictional Adjusted - Per Company (D)=(A)*(C)	Jurisdictional Adjusted - Per Staff (E)=(B)*(C)	Staff Net Jurisdictional Adjustment (F)=(E)-(D)
	Operations and Maintenance						
1	500	$ 950,720	$ 892,818	89.05%	$ 846,632	$ 795,069	$ (51,562)
2	501	$ 6,987	$ 6,987	100.00%	$ 6,987	$ 6,987	$ -
3	502	$ 6,048,184	$ 5,668,769	89.07%	$ 5,386,959	$ 5,049,025	$ (337,935)
4	505	$ 565,242	$ 531,037	89.07%	$ 503,436	$ 472,972	$ (30,465)
5	506	$ 1,215,169	$ 1,099,650	89.07%	$ 1,082,327	$ 979,437	$ (102,890)
6	507	$ 86,718,281	$ 86,718,281	89.07%	$ 77,237,444	$ 77,237,444	$ -
7	510	$ 451,463	$ 424,032	89.06%	$ 402,093	$ 377,662	$ (24,431)
8	511	$ 1,354,965	$ 1,269,220	89.07%	$ 1,206,841	$ 1,130,469	$ (76,372)
9	512	$ 7,189,129	$ 6,546,695	93.85%	$ 6,746,841	$ 6,143,930	$ (602,910)
10	513	$ 3,049,172	$ 2,856,210	89.07%	$ 2,715,793	$ 2,543,929	$ (171,864)
11	514	$ 2,044,882	$ 1,897,754	89.07%	$ 1,821,292	$ 1,690,251	$ (131,041)
						$ -	$ -
	Administrative and General					$ -	$ -
12	920	$ 507,602	$ 476,618	88.41%	$ 448,773	$ 421,381	$ (27,393)
13	921	$ 79,003	$ 73,976	88.43%	$ 69,863	$ 65,418	$ (4,445)
14	923	$ 125,852	$ 117,844	88.46%	$ 111,328	$ 104,244	$ (7,084)
15	924	$ 388,241	$ 363,537	88.45%	$ 343,393	$ 321,542	$ (21,850)
16	925	$ 71,208	$ 66,711	88.45%	$ 62,987	$ 59,009	$ (3,978)
17	926	$ 2,588,224	$ 2,481,578	88.45%	$ 2,289,270	$ 2,194,942	$ (94,328)
18	930	$ 14,211	$ 13,307	88.44%	$ 12,569	$ 11,769	$ (800)
19	931	$ 2,590	$ 2,425	88.42%	$ 2,290	$ 2,144	$ (146)
20	408	$ 3,657,904	$ 5,521,578	89.92%	$ 3,289,042	$ 4,964,784	$ 1,675,742
21	408	$ 26,173	$ 26,173	74.12%	$ 19,399	$ 19,399	$ -
22	Total Adjusted Cost of Service	$ 117,055,200 [a]	$ 117,055,200 [a]		$ 104,605,559	$ 104,591,808	$ (13,752)
23	O&M Expense						$ (1,689,494)
24	Taxes Other Than Income Taxes						$ 1,675,742
25	Staff Net Jurisdictional Adjustment						$ (13,752)

Notes and Source:
Col.A: See this Schedule, page 2, Col. G, and TEP workpaper TEP(0291)007525
Col. B: See this Schedule, page 3, Col. G
Col. C; See this Schedule, page 2, Col. J
[a]: Total Allowance for Springerville Unit 1 Levelized Costs, as shown on Bates No. TEP(0291)007525:

26 Allowed Levelized Lease Expense $25.67 cost per kW/Month * 380 MW * 12 Months * 1000 = $117,055,200

Tucson Electric Power Company
Springerville Unit 1 - Company's Adjustment

Test Year Ended December 31, 2011

Docket No. E-01933A-12-0291
Schedule C-12
Page 2 of 3

Line No.	FERC Account	Test Year O&M Expenses Per GL (A)	Test Year O&M - Excluding Lease (B)	Lease & Property Tax (C)	Payroll Related Adjustments (D)	Overhaul & Outage Adjustment (E)	Less: Overall Adjustment (F)	Springerville Unit 1 Levelized Expense Allowance (G)	Total Company Adjustment (H)	Jurisdictional Adjustment (I)	Jurisdictional Allocator (J)
	Operations and Maintenance										
1	500	$ 946,533	$ 946,533		$ 40,749		$ (36,561)	$ 950,720	$ 4,187	$ 3,729	89.05%
2	501				$ 6,987		$ -	$ 6,987	$ 6,987	$ 6,987	100.00%
3	502	$ 6,202,388	$ 6,202,388		$ 85,372		$ (239,577)	$ 6,048,184	$ (154,205)	$ (137,346)	89.07%
4	505	$ 559,153	$ 559,153		$ 27,687		$ (21,598)	$ 565,242	$ 6,089	$ 5,423	89.07%
5	506	$ 1,145,899	$ 1,145,899		$ 113,532 [1]		$ (44,262)	$ 1,215,169	$ 69,270	$ 61,697	89.07%
6	507	$ 41,480,154		$ 86,718,281			$ -	$ 86,718,281	$45,238,128	$ 40,292,281	89.07%
7	510	$ 448,424	$ 448,424		$ 20,360		$ (17,321)	$ 451,463	$ 3,039	$ 2,707	89.06%
8	511	$ 1,401,698	$ 1,401,698		$ 7,410		$ (54,143)	$ 1,354,965	$ (46,733)	$ (41,624)	89.07%
9	512	$ 10,502,030	$ 10,502,030		$ 67,573	$ (2,974,818)	$ (405,657)	$ 7,189,129	$ (3,312,902)	$ (3,109,086)	93.85%
10	513	$ 3,154,391	$ 3,154,391		$ 16,624		$ (121,843)	$ 3,049,172	$ (105,219)	$ (93,715)	89.07%
11	514	$ 2,055,699	$ 2,055,699		$ 68,588 [2]		$ (79,405)	$ 2,044,882	$ (10,817)	$ (9,634)	89.07%
	Administrative and General										
12	920	$ 506,494	$ 506,494		$ 20,671		$ (19,564)	$ 507,602	$ 1,107	$ 979	88.41%
13	921	$ 82,177	$ 82,177				$ (3,174)	$ 79,003	$ (3,174)	$ (2,807)	88.43%
14	923	$ 130,909	$ 130,909				$ (5,057)	$ 125,852	$ (5,057)	$ (4,473)	88.46%
15	924	$ 403,840	$ 403,840				$ (15,599)	$ 388,241	$ (15,599)	$ (13,797)	88.45%
16	925	$ 73,522	$ 73,522		$ 526		$ (2,840)	$ 71,208	$ (2,314)	$ (2,047)	88.45%
17	926	$ 1,743,366	$ 1,743,366		$ 912,198		$ (67,340)	$ 2,588,224	$ 844,858	$ 747,272	88.45%
18	930	$ 14,782	$ 14,782				$ (571)	$ 14,211	$ (571)	$ (505)	88.44%
19	931	$ 2,694	$ 2,694				$ (104)	$ 2,590	$ (104)	$ (92)	88.42%
20	408			$ 3,657,904 [3]			$ -	$ 3,657,904	$ 3,657,904	$ 3,289,042	89.92%
21	408				$ 26,173		$ -	$ 26,173	$ 26,173	$ 19,399	74.12%
22	Total Adjustment to Cost of Service	$ 70,854,153	$ 29,373,999	$ 90,376,185	$ 1,414,450	$ (2,974,818)	$ (1,134,616)	$ 117,055,200	$46,201,047	$ 41,014,390	

Notes and Source:
This page is to reproduce TEP's adjustment on Springerville Unit 1 as shown on Bates No. TEP(0291)007525
[1]: Company's data $113,532 = $22,689 + $90,843 (Incentive Comp)
[2]: Company's data $68,588 = $25,836 + $42,751 (Incentive Comp)
[3]: Company proposed property tax expense for Springerville Unit 1

Tucson Electric Power Company
Springerville Unit 1 - Staff's Adjustment

Test Year Ended December 31, 2011

Line No.	FERC Account	Test Year O&M Expenses Per GL (A)	Test Year O&M - Lease & Property Tax Excluding Lease (B)	Lease & Property Tax (C)	Payroll Related Adjustments (D)	Overhaul & Outage Adjustment (E)	Less: Overall Adjustment (F)	Total Adjusted (G)	Adjustment (H)
	Operations and Maintenance								
1	500	$ 946,533	$ 946,533		$ 40,749		$ (94,463)	$ 892,818	$ (53,714)
2	501				$ 6,987		$ -	$ 6,987	$ 6,987
3	502	$ 6,202,388	$ 6,202,388		$ 85,372		$ (618,992)	$ 5,668,769	$ (533,619)
4	505	$ 559,153	$ 559,153		$ 27,687		$ (55,803)	$ 531,037	$ (28,116)
5	506	$ 1,145,899	$ 1,145,899		$ 68,111 [1]		$ (114,360)	$ 1,099,650	$ (46,249)
6	507	$ 41,480,154		$ 86,718,281			$ -	$ 86,718,281	$ 45,238,128
7	510	$ 448,424	$ 448,424		$ 20,360		$ (44,752)	$ 424,032	$ (24,392)
8	511	$ 1,401,698	$ 1,401,698		$ 7,410		$ (139,888)	$ 1,269,220	$ (132,478)
9	512	$ 10,502,030	$ 10,502,030		$ 67,573	$ (2,974,818)	$ (1,048,091)	$ 6,546,695	$ (3,955,336)
10	513	$ 3,154,391	$ 3,154,391		$ 16,624		$ (314,805)	$ 2,856,210	$ (298,181)
11	514	$ 2,055,699	$ 2,055,699		$ 47,212 [2]		$ (205,157)	$ 1,897,754	$ (157,945)
	Administrative and General								
12	920	$ 506,494	$ 506,494		$ 20,671		$ (50,548)	$ 476,618	$ (29,876)
13	921	$ 82,177	$ 82,177				$ (8,201)	$ 73,976	$ (8,201)
14	923	$ 130,909	$ 130,909				$ (13,065)	$ 117,844	$ (13,065)
15	924	$ 403,840	$ 403,840				$ (40,303)	$ 363,537	$ (40,303)
16	925	$ 73,522	$ 73,522		$ 526		$ (7,337)	$ 66,711	$ (6,812)
17	926	$ 1,743,366	$ 1,743,366		$ 912,198		$ (173,986)	$ 2,481,578	$ 738,212
18	930	$ 14,782	$ 14,782				$ (1,475)	$ 13,307	$ (1,475)
19	931	$ 2,694	$ 2,694				$ (269)	$ 2,425	$ (269)
20	408			$ 5,521,578 [3]			$ -	$ 5,521,578	$ 5,521,578
21	408				$ 26,173		$ -	$ 26,173	$ 26,173
22	Total Adjustment to Cost of Service	$ 70,854,153	$ 29,373,999	$ 92,239,859	$ 1,347,652	$ (2,974,818)	$ (2,931,493)	$ 117,055,200	$ 46,201,047

Notes and Source:
This reflects Staff's adjustments for Property Tax and Incentive Compensation Expense
[1]: Company's data $113,532 = $22,689 + $90,843 (Incentive Comp), Staff removes 50% of $90,843
[2]: Company's data $68,588 = $25,836 + $42,751 (Incentive Comp), Staff removes 50% of $42,751.
[3]: Staff: 2013 property taxes for Springerville Unit 1, from TEP's response to STF 28.1(d); also see Schedule C-9

Tucson Electric Power Company
Day Nite Design Branding/ Marketing/ General Corporate Advertising

Test Year Ended December 31, 2011

Docket No. E-01933A-12-0291
Schedule C-13
Page 1 of 1

Line No.	Description	Amount Per Company (A)	Amount Per Staff (B)	Staff Adjustment (C)=(B)-(A)
	General Advertising Expense			
1	CBU Corporate Advertising	$ 75	$ -	$ (75)
2	TEP Branding/Marketing	$ 14,681	$ -	$ (14,681)
3	Subtotal Before Jurisdictional Allocation	$ 14,756	$ -	$ (14,756)
4	Jurisdictional Allocation	88.45%	88.45%	88.45%
5	Jurisdictional Expense	$ 13,052	$ -	$ (13,052)
6	Adjustment for TEP Branding/Marketing/General Corporate Advertising			$ (13,052)

Notes and Source:
Col. A: TEP response to STF 26.10
Account 930

Tucson Electric Power Company
Lime Expense

Test Year Ended December 31, 2011

Docket No. E-01933A-12-0291
Schedule C-14
Page 1 of 1

Line No.	Description	Amount Per Company (A)	Amount Per Staff (B)	Staff Adjustment (C)=(B)-(A)
	Lime Expense			
1	Lime Expense, Account 502	$ 14,460,577	$ 14,460,577	$ -
2	Sulfur Credits (reduction to coal expense)	$ (5,699,539)	$ -	$ 5,699,539
3	Subtotal Before Jurisdictional Allocation	$ 8,761,038	$ 14,460,577	$ 5,699,539
4	Jurisdictional Allocation	89.07%	89.07%	89.07%
5	Jurisdictional Expense	$ 7,803,200	$ 12,879,613	$ 5,076,413
6	Adjustment for Lime Expense in Account 502			$ 5,076,413

Notes and Source:

Col. A: TEP workpaper TEP(0291)007230; also see, Schedule C-5, page 2

Line 1: Account 502

Line 2: TEP proposes to reflect sulfur credits as a reduction to lime expense in account 502. Staff proposes to reflect sulfur credits as a reduction to the cost of coal expense in account 501 (which is a PPFAC-includable account). Also, see the direct testimony of Staff witness Emily Medine.

Tucson Electric Power Company
Docket No. E-01933A-12-0291
Attachment RCS-3
Copies of TEP's Non-Confidential Responses to Data Requests and Documents Referenced in the Direct Testimony and Schedules of Ralph C. Smith

Data Request/ Workpaper No.	Subject	Confidential	No. of Pages	Page No.
STF 24.1(a)	Total and Jurisdictional amount of Prepaid Directors and Officers Liability Insurance TEP included in 2011 rate base	No	1	2
STF 22.6(l) December 6, 2012 Supplemental	Downtown Tucson has abundant relatively inexpensive parking and TEP did not need area in the headquarters parking garage to be available for the 12,000 gsf of retail space	No	5	3 - 7
STF 26.07	Cost of the new UniSource headquarters building broken out by components, including cost for the parking structure	No	2	8 - 9
STF 23.1 December 6, 2012 Supplemental	TEP allocated 4.5 percent of the building cost for the new headquarters to affiliates as of September 2012	No	3	10 - 12
STF 12.01	Total and Jurisdictional amount of PEP expense requested by TEP, by account	No	1	13
UDR 1.63(a)	TEP's admission that its claim for incentive compensation deviates from policies established in prior Commission Orders	No	1	14
TEP Workpaper TEP(0291)007301-007303	TEP's PPFAC proposed rate, Kwh, and adjustment for 2011	No	3	15 - 17
STF 9.12 October 16, 2012	Explanation of PPFAC rate derivation; TEP's test year recorded cost of fuel and purchased power and purchased transmission by account	No	5	18 - 22
TEP(0402)002591 Workpaper from AZCC Docket No. E-01933A-07-0402	Total amount of rate case expense allowed in prior TEP rate case, test year ended December 31, 2006	No	1	23
UDR 1.55(a)	Purpose and objective of WEST Associates; total 2011 dues	No	3	24 - 26
STF 11.10	2011 and 2012 timeline of TEP's property tax assessment, expense recording and property tax payment dates	No	1	27
STF 11.11	Impact of computing property tax expense on a standalone basis instead of a combined basis	No	1	28
STF 25.3	TEP has not used a 34% federal income tax rate on a tax return or ratemaking purposes during the last 10 years	No	1	29
STF 1.066	Number of customers, and their dollar value, participating in the Green Watts program from January 2009 - July 2012	No	2	30 - 31
STF 11.03	GreenWatts Revenue regulatory liability amounts for January - August 2012; projects for which GreenWatts revenue is recognized during 2011	No	4	32 - 35
UDR 1.36(b)	Incentive and bonus program expense incurred by TEP in 2010 and 2011	No	4	36 - 39
STF 9.01	Overhaul expense by unit for years 1999-2003	No	2	40 - 41
STF 9.07	TEP's Overhaul Expense projections in years 2004-2011 to test accuracy of TEP's projections of overhaul costs (without attachment)	No	1	42
UDR 1.60 September 25, 2012 Supplemental	TEP's Insurance Expense included in the test year for years 2009-2011 and June 2012 year-to-date, by insurance component	No	2	43 - 44
UDR 1.64 September 25, 2012 Supplemental	TEP provided copies of Edison Electric Institute invoices related to EEI expenses recorded during the test year, for years 2008-2011	No	21	45 - 65
STF 11.01(c)	Information on test year of EEI dues and $15,000 charitable contributions that were allocated entirely to TEP	No	3	66 - 68
STF 26.10	Day Nite Design charges for CBU Corporate Advertising and TEP Branding/Marketing included in the test year (without voluminous attachments)	No	6	69 - 74
	Total Pages Including this Page		74	

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S TWENTYFOURTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
November 16, 2012

STF 24.1

Directors and Officers Liability Insurance. Refer to UDR 1.81, prepayments, and UDR 1.60, insurance expense.

a. How much Prepaid Directors and Officers Liability Insurance did TEP include in the 2011 rate base (1) in total and (2) for ACC Jurisdictional?

b. For the Prepaid Insurance amounts listed in the response to UDR 1.81 for account 14010, show how much of each of those amounts is for Prepaid Directors and Officers Liability Insurance.

c. Refer to the supplemental response to UDR 1.60. Did TEP include the $654,200 amount listed there for 2011 as its requested amount for D&O insurance expense?

   1. If not, identify the amount TEP has requested for D&O insurance expense and show how it was derived.

d. On an ACC jurisdictional basis, did TEP request a jurisdictional expense amount of $578,640 ($654,200 x 88.45%) as its requested amount for D&O insurance expense?

   1. If not, identify the amount TEP has requested for D&O insurance expense on an ACC jurisdictional basis and show how it was derived.

RESPONSE:

a. Total Prepaid Directors and Officers Liability Insurance is as follows: (1) Total Company, $310,572; and (2) ACC Jurisdictional, $234,014.

b. Please see TEP's response to part "a".

c. Yes.

d. Yes.

RESPONDENT:

Pricing (David Lewis and Anne Liu)

WITNESS:

Dallas Dukes

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO STAFF'S TWENTY SECOND SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
December 6, 2012

STF 22.06

UniSource Headquarters Building. Refer to the response to STF 16.08 and to TEP's workpapers for TEP rate base adjustment A and expense adjustments O and P.

a. What is the total cost of the new UniSource headquarters building? Identify all costs by balance sheet account as of 12/31/2011, and by income statement account for each month of 2011 and 2012.

b. What amounts for the new UniSource headquarters building has TEP included in jurisdictional rate base (1) before and (2) after TEP's pro forma adjustments? Show by account.

c. What amounts for the new UniSource headquarters building has TEP included in jurisdictional operating expenses (1) before and (2) after TEP's pro forma adjustments? Show by account.

d. Has TEP included any rental income related to the new UniSource headquarters building in jurisdictional revenues? If so, please identify the amounts of such jurisdictional revenue (1) before and (2) after TEP's pro forma adjustments and show the revenue amounts by account.

e. Identify all costs in rate base and operating expenses for the 12,000 gsf of retail space, by account.

f. Refer to the response to STF 16.08(d). Why are there no UniSource personnel in the UniSource headquarters building?

g. Refer to STF 16.08 TEP HQ Stacking Plan 2012-20-24-Confidential. On what floor (or floors) is the 12,000 gsf of retail space?

    1. Show the amount of retail space on each floor and reconcile it to the diagram provided in STF 16.08 TEP HQ Stacking Plan 2012-20-24-Confidential.

h. What is the total cost of the underground parking? Provide by account.

    1. Identify all costs by balance sheet account as of 12/31/2011, and by income statement account for each month of 2011 and 2012.

i. How much of the underground parking will be available for retail use?

j. What other parking besides the [BEGIN CONFIDENTIAL] 249,410 gsf of underground parking [END CONFIDENTIAL] is available in the HQ building area for the 12,000 gsf of retail space?

k. Is TEP aware of any ordinances or regulations that provide for a certain number of parking places or that require the availability of parking for buildings with retail space?

    1. If so, please identify those requirements as it would apply to the 12,000 gsf of retail space.

    l. How much parking area needs to be available related to 12,000 gsf of retail space? Explain fully and identify any source documents relied upon.

m. Identify the cost for each floor, for floors 1 through 9, by account.

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO STAFF'S TWENTY SECOND SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
December 6, 2012

1. Identify the cost by balance sheet account as of 12/31/2011, and by income statement account for each month of 2011 and 2012.

n. Identify the total cost for floors 1 through 9, by account.

1. Identify the cost by balance sheet account as of 12/31/2011, and by income statement account for each month of 2011 and 2012.

o. Identify in detail how TEP has allocated the cost of non-occupied space in total and for each floor.

p. Please confirm the occupied space per occupant listed in the following table, compiled from TEP's responses to STF 16.08(a) and (d), and identify any corrections or revision needed to make the information totally accurate:

UniSource Headquarters
Occupied and Unoccupied Space and Space Per Occupant
[BEGIN CONFIDENTIAL]

Floor	Space GSF	Occupied Percent	Occupied Space	Unoccupied Space
9	28,750	87%	25,013	3,738
8	28,750	75%	21,563	7,188
7	28,750	86%	24,725	4,025
6	28,750	94%	27,025	1,725
5	28,750	87%	25,013	3,738
4	37,410	95%	35,540	1,871
3	40,660	59%	23,989	16,671
2	31,730	79%	25,067	6,663
1	27,730	100%	27,730	-
Total	281,280		235,663	45,617
	[END CONFIDENTIAL]			
Current occupancy			539	
Space per occupant			437.22	

Source: TEP response to STF 16.08(a) and (d)

q. Refer to the response to STF 16.08(d). Please confirm that there are no employees in the UniSource headquarters building for any of the following affiliates, and if there are any employees at the headquarters building for any of these, identify the count (1) as of 12/31/2011 and (2) at present/most recent available:

1. UniSource Energy, Inc.
2. UNSE
3. UNSG
4. UED
5. Millennium

r. Show in detail how each of the cost per square foot figures in the response to STF 16.08(e) were derived.

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO STAFF'S TWENTY SECOND SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
December 6, 2012

s. Are the costs per square foot figures in the response to STF 16.08(e) annual costs?

1. If not, for what period do they represent?

t. Can the cost of the unoccupied office space in the UniSource headquarters building be derived by multiplying the $263/sf listed in the response to STF 16.08(e) by the number of unoccupied square feet?

1. If not, explain fully why not.

u. Does TEP have any calculation of the cost of the unoccupied office space in the UniSource headquarters building?

1. If so, please identify and provide those calculations.

RESPONSE: **November 19, 2012**

a. Please see TEP's response AECC 9.1.

b. Please see TEP's response AECC 9.1.

c. TEP included a net $286,055 of operating expenses in jurisdictional rate base for the new UNS headquarters building less the costs associated with the old UNS headquarters building. Please see the rate case adjustment labeled Income - Building Expense Annualization.pdf and Income - Building Allocation to Affiliates.xlsm for details. (The referenced files are located in TEP's electronic data room in TEP Uniform Data Requests\Attachments\UDR 1.01\Workpapers – Schedules\Pro Forma Adjustments.)

d. TEP did not include any rental income for the new UNS headquarters building in jurisdictional revenue, as there is no rental income.

e. TEP estimated/allocated roughly $2.1 million ($1.6 million ACC Jusrisdiction) to the retail space construction costs in response to STF 16.08 that are included in rate base. TEP does not track operating costs associated with the currently un-leased retail space.

g. All of the retail space is located on the first floor.

1. There is no retail space on Floors 2 – 9. The 12,000 gross square footage ("gsf") of retail is not shown on STF 16.08 TEP HQ Stacking Plan 2012-20-24-Confidential.pdf, which was provided in response to STF 16.08 as a diagram showing the gross square footage and current occupancy of the new TEP headquarters office building.

h. TEP estimated/allocated roughly $16.0 million ($11.8 million ACC Jurisdiction) to the parking construction costs in response to STF 16.08 that are included in rate base.

i. None of the underground parking is available for retail space. 100% of the parking in the building is for TEP employees and secured by a cardkey access system.

j. There is no parking available in the building for the retail space.

k. Yes.

1. The City of Tucson Land Use Code specifically addresses parking requirements for all

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO STAFF'S TWENTY SECOND SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
December 6, 2012

new facilities located in the Tucson city limits. Due to the urban setting of the building location and the availability of public parking in the downtown area, no parking for the retail space was required within the building.

l. TEP is not required to provide parking for the 12,000gsf of retail space. The Downtown Tucson Partnership on their website states "**PARKING,** With over 15,000 spaces, parking Downtown is quick and easy. Metered street parking is less expensive than in almost any other city (free on evenings and weekends). Private and public parking lots and garages are also a great deal. You walk farther in a mall parking lot than you do parking anywhere Downtown. With parking Downtown, you're never far from where you need to be. For more information about parking downtown, visit ParkWise or call their office at (520) 791-5071" - http://www.downtowntucson.org/get-around/parking/.

m. TEP does not have construction or operating costs by floor for the UNS headquarters building.

n. TEP does not have construction or operating costs by floor for the UNS headquarters building.

o. TEP does not allocate building costs directly. Building costs are allocated through labor. Building costs are allocated based on total building dollars and not by individual building.

p. The table shown in data request STF 22.06 (p) is not accurate based on the following assumptions. The gsf numbers as listed in response to STF 16.08 (a) includes all common areas, mechanical space, electrical rooms, communication rooms, restrooms, conference space, copy rooms, file rooms, break rooms, elevators, elevator lobbies, dedicated computer room space, an auditorium, area for outside auditors, the main lobby, and service areas. The occupancy numbers were based on a comparison of vacant cubicles and offices to occupied cubicles and offices. All of the common and ancillary areas throughout the entire building are being used by the current building occupants every day.

The entire office building was designed using a standard floorplate methodology which maximizes all space, capitalizing on standardization as a means to operational efficiencies. All space assignment is based on pay grade, strictly enforced, and designed for maximum efficiency. All cubicles are 80sf and in one of two configurations. The offices and conference rooms are common sizes and have a standard layout. We have three office sizes; these three sizes correspond to the same size conference room. Small office/conference rooms are 120sf. Medium office/conference rooms are 180sf. Large office/conference rooms are 345sf and, when configured as an office, includes conference space within the office. In application, if there is no employee with the proper criteria to be housed in an office, the room is fitted with conference room furniture and made available for all employee use.

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO STAFF'S TWENTY SECOND SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
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December 6, 2012

q. There are no employees in the UNS headquarters building from affiliates UNS, UNS Electric, UNS Gas or UED. There were approximately 8-10 SES (a Millennium subsidiary) employees in the building as of 12/31/2011.

r. The cost per square foot figures were based on total construction costs and gross square footage.

The square foot cost for the parking was calculated based on ½ of the land cost, direct construction cost, and 20% of the sales tax/ plans, permits, and impact fees/ capital cost.

The square foot cost for the retail space was calculated based on ½ of the land cost, direct construction cost for the shell building, and 80% of the sales tax/ plans, permits, and impact fees/ capital cost.

The square foot cost for the office space was calculated based on ½ of the land cost, direct construction cost for the shell building, 80% of the sales tax/plans, permits, and impact fees/capital cost, tenant improvements, and furniture fixtures and equipment ("FF&E").

s. No, the costs per square foot figures in the response to STF 16.08 (e) are based on one-time construction costs. As such, they do not represent a time period.

t. No, the costs per square foot figures in the response to STF 16.08 (e) are based on one-time construction costs. The unoccupied office space represents vacant cubicles and office/conference rooms designed for operational flexibility and does not take into consideration all of the common and ancillary space as listed in STF 22.06 (p). While there are vacant cubicles and offices within the building, all of the common and ancillary areas are being used by the current occupants every day.

u. It does not.

RESPONDENT:

Steve Sims, Scott Rathbun and Pricing (David Lewis)

WITNESS:

Michael DeConcini, Karen Kissinger, Craig A. Jones and Dallas Dukes

SUPPLEMENTAL RESPONSE: December 6, 2012

f. The response to part "f" was mistakenly left out of the original response.

UNS is a holding company and does not have any employees.

RESPONDENT:

Dallas Dukes

WITNESS:

Dallas Dukes

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
STAFF'S TWENTYSIXTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
December 6, 2012

STF 26.07

Refer to the response to STF 22.06(r), which describes how TEP calculated the cost per square foot of (1) parking; (2) retail space; and (3) office space. Provide TEP's detailed calculations for each: (1) parking; (2) retail space; and (3) office space.

RESPONSE:

Please see STF 26.07.xlsx for the requested information.

RESPONDENT:

Pricing (David Lewis)

WITNESS:

Michael DeConcini

Tucson Electric Power
New Building Expenditures
Cost per Square Foot

New Building Expenditures

Land	8,000,000
Building (Shell)	39,000,000
Overhead	8,750,000
Tenant Improvements	11,366,894
Furniture & Equipment	4,000,000
IT Infrastructure	2,500,000
Data Center	4,200,000
LEED	1,800,000
Parking Structure	10,500,000
	90,116,894

Cost per Square Foot

	Total SF	$/SF
Retail	281,280	177.76
Office	281,280	261.61
Parking	249,410	64.15

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO STAFF'S TWENTY THIRD SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
December 6, 2012

STF 23.1

UniSource [SIC] Headquarters Building. Refer to TEP's workpapers at TEP (0291) 007029 through 007071.

a. Show in detail how the 12.94% (or $12.94) on TEP (0291) 007031 was derived and provide supporting calculations in Excel.

b. Can the 12.94% (or $12.94) on TEP (0291) 007031 be stated in terms of a cost per headquarters employee?

   1. If not, explain fully why not.

   2. If so, show the equivalent cost per employee. Include supporting calculations.

c. Can the 12.94% (or $12.94) on TEP (0291) 007031 be stated in terms of a cost per square foot?

   1. If not, explain fully why not.

   2. If so, show the equivalent cost per square foot. Include supporting calculations.

d. Page TEP (0291) 007031 shows the 12.94% as a percent. Pages TEP (0291) 007032 and 007033 shows the Current Rate of $12.94 (as a dollar amount). Is the $12.94 applied by multiplying TEP hours charged to UNSG and UNSE?

e. Pages TEP (0291) 007032 and 007033 list hours allocated from TEP to UNSG and UNSE. Identify for each year, 2009, 2010 and 2011 the comparable TEP hours that were not allocated to any affiliates.

f. In each year, 2009, 2010 and 2011 were there additional hours for SES and contractor personnel located at the headquarters? If so:

   1. Identify the hours for the SES personnel located at headquarters for each year and show how the building cost related to them was allocated and charged.

   2. Identify the hours for nonaffiliated contract personnel located at headquarters for each year and show how the building cost related to them was allocated and charged.

RESPONSE: November 19, 2012

THE FILE LISTED BELOW CONTAINS CONFIDENTIAL INFORMATION AND IS BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT DATED JULY 6, 2012.

a. Please see STF 23.5-Confidential.xlsx provided in response to STF 23.5.

b. The $12.94/hour can be stated in terms of a cost per TEP Tucson (non-Springerville) employee (not just those at headquarters) by multiplying it by the annual labor hours of

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO STAFF'S TWENTY THIRD SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
December 6, 2012

an employee of 2,080 hours (52 weeks x 5 days/week x 8 hours per day). Therefore, the total facility cost per TEP Tucson employee for all TEP facilities is $26,915/year ($12.94 x 2,080).

c. No. The costs in the calculation include non-square footage costs including security, tax and return, etc. Please see costs included in the calculation in STF 23.5-Confidential.xlsx provided in response to STF 23.5.

d. The $12.94 applied is allocated based on TEP Tucson personnel hours charged to affiliates.

e. See TEP Tucson employee hours not allocated to affiliates below:

	2009	2010	2011
12/31 TEP Tucson Employees	1,026.00	1,051.50	1,045.75
Hours/Year	2,080	2,080	2,080
Total Hours	2,134,080	2,187,120	2,175,160
Hours Allocated to Affiliates	37,277	37,764	44,944
TEP Tucson Hours not Allocated	2,096,803	2,149,356	2,130,216

f. TEP personnel moved into the new headquarters building November 2011. Building costs are not allocated and charged for SES or contractor hours.

RESPONDENT:

Steve Sims

WITNESS:

Karen Kissinger

SUPPLEMENTAL RESPONSE: **December 6, 2012**

Upon review of the response to 23.1(e) it was noticed that the response only included TEP Tucson hours allocated to UNS Gas. As such, below are the revised amounts for 2009-2011 as well as September 2012 year-to-date.

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO STAFF'S TWENTY THIRD SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
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December 6, 2012

	Year-end			September
TEP Tucson Employee Hours	2009	2010	2011	2012
TEP Tucson Employees	1,026.0	1,051.5	1,045.8	1,054.5
Hours/year	2,080	2,080	2,080	
Hours thru 9/30/12 @ 75%				1,560
Total Hours	2,134,080	2,187,120	2,175,160	1,645,020
Hours Allocated to Affiliates	99,669	95,197	100,452	74,019
TEP Tucson Hours not Allocated	2,034,411	2,091,923	2,074,708	1,571,001
% of hours Allocated	4.7%	4.4%	4.6%	4.5%

RESPONDENT:

Steve Sims

WITNESS:

Karen Kissinger

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S TWELFTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291 October 22, 2012

STF 12.01

Annual Incentive Compensation. Please review the following table and confirm that it accurately reflects the total company and ACC jurisdictional amounts of annual incentive compensation expense that TEP has requested in its filing. If any amounts are determined to not be completely accurate, please provide replacement information, with references, so the information on TEP's requested amounts for annual incentive compensation, by account, is completely accurate:

Line No.	Description	TEP 2011 Recorded Total Company (A)	TEP Pro Forma Adjustments Total Company (B)	Total Company (C)=(A)+(B)	ACC Jurisdictional Factor (D)	TEP Requested ACC Jurisdictional (E)=(C)*(D)
	FERC Account					
1	0500	$ 83,927	$ 55,519	$ 139,446	0.89067	$ 124,200
2	0506	$ 786,569	$ 520,332	$ 1,306,901	0.89067	$ 1,164,020
3	0514	$ 309,913	$ 205,015	$ 514,928	0.89067	$ 458,632
4	0566	$ 587,565	$ 388,687	$ 976,252	0.00000	$ -
5	0570	$ 62,030	$ 41,033	$ 103,063	0.00000	$ -
6	0580	$ 53,316	$ 35,269	$ 88,585	1.00000	$ 88,585
7	0588	$ 215,121	$ 142,306	$ 357,427	1.00000	$ 357,427
8	0598	$ 34,017	$ 22,502	$ 56,519	1.00000	$ 56,519
9	0903	$ 226,452	$ 149,804	$ 376,256	1.00000	$ 376,256
10	0902	$ 1,418,591	$ 938,441	$ 2,357,032	0.88449	$ 2,084,782
11	0408 FICA Tax	$ 283,313	$ 187,418	$ 470,731	0.74117	$ 348,890
12	Total Expense	$ 4,060,814	$ 2,686,326	$ 6,747,140		$ 5,059,310

Notes and Source
Col. A: TEP response to UDR 1.36b
Col. B: TEP Income Statement Pro Forma Adjustment, Income - Incentive Compensation.pdf, Bates No. TEP(0291)007212
Col. D: ACC Jurisdictional Factors from TEP Income - Incentive Compensation.pdf, Bates No. TEP(0291)007212.

	FERC	Total Company	ACC	ACC Factor
13	0500	$ 55,519	$ 49,449	0.89067
14	0506	$ 520,332	$ 463,445	0.89067
15	0514	$ 205,015	$ 182,601	0.89067
16	0566	$ 388,687	$ -	0.00000
17	0570	$ 41,033	$ -	0.00000
18	0580	$ 35,269	$ 35,269	1.00000
19	0588	$ 142,306	$ 142,306	1.00000
20	0598	$ 22,502	$ 22,502	1.00000
21	0903	$ 149,804	$ 149,804	1.00000
22	0902	$ 938,441	$ 830,046	0.88449
23	0408	$ 187,418	$ 138,908	0.74117
24	Total	$ 2,686,326	$ 2,014,330	

RESPONSE:

The table is mostly accurate. FERC 0902 noted on the tables should be FERC 0920. There is a slight footing adjustment due to rounding: $5,059,310 should be $5,059,311.

RESPONDENT:

Pricing (Anne Liu)

WITNESS:

Craig A. Jones

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
UNIFORM DATA REQUESTS - 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
July 13, 2012

UDR 1.63

Accounting Adjustments.

a. Please identify any aspects of the Company's accounting adjustments and revenue requirement claim that represent a conscious deviation from the principles and policies established in prior Commission Orders.

b. Identify each area of deviation, and for each deviation explain the Company's perception of the principle established in the prior Commission Orders, and the dollar impact resulting from such deviation.

c. Show which accounts are affected and the dollar impact on each account for each such deviation.

RESPONSE:

a. The only revenue requirement claims that knowingly deviate from the Commission's prior decision for TEP is the "Incentive Compensation Adjustment".

b. In Commission Decision No. 70628 (December 1, 2008), based on the Direct Testimony of Commission Staff witness, Ralph C. Smith, 50 percent of the incentive compensation expense was removed. To cite Mr. Smith's testimony, "the removal of 50 percent of the incentive compensation expense provides an equal sharing of such cost, and therefore provides an appropriate balance between the benefits attained by both shareholders and ratepayers."

In compliance with this principle, TEP is requesting full recovery of the normal and recurring level of incentive compensation expense for unclassified employees and 50% of incentive compensation for officer and senior management level employees.

c. Please see supporting pro forma workpapers provided in response to UDR 1.1, specifically the files Income – Incentive Compensation.pdf, Bates Nos. TEP\007212-007219 and Income – Incentive Compensation.xlsm, for the accounts affected and dollars impacted.

RESPONDENT:

Pricing

WITNESS:

Dallas Dukes

TUCSON ELECTRIC POWER COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED DECEMBER 31, 2011

ADJUSTMENT NAME:	Income - PPFAC
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	June 19, 2012
PREPARED BY:	Anne Liu AR 6/19/12
CHECKED BY:	DR 6-24-12
REVIEWED BY:	DJO - 6-26-12

			Total Company		ACC Jurisdictional	
FERC ACCT	FERC ACCOUNT DESCRIPTION		DEBIT	CREDIT	DEBIT	CREDIT
	Revenue					
440 - 445	Net Sales to Ultimate Customers	1a	$12,436,902		$12,436,902	
501	Fuel - PPFAC Eligible	1b	$292,189,698		$168,304,294	
	Expense*					
501	Fuel - PPFAC Eligible			$123,885,404		
547	Fuel - PPFAC Eligible			$33,441,115		
555	Purchased Power - Demand - PPFAC Eligible		$532,093			
555	Purchased Power - Energy - PPFAC Eligible			$132,884,633		
565	Transmission of Electricity by Others - PPFAC Non-Eligible		$673,664			
	ENTRY TOTAL		**$305,832,357**	**$290,211,152**	**$180,741,196**	**$0**
	NET ENTRY		**$15,621,205**		**$180,741,196**	

Reason for Adjustment

To adjust fuel and purchased power revenue and expense at the expected level for the first year that rates set in this case will be in effect.

*Per Revenue Requirement Model - Amounts needed to zero out PPFAC balance.

TUCSON ELECTRIC POWER COMPANY
PPFAC ADJUSTMENT
TEST YEAR ENDED DECEMBER 31, 2011

Revenue - excluding Fuel, and including Weather and Customer Annualization Adjustment		2a $ 544,748,189
Revenue - including Fuel, Purchase Power and Purchase Transmission Revenue	2b $ 9,285,592,991	
PPFAC Rate (Proposed)	2c 0.031467	
Fuel and Purchase Power Adjustment - PPFAC		292,189,698 b
Adjusted Revenue Should Be		836,937,887
Revenue - undadjusted per Books	857,296,896	
Less Customer and Weather Annualization	2d (7,922,107)	
		849,374,789
Pro Forma Adjustment - Revenue		$ (12,436,902) a

Income - PPFAC Adjustment.pdf

Attachment KCS-3
Docket No. E-01933A-12-0291
Page 16 of 74

6/1/2012 3:10 PM

TUCSON ELECTRIC POWER COMPANY
CUSTOMER AND WEATHER ADJUSTMENT SUMMARY
TEST PERIOD ENDING DECEMBER 31, 2011

Line No.	Rate Class	Adjusted Customers	Adjusted Sales (kWh)	Margin Revenue	Purchase Power & Fuel	Test Year Adjusted Revenue	Test Year Adjusted Sales (Net kWh)	Test Year Adjusted Revenue ($)
1	Residential Service	360,521	3,699,107,059	$241,095,410	$111,635,462	$352,730,872	-53,465,998	-$4,876,195
2	Residential Time Of Use	8,873	129,923,963	7,043,984	3,797,665	10,841,649	-4,806,945	-379,135
3	Small General Service	35,978	1,947,489,380	156,798,459	55,398,880	212,197,338	1,257,343	99,546
4	Small General Service Time of Use	924	123,590,519	8,103,358	3,384,976	11,488,333	-1,538,909	-92,933
5	Irrigation & Water Pumping	484	107,584,687	4,446,839	2,908,651	7,355,490	-192,109	-10,403
6	Large General Service	536	1,046,539,305	55,085,198	30,598,384	85,683,582	-8,479,198	-973,902
7	Large General Service Time of Use	87	216,614,667	8,424,561	6,579,663	15,004,224	48,811,556	3,267,210
8	Large Light & Power Service	4	351,454,280	12,469,651	10,271,504	22,741,155	0	0
9	Large Light & Power Service Time of Use	9	542,786,937	17,883,872	13,900,001	31,783,872	-28,099,796	-3,012,116
10	Mining Service	2	1,083,071,404	30,374,675	29,264,219	59,638,894	0	-1,944,178
11	Traffic Signals & Lighting Service	19,566	37,430,789	3,022,183	913,817	3,936,000	0	0
12	TOTAL	426,985	9,285,592,991	$544,748,189	$268,653,221	$813,401,411	-46,514,056	-$7,922,107
			b	a				d
13	Residential Service	359,580	3,752,573,057	$244,290,132	$113,316,935	$357,607,067		
14	Residential Time Of Use	9,029	134,730,908	7,282,404	3,938,381	11,220,784		
15	Small General Service	35,820	1,946,232,036	156,707,943	55,389,849	212,097,792		
16	Small General Service Time of Use	937	125,129,428	8,157,629	3,423,638	11,581,267		
17	Irrigation & Water Pumping	492	107,776,796	4,451,723	2,914,170	7,365,894		
18	Large General Service	551	1,055,018,503	55,791,356	30,866,129	86,657,484		
19	Large General Service Time of Use	70	167,803,111	6,763,232	4,973,782	11,737,014		
20	Large Light & Power Service	4	351,454,280	12,469,651	10,271,504	22,741,155		
21	Large Light & Power Service Time of Use	11	570,886,733	20,220,753	14,575,235	34,795,988		
22	Mining Service	2	1,083,071,404	31,515,193	30,067,880	61,583,072		
23	Traffic Signals & Lighting Service	19,566	37,430,790	3,022,183	913,817	3,936,000		
24	TOTAL	426,062	9,332,107,046	$550,672,198	$270,651,318	$821,323,518		
25								

FUEL ADJUSTMENT

Proposed Increased

							REVENUE NETRUAL				
26											
27											
28						Test Year Adjusted			Fuel Revenue		TY Adjustd Fuel
29	Rate Class	Adjusted Customers	Adjusted Sales (kWh)	Margin Revenue	Purchase Power & Fuel	Revenue	Purchase Power & Fuel	Total Revenues	Change	New Fuel Rate	Revenue
30	Residential Service	360,521	3,699,107,059	241,095,410	111,635,462	$352,730,872	118,437,103	359,532,513			
31	Residential Time Of Use	8,873	129,923,963	7,043,984	3,797,665	$10,841,649	4,247,187	11,291,171			
32	Small General Service	35,978	1,947,489,380	156,798,459	55,398,880	$212,197,338	62,121,076	218,919,534			
33	Small General Service Time of Use	924	123,590,519	8,103,358	3,384,976	$11,488,333	3,977,560	12,080,918			
34	Irrigation & Water Pumping	484	107,584,687	4,446,839	2,908,651	$7,355,490	3,439,313	7,886,152			
35	Large General Service	536	1,046,539,305	55,085,198	30,598,384	$85,683,582	33,350,553	88,435,752			
36	Large General Service Time of Use	87	216,614,667	8,424,561	6,579,663	$15,004,224	6,933,789	15,358,350			
37	Large Light & Power Service	4	351,454,280	12,469,651	10,271,504	$22,741,155	10,423,711	22,893,363			
38	Large Light & Power Service Time of Use	9	542,786,937	17,883,872	13,900,001	$31,783,872	16,075,792	33,959,664			
39	Mining Service	2	1,083,071,404	30,374,675	29,264,219	$59,638,894	31,997,311	62,371,986			
40	Traffic Signals & Lighting Service	19,566	37,430,789	3,022,183	913,817	$3,936,000	1,186,301	4,208,483			
41	TOTAL	426,985	9,285,592,991	$44,748,189	$268,653,221	$813,401,411	292,189,697	836,937,886	23,536,476	$0.031467	$292,189,698
										c	

Source: B. Pries 5/26/12

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S NINTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291 October 16, 2012

STF 9.12

PPFAC adjustment and base cost of fuel and purchased power.

a. Is the $9,285,592,991 item, "Revenue – including Fuel, Purchase Power and Purchase Transmission Revenue" on TEP's PPFAC Adjustment workpaper, supposed to be a kWh sales quantity, rather than a dollar amount? If not, explain fully.

b. Were the actual test year sales 9,332,107,046 kWh (shown on line 24 "Adjusted Sales (kWh)" column, of TEP's workpaper "Customer and Weather Adjustment Summary)?" If not, explain fully what the 9,332,107,046 kWh on line 12 of that TEP workpaper represents.

c. Show in detail exactly how the "PPFAC" rate of 0.031467 was derived from the 2012 PPFAC forward rate and the average system base rate. Include supporting calculations.

d. Can the test year base cost of fuel be derived by dividing the PPFAC includable costs by the test year recorded kWh sales? If not, explain fully why not.

e. Provide the test year recorded cost of fuel and purchased power and purchased transmission by account. This should include each cost and account that is currently includable in TEP's PPFAC.

f. Does the $292,189,698 amount on TEP's PPFAC workpaper include any costs or expenses that are not currently includable in TEP's PPFAC (e.g., for any costs that are not currently includable in the PPFAC but for which TEP is requesting be included in the PPFAC prospectively)?

   1) If not, explain fully why not.

   2) If so, identify all such costs, by account.

RESPONSE: October 5, 2012

TEP is in the process of gathering this information and will provide it as soon as possible.

RESPONDENT:

Pricing

WITNESS:

Craig A. Jones

RESPONSE: October 16, 2012

a. Yes, it should be kWh.

b. Yes, it represents actual test-year sales.

c. The $.031467/kWh rate was based on the assumption of test-year revenues of $292,189,698 and adjusted sales of 9,285,592,991 kWh. The intent, however, was to use an average rate of $.031511/kWh (which reflects the $.002615/kWh 2012 Forward Component and the $.028896/kWh current Average Base Rate) with adjusted sales of

**TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
STAFF'S NINTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
October 16, 2012**

9,285,592,991 kWh, giving test-year adjusted revenues of $292,598,320. However, the requested $.031467/kWh still provides a valid PPFAC average rate between customer classes and will ultimately be trued up under the PPFAC Plan of Administration.

d. If a new base cost of fuel were to be established based only on test-year fuel costs, the answer to the question is yes. The total unadjusted includible costs of $270,867,779 divided by 9,332,107,046 kWh would equate to $.02903/kWh. This would represent the average test-year base cost of fuel Billed / Booked.

e. Please see STF 9.12.xlsx. The Excel file is not identified by Bates numbers.

f. No, it does not. At this time, estimates are not material for known prospective cost changes.

RESPONDENT:

Pricing (Brenda Pries and David Lewis)

WITNESS:

Craig A. Jones

Tucson Electric Power
PPFAC Recovery by FERC

FERC	Description	Amount
501	Fuel (Steam)	196,611,389.72
547	Fuel (Other Production)	27,551,277.68
555	Purchased Power	41,287,756.10
564	Wheeling (Transmission of Electricity by Others)	5,417,355.57
	Total PPFAC Recoverable Costs	**270,867,779.07**

Tucson Electric Power
PPFAC Recoverable Expenses

Test year Fuel expense Incurred		**437,392,280**
Less: PPFAC Adjustments		
Deduct FMR Accretion	(3,034,462)	
Deduct Springerville 3	(4,997,788)	
Deduct Springerville4	(3,193,783)	
Deduct San Juan Coal Contract	(1,027,000)	
Excluded Portion of Coal Handling Capital Lease Interest	(313,244)	
Excluded Portion of Coal Handling Lease Amortization	(303,391)	
Other Excludable 501 Cost	1,294,189	
Add Cash Payments for FMR FAS 106	1,044,539	
Includable Transmission Expense	3,974,781	
Exclude Jurisdictional Allocation	(39,461,512)	
Total PPFAC Adjustments to Fuel and Transmission		(46,017,671)
Less: Short Term Sales		(76,289,682)
Total Recoverable Costs		**315,084,927**
Less: Other Adjustments to PPFAC		
CTC Revenue Collected	(35,958,019)	
In-Kind Trans Loss (Associated pre PPFAC transactions)	(530,511)	
Unbilled	120,157	
Remote Fuel	(1,533,338)	
Luna Gas PNM Accrual	(150,725)	
Total Other PPFAC Adjustments		(38,052,435)
Total Net Recoverable Costs		**277,032,492**
Less: PPFAC Booked / Billed		**(6,164,713)**
Total Billed / Booked PPFAC eligible Rev / Exp		**270,867,779**
Test Fuel Expense Incurred		**437,392,280**
Less: PPFAC Booked / Billed		**(6,164,713)**
TEST Year Adjusted Fuel Balance (per RR Model)		**431,227,567**

PPFAC and BP Recoveries

Billed													
FERC	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
0501	12,957,743.58	11,341,511.08	11,635,098.99	11,099,081.21	14,104,737.72	19,652,235.79	22,860,532.00	25,598,611.56	23,816,670.38	17,893,471.76	13,542,209.92	12,109,485.73	196,611,389.72
0547	1,619,717.95	1,417,688.88	1,454,387.37	1,387,385.15	1,763,092.22	2,456,529.47	3,444,737.70	3,857,325.03	3,588,813.34	2,696,276.57	2,040,606.97	1,824,717.03	27,551,277.68
0555	3,059,467.23	2,677,856.78	2,747,176.15	2,620,616.40	3,330,285.30	4,640,111.23	4,384,211.62	4,909,322.77	4,567,580.62	3,431,624.72	2,597,136.15	2,322,367.13	41,287,756.10
0565	359,937.32	315,041.97	323,197.19	308,307.81	391,798.27	545,895.44	626,315.95	701,331.82	652,511.52	490,232.10	371,019.45	331,766.73	5,417,355.57
	17,996,866.08	**15,752,098.71**	**16,159,859.70**	**15,415,390.57**	**19,589,913.51**	**27,294,771.93**	**31,315,797.27**	**35,066,591.18**	**32,625,575.86**	**24,511,605.15**	**18,550,972.49**	**16,588,336.62**	**270,867,779.07**

Cost charged													
FERC	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
0501	(19,707,945.00)	(17,313,517.00)	(19,097,417.00)	(20,527,016.00)	(21,193,398.00)	(23,453,100.00)	(24,843,366.00)	(25,371,986.00)	(26,147,946.00)	(18,510,390.00)	(19,978,475.00)	(20,627,788.00)	(256,772,344.00)
0547	(1,832,156.00)	(2,664,574.00)	(555,950.00)	(1,102,870.00)	(2,213,099.00)	(2,883,828.00)	(3,215,182.00)	(3,555,164.00)	(2,653,754.00)	(1,735,029.00)	(1,137,547.00)	(2,026,860.00)	(25,576,013.00)
0555	(4,175,323.00)	(4,353,792.00)	(4,866,917.00)	(4,452,545.00)	(5,652,901.00)	(15,810,469.00)	(14,569,300.00)	(16,553,334.00)	(12,082,395.00)	(9,859,875.00)	(6,599,512.00)	(4,673,685.00)	(103,650,048.00)
0565	(151,657.00)	(165,287.00)	(311,557.00)	(27,851.00)	(179,741.00)	(934,373.00)	(154,802.00)	(269,345.00)	(2,383,974.00)	(197,088.00)	(311,463.00)	(289,066.00)	(5,376,204.00)
Net Short Term Sales	6,076,602.00	4,522,467.00	5,985,899.00	5,809,225.00	6,024,726.00	7,251,995.00	6,801,551.00	6,533,304.00	7,611,689.00	4,924,534.00	7,742,850.00	7,004,840.00	76,289,682.00
(0555)	**(19,790,479.00)**	**(19,974,703.00)**	**(18,845,942.00)**	**(20,301,057.00)**	**(23,214,413.00)**	**(35,829,775.00)**	**(35,981,099.00)**	**(39,216,525.00)**	**(35,656,380.00)**	**(25,377,848.00)**	**(20,284,147.00)**	**(20,612,559.00)**	**(315,084,927.00)**

CTC													
FERC	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
0501	478,170.22	419,460.17	432,007.60	2,369,927.71	2,541,599.85	3,183,298.15	3,671,265.98	4,111,598.07	3,835,709.21	2,909,105.16	2,166,316.48	0.00	26,118,458.60
0547	59,771.28	52,432.52	54,000.95	296,240.96	317,699.98	397,912.27	553,204.46	619,555.87	577,983.58	438,358.31	326,431.25	0.00	3,693,591.43
0555	112,901.30	99,039.21	102,001.80	559,566.26	600,099.97	751,612.06	704,078.41	788,525.66	735,615.46	557,910.58	415,457.95	0.00	5,426,808.66
0565	13,282.51	11,651.67	12,000.21	65,831.33	70,600.00	88,424.95	100,582.63	112,646.52	105,087.92	79,701.51	59,351.14	0.00	719,160.39
	664,125.31	**582,583.57**	**600,010.56**	**3,291,566.26**	**3,529,999.80**	**4,421,247.43**	**5,029,131.48**	**5,632,326.12**	**5,254,396.17**	**3,985,075.56**	**2,967,556.82**	**0.00**	**35,958,019.08**
Total 51475	**(1,129,487.61)**	**(3,640,020.72)**	**(2,086,071.74)**	**(1,594,100.17)**	**(94,499.69)**	**(4,113,755.64)**	**363,829.75**	**1,482,392.30**	**2,223,592.03**	**3,118,832.71**	**1,234,382.31**	**(4,024,222.38)**	**(8,259,128.85)**
Total 501	**(6,272,031.20)**	**(5,552,545.75)**	**(7,030,310.41)**	**(7,058,007.08)**	**(4,547,060.43)**	**(617,566.06)**	**1,688,431.98**	**4,338,223.63**	**1,504,433.59**	**2,292,186.92**	**(4,269,948.60)**	**(8,518,302.27)**	**(34,042,495.68)**
In-Kind Trans Loss	111,004.00	354,208.00	388,742.00	265,815.00	221,654.00	275,688.00	2,336,936.28	(2,084,666.28)	(8,366.00)	0.00	0.00	763,271.00	2,624,286.00
Unbilled	(599,000.00)	(385,000.00)	(336,000.00)	1,527,000.00	2,170,000.00	3,474,000.00	1,484,000.00	(60,000.00)	(3,212,000.00)	(1,116,000.00)	(2,815,000.00)	(136,000.00)	(4,000.00)
Remote Fuel	(134,478.22)	(301,921.53)	(216,698.48)	(223,673.17)	(211,777.14)	(211,777.14)	(214,965.13)	(206,197.14)	(203,790.35)	(207,643.43)	(206,384.10)	3,872,643.47	1,533,337.64
GL Balance 0501	**(6,894,505.42)**	**(5,885,259.28)**	**(7,194,266.89)**	**(5,488,865.25)**	**(2,367,183.57)**	**2,920,344.80**	**5,294,403.13**	**1,987,360.21**	**(1,919,722.76)**	**968,543.49**	**(7,291,332.70)**	**(4,018,387.80)**	**(29,888,872.04)**
Total 0547	**(152,666.77)**	**(1,194,452.60)**	**952,438.32**	**580,756.11**	**(132,306.80)**	**(29,386.26)**	**782,760.16**	**921,716.90**	**1,513,042.92**	**1,399,605.88**	**1,229,491.22**	**(202,142.97)**	**5,668,856.11**
Unbilled	(74,000.00)	(49,000.00)	(41,000.00)	190,000.00	272,000.00	434,000.00	533,000.00	(8,000.00)	(484,000.00)	(168,000.00)	(424,000.00)	(21,000.00)	160,000.00
Luna Gas PNM Accrual									130,791.60			19,933.00	150,724.60
GL Balance 0547	**(226,666.77)**	**(1,243,452.60)**	**911,438.32**	**770,756.11**	**139,693.20**	**404,613.74**	**1,315,760.16**	**913,716.90**	**1,159,834.52**	**1,231,605.88**	**805,491.22**	**(203,209.97)**	**5,979,580.71**
Total 0555	**5,073,647.53**	**2,945,570.99**	**3,968,159.95**	**4,536,862.66**	**4,302,210.27**	**(3,166,750.71)**	**(2,679,458.97)**	**(4,322,181.57)**	**832,490.08**	**(945,805.70)**	**4,155,932.10**	**4,653,522.13**	**19,354,198.76**
In-Kind Trans Loss	(167,828.39)	(199,135.30)	(82,338.05)	(75,819.20)	(475,535.00)	(1,047,911.00)	0.00	0.00	(24,249.00)	0.00	0.00	(20,959.00)	(2,093,774.94)
Unbilled	(141,000.00)	(91,000.00)	(80,000.00)	361,000.00	513,000.00	820,000.00	(252,000.00)	(11,000.00)	(616,000.00)	(214,000.00)	(540,000.00)	(26,000.00)	(277,000.00)
GL Balance 0555	**4,764,819.14**	**2,655,435.69**	**3,805,821.90**	**4,822,043.46**	**4,339,675.27**	**(3,394,661.71)**	**(2,931,458.97)**	**(4,333,181.57)**	**192,241.08**	**(1,159,805.70)**	**3,615,932.10**	**4,606,563.13**	**16,983,423.82**
Total 0565	**221,562.83**	**161,406.64**	**23,640.40**	**346,288.14**	**282,657.27**	**(300,052.61)**	**572,096.58**	**544,633.34**	**(1,626,374.56)**	**372,845.61**	**118,907.59**	**42,700.73**	**760,311.96**
Unbilled	(16,000.00)	(12,000.00)	(9,000.00)	43,000.00	60,000.00	97,000.00	36,000.00	(2,000.00)	(88,000.00)	(30,000.00)	(78,000.00)	(3,000.00)	(2,000.00)
Trans Correction												2,843.00	2,843.00
GL Balance 0565	**205,562.83**	**149,406.64**	**14,640.40**	**389,288.14**	**342,657.27**	**(203,052.61)**	**608,096.58**	**542,633.34**	**(1,714,374.56)**	**342,845.61**	**40,907.59**	**42,543.73**	**761,154.96**

TUCSON ELECTRIC POWER COMPANY
RATE CASE EXPENSE
FOR THE TEST YEAR ENDED DECEMBER 31, 2006

Outside Counsel	$500,000
Depreciation Study	$90,000
Fair Market Value Study	$150,000
Cost of Equity	$75,000
Miscellaneous	$85,000
Total Estimated Expense	$900,000
Amortization per year (4 years)	$225,000

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO UNIFORM DATA REQUESTS - 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
July 13, 2012

UDR 1.55

Industry Association Dues. Please list all membership payments made to industry associations (e.g., Edison Electric Institute, etc.) requested for recovery during the test year. Identify the account into which such amounts are charged.

a. State the purpose and objective of each organization listed.

b. Provide descriptive material the Company has concerning each organization's financial statements, annual budget, and activities.

c. Do any of the organizations listed engage in lobbying activities, attempts to influence public opinion, institutional or image-building advertising? If so, list each organization which engages in such activities, and state the Company's best estimate of the portion of the organization's expenses devoted to such activities. Explain and show how such estimates were derived. State if the Company has included the portions of dues related to such activities in the test year.

d. For each of the organizations identified, please describe how the Company perceives such expense to benefit ratepayers.

RESPONSE:

Please see part "a", below, for the membership payments made to industry associations requested for recovery during the test year. The account used was FERC 930.

a. Utility Air Regulatory Group ("UARG"). UARG is a voluntary association of electric utility companies and organizations established to advance the interests of its members at the federal level in air quality regulation matters by: i) participating in administrative and regulatory proceedings; ii) advocacy before administrative and regulatory agencies; and iii) conducting litigation. UARG also provides its members with interpretations and clarifications of federal air regulations.

TEP's total dues for UARG in 2011 were $143,470, which included $138,470 for standard dues, calculated based on total generating nameplate capacity and total gas-fired generation nameplate capacity, and $5,000 for a special assessment. No portion of the dues relates to lobbying activities.

Western Energy Supply and Transmission ("WEST") Associates. WEST Associates is a coalition of 10 cooperative, public power and investor-owned electric utilities serving over 12 million customers in 11 Western states. WEST Associates advocates on behalf of the member utilities to ensure that uniquely western issues impacting member companies and their operations are recognized in federal, state and local regulatory proceedings.

TEP's total dues for WEST Associates in 2011 were $11,632, based on total energy generation.

Edison Electric Institute ("EEI"). EEI is the association of U.S. shareholder-owned electric companies. Organized in 1933, EEI works closely with all of its members, representing their interests and advocating equitable policies in legislative and regulatory arenas. Please see part "c", below, for dues paid.

Utility Solid Waste Activities Group ("USWAG"). Please see the files listed below and on the enclosed CD for USWAG membership and dues information.

File Name	Bates Numbers
UDR 1.55 USWAG Dues Formula1.pdf	TEP\003285
UDR 1.55 USWAG Member Assessment Form.pdf	TEP\003286
UDR 1.55 USWAG Member Information.pdf	TEP\003287

The USWAG membership costs are charged as follows: 90% to TEP and 10% to UNS Electric.

b. Through TEP's membership in these organizations, the Company possesses information on the budgets or activities of these organizations, that information could shed light on strategic direction and is considered confidential business information. Information about the associations' finances and activities is available on public websites and member-only websites. Both EEI and USWAG have public websites, but restrict confidential information to their member-only websites. UARG and WEST only have members'-only sites. These sites require membership and password access.

c. UARG's charter specifically excludes legislative lobbying activities.

WEST Associates will engage in very limited lobbying activity when approved by the Board in order to ensure prudent policy and regulation affecting member operations. Due to the limited lobbying activity, it is extremely difficult to estimate the percentage of total dues dedicated to this activity. TEP has included the entire annual dues amount in the test year.

EEI and USWAG engage in legislative advocacy activities. The portions of the dues related to such activities were per EEI's letter of March 29, 2012 and have been excluded in the test year, this includes EEI's lobbying efforts to preserve or retain significant funding from Congress for the low-income home-energy assistance program. Please see the file, UDR 1.55 EEI 2011 Lobbying Letter.pdf, Bates Nos. TEP\003284, on the enclosed CD for the referenced EEI letter.

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO UNIFORM DATA REQUESTS - 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291 July 13, 2012

	Total Paid	% for Legislative Advocacy*	Expenses Excluded
EEI	347,085	21.3%	73,929
USWAG	28,800	8.2%	2,362
Total	375,885		76,291
*Per EEI March 29, 2012 Letter – Copy attached.			

d. Compliance with federal air quality regulations can result in the need to install and operate pollution control equipment costing hundreds of millions of dollars. UARG's involvement in new rulemakings and rule updates provides a check against overly burdensome and costly regulations. When federal agencies pass regulations that overstep their authority, UARG has a strong track record for having those regulations rescinded or modified, resulting in reduced operating costs for UARG members.

Compliance with state and federal regulations impacting both generation and transmission operations can result in significant increases to operating cost that will ultimately be passed on to customers. WEST Associates seeks to educate policy makers about those impacts from a western perspective and to ensure that only prudent regulations are applied to utility operations.

Similarly, EEI works to ensure favorable regulatory outcomes at the Federal Energy Regulatory Commission, the Department of Energy, the Environmental Protection Agency and other federal agencies through direct dialogue, and formal comments on key policy issues affecting the electric utility industry. In addition to public policy leadership, EEI provides critical industry data, strategic business intelligence, and one-of-a-kind conferences and forums. All of which assist TEP in reducing operating costs, which savings are passed on to our customers.

USWAG allows TEP to stay informed on various waste issues relating to Resource Conservation and Recovery Act ("RCRA"), the Toxic Substances Control Act ("TSCA"), and the Hazardous Materials Transportation Act ("HMTA"). Issues include proposed rulemaking, regulatory interpretation, regulatory compliance, and individual counseling. These benefits result in a more efficient and effective Corporate Environmental Services. The knowledge obtained from membership is very valuable and would be nearly impossible to obtain from any single source at a cost effective price that is realized through the power of the membership consortium.

RESPONDENT:

Pricing, Chuck Komadina, Erik Bakken and Jeffrey Yockey

WITNESS:

Dallas Dukes

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S ELEVENTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291 October 15, 2012

STF 11.10

Property Taxes. Provide the timeline of property tax assessment, expense recording and property tax payment that applies to TEP in years 2011 and 2012.

RESPONSE:

For Tax Year 2011, relevant dates are as follows:

Assessment date	January 1, 2010
Lien date	January 1, 2011
Expense Recording	50% in 2011 and 50% in 2012
Payment Due Dates	October 1, 2011 and March 1, 2012
Payment Delinquent Dates	Nov. 1, 2011 and May 1, 2012

For Tax Year 2012, relevant dates are as follows:

Assessment date	January 1, 2011
Lien date	January 1, 2012
Expense Recording	50% in 2012 and 50% in 2013
Payment Due Dates	October 1, 2012 and March 1, 2013
Payment Delinquent Dates	Nov. 1, 2012 and May 1, 2013

RESPONDENT:

Rigo Ramirez

WITNESS:

Karen Kissinger

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S ELEVENTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291 October 15, 2012

STF 11.11

Property tax expense.

a. Identify the amount of property tax expense requested by TEP in its last rate case.

b. Identify the amount of property tax expense recorded by TEP on its books in each year subsequent to the test year used in its last rate case.

c. Has the Company ever tested the method it uses to produce pro forma adjusted property tax expense for ratemaking purposes against its actual property tax expense? If not, explain fully why not. If so, please describe all such testing and show all results.

d. If a method of estimating property taxes in rate cases seems logical but is in fact producing estimates of property tax expense that significantly overstate the utility's actual property tax expenses in all actual known years after the test year, would that call into question the accuracy of the estimation method? If not, explain fully why not.

RESPONSE:

a. In its last rate case, TEP requested $30,751,386 and in Decision. No. 70628 the Commission approved $31,584,027. Both the requested amount and the approved amount excluded property taxes related to Springerville Unit 1 and PV property.

b. Please see the response to UDR 1.66.

c. No. The Commission has had a long standing policy of computing items on a standalone basis. For example, the Commission's stand alone policy can be seen on page 21 of its Decision No. 59951, issued in January 1997 in connection with a rate case of the Arizona Electric Division of Citizens Utilities Company ("Citizens"). The Citizens filing included pro forma income taxes computed using a 35% Federal rate, reflecting the fact that it participated in a consolidated tax return. The Commission rejected the use of a 35% rate and ordered use of a 34% rate because that rate would apply on a standalone basis.

TEP has followed this standalone policy when calculating property taxes in this rate case. This approach was used by TEP and approved in its last rate case (Decision No. 70628). In addition, all UNS affiliates have followed this standalone policy in their respective rate cases when calculating property taxes. This methodology has been accepted by Commission Staff.

The Company does not expect pro forma property tax expense for ratemaking purposes, computed on a standalone basis, to produce the same results as actual property tax bills. Actual property tax bills are computed on a combined basis.

d. As explained in part c, the method of computing property taxes is consistent with past Commission directives for computing items on a standalone basis.

RESPONDENT:

Rigo Ramirez

WITNESS:

Karen Kissinger

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S TWENTYFIFTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
December 6, 2012

STF 25.3

TEP's response to STF 11.11(c) refers to the use by the electric division of Citizens Utilities of a 34% and a 35% federal income tax rate. During any of the past 10 years has TEP used a 34% federal income tax rate either (1) on a tax return or (2) for ratemaking purposes? If so, identify the circumstances. If not, explain fully why not.

RESPONSE:

TEP has not used a 34% tax rate on a tax return or for ratemaking purposes in the last 10 years, since TEP's taxable income has not fallen within the 34% tax rate range of $335,000 to $10,000,000.

RESPONDENT:

Jason Rademacher

WITNESS:

Karen Kissinger

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S FIRST SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291 September 7, 2012

STF 1.066

Rate Design: Please provide in an Excel worksheet (with all supporting inputs, data sources and information defined) the monthly participation history (and dollar value) since January 2008 through the present of the number of customers on the Green Watts program. Also, please provide any research or surveys performed on this issue. [Jones Direct 48:3]

RESPONSE:

Please see STF 1.066.xlsx for the requested information for January 2009 through July 2012. TEP is not providing 2008 data because it would be unduly burdensome to obtain the information in the time requested, because Green Watts reports were not developed to track monthly data prior to 2009.

RESPONDENT:

Pricing (David Lewis)

WITNESS:

Craig A. Jones

GreenWatts
January 2009 Through July 2012
STF 1.066

Date	Commercial Customers	Commercial Dollars	Residential Customers	Residential Dollars	Total Company Dollars
JAN-09	48	$1,137.50	2,176	$8,038.50	$9,176.00
FEB-09	46	$1,475.50	2,070	$7,527.50	$9,003.00
MAR-09	48	$1,535.50	2,163	$8,318.50	$9,854.00
APR-09	48	$1,427.00	2,184	$8,459.00	$9,886.00
MAY-09	45	$1,592.00	2,124	$7,796.50	$9,388.50
JUN-09	50	$1,187.00	2,206	$8,520.50	$9,707.50
JUL-09	50	$1,391.00	2,196	$8,129.50	$9,520.50
AUG-09	48	$1,352.00	2,179	$7,990.50	$9,342.50
SEP-09	46	$1,352.00	2,106	$7,602.00	$8,954.00
OCT-09	45	$154.50	2,145	$7,864.00	$8,018.50
NOV-09	39	$1,078.50	1,941	$7,054.50	$8,133.00
DEC-09	43	$1,244.00	2,118	$7,692.00	$8,936.00
JAN-10	40	$1,134.50	2,010	$7,307.00	$8,441.50
FEB-10	43	$1,244.00	2,007	$7,301.00	$8,545.00
MAR-10	43	$1,353.50	2,088	$8,241.00	$9,594.50
APR-10	43	$1,398.00	2,074	$7,952.00	$9,350.00
MAY-10	41	$1,085.50	1,964	$7,146.00	$8,231.50
JUN-10	41	$1,286.00	2,015	$7,608.00	$8,894.00
JUL-10	43	$1,239.50	2,034	$7,437.00	$8,676.50
AUG-10	46	$1,071.50	1,953	$7,102.50	$8,174.00
SEP-10	46	$1,236.50	2,012	$7,399.50	$8,636.00
OCT-10	46	$1,236.50	1,924	$7,014.00	$8,250.50
NOV-10	44	$1,229.50	1,911	$6,990.00	$8,219.50
DEC-10	45	$1,257.00	1,922	$6,945.50	$8,202.50
JAN-11	47	$966.00	1,987	$7,248.50	$8,214.50
FEB-11	45	$1,086.00	1,906	$6,965.00	$8,051.00
MAR-11	46	$1,126.50	1,964	$7,695.50	$8,822.00
APR-11	46	$1,124.50	1,957	$7,166.50	$8,291.00
MAY-11	46	$1,094.50	1,952	$7,052.50	$8,147.00
JUN-11	44	$1,109.00	1,936	$5,576.50	$6,685.50
JUL-11	40	$893.50	1,747	$6,401.00	$7,294.50
AUG-11	42	$802.00	1,900	$7,537.50	$8,339.50
SEP-11	40	$809.00	1,888	$6,928.00	$7,737.00
OCT-11	38	$805.00	1,792	$6,523.00	$7,328.00
NOV-11	38	$802.00	1,802	$6,541.00	$7,343.00
DEC-11	40	$812.00	1,791	$6,491.50	$7,303.50
JAN-12	40	$812.00	1,836	$6,683.50	$7,495.50
FEB-12	40	$812.00	1,818	$6,641.50	$7,453.50
MAR-12	40	$721.00	1,803	$6,808.00	$7,529.00
APR-12	39	$771.50	1,792	$6,543.00	$7,314.50
MAY-12	39	$771.50	1,774	$6,593.00	$7,364.50
JUN-12	37	$756.50	1,698	$6,103.50	$6,860.00
JUL-12	39	$766.50	1,745	$6,327.00	$7,093.50

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S ELEVENTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291
October 15, 2012

STF 11.03

GreenWatts. Refer to the responses to UDR 1.89, STF 1.066 and to TEP(0291)007203 through 206.

a. Provide the GreenWatts Revenue regulatory liability amounts in account 24600 (and 14600 if there are any asset amounts) for each month after 12/31/2011 through the present.

b. Provide the projected GreenWatts Revenue (account 40290), expenses (by account) and net regulatory liability amount in account 246 projected by month through the effective date of new rates in the current TEP rate case.

c. If there is a balance remaining in the account 246 for GreenWatts and if the GreenWatts program is terminated as of the effective date of new rates in the current TEP rate case, what does TEP propose to do with the balance that remains in account 246? Explain fully.

d. Refer to TEP(0291)007205. Provide more detailed explanations for the debit items listed there as "J360 – TEP REST Adjustment USD." Explain in detail what the payments are for and identify the payee. Also, explain why the debits are being recorded in the Green Watts Program revenue account, as opposed to being recorded in an expense account.

RESPONSE:

a.

January 2012	$(19,872.03)
February 2012	$(27,325.53)
March 2012	$(34,854.53)
April 2012	$(33,271.84)
May 2012	$(11,115.78)
June 2012	$(17,975.78)
July 2012	$(25,069.28)
August 2012	$(32,658.78)

b. Due to the immateriality of the revenue, it has not been forecasted. When the new rates are approved and put into place, the revenue from GreenWatts will be terminated.

c. If there is a balance remaining in account 246 for GreenWatts and the program is terminated, then TEP will use that to construct a new system. Unless otherwise directed, TEP would use the money for a system sized appropriately considering the balance of the account. Currently, costs for an installed photovoltaic ("PV") system range between $2.50 - $3.50 per watt. Any remaining imbalances could also be applied to the Renewable Energy Standard and Tariff ("REST") budget.

d. GreenWatts revenue is collected through the Customer Care & Billing ("CC&B") System. Revenue collected in excess of expenditures for a given period is deferred on the balance sheet (Debit 40290.5635; Credit 24600.5635, Current Regulatory Liability-GreenWatts Revenue). Expenditures in excess of collections are deferred on the balance sheet (Debit 14600.5635, Current Regulatory Asset, GreenWatts Revenue; Credit 51500.0000). The

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S ELEVENTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291
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current regulatory asset is reduced by collections until the balance is zero (0). The regulatory liability is reduced as expenditures in excess of the current month's collections are incurred. Please see STF 11.03 TEP GreenWatts 2011 J360 Related.xls for the transactions among the various accounts for the requested period.

Excel files are not Bates stamped.

Payments for Green Watts Projects:

TEP GreenWatts revenue recognized during 2011 relates to the following projects:

Project Name	Payee	Amount
Reid Park Zoo Elephant Habitat	Schott Solar and SMA American	26,136.72 2,984.62
Clements Recreation Center	BP Solar	1,000.00
U of A Visitor Center	Xantrex	20,625.00
	Total	**50,746.34**

RESPONDENT:

Pricing, Carmine Tilghman, Carolyn Owen and Georgia Hale

WITNESS:

Craig A. Jones

Green Watts Transactions per TEP REST Journal J360
For 2011

				Offsetting Accounts							
		Transfer from/(to)	Collections	14600.5635, Current Regulatory Asset				Expense Account	24600.5635, Current Regulatory Liability		
	40290.5635	40290.5635	CC&B - 40290	Open Bal	Debit	Credit	Balance	51500	Open Bal	Transfer from/(to)	Balance
Jan-11	-		(8,214.50)	28,093.58		(7,399.00)	20,694.58	7,399.00	-	-	-
Feb-11			(8,051.00)	20,694.58		(7,342.00)	13,352.58	7,342.00		-	-
Mar-11			(8,822.00)	13,352.58		(8,822.00)	4,530.58	8,822.00			-
Apr-11		2,944.87	(8,291.00)	4,530.58		(4,530.58)	-	4,530.58		(2,944.87)	(2,944.87)
May-11		8,147.00	(8,147.00)	-			-			(8,147.00)	(11,091.87)
Jun-11		6,685.50	(6,685.50)	-			-			(6,685.50)	(17,777.37)
Jul-11		7,294.50	(7,294.50)	-			-			(7,294.50)	(25,071.87)
Aug-11		8,339.50	(8,339.50)	-			-			(8,339.50)	(33,411.37)
Sep-11		(33,411.37)	(7,737.00)	-	9,597.97		9,597.97	(9,597.97)		33,411.37	-
Oct-11			(7,328.00)	9,597.97		(7,328.00)	2,269.97	7,328.00		-	-
Nov-11		5,073.03	(7,343.00)	2,269.97		(2,269.97)	-	2,269.97		(5,073.03)	(5,073.03)
Dec-11		7,303.50	(7,303.50)	-			-			(7,303.50)	**(12,376.53)**
Total Dr/Cr		12,376.53	(93,556.50)	Total Dr/Cr	9,597.97	(37,691.55)		**28,093.58**			
						(28,093.58)					
Total Per TEP 12-0291		45,787.90	(126,967.87)								
Transfer- Def Liab		(33,411.37)	33,411.37								
		12,376.53	(93,556.50)								

Notes:

14600.5635 *Debits to this account are transfers from expenses, like 51500, and occur when there are more expenditures than collected and/or deferred revenue*
Credits to this accounts are transfers back to expenses and occur when revenue is available to cover the expense.
These transactions are recorded by means of the J360 - TEP REST Adjustment.

24600.5635 *Debits to this account are transfers to revenue, 40290, and occur when there are more current period expenditures than current period revenue.*
Debits to the account do not exceed the current balance.
Credits to this accounts are transfers from revenue, 40290, and occur when there are no expenditures for the period; they are available to cover future expenses
These transactions are recorded by means of the J360 - TEP REST Adjustment.

Dept Corp Acct - GL - Balance - - - Acct, SubAcct Conditions: "Acct$UNS_GL_Account" = :Enter Account, "Acct$UNS_GL_Company" = :Enter Company, "Acct$UNS_GL_SubAccount" = :Enter SubAccount, Summary_Flag = 'N', Currency_Code = 'USD', Period_Name = :Period Name Parameters: Period Name : 'APR-11, AUG-11, DEC-11, FEB-11, JAN-11, JUL-11, JUN-11, MAR-11, MAY-11, NOV-11, OCT-11, SEP-11' , Company : '002' , Account : '14600' , Subaccount : '5635' 09-OCT-12 - 07.39.25 AM

Co.	Period Name	Acct	Acct Name	Sub Acct	SubAcct Name	Beginning Balance	Debits	Credits	Period Net	Ending Balance
002	JAN-11	14600	Current Regulatory Assets	5635	Green Watts Revenue	28,093.58	0.00	7,399.00	<7,399.00>	20,694.58
002	FEB-11	14600	Current Regulatory Assets	5635	Green Watts Revenue	20,694.58	0.00	7,342.00	<7,342.00>	13,352.58
002	MAR-11	14600	Current Regulatory Assets	5635	Green Watts Revenue	13,352.58	0.00	8,822.00	<8,822.00>	4,530.58
002	APR-11	14600	Current Regulatory Assets	5635	Green Watts Revenue	4,530.58	0.00	4,530.58	<4,530.58>	0.00
002	MAY-11	14600	Current Regulatory Assets	5635	Green Watts Revenue	0.00	0.00	0.00	0.00	0.00
002	JUN-11	14600	Current Regulatory Assets	5635	Green Watts Revenue	0.00	0.00	0.00	0.00	0.00
002	JUL-11	14600	Current Regulatory Assets	5635	Green Watts Revenue	0.00	0.00	0.00	0.00	0.00
002	AUG-11	14600	Current Regulatory Assets	5635	Green Watts Revenue	0.00	0.00	0.00	0.00	0.00
002	SEP-11	14600	Current Regulatory Assets	5635	Green Watts Revenue	0.00	9,597.97	0.00	9,597.97	9,597.97
002	OCT-11	14600	Current Regulatory Assets	5635	Green Watts Revenue	9,597.97	0.00	7,328.00	<7,328.00>	2,269.97
002	NOV-11	14600	Current Regulatory Assets	5635	Green Watts Revenue	2,269.97	0.00	2,269.97	<2,269.97>	0.00
002	DEC-11	14600	Current Regulatory Assets	5635	Green Watts Revenue	0.00	0.00	0.00	0.00	0.00
Grand Total							**9,597.97**	**37,691.55**	**<28,093.58>**	

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO UNIFORM DATA REQUESTS - 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
September 25, 2012

UDR 1.36

Payroll, Incentive Programs.

a. Please provide complete copies of any bonus programs or incentive award programs in effect at the Company for the most recent three years.

b. Identify all incentive and bonus program expense incurred in 2010 and 2011. Identify the accounts charged.

c. Identify all incentive and bonus program expense charged or allocated to the Company from affiliates in 2010 and 2011.

RESPONSE: July 13, 2012

a. Please see TEP's response to UDR 1.35 for the description of the short term incentive program available to TEP non-union employees related to their annual compensation. Union employees are not eligible for the short term incentive program – their annual compensation is not based in part on performance incentives as is the case with non-Union employees.

Long-term Incentive Program:

As set forth in the Direct Testimony of Karen Kissinger, TEP is not seeking recovery of the Long-term Incentive ("LTI") Program in this rate case. Notwithstanding the relevance, TEP states that TEP Officers are eligible to participate in a long-term incentive program. Please see the file, UDR 1.36 2011 LTI Term Sheet-Confidential.pdf, Bates Nos. TEP\003173-003180 on the enclosed CD for the description of the program.

Bates Nos. TEP\003173-003180 contain confidential information and are being provided pursuant to the terms of the Protective Agreement dated July 6, 2012.

b. Please see the file, UDR 1.36 Incentive Compensation and Bonuses.xls, on the enclosed CD for incentive and bonus program expense incurred in 2010 and 2011 and accounts charged. The Excel file is not identified by Bates numbers.

c. There was no incentive or bonus program expense charged or allocated to TEP from affiliates in 2010 or 2011.

RESPONDENT:

Gabrielle Camacho, Georgia Hale and Ann Eckert

WITNESS:

Karen Kissinger

SUPPLEMENTAL RESPONSE: September 25, 2012

In response to STF 5.16, UDR 1.36 Incentive Compensation and Bonuses (SERP).xls is hereby added to part b to include the SERP detail.

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO UNIFORM DATA REQUESTS - 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
September 25, 2012

RESPONDENT:

Gabrielle Camacho, Georgia Hale and Ann Eckert

WITNESS:

Karen Kissinger

Tucson Electric Power Company
Incentive Compensation and Bonuses
In response to UDR 1.36b

Incentive Compensation (PEP) Program Expense:

FERC	2010	2011
0426	$ 3,568,178	$ 3,404,253
0500	173,553	83,927
0506	729,383	786,569
0514	375,720	309,913
0566	327,220	587,565
0570	117,544	62,030
0580	54,731	53,316
0588	230,012	215,121
0598	39,812	34,017
0903	247,009	226,452
0920	1,411,569	1,418,591
	$ 7,274,731	$ 7,181,754

Officer's Long-term Incentive Compensation Expense:

FERC	2010	2011
0426	$ 1,724,472	$ 1,612,511

Spot Awards Expense:

FERC	2010	2011
0920	$ 227,280	$ 252,950

Tucson Electric Power Company
Incentive Compensation
For the Test Year Ended December 31, 2011
In response to STF 5.16a

Supplemental Response to UDR 1.36b:

Incentive Compensation (PEP) Program Expense:

Account	Subaccount	Test Year 2011
50100	0000	$ 3,777,501
88090	3600	3,404,253
		$ 7,181,754

Officer's Long-term Incentive Compensation Expense:

Account	Subaccount	Test Year 2011
88090	4013	$ 1,362,214
88090	4014	250,297
		$ 1,612,511

Spot Awards Expense:

Account	Subaccount	Test Year 2011
50100	0000	$ 252,950

**TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
STAFF'S NINTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
October 5, 2012**

STF 9.01

Overhaul expense, past actual information for additional overhaul cycles.

a. Please provide overhaul expense by unit for 1994 through 2003 similar to the actual information shown on TEP(0291)007244.

RESPONSE:

Please see STF 9.01 PlntOverhaul-OutageNormalizationV1 1999-2003.pdf, Bates No. TEP\023495, for the requested information. Records prior to 1999 are not available through TEP's current ERM system.

RESPONDENT:

Mark Mansfield

WITNESS:

Mark Mansfield

Tucson Electric Power Company
Overhaul O&M Costs
1999-2003

Outage Type (Major or Minor)

Plant	1999	2000	2001	2002	2003
Four Corners unit 4		Major			Minor
Four Corners unit 5	Minor			Major	Minor
Navajo unit 1	Major		Minor		Minor
Navajo unit 2		Minor		Minor	
Navajo unit 3	Minor		Minor		Major
San Juan unit1		Major		Minor	
San Juan unit 2	Major		Minor		Major
Luna 1					
Luna 2					
Springerville unit 1	Minor	Major		Minor	
Springerville unit 2	Major		Minor		Minor
Irvington unit 1					
Irvington unit 2					Minor
Irvington unit 3			Major		Minor
Irvington unit 4	Minor		Minor		Major

Outage Cost ($ 000's)

Plant		1999	2000	2001	2002	2003
Four Corners unit 4		-	987	-	-	94
Four Corners unit 5		315	-	-	772	152
Total Four Corners		315	987	-	772	246
Navajo unit 1		1,551	-	282	-	393
Navajo unit 2		-	495	-	293	-
Navajo unit 3		508	-	281	-	2,115
Total Navajo	#	2,059	495	563	293	2,508
San Juan unit1		-	1,916	-	3,579	-
San Juan unit 2		1,753	-	4,216	-	2,075
Total San Juan	#	1,753	1,916	4,216	3,579	2,075
Luna 1						
Luna 2						
Total Luna		-	-	-	-	-
Springerville unit 1		989	5,388	-	3,505	-
Springerville unit 2		4,719	-	1,927	-	3,620
Total Luna	#	5,708	5,388	1,927	3,505	3,620
Irvington unit 1						
Irvington unit 2						28
Irvington unit 3		-	-	1,624	-	184
Irvington unit 4		287	-	421	-	2,517
Total Irvington	#	287	-	2,045	-	2,729

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S NINTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291
October 5, 2012

STF 9.07

Overhauls. Does TEP receive overhaul budgets from the operators of any jointly-owned units that are operated by others?

a. If not, explain fully why not.

b. If so, provide the joint-owner provided overhaul budget provided to TEP in each year, 2004 through 2012.

RESPONSE:

Yes. Please see STF 9.07.xlsx for the joint-owner provided overhaul budgets 2004-2012.

RESPONDENT:

Mark Mansfield

WITNESS:

Mark Mansfield

Error

An error occurred while processing this page. See the system log for more details.

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO UNIFORM DATA REQUESTS - 2012 TEP RATE CASE
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September 25, 2012

RESPONDENT:

Pricing (Anne Liu)

WITNESS:

Dallas Dukes

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO UNIFORM DATA REQUESTS - 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
September 25, 2012

UDR 1.64

EEI Expense. Please provide all Edison Electric Institute invoices related to EEI expenses recorded during the test year.

a. Please reconcile the amounts shown on the EEI invoices with the EEI expense recorded in each account during the test year.

RESPONSE: July 13, 2012

Please see the attached file, UDR 1.64 EEI Invoices.pdf, Bates Nos. TEP\003288-003293 on the enclosed CD for copies of the Edison Electric Institute ("EEI") invoices.

a. Please see supporting pro forma workpapers provided in response to UDR 1.1, specifically the file Income – Membership Dues.xlsm, which shows the reconciliation between the invoices and the expenses recorded in the test year.

RESPONDENT:

Pricing

WITNESS:

Dallas Dukes

SUPPLEMENTAL RESPONSE: September 25, 2012

In response to STF 5.18, please see UDR 1.64 EEI Invoices 2009-2010.pdf, Bates Nos. TEP\022877-022890, to expand this response to include 2009 and 2010 EEI invoices.

RESPONDENT:

Pricing (Anne Liu)

WITNESS:

Dallas Dukes

EDISON ELECTRIC INSTITUTE

INVOICE FOR MEMBERSHIP DUES

701 PENNSYLVANIA AVENUE, NW
WASHINGTON, DC 20004-2696
PHONE (202) 508-5000

MR. PAUL J. BONAVIA
CHAIRMAN, PRESIDENT AND CEO
UNISOURCE ENERGY CORP
1 S CHURCH AVE
TUCSON, AZ 85701-0000

26812-1

Date	Invoice Number
11/15/2010	DUES201168

Payment Due on or before 2/1/2011
(Interest charges will accrue after due date)

Description	Total
This invoice reflects the five percent increase in EEI regular activity dues unanimously approved by the EEI Board of Directors on June 16, 2010. Each company's dues will vary based on changes in company statistics and the relative change in those statistics.	
2011 EEI Membership Dues for:	
Regular Activities of Edison Electric Institute[1] Industry Issues[2] Mutual Assistance Program[3]	$342,085 ~~34,209~~ ~~1,000~~
2011 Contribution to The Thomas Alva Edison Foundation (Edison Foundation), including the Institute for Electric Efficiency The Edison Foundation is an IRC 501(c)(3) educational and charitable organization. The Institute for Electric Efficiency (IEE) is a program of the Edison Foundation. **Contributions are tax deductible in the same manner as contributions to any 501(c)(3) organization.**	15,000 347,085 TEP MB 10,000 UNSE MB
Total	~~397,294~~

1- The portion of membership dues allocable during 2011 relating to influencing legislation not deductible for federal income tax purposes is estimated to be 21%.
2- The portion of the voluntary industry issues allocable during 2011 relating to influencing legislation is estimated to be 35%.
3- Voluntary assessment approved by EEI Executive Committee relating to improvements for the rapid response to disasters. No portion of this assessment is allocable to influencing legislation.

PLEASE NOTE INFORMATION FOR WIRING.

The following is instruction for transferring funds electronically to Edison Electric Institute's account at the Wachovia Bank N.A. in Washington, DC:

Beneficiary's Bank:	**Wachovia Bank, N.A.**
Bank's Address:	**Washington, DC**
Bank's ABA Number:	**054001220**
Beneficiary:	**Edison Electric Institute**
Beneficiary's Acct No:	**2000013842897**
Beneficiary's Address:	**701 Pennsylvania Avenue, NW Washington, DC 20004-2696 USA**
Beneficiary Reference:	**2011 Membership Dues**

Ben - Please process payment as follows:
$10,600 UNSE MB
$347,085 TEP MB -
Reg 2-711

Please refer any questions to Terri Oliva at: phone-(202) 508-5541; fax-(202) 508-5037; *or* e-mail- Toliva@eei.org.

Edison Electric Institute

701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2696
www.eei.org

Accounts Receivable: 202.508.5428

RECEIVED
MAR 15 2011
BY:

INVOICE

INVOICE NO: 1877

DATE: MARCH 7, 2011

PPO # 12067

APPROVED FOR PAYMENT
By ____ Date 3-16-11

TUCSON ELECTRIC POWER CO.
3950 E. IRVINGTON ROAD
MS-DS503
TUCSON, AZ 85714-0000
CHARLES W. KOMADINA

SALESPERSON	VAT NUMBER	DATE SHIPPED	SHIPPED VIA	F.O.B. POINT	TERMS
G. NOVAK		03/07/11			NET 30

QUANTITY	DESCRIPTION	UNIT PRICE	AMOUNT
	2011 USWAG MEMBERSHIP DUES		
	2011 PER SHARE ASSESSMENT = 32,000		
	UNISOURCE ENERGY SHARES - 1.00 = $32,000		32,000.00
	CONTACT: CHARLES KOMADINA		
	PH: 520-918-8316		
	EMAIL: CKOMADINA@TEP.COM		
	PLEASE SEND A COPY OF THIS INVOICE WITH YOUR PAYMENT.		
	Release #12067-21		
	3/16/11	**Remit this amount**	**$32,000.00**

Line 1 = Proj #C000001/Task#A101805/CC805/$28,800.00 → TEP
Line 2 = Proj # UNS4200/Task# ETP0430/CC805/$3,200.00

Edison Electric Institute

701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2696
www.eei.org

Accounts Receivable: 202.508.5428

RECEIVED
APR 6 2011
BY:

INVOICE

INVOICE NO: 76250-B

DATE: MARCH 31, 2011

P.O. #12067

TUCSON ELECTRIC POWER CO.
P.O. BOX 711
TUCSON, AZ 85702-0711
MR. JEFF YOCKEY

SALESPERSON	VAT NUMBER	DATE SHIPPED	SHIPPED VIA	F.O.B. POINT	TERMS
C. RAY		03/31/11			NET 30

QUANTITY	DESCRIPTION	UNIT PRICE	AMOUNT
	2011 UARG MEMBERSHIP DUES - 2ND QTR		**34,617.50**
	JANUARY 1 – DECEMBER 31, 2011		
	CONTACT: JEFF YOCKEY		
	PH: 520-745-3192		
	EMAIL: JYOCKEY@TEP.COM		
	APPROVED FOR PAYMENT By JSH Date 4/6/11 Release #12067-22		
	PLEASE SEND A COPY OF THIS INVOICE WITH YOUR PAYMENT.	4/7/11	
		Remit this amount	**$34,617.50**

90% TEP = 31,155.75
10% UNSE = 3,461.75
34,617.50

Edison Electric Institute

701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2696
www.eei.org

Accounts Receivable: 202.508.5426

RECEIVED
JUL 21 2011
BY:

INVOICE

INVOICE NO: 76250-C

DATE: JULY 20, 2011

PC #12067

TUCSON ELECTRIC POWER CO.
P.O. BOX 711
TUCSON, AZ 85702-0711
MR. JEFF YOCKEY

SALESPERSON	VAT NUMBER	DATE SHIPPED	SHIPPED VIA	F.O.B. POINT	TERMS
C. RAY		07/20/11			NET 30

QUANTITY	DESCRIPTION	UNIT PRICE	AMOUNT
	2011 UARG MEMBERSHIP DUES – 3RD QTR JANUARY 1 – DECEMBER 31, 2011		34,617.50
	Remit this amount		**$34,617.50**

APPROVED FOR PAYMENT
By _____ Date 7/21/11
Release #12067-23
7/21/11

CONTACT: JEFF YOCKEY

PH: 520-745-3192

EMAIL: JYOCKEY@TEP.COM

PLEASE SEND A COPY OF THIS INVOICE WITH YOUR PAYMENT.

90% TEP 31,155.75
10% UNSE 3,461.75
34,617.50

Received 07/22/11 Interoffice

Edison Electric Institute

701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2696
www.eei.org

Accounts Receivable: 202.508.5428

RECEIVED
OCT 10 2011
BY:

INVOICE

INVOICE NO: 77701CR

DATE: OCTOBER 10, 2011

PPO#12067

APPROVED FOR PAYMENT
By_____Date_____

Release #12067-24
10/10/11

MR. ERIK BAKKEN
MGR, CORP. ENVIRONMENTAL SERVICES
TUCSON ELECTRIC POWER CO.
1 S. CHURCH STREET
TUCSON, AZ 85701-0000

SALESPERSON	VAT NUMBER	DATE SHIPPED	SHIPPED VIA	F.O.B. POINT	TERMS
C. RAY		10/10/11			NET 30

QUANTITY	DESCRIPTION	UNIT PRICE	AMOUNT
	UARG		
	SPECIAL ASSESSMENT FOR 2011		5,000.00
	CONTACT: ERIK BAKKEN		
	PH: 520-918-8351		
	EMAIL: EBAKKEN@TEP.COM		
	PLEASE SEND A COPY OF THIS INVOICE WITH YOUR PAYMENT.		
	YOUR PAYMENT CAN BE MADE WITH AN AMERICAN EXPRESS, MASTERCARD OR VISA.		
		Remit this amount	$5,000.00

Edison Electric Institute

701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2696
www.eei.org

Accounts Receivable: 202.508.5428

RECEIVED
OCT 26 2011
BY:

INVOICE

INVOICE NO: 76250-D

DATE: OCTOBER 20, 2011

PPO #12067

TUCSON ELECTRIC POWER CO.
P.O. BOX 711
TUCSON, AZ 85702-0711
MR. JEFF YOCKEY

SALESPERSON	VAT NUMBER	DATE SHIPPED	SHIPPED VIA	F.O.B. POINT	TERMS
C. RAY		10/20/11			NET 30

QUANTITY	DESCRIPTION	UNIT PRICE	AMOUNT
	2011 UARG MEMBERSHIP DUES – 4TH QTR JANUARY 1 – DECEMBER 31, 2011		34,617.50
	CONTACT: JEFF YOCKEY PH: 520-745-3192 EMAIL: JYOCKEY@TEP.COM		
	APPROVED FOR PAYMENT By _____ Date 11/1/11 Release #12067-25		
	PLEASE SEND A COPY OF THIS INVOICE WITH YOUR PAYMENT.		
		Remit this amount	$34,617.50

EDISON ELECTRIC INSTITUTE

INVOICE FOR MEMBERSHIP DUES

701 PENNSYLVANIA AVENUE, NW
WASHINGTON, DC 20004-2696
PHONE (202) 508-5000

Date	Invoice Number
11/14/2008	DUES200967

MR. JAMES S. PIGNATELLI
CHAIRMAN, PRESIDENT & CEO
UNISOURCE ENERGY CORP
1 S CHURCH AVE SUITE 201
TUCSON, AZ 85701-0000

Payment Due on or before 2/1/2009
(Interest charges will accrue after due date)

PO# 11365 -3

Description	Total
2009 EEI Membership Dues for:	$301,184 TEP mb / $10,000 UNSE mb
Regular Activities of Edison Electric Institute[1]	$311,184
Industry Issues[2]	~~$1,118~~
Mutual Assistance Program[3]	5,000
2009 Contribution to The Thomas Alva Edison Foundation (Edison Foundation), including the Institute for Electric Efficiency The Edison Foundation is an IRC 501(c)(3) educational and charitable organization. The Institute for Electric Efficiency (IEE) is a program of the Edison Foundation. **Contributions are tax deductible in the same manner as contributions to any 501(c)(3) organization.**	15,000
Total	~~$332,302~~

1- The portion of membership dues allocable during 2009 relating to influencing legislation not deductible for federal income tax purposes is estimated to be 16%.
2- The portion of the voluntary industry issues allocable during 2009 relating to influencing legislation is estimated to be 35%.
3- Voluntary assessment approved by EEI Executive Committee relating to improvements for the rapid response to disasters. No portion of this assessment is allocable to influencing legislation.

PLEASE NOTE INFORMATION FOR WIRING.

The following is instruction for transferring funds electronically to Edison Electric Institute's account at the Wachovia Bank N.A. in Washington, DC:

Beneficiary's Bank:	**Wachovia Bank, N.A.**
Bank's Address:	**Washington, DC**
Bank's ABA Number:	**054001220**
Beneficiary:	**Edison Electric Institute**
Beneficiary's Acct No:	**2000013842897**
Beneficiary's Address:	**701 Pennsylvania Avenue, NW Washington, DC 20004-2696 USA**
Beneficiary Reference:	**2009 Membership Dues**

Ben -
Please arrange for A/P to pay immediately by wire. Full amount as above
Thanks
S Fok

Please refer any questions to Ed Milad at: phone-(202) 508-5430; fax-(202) 508-5037; *or* e-mail-emilad@eei.org.

EDISON ELECTRIC INSTITUTE

Remit To: EEI Accounts Receivable
701 Pennsylvania Avenue, N.W.
Washington, DC 20004-2696

Main Number: 202-508-5000
Accounts Receivable: 202-508-5428
FAX: 202-508-5030

RECEIVED 2008
DEC 15 2008
BY:

INVOICE NO.	INVOICE DATE	CUST NO.
1-000080945	12/9/08	407476

FEIN: 13-0659550

Remittance Copy
Please return this copy with payment

SOLD TO
Jeff Yockey, P.E.
Tucson Electric Power Co
PO Box 711
MS-OH127
Tucson, AZ 85702-0711
United States

SHIP TO
Jeff Yockey, P.E.
Tucson Electric Power Co
PO Box 711
MS DS503
Tucson, AZ 85702-0711
United States

DATE SHIPPED	PURCHASE ORDER NO.	SHIP VIA	TERMS
	12067		Net 30
PRINT DATE	LOCATION	SALESPERSON	
12/9/08		CRay	

ITEM NUMBER	DESCRIPTION	QUANTITY ORDERED	QUANTITY SHIPPED	UNIT PRICE	EXTENSION	TAX
	2009 UARG Membership Dues - Unit Price: 0.00, Member Type: Non-Member - NONE Contact: Jeff Yockey, P.E. Ph: 520-918-8306 Email: jyockey@tep.com PH: (520) 571-4000	1		129,653.00	129,653.00	N

1st Qtr 2009
Release #12067-1C
Line 1 = C000001 - Task A101805 for $29,171.93 CC805
Line 2 = UNSE200 - Task ETP0930 for $3,241.32 CC805

APPROVED FOR PAYMENT
By _____ Date 2/10/09

Please reference invoice number on check and return remittance copy with payment

AMOUNT PAID 0.00

SUB TOTAL (Payable in U.S. Dollars) 129,653.00

VERISIGN NUMBER:

INVOICE NUMBER: **1-000080945**

129,653.00
PLEASE REMIT THIS AMOUNT

INVOICE

EDISON ELECTRIC INSTITUTE
MEETING REGISTRATION OFFICE
701 PENNSYLVANIA AVENUE, NW
WASHINGTON, DC 20004
ACCOUNTS RECEIVABLE: (202)508-5428

INVOICE NO: 1-000080945B
DATE: APRIL 1, 2009

RECEIVED
APR - 6 2009
BY:

TO: TUCSON ELECTRIC POWER CO.
PO BOX 711
MS-OH127
TUCSON , AZ 85702-0711
MR. JEFFREY G.YOCKEY, P.E.

SALESPERSON	P.O. NUMBER	DATE SHIPPED	SHIPPED VIA	F.O.B. POINT	TERMS
C. RAY	12067	04/01/09			NET 30

QUANTITY	DESCRIPTION	UNIT PRICE	AMOUNT
	2009 UARG MEMBER DUES – 2ND QUARTER		32,413.25
	CONTACT: JEFFREY G. YOCKEY, P.E.		
	PH: (520) 918-8306 FAX: (520) 918-8250		
	EMAIL: JYOCKEY@TEP.COM		
	PLEASE REFERENCE INVOICE NUMBER ON THE CHECK. THANK YOU.		
	APPROVED FOR PAYMENT By _____ Date 4/10/09 Release #12067-12 4/14/09		
		Remit this amount	$32,413.25

Line 1 = Proj #C00001/Task #A101805/CC805/$29,171.93
Line 2 = Proj #UNSE200/Task #ETP0930/CC805/$3,241.32

EDISON ELECTRIC INSTITUTE
Remit To: EEI Accounts Receivable
Third Floor
701 Pennsylvania Avenue, N.W.
Washington, DC 20004-2696

Main Number: 202-508-5000
Accounts Receivable: 202-508-5428
FAX: 202-508-5030

INVOICE NO.	INVOICE DATE	CUST NO.
1-000082231	2/20/09	407476

FEIN: 13-0659550

Remittance Copy
Please return this copy with payment

SOLD TO
Charles W. Komadina
Tucson Electric Power Co
3950 E Irvington Rd
MS-DS503
Tucson, AZ 85714-0000
United States

SHIP TO
Charles W. Komadina
Tucson Electric Power Co
3950 E Irvington Rd
MS-DS503
Tucson, AZ 85714-0000
United States

DATE SHIPPED	PURCHASE ORDER NO.	SHIP VIA	TERMS
			Net 30
PRINT DATE	**LOCATION**	**SALESPERSON**	
4/21/09		CRay	

ITEM NUMBER	DESCRIPTION	QUANTITY ORDERED	QUANTITY SHIPPED	UNIT PRICE	EXTENSION	TAX
	2009 USWAG Dues - Unit Price: 0.00, Member Type: Non-Member - NONE Contact: Charles W. Komadina 2009 Per Share Assessment = $30,000 UniSource Energy Corp Share - 1.00 = $30,000 Ph: 520-918-8316 PH: (520) 571-4000	1		30,000.00	30,000.00	N

Please reference invoice number on check and return remittance copy with payment

PN Reference:

AMOUNT PAID 0.00

SUB TOTAL (Payable In U.S. Dollars)
30,000.00

INVOICE NUMBER: 1-000082231

30,000.00
PLEASE REMIT THIS AMOUNT

INVOICE

EDISON ELECTRIC INSTITUTE
MEETING REGISTRATION OFFICE
701 PENNSYLVANIA AVENUE, NW
WASHINGTON, DC 20004
ACCOUNTS RECEIVABLE: (202)508-5428

INVOICE NO: 1-000080945C
DATE: JULY 6, 2009

RECEIVED
JUL 10 2009
BY:

TO: TUCSON ELECTRIC POWER CO.
PO BOX 711
MS-OH127
TUCSON , AZ 85702-0711
MR. JEFFREY G.YOCKEY, P.E.

SALESPERSON	P.O. NUMBER	DATE SHIPPED	SHIPPED VIA	F.O.B. POINT	TERMS
C. RAY	12067	07/06/09			NET 30

QUANTITY	DESCRIPTION	UNIT PRICE	AMOUNT
	2009 UARG MEMBER DUES – 3RD QUARTER		32,413.25
	CONTACT: JEFFREY G. YOCKEY, P.E.		
	PH: (520) 918-8306 FAX: (520) 918-8250		
	EMAIL: JYOCKEY@TEP.COM		
	PLEASE REFERENCE INVOICE NUMBER ON THE CHECK. THANK YOU.		
		Remit this amount	$32,413.25

APPROVED FOR PAYMENT
By [signature] Date 8/13/09
Release #12067-13 8/13/09
Line 1 = Proj #C00001/Task # A101805/CC805/$29,171.93
Line 2 = Proj # UNSE200/Task #ETP0930/CC805/$3241.32

INVOICE

EDISON ELECTRIC INSTITUTE
MEETING REGISTRATION OFFICE
701 PENNSYLVANIA AVENUE, NW
WASHINGTON, DC 20004
ACCOUNTS RECEIVABLE: (202)508-5428

INVOICE NO: 1-000080945D
DATE: OCTOBER 8, 2009

TO: TUCSON ELECTRIC POWER CO.
PO BOX 711
MS-OH127
TUCSON , AZ 85702-0711
MR. JEFFREY G.YOCKEY, P.E.

SALESPERSON	P.O. NUMBER	DATE SHIPPED	SHIPPED VIA	F.O.B. POINT	TERMS
C. RAY		10/08/09			NET 30

QUANTITY	DESCRIPTION	UNIT PRICE	AMOUNT
	2009 UARG MEMBER DUES – 4TH QUARTER		32,413.25
	CONTACT: JEFFREY G. YOCKEY, P.E.		
	PH: (520) 918-8306 FAX: (520) 918-8250		
	EMAIL: JYOCKEY@TEP.COM		
	PLEASE REFERENCE INVOICE NUMBER ON THE CHECK. THANK YOU.		
		Remit this amount	$32,413.25

M I R E

RECEIVED
OCT 14

EDISON ELECTRIC INSTITUTE

INVOICE FOR MEMBERSHIP DUES

701 PENNSYLVANIA AVENUE, NW
WASHINGTON, DC 20004-2696
PHONE (202) 508-5000

Date	Invoice Number
11/12/2009	DUES201069

MR. PAUL J. BONAVIA
CHAIRMAN, PRESIDENT AND CEO
UNISOURCE ENERGY CORP
1 S CHURCH AVE SUITE 1820
TUCSON, AZ 85701-0000

Payment Due on or before 2/1/2010
(Interest charges will accrue after due date)

11365-4

Description	Total
2010 EEI Membership Dues for:	
Regular Activities of Edison Electric Institute[1]	$322,008
Industry Issues[2]	32,201
Mutual Assistance Program[3]	1,000
2010 Contribution to The Thomas Alva Edison Foundation (Edison Foundation), including the Institute for Electric Efficiency The Edison Foundation is an IRC 501(c)(3) educational and charitable organization. The Institute for Electric Efficiency (IEE) is a program of the Edison Foundation. **Contributions are tax deductible in the same manner as contributions to any 501(c)(3) organization.**	15,000
	$322,008
Total	~~$370,209~~

1- The portion of membership dues allocable during 2010 relating to influencing legislation not deductible for federal income tax purposes is estimated to be 16%.
2- The portion of the voluntary industry issues allocable during 2010 relating to influencing legislation is estimated to be 35%.
3- Voluntary assessment approved by EEI Executive Committee relating to improvements for the rapid response to disasters. No portion of this assessment is allocable to influencing legislation.

$312,008 TEP MB
$10,000 UNSE MB

PLEASE NOTE INFORMATION FOR WIRING. 1-5-10

The following is instruction for transferring funds electronically to Edison Electric Institute's account at the Wachovia Bank N.A. in Washington, DC:

Beneficiary's Bank:	**Wachovia Bank, N.A.**
Bank's Address:	**Washington, DC**
Bank's ABA Number:	**054001220**
Beneficiary:	**Edison Electric Institute**
Beneficiary's Acct No:	**2000013842897**
Beneficiary's Address:	**701 Pennsylvania Avenue, NW Washington, DC 20004-2696 USA**
Beneficiary Reference:	**2010 Membership Dues**

Please refer any questions to Coleen McDonald at: phone-(202) 508-5101; fax-(202) 508-5037; *or* e-mail- Cmcdonald@eei.org.

EEI

RECEIVED
DEC 1 1 2009
BY:

Edison Electric Institute
701 Pennsylvania Avenue, N.W.
Washington, DC 20004-2696
USA

Customer #: 000407476O

Mr. Jeff Yockey
Tucson Electric Power Co
PO Box 711
Tucson, AZ 85702-0711

Invoice

Invoice # : 63928
Invoice Date: 12/09/2009

Description	Quantity	Price	Discount	Amount
2010 UARG Membership Dues	1	$134,258.00	$0.00	$134,258.00

Pay quarterly
$ 33,564.50

1st Qtr Dues

APPROVED FOR PAYMENT
By _____ Date 12/30/09

Release #12067-15
1/13/10
Line 1 = Proj #C00001/Task #A101805/CC805/$30,208.05
Line 2 = Proj #4NSE200/Task #ETP0930/CC805/$3,356.45

This invoice is for your participation in the Utility Air Regulatory Group (UARG) for the current calendar year. If you have questions about the program, or questions about this invoice or to make payment arrangements, contact Carol Ray, in EEI's Internal Accounting Department, on 202-508-5428.

Invoice Total	$134,258.00
Taxes	$0.00
Amount Paid	$0.00
PLEASE PAY	**$134,258.00**

PLEASE DETACH AND REMIT WITH YOUR PAYMENT

Invoice #: 63928

Customer #: 000407476O

Mr. Jeff Yockey
Tucson Electric Power Co
PO Box 711
Tucson, AZ 85702-0711

Select Payment Method

☐ Check Enclosed
Card Provider _____ Exp Date ___/___
Card # _____
Card Holder's Name _____
Card Holder's Signature _____

Remit Payment To:

Edison Electric Institute
701 Pennsylvania Avenue, N.W., Washington, DC 20004-2696, USA

Total Due: $134,258.00
Amt Remitted : _____

EEI

Edison Electric Institute
701 Pennsylvania Avenue, N.W.
Washington, DC 20004-2696
USA

Customer #: 0004075200

UniSource Energy Corp
PO Box 711
Tucson, AZ 85702-0711

Invoice

Invoice # : 63435
Invoice Date: 11/16/2009

Description	Quantity	Price	Discount	Amount
Standards of Conduct Training Program	1	$12,000.00	$0.00	$12,000.00

PAST DUE

PAYMENT CAN BE
MADE WITH
VISA, MASTERCARD OR
AMERICAN EXPRESS

Wiring Instructions For Electronic Funds Transfer ALL FUNDS TO BE PAID IN U.S. DOLLARS. YOU ARE RESPONSIBLE FOR ANY WIRING FEES, adjust your amount accordingly. Beneficiary's Bank: Wachovia Bank, N.A., Washington DC–USA Bank's ABA Number: 054001220 Beneficiary: Edison Electric Institute Account Number: 2000013842897 Reference: Please reference invoice number & purpose of payment.

Invoice Total	$12,000.00
Taxes	$0.00
Amount Paid	$0.00
PLEASE PAY	**$12,000.00**

PLEASE DETACH AND REMIT WITH YOUR PAYMENT

Invoice #: 63435

Customer #: 0004075200

UniSource Energy Corp
PO Box 711
Tucson, AZ 85702-0711

Select Payment Method

☐ Check Enclosed
Card Provider _____ Exp Date___/___
Card #_____
Card Holder's Name_____
Card Holder's Signature_____

Remit Payment To:

Edison Electric Institute
701 Pennsylvania Avenue, N.W., Washington, DC 20004-2696, USA

Total Due: **$12,000.00**
Amt Remitted : _____

M I R E

ACCOUNTS PAYABLE
JAN 26 2010

INVOICE

EDISON ELECTRIC INSTITUTE
MEETING REGISTRATION OFFICE
701 PENNSYLVANIA AVENUE, NW
WASHINGTON, DC 20004
ACCOUNTS RECEIVABLE: (202) 508-5428

INVOICE NO: 1-02010017GNAW
DATE: MARCH 11, 2010

RECEIVED
MAR 18 2010
BY:_____

TO: Tucson Electric Power Co
3950 E Irvington Rd
MS-DS503
Tucson, AZ 85714-0000
Charles W. Komadina

SALESPERSON	P.O. NUMBER	DATE SHIPPED	SHIPPED VIA	F.O.B. POINT	TERMS
G. NOVAK		03/11/10			NET 30

QUANTITY	DESCRIPTION	UNIT PRICE	AMOUNT
	2010 USWAG MEMBERSHIP DUES		
	2010 PER SHARE ASSESSMENT = $30,900		
	UniSource Energy Corp Share - 1.00 = $30,900		30,900.00
	PLEASE SEND A COPY OF THIS INVOICE WITH YOUR PAYMENT.		
	APPROVED FOR PAYMENT By CWK Date 3-19-2010		
	Release #12067-16		
	3/19/10	Remit this amount	$30,900.00

Line 1 = Proj # C00001/Task #101805/CC805/$ 27,810.00
Line 2 = Proj # UNSE200/Task # ETP0930/CC805/$ 9,030.00

INVOICE

EDISON ELECTRIC INSTITUTE
MEETING REGISTRATION OFFICE
701 PENNSYLVANIA AVENUE, NW
WASHINGTON, DC 20004
ACCOUNTS RECEIVABLE: (202)508-5428

INVOICE NO: 63928B
DATE: APRIL 1, 2010

RECEIVED
APR – 5 2010
BY:

TO: TUCSON ELECTRIC POWER CO.
PO BOX 711
MS-OH127
TUCSON , AZ 85702-0711
MR. JEFFREY G.YOCKEY, P.E.

SALESPERSON	P.O. NUMBER	DATE SHIPPED	SHIPPED VIA	F.O.B. POINT	TERMS
C. RAY		04/01/10			NET 30

QUANTITY	DESCRIPTION	UNIT PRICE	AMOUNT
	2010 UARG MEMBER DUES – 2ND QUARTER		33,564.50
	CONTACT: JEFFREY G. YOCKEY, P.E.		
	PH: (520) 918-8306 FAX: (520) 918-8250		
	EMAIL: JYOCKEY@TEP.COM		
	APPROVED FOR PAYMENT By _____ Date 4/5/10		
	PLEASE REFERENCE INVOICE NUMBER ON THE CHECK. THANK YOU.		
	Release #12067-17 4/5/10 Line 1 = Proj # C00001/Task #A101805/CC805/$30,208.05 Line 2 = Proj # UNS220/Task # ETP0930/CC805/$3,356.45		
		Remit this amount	$33,564.50

INVOICE

EDISON ELECTRIC INSTITUTE
MEETING REGISTRATION OFFICE
701 PENNSYLVANIA AVENUE, NW
WASHINGTON, DC 20004
ACCOUNTS RECEIVABLE: (202)508-5428

INVOICE NO: 63928C
DATE: JULY 7, 2010

RECEIVED
JUL 12 2010
BY:_____

TO: TUCSON ELECTRIC POWER CO.
PO BOX 711
MS-OH127
TUCSON , AZ 85702-0711
MR. JEFFREY G. YOCKEY, P.E.

SALESPERSON	P.O. NUMBER	DATE SHIPPED	SHIPPED VIA	F.O.B. POINT	TERMS
C. RAY	12067	07/07/10			NET 30

QUANTITY	DESCRIPTION	UNIT PRICE	AMOUNT
	2010 UARG MEMBER DUES – 3RD QUARTER		33,564.50
	CONTACT: JEFFREY G. YOCKEY, P.E.		
	PH: (520) 918-8306 FAX: (520) 918-8250		
	EMAIL: JYOCKEY@TEP.COM		
	PLEASE REFERENCE INVOICE NUMBER ON THE CHECK. THANK YOU.		
	Release #12067-18 8/16/10 Line 1 = Proj: C00001/Task #A101805/$ 30,208.05 Line 2 = Proj: UNSE200/Task #ETP0930/$ 3,356.45		
		Remit this amount	$33,564.50

APPROVED FOR PAYMENT
By _____ Date 8/16/10

RECEIVED AP 08/17/10- INTEROFFICE

INVOICE

EDISON ELECTRIC INSTITUTE
MEETING REGISTRATION OFFICE
701 PENNSYLVANIA AVENUE, NW
WASHINGTON, DC 20004
ACCOUNTS RECEIVABLE: (202)508-5428

INVOICE NO: 63928D
DATE: OCTOBER 20, 2010

ACCOUNTS PAYABLE
OCT 25 2010

TO: TUCSON ELECTRIC POWER CO.
PO BOX 711
MS-OH127
TUCSON , AZ 85702-0711
MR. JEFFREY G. YOCKEY, P.E.

SALESPERSON	P.O. NUMBER	DATE SHIPPED	SHIPPED VIA	F.O.B. POINT	TERMS
C. RAY		10/20/10			NET 30

QUANTITY	DESCRIPTION	UNIT PRICE	AMOUNT
	2010 UARG MEMBER DUES – 4TH QUARTER		33,564.50
	CONTACT: JEFFREY G. YOCKEY, P.E.		
	PH: (520) 918-8306 FAX: (520) 918-8250		
	EMAIL: JYOCKEY@TEP.COM		
	PLEASE REFERENCE INVOICE NUMBER ON THE CHECK. THANK YOU.		
		Remit this amount	$33,564.50

EEI

RECEIVED
DEC 10 2010
BY:_____

Edison Electric Institute
701 Pennsylvania Avenue, N.W.
Washington, DC 20004-2696
USA

Customer #: 0004074760

Mr. Jeff Yockey
Tucson Electric Power Co
PO Box 711
Tucson, AZ 85702-0711

Invoice

Invoice # : 76250
Invoice Date: 12/07/2010
FEIN: 13-0659550

P.O. # 12067

Description	Quantity	Price	Discount	Amount
UARG Membership Dues	1	$138,470.00	$0.00	$138,470.00

1st Qtr 2011

Pay Quarterly
$34,617.50

APPROVED FOR PAYMENT
By _____ Date 12/15/10 Release # 12067-20 12/15/10

90% TED
10% LOUE

This invoice is for your participation in the Utility Air Regulatory Group (UARG) for the calendar year 2011. If you have questions about the program, or questions about this invoice or to make payment arrangements, contact Carol Ray, in EEI's Internal Accounting Department, on 202-508-5428.

Invoice Total	$138,470.00
Taxes	$0.00
Amount Paid	$0.00
PLEASE PAY	**$138,470.00**

PLEASE DETACH AND REMIT WITH YOUR PAYMENT

Invoice #: 76250

Customer #: 0004074760

Mr. Jeff Yockey
Tucson Electric Power Co
PO Box 711
Tucson, AZ 85702-0711

Select Payment Method

☐ Check Enclosed
Card Provider _____ Exp Date___/___
Card #_____
Card Holder's Name_____
Card Holder's Signature_____

Remit Payment To:

Edison Electric Institute
701 Pennsylvania Avenue, N.W., Washington, DC 20004-2696, USA

Total Due: **$138,470.00**
Amt Remitted : _____

RECEIVED AP 12/16/10- INTEROFFICE

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S ELEVENTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291 October 15, 2012

STF 11.01

Industry association dues. Refer to the responses to UDR 1.55, UDR 1.64, STF 5.07 and STF 5.18, and to TEP(0291)007231 through 007241.

a. Provide a breakout of the EEI core dues and/or EEI core activities budgets and/or financial results into the following NARUC operating expense categories for each year, 2005 through 2011:

1. Legislative Advocacy
2. Legislative Policy Research
3. Regulatory Advocacy
4. Regulatory Policy Research
5. Advertising
6. Marketing
7. Utility Operations and Engineering
8. Finance, Legal, Planning and Customer Service
9. Public Relations
10. Other (explain any items in other)

b. Referring to TEP(0291)007236 please confirm that the EEI Regular Activities dues of $342,085 and the Contribution to the Thomas Alva Edison Foundation (an IRC 501(c)(3) charitable organization) of $15,000 are what comprised the $357,085 that was allocated between TEP ($347,085) and UNSE ($10,000). If this is not accurate, please explain.

c. Please show in detail how the $15,000 was allocated between TEP and UNSE.

d. Please show in detail how the $342,085 EEI regular dues amount was allocated between TEP and UNSE.

e. Please explain the handwritten note on TEP(0291)007236 "all record as general advertising."

f. Provide a breakout of the Utility Solid Waste Activities Group (USWAG) budgets and financial results for each year 2005 through 2011 into the following NARUC categories:

1. Legislative Advocacy
2. Legislative Policy Research
3. Regulatory Advocacy
4. Regulatory Policy Research
5. Advertising
6. Marketing
7. Utility Operations and Engineering
8. Finance, Legal, Planning and Customer Service

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9. Public Relations

10. Other (explain any items in other)

g. Provide a breakout of the Utility Air Regulatory Group (UARG) budgets and financial results for each year 2005 through 2011 into the following NARUC categories:

1. Legislative Advocacy

2. Legislative Policy Research

3. Regulatory Advocacy

4. Regulatory Policy Research

5. Advertising

6. Marketing

7. Utility Operations and Engineering

8. Finance, Legal, Planning and Customer Service

9. Public Relations

10. Other (explain any items in other)

h. Provide the EEI, USWAG and UARG financial statements for each year, 2005 through 2011.

i. Provide the EEI, USWAG and UARG budgets for each year, 2005 through 2011.

RESPONSE:

a. TEP is only a member of EEI. The Company does not retain the information requested through its normal course of business and/or does not have immediate access to, or authority from EEI, to provide the information requested. Please see TEP's response to UDR 1.55 TEP (0291)003284 for the EEI percentage devoted to legislative advocacy.

b. TEP confirms that EEI Regular Activities dues of $342,085 and the Contribution to the Thomas Alva Edison Foundation (an IRC 501(c)(3) charitable organization) of $15,000 are what comprised the $357,085 that was allocated between TEP ($347,085) and UNSE ($10,000).

c. The $15,000 was allocated entirely to TEP.

d. UNS Electric has received some benefit from TEP's regular membership to EEI, therefore it was determined that $10,000 was a reasonable portion of the EEI regular activities dues to be allocated to UNS Electric.

e. The handwritten notation on TEP(0291)007236 "general advertising" refers to the General Ledger account description for FERC 930. The expense is further broken down into subcategories 930.1, General Advertising Expense, and 930.2, Miscellaneous General Expense for rate case purposes. The EEI membership dues totaling $347,085 are in FERC 930.2 Miscellaneous General Expense.

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f. TEP is only a member of USWAG. The Company does not retain the information requested through its normal course of business and/or does not have immediate access to or authority from USWAG to provide the information requested. Please see TEP's response to UDR 1.55 TEP(0291)003284 for USWAG's percentage devoted to legislative advocacy.

g. TEP is only a member of UARG. The Company does not retain the information requested through its normal course of business and/or does not have immediate access to or authority from UARG to provide the information requested. However, to the best of TEP's knowledge, UARG did not engage in any legislative advocacy activities during the test year.

h. Please see responses to STF 11.01(a), (f), and (g).

i. Please see responses to STF 11.01(a), (f), and (g).

RESPONDENT:

Pricing (Anne Liu), Jeffrey Yockey, Chuck Komadina and Erik Bakken

WITNESS:

Dallas Dukes

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STF 26.10

Day Nite Design Charges. Refer to the response to STF 22.09 and 22.05. Has TEP included any expenses or costs in any account in the test year for any Day Nite Design charges for any cost category or component other than rate case expense?

a. If not, explain fully why not.

b. If so, provide a detailed listing of all costs and expenses included in the test year by TEP for Day Nite Design charges, by account.

c. Provide the information on Day Nite Design charges requested in STF 22.09 and 22.05 for all Day Nite Design costs that TEP is requesting (in some category or account other than as rate case expense).

d. Identify and provide a copy of each advertisement, branding item, logo, and each item for which TEP has included charges for Day Nite Design.

RESPONSE:

a. Yes.

b. Please see below for the Day Nite Design costs included in the 2011 test year by account. These are general advertising expenses and not rate case expenses.

Ferc Account	Account$$Desc$$Uns Gl Ferc	Pa Task Desc	Total
0593	Dist-Maint of OH Lines	Environmental - Raptors – Corporate	450.00
0908	Customer Assistance Exp	Safety Communication - Schools	112.50
0909	Informational/Instrct Adv Exp	TEP Safety Media	3,337.50
0930	General Advertising Exp	CBU Corporate Advertising	75.00
		TEP Branding/Marketing	14,681.25
		Training & Develop Expenses	1,125.00
		WEB - Internet Page	8,586.50
Grand Total			28,367.75

c. STF 22.09 refers to Bates Nos. CONFIDENTIAL TEP (0291) 020293 through 020298, which are Day Nite Design invoices for 2012. These invoices were initially charged to the rate case project number and provided in response to STF 5.34, but, as noted in response to STF 22.05, TEP did not include these 2012 invoices in rate case expense.

TEP does not intend to recover the costs associated with these invoices as rate case expense and these invoices are not included in the 2011 test year in any category or account.

d. Please see the files listed below for the requested information.

File Name	Bates Numbers
STF 26.10(d) 2011 20 Years CAT logo.eps	N/A
STF 26.10(d) 2011 20-Years-CAT-logo.jpg	N/A
STF 26.10(d) 2011 Accenture Working Today ad.pdf	TEP\029923
STF 26.10(d) 2011 Account Manager Marketing D.jpg	N/A
STF 26.10(d) 2011 Benefits by Design logo v2.pdf	TEP\029924
STF 26.10(d) 2011 Benefits logo v2.pdf	TEP\029925

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STF 26.10(d) 2011 bill back v7.pdf	TEP\029926
STF 26.10(d) 2011 bill back v9.pdf	TEP\029927
STF 26.10(d) 2011 BizTuc v1.pdf	TEP\029928
STF 26.10(d) 2011 Book of Lists.pdf	TEP\029929
STF 26.10(d) 2011 BoysGirlsC v1.pdf	TEP\029930
STF 26.10(d) 2011 BrightSolns v1.pdf	TEP\029931
STF 26.10(d) 2011 BrightSolutionswithSaguaro.pdf	TEP\029932
STF 26.10(d) 2011 BS ad Padres v1.pdf	TEP\029933
STF 26.10(d) 2011 BS CASA ad v1.pdf	TEP\029934
STF 26.10(d) 2011 BS logo ideas v1.pdf	TEP\029935
STF 26.10(d) 2011 BSolns Solar Banner.pdf	TEP\029936
STF 26.10(d) 2011 BSolnsTucsonCommSolarWEB tile.pdf	TEP\029937
STF 26.10(d) 2011 BSolnsTucsonComSolarbrochure.pdf	TEP\029938-029939
STF 26.10(d) 2011 BTCS FB graphic v1 (2).pdf	TEP\029940
STF 26.10(d) 2011 BTCS transit sign.pdf	TEP\029941
STF 26.10(d) 2011 CAT Logo with TEP.png	N/A
STF 26.10(d) 2011 CAT logo.eps	N/A
STF 26.10(d) 2011 CAT logo.png	N/A
STF 26.10(d) 2011 CAT t-shirt v9 (1).pdf	TEP\029942
STF 26.10(d) 2011 CAT t-shirt v9 (2).pdf	TEP\029943
STF 26.10(d) 2011 CAT t-shirt v9 (3).pdf	TEP\029944
STF 26.10(d) 2011 CAT t-shirt v9 (4).pdf	TEP\029945
STF 26.10(d) 2011 CAT t-shirt v9 (5).pdf	TEP\029946
STF 26.10(d) 2011 CAT t-shirt v9 (6).pdf	TEP\029947
STF 26.10(d) 2011 CAT t-shirt v9 (7).pdf	TEP\029948
STF 26.10(d) 2011 CAT t-shirt v9 (8).pdf	TEP\029949
STF 26.10(d) 2011 CAT t-shirt v9 (9).pdf	TEP\029950
STF 26.10(d) 2011 CAT t-shirt v9 (10).pdf	TEP\029951
STF 26.10(d) 2011 CAT t-shirt v9 (11).pdf	TEP\029952
STF 26.10(d) 2011 CAT t-shirt v9 (12).pdf	TEP\029953
STF 26.10(d) 2011 CAT t-shirt v9 (13).pdf	TEP\029954
STF 26.10(d) 2011 CAT t-shirt v9.pdf	TEP\029955
STF 26.10(d) 2011 CAT-logo.jpg	N/A
STF 26.10(d) 2011 CustAssist Brochure.pdf	TEP\029956
STF 26.10(d) 2011 EdubrochureEnergyPatrolManual.pdf	TEP\029958-029968
STF 26.10(d) 2011 Education Sheets.pdf	TEP\029969-029975
STF 26.10(d) 2011 EEC logo alterations poof41111.pdf	TEP\029976
STF 26.10(d) 2011 EEC PPT template.pdf	TEP\029977-029979
STF 26.10(d) 2011 EEC Spring header v1.pdf	TEP\029980-029985

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STF 26.10(d) 2011 Energy Usage FINAL.PDF	TEP\029986
STF 26.10(d) 2011 Energy Usage insert v1.pdf	TEP\029987-029990
STF 26.10(d) 2011 Energy Wasteline fliers v5.pdf	TEP\029991-029992
STF 26.10(d) 2011 ExecFemale image.jpg	N/A
STF 26.10(d) 2011 FB icon v2.jpg	N/A
STF 26.10(d) 2011 Go Solar ad.pdf	TEP\029993
STF 26.10(d) 2011 GovernmentResourceDirectad.pdf	TEP\029994
STF 26.10(d) 2011 Green vehicle decal1.pdf	TEP\029995
STF 26.10(d) 2011 Green vehicle decal2.pdf	TEP\029996
STF 26.10(d) 2011 hand sketching lightbulb.jpg	N/A
STF 26.10(d) 2011 Happy Holidays web v2.pdf	TEP\029997-029998
STF 26.10(d) 2011 HEERO ad PCOA newsletter.pdf	TEP\029999
STF 26.10(d) 2011 Home Program logo v7.pdf	TEP\030000
STF 26.10(d) 2011 Home Program logo v8.pdf	TEP\030001
STF 26.10(d) 2011 image 6 kids in row.jpg	N/A
STF 26.10(d) 2011 Man of theYear Ad.pdf	TEP\030002
STF 26.10(d) 2011 NissanLeafFlier.pdf	TEP\030003-030004
STF 26.10(d) 2011 PCOA newsletter.pdf	TEP\030005
STF 26.10(d) 2011 PCOA.pdf	TEP\030006
STF 26.10(d) 2011 Phenominal Woman v1.pdf	TEP\030007
STF 26.10(d) 2011 Raptor-Bufflegrs Bill Insert_Jan.pdf	TEP\030008-030009
STF 26.10(d) 2011 Raptor-Tortoise Bill Insert_Oct.pdf	TEP\030010-030011
STF 26.10(d) 2011 Safety TruckWrap.jpg	N/A
STF 26.10(d) 2011 Sedona.jpg	N/A
STF 26.10(d) 2011 SIIS t-shirt v1.pdf	TEP\030012-030018
STF 26.10(d) 2011 Smart Grid graphics.pdf	TEP\030019-030021
STF 26.10(d) 2011 Smart Gride PPT template.pdf	TEP\030022-030024
STF 26.10(d) 2011 SNAP Brochure.pdf	TEP\030025-030027
STF 26.10(d) 2011 Snowman background.jpg	N/A
STF 26.10(d) 2011 SpringSafetyBillInsertMar.pdf	TEP\030028-030029
STF 26.10(d) 2011 State of City v1.pdf	TEP\030030
STF 26.10(d) 2011 Stock Images (14).jpg	N/A
STF 26.10(d) 2011 Stock Images (15).jpg	N/A
STF 26.10(d) 2011 Stock Images (16).jpg	N/A
STF 26.10(d) 2011 Stock Images (17).jpg	N/A
STF 26.10(d) 2011 Stock Images (18).jpg	N/A
STF 26.10(d) 2011 Stock Images (19).jpg	N/A
STF 26.10(d) 2011 Stock Images (20).jpg	N/A
STF 26.10(d) 2011 Stock Images (21).jpg	N/A

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STF 26.10(d) 2011 Stock Images (22).jpg	N/A
STF 26.10(d) 2011 Stock Images (23).jpg	N/A
STF 26.10(d) 2011 Stock Images (24).jpg	N/A
STF 26.10(d) 2011 Stock Images (25).jpg	N/A
STF 26.10(d) 2011 Stock Images (26).jpg	N/A
STF 26.10(d) 2011 Stock Images (27).jpg	N/A
STF 26.10(d) 2011 Stock Images (28).jpg	N/A
STF 26.10(d) 2011 Stock Images (29).jpg	N/A
STF 26.10(d) 2011 SumSafety Bill Insert_Jun.pdf	TEP\030031-030032
STF 26.10(d) 2011 SumSafety Box WEB Ad.pdf	TEP\030033
STF 26.10(d) 2011 SumSafety Leaderboard Ad.pdf	TEP\030034
STF 26.10(d) 2011 SumSafetyeventSunscreenPacketProofA.pdf	TEP\030035
STF 26.10(d) 2011 SumSafetyTransit_Spanish.pdf	TEP\030036
STF 26.10(d) 2011 SumSafetyTransitSign.pdf	TEP\030037
STF 26.10(d) 2011 Sunscreen Packet_Proof_B.pdf	TEP\030038
STF 26.10(d) 2011 Survey web billboard v5.jpg	N/A
STF 26.10(d) 2011 Survey web billboard v6.jpg	N/A
STF 26.10(d) 2011 Survey web billboard v7.jpg	N/A
STF 26.10(d) 2011 TEP 10x10 Tent v2.pdf	TEP\030039
STF 26.10(d) 2011 TEP Area Map sheet v1.pdf	TEP\030040-030041
STF 26.10(d) 2011 TEP BS ad BWTF v1.pdf	TEP\030042
STF 26.10(d) 2011 TEP BSH letterhead.pdf	TEP\030043
STF 26.10(d) 2011 TEP Business Cards v5.pdf	TEP\030044
STF 26.10(d) 2011 TEP CAT form.pdf	TEP\030047
STF 26.10(d) 2011 TEP CustomerAssistformv3.pdf	TEP\030048-030049
STF 26.10(d) 2011 TEP Employee ideas logo v2.pdf	TEP\030050
STF 26.10(d) 2011 TEP IT bag art.pdf	TEP\030051
STF 26.10(d) 2011 TEP IT shirt.pdf	TEP\030052
STF 26.10(d) 2011 TEP Lanyard v1.pdf	TEP\030053
STF 26.10(d) 2011 TEP Leaf driving log.pdf	TEP\030054-030055
STF 26.10(d) 2011 TEP logo v1.pdf	TEP\030056
STF 26.10(d) 2011 TEP logo v2.pdf	TEP\030057
STF 26.10(d) 2011 TEP logo v3.pdf	TEP\030058
STF 26.10(d) 2011 TEP logo v4.pdf	TEP\030059
STF 26.10(d) 2011 TEP logo v5.pdf	TEP\030060
STF 26.10(d) 2011 TEP logo v6.pdf	TEP\030061
STF 26.10(d) 2011 TEP logo v7.pdf	TEP\030062
STF 26.10(d) 2011 TEP logo v10.pdf	TEP\030063
STF 26.10(d) 2011 TEP logo v11.pdf	TEP\030064

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STF 26.10(d) 2011 TEP logo v12a.pdf	TEP\030065
STF 26.10(d) 2011 TEP logo v12b.pdf	TEP\030066
STF 26.10(d) 2011 TEP logo v12c.pdf	TEP\030067
STF 26.10(d) 2011 TEP logo v12d.pdf	TEP\030068
STF 26.10(d) 2011 TEP logo v13a.pdf	TEP\030069
STF 26.10(d) 2011 TEP logo v13b.pdf	TEP\030070
STF 26.10(d) 2011 TEP logo v13c.pdf	TEP\030071
STF 26.10(d) 2011 TEP logo v13d.pdf	TEP\030072
STF 26.10(d) 2011 TEP New Const form v1.pdf	TEP\030073
STF 26.10(d) 2011 TEP New Website tile.pdf	TEP\030074
STF 26.10(d) 2011 TEP Power Partners.jpg	N/A
STF 26.10(d) 2011 TEP PPT slide v4.jpg	N/A
STF 26.10(d) 2011 TEP PPT slide.jpg	N/A
STF 26.10(d) 2011 TEP web icons v1.pdf	TEP\030075
STF 26.10(d) 2011 TEPBS ad BWTF v1.pdf	TEP\030076
STF 26.10(d) 2011 TEP-CAT-logo.jpg	N/A
STF 26.10(d) 2011 TEPGree Pro.brochure.pdf	TEP\030077-030078
STF 26.10(d) 2011 TEPLeadershipAcadv11.pdf	TEP\030079-030098
STF 26.10(d) 2011 Thermostat.jpg	N/A
STF 26.10(d) 2011 Tree ad v1 (2).pdf	TEP\030099
STF 26.10(d) 2011 TucBrightCommvidbanner2.jpg	N/A
STF 26.10(d) 2011 TucBrightComvidbanner.jpg	N/A
STF 26.10(d) 2011 TV title page.jpg	N/A
STF 26.10(d) 2011 Twitter bkgrds2.jpg	N/A
STF 26.10(d) 2011 Twitter bkgrds3.jpg	N/A
STF 26.10(d) 2011 Twitterbackground.jpg	N/A
STF 26.10(d) 2011 UA Science v2.pdf	TEP\030100
STF 26.10(d) 2011 UES CAT logo.eps	N/A
STF 26.10(d) 2011 UES ElecComConst v1.pdf	TEP\030101-030103
STF 26.10(d) 2011 UES ElecResConst v1.pdf	TEP\030104-030106
STF 26.10(d) 2011 UES New Website tile.pdf	TEP\030107
STF 26.10(d) 2011 UES-CAT-logo-.jpg	N/A
STF 26.10(d) 2011 United Way_Ad_Flyer.pdf	TEP\030108
STF 26.10(d) 2011 UNS Power Cat 2007 b&w.jpg	N/A
STF 26.10(d) 2011 UNS Power Cat 2007 copy.jpg	N/A
STF 26.10(d) 2011 UNS Volunteer flier v3.pdf	TEP\030109
STF 26.10(d) 2011 UW web banner v3.jpg	N/A
STF 26.10(d) 2011 web site poster v1.pdf	TEP\030110-030114
STF 26.10(d) 2011 Working Today ad.pdf	TEP\030115

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STF 26.10(d) DayNite Advr_STF 26.10.xls	N/A

RESPONDENT:

Pricing (Anne Liu) (a-c), Kim Mayhew (d)

WITNESS:

Dallas Dukes

Tucson Electric Power Company
Docket No. E-01933A-12-0291
Attachment RCS-4
Copies of Confidential TEP's Responses to Data Requests and Workpapers Referenced in the Direct Testimony and Schedules of Ralph C. Smith

****TEP Confidential Pages Have Been Redacted****

Data Request/ Workpaper No.	Subject	Confidential	No. of Pages	Page No.
STF 16.08	Square footage and current occupancy of new UniSource Energy headquarters building; plans to lease or sub-lease portions of the new building to affiliates or non-affiliates; cost per square foot for office, retail, and parking areas of new building; UniSource is not currently leasing or sub-leasing any portion of the new headquarters building	Yes	4	2 - 5
STF 26.06	Square footage on each floor designated for ancillary space, cubicles, offices, and conference rooms; Amount of all vacant cubicles and offices, by floor and square footage (without floorplate diagrams)	Yes	7	6 - 12
UDR 1.35 Supplemental	Description of Company's incentive and retirement programs; 2011 and 2012 PEP goals and targets	Yes	7	13 - 19
STF 5.34 September 26, 2012 Supplemental	Copies of outside consultant contracts/agreements and invoices pertaining to the rate case expense related to the current proceeding (without confidential and voluminous attachments)	Yes	2	20 - 21
STF 5.42	Actual property tax assessments and rates for the 2011 property tax year; total Arizona property tax expense for TEP and its affiliates for years 2007-2011; amount of property tax expense being recorded by TEP for 2012 through May	Yes	5	22 - 26
STF 16.10 November 19, 2012 Supplemental	Comparison, for each year 2008-2012, for TEP, UNSE, UNSG, and all 3 utilities combined, of "standalone" versus actual property taxes	Yes	5	27 - 31
UDR 1.66	Annual level of property tax expense and the year end plant-in-service for 2009 through March 2012	Yes	9	32 - 40
UDR 1.68	Summary of property tax activity for years 2008-2011; TEP states that there are no property taxes in dispute nor being disputed at December 31, 2011; There are no property tax refunds or abatements for any year 2008-2011	Yes	3	41 - 43
STF 28.1	Actual versus "stand-alone" Property Tax calculations for TEP, UNSE, UNSG, Springerville Unit 1 Plant-in-Service, and Springerville Units 3 and 4 for 2013 based on Plant-in-Service at 12/31/2011	Yes	6	44 - 49
	Total Pages Including this Page		49	

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S SIXTEENTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291 October 29, 2012

STF 16.08

UniSource headquarters.

a. Provide a diagram showing the square footage and current occupancy of the UniSource headquarters building.

b. Identify and provide a copy of plans to lease or sub-lease portions of the headquarters building to affiliates.

c. Identify and provide a copy of plans to lease or sub-lease portions of the headquarters building to non-affiliates, including areas planned for retail space.

d. Identify the number of employees occupying the headquarters building as of each date (a) 12/31/2011 and (b) currently, and identify the affiliation of the employees (e.g., UniSource Energy, Inc., TEP, UNSE, UNSG, UED, SES, other-explain).

e. Identify the cost per square foot for the various areas in the headquarters building.

f. Are any portions of the headquarters building currently being leased or sub-leased to others? If so, identify and describe the leases and sub-leases and provide the monthly rent revenues from each lease and sub-lease.

1. Provide the monthly headquarters lease revenues for the period 2011 and 2012.

RESPONSE:

THE FILE LISTED BELOW CONTAINS CONFIDENTIAL INFORMATION AND IS BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT DATED JULY 6, 2012.

a. Please see STF 16.08 TEP HQ Stacking Plan 2012 10-24-Confidential.pdf, Bates No. TEP\027311-027312, for a diagram showing the gross square footage ("gsf") and current occupancy of the new TEP headquarters office building. All 12,000 gsf of retail space is currently unoccupied.

b. There are no plans to lease or sub-lease portions of the headquarters building to affiliates.

c. The only area of the building with a plan to lease is the retail space. We are currently working with a commercial real estate broker to identify potential tenants. There are currently no leases in place for the retail portion of the headquarters building.

d. Individuals occupying the headquarters building (all working under supervision of TEP, doing work on behalf of TEP):

12/31/2011:		Current:	
TEP	413	TEP	451
SES	15	SES	8
other-contractor	56	other-contractor	80
	484		539

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e. The actual cost per square foot for the various areas in the headquarters building is:

Office	$263/sf
Retail	$178/sf
Parking	$64/sf

f. None of the headquarters building is currently being leased or sub-leased to others.

RESPONDENT:

Scott Rathbun

WITNESS:

Michael DeConcini

STF 16.08 TEP HQ Stacking Plan 2012 10-24-Confidential.pdf

THE FOLLOWING DOCUMENT CONTAINS "CONFIDENTIAL INFORMATION" THAT IS BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT IN DOCKET NO. E-01933A-12-0291 AND MAY NOT BE SHARED WITH ANYONE WHO HAS NOT SIGNED THE PROTECTIVE AGREEMENT DATED JULY 6, 2012.

PAGE 5 IS CONFIDENTIAL AND HAS BEEN REDACTED

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STF 26.06

Refer to the response to STF 22.06(p) and (t).

1. Identify the square footage on each floor that is for common areas, mechanical space, copy rooms, file rooms, break rooms, elevators, elevator lobbies, dedicated computer room space; auditorium; outside auditor area; lobby; and service areas. Provide diagrams of same.

2. Identify the square footage on each floor that is for cubicles, offices and conference rooms. Provide diagrams of same.

3. Identify the square footage on each floor that is not occupied by the items identified in response to parts f1 and f2.

4. Referring to the response to STF 22.06(t), identify the "vacant cubicles and offices within the building" by floor and square footage.

RESPONSE:

THE FILES LISTED BELOW CONTAIN CONFIDENTIAL INFORMATION AND ARE BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT DATED JULY 6, 2012.

The files listed below are provided in response to this request.

File Name	Bates Numbers
STF 26.06 Ancillary Space 2010 11-29-Confidential.pdf	TEP\029601-029602
STF 26.06 Floorplates 2012 11-29-Confidential.pdf	TEP\029603-029611
STF 26.06 Office-Cubicle SFs 2012 11-29-Confidential.pdf	TEP\029612-029613
STF 26.06 Vacant Space 2012 11-29-Confidential.pdf	TEP\029614-029615

1. Please see STF 26.06 Ancillary Space 2010 11-29-Confidential.pdf for a list of all ancillary space throughout the building identifying the square footage on each floor. Please see STF 26.06 Floorplates 2012 11-29-Confidential.pdf for the requested diagrams.
2. Please see STF 26.06 Office-Cubicle SFs 2012 11-29-Confidential.pdf for a list of the cubicle, office, conference room, and circulation space throughout the building identifying the square footage on each floor. Please see STF 26.06 Floorplates 2012 11-29-Confidential.pdf for the requested diagrams.
3. Please see STF 26.06(1).
4. Please see STF 26.06 Vacant Space 2012 11-29-Confidential.pdf for a list of all vacant offices and cubicles, by floor and square footage.

RESPONDENT:

Scott Rathbun

WITNESS:

Michael DeConcini

THE FOLLOWING DOCUMENT CONTAINS "CONFIDENTIAL INFORMATION" THAT IS BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT IN DOCKET NO. E-01933A-12-0291 AND MAY NOT BE SHARED WITH ANYONE WHO HAS NOT SIGNED THE PROTECTIVE AGREEMENT DATED JULY 6, 2012.

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TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO UNIFORM DATA REQUESTS - 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
September 25, 2012

UDR 1.35

Incentive Programs. List and describe all retirement and incentive programs available to Company officers and employees. Provide a complete copy of each incentive compensation program and all related materials. Identify the goals and targets in each year 2009-2011, and all evaluations of whether such goals were exceeded.

a. Specifically identify the cost of any SERP or similar programs directly charged or allocated.

b. State the cost by program, of each retirement program directly charged or allocated.

RESPONSE: July 13, 2012

Incentives:

All TEP non-union employees, including officers, participate in UNS's short-term incentive program ("PEP"), which is tied to annual compensation.

The structure determines eligibility for certain bonus levels by measuring UNS's performance as it impacts four stakeholder categories:

- Investors;
- Customers;
- Community/Environment; and
- Employees.

Levels of achievement in each category are assigned percentage-based "scores," and those scores are combined to calculate the final payout level. The amount made available for bonuses through this formula may range from 15 percent to 147.5 percent maximum of the targeted payout level.

Over the three-year period of 2009-2011, the Investor category has encompassed a range of 35-40 percent of the bonus structure, the Customer category has ranged from 30-35 percent, and the Community/Environment and Employees categories respectively account for 15% each.

The scores from each goal are totaled and then multiplied by the targeted bonus of each employee to determine the total available dollars to be paid out. Targeted bonus percentages, as a percent of base salary, range from 9% - 12% for regular unclassified employees, and 20% - 80% for officer and senior management level employees. Bonus percentages, as a percent of base salary, are used in the calculation of total available dollars, and actual awards may vary at management's discretion based on individual employee contribution. If a payout is achieved, employee PEP bonuses will be distributed near the end of the first quarter the following year. Please see the files listed below, and enclosed on the attached CD, for the goals for each year and evaluations of yearly performance.

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO UNIFORM DATA REQUESTS - 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
September 25, 2012

File Name	Bates Numbers
UDR 1.35 - 2009-2011 PEP Hist Prcnts-Pos-Confidential.pdf	TEP\003107-003108
UDR 1.35 - 2009 PEP Goals-Confidential.pdf	TEP\003109-003110
UDR 1.35 - 2010 PEP Goals-Confidential.pdf	TEP\003111-003112
UDR 1.35 - 2011 PEP Goals-Confidential.pdf	TEP\003113-003114

Retirement Programs:

TEP non-union employees are eligible to participate in the Tucson Electric Power Company Salaried Retirement Plan while TEP union employees are eligible to participate in the Pension Trust Plan for Employees of Tucson Electric Power Company represented by IBEW 1116. Please see the file listed below, and enclosed on the attached CD, for the summary plan description.

File Name	Bates Numbers
UDR 1.35 - Salaried_Plan_SPD_2011 (Confidential).pdf	TEP\003115-003143
UDR 1.35 - TEP-SPD-IBEW1116PensTrustPlan-Confidential.pdf	TEP\003144-003172

Additionally, TEP employees are eligible to participate in the TEP 401(k) Plan as described below:

401(k) Plan

TEP's 401(k) Plan takes advantage of Section 401(k) of the Internal Revenue Code and permits employees to voluntarily save from 1/2% to 25% of their pay, before any deduction for state or federal income taxes. The Company matches dollar for dollar, up to 4.5% of pay saved in the 401(k) Plan for TEP employees.

Employees' savings and Company matching contributions are invested in one or any combination of a selection professionally managed investment funds at the direction of the employee. Employees are eligible to join the 401(k) Plan upon their date of employment. Company matching contributions are fully and immediately vested. Please see the file listed below, and enclosed on the attached CD, for the summary plan description.

File Name	Bates Numbers
UDR 1.35 - 401K_SPD-Confidential.pdf	TEP\003051-003106

a. SERP expense charged to TEP FERC 0426 during the test year was $1,307,784. However, as set forth in the Direct Testimony of Karen Kissinger, TEP is not seeking recovery of SERP expenses in this rate case.

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO UNIFORM DATA REQUESTS - 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
September 25, 2012

b. Retirement program expense (other than SERP) charged to TEP FERC 0920 and 0926 during the test year (before consideration of proforma adjustments) was as follows:

TEP Union and Salaried Pension Plans (FERC 0926)	$ 6,889,202
TEP 401K Plan (FERC 0926)	2,733,779
UNS Electric Pension/401K (FERC 0926)	37,640
UNS Gas Pension/401K (FERC 0926)	17,221
Deferred Compensation Plan (FERC 0920)	(9,737)
Total	**$9,668,105**

All files labeled "confidential" contain confidential information and are being provided pursuant to the terms of the Protective Agreement dated July 6, 2012.

RESPONDENT:

Georgia Hale, Ann Eckert and Gabrielle Camacho

WITNESS:

Karen Kissinger

SUPPLEMENTAL RESPONSE: September 25, 2012

THE FILES LISTED BELOW CONTAIN CONFIDENTIAL INFORMATION AND ARE BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT DATED JULY 6, 2012.

In response to STF 5.05 and STF 5.06, please see UDR 1.35 - 2012 PEP Goals-Confidential.pdf, Bates No. TEP\022720-022721.

In response to STF 5.16(b), Supplemental Executive Retirement Plan (SERP) expense is provided below as a supplement to UDR 1.35(b).

Supplemental Executive Retirement Plan (SERP) Expense:

Account	Subaccount	Test Year 2011
88090	7102	$ 1,307,784

In response to STF 5.16(d), please see UDR 1.35 - 008-2011 PEP Hist Prcnts-Pos-Confidential.pdf, Bates Nos. TEP\022718-022719, to add the 2008 incentive plan actual percentage scores of performance goals to the previously provided file.

RESPONDENT:

Steve Sims, Gabrielle Camacho, Georgia Hale and Ann Eckert

WITNESS:

Karen Kissinger

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TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO STAFF'S FIFTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291
September 26, 2012

STF 5.34

Please provide all outside consultant contracts/agreements and invoices received to date pertaining to the rate case expense included in this proceeding

RESPONSE: September 25, 2012

THE PDF FILES LISTED BELOW CONTAIN CONFIDENTIAL INFORMATION AND ARE BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT DATED JULY 6, 2012.

Please see the files listed below for the requested information. The Excel file is not identified by Bates numbers.

File Name	Bates Numbers
STF 5.34 Black and Veach 32313-Confidential.pdf	TEP\020213-020218
STF 5.34 Burns - McDonnell 28397-Confidential.pdf	TEP\020219-020222
STF 5.34 CCA 32844-Confidential.pdf	TEP\020223-020226
STF 5.34 Concentric Energy Advisors 31148-Confidential.pdf	TEP\020227-020252
STF 5.34 Day Nite Design 4201-Confidential.pdf	TEP\020253-020261
STF 5.34 Foster Associates 19052Amend1-Confidential.pdf	TEP\020262-020264
STF 5.34 Foster Associates 19052-Confidential.pdf	TEP\020265-020271
STF 5.34 Invoices(1)-Confidential.pdf	TEP\020272-020320
STF 5.34 Miller Chevalier 31956-Confidential.pdf	TEP\020321-020324
STF 5.34 PWC Engagement Ltr 5-14-12-Confidential.pdf	TEP\020325-020330
STF 5.34 PWC Invoices-Confidential.pdf	TEP\022403-022404
STF 5.34 Rate Case Expense - Outside Consultants (1) (3).xlsx	N/A
STF 5.34 Roshka-Confidential.pdf	TEP\020331-020333
STF 5.34 Sargent - Lundy 29522-Confidential.pdf	TEP\020334-020336

Please find STF 5.34 Rate Case Expense – Outside Consultants.xlsm for a list of invoices received to date pertaining to the rate case. This data will be updated periodically as additional invoices are received.

Invoices are listed as STF 5.34 Invoices.PDF. Invoices for Roshka DeWulf & Patten, LLC are not being provided due to attorney-client privilege.

Individual contracts/agreements are listed individually.

RESPONDENT:

Pricing (Anne Liu)

WITNESS:

Dallas Dukes

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO STAFF'S FIFTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291
September 26, 2012

SUPPLEMENTAL RESPONSE: September 26, 2012

STF 5.34 CommCounsel of Amer-Confidential.pdf, Bates Nos. TEP\023076-023077, is hereby added to this response as a consultants retainer/agreement.

RESPONDENT:

Pricing (Anne Liu)

WITNESS:

Dallas Dukes

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S FIFTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291
September 25, 2012

STF 5.42

Property Tax Expense.

a. Please provide the most recent actual property tax assessments and rates.

b. Please provide comparable actual property tax expense for each year, 2005 through 2011.

c. Please provide the total Arizona property tax expense for TEP and its affiliates and show the amounts recorded by TEP and each affiliate, for each year, 2005 through 2011.

d. Please identify the amounts of property tax expense being recorded by TEP for each month in 2012 and show how those amounts were determined.

RESPONSE:

THE FILES LISTED BELOW CONTAIN CONFIDENTIAL INFORMATION AND ARE BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT DATED JULY 6, 2012.

Please see the following files for the requested information.

File Name	Bates Numbers
STF 5.42(a)-Confidential.pdf	TEP\
STF 5.42(c) Property Tax Expense 2007-2011 TEP-Affiliates-Confidential.xls	N/A
STF 5.42(d) Property Tax Expense 2012-Confidential.xls	N/A

a. Please see STF 5.42(a)-Confidential.pdf for the most recent property tax assessments and rates for the 2011 property tax year. TEP expects to have the 2012 property tax assessments and rates for Arizona by November 1, 2012 and New Mexico by December 1, 2012.

b. Please see TEP's response to UDR 1.66.

c. TEP is providing information since the last test year. For 2007-2011 Arizona property tax expense, see STF 5.42(c) 2007-2011 TEP-Affiliates-Confidential.pdf.

d. See STF 5.42d Property Tax Expense 2012-Confidential.pdf.

RESPONDENT:

Rigo Ramirez

WITNESS:

Karen Kissinger

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TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO STAFF'S SIXTEENTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291
November 19, 2012

STF 16.10

Property taxes.

a. Refer to the response to STF 11.08. Provide the property tax recorded by TEP in each month, July, August and September 2012.

b. Refer to the response to STF 11.10. Provide the amounts of property taxes paid by TEP and the payment date for the payments made on/by each of the following payment due dates:

   1. October 1, 2011

   2. March 1, 2012

   3. October 1, 2012

c. In 2011 or 2012 has TEP incurred any delinquent fees for failing to pay property taxes before the delinquent dates?

   1. If so, identify, quantify and explain the delinquent charges and show the amounts in 2011 and 2012 by account.

d. Does TEP receive payments for property taxes from any affiliates?

   1. If so, identify the amounts, dates, and affiliate making the payments for property taxes to TEP in each month of 2011 and 2012.

e. Does TEP make payments for property taxes to any affiliates?

   1. If so, identify the amounts, dates, and affiliate to whom TEP made the payments for property taxes in each month of 2011 and 2012.

f. Does TEP receive payments for property taxes from any non-affiliated companies?

   1. If so, identify the amounts, dates, and the non-affiliated company making the payments for property taxes to TEP in each month of 2011 and 2012.

g. Does TEP make payments for property taxes to any non-affiliated company?

   1. If so, identify the amounts, dates, and non-affiliated company to whom TEP made the payments for property taxes in each month of 2011 and 2012.

h. Refer to the response to STF 11.11(a). Does TEP's request in the current rate case include any property taxes related to Springerville Unit 1 and PV property?

   1. If so, identify the amounts, and where they are reflected in TEP's filing.

i. Refer to the response to STF 11.11 (d) which states that all UNS affiliates have followed a standalone policy in their rate cases for computing property taxes. Additionally, the Company does not expect pro forma property tax expense for ratemaking purposes to produce the same result as actual property tax bills. Provide a comparison for each utility (TEP, UNSE, UNSG, and all 3 utilities combined), for each year 2008-2012 of (1) standalone property taxes and (2) actual property taxes.

j. Identify all decisions and Commission directives of which TEP is aware which specifically addressed whether property tax expense should be considered reasonable for ratemaking purposes if the combined "standalone" total for TEP, UNSE and UNSG for

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO STAFF'S SIXTEENTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291
November 19, 2012

each year consistently exceeds the amount of actual property taxes that are paid by the three utilities combined.

RESPONSE: **October 29, 2012**

THE FILES LISTED BELOW CONTAIN CONFIDENTIAL INFORMATION AND ARE BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT DATED JULY 6, 2012.

a. TEP will provide the requested information after the Company has reported its 3rd quarter 2012 results to the public.

b. 1. TEP paid $16,182,582.32 on October 31, 2011.

2. TEP paid $16,181,812.19 on April 30, 2012.

3. 1st half 2012 Property taxes due October 1, 2012 are not delinquent until after November 1, 2012. TEP is in the process of receiving and compiling its 2012 property tax bills and will forward this information as soon as it is available. TEP expects to make its 1st half 2012 payment on October 31, 2012.

The amounts above relate to Arizona property taxes. TEP also pays New Mexico property taxes and Navajo Nation possessory interest taxes. The payment dates and amounts are as follows:

New Mexico Property Taxes

Due Date: November 10, 2011. TEP paid $1,261,064.90 on December 2, 2011.

Due Date: April 10, 2012. TEP paid $1,261,064.87 on May 4, 2012.

Due Date: November 10, 2012. 1st half property taxes for New Mexico are due on November 10 of each year, but do not become delinquent until after December 10 of each year. TEP has not received its New Mexico property taxes bills for 2012, but expects to make payment on December 7, 2012.

Navajo Nation Possessory Interest Taxes

Due Date: November 1, 2011. TEP paid $638,095.85 on October 31, 2011.

Due Date: May 1, 2012. TEP paid $638,095.85 on April 30, 2012.

Due Date: November 1, 2012. 1st half Navajo Nation property taxes are due November 1, 2012. TEP has not yet paid its Navajo Nation property taxes due on November 1, 2012, but expects to make payment on October 31, 2012.

c. No, TEP did not incur any delinquent fees.

d. TEP neither directly receives payments from, nor makes payments to, affiliates specifically for property taxes. However, through the building allocation process, TEP and affiliates are indirectly billed for a portion of the property taxes on shared buildings, including the corporate headquarters building. In connection therewith, an hourly allocation billing rate is computed based on a ratio, the numerator of which is the computed annual revenue requirement for the building, and the denominator of which is computed as total number of UNS employees X 2,080 annual hours. The revenue requirement for the building is computed as the sum of a return on the building

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO STAFF'S SIXTEENTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291
November 19, 2012

investment (plant in service – accumulated depreciation – accumulated deferred income taxes) using TEP's Commission-authorized rate of return ordered in its last rate case, plus related operations and maintenance expenses, depreciation, property tax expense, and income taxes associated with the investment return. Amounts billed to affiliates are computed using the billing rate described above multiplied by the number of payroll hours reported by the bill recipient for the respective period. When recording intercompany billings under the building allocation process, a charge to intercompany accounts receivable is recorded with a corresponding credit to Acct. 454, Rent from Electric Property. In this rate case, such intercompany billings, on an annualized basis, are included in test-year operating revenues.

e. See response to part d, above.

f. Yes, the owners of Springerville Unit 3 and Unit 4 reimburse TEP for a portion of the property taxes on the Springerville common and coal handling facilities. See STF 16.10(f) Pmts Recd from Non-affil Companies-Confidential.xls.

g. No, TEP does not make payments for property taxes to any non-affiliated company.

h. TEP's pro forma property tax adjustment does not include a request for property taxes related to Springerville Unit 1, but does include PV property taxes. Property taxes on PV property in the amount of $312,066 are included in the property tax pro forma adjustment work papers submitted in UDR 1.01. Springerville Unit 1 property taxes are included separately in the Springerville Unit 1 adjustment. Please refer to page 11 of the Direct Testimony of Karen G. Kissinger.

i. Please see STF 16.10(i) Standalone vs Actual Property Taxes-Confidential.xls for the requested information.

j. TEP is not aware of any decisions or Commission directives which specifically address the issue of actual property taxes vs. standalone property taxes. However, the Commission has addressed the issue of actual income taxes vs. standalone income taxes as explained in STF 11.11. It is not correct that the combined standalone property taxes for TEP, UNS Electric, and UNS Gas consistently exceed the actual property taxes paid by the three utilities combined. As shown on STF 16.10(i) Standalone vs Actual Property Taxes-Confidential.xls, the 2011 combined "standalone" total was less than the combined "actual" total.

Excel files are not identified by Bates numbers.

RESPONDENT:

Rigo Ramirez

WITNESS:

Karen Kissinger

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO STAFF'S SIXTEENTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291
November 19, 2012

SUPPLEMENTAL RESPONSE: November 19, 2012

THE FILE LISTED BELOW CONTAINS CONFIDENTIAL INFORMATION AND IS BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT DATED JULY 6, 2012.

a.

July	2,884,771
August	2,884,771
September	2,236,422

b.3. Please see the response to STF 22.07 filed on November 19, 2012.

i. Please see STF 16.10(i) Standalone vs Actual Property Taxes(1)-Confidential.xls, which has been updated to include 2012.

Excel files are not identified by Bates numbers.

RESPONDENT:

Rigo Ramirez

WITNESS:

Karen Kissinger

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TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
UNIFORM DATA REQUESTS - 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
July 13, 2012

TAXES:

UDR 1.66

Property Tax Expense. Please provide the annual level of property tax expense, for 2009 through 2011 and 2012 to date, as well as the year end plant in service for 2009 through 2011 and 2012 to date.

RESPONSE:

Please see the files listed below and enclosed on the attached CD for 1) property tax expense for 2009 through 2011 and 2012 through Q1, as well as year-end plant in service used to calculate property tax for tax years 2009 through 2012; and 2) supporting documents.

File Name	Bates Numbers
UDR 1.66 Property Tax and Plant in Srvc-Confidential.pdf	TEP\003323-003324
UDR 1.66 Property Tax and Plant-Support-Confidential.pdf	TEP\003325-003330

All files labeled "confidential" contain confidential information and are being provided pursuant to the terms of the Protective Agreement dated July 6, 2012.

RESPONDENT:

Rigo Ramirez

WITNESS:

Karen Kissinger

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TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO UNIFORM DATA REQUESTS - 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291 July 13, 2012

UDR 1.68

Property Taxes. List all amounts of property taxes and public utility realty taxes still under dispute at December 31, 2011 and present, and indicate the tax year and the taxing district to which each relates. List total property taxes and property tax refunds or abatements each year, for the test year and the preceding three calendar years. Also, list any refunds received subsequent to the test year. Describe and show the accounting treatment accorded to each item, showing journal entries, dates, accounts, amounts, and descriptions.

RESPONSE:

Please see the file, UDR 1.68 Property Taxes-Confidential.pdf, Bates Nos. TEP\003370-003371, on the enclosed CD for a summary of property tax activity for December 31, 2011 and the preceding three calendar years. There are no property taxes currently in dispute, nor were any being disputed at December 31, 2011. Moreover, there have been no property tax refunds or abatements for any of the periods indicated.

Bates Nos. TEP\003370-003371 contain confidential information and are being provided pursuant to the terms of the Protective Agreement dated July 6, 2012.

RESPONDENT:

Rigo Ramirez

WITNESS:

Karen Kissinger

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TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S TWENTY-EIGHTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291
December 10, 2012

STF 28.1

Property Taxes. Per the December 4, 2012 interview with Jason Rademacher and Carl Dabelstein concerning property taxes, please provide the following information (preferably in Excel):

a. Actual versus stand-alone property tax calculations for TEP for plant in service as of 12/31/2011.

b. Actual versus stand-alone property tax calculations for UNS Electric for plant in service as of 12/31/2011.

c. Actual versus stand-alone property tax calculations for UNS Gas for plant in service as of 12/31/2011.

d. Actual versus stand-alone property tax calculations for TEP for plant in service as of 12/31/2011, restricting the plant to Springerville Unit 1. (Results should be comparable with the response to STF 22.7(c).

e. The equivalent actual and stand- alone property taxes for Springerville Unit 3 and 4 property taxes based on plant in service as of 12/31/2011; if the results would vary from the $452,720 adjustment to account 408, property taxes other production, made in Company Pro Forma Adjustment No. 5. If the results of Springerville Unit 3 and 4 property taxes based on plant in service as of 12/31/2011 would not vary from the $452,720 amount in Company Pro Forma Adjustment No. 5, please state so in your response.

RESPONSE:

THE FILES LISTED BELOW CONTAIN CONFIDENTIAL INFORMATION AND ARE BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT DATED JULY 6, 2012.

File Name	Bates Numbers
STF 28.1(a) TEP PropTaxCombvsStandalone-Confidential.xls	N/A
STF 28.1(b) UNSE PropTaxCombvsStandalone-Confidential.xls	N/A
STF 28.1(c) UNSG PropTaxCombvsStandalone-Confidential.xls	N/A
STF 28.1(d) PropTaxSpvU1CombvsStandalone-Confidential.xls	N/A
STF 28.1(e) PropTaxSpvU3-U4-Confidential.xls	N/A

a.-d. Please see the files listed above for the requested information.

e. The results vary from the $452,720 adjustment to account 408. Please see STF 28.1(e) PropTaxSpvU3-U4-Confidential.xls listed above.

RESPONDENT:

Jason Rademacher

WITNESS:

Karen Kissinger

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BEFORE THE ARIZONA CORPORATION COMMISSION

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

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

DIRECT

TESTIMONY

OF

DR. S. KEITH BERRY

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

DECEMBER 21, 2012

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INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is S. Keith Berry and my business address is 1600 Washington Avenue, Hendrix College, Conway, AR 72032.

Q. Where are you employed?

A. My academic affiliation is Professor of Economics and Business at Hendrix College in Conway, Arkansas. I am also a principal in the firm of Economic and Financial Consulting Group, Inc.

Q. Please describe your educational background and experience.

A. I received my B.A. in mathematics from Hendrix College, and my Ph.D. in economics from Vanderbilt University. I was an instructor in statistics at Vanderbilt in 1976-77 and an instructor/assistant professor at Hendrix College from 1977-79. In July 1979, I joined the Staff of the Arkansas Public Service Commission as Manager of the Finance Section. The primary responsibility of that Section was the preparation and presentation of testimony concerning the cost of capital in utility rate cases. I assumed the duties of Manager of both the Finance and Rate Sections in July 1980. I was promoted to Director of Research and Policy Development in September 1986. Beginning in September 1989, I returned to teaching at Hendrix College.

I have submitted testimony in more than seventy different proceedings before public service commissions or other regulatory agencies, including testimony in the area of cost of capital. My publications include articles in the *American Economic Review*, *Journal of Regulatory Economics*, *Land Economics*, the *Energy Journal* (coauthor), the *Journal of Economics and Business*, *The Quarterly Review of Economics and Business*, *The*

Financial Review, the *Eastern Economic Journal*, *Managerial and Decision Economics*, *Public Choice*, and the *Review of Industrial Organization.* I have made presentations concerning utility regulation and the cost of capital at the National Association of Regulatory Utility Commissioners ("NARUC") Advanced Studies Program, the Eastern NARUC Utility Rate Seminar, the Western NARUC Utility Rate Seminar, the National Conference of Regulatory Utility Commission Engineers, and the Annual Conference of the Institute of Public Utilities. While on the Staff of the Arkansas Public Service Commission, I served on the NARUC Subcommittee on Electricity and the Research Advisory Committee of the National Regulatory Research Institute (Deputy Chairman, 1988-89). I am currently a member of the American Economic Association and the Southern Economic Association. A copy of my *Curriculum Vita* is provided in Exhibit SKB-1.

Q. On whose behalf are you appearing?

A. I am appearing on behalf of the Utilities Division Staff ("Staff") of the Arizona Corporation Commission ("Commission").

SUMMARY OF TESTIMONY

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

A. I will make recommendations concerning the cost of capital, including cost of equity and rate of return on the Fair Value Rate Base ("FVRB") Increment, of Tucson Electric Power Company ("TEP" or "Company"). I will also rebut the Direct Testimony of TEP cost of capital witnesses Kevin P. Larson and John J. Reed.

Q. Please summarize your recommendations.

A. I recommend a capital structure, before adjustment for FVRB, with 43.50 per cent common equity, 55.97 per cent long-term debt, and 0.53 per cent short-term debt. These are the same capital structure proportions for Test Year ending December 31, 2011 that are reflected in the Company's Schedule D-1, Page 1 of 2, which I find to be reasonable.

The Company is requesting a hypothetical capital structure of 46.00 per cent common equity and 54.00 per cent long-term debt. As I will discuss later, it is my opinion that the Company's proposed hypothetical structure is inappropriate and should not be utilized by the Commission for purposes of setting TEP's rates.

I recommend a cost of equity of 9.4 percent, with a range of 8.9 percent - 9.9 percent, while the Company proposes a 10.75 percent cost of equity. As I will discuss later, it is my opinion that the Company's proposed cost of equity is inappropriately high in this case, and should not be utilized by the Commission for purposes of setting TEP's rates.

I recommend an overall cost of capital of 7.00 percent before adjustment for FVRB. This is shown in my Exhibit SKB-2. The Company recommends an overall cost of capital of 7.74 percent before adjustment for FVRB. As I will discuss later, it is my opinion that the Company's proposed overall cost of capital is inappropriate in this case and should not be utilized by the Commission for purposes of setting TEP's rates.

I recommend a rate of return of 0.0 percent to 0.68 percent on the FVRB Increment, which information was provided to Staff witness Ralph Smith. He calculated an overall rate of return range is 4.63 percent to 4.86 percent, which is applicable to the FVRB ("FVROR").

These numbers are based on Staff Attachment RCS-2, page 10 of Staff witness Ralph Smith Exhibits.

CAPITAL STRUCTURE FOR TEP

Q. How did you calculate the overall rate of return, or weighted average cost of capital?

A. I utilized the weighted average cost of capital approach wherein the various components' capital costs are weighted by their proportions in the capital structure and then summed.

Q. What capital components did you employ?

A. Common equity, long-term debt, and short-term debt, as shown in Exhibit SKB-2.

Q. Please explain the determination of the relative proportions of these capital components.

A. I used the same capital structure as is reflected in the Company's Schedule D-1, page 1 of 2, which I found to be reasonable. It corresponds to the Company's actual capital structure at December 31, 2011, and gives the Company the opportunity to earn a fair rate of return.

COST OF DEBT FOR TEP

Q. How did you determine the cost of long-term debt for TEP?

A. I used a 5.18 percent cost rate, which is the same as the Company's.

Q. How did you determine the cost of short-term debt for TEP?

A. I used a 1.42 percent cost rate, which is the same as the Company's.

COST OF EQUITY FOR TEP

Q. Please discuss the financial and economic tenets that guided you in estimating TEP's cost of equity.

A. The cost of, or required return on, equity is a valid cost just as other more explicit expenses incurred by the utility in the provision of utility service to ratepayers. The difficulty with estimating the cost of equity is that it is nowhere explicitly stated in a utility's accounts, and must be inferred from market data.

If the return allowed by the regulatory authority is set higher than the required return on equity, then monopoly profits will inure to the benefit of the shareholders, at the expense of customers. If the return is set too low, then the financial position of the shareholders will be eroded and the utility will be unable to adequately attract necessary capital. When the allowed return on equity is set equal to the cost of equity, stockholders will be given the opportunity to earn a fair return on equity, which will also afford the utility the opportunity to viably attract capital. Thus, from the perspective of balancing the interests of ratepayers and shareholders, and simulating the competitive market model, a cost-based allowed return on equity is a desirable goal. Note that, in the case of the cost of equity that is estimated with current data, the cost of equity is also the marginal cost of equity. The decisions that consumers make will be based on those price signals which reflect the economic costs, including the marginal cost of equity, to society of providing utility service. In that sense, an allowed return based on the cost of equity is economically efficient.

Q. Please discuss your risk-comparable sample.

A. In order to develop a market-based cost of equity and have sufficient data in the analysis it is appropriate to use a sample of companies comparable in risk to TEP. As a starting

point, I utilized the same Risk-Comparable sample as did TEP witness John J. Reed except that I included UNS Energy, the parent company of TEP. For cost of capital purposes it is reasonable to include TEP's parent company as a part of the risk-comparable sample. There is no circularity involved in doing so since UNS Energy's common equity is used to supply TEP's common equity. That is the only source of common stock for TEP. Surely, an analysis of TEP's cost of equity should include an analysis of the cost of equity of the sole supplier of TEP's common equity. Further, note that TEP accounted for approximately 77 percent of UNS Energy's Net Income and 77 percent of UNS Energy's Operating Revenues in calendar year 2011. This indicates that TEP accounts for a significant part of UNS Energy's operations and, implicitly, UNS Energy's cost of equity.

My Risk-Comparable sample is shown in Exhibits SKB-3 and SKB-4.

Q. Did you consider multiple methods for estimating the cost of equity for TEP?

A. Yes, I did. I considered the Constant Growth Discounted Cash Flow ("DCF") Method, the Multi-Stage Growth DCF Method, the Capital Asset Pricing Model ("CAPM"), and the Risk Premium Method. Those results are shown in my Table 1 later in my testimony.

DISCOUNTED CASH FLOW METHODOLOGY

Q. Please discuss your application of the constant growth DCF method to estimate TEP's cost of equity.

A, The concept of a return to capital is closely associated with time: a reward to the suppliers of capital for deferring consumption. Calculations of the embedded costs of debt are relatively straightforward since those costs are fixed and contractual in nature. The cost of equity, in contrast, is not spelled out in a contractual manner and is more difficult to

calculate. However, it can be inferred through an appropriate examination of current stock market data and widely disseminated financial information.

Rational investors in common stock are primarily concerned with the cash flows that they expect to receive from ownership of the stock. For the individual investor those cash flows consist of expected future dividends as well as capital gains or losses expected from selling the stock at some future point in time. However, for investors in aggregate (across ownership changes) expected cash flows are comprised of future dividends only. There is no conceptual difference between these two interpretations of cash flow.

The market price of the common stock embodies investors' expectations about that stream of future dividends. However, a dividend expected to be received in the future is not valued as highly by investors as that same dividend received today. The investor implicitly imputes a discount to future dividends. Also, the further in the future the dividend is expected to be received, the greater is the discount.

This value, or market price, that investors impute to that share of common stock is the present value of the stream of dividends expected to be received by them. These future dividends are discounted by an amount determined by the discount rate, or cost of equity. This relationship is characterized in Equation (1) below where P_0 represents the current share price, D_i represents the dividend expected to be received at the end of period "i", and "k" is the discount rate, or cost of equity:

$$(1) \qquad P_0 = D_1/(1+k) + D_2/(1+k)^2 + D_3/(1+k)^3 + \ldots$$

In this form, without further simplifying and reasonable assumptions, Equation (1) is mathematically intractable. However, if we assume that investors expect future dividends to increase at a constant rate of growth, g, then Equation (1) can be expressed as:

$$(2) \qquad P_0 = D_1/(1+k) + D_1(1+g)/(1+k)^2 + D_1(1+g)^2/(1+k)^3 + \ldots$$

Equation (2) can then be solved for P_0 as:

$$(3) \qquad P_0 = D_1/(k-g), \quad \text{for } k > g.$$

Equation (3) demonstrates that this constant growth DCF method is a market-based approach. Any changes in investors' discount rate, expected growth rate in dividends, or dividends expected one period hence are actually captured by changes in the market price of the stock. For example, other things being equal, if the cost of equity decreases, then investors will bid the market price up.

The constant growth DCF model shown in Equation (3) can be re-expressed as:

$$(4) \qquad k = D_1/P_0 + g,$$

which implies that the cost of equity is simply the sum of the expected dividend yield and the anticipated growth rate. Because of the quarterly nature of dividend payments, I have defined $D_1 = D_0(1 + g/2)$, where D_0 is the current annualized dividend. Thus, the final form of the DCF equation is:

$$(5) \qquad k = [\, D_0(1 + g/2)/P_0] + g.$$

Q. How did you determine the growth rate in your constant growth DCF model?

A. It is important for the analyst to ascertain investors' expectations about future sustainable long-term growth in dividends per share in order to properly implement the DCF method. Keep in mind that it is not what the analyst believes future growth will be, but what investors believe about future long-term sustainable growth. It is those expectations that influence the stock price. Further, if sustainable, growth in book value per share ("BVPS"), earnings per share ("EPS"), and dividends per share ("DPS") will be equivalent.

I utilized recent editions of *Value Line Investment Survey*, a well-respected and widely disseminated source of information about companies, to develop my array of data for inferring investors' growth expectations. I also used the growth estimates of Mr. Reed, shown in Exhibit JJR-2.

I employed six different estimates of investor-expected growth:

(1) g1 – Average of the combined historical/projected 10-year EPS, DPS, and BVPS annual compound growth rates for the years 2006 to 2016 as reported in *Value Line*;

(2) g2 – Average of the projected 5-year EPS, DPS, and BVPS annual compound growth rates for the years 2011 to 2016 as reported in *Value Line*;

(3) g3 –"br + vs" using data reported in *Value Line* for the years 2011-12.

(4) g4 -"br + vs" using data reported in Value Line for the years 2015-17;

(5) g5 – Zack's projected EPS annual growth rate as shown in Reed Exhibit JJR-2;

(6) g6 – First Call's projected EPS annual growth rate as shown in Reed Exhibit JJR-2

It is my opinion that, taken together, these six growth rates provide a reasonable basis upon which to infer the investor-expected growth rate in the DCF method.

Note that the expression "br + vs" is a measure of long-term sustainable expected growth in BVPS, based on two fundamental sources of BVPS growth: earnings retention ("br") and accretion (or dilution) of BVPS due to the issuance of new common stock ("vs"). Since the DCF formula relies on investor-expected growth in DPS, and since long-term growth is ultimately derived from, and equal to, long-term growth in BVPS, this approach is useful in gauging investors' dividend growth expectations.

The "br" component implicitly considers factors that cause sustainable growth in DPS, EPS, and BVPS due to earnings retention, where "b", the expected retention ratio, is multiplied times "r", the expected return on equity. A simple example, assuming no stock issuance, should clarify the working of this component. Assume that a company has an initial BVPS of $20, "r" is equal to 10 percent, and "b" is equal to 40 percent. Investors expect this hypothetical utility to earn 10 percent X $20 = $2.00 per share. Of this amount 40 percent, or $.80 per share is retained, and 60 percent, or $1.20 per share, will be paid out in dividends. The BVPS will grow to $20.80 in the next period because of earnings retention. This represents a growth in BVPS of ($20.80-$20)/$20 = 4%. EPS in the next period will be 10 percent X $20.80, which represents growth in EPS of 4 percent. DPS in the next period are 60 percent X $2.08 = $1.248, which also represents growth of 4 percent. DPS, EPS, and BVPS all grow at the long-term sustainable growth rate of 4 percent.

At this juncture, it is important to point out that "r", the *expected* return on equity, is not necessarily equal to "k", the *required* return on equity. That investor-expected return on

equity, "r", may be greater or less than "k", the investor-expected required return on equity. In particular, if "r" is greater (less) than "k", then the stock-market price-to-book value ratio is greater (less) than one. It is only when r = k that the price-to-book ratio is equal to one.

Another fundamental factor that determines sustainable growth in BVPS, EPS, and DPS is represented by the "vs" term. This second determinant of growth in BVPS is caused by the issuance of new common stock. If new stock is issued at a price below BVPS, dilution decreases the BVPS, and the investor-expected growth rate is thereby decreased. Conversely, if new stock is issued at a price above BVPS, accretion occurs and the growth rate is correspondingly increased. This factor is significant to investor expectations if the price-to-book value is significantly greater than one and if the firm is expected to issue common stock in the future (as reflected in *Value Line*). In this case those two conditions are met with regard to the Risk-Comparable sample. This factor is discussed extensively in *Cost of Capital to a Public Utility* by Myron Gordon, who provided a major impetus for the use of the DCF method in utility rate proceedings.

For each firm, "vs" was calculated as n*(P/B – 1) where n* is the expected annual rate of growth in common shares outstanding, P is the average of the stock prices for the period April 2012 – September 2012, and B is the BVPS at the end of calendar year 2011 (as reported in *Value Line*).

These different growth rate estimates are shown in Exhibit SKB-3.

Q. Please discuss your calculations of the other components in the constant growth DCF method.

A. In the DCF procedure, it is important to utilize a price term that is fairly current since a current price embodies all of the information currently available to investors, and will implicitly embody a current estimate of investors' required return on equity. However, that price should be averaged in an appropriate manner so as to eliminate the influence of random fluctuations in price. In order to minimize the possibility of an aberrant price I utilized an average price over a recent time period, April 2012 – September 2012. Those results are shown in Exhibit SKB-4.

The appropriate dividend yield for each firm was calculated using the annualized dividends as of October 1, 2012, and the average stock price as discussed above. Those results are shown in Exhibit SKB-4.

Q. What are your constant growth DCF results using these six different growth rate estimates and the adjusted dividend yields for each Company in the risk comparable sample?

A. Those results are shown in Exhibit SKB-4 for k1 through k6, which correspond to growth rates g1 through g6, respectively. As shown there, the average Constant Growth DCF point estimate cost of equity is 9.33 percent. My Constant Growth DCF range is 8.83 percent to 9.83 percent.

Q. Did you also consider a multi-stage growth DCF estimate here?

A. Yes, I did in this case. As I discuss later, I utilize the Company's Multi-Stage Growth DCF model, and simply change two inputs to the Company's model. As shown later, my Multi-Stage Growth DCF cost of equity results are 9.43 percent to 9.55 percent.

CAPITAL ASSET PRICING MODEL

Q. Please describe the CAPM.

A. The CAPM is a risk-premium based model which uses the volatility of a company's stock price relative to the market as a key input. It is expressed as:

$$(6) \qquad k = R_F + \beta(R_M - R_F)$$

Where k is the company's cost of equity, R_F is the current risk free rate (generally, a U.S. Treasury Bond yield), and "β", or beta, is the volatility of the company's stock price relative to the market in the context of a diversified portfolio. It represents non-diversifiable risk. R_M represents the market required return and $R_M - R_F$ represents the "required market risk premium."

Q. Please describe your implementation of the CAPM in this case.

A. For the risk-free rate, R_F, I used the weekly average of 30-year U. S. Treasury Bond yields for the months of July through September of 2012 as reported in *Value Line*. That risk-free rate is 2.74 percent as shown in Exhibit SKB-5. For "β" I used the same average beta for the risk comparable sample that Mr. Reed used in his CAPM analysis. That average β is 0.73.

According to a summary in Fernandez, the market risk premium estimates (relative to Treasury bonds) range from 4 percent to 10 percent[1]

Additionally, as shown in Ibbotson SBBI, 2012 Classic Yearbook, Market Results for Stocks Bonds, Bills, and Inflation, for the periods 1926-2011 and 1951-2011 the Total

[1] Pablo Fernandez "Equity Premium: Historical, Expected, Required and Implied." IESE Business School working paper. 2007

Returns of Large Corporate Stocks are 9.8 percent and 10.6 percent, respectively (pp. 239 and 241). The Total Returns on Treasury Long-Term Bonds for the periods 1926-2011 and 1951-2011 are 5.7 percent and 6.4 percent, respectively (pp. 257 and 259). This implies risk premiums of 9.8 percent less 5.7 percent = *4.1 percent* and 10.6 percent less 6.4 percent = *4.2 percent* for the periods 1926-51 and 1951-2011, respectively.

For my purposes here I will use the midpoint of the Fernandez summary, or 7 percent. Substitution of all of the above-mentioned values into the CAPM model results in a cost of equity of:

(7) $k = 2.74\% + .73X(7\%) = 7.85\%,$

which is my CAPM estimate.

RISK PREMIUM MODEL

Q. Please discuss the Risk Premium model.

A, The Risk Premium model simply uses the following equation:

(8) $k = R_B + RP$

Where k is the cost of equity, R_B is the current yield on utility bonds, and RP is the risk premium, comparing required utility returns with utility bond yields. The variable RP may be dependent on the overall level of interest rates and the overall volatility of interest rates. I have done research on this issue, which was published in *Managerial and Decision Economics*[2] (attached as Exhibit SKB-6). In that article I demonstrate that there

[2] S. Keith Berry, "Interest Rate Risk and Utility Risk Premia During 1982-93" *Managerial and Decision Economics.* (1998).

is an inverse relationship between the risk premium and the current level of utility bond yields, as well as a positive relationship between the risk premium and investor-perceived volatility in utility bond yields.

Focusing on the inverse relationship between the risk premium and the current level of utility bond yields, I estimated the following regression equation for RP in my article:

$$(9) \qquad RP = .07722 \ -.48392R_B$$

Utility Baa/BBB bond yields have averaged 4.24 percent for the period July 2012 through September 2012 as reported in *Value Line*. This is shown in Exhibit SKB-5.

Substitution of this data into the above Eq. (9) produces a RP of 5.668 percent. Substitution of this RP and R_B = 4.24 percent into above Eq. (8) produces a risk premium cost of equity of 9.91 percent.

In that same article I did a similar analysis using U.S. Treasury Bond Yields. The equation from the article is:

$$(10) \qquad k = R_F + RP_F$$

where R_F is the Treasury Bond yield and RP_F is the risk premium, comparing required utility returns with Treasury Bond yields.

In my article, the regression equation for RP_F is:

(11) $RP_F = .07533 - .39096R_F$.

Using the U.S. Treasury Bond yield of 2.74 percent that I discussed earlier in the Section on the CAPM produces a risk premium of $RP_F = 6.462$ percent. Substitution of that and $R_F = 2.74$ percent into Eq. (10) above produces a cost of equity estimate of 9.202 percent

My Risk Premium-based cost of equity range is 9.20 percent to 9.91 percent.

Q. What is your recommended cost of equity in this case?

A. A summary of my results is presented in Table 1 below.

TABLE 1
COST OF EQUITY RESULTS

Method	**Cost of Equity**
Constant Growth DCF	**8.83% - 9.83%**
Multi-Stage DCF	**9.43% - 9.55%**
CAPM	**7.85%**
Risk Premium	**9.20% - 9.91%**

The maximum range of cost of equity estimates is from 7.85 percent to 9.91 percent. Giving more weight to the DCF estimates, my point estimate of the cost of equity for TEP in this case is 9.4 percent with a range of 8.9 percent to 9.9 percent.

Q. What is your overall original cost rate base rate of return recommendation, before adjustment for FVRB, for TEP, in this case?

A. My overall recommendation is 7.00 percent, as shown in Table 2 below.

TABLE 2
ORIGINAL COST RATE BASE RATE OF RETURN

Capital Component	Proportion	Cost	Weighted Cost
Short-Term Debt	**0.53%**	**1.42%**	**0.01%**
Long-Term Debt	**55.97%**	**5.18%**	**2.90%**
Common Equity	**43.50%**	**9.40%**	**4.09%**

Overall weighted cost of capital = 7.00%

REBUTTAL OF TEP WITNESSES REED AND LARSON

Q. Dr. Berry, have you read and analyzed the Cost of Capital Testimony, exhibits and workpapers of TEP Witnesses John J. Reed and Kevin P. Larson?

A. Yes, I have.

Q. Do you disagree with parts of their analysis and conclusions?

A. Yes, I do.

Q. With which parts of their analysis do you disagree?

A. I disagree with their analysis and conclusions in the following areas:

(1) The capital structure recommended by Mr. Reed and Mr. Larson for TEP;

(2) The Risk-Comparable sample used by Mr. Reed;

(3) The long-term growth rate estimates used in Mr. Reed's constant growth rate DCF analysis;

(4) The GDP growth rate and payout ratios used in Mr. Reed's multi-stage DCF analysis;

(5) The risk-free rate and market risk premium used in Mr. Reed's CAPM analysis;

(6) The risk-free rate used in Mr. Reed's Bond Yield plus Risk Premium analysis;

(7) Mr. Reed's evaluation of the Company's risk compared with the risk-comparable sample using the ratio of capital expenditures to net plant; and

(8) The calculation of the rate of return on the FVRB Increment by Mr. Reed.

Q. Please discuss your disagreement with Mr. Reed's and Mr. Larson's capital structure.

A. They both recommend a hypothetical structure for TEP in this case. It is composed of 46 percent common equity, 54 percent long-term debt, and 0 percent short-term debt. That compares with TEP's actual capital structure, as of December 31, 2011, of 43.50 percent common equity, 55.97 percent long-term debt, and 0.53 percent short-term debt (Company Schedule D-1, page 1 of 2). The Company's proposed capital structure results in an inflated overall rate of return and an implicitly higher return on equity. The Company has provided an insufficient basis for use of a hypothetical capital structure in this case.

Q. How does the Company's hypothetical capital structure compare to its actual capital structure during the past year?

A. As compared with the past year, the Company-proposed common equity ratio of 46 percent exceeds TEP's actual common equity for each of the five quarters ending with the Third Quarter of 2012. This is shown in Exhibit SKB-7. Further, as shown there, the average common equity ratio for the Third Quarter 2011, through the Third Quarter 2012,

is 42.51 percent. Additionally, since the end of the test year (December 31, 2011) the Company's common equity ratio has been below 42 percent. All of this indicates that the Company's proposed common equity ratio of 46 percent is outside the range of its recent historical experience.

Q. Does the Company-proposed capital structure artificially inflate the Company's Cost of Capital?

A. Yes, it does. The Company's proposal artificially increases the common equity proportion and artificially decreases the debt proportion. Since the cost of equity is greater than the cost of debt, the overall rate of return is, consequently, inflated. Additionally, the Company's exclusion of short-term debt from the capital structure inflates the overall rate of return, since the cost of short-term debt is smaller than either the cost of equity or the cost of long-term debt. It is appropriate to include short-term debt since that is a source of funds for TEP and the Company generally has some amount of short-term debt.

Q. Does the Company-proposed capital structure artificially inflate the Company's allowed Return on Equity?

A. Yes, it does. As shown in Exhibit SKB-8, use of the Company's **proposed** capital structure results in an effective allowed return on equity of 11.22 percent based on the Company's **actual** test year capital structure. The Company's proposed capital structure has the same effect as increasing the effective return on equity by 47 basis points. This high of an allowed return on equity is not supported by any evidence presented by Mr. Reed.

Q. Please discuss your disagreement with Mr. Reed's risk-comparable sample.

A. The only disagreement I have with Mr. Reed's risk-comparable sample is that I recommend inclusion of UNS Energy, TEP's parent company, in the sample. For Cost of Capital purposes it is reasonable to include TEP's parent company as a part of the risk-comparable sample. There is no circularity in including it since UNS Energy's common equity is used to supply TEP's common equity. That is the only source of common stock for TEP. Surely, an analysis of TEP's cost of equity should include an analysis of the cost of equity of the sole supplier of TEP's common equity. Further, note that TEP accounted for approximately 77 percent of UNS Energy's Net Income and 77 percent of UNS Energy's Operating Revenues in calendar year 2011. This indicates that TEP accounts for a significant part of UNS Energy's operations and, implicitly, UNS Energy's cost of equity.

Q. Please discuss the long-term growth rate estimates used by Mr. Reed in his constant growth DCF analysis.

A. As discussed in his Direct Testimony (See Reed Direct at 20:11-28 - 21:7), Mr. Reed solely relied upon EPS growth rate projections to estimate the investor-expected sustainable long-run growth rate in DPS. There are three general problems with relying *exclusively* on his specific growth rate approach.

First, in the Constant Growth DCF method it is important to estimate sustainable long-run growth rates in DPS. No doubt expected EPS growth rates are a factor in expected DPS growth rates but they are not the **sole** factor investors would look to in formulating their long-term dividend growth rate expectations. As I discussed earlier, investors also look to expected DPS growth rates, expected BVPS growth rates, and expected earnings retention. Mr. Reed places entirely too much weight on short-term EPS growth rate expectations.

Second, the earnings growth rates that he exclusively utilizes are simply not sustainable. As shown in Exhibit JJR-2, the average growth rate in earnings per share ("g") he uses is 6.49 percent. However, as I discussed earlier, a key long-term component of dividend growth is derived from growth in BVPS. Most of that growth is derived from earnings retention, or the "br" factor I discussed earlier. The "b" factor for the Risk-Comparable Sample is approximately 38 percent. Given that "g" is approximately equal to "br", this implies that, in the context of Mr. Reed's analysis, 6.49 percent = 38 percent times r, or that r, the investor-expected return on equity, is r = 6.49 percent/38 percent = 17.079 percent, or approximately 17 percent. There is absolutely no evidence that investors expect the utilities in the Risk-Comparable sample to earn approximately 17 percent on a long-term sustainable basis. Both historical and expected returns on equity in my Risk-Comparable Sample are in the range of 9-10 percent, significantly less than 17 percent. Consequently, Mr. Reed's 6.49 percent growth rate factor, relying exclusively on short-term EPS analyst-projected growth rates, is simply not sustainable, and is inappropriate for usage in the DCF method.

There are a number of articles and studies that discuss the upward bias and lack of reliability in these five-year EPS growth forecasts by stock analysts. For example, in a study by Cusatis and Woolridge, they find that:

> "Long-term EPS growth rate forecasts are consistently over-optimistic...We do discover that a contributing factor in the bias in analysts' long-term and one-year EPS growth rate estimates is the resistance of analysts to project negative earnings growth rates."[3]

[3] Patrick Cusatis, CFA and J. Randall Woolridge, "The Accuracy of Analysts' Long-Term Earnings Per Share Growth Rate Forecasts," January 24, 2008.

This study was also publicized in *The Wall Street Journal*, a well-known periodical relied upon by investors.[4]

In an article from McKinsey & Company, the authors state that:

> "[In research we undertook nearly a decade ago], analysts, we found, were typically overoptimistic…Alas, a recently completed update of our work only reinforces this view despite a series of rules and regulations, dating to the last decade, that were intended to improve the quality of the analysts' long-term earnings forecasts, restore investor confidence in them, and prevent conflicts of interest…On average analysts' forecasts have been almost 100 percent too high."5

This article was also publicized in *Bloomberg Businessweek*, a general source of financial information for investors.[6]

Also, from a study by Lacina, Lee, and Xu:

> "Our findings imply that analysts' long-term earnings forecasts should be used with caution by researchers and practitioners as they do not appear to be more accurate than long-term forecasts from naïve models."[7]

Third, while Mr. Reed characterizes his EPS growth estimates as long-term, they are not. The *Value Line* earnings growth rate estimates are for approximately seven years, and the Zach's and First Call estimates are for approximately five years. As I pointed out earlier, the investor-expected growth rates appropriate for usage in the DCF method are long-term

[4] Andrew Edwards, "Study Suggests Bias in Analysts' Rosy Forecasts.' *The Wall Street Journal*, March 21, 2008, Page C6.
[5] Marc H. Goedhart, Rishi Raj, and Abhishek Saxena, "Equity analysts: Still too bullish." McKinsey on Finance, Number 35, Spring 2010.
[6] Roben Farzad, "For Analysts, Things Are Always Looking Up," *Bloomberg Businessweek, Markets and Finance*, June 10, 2012.
[7] Michael Lacina, B. Brian Lee and Randall Zhaohui Xu, "An Evaluation of Financial Analysts and Naïve Methods in Forecasting Long-Term Earnings." *Advances in Business and Management Forecasting*, Volume 8, 77-101. 2011.

in nature. In the determination of the price in the DCF method, only about 18 percent to 27 percent of the market price is determined by the dividends in the first 5 to 7 years. Mr. Reed neglects the remaining 73 percent to 82 percent of future dividends, from years after the first 5 to 7 years, that determine the market price and, consequently, fails to consider investors' long-term growth rate expectations. To base long-term investor growth rate expectations *exclusively* on 5-year EPS growth rates, as Mr. Reed did, is inappropriate.

Q. Should the Commission place any reliance upon Mr. Reed's constant growth DCF results?

A. No, it should not. His constant growth DCF mean results are in the range of 10.77 percent to 10.87 percent. These results are inflated because of Mr. Reed's *sole* reliance upon analysts' projected EPS growth rate projections, and the unlikelihood of investors relying *solely* on those projections. The Commission should not rely on Mr. Reed's constant growth rate DCF results, and should rely upon my results as I previously discussed.

Q. Please generally describe Mr. Reed's multi-stage DCF model.

A. The equation underlying his model is

$$(12) \quad P_0=[D_{2012}/(1+k)] + [D_{2013}/(1+k)^2 +\ldots + [D_{2025}/(1+k)^{14}] + [D_{2026}/((1+k)^{15}(k-g))]$$

Where P_0 refers to the current market price per share, D refers to dividends per share in a given year, subscripts refer to the year in which the dividends per share are expected, g is the long-term growth rate expected in 2026 and thereafter, and k refers to the cost of equity.

Mr. Reed used the Solver function in the Excel spreadsheet program to solve for "k" given his inputs on all of the other variables, dividends, growth, and stock market prices. It is important to note that given the way Solver works, if the dividend inputs from year 2012 to year 2025 are over-estimated and if "g", the long-term growth rate input, is overestimated, the estimated, or "Solved", value of "k" is biased upward. This is, indeed, what happened in Mr. Reed's analysis.

As a result, Mr. Reed's multi-stage DCF cost of equity estimates of 10.55 percent - 10.67 percent are inappropriately biased upward.

Q. Are there any specific problems with his inputs to the model?

A. Yes, I have identified two input flaws in that analysis. First, he used inflated dividend payout ratios for the long-term. These payout ratios were based on average payout ratios from the year 1990 to present, and exceed the projected dividend payout ratios for 2016. This approach inflated the expected dividends over the years 2011 to 2026 and inflated the estimate of the cost of equity.

Second, he over-estimated his long-term growth rate. He calculated that growth rate based on an estimated real GDP growth rate of 3.24 percent from 1929 through 2011, and on a projected inflation rate of 2.14 percent. Generally, the "nominal" GDP growth rate is the sum of the real GDP growth rate plus inflation. More particularly, in this case he multiplied 1.0214 times 1.0324 and subtracted 1.0, to obtain a nominal GDP growth rate of 5.45 percent, He then used this data input as his long-term growth in dividends per share for each company in his Risk-Comparable sample. This long-term growth rate estimate methodology is biased upward, which inappropriately biases upward the Company's estimated cost of equity.

Q. How did you correct for these two input flaws in Mr. Reed's multi-stage DCF model?

A. With regard to Mr. Reed's first error, I used the projected dividend payout ratio for 2016 as the long-term dividend payout ratio. I believe these ratios more accurately reflect investor expectations than do Mr. Reed's dividend payout assumptions based on average payout ratios from the year 1990 to present.

Second, instead of relying on historical real GDP growth rates, as did Mr. Reed, I used projected real GDP growth rates obtained from the U.S. Energy Information Administration, Annual Energy Outlook 2012 Early Release, and the Social Security Administration. Those long-term projected growth rates in real GDP were 2.6 percent and 2.1 percent, respectively. The average of those two estimates is 2.35 percent. This modification, in conjunction with the projected inflation growth rate of 2.14 percent, which I do not disagree with, produces a projected nominal GDP growth rate of 4.54 percent (1.0214 times 1.0235 less 1.0). I used that 4.54 percent growth rate as the long-term growth rate in the multi-stage DCF model. I believe that this more accurately reflects investors' long-term growth estimates than does Mr. Reed's 5.45 percent growth rate.

Q. How did you use these two corrected input assumptions to Mr. Reed's multi-stage DCF model?

A. I used the exact same spreadsheets that Mr. Reed employed in his multi-stage DCF analysis (Exhibit JJR-3), which were provided in his workpapers. I then substituted the long-term payout ratios and long-term growth rates I calculated above for Mr. Reed's corresponding inputs, and used the Solver function in Excel to calculate the estimated cost of equity. Those results are shown in Exhibit SKB-9. The corrected multi-stage DCF cost of equity range is 9.43 percent - 9.55 percent, which is approximately at the middle of my recommended cost of equity range.

Q. Please discuss your disagreements with Mr. Reed's CAPM analysis.

A. Mr. Reed estimates a CAPM cost of equity of 10.53 percent to 10.55 percent. While I do not have any disagreement with his Beta estimate, I do have two problems with other components of his CAPM analysis. First, the risk-free rate he used does not reflect current market conditions. The risk-free rate he used is in the range of 3.24 percent - 5.10 percent (Exhibit JJR-4, page 1 of 8). The top end of that range, 5.1 percent, reflects projected 30-year U.S. Treasury Bond yields for the period 2013-2017 from *Blue Chip Financial Forecasts*, December 1, 2011 at 14. That interest rate assumption is entirely speculative and does not reflect current market conditions. Note, in particular, that on the same page of that particular *Blue Chip Financial Forecasts* (page 14 from that document shown in Exhibit SKB-10) the following statement is made:

> "Shown are estimates for the years 2013 through 2017 and averages for the five-year periods 2013-2017 and 2018-2022. *Apply these projections cautiously. Few economic, demographic, and political forces can be evaluated accurately over such long time spans.*" (Emphasis added).

Thus, the source of the 5.1 percent risk-free rate used by Mr. Reed emphasizes the potential for inaccuracy in the exact same long-term projections that it presents. Consequently, the 5.1 percent datum used by Mr. Reed in his CAPM should be disregarded. Further, the 3.24 percent and 3.58 percent estimates of the risk-free rate (shown in Exhibit JJR-4) should also be disregarded since they do not reflect *current* market conditions. As I discussed earlier, the recent 30-year U.S. Treasury Bond yield is 2.74 percent (Exhibit SKB-5) and it is that risk-free rate that should be used in a CAPM analysis.

The second area in which I disagree with Mr. Reed's CAPM analysis is with regard to his calculation of the required market risk premium. As shown in Exhibit JJR-4, page 2 of 8,

in order to calculate that risk premium, he estimates an S&P 500 Required Market Return of 12.97 percent. This is based on a DCF model with a 2.13 percent dividend yield for the S&P 500 and a 10.72 percent long-term growth rate for the S&P 500. As shown in Supplemental Response to Staff 15.2 (Exhibit SKB-11), that long term growth rate is derived from analysts' EPS forecasts for each S&P company over the next 3 to 5 years.

Based on this analysis, the risk premium derived in the Company's CAPM analysis is as high as 9.73 percent.

As I noted earlier in my discussion of Mr. Reed's constant growth DCF model, it is inappropriate to use analysts' EPS growth forecasts of 5 years or less in a constant growth DCF model. It should also be noted that there is a glaring inconsistency between the Company's multi-stage DCF cost of equity analysis and its CAPM analysis. The estimate of a 10.72 percent long-term DCF growth rate in its CAPM model is inconsistent with its 5.45 percent estimate of long-term growth in his multi-stage DCF model. The estimate of long-term growth in his CAPM model is approximately *two times greater* than his estimate of long-term growth in his multi-stage DCF model (10.72 percent versus 5.45 percent).[8]

Reasonable arguments have been made that long-term EPS growth should track long-term nominal GDP growth.[9] It is unreasonable to expect, as does Mr. Reed, that long-term EPS growth will be *twice as much* as long-term growth in nominal GDP.

[8] Using my 4.54 percent long-term growth rate in the multi-stage DCF model, the 10.72 percent figure is 2.4 times the appropriate long-term growth rate.
[9] For example, see Bradford Cornell, "Economic Growth and Equity Investing," Financial Analysts Journal, Vol. 66, Number 1, 2010.

For the above reasons, it is inappropriate to use a 10.72 percent EPS growth rate in an S&P 500 DCF model, and also to use an approximate 10 percent market risk premium for purposes of the CAPM. As I discuss earlier in my testimony, a reasonable CAPM cost of equity estimate is 7.85 percent.

Q. Please discuss your disagreements with Mr. Reed's "Bond Yield plus Risk Premium" analysis.

A. In his Bond Yield plus Risk Premium analysis, Mr. Reed appropriately recognizes the inverse relationship between utility required ROEs and bond yields, which is demonstrated in my article in *Managerial and Decision Economics*. However, he uses an inappropriate risk-free rate. He uses the same 3.24 percent to 5.10 percent range for the risk-free rate here that he used in his CAPM model. For the same reasons I discussed earlier, that risk-free rate range is inappropriately high.

As shown in Exhibit JJR-5, page 2 of 2, his estimated regression equation, comparable to my Eq. (11) shown above, is:

$$(13) \quad RP_F = .089375 - .62186R_F.$$

Using a current Treasury bond yield of 2.74 percent, as I discussed above, and substituting that into Eq. (13) yields a risk premium of 7.234 percent and a cost of equity estimate of 9.97 percent which is *19 to 90 basis points less* than his derived cost of equity range of 10.16 percent to 10.87 percent.

Q. Please discuss Mr. Reed's analysis of the ratio of projected capital expenditures to net plant.

A. Mr. Reed makes the claim that TEP's ratio of projected capital expenditures to net plant is significantly greater than the corresponding ratios for the Risk-Comparable sample, and therefore an allowed return on equity above the proxy group mean is appropriate. See Reed Direct at 31-33.

However, he is focusing on just one risk factor that investors are aware of in evaluating their risk expectations of TEP. In fact, there is a myriad of risk factors that investors will consider. For example, investors consider:

(1) Macroeconomic conditions, both national and regional, such as inflation rates, unemployment rates, Gross Domestic Product growth rates, and interest rates;

(2) Volatility in financial markets;

(3) Wholesale contract disputes;

(4) Financial or regulatory accounting principles or policies imposed by the Financial Accounting Standards Board, the SEC, the Federal Energy Regulatory Commission, and similar entities with regulatory oversight;

(5) Changes in tax laws;

(6) Disputes with the IRS;

(7) Unusual weather conditions which may result in weather-induced decreases in usage;

(8) Changes in copper prices which could affect the mining sector's electricity usage;

(9) Unscheduled generation, transmission, or distribution outages, maintenance, or repair;

(10) Susceptibility to cyber-attacks and information security risks;

(11) Unanticipated changes to fuel supply costs, or unavailability due to higher demand, shortages, transportation problems or other developments;

(12) Changes in environmental laws and regulations including regulations related to carbon charges;

(13) Customer business conditions including the percentage of load accounted for by business cycle sensitive industrial load;

(14) Credit risk associated with customers that do not pay their bills and counterparties that owe money or product and breach their obligations;

(15) Risks associated with funding of defined benefit pensions and post-retirement plans for employees; and

(16) Increasing costs associated with health care plans.

Q. Does this array of risk factors imply that adjustments should be made to your DCF-based Cost of Equity?

A. No, it does not. The common stock market price terms in the Risk-Comparable sample implicitly reflect investor evaluations of these risk factors. To the extent investors are concerned with these risk factors the stock market price terms will be correspondingly lower and reflected in a greater dividend yield, and higher cost of equity, in the DCF model.

Consequently, Mr. Reed's implicit argument that investors focus disproportionately on the ratio of capital expenditures to net plant is fallacious, and should be accorded no weight by this Commission.

RATE OF RETURN ON FVRB INCREMENT

Q. What is your understanding of the 2007 Chaparral City remand on the issue of FVRB?

A, While I am not an attorney, my lay understanding of that Court decision is that the Commission must consider the fair value of a utility's assets in setting rates. However, that does not imply that the Company's cost of capital must be applied to the fair value of the Rate Base. That decision also notes that "If the Commission determines that the cost of capital analysis is not the appropriate methodology to determine the rate of return to be applied to the FVRB, the Commission has the discretion to determine the appropriate methodology." Here, I am recommending the appropriate methodology for use in conjunction with a FVRB.

Q. Do you have any general observations about the Application of a Rate of Return to a FVRB?

A. Yes, I do. Based on my experience, the weighted Cost of Capital is designed to apply to an original cost rate base. That weighted Cost of Capital is derived from the liabilities side of the balance sheet, and is then applied to the Original Cost Rate Base, which is from the asset side of the balance sheet. Then the weighted Cost of Capital is multiplied times the Original Cost Rate Base. This approach matches up the total liabilities that undergird the rate base to that same Original Cost Rate Base. Investors, in both debt and equity, receive returns on their investments, which are reflected on the liabilities side of the balance sheet. The utility is then allowed the opportunity to earn a fair return on its investments.

However, with the introduction of a FVRB, the financial link between the capital structure and the rate base is essentially broken. Clearly, the amount of FVRB that is in excess of

the Original Cost Rate Base ("FVRB Increment") is not financed with any investor-supplied capital, and cannot be associated with any of the components on the liability side of the balance sheet.

Because of this, it is reasonable from a financial standpoint to assume that this Increment has no, or zero, financing costs. As a result, the capital structure and cost of capital can be modified to include a zero-cost component in the capital structure. That zero-cost component in the capital structure would correspond to the increment of FVRB over the Original Cost Rate Base ("FVRB Increment") and would receive a zero-cost assignment.

Alternatively, if the Commission determines that there should be a specific return applicable to the FVRB Increment, I provide here such a method.

Since the FVRB Increment is not financed with any investor-supplied capital, there is no risk attached to that Increment. Consequently, the return assigned to that Increment should be risk-free. Risk-free investments are generally defined as U.S. Treasury Securities. Additionally, since the FVRB implicitly includes the effects of inflation, it is appropriate to remove the effects of inflation from that risk-free rate of return. We can call that the "real" risk-free rate of return.

One approach to estimating the real risk-free rate of return is to use yields on U.S. Treasury Inflation Protected Securities ("TIPS"). These securities periodically adjust the face amount of the security by the amount of inflation, and then apply the TIPS interest rate to that amount. Because of that adjustment, investors are protected from the effects of inflation eating away at the invested principal. Consequently, the yield on TIPS is both risk-free and adjusted for inflation, and is a *real risk-free rate of return.*

A second approach to estimating a risk-free rate of return is to take the yield on a traditional risk-free long-term U.S. Treasury Bond ("nominal risk-free rate") and subtract from that the inflation rate. This is the approach Mr. Reed used in his estimation of a real risk-free rate of return. (See Reed Testimony at 47: 6-12).

For my first approach, I averaged average annual yields on long-term (over 10 years) TIPS for the period 2003 -2011 (Exhibit SKB-12). That average is 2.07 percent and represents one estimate of the real risk-free rate of return.

For the second approach, I utilized the recent nominal risk-free yield of 2.74 percent on long-term U.S. Treasury Securities, as I discussed above in the context of the CAPM. For the annual inflation rate, I use a 2.10 percent rate which is the same as used by Mr. Reed. The real risk-free rate of return with this approach is then:

(14) Nominal risk-free rate – Inflation = Real Risk-Free Rate

or

(15) 2.74% - 2.10% = 0.64%.

Q. Given these two approaches for estimating the real risk-free rate of return, what is your real risk-free Rate of Return?

A. I averaged these two approaches to obtain my estimate of 1.36 percent (2.07 percent plus 0.64 percent divided by 2). However, it should be noted that this is a maximum value that could be applied to the FVRB Increment.

I provided this data to Staff witness Ralph Smith for purposes of calculating the FVROR.

Q. Do You Have Any Comments on Mr. Reed's Calculation of a Rate of Return on the FVRB increment for TEP?

A. Yes, I do. He used my second approach for estimating the real risk-free rate of return, with one major exception. He used projected yields from the period 2013 to 2022 on 30-year U.S. Treasury Bonds and obtained a 5.29 percent nominal risk-free rate of return before adjusting for a 2.10 percent inflation rate. He obtained a 3.12 percent real risk-free rate of return. (Reed Direct at 47: 6-12).

The problem with this approach is that he used projected yields for the future from *Blue Chip Financial Forecasts* and they are simply not reliable. That interest rate assumption is entirely speculative and does not reflect current market conditions. Note, in particular, that on the same page of that particular *Blue Chip Financial Forecasts* (page 14 from that document shown in my Exhibit SKB-10) the following statement is made:

> "Shown are estimates for the years 2013 through 2017 and averages for the five-year periods 2013-2017 and 2018-2022. *Apply these projections cautiously. Few economic, demographic, and political forces can be evaluated accurately over such long time spans.*" (Emphasis added).

Thus, the source of the 5.29 percent nominal risk-free rate used by Mr. Reed emphasizes the potential for inaccuracy in the exact same long-term projections that it presents. Consequently, the 5.29 percent datum, as well as the real risk-free rate of return of 3.12 percent used by Mr. Reed in his FVROR, should be disregarded.

Q. Do you have any other comments on the FVROR.

A. As shown in Staff Attachment RCS-2, page 11, sponsored by Staff witness Ralph Smith, the Company's proposed rate of return on FVRB Increment of 1.56 percent results in an

effective 12.45 percent allowed return on equity. This is **170 basis points** greater than the Company's requested rate of return on equity.

Q. Why does this occur?

A. This occurs because that return is applied to the FVROB Increment, which is not supported or supplied by any investors. That return inures **solely** to the benefit of the Company's shareholders, who supplied zero funds to support that Increment.

Q. Why is this relevant in this case?

A. While the Commission should be mindful of the Court's rulings in the 2007 Chaparral City Remand, the Commission should also be aware of this increased **170 basis point increment** to the Company's effective allowed return on equity in evaluating the reasonableness of the Company's requested rate increase,

This is in addition to the increment of 47 basis points associated with the Company's proposed hypothetical capital structure, as I discuss earlier.

Q. Is there a similar return on equity increment associated with the FVRB in Staff's case?

A. Yes, there is. As shown in Staff Attachment RCS-2, page 13, sponsored by Staff witness Ralph Smith, the effective allowed return on equity in FVROR Option 2 is 10.19 percent. This is 79 **basis points** above my recommended allowed return on equity of 9.40 percent. The Commission should also be aware of this increased increment to the Company's effective allowed return on equity in making its decision in this case.

CONCLUSIONS

Q. Please summarize your conclusions.

A. I recommend a capital structure, before adjustment for FVRB, with 43.50 per cent common equity, 55.97 per cent long-term debt, and 0.53 per cent short-term debt. This is the same capital structure proportions for Test Year ending December 31, 2011 that is reflected in the Company's Schedule D-1, Page 1 of 2, which I find to be reasonable.

I recommend a cost of equity of 9.4 percent, with a range of 8.9 percent - 9.9 percent, while the Company proposes a 10.75 percent cost of equity. I also recommend an overall cost of capital of 7.00 percent before adjustment for FVRB.

I recommend a rate of return of 0.0 percent to 0.68 percent on the FVRB Increment. This results in an overall rate of return range of 4.63 percent to 4.86 percent, which is applicable to the FVROR. These numbers are based on Staff Attachment RCS-2, page 10 of Ralph Smith Exhibits.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

Exhibit SKB-1

S. KEITH BERRY

Department of Economics and Business, Hendrix College, 1600 Washington Avenue, Conway, AR 72032, Office Tel # (501) 450-1233, Fax # (501) 450-1233,Home Tel # (501) 217-4048, E-mail: berry@hendrix.edu

CURRENT POSITIONS

Professor, Department of Economics and Business
Hendrix College, 2002-Present

Vice President
Economic & Financial Consulting Group, Inc., 1990-Present
Conway, AR 72032

EDUCATION

Ph.D., Economics
Vanderbilt University, 1979

B.A., Mathematics
Hendrix College, 1973

PREVIOUS POSITIONS

Director, Center for Entrepreneurial Studies
Hendrix College, 2001-2007

Chair, Department of Economics and Business –Supervisor of five faculty
Hendrix College, 2003-05

Associate Professor of Economics and Business
Hendrix College, 1994-2002

Assistant Professor of Economics and Business
Hendrix College, 1989-1994

Director of Research and Policy Development-Supervisor of six policy analysts
Arkansas Public Service Commission, Little Rock, AR, 1986-1989

Manager of Rates and Finance Sections-Supervisor of six rate and financial analysts
Arkansas Public Service Commission, Little Rock, AR, 1979-1986

Instructor/Assistant Professor of Economics and Business
Hendrix College, Conway, AR, 1977-1979

Instructor
Vanderbilt University, 1976-77

CURRENT AND PAST CONSULTING ACTIVITIES WITH THE ARKANSAS PUBLIC SERVICE COMMISSION

I have been retained as a consultant and expert witness by the Arkansas Public Service Commission continuously since 1990. In that capacity, I have advised the Arkansas Commission, and filed testimony on behalf of the Arkansas Commission, on the following subjects:

(1) Regional Transmission Organizations;
(2) Independent Coordinator of Transmission;
(3) Locational marginal pricing;
(4) Resource Planning;
(5) Mergers;
(6) National Interest Electric Transmission Corridors;
(7) Transmission Planning;
(8) Standard Market Design;
(9) Demand Side Resources;
(10) System Pooling Agreements;
(11) Stranded Costs;
(11) FERC Rulemaking on Transmission Issues;
(13) Fuel Adjustment Clauses;
(14) Interruptible Rates;
(15) Avoided Cost Pricing;
(16) Nuclear decommissioning rates;
(17) Retail electric utility rate cases;
(18) Gas Distribution utility rate cases;
(10) Regional Transmission Organizations;
(19) Independent Transmission Companies;
(20) Cost of capital;
(21) Depreciation expense reflected in formula rates;
(22) Plant cancellation costs reflected in formula rates;
(23) Nuclear decommissioning rates;

(24) Utility mergers;
(25) Nuclear plant purchases;
(26) Interruptible rates.

TECHNICAL ASSISTANCE PROVIDED

Technical assistance on cost of capital issues provided to District of Columbia Public Service Commission and Staff, Formal Case No. 1087, Pepco Electric Rate Case, 2011-12.

Technical assistance on cost of capital issues provided to District of Columbia Public Service Commission and Staff, Formal Case No. 1093, Washington Gas Light Company Rate Case, 2012.

TESTIMONY OR REPORTS PRESENTED TO COMMISSIONS, COURTS OR AGENCIES

Federal Energy Regulatory Commission, Docket No. EL12-1384-000, Testimony concerning inclusion of cancelled production costs on Entergy's bandwidth calculations. October, 2012.

U.S. District Court for the Middle District of Louisiana, Civil Action No.09-100-RET-CN, United States of America et al. v. Louisiana Generating, LLC. Expert Report concerning the financial integration between Louisiana Generating, LLC and NRG Energy, August, 2012

Federal Energy Regulatory Commission, Docket No. EL12-1384-000. Affidavit concerning impact of cancelled production costs on Entergy's bandwidth calculations. May, 2012.

Federal Energy Regulatory Commission, Docket No. EL12-1384-000. Affidavit concerning impact of cancelled production costs on Entergy's bandwidth calculations. April, 2012.

Federal Energy Regulatory Commission, Docket No. EL01-88-000. Affidavit concerning increase in EAI bandwidth payments for seven months in the year 2005. January, 2012.

Missouri Public Service Commission, Case No. HR-2011-0241. Testimony concerning the cost of capital of Veolia Energy Kansas City, Inc., September, 2011.

North Dakota Public Service Commission, Case Nos. PU-10-6576 and PU11-55. Testimony concerning cost of capital of Northern States Power Minnesota operating in North Dakota, August, 2011.

Federal Energy Regulatory Commission, Docket No. EL11-57-000. Affidavit concerning impact of cancelled production costs on Entergy's bandwidth calculations. August, 2011.

Federal Energy Regulatory Commission, Docket No. ER10-2001. Testimony concerning depreciation expense used in bandwidth calculations. April, 2011.

Federal Energy Regulatory Commission, Docket No. ER10-1350. Testimony concerning bandwidth calculations. December, 2010-January, 2011.

Federal Energy Regulatory Commission, Docket No. EL10-55-000. Testimony concerning depreciation expense used in bandwidth calculations. October, 2010.

Federal Energy Regulatory Commission, Docket No. EL09-1224-000. Testimony concerning 2009 bandwidth calculations for Entergy Operating Companies. January and February, 2010.

Connecticut Department of Public Utility Control. Participation in task force that performed a Management Audit of the Connecticut Light & Power Company, May, 2009.

Federal Energy Regulatory Commission, Docket No. ER09-636-000. Affidavit concerning Entergy Arkansas notice of intent to withdraw from the Entergy System Agreement, April, 2009.

Federal Energy Regulatory Commission, Docket No. EL08-51-000. Testimony concerning recovery of Spindletop regulatory asset in 2008 bandwidth remedy. February, 2009.

Federal Energy Regulatory Commission, Docket No. ER08-1056-000. Testimony concerning inclusion of certain Evangeline gas costs in 2008 bandwidth calculations for Entergy, January, 2009.

Federal Energy Regulatory Commission, Docket No. ER08-1056-000. Affidavit on 2008 bandwidth remedy on Entergy System. July 2008.

Federal Energy Regulatory Commission, Docket No. ER07-956-000. Testimony concerning Entergy System Agreement 2007 bandwidth effects of imprudence and depreciation, February-March, 2008.

Federal Energy Regulatory Commission, Docket No. EC07-70-000. Affidavit concerning Entergy acquisition of Calcasieu Power, LLC.

Maryland Public Service Commission, Case No. 9062. Testimony concerning the cost of capital of Chesapeake Utilities Corporation, August, 2006.

Federal Energy Regulatory Commission, Docket No. EL06-76-000. Affidavit in Complaint by APSC concerning production costs on the Entergy System, April, 2006.

Federal Energy Regulatory Commission, Docket No. ER03-583-000, et al. Testimony concerning purchased power agreements on Entergy System, November, 2003.

Federal Energy Regulatory Commission, Docket No. ER03-753-000. Testimony concerning unit power rate schedule on Entergy System, November, 2003.

Federal Energy Regulatory Commission, Docket No. EL01-88-000.
Testimony opposing production cost equalization on the Entergy System, March, 2003, April, 2003, and July, 2003.

Securities and Exchange Commission, File No. 70-9785, Affidavit concerning issues associated with exempt wholesale generators for American Electric Power, September, 2002.

Federal Energy Regulatory Commission, Docket No. EL01-88-000.
Affidavit opposing production cost equalization on the Entergy System, July, 2001.

Federal Energy Regulatory Commission, Docket Nos. EL00-66-000 et al.
Affidavit concerning production cost equalization on the Entergy System, May, 2001.

State of Arkansas General Assembly, Testimony concerning HB 1411 regarding funding of the White River Navigation Project, January, 2001.

Federal Energy Regulatory Commission, Docket Nos. EL00-66-000 et al.
Testimony concerning modification of Entergy System Agreement to accommodate deregulation and interruptible rates, December, 2000, January, 2001, and February, 2001.

Federal Energy Regulatory Commission, Docket Nos. EL98-40-000 et al.
Testimony concerning the merger of American Electric Power and Central and South West, May, 1999 and June, 1999.

Federal Energy Regulatory Commission, Docket No. EC99-18-000
Affidavit concerning the proposed acquisition of Pilgrim Nuclear Unit by Entergy Corporation, January, 1999.

Securities and Exchange Commission, File No. 70-9049
Affidavit concerning financial risk of diversification of Entergy Corporation, October, 1998.

Arkansas Public Service Commission, Docket No. 98-081-TF
Testimony concerning off-peak rates, March, 1998.

"Report on the Cost of Equity of New York Power Authority," December, 1997.

State of Arkansas General Assembly
Economic Policy Analysis of Telecommunications Reform Act of 1997, January, 1997.

Securities and Exchange Commission, File No. 70-8725
Affidavit concerning financial risk of diversification of Southern Company, October, 1996 and January, 1997.

Federal Energy Regulatory Commission, Docket No. ER95-53-000
Testimony concerning the equalization of nuclear decommissioning costs of Entergy, October, 1996.

Securities and Exchange Commission, File No. 70-8809
Affidavit concerning financial risk of diversification of Central and Southwest. May, 1996.

"Report on the Cost of Equity of New York Power Authority," January, 1996.

Federal Energy Regulatory Commission, Docket No. ER95-1042-000
Testimony concerning the cost of capital and nuclear decommissioning of System Energy Resources, October, 1995.

Federal Energy Regulatory Commission, Docket No. ER95-53-000
Affidavit concerning nuclear decommissioning cost equalization on the Entergy System. June, 1995.

"Report on the Development of Electric Utility and Railroad Comparable Samples for the Tax Division of the Arkansas Public Service Commission," February, 1995.

Federal Energy Regulatory Commission, Docket No. EL94-13-000
Testimony concerning the merger of Entergy and Gulf States Utilities. October, 1994.

Arkansas Public Service Commission, Docket No. 94-355-U
Testimony concerning the cost of capital of Louisiana-Nevada Transit. October, 1994.

Oklahoma Corporation Commission, PUD 940000354
Testimony concerning the cost of capital of Arkansas Louisiana Gas Co. July, 1994.

Arkansas Public Service Commission, Docket No. 94-175-U
Testimony concerning the cost of capital of Arkansas Louisiana Gas Co. June, 1994.

Securities and Exchange Commission, File No. 70-8339
Affidavit concerning the merger of Central and Southwest and El Paso Electric. April, 1994.

Federal Energy Regulatory Commission, Docket Nos. EC94-7-000 and ER94-898-000
Testimony concerning the merger of Central and Southwest and El Paso Electric. February, 1994.

Arkansas Public Service Commission, Docket No. 93-081-U
Testimony concerning the cost of debt of Arkansas Louisiana Gas Co. October, 1993.

Federal Energy Regulatory Commission, Docket Nos. EC92-21-000 and ER92-806-00
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Federal Energy Regulatory Commission, Docket Nos. ER92-341-000, EL92-35-000, and EL92-36-000
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Testimony concerning franchise fee or tax on AT&T in the City of Little Rock. January, 1992.

Federal Energy Regulatory Commission, Docket No. EL90-48-000
Testimony concerning the spin-off of a coal unit on the Entergy System. January, 1992.

Arkansas State Banking Commission
Economic and Financial Report on the Feasibility of the Proposed First Community Bank, Conway, Arkansas (prepared by Economic & Financial Consulting Group, Inc.), May, 1991

Arkansas Public Service Commission, Docket No. 90-133-U

Testimony concerning non-traffic sensitive costs on telephone systems. November, 1990.

Federal Energy Regulatory Commission, Docket Nos. ER89-678-000 and EL90-16-000
Testimony concerning the cost of capital and nuclear decommissioning of System Energy Resources. November, 1990

Arkansas Public Service Commission, Docket No. 90-004-U
Testimony concerning the capital structure of Arkansas Western Gas Co. October, 1990.

Arkansas Public Service Commission, Docket No. 88-115-TF
Testimony concerning phase-in plan for Arkansas Power and Light Co. September, 1988.

Arkansas Public Service Commission, Docket No. 87-201-U
Testimony concerning the cost of capital of GTE Southwest, Inc. August, 1988.

Arkansas Public Service Commission, Docket No. 87-166-TF
Testimony concerning nuclear decommissioning trust fund of Arkansas Power and Light Co. January, 1988.

Arkansas Public Service Commission, Docket No. 87-070-U
Testimony concerning the cost of capital of Arkansas Louisiana Gas Co. September, 1987.

Arkansas Public Service Commission, Docket No. 87-071-U
Testimony concerning the cost of capital of Arkansas Energy Resources. August, 1987.

Federal Energy Regulatory Commission, Docket Nos. EL86-58-000 and EL86-59-000
Testimony concerning the cost of capital of System Energy Resources, Inc. and Middle South Services. March, 1987

Arkansas Public Service Commission, Docket No. 87-028-U
Testimony concerning a preferred stock issuance by Arkla. March, 1987.

Arkansas Public Service Commission, Docket No. 84-165-U
Testimony concerning the cost of capital of Southwestern Bell. February, 1987.

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Testimony concerning incentive ratesfor Arkansas Power and Light Co. January, 1987.

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Affidavit concerning a preferred stock issuance by System Energy Resources. December, 1986.

Arkansas Public Service Commission, Docket No. 86-175-TF
Testimony concerning incentive rates for Arkansas Power and Light Co. September, 1986.

Arkansas Public Service Commission, Docket No. 86-147-TF
Testimony concerning a tax adjustment rider for Arkansas Power and Light Co. August, 1986.

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Testimony concerning seasonally differentiated rates of Arkansas Power and Light Co. June, 1986.

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Testimony concerning gas transportation policy. June, 1986.

Arkansas Public Service Commission, Docket No. 85-299-U
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Testimony concerning the cost of capital, incentive rates, and phase-in plan for Arkansas Power and Light Co. May, 1985.

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Testimony concerning interruptible incentive rates for Arkansas Power and Light Co. May, 1985.

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Testimony concerning a rate freeze for Arkansas Louisiana Gas Co. February, 1985.

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Testimony concerning cost allocations and phase-in plan for Arkansas Electric Cooperative Corporation. September, 1984.

Arkansas Public Service Commission, Docket No. 84-199-U
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Testimony concerning the cost of capital and replacement cost pricing for Arkansas Louisiana Gas Co. March 1984.

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Testimony concerning the cost of capital of AT&T. January, 1984.

Arkansas Public Service Commission, Docket No. 83-153-U
Testimony concerning the cost of capital of Allied Telephone Co. December, 1983.

Arkansas Public Service Commission, Docket No. 83-206-U
Testimony concerning a rate reduction for Arkansas Power and Light. December, 1983

Arkansas Public Service Commission, Docket No. 83-045-U
Testimony concerning the cost of capital and customer stock purchase plan on Southwestern Bell. September, 1983.

Arkansas Public Service Commission, Docket No. 81-104-AP-2
Testimony concerning nuclear fuel negative salvage costs of Arkansas Power and Light Co. July, 1983.

Arkansas Public Service Commission, Docket No. 82-314-U
Testimony concerning the cost of capital and customer stock purchase plan on Arkansas Power and Light Co. April, 1983.

Federal Energy Regulatory Commission, RM-80-36-000
Comments concerning a generic rate of return. December, 1982.

Illinois Commerce Commission, Docket No. 82-0152
Testimony concerning the cost of capital of Illinois Power Co. July, 1982.

Arkansas Public Service Commission, Docket No. 81-260-U
Testimony concerning the rate of return of Arkansas Electric Cooperative Corporation. June, 1982.

Arkansas Public Service Commission, Docket No. 82-037-U
Testimony concerning the cost of capital for Southwestern Bell. May, 1982.

Arkansas Public Service Commission, Docket No. 81-349-U
Testimony concerning the cost of capital of Associated Natural Gas Co. April, 1982.

Arkansas Public Service Commission, Docket No. TD-80-06

Testimony concerning overall capitalization rate. November, 1981.

Arkansas Public Service Commission, Docket No. 81-161-U
Testimony concerning the cost of capital of Oklahoma Gas and Electric. October, 1981.

Arkansas Public Service Commission, Docket No. 81-144-U
Testimony concerning the cost of capital and nuclear decommissioning trust funds for Arkansas Power and Light Co. September, 1981.

Arkansas Public Service Commission, Docket No. U-3136
Testimony concerning the cost of capital of Southwestern Electric Power Co. April, 1981.

Arkansas Public Service Commission, Docket No. U-3117
Testimony concerning an econometric model for directory assistance for Southwestern Bell Co. April, 1981.

Arkansas Public Service Commission, Docket No. U-3071
Testimony concerning the rate of return and an econometric model of demand for Arkansas Electric Cooperative Corp. July, 1980.

Arkansas Public Service Commission, Docket No. U-3089
Testimony concerning the rate of return of North Arkansas Telephone Cooperative. July, 1980.

Arkansas Public Service Commission, Docket No. U-3096
Testimony concerning the cost of capital of United Telephone Co. March, 1980.

Arkansas Public Service Commission, Docket No. U-3052
Testimony concerning the cost of capital of Associated Natural Gas Co. March, 1980.

Arkansas Public Service Commission, Docket No. U-3036
Testimony concerning the cost of capital of United Telephone Co. November, 1979.

HONORS AND AWARDS

Wincott Visiting Research Fellowship
University of Buckingham, United Kingdom, Fall, 1997

Earhart Fellowship (with Nicholas Georgescu-Roegen)
Vanderbilt University, 1975-1976

Graduate School Assistantship
Vanderbilt University, 1973-1976

Mosley Economics Award
Hendrix College, 1973

Hogan Math Award
Hendrix College, 1972

Alpha Chi (scholastic),
Hendrix College

Rensselaer Math and Science Award, 1968

PUBLICATIONS

"Sub-Optimal Generation Portfolio Variance with Rate of Return Regulation," *Technology and Investment, 1*, 2010, pp. 114-17.

"Firm Incentives for Invention Prizes With Multiple Winners," *Eastern Economic Journal, 32*, 2006, pp. 83-95.

"Generation Search Costs and Ramsey Pricing in a Partially Deregulated Electric Utility Industry," *Journal of Economics and Business, 54*, 2002, pp. 331-343.

"Substitution Between Bundled and Unbundled Products After Deregulation in Electricity Generation," *Eastern Economic Journal, 26*, 2000, pp. 455-68.

"Stranded Costs, Access Charges, and Ramsey Pricing in the U.S. Electric Utility Industry," *The Quarterly Review of Economics and Finance, 40*, 2000, pp. 503-17.

"Excess Returns in Electric Utility Mergers During Transition to Competition," *Journal of Regulatory Economics, 18*, 2000, pp.175-88.

"Interest Rate Risk and Utility Risk Premia During 1982-93," *Managerial and Decision Economics, 19*, 1998, pp. 127-35.

"Asymmetric Demand Information in Regulation," *Studies in Economics and Finance, 18*, 1998, pp. 129-41.

"Utility Mergers and the Cost of Capital," *Journal of Financial and Strategic Decisions, 11*, 1998,

pp.73-82.

"Interest Rate Risk and Utility Bond and Dividend Yields," *Advances in Investment Analysis and Portfolio Management*, Volume III, 1995, pp. 183-191.

"Rent-Seeking With Multiple Winners," *Public Choice*, *8*, 1993, pp. 437-43.

"A Risk-Adjusted Approach for Assessing Factors that Determine Utilities' Allowed Returns on Equity," (with Timothy Mason), *The Review of Industrial Organization*, *8*, 1993, pp. 113-23.

"Ramsey Pricing in the Presence of Risk," *Managerial and Decision Economics*, March-April, 1992, pp. 111-17.

"The Impact of Consumers on the Dissipation of Rents," *Eastern Economic Journal*, July-September, 1991, pp. 345-49.

"Expected Rate Minimization and Excess Capacity in Regulated Utilities," *The Quarterly Review of Economics and Business*, Volume 30, Number 3, Fall 1990, pp. 85-95.

"Flotation Cost Allowance Methodologies: A Synthesis Using Present Value Analysis," *The Financial Review*, Volume 25, Number 3, August, 1990, pp.487-500.

"The Allocation of Risk Between Stockholders and Ratepayers in Regulated Utilities," *Land Economics*, Volume 64, Number 2, May, 1988, pp. 114-24.

"Rate-of-Return Regulation and Demand Uncertainty with a Symmetric Regulatory Constraint," *The American Economist*, Fall, 1987, pp. 8-12.

"The Relevance of Quasi Rationality in Competitive Markets: Comment," *American Economic Review*, Volume 77, Number 3, June, 1987, pp. 496-8.

"The Ratepayer and Stockholder under Alternative Regulatory Policies: Comment," *Land Economics*, Volume 63, Number 2, May, 1987, pp. 201-5.

"The Impact of Nuclear Power Plant Construction Activity on the Electric Utility Industry's Cost of Capital," (with Samuel Loudenslager), *The Energy Journal*, Volume 8, Number 2, April, 1987, pp. 63-75.

"When is Excess Capacity Desirable?" *New Regulatory and Management Strategies in a Changing Market Environment*, Institute of Public Utilities, 1987, pp. 358-371.

"Random Pseudo-Disturbance Generators in a Stochastic Simulation of an Econometric

Model,"(with Cliff Huang), *Journal of Statistical Computation and Simulation*, Vol.22, Nos. 3 and 4, pp. 285-302.

"The Quarterly Cost of Equity: Implications for Setting the Annual Return on Equity," *Electric Ratemaking*, Volume 2, Number 2, April/May, 1983, pp.8-10.

Book Review of *Issues in Public-Utility Pricing and Regulation*, edited by Michael A. Crew, Lexington. Mass.: D.C. Heath & Co., 1980, in *Southern Economic Journal*, Volume 48, Number 4, April, 1982, pp. 1112-3.

"The Discounted Cash Flow Formula: Validation and Estimation," *Proceedings of the Second NARUC Biennial Regulatory Information Conference*, pp.397-400.

WORKING PAPERS

"A Comparison of Pay-as-Bid and Market-Clearing-Price Bidding Processes in Electric Utility Auctions"

"Pay-as-Bid and Market-Clearing-Price Bidding Processes in Electric Utility Auctions with Merchants' Risk Preference"

"Collusion in Rent-Seeking With Decreasing Returns to Scale"

PRESENTATIONS

"Offer Curve Behavior for Merchant Plants in Electric Utility Regional Transmission Organizations", 2005 Southern Economics Association Meetings, Washington, D.C.

"Deans, Teams, and Faculty Dreams: Cooperation in Hard Work," Speaker, Session at 57th Annual Meeting of the American Conference of Academic Deans, New Orleans, January, 2001.

"Changes in Risk in Electric Utility Mergers During Transition to Competition", 1999 Southern Economic Association Convention.

"Stranded Cost in the U.S. Electric Utility Industry: Last Gasp of Ramsey Pricing?" Discussion Paper, Wincott Series, University of Buckingham, United Kingdom, December, 1997.

"Interest Rate Risk and Utility Risk Premia During 1982-93," 1994 Southern Economic Association Convention.

"Interest Rate Risk and Utility Bond and Dividend Yields," 1992 Western Economic Association Convention.

"Scaling Up Nuclear Decommissioning Costs," NARUC Advanced Regulatory Studies Program, Williamsburg, VA, 1992.

"Assessing Factors That Determine Utilities' Allowed Returns on Equity: A Risk-Adjusted Institutional Approach," (with Timothy Mason), 1989 Southern Economic Association Convention.

"The Grand Gulf Experience," Sixty-Fifth National Conference of Regulatory Utility Commission Engineers, Hot Springs, AR, 1987.

"Some Fundamental Principles in the Determination of a Utility's Cost of Capital," Seventh Annual Western Utility Rate Seminar, Salt Lake City, Utah, 1987.

"A Critique of Various Phase-in Plans," NARUC Advanced Regulatory Studies Program, Williamsburg, VA, 1986.

"Principles in the Determination of a Utility's Cost of Capital," Thirteenth Annual Eastern NARUC Utility Rate Seminar, Ft. Lauderdale, Florida, 1985.

"Nuclear Unit Construction and Electric Utilities' Cost of Capital," Western Economic Association Convention, 1984.

"Current Issues in Utility Regulation," Fifth Annual Seminar Series, Hendrix College, 1984.

"The Economics of Two-Part Rate Structures for Regulated Utilities," Midwest Economics Association Convention, 1981.

COLLEGIATE SERVICE

Chair, Department of Economics and Business. While Chair I led the Department in the development of an International Business Minor. This will be a precursor to an International Business Major.

Director, Center for Entrepreneurial Studies, Hendrix College, 2001-Present. I obtained $200,000 in external funding for the Center's start-up. The Center brought Secretary of Commerce Don Evans, former Secretary of HUD Jack Kemp, and former Council of Economic Advisors Chair Dr. Glenn Hubbard to speak to the Hendrix campus. Additionally, the Center sponsored a number of Business Roundtables where local businesspeople spoke to Hendrix students. In 2004, the Center provided supervision for a Hendrix Team that was a semi-finalist in the Arkansas Governor's Business Plan Competition.

Faculty Advisor, Phi Beta Lambda, the Collegiate Division of Future Business Leaders of America, 2002-Present

Chair, Committee on Curriculum, Hendrix College, 1998-2002. Responsible for development of new General Education Requirements as Hendrix moved from a trimester calendar to a semester calendar

Member of Search Committee for Provost for Hendrix College, 2002

Member of Faculty Committee that assisted in the writing of a $3.9 million grant to Hendrix College from the Robert & Ruby Priddy Charitable Trust, 2002

Hendrix College Alumni Association Board of Governors Awards Committee, 1999-2000

Chair, Committee on Student Life, Hendrix College, 1995-96

OTHER EXPERIENCE

Presentation on China Odyssey III at Conway Rotary Club, November, 2007.

"Symposium on Business and the Liberal Arts: Integrating Professional and Liberal Education," Sponsored by the Council of Independent Colleges, Chicago, IL, May, 2007.

Member, eSTEM Public Charter Schools, Inc. Board of Directors, Little Rock, AR, 2007-Present

Discussant at 2005 American Economics Association/TPUG Session.

Chair, Finance Committee, Trinity United Methodist Church, 2005-06, Little Rock, AR.

Reviewer for *Quarterly Review of Economics and Finance, Eastern Economic Journal, Journal of Economic Surveys, Contemporary Economic Policy, Economics and Politics, Land Economics, The American Economist, Managerial and Decision Economics, International Journal of Energy Systems, Journal of Economics and Business,* and *IEEE PES Transactions on Power Systems*

Blue Ribbon Panel, advice to Frueauff Foundation concerning modification of its investment objectives, 2003

Discussant at 2001 Southern Economics Association Convention

"Report on the Economic Feasibility of the White River Navigation Project," February, 2000

Member, Board of the Arkansas Policy Foundation, 1999-Present

"The Democratization of Capitalism on Wall Street," *Log Cabin Democrat*, Conway, Arkansas, June 7, 1999

Panelist on Governor's Economic Summit, Roundtable on Tax and Regulatory Policy, June 9-10, 1998, Little Rock, AR

"Taxes and Savings in Arkansas," Murphy Commission Report, May, 1998

"Feasibility Analysis of the Formation of a Local Electric Utility in Batesville and Independence County," with Mike Hughes and W.W. Elrod,II, April, 1998

Discussant at 1999 Southern Economics Association Convention

Discussant at 1996 Western Economics Association Convention

Discussant at 1994 Southern Economics Association Convention

Discussant at 1993 Southern Economics Association Convention

Participant on judges' panel for selection of outstanding Arkansas businesses and executives in 1988 for *Arkansas Business*

Lecturer, Business Leaders Day, 1988, University of Arkansas, Fayetteville, Arkansas

Research Advisory Committee, National Regulatory Research Institute, 1986-1989, Deputy Chairman (1988-1989)

Subcommittee on Electricity, National Association of Regulatory Utility Commissioners, 1987-1989

Subcommittee on Economics, National Association of Regulatory Utility Commissioners, 1979-1987

PROFESSIONAL ORGANIZATIONS

American Economics Association
Southern Economics Association

Exhibit SKB-2

Tucson Electric Power Company
Cost of Capital (Before Fair Value Rate Base Adjustment)
Test Year Ended December 31, 2011
(Thousands of Dollars)

Component	Amount	Proportion	Cost Rate	Weighted Cost
ST Debt	$10,000	0.53%	1.42%	0.01%
LT Debt	$1,061,389	55.97%	5.18%	2.90%
Common Equity	$824,943	43.50%	9.40%	4.09%
Total	$1,896,332	100%		7.00%

Exhibit SKB-3

DCF GROWTH RATES

Company	g1	g2	g3	g4	g5	g6
AEP	3.70%	3.69%	4.43%	4.50%	4.30%	3.54%
CLECO	7.96%	6.92%	6.00%	4.68%		3.00%
Empire District	1.11%	7.21%	2.75%	3.13%		10.20%
Entergy	2.67%	-1.34%	5.18%	3.01%	2.00%	
Great Plains Energy	0.11%	4.76%	1.66%	2.66%	7.00%	4.97%
Hawaiian Electric	3.19%	4.71%	5.21%	6.44%	6.50%	11.37%
IDACORP	4.40%	4.71%	6.07%	3.96%	5.00%	4.00%
NV Energy	3.47%	12.18%	2.45%	3.19%	10.20%	12.63%
Pinnacle West	1.78%	3.66%	3.56%	3.91%	5.30%	5.88%
PNM Resources	1.11%	10.35%	3.24%	4.73%	12.60%	10.95%
Portland General	5.43%	3.26%	3.94%	3.87%	5.20%	4.27%
Southern Co.	4.64%	4.66%	5.32%	5.94%	5.10%	5.58%
UNS Energy	7.22%	5.03%	4.17%	6.45%		
Westar	3.83%	4.62%	2.85%	3.72%	5.80%	6.13%

Exhibit SKB-4

DCF COST OF EQUITY ESTIMATES

Company	Dividend	Price, 6 months Ending 9/30/12	Unadjusted Div. Yield	k1	k2	k3	k4	k5	k6
AEP	$1.88	$40.63	4.63%	8.41%	8.40%	9.16%	9.23%	9.03%	8.25%
CLECO	$1.35	$41.41	3.26%	11.35%	10.29%	9.36%	8.01%		6.31%
Empire District	$1.00	$20.92	4.78%	5.92%	12.16%	7.60%	7.99%		15.22%
Entergy	$3.32	$67.62	4.91%	7.65%	3.53%	10.22%	8.00%	6.96%	
Great Plains Energy	$0.85	$21.09	4.03%	4.14%	8.89%	5.73%	6.75%	11.17%	9.10%
Hawaiian Electric	$1.24	$27.28	4.55%	7.81%	9.37%	9.87%	11.14%	11.19%	16.17%
IDACORP	$1.52	$41.23	3.69%	8.17%	8.48%	9.87%	7.72%	8.78%	7.76%
NV Energy	$0.68	$17.37	3.91%	7.45%	16.33%	6.42%	7.17%	14.31%	16.79%
Pinnacle West	$2.18	$50.86	4.29%	6.10%	8.03%	7.92%	8.28%	9.70%	10.29%
PNM Resources	$0.58	$19.55	2.97%	4.10%	13.47%	6.25%	7.76%	15.75%	14.08%
Portland General	$1.08	$26.31	4.10%	9.65%	7.43%	8.13%	8.05%	9.41%	8.46%
Southern Co.	$1.96	$46.20	4.24%	8.98%	9.01%	9.67%	10.31%	9.45%	9.94%
UNS Energy	$1.72	$38.70	4.44%	11.82%	9.58%	8.71%	11.03%		
Westar	$1.32	$29.21	4.52%	8.43%	9.24%	7.44%	8.33%	10.45%	10.79%
Average				7.86%	9.59%	8.31%	8.55%	10.56%	11.10%

OVERALL AVERAGE **9.33%**

Exhibit SKB-5

BOND YIELDS

Date	30 Yr. U.S Treasury	Utility Baa/BBB
7/3/2012	2.74%	4.37%
7/11/2012	2.61%	4.25%
7/18/2012	2.60%	4.17%
7/25/2012	2.48%	4.01%
8/1/2012	2.62%	4.13%
8/8/2012	2.75%	4.24%
8/15/2012	2.92%	4.39%
8/22/2012	2.82%	4.28%
8/29/2012	2.74%	4.26%
9/5/2012	2.76%	4.15%
9/12/2012	2.90%	4.33%
9/19/2012	2.93%	4.33%
9/26/2012	2.81%	4.16%
AVERAGE	**2.74%**	**4.24%**

Sources: Federal Reserve and Value Line

MANAGERIAL AND DECISION ECONOMICS
Manage. Decis. Econ. **19**: 127–135 (1998)

Interest Rate Risk and Utility Risk Premia During 1982–93

S. Keith Berry*

Department of Economics and Business, Hendrix College, Conway, USA

INTRODUCTION

The risk premium method of calculating a fair return on equity for a regulated utility is frequently used in regulatory proceedings. That method considers the relationship between a utility's bond yield and its required return on equity, and is especially useful when other methods, such as the capital asset pricing model and the discounted cash flow (DCF) model exhibit less reliability.[1] Although the discounted cash flow method is the favored method for estimating a utility's cost of equity in rate proceedings, the risk premium method provides a useful check on the DCF results. This is even more important in today's financial environment because of the difficulty of measuring investor-expected growth rates in the DCF method.

If bond yields and required returns on equity move up and down in lockstep, it is straightforward to calculate the appropriate cost of equity using the risk premium method. However, if they do not, estimation of the cost of equity is much more difficult. One explanation of this variability in risk premia is differences in 'interest rate risk'. In particular, arguments have been made in rate cases that utility bonds are riskier in the 1980s than they were earlier because of the significant increase in interest rate variability that occurred in the early 1980s (primarily caused by increased inflation rate variability).[2] In particular, when capital costs, and interest rates, increase, utility bondholders, who earlier 'locked-in' at lower interest rates, miss out on those higher interest rates. Bondholders who experience this will then prospectively require an 'interest rate risk' premium, and utility bond interest rates will be correspondingly greater. Furthermore, utility bonds of differing overall risk may exhibit differing sensitivities to that 'interest rate risk'.

In contrast, the argument goes, utility common stock returns have some protection from that risk. If capital costs increase, utilities can request a rate increase to increase the allowed return. Consequently, utility common shareholders can earn the higher capital costs, and do not necessarily require an 'interest rate risk' premium.[3] Thus, over time we would not necessarily expect to see utility bond yields and required equity returns move in one-to-one lockstep. Furthermore, to the extent that there is some substitutability between utility common stocks and utility bonds as interest rate risk associated with bonds increases, investors may increase their preferences for utility stocks. This should tend to decrease required returns on utility common stock.

Berry (1995) performed an analysis of the impact of interest rate (and capital cost) risk on interest rates and dividend yields. Those results indicate that interest rates are positively related to interest rate variability, but dividend yields are not affected by dividend yield variability. However, that study focused on *dividend yields*, which are easy to measure, and did not consider required equity returns which are much more difficult to measure. Furthermore, that study did not focus on risk premia, and the relationship between bond yields and required returns on equity, as does this paper. This paper utilizes required returns, as measured by Commission-allowed returns, in the risk premium analysis.

* Correspondence to: Department of Economics and Business, Box 3180, Hendrix College, Conway, AR 72032, USA.

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Other studies have shown that there is an inverse relationship between interest rates and risk premia in recent years, but not in earlier years. Carleton *et al.* (1983) found that there was no relationship between electric utility risk premia and interest rates during the 1970s. Brigham *et al.* (1985) estimated a positive relationship between risk premia and interest rates for the 1966–79 period and a negative relationship between the variables during the 1980–84 period. They attributed this to increased inflation risk and its effect on interest rates. Similarly, Harris (1986) showed that there was a negative relationship between utility risk premia and interest rates during the 1982–84 period. Harris and Marston (1992) concluded that there was a negative relationship between the S&P 500 risk premia and interest rates for the 1982–91 period. However, none of these studies used Commission-allowed returns in the calculations of risk premia.

This paper considers two factors not previously considered in the literature. First, allowed returns are used as a proxy for required returns on equity, with appropriate consideration for partial adjustment. Second, explicit usage is made of measures of interest rate risk to gauge their impact on risk premia. Regression analyses is employed to estimate the effects of utility bond yields, interest rate variability, and time trends on required returns on equity and risk premia over the period 1982–93. In the second section, we present a simple regression model, which tests for an inverse relationship between required returns on equity and interest rates. This model, while not very sophisticated, has the inherent advantage that it can be easily used to estimate risk premia. In the third section, we consider a more complex model which explicitly considers various measures of interest rate variability, as well as interest rate levels.

REGRESSION RESULTS WITH INTEREST RATES

A common formulation of the risk premium is:

$$K = YD + RP \tag{1}$$

where K is the required return on common equity, YD is the utility's current cost of long-term debt (yield) and RP is the risk premium. Since YD is directly measurable, and *if* RP can be properly measured, K can then be directly estimated.[4] However, there are two general problems with the implementation of a risk premium methodology:

1. The estimation of RP is often based on historical earned returns, which may or may not be indicative of *required* returns; and
2. The level of RP may not be constant through time. In particular, there may be an inverse relationship between interest rates and risk premia.[5]

To address the first problem we use Commission-allowed returns as a reasonable surrogate for required returns, with a partial adjustment feature, as will be discussed later. Commissions and their staff spend a significant amount of time in rate cases considering the determination of a utility's appropriate return on equity. As discussed earlier, the primary method employed is the DCF method, which, when performed properly, estimates the required return on equity.[6] Furthermore, Commission-allowed returns may represent better estimates of equity costs, than DCF methods using analysts' forecasts, since Commissions comprehend a wide variety of cost of capital methods.

For illustration we have arrayed risk premia by year in Table 1. For comparative purposes we also show the estimated risk premia using the long-term US Treasury bond yield. Note that there is a general upward trend in risk premia associated with Moody's utility bond yields, which occurs during a period of generally decreasing interest rates. Furthermore, the estimated risk premia are less than those reported in Harris and Marston (1992). This can be attributed to two factors. First, utilities are generally less risky than the S&P 500 which were used in the Harris and Marston study, with corresponding lower required returns. Second, Commission-allowed returns may incorporate lower DCF growth rates than the analysts' forecasts used by Harris and Marston.

Finally, risk premia for Treasury bonds, shown in Table 1, appear to be fairly stable, albeit with a slight upward drift over the 1982–93 period. Moody's yields fell by much more (777 basis points) over that period, than did Treasury yields (578 points). An explanation for this is provided in Berry (1995). As shown there, although there is a close one-to-one relationship between Moody's utility bond yields and Treasury yields, interest rate risk had a significant impact on Moody's

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Table 1. Equity Risk Premia

Year (1)	US Treasury Bond Yields (2) (%)	Allowed Return on Equity (3) (%)	Equity Risk Premia on Treasury Yields [(3)–(2)] (4) (%)	Moody's Utility Bond Yields (5) (%)	Equity Risk Premia on Moody's Yields [(3)–(5)] (6) (%)
1982	12.23	15.46	3.23	15.33	0.13
1983	10.84	15.18	4.34	13.31	1.87
1984	11.99	15.25	3.26	14.03	1.22
1985	10.75	14.38	3.63	12.29	2.09
1986	8.14	13.2	5.06	9.46	3.74
1987	8.64	12.86	4.22	9.98	2.88
1988	8.98	12.82	3.84	10.45	2.37
1989	8.58	12.92	4.34	9.66	3.26
1990	8.74	12.63	3.89	9.76	2.87
1991	8.16	12.41	4.25	9.21	3.20
1992	7.52	11.84	4.32	8.57	3.27
1993	6.45	11.54	5.09	7.56	3.98
Change 1982–93	−5.78	−3.92	+1.86	−7.77	+3.85

Note: 1993 data are partial year.

yields. The decrease in interest rate risk during the 1980s, consequently, caused an incremental decrease in Moody's yields, in excess of that corresponding to the decrease in Treasury yields.[7] As will be discussed later, although the risk premia associated with Treasury bonds appear to be fairly stable during the 1982–93 period, there are specific reasons for that, which will not necessarily be repeated in the future.

In our regression analysis we use allowed returns and the corresponding bond yields for that utility's Moody's bond rating from 6 months earlier than the date of the Commission rate order.[8] This provides a better matching since the evidentiary record on the required return on equity is usually developed some months before the date of the rate order. The data on allowed returns was obtained from various editions of *Public Utilities Fortnightly* (1983–93).[9] The data on Moody's bond yields was obtained from various editions of *Moody's Public Utility Manual* (1982–93). This yielded a total of 1226 rate case observations over the period 1982–93. For each month we averaged the cross-sectional data to obtain 130 usable time series observations.[10]

Consistent with Equation (1), let K_t^* represent the required return on equity at time t such that

$$K_t^* = RP_t + YD_t \tag{2}$$

where RP_t and YD_t are the risk premium and current cost of debt at time t, respectively. To allow for a varying risk premium set

$$RP_t = \alpha + \beta YD_t. \tag{2a}$$

Postulate a regulator adjustment function of the form:

$$K_t - K_{t-1} = \gamma(K_t^* - K_{t-1}), \quad 0 < \gamma < 1 \tag{3}$$

where K_t is the allowed return at time t and γ is the adjustment factor. This equation implies an inertia on the part of regulators such that with a change in the required return on equity from the prior period's allowed return on equity, $K_t^* - K_{t-1}$, the regulator only moves part way to a new allowed return. The greater the value of γ, the greater the degree of regulator adjustment.[11]

Substitution of Equation (2) into Equation (3) yields

$$K_t = \gamma RP_t + \gamma YD_t + (1-\gamma)K_{t-1} \tag{4}$$

or

$$K_t = \alpha\gamma + (1+\beta)\gamma YD_t + (1-\gamma)K_{t-1} \tag{4a}$$

For purposes here, we used the allowed return from 1 month earlier. Regulators are aware of recent allowed returns and will likely partially base their current allowed return awards on those recent historical allowed returns, consistent with Equation (3).[12] We then performed an ordinary least squares regression of the allowed returns on the corresponding bond yields and lagged allowed returns. This resulted in the following regression equation:

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$$K_t = 0.03337 + \underset{(6.11)}{0.22301}\,YD + \underset{(8.58)}{0.56788}K_{t-1},$$
$$(\text{Durbin–Watson} = 2.41,\ R^2 = 0.905). \quad (5)$$

The t-statistics are shown in parentheses, and indicate significance for both independent variables at the 1% level. The implied value of γ, the adjustment factor, is $1 - 0.56788 = 0.43212$.

The implied risk premium equation, corresponding to Equation (2a), is

$$RP_t = 0.07722 - 0.48392\,YD_t. \quad (6)$$

Equation (6) indicates the presence of an inverse relationship between risk premia and interest rates. For every 100 basis point drop in interest rates, the risk premium *increases* by approximately 48 basis points and the cost of equity decreases by approximately 52 basis points. Conversely, for every 100 basis point increase in interest rates, the risk premium *decreases* by approximately 48 basis points and the cost of equity increases by approximately 52 basis points.

To the extent interest rate variability is a major factor in the level of capital costs, we would expect to empirically observe this inverse relationship between risk premia and interest rates.[13] That is, as interest rate variability increases, interest rate risk increases, interest rates increase, and risk premia fall since utility equity costs change very little, or decrease, for the reasons mentioned in the introduction. The converse would be true in the case of a decrease in interest rate variability.[14]

An alternative formulation of Equation (1) is

$$K_t^* = RP_t + GOV_t. \quad (7)$$

where GOV_t is the yield on long-term US Treasury bonds and RP_t is the corresponding risk premium. Performing a similar regression analysis with GOV instead of YD produces:

$$K_t = 0.1981 + \underset{(3.74)}{0.16016}GOV_t + \underset{(12.09)}{0.73703}K_{t-1},$$
$$(\text{Durbin–Watson} = 2.56,\ R^2 = 0.889). \quad (8)$$

The R^2 is statistically significant at the 1% level with both independent variables statistically significant.

The implied risk premium equation, corresponding to Equation (2a), is

$$K_t^* = 0.07533 - 0.39096GOV_t. \quad (9)$$

This formulation, too, indicates an inverse relationship between risk premia, measured relative to Treasury bonds, and Treasury bond yields. In particular, note that for a given 100 basis point increase in interest rates the risk premium decreases by 39 basis points. The relative change in risk premia is not as great, which is attributable to less interest rate variability and interest rate risk associated with Treasury bonds.[15] Over the 1982–93 period, while Treasury yields fell by 578 basis points, Moody's utility bond yields fell by 777 basis points.

REGRESSION RESULTS WITH BOND YIELD VARIABILITY

A factor that could directly and significantly affect risk premia is investor-perceived variability in utility bond yields. It is likely that historical variability in those bond yields would impact investor perceptions of interest rate risk and increase utility bond yields. Furthermore, to the extent that there is some substitutability between utility common stocks and utility bonds, as interest rate risk associated with bonds increases, investors may increase their preferences for utility stocks. This should tend to decrease required returns on utility common stock.[16] Both of these effects will tend to reduce the risk premium when utility bond interest rate risk increases.

While some of that interest rate variability may be picked up in the data on interest rate levels, those interest rate levels also reflect other factors, such as general tightness (or laxity) in capital market conditions, prevalence of call provisions, and differential tax wedges.[17] Thus, we performed a regression analysis that explicitly included a measure for interest rate variability. An obvious measure is the standard deviation (S.D.) in interest rates in the immediate past. If our hypothesis is correct, an increase in the S.D. should decrease RP.

We considered two different historical timeframes for estimating the S.D.: 3 years and 5 years (*SD3* and *SD5*, respectively). For example, with the 3 year time frame, the S.D. at month n is calculated using the 36 months prior to month n. With the 5-year time frame, the prior 60 months were used. Each of these measures was calculated separately for bond yields for Moody's *Aaa*, *Aa*, *A* and *Baa* utility bonds and then averaged across bond ratings to obtain the average *SD3* and *SD5* for each month.

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Table 2. Regression Results With *YD*, Dependent Variable = *K*

Variable				
Constant	0.1077	0.0981	0.0790	0.1001
t	−0.0002** (−7.25)	−0.0002** (−6.16)	−0.0001** (−4.47)	−0.0002** (−6.09)
YD	0.2584** (7.55)	0.2032** (6.12)	0.1947** (5.57)	0.1950** (5.89)
SD3	−0.5087** (−5.31)			
RMSD3		−0.1695** (−3.91)		
SD5			−0.1282 (−1.43)	
RMSD5				−0.1307** (−3.83)
K_{t-1}	0.1302 (1.59)	0.2131* (2.60)	0.3312** (4.18)	0.2099* (2.53)
R^2	0.9332**	0.9270**	0.9194**	0.9267**
Durbin–Watson	2.06	2.08	2.15	2.07
N	130	130	130	130

Note: *t*-statistics in parentheses. * and** indicate significance at the 5% and 1% levels, respectively.

These are reasonable historical time frames for purposes of estimating forward-looking investor expectations of interest rate risk. Of course, if there has been little change in these S.D.s during the sample period, then none of this matters. However, as discussed in Berry (1995) there has been significant volatility in bond yields. This has led to sharp increases in S.D.s in the early 1980s (almost triple the level in the 1970s), with some decrease in the latter 1980s.

Another way of gauging this variability is to consider the deviation of the immediately preceding month's yield from the relevant prior months' yields. As in the case of S.D.s, 3- and 5-year lags were considered. For example, in the case of 3 years, the formula used to calculate the root mean square deviation (*RMSD*) in month *n* is

$$RMSD3(n) = \left(\left[\sum_{i=n-36}^{n-1} (YD_{n-1} - YD_i)^2 \right] / 36 \right)^{1/2} \tag{10}$$

where YD_{n-1} is the yield in the immediately preceding month and YD_i, $i = 1, \ldots, n-1$, corresponds to the yields in the prior months. An analogous formula for *RMSD* (*RMSD5*) was used for the case of 5 years. As in the cases for *SD3* and *SD5*, different data series were calculated for the four Moody's bond ratings and then averaged across bond ratings.

The *RMSD* may be an appropriate measure of the risk perceived by an investor since it measures the potential interest rate swings (based on prior months' interest rates) relative to the immediately preceding month's yield. In contrast, the variable S.D. measures interest variability over a prior time frame relative to the mean over that same time frame. That mean does not necessarily equal a current yield, and hence may underestimate investor perceptions with regard to potential interest rate variability. Thus, usage of the *RMSD* assumes that, in month *n*, investors may look at month $n-1$'s yield relative to prior months' interest rates to gauge the full impact of any potential interest rate swing. Note that, as discussed in Berry (1995) the trends in *RMSD* are similar to those of S.D.To comprehend for the possibility of a time trend in risk premia we included a monthly trend variable, *t*. This type of variable was discussed in Morin (1994), pp. 291–292) and was statistically significant there.

Our more complete formulation using *SD3* is then:

$$K_t^* = RP_t + YD_t \tag{11}$$

where

$$RP_t = \alpha + \beta t + \delta YD_t + \theta SD3_t. \tag{11a}$$

Assuming a regulator adjustment function as shown in Equation (3) and substituting Equations (11) and (11a) into Equation (3) produces our regression equation:

$$K_t = \alpha\gamma + \beta\gamma t + (\delta + 1)\gamma YD_t + \theta\gamma SD3_t + (1-\gamma)K_{t-1}. \tag{12}$$

Similar regression equations were used for *SD5*, *RMSD3* and *RMSD5*, where each of those variables were used in place of *SD3*. Our hypotheses are that the coefficient associated with *t* will be negative (consistent with Morin), the coefficient associated with *YD* will be positive, and that the coefficient associated with *SD3* (*SD5*, *RMSD3*, *RMSD5*) will be negative, as investors shift their relative preference to utility stock as interest rate risk on utility bonds increase.

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Table 3. Implied Risk Premium Results, Dependent Variable = *RP*

Variable				
Constant	0.1238	0.1247	0.1181	0.1267
t	−0.0002	−0.0003	−0.0002	−0.0003
YD	−0.7029	−0.7418	−0.7089	−0.7532
SD3	−0.5849			
RMSD3		−0.2154		
SD5			−0.1917	
RMSD5				−0.1654

Table 5. Implied Risk Premium Results, Dependent Variable = *RP*

Variable				
Constant	0.1366	0.1390	0.1208	0.1408
t	−0.0004	−0.0003	−0.0002	−0.0003
GOV	−0.7906	−0.8169	−0.7399	−0.8215
SD3	−0.3357			
RMSD3		−0.1848		
SD5			0.1045	
RMSD5				−0.1655

The dependent variable, K, was then regressed on the three independent variables: time, yield and measures of variability in yields. Those four regression results are shown in Table 2.

Note that the regression slope coefficients are generally significant, although the coefficient for *SD5* was not. There is a statistically significant downward time trend, which is consistent with the result in Morin. The effects of *YD* on K are positive and significant. Three of the four coefficients associated with interest rate risk, *SD3*, *RMSD3* and *RMSD5* are significant and negative as was hypothesized. Finally, note that all of the slope coefficients associated with *YD* are significantly less than one, which supports the hypothesis that as interest rates decrease risk premia increase.

As can be seen in Table 2, the adjustment coefficients are in the range 67–87%, which are higher than the adjustment coefficient of 43% from Equation (5). This can be explained by noting that Equation (5) does not include the other factors shown in Table 2 (in particular, interest rate variability). Consequently, the adjustment coefficient measurement in Equation (5) is clouded by the effects of the other factors. It appears that regulators are not adjusting K to K^* very much (only 43%), simply because K is also reacting to other factors not captured in Equation (5). Table 2 properly captures those additional effects and isolates the larger adjustment coefficient effect.

The implied risk premium results, corresponding to Equation (11a), are shown in Table 3. As can be seen there, the coefficient associated with *YD* is between approximately −0.70 and −0.75. This indicates that each increase in utility bond yields of 100 basis points produces a decrease in the risk premium of 70 to 75 basis points. Increases in interest rates result in decreases in risk premia. Furthermore, the negative slope coefficients associated with interest rate risk, imply smaller risk premia as hypothesized. The trend variable in Table 3 has a negative slope, which is consistent with results reported in Morin (1994).[18]

To some extent the variable *YD* may include both the effects of general tightness or laxity in financial markets and interest rate risk. In order to better focus on the two separate factors, it would be appropriate to replace *YD* with *GOV* in

Table 4. Regression Results With *GOV*, Dependent Variable = *K*

Variable				
Constant	0.0781	0.0818	0.0639	0.0874
t	−0.0002** (−4.85)	−0.0002** (−5.10)	−0.0001** (−3.21)	−0.0002** (−5.44)
GOV	0.1197** (2.99)	0.1078** (2.66)	0.1376** (3.18)	0.1108** (2.80)
SD3	−0.1919 (−1.85)			
RMSD3		−0.1088* (−2.21)		
SD5			0.0553 (0.54)	
RMSD5				−0.1027** (−2.71)
K_{t-1}	0.4283** (5.30)	0.4113** (5.04)	0.4709** (6.01)	0.3794** (4.55)
R^2	0.9092**	0.9102**	0.9069**	0.9119**
Durbin–Watson	2.18	2.17	2.24	2.13
N	130	130	130	130

Note: *t*-statistics are in parentheses. * and ** indicate significance at the 5% and 1% levels, respectively.

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Equations (11) and (11a), since *GOV* will more directly reflect changes in the supply and demand for loan funds, without the effect of utility bonds' interest rate risk. The corresponding equations with *SD3* are:

$$K_t^* = RP_t + GOV_t \tag{13}$$

$$RP_t = \alpha + \beta t + \delta GOV_t + \theta SD3_t \tag{13a}$$

These Equations focus on the relationship between utility stocks and government bonds. Assuming an adjustment mechanism as shown in Equation (3) a regression equation analogous to Equation (12) can be developed. Those regression results are shown in Table 4 and are similar to those from Table 2. However, note that the slope coefficients associated with *GOV* are smaller than those associated with *YD* in Table 2. This is consistent with the results in Berry (1995) wherein it was shown that *GOV* had a larger effect on utility bond yields than on utility common stock dividend yields. Given an imperfect, although positive, relationship between Treasury bonds and utility bonds, and an imperfect relationship between utility bonds and utility stocks, it naturally follows that there would be an even more imperfect relationship between Treasury bonds and utility stocks. This means that there is more substitutability between utility common stocks and utility bonds than between utility stocks and US Treasury bonds. A further point to note from Table 4 is that the slope coefficients associated with S.D. are statistically insignificant, while those associated with *RMSD* are significant.

The implied risk premium results, corresponding to Equation (13a) are shown in Table 5. As can be seen there, the coefficient associated with *GOV* is between approximately -0.74 and -0.82 less than those associated with *YD* in Table 3. This is consistent with the point raised above concerning relative substitutability between stocks and bonds. An increase in Treasury yields of 100 basis points produces an increase of 18–26 basis points in the cost of equity, and a corresponding decrease in the risk premium of 74–82 basis points. In sharp contrast to the reported results in Table 1, controlling for other factors, risk premia relative to Treasury yields are not necessarily stable, but change as Treasury yields change. Increases in Treasury yields result in decreases in risk premia, and those decreases are greater than those associated with similar increases in utility bond yields. Furthermore, the negative slope coefficients associated with utility bond interest rate risk, imply smaller risk premia as hypothesized. The trend variable in Table 5 has a negative slope, which is consistent with results reported in Morin (1994), as well as in Table 3.

CONCLUSIONS

This paper examined, through regression analysis, the possibility that there is an inverse relationship between risk premia and both interest rates and interest rate risk in the utility industry. We demonstrated that that is the case over the 1982–93 time period. Furthermore, it was shown that there is a statistically significant basis for asserting that risk premia increase as interest rates decrease. Our analysis also indicated that there was a downward time trend in risk premia in that period. All of these phenomena occurred with either utility bond yields or long-term US Treasury bond yields. However, for an equivalent increase in either utility bond yields or Treasury yields, required equity returns increase by a slightly greater amount with regard to utility bond yields.

It was also shown that regulators may exhibit an inertia in their setting of allowed returns, such that they move partially to the new required return, in the event capital conditions warrant a change. The degree of movement is in the range of 50–80% relative to the prior month's allowed return.

There are several policy implications from the above analysis. First, when regulators use the risk premium method for setting the allowed return on equity, they should consider the degree of recent interest rate variability and consequent interest rate risk, in comparing utility common stocks and utility bonds. The appropriate risk premium will be narrower the greater the interest rate risk. As demonstrated here, the better measure of interest rate risk is *RMSD*, not S.D. Second, objective regulators who attempt to utilize the risk premium method should implicitly compensate for the indicated regulator inertia. For example, calculate the risk premium using K^*, rather than K. Third, while Table 1 implies that risk premia relative to Treasury bonds are more stable, that is not the case when consideration is made for other factors, as shown in Tables 4 and 5. There is not necessarily any gain in precision in using a risk premium method based on Treasury bonds.

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Fourth, if the US enters a period of relative stability in interest rates, we are likely to see utility risk premia increase, a phenomenon utility executives nor regulators have any degree of control over. This widening will not occur because of increases in required equity returns, but because of relatively lower interest rates and less interest rate risk.

NOTES

1. See Bonbright *et al.*, 1988 (pp. 317–28) for a discussion of these methods.
2. Gordon and Halpern (1976) show that an increase in variable and uncertain inflation will theoretically decrease the spread between bond and share yields. This acts through the Fisher effect and the resultant increase in interest rate uncertainty. Examples of rate cases where this argument has been made are Arkansas Public Service Commission (1987), Docket No. 87-070-U, Federal Energy Regulatory Commission (1986), Docket Nos. EL86-58-000 and EL86-59-000, Hawaii Public Utility Commission, Docket No. 4156, Kentucky Public Service Commission, Case No. 8045, and Pennsylvania Public Utility Commission, Docket R-811510.
3. These points are noted in Brigham *et al.* (1985) and Taylor and Peake (1982).
4. See Ibbotson Associates (1993), Carleton *et al.* (1983), Brigham *et al.* (1985) and Harris (1986) for a discussion of risk premia.
5. See Brennan (1982), Brigham *et al.* (1985) and Harris (1986). Other sources are Harris and Marston (1992), Gordon and Halpern (1976) and Federal Energy Regulatory Commission Staff (1992).
6. This approach was also taken in the Federal Energy Regulatory Commission (1992) Staff study.
7. During the same period, any interest rate risk associated with Treasury bonds was not as large, nor did it exhibit as large a decrease.
8. Given the rate case process (testimony, hearing, order writing) a 6 month lag is reasonable. However, if the 6 month period is either too long or short, the analysis here would only result in a mis-estimate of the intercept term, not the slope coefficients. For example, in a period of increasing interest rates(non-accelerating), if the appropriate lag should have been only 3 months, the 6 month lag will result in an over-estimate of the intercept term, but no mis-estimate of the slope terms. With a non-decelerating decrease in interest rates, the intercept term will be under-estimated, with no mis-estimated slope terms. The focus of this paper is on the slope terms. Furthermore, regression analyses was also performed using (a) bond yields contemporaneous with the date of the allowed return and (b) bond yields from 12 months earlier. In both those cases, the Durbin–Watson statistics were worse and the corresponding R^2 were less than with the 6 month lag. Additionally, the slope coefficients for the *YD* and *GOV* variables were not as large, nor as significant as in the 6 month lag case. Consequently, the 6 month lag scenario was utilized here.
9. For the electric and gas rate cases the data was from *Public Utilities Fortnightly's* 'Annual Surveys', while the telecommunications data was from *Public Utilities Fortnightly's* 'Selected Utility Rate Filings'.
10. The data was aggregated into monthly data for three reasons. First, Durbin–Watson statistics can then be sensibly calculated. Second, this approach is consistent with prior studies. Third, this aggregation facilitates the partial adjustment feature. There were months when there were no reported allowed returns, which decreased our total sample size.
11. See Johnston, 1972 (pp. 300–301), for discussion of this technique.
12. This approach implicitly assumes that regulators focus on allowed returns in other jurisdictions in the prior month. This is reasonable for two reasons. First, there is a certain amount of 'peer pressure' amongst regulators wherein they generally do not want their own jurisdiction's allowed returns to be out of line with other jurisdictions, unless justified by general financial and economic circumstances (such as changes in interest rates). Second, the last allowed rate of return for a particular utility may be anywhere from 6 months to 3 years earlier. Modelling those differing periods adds unnecessary complexity to the analysis, in light of the first point raised.
13. See Berry (1995) for an empirical investigation of the impact of interest rate variability on the level of interest rates.
14. Other explanations for an inverse relationship between interest rates and risk premia have to do with call provisions and tax rates. In a high interest rate environment firms will include more call provisions in new bond issues, for which bond investors require even higher interest rate compensation. Additionally, with increasing interest rates, the tax wedge applied to interest on bonds grows relative to that on common stock due to the favorable tax treatment on the capital gains component of stock returns.
15. It could also be attributable to increased utility credit risk during that period.
16. This effect can be readily observed in the DCF method where K is calculated as $D/P + g$. D is the expected dividend, P is the stock's market price, and g is the investor-expected long-term growth rate in dividends. As P increases because of investors' relative preference for utility stocks, K will decrease.
17. As shown in Berry (1995), the impact of the tightness of capital markets has differential effects on interest rates and common stock dividend yields.
18. This negative slope coefficient associated with the time variable also provides an explanation as to why the positive interest rate slope coefficients are

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smaller in Table 3 than that reflected in Equation (2). Throughout the 1982–93 period, interest rates were generally decreasing, which according to the results in Table 3, will lead to decreases in required equity returns. However, during that same period the trend variable t was increasing. This increasing trend variable implies an additional source for decreases in required equity returns over that time period. Since Equation (2) does not explicitly separate out the trend variable, the overall effect in Equation (2) includes both of these effects, which will make the Equation (2) slope coefficient larger.

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Exhibit SKB-7

Tucson Electric Company Capital Proportions From September 30, 2011 to September 30, 2012

	9/30/2011		12/31/2011		3/31/2012		6/30/2012		9 /30/2012		Proportion
Component	Amount	Proportion	Amount	Proportion	Amount	Proportion	Amount	Proportion	Amount	Proportion	Average
Common Equity	$792,451	44.49%	$824,943	43.52%	$823,628	41.54%	$845,982	41.29%	$861,071	41.70%	42.508%
LT Debt	$983,849	55.23%	$1,060,507	55.95%	$1,054,092	53.16%	$1,054,112	51.44%	$1,203,644	58.30%	54.817%
ST Debt	$5,000	0.28%	$10,000	0.53%	$105,000	5.30%	$149,000	7.27%	$0	0.00%	2.675%
Total	$1,781,300	100.00%	$1,895,450	100.00%	$1,982,720	100%	$2,049,094	100%	$2,064,715	100%	100.000%

Exhibit SKB-8

ARTIFICIAL INCREASE IN TEP-PROPOSED COST OF EQUITY CAUSED BY
TEP-PROPOSED HYPOTHETICAL CAPITAL STRUCTURE

TEP Proposed Capital Structure

Component	Proportion [1]	Cost [2]	Tax Factor [3]	Pre-Tax Weighted Cost [1]X[2]X[3]
Common Equity	46.00%	10.75%	1.655	8.18%
Long-term Debt	54.00%	5.18%	1	2.80%

TEP-Proposed Pre-Tax Cost of Capital 10.98%

TEP Actual Capital Structure
(December 31, 2011)

Component	Proportion [1]	Cost [2]	Tax Factor [3]	Pre-Tax Weighted Cost [1]X[2]X[3]
Common Equity	43.50%	10.75%	1.655	7.74%
Long-term Debt	55.97%	5.18%	1	2.90%
Short-Term Debt	0.53%	1.42%	1	0.01%

Weighted Cost of Long-term Debt	2.90%	
Weighted Cost of Short-Term Debt	0.01%	
Weighted Cost of Debt	2.91%	
TEP-Proposed Pre-Tax Weighted Cost of Equity (10.98% - 2.91%)		8.07%
TEP-Proposed Pre-Tax Cost of Equity (8.07%/43.5%)		18.56%
TEP-Proposed After-Tax Cost of Equity (18.56%X (1-.39571))		**11.22%**

Notes: Cost of Equity is that proposed by TEP.
Composite tax rate is 39.571%
Tax factor is 1/(1-.39571) = 1.655

MULTI-STAGE DCF MODEL – 30-DAY AVERAGE PRICE
TERMINAL VALUE - GORDON MODEL

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
		Stock	EPS	GDP		Payout Ratio		Solver Cells		Near-Term	Intermediate	Long-Term
Company	Ticker	Price	Growth	Growth	2012	2016	2026	Delta	Solution	Growth	Growth	Growth
American Electric Power	AEP	$38.21	3.95%	4.54%	60.00%	58.00%	58.00%	($0.00)	9.57%	3.95%	4.24%	4.54%
Cleco Corp.	CNL	$39.52	5.50%	4.54%	52.00%	52.00%	52.00%	($0.00)	8.48%	5.50%	5.02%	4.54%
Empire District Electric	EDE	$20.13	8.10%	4.54%	80.00%	68.00%	68.00%	$0.00	10.67%	8.10%	6.32%	4.54%
Entergy Corp.	ETR	$66.37	2.00%	4.54%	62.00%	61.00%	61.00%	$0.00	11.14%	2.00%	3.27%	4.54%
Great Plains Energy Inc.	GXP	$20.04	5.82%	4.54%	66.00%	60.00%	60.00%	($0.00)	9.00%	5.82%	5.18%	4.54%
Hawaiian Electric	HE	$25.45	8.96%	4.54%	77.00%	65.00%	65.00%	$0.00	9.89%	8.96%	6.74%	4.54%
IDACORP, Inc.	IDA	$40.37	4.00%	4.54%	43.00%	54.00%	54.00%	($0.00)	9.18%	4.00%	4.27%	4.54%
NV Energy	NVE	$15.95	11.28%	4.54%	49.00%	64.00%	64.00%	($0.00)	9.04%	11.28%	7.90%	4.54%
Pinnacle West Capital	PNW	$47.38	5.39%	4.54%	63.00%	64.00%	64.00%	($0.00)	9.18%	5.39%	4.97%	4.54%
PNM Resources	PNM	$18.41	13.02%	4.54%	42.00%	44.00%	44.00%	($0.00)	9.26%	13.02%	8.76%	4.54%
Portland General	POR	$25.01	4.99%	4.54%	55.00%	54.00%	54.00%	($0.00)	9.28%	4.99%	4.76%	4.54%
Southern Co.	SO	$44.99	5.23%	4.54%	73.00%	69.00%	69.00%	($0.00)	9.05%	5.23%	4.88%	4.54%
Westar Energy	WR	$27.80	6.14%	4.54%	70.00%	63.00%	63.00%	($0.00)	9.49%	6.14%	5.34%	4.54%
MEAN:		$33.05	6.49%	4.54%	60.92%	59.69%	59.69%		9.48%	6.49%	5.51%	4.54%

Earnings per Share		[12]	[13]	[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]
Company	Ticker	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
American Electric Power	AEP	$3.13	$3.25	$3.38	$3.52	$3.65	$3.80	$3.95	$4.12	$4.29	$4.48	$4.68	$4.89	$5.11	$5.34	$5.58	$5.84
Cleco Corp.	CNL	$2.59	$2.73	$2.88	$3.04	$3.21	$3.39	$3.57	$3.75	$3.94	$4.13	$4.32	$4.52	$4.73	$4.94	$5.16	$5.40
Empire District Electric	EDE	$1.31	$1.42	$1.53	$1.65	$1.79	$1.93	$2.08	$2.22	$2.36	$2.50	$2.63	$2.75	$2.87	$3.00	$3.14	$3.28
Entergy Corp.	ETR	$7.55	$7.70	$7.86	$8.01	$8.17	$8.34	$8.54	$8.78	$9.07	$9.40	$9.79	$10.23	$10.70	$11.18	$11.69	$12.22
Great Plains Energy Inc.	GXP	$1.25	$1.32	$1.40	$1.48	$1.57	$1.66	$1.75	$1.85	$1.94	$2.04	$2.14	$2.23	$2.33	$2.44	$2.55	$2.67
Hawaiian Electric	HE	$1.44	$1.57	$1.71	$1.86	$2.03	$2.21	$2.39	$2.57	$2.75	$2.91	$3.06	$3.20	$3.35	$3.50	$3.66	$3.83
IDACORP, Inc.	IDA	$3.36	$3.49	$3.63	$3.78	$3.93	$4.09	$4.26	$4.43	$4.62	$4.82	$5.04	$5.27	$5.51	$5.76	$6.02	$6.29
NV Energy	NVE	$0.69	$0.77	$0.85	$0.95	$1.06	$1.18	$1.30	$1.41	$1.53	$1.63	$1.72	$1.80	$1.88	$1.97	$2.06	$2.15
Pinnacle West Capital	PNW	$2.99	$3.15	$3.32	$3.50	$3.69	$3.89	$4.09	$4.30	$4.51	$4.73	$4.95	$5.18	$5.41	$5.66	$5.92	$6.19
PNM Resources	PNM	$1.08	$1.22	$1.38	$1.56	$1.76	$1.99	$2.22	$2.45	$2.66	$2.86	$3.03	$3.17	$3.31	$3.46	$3.62	$3.78
Portland General	POR	$1.95	$2.05	$2.15	$2.26	$2.37	$2.49	$2.61	$2.74	$2.87	$3.00	$3.14	$3.28	$3.43	$3.59	$3.75	$3.92
Southern Co.	SO	$2.57	$2.70	$2.85	$2.99	$3.15	$3.32	$3.49	$3.66	$3.84	$4.02	$4.21	$4.40	$4.60	$4.81	$5.03	$5.25
Westar Energy	WR	$1.79	$1.90	$2.02	$2.14	$2.27	$2.41	$2.55	$2.70	$2.84	$2.98	$3.13	$3.27	$3.42	$3.57	$3.74	$3.91

Projected Annual Data Dividend Payout Ratio		[28]	[29]	[30]	[31]	[32]	[33]	[34]	[35]	[36]	[37]	[38]	[39]	[40]	[41]	[42]
Company	Ticker	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
American Electric Power	AEP	60.00%	59.50%	59.00%	58.50%	58.00%	58.00%	58.00%	58.00%	58.00%	58.00%	58.00%	58.00%	58.00%	58.00%	58.00%
Cleco Corp.	CNL	52.00%	52.00%	52.00%	52.00%	52.00%	52.00%	52.00%	52.00%	52.00%	52.00%	52.00%	52.00%	52.00%	52.00%	52.00%
Empire District Electric	EDE	80.00%	77.00%	74.00%	71.00%	68.00%	68.00%	68.00%	68.00%	68.00%	68.00%	68.00%	68.00%	68.00%	68.00%	68.00%
Entergy Corp.	ETR	62.00%	61.75%	61.50%	61.25%	61.00%	61.00%	61.00%	61.00%	61.00%	61.00%	61.00%	61.00%	61.00%	61.00%	61.00%
Great Plains Energy Inc.	GXP	66.00%	64.50%	63.00%	61.50%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%
Hawaiian Electric	HE	77.00%	74.00%	71.00%	68.00%	65.00%	65.00%	65.00%	65.00%	65.00%	65.00%	65.00%	65.00%	65.00%	65.00%	65.00%
IDACORP, Inc.	IDA	43.00%	45.75%	48.50%	51.25%	54.00%	54.00%	54.00%	54.00%	54.00%	54.00%	54.00%	54.00%	54.00%	54.00%	54.00%
NV Energy	NVE	49.00%	52.75%	56.50%	60.25%	64.00%	64.00%	64.00%	64.00%	64.00%	64.00%	64.00%	64.00%	64.00%	64.00%	64.00%
Pinnacle West Capital	PNW	63.00%	63.25%	63.50%	63.75%	64.00%	64.00%	64.00%	64.00%	64.00%	64.00%	64.00%	64.00%	64.00%	64.00%	64.00%
PNM Resources	PNM	42.00%	42.50%	43.00%	43.50%	44.00%	44.00%	44.00%	44.00%	44.00%	44.00%	44.00%	44.00%	44.00%	44.00%	44.00%
Portland General	POR	55.00%	54.75%	54.50%	54.25%	54.00%	54.00%	54.00%	54.00%	54.00%	54.00%	54.00%	54.00%	54.00%	54.00%	54.00%
Southern Co.	SO	73.00%	72.00%	71.00%	70.00%	69.00%	69.00%	69.00%	69.00%	69.00%	69.00%	69.00%	69.00%	69.00%	69.00%	69.00%
Westar Energy	WR	70.00%	68.25%	66.50%	64.75%	63.00%	63.00%	63.00%	63.00%	63.00%	63.00%	63.00%	63.00%	63.00%	63.00%	63.00%

Projected Annual Data Dividends per Share & Terminal Market Value		[43]	[44]	[45]	[46]	[47]	[48]	[49]	[50]	[51]	[52]	[53]	[54]	[55]	[56]	[57]	[58]	[59]
Company	Ticker	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Terminal Price	Terminal P/E Ratio
American Electric Power	AEP	$1.95	$2.01	$2.07	$2.14	$2.20	$2.29	$2.39	$2.49	$2.60	$2.71	$2.83	$2.96	$3.10	$3.24	$3.39	$70.38	12.06
Cleco Corp.	CNL	$1.42	$1.50	$1.58	$1.67	$1.76	$1.85	$1.95	$2.05	$2.15	$2.25	$2.35	$2.46	$2.57	$2.69	$2.81	$74.49	13.80
Empire District Electric	EDE	$1.13	$1.18	$1.22	$1.27	$1.31	$1.41	$1.51	$1.61	$1.70	$1.79	$1.87	$1.95	$2.04	$2.13	$2.23	$38.04	11.60
Entergy Corp.	ETR	$4.77	$4.85	$4.93	$5.01	$5.08	$5.21	$5.36	$5.53	$5.74	$5.97	$6.24	$6.53	$6.82	$7.13	$7.46	$118.15	9.67
Great Plains Energy Inc.	GXP	$0.87	$0.90	$0.93	$0.96	$1.00	$1.05	$1.11	$1.17	$1.22	$1.28	$1.34	$1.40	$1.46	$1.53	$1.60	$37.47	14.05
Hawaiian Electric	HE	$1.21	$1.27	$1.32	$1.38	$1.44	$1.56	$1.67	$1.78	$1.89	$1.99	$2.08	$2.18	$2.28	$2.38	$2.49	$48.56	12.69
IDACORP, Inc.	IDA	$1.50	$1.66	$1.83	$2.01	$2.21	$2.30	$2.39	$2.50	$2.60	$2.72	$2.84	$2.97	$3.11	$3.25	$3.40	$76.47	12.16
NV Energy	NVE	$0.38	$0.45	$0.54	$0.64	$0.75	$0.83	$0.90	$0.98	$1.04	$1.10	$1.15	$1.20	$1.26	$1.32	$1.38	$31.99	14.88
Pinnacle West Capital	PNW	$1.99	$2.10	$2.22	$2.35	$2.49	$2.62	$2.75	$2.89	$3.03	$3.17	$3.31	$3.47	$3.62	$3.79	$3.96	$89.17	14.41
PNM Resources	PNM	$0.51	$0.59	$0.67	$0.77	$0.88	$0.98	$1.08	$1.17	$1.26	$1.33	$1.39	$1.46	$1.52	$1.59	$1.66	$36.91	9.75
Portland General	POR	$1.13	$1.18	$1.23	$1.29	$1.34	$1.41	$1.48	$1.55	$1.62	$1.70	$1.77	$1.85	$1.94	$2.02	$2.12	$46.71	11.92
Southern Co.	SO	$1.97	$2.05	$2.13	$2.21	$2.29	$2.40	$2.52	$2.65	$2.77	$2.90	$3.04	$3.17	$3.32	$3.47	$3.63	$83.97	15.98
Westar Energy	WR	$1.33	$1.38	$1.42	$1.47	$1.52	$1.61	$1.70	$1.79	$1.88	$1.97	$2.06	$2.15	$2.25	$2.35	$2.46	$52.00	13.31
																		12.79
																		12.69

Projected Annual Data Investor Cash Flows		[60]	[61]	[62]	[63]	[64]	[65]	[66]	[67]	[68]	[69]	[70]	[71]	[72]	[73]	[74]	[75]	[76]
		Initial																
Company	Ticker	Outflow	4/30/12	10/30/12	10/30/13	10/30/14	10/30/15	10/30/16	10/30/17	10/30/18	10/30/19	10/30/20	10/30/21	10/30/22	10/30/23	10/30/24	10/30/25	10/30/26
American Electric Power	AEP	($38.21)	$0.00	$1.95	$2.01	$2.07	$2.14	$2.20	$2.29	$2.39	$2.49	$2.60	$2.71	$2.83	$2.96	$3.10	$3.24	$73.76
Cleco Corp.	CNL	($39.52)	$0.00	$1.42	$1.50	$1.58	$1.67	$1.76	$1.85	$1.95	$2.05	$2.15	$2.25	$2.35	$2.46	$2.57	$2.69	$77.29
Empire District Electric	EDE	($20.12)	$0.00	$1.13	$1.18	$1.22	$1.27	$1.31	$1.41	$1.51	$1.61	$1.70	$1.79	$1.87	$1.95	$2.04	$2.13	$40.27
Entergy Corp.	ETR	($66.37)	$0.00	$4.77	$4.85	$4.93	$5.01	$5.08	$5.21	$5.36	$5.53	$5.74	$5.97	$6.24	$6.53	$6.82	$7.13	$125.61
Great Plains Energy Inc.	GXP	($20.04)	$0.00	$0.87	$0.90	$0.93	$0.96	$1.00	$1.05	$1.11	$1.17	$1.22	$1.28	$1.34	$1.40	$1.46	$1.53	$39.07
Hawaiian Electric	HE	($25.45)	$0.00	$1.21	$1.27	$1.32	$1.38	$1.44	$1.56	$1.67	$1.78	$1.89	$1.99	$2.08	$2.18	$2.28	$2.38	$51.05
IDACORP, Inc.	IDA	($40.37)	$0.00	$1.50	$1.66	$1.83	$2.01	$2.21	$2.30	$2.39	$2.50	$2.60	$2.72	$2.84	$2.97	$3.11	$3.25	$79.87
NV Energy	NVE	($15.95)	$0.00	$0.38	$0.45	$0.54	$0.64	$0.75	$0.83	$0.90	$0.98	$1.04	$1.10	$1.15	$1.20	$1.26	$1.32	$33.37
Pinnacle West Capital	PNW	($47.38)	$0.00	$1.99	$2.10	$2.22	$2.35	$2.49	$2.62	$2.75	$2.89	$3.03	$3.17	$3.31	$3.47	$3.62	$3.79	$93.13
PNM Resources	PNM	($18.41)	$0.00	$0.51	$0.59	$0.67	$0.77	$0.88	$0.98	$1.08	$1.17	$1.26	$1.33	$1.39	$1.46	$1.52	$1.59	$38.57
Portland General	POR	($25.01)	$0.00	$1.13	$1.18	$1.23	$1.29	$1.34	$1.41	$1.48	$1.55	$1.62	$1.70	$1.77	$1.85	$1.94	$2.02	$48.83
Southern Co.	SO	($44.99)	$0.00	$1.97	$2.05	$2.13	$2.21	$2.29	$2.40	$2.52	$2.65	$2.77	$2.90	$3.04	$3.17	$3.32	$3.47	$87.59
Westar Energy	WR	($27.80)	$0.00	$1.33	$1.38	$1.42	$1.47	$1.52	$1.61	$1.70	$1.79	$1.88	$1.97	$2.06	$2.15	$2.25	$2.35	$54.46

MULTI-STAGE DCF MODEL – 90-DAY AVERAGE PRICE
TERMINAL VALUE - GORDON MODEL

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
		Stock	EPS	GDP		Payout Ratio		Solver Cells		Near-Term	Intermediate	Long-Term
Company	Ticker	Price	Growth	Growth	2012	2016	2026	Delta	Solution	Growth	Growth	Growth
American Electric Power	AEP	$39.30	3.95%	4.54%	60.00%	58.00%	58.00%	($0.00)	9.42%	3.95%	4.24%	4.54%
Cleco Corp.	CNL	$38.73	5.50%	4.54%	52.00%	52.00%	52.00%	($0.00)	8.56%	5.50%	5.02%	4.54%
Empire District Electric	EDE	$20.45	8.10%	4.54%	80.00%	68.00%	68.00%	$0.00	10.57%	8.10%	6.32%	4.54%
Entergy Corp.	ETR	$68.50	2.00%	4.54%	62.00%	61.00%	61.00%	$0.00	10.92%	2.00%	3.27%	4.54%
Great Plains Energy Inc.	GXP	$20.55	5.82%	4.54%	66.00%	60.00%	60.00%	($0.00)	8.89%	5.82%	5.18%	4.54%
Hawaiian Electric	HE	$25.66	8.96%	4.54%	77.00%	65.00%	65.00%	$0.00	9.85%	8.96%	6.74%	4.54%
IDACORP, Inc.	IDA	$41.15	4.00%	4.54%	43.00%	54.00%	54.00%	($0.00)	9.09%	4.00%	4.27%	4.54%
NV Energy	NVE	$16.00	11.28%	4.54%	49.00%	64.00%	64.00%	($0.00)	9.02%	11.28%	7.90%	4.54%
Pinnacle West Capital	PNW	$47.51	5.39%	4.54%	63.00%	64.00%	64.00%	($0.00)	9.17%	5.39%	4.97%	4.54%
PNM Resources	PNM	$18.17	13.02%	4.54%	42.00%	44.00%	44.00%	($0.00)	9.31%	13.02%	8.76%	4.54%
Portland General	POR	$24.97	4.99%	4.54%	55.00%	54.00%	54.00%	($0.00)	9.29%	4.99%	4.76%	4.54%
Southern Co.	SO	$44.95	5.23%	4.54%	73.00%	69.00%	69.00%	($0.00)	9.06%	5.23%	4.88%	4.54%
Westar Energy	WR	$26.08	6.14%	4.54%	70.00%	63.00%	63.00%	($0.00)	9.44%	6.14%	5.34%	4.54%
MEAN:		$33.39	6.49%	4.54%	60.92%	59.69%	59.69%		9.43%	6.49%	5.51%	4.54%

Projected Annual Data
Earnings per Share

Company	Ticker	[12] 2011	[13] 2012	[14] 2013	[15] 2014	[16] 2015	[17] 2016	[18] 2017	[19] 2018	[20] 2019	[21] 2020	[22] 2021	[23] 2022	[24] 2023	[25] 2024	[26] 2025	[27] 2026
American Electric Power	AEP	$3.13	$3.25	$3.38	$3.52	$3.65	$3.80	$3.95	$4.12	$4.29	$4.48	$4.68	$4.89	$5.11	$5.34	$5.58	$5.84
Cleco Corp.	CNL	$2.59	$2.73	$2.88	$3.04	$3.21	$3.39	$3.57	$3.75	$3.94	$4.13	$4.32	$4.52	$4.73	$4.94	$5.16	$5.40
Empire District Electric	EDE	$1.31	$1.42	$1.53	$1.65	$1.79	$1.93	$2.08	$2.22	$2.36	$2.50	$2.63	$2.75	$2.87	$3.00	$3.14	$3.28
Entergy Corp.	ETR	$7.55	$7.70	$7.86	$8.01	$8.17	$8.34	$8.54	$8.78	$9.07	$9.40	$9.79	$10.23	$10.70	$11.18	$11.69	$12.22
Great Plains Energy Inc.	GXP	$1.25	$1.32	$1.40	$1.48	$1.57	$1.66	$1.75	$1.85	$1.94	$2.04	$2.14	$2.23	$2.33	$2.44	$2.55	$2.67
Hawaiian Electric	HE	$1.44	$1.57	$1.71	$1.86	$2.03	$2.21	$2.39	$2.57	$2.75	$2.91	$3.06	$3.20	$3.35	$3.50	$3.66	$3.83
IDACORP, Inc.	IDA	$3.36	$3.49	$3.63	$3.78	$3.93	$4.09	$4.26	$4.43	$4.62	$4.82	$5.04	$5.27	$5.51	$5.76	$6.02	$6.29
NV Energy	NVE	$0.69	$0.77	$0.85	$0.95	$1.06	$1.18	$1.30	$1.41	$1.53	$1.63	$1.72	$1.80	$1.88	$1.97	$2.06	$2.15
Pinnacle West Capital	PNW	$2.99	$3.15	$3.32	$3.50	$3.69	$3.89	$4.09	$4.30	$4.51	$4.73	$4.95	$5.18	$5.41	$5.66	$5.92	$6.19
PNM Resources	PNM	$1.08	$1.22	$1.38	$1.55	$1.76	$1.99	$2.22	$2.45	$2.66	$2.86	$3.03	$3.17	$3.31	$3.46	$3.62	$3.78
Portland General	POR	$1.95	$2.05	$2.15	$2.26	$2.37	$2.49	$2.61	$2.74	$2.87	$3.00	$3.14	$3.28	$3.43	$3.59	$3.75	$3.92
Southern Co.	SO	$2.57	$2.70	$2.85	$2.99	$3.15	$3.32	$3.49	$3.66	$3.84	$4.02	$4.21	$4.40	$4.60	$4.81	$5.03	$5.25
Westar Energy	WR	$1.79	$1.90	$2.02	$2.14	$2.27	$2.41	$2.55	$2.70	$2.84	$2.98	$3.13	$3.27	$3.42	$3.57	$3.74	$3.91

Projected Annual Data
Dividend Payout Ratio

Company	Ticker	[28] 2012	[29] 2013	[30] 2014	[31] 2015	[32] 2016	[33] 2017	[34] 2018	[35] 2019	[36] 2020	[37] 2021	[38] 2022	[39] 2023	[40] 2024	[41] 2025	[42] 2026
American Electric Power	AEP	60.00%	59.50%	59.00%	58.50%	58.00%	58.00%	58.00%	58.00%	58.00%	58.00%	58.00%	58.00%	58.00%	58.00%	58.00%
Cleco Corp.	CNL	52.00%	52.00%	52.00%	52.00%	52.00%	52.00%	52.00%	52.00%	52.00%	52.00%	52.00%	52.00%	52.00%	52.00%	52.00%
Empire District Electric	EDE	80.00%	77.00%	74.00%	71.00%	68.00%	68.00%	68.00%	68.00%	68.00%	68.00%	68.00%	68.00%	68.00%	68.00%	68.00%
Entergy Corp.	ETR	62.00%	61.75%	61.50%	61.25%	61.00%	61.00%	61.00%	61.00%	61.00%	61.00%	61.00%	61.00%	61.00%	61.00%	61.00%
Great Plains Energy Inc.	GXP	66.00%	64.50%	63.00%	61.50%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%
Hawaiian Electric	HE	77.00%	74.00%	71.00%	68.00%	65.00%	65.00%	65.00%	65.00%	65.00%	65.00%	65.00%	65.00%	65.00%	65.00%	65.00%
IDACORP, Inc.	IDA	43.00%	45.75%	48.50%	51.25%	54.00%	54.00%	54.00%	54.00%	54.00%	54.00%	54.00%	54.00%	54.00%	54.00%	54.00%
NV Energy	NVE	49.00%	52.75%	56.50%	60.25%	64.00%	64.00%	64.00%	64.00%	64.00%	64.00%	64.00%	64.00%	64.00%	64.00%	64.00%
Pinnacle West Capital	PNW	63.00%	63.25%	63.50%	63.75%	64.00%	64.00%	64.00%	64.00%	64.00%	64.00%	64.00%	64.00%	64.00%	64.00%	64.00%
PNM Resources	PNM	42.00%	42.50%	43.00%	43.50%	44.00%	44.00%	44.00%	44.00%	44.00%	44.00%	44.00%	44.00%	44.00%	44.00%	44.00%
Portland General	POR	55.00%	54.75%	54.50%	54.25%	54.00%	54.00%	54.00%	54.00%	54.00%	54.00%	54.00%	54.00%	54.00%	54.00%	54.00%
Southern Co.	SO	73.00%	72.00%	71.00%	70.00%	69.00%	69.00%	69.00%	69.00%	69.00%	69.00%	69.00%	69.00%	69.00%	69.00%	69.00%
Westar Energy	WR	70.00%	68.25%	66.50%	64.75%	63.00%	63.00%	63.00%	63.00%	63.00%	63.00%	63.00%	63.00%	63.00%	63.00%	63.00%

Projected Annual Data
Dividends per Share & Terminal Market Value

Company	Ticker	[43] 2012	[44] 2013	[45] 2014	[46] 2015	[47] 2016	[48] 2017	[49] 2018	[50] 2019	[51] 2020	[52] 2021	[53] 2022	[54] 2023	[55] 2024	[56] 2025	[57] 2026	[58] Terminal Price	[59] Terminal P/E Ratio
American Electric Power	AEP	$1.95	$2.01	$2.07	$2.14	$2.20	$2.29	$2.39	$2.49	$2.60	$2.71	$2.83	$2.96	$3.10	$3.24	$3.39	$72.47	12.41
Cleco Corp.	CNL	$1.42	$1.50	$1.58	$1.67	$1.76	$1.85	$1.95	$2.05	$2.15	$2.25	$2.35	$2.46	$2.57	$2.69	$2.81	$72.98	13.52
Empire District Electric	EDE	$1.13	$1.18	$1.22	$1.27	$1.31	$1.41	$1.51	$1.61	$1.70	$1.79	$1.87	$1.95	$2.04	$2.13	$2.23	$38.67	11.79
Entergy Corp.	ETR	$4.77	$4.85	$4.93	$5.01	$5.08	$5.21	$5.36	$5.53	$5.74	$5.97	$6.24	$6.53	$6.82	$7.13	$7.46	$122.17	9.99
Great Plains Energy Inc.	GXP	$0.87	$0.90	$0.93	$0.96	$1.00	$1.05	$1.11	$1.17	$1.22	$1.28	$1.34	$1.40	$1.46	$1.53	$1.60	$38.45	14.42
Hawaiian Electric	HE	$1.21	$1.27	$1.32	$1.38	$1.44	$1.56	$1.67	$1.78	$1.89	$1.99	$2.08	$2.18	$2.28	$2.38	$2.49	$48.96	12.80
IDACORP, Inc.	IDA	$1.50	$1.66	$1.83	$2.01	$2.21	$2.30	$2.39	$2.50	$2.60	$2.72	$2.84	$2.97	$3.11	$3.25	$3.40	$77.97	12.39
NV Energy	NVE	$0.38	$0.45	$0.54	$0.64	$0.75	$0.83	$0.90	$0.98	$1.04	$1.10	$1.15	$1.20	$1.26	$1.32	$1.38	$32.08	14.92
Pinnacle West Capital	PNW	$1.99	$2.10	$2.22	$2.35	$2.49	$2.62	$2.75	$2.89	$3.03	$3.17	$3.31	$3.47	$3.62	$3.79	$3.96	$89.42	14.45
PNM Resources	PNM	$0.51	$0.59	$0.67	$0.77	$0.88	$0.98	$1.08	$1.17	$1.26	$1.33	$1.39	$1.46	$1.52	$1.59	$1.66	$36.45	9.63
Portland General	POR	$1.13	$1.18	$1.23	$1.29	$1.34	$1.41	$1.48	$1.55	$1.62	$1.70	$1.77	$1.85	$1.94	$2.02	$2.12	$46.63	11.90
Southern Co.	SO	$1.97	$2.05	$2.13	$2.21	$2.29	$2.40	$2.52	$2.65	$2.77	$2.90	$3.04	$3.17	$3.32	$3.47	$3.63	$83.90	15.97
Westar Energy	WR	$1.33	$1.38	$1.42	$1.47	$1.52	$1.61	$1.70	$1.79	$1.88	$1.97	$2.06	$2.15	$2.25	$2.35	$2.46	$52.52	13.45
																		12.90
																		12.60

Projected Annual Data
Investor Cash Flows

Company	Ticker	[60] Initial Outflow	[61] 4/30/12	[62] 10/30/12	[63] 10/30/13	[64] 10/30/14	[65] 10/30/15	[66] 10/30/16	[67] 10/30/17	[68] 10/30/18	[69] 10/30/19	[70] 10/30/20	[71] 10/30/21	[72] 10/30/22	[73] 10/30/23	[74] 10/30/24	[75] 10/30/25	[76] 10/30/26
American Electric Power	AEP	($39.30)	$0.00	$1.95	$2.01	$2.07	$2.14	$2.20	$2.29	$2.39	$2.49	$2.60	$2.71	$2.83	$2.96	$3.10	$3.24	$75.85
Cleco Corp.	CNL	($38.73)	$0.00	$1.42	$1.50	$1.58	$1.67	$1.76	$1.85	$1.95	$2.05	$2.15	$2.25	$2.35	$2.46	$2.57	$2.69	$75.79
Empire District Electric	EDE	($20.45)	$0.00	$1.13	$1.18	$1.22	$1.27	$1.31	$1.41	$1.51	$1.61	$1.70	$1.79	$1.87	$1.95	$2.04	$2.13	$40.90
Entergy Corp.	ETR	($68.50)	$0.00	$4.77	$4.85	$4.93	$5.01	$5.08	$5.21	$5.36	$5.53	$5.74	$5.97	$6.24	$6.53	$6.82	$7.13	$129.63
Great Plains Energy Inc.	GXP	($20.55)	$0.00	$0.87	$0.90	$0.93	$0.96	$1.00	$1.05	$1.11	$1.17	$1.22	$1.28	$1.34	$1.40	$1.46	$1.53	$40.04
Hawaiian Electric	HE	($25.66)	$0.00	$1.21	$1.27	$1.32	$1.38	$1.44	$1.56	$1.67	$1.78	$1.89	$1.99	$2.08	$2.18	$2.28	$2.38	$51.44
IDACORP, Inc.	IDA	($41.15)	$0.00	$1.50	$1.66	$1.83	$2.01	$2.21	$2.30	$2.39	$2.50	$2.60	$2.72	$2.84	$2.97	$3.11	$3.25	$81.37
NV Energy	NVE	($16.00)	$0.00	$0.38	$0.45	$0.54	$0.64	$0.75	$0.83	$0.90	$0.98	$1.04	$1.10	$1.15	$1.20	$1.26	$1.32	$33.45
Pinnacle West Capital	PNW	($47.51)	$0.00	$1.99	$2.10	$2.22	$2.35	$2.49	$2.62	$2.75	$2.89	$3.03	$3.17	$3.31	$3.47	$3.62	$3.79	$93.38
PNM Resources	PNM	($18.17)	$0.00	$0.51	$0.59	$0.67	$0.77	$0.88	$0.98	$1.08	$1.17	$1.26	$1.33	$1.39	$1.46	$1.52	$1.59	$38.12
Portland General	POR	($24.97)	$0.00	$1.13	$1.18	$1.23	$1.29	$1.34	$1.41	$1.48	$1.55	$1.62	$1.70	$1.77	$1.85	$1.94	$2.02	$48.75
Southern Co.	SO	($44.95)	$0.00	$1.97	$2.05	$2.13	$2.21	$2.29	$2.40	$2.52	$2.65	$2.77	$2.90	$3.04	$3.17	$3.32	$3.47	$87.52
Westar Energy	WR	($26.08)	$0.00	$1.33	$1.38	$1.42	$1.47	$1.52	$1.61	$1.70	$1.79	$1.88	$1.97	$2.06	$2.15	$2.25	$2.35	$54.98

MULTI-STAGE DCF MODEL – 180-DAY AVERAGE PRICE
TERMINAL VALUE - GORDON MODEL

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
		Stock	EPS	GDP		Payout Ratio		Solver Cells		Near-Term	Intermediate	Long-Term
Company	Ticker	Price	Growth	Growth	2012	2016	2026	Delta	Solution	Growth	Growth	Growth
American Electric Power	AEP	$38.82	3.95%	4.54%	60.00%	58.00%	58.00%	($0.00)	9.49%	3.95%	4.24%	4.54%
Cleco Corp.	CNL	$36.98	5.50%	4.54%	52.00%	52.00%	52.00%	($0.00)	8.75%	5.50%	5.02%	4.54%
Empire District Electric	EDE	$20.20	8.10%	4.54%	80.00%	68.00%	68.00%	$0.00	10.65%	8.10%	6.32%	4.54%
Entergy Corp.	ETR	$67.66	2.00%	4.54%	62.00%	61.00%	61.00%	$0.00	11.00%	2.00%	3.27%	4.54%
Great Plains Energy Inc.	GXP	$20.27	5.82%	4.54%	66.00%	60.00%	60.00%	($0.00)	8.95%	5.82%	5.18%	4.54%
Hawaiian Electric	HE	$25.19	8.96%	4.54%	77.00%	65.00%	65.00%	$0.00	9.95%	8.96%	6.74%	4.54%
IDACORP, Inc.	IDA	$40.06	4.00%	4.54%	43.00%	54.00%	54.00%	($0.00)	9.22%	4.00%	4.27%	4.54%
NV Energy	NVE	$15.47	11.28%	4.54%	49.00%	64.00%	64.00%	($0.00)	9.17%	11.28%	7.90%	4.54%
Pinnacle West Capital	PNW	$46.02	5.39%	4.54%	63.00%	64.00%	64.00%	($0.00)	9.32%	5.39%	4.97%	4.54%
PNM Resources	PNM	$17.46	13.02%	4.54%	42.00%	44.00%	44.00%	($0.00)	9.50%	13.02%	8.76%	4.54%
Portland General	POR	$24.51	4.99%	4.54%	55.00%	54.00%	54.00%	($0.00)	9.38%	4.99%	4.76%	4.54%
Southern Co.	SO	$43.76	5.23%	4.54%	73.00%	69.00%	69.00%	($0.00)	9.18%	5.23%	4.88%	4.54%
Westar Energy	WR	$27.31	6.14%	4.54%	70.00%	63.00%	63.00%	($0.00)	9.58%	6.14%	5.34%	4.54%
MEAN:		$32.59	6.49%	4.54%	60.92%	59.69%	59.69%		9.55%	6.49%	5.51%	4.54%

Projected Annual Data
Earnings per Share

Company	Ticker	[12] 2011	[13] 2012	[14] 2013	[15] 2014	[16] 2015	[17] 2016	[18] 2017	[19] 2018	[20] 2019	[21] 2020	[22] 2021	[23] 2022	[24] 2023	[25] 2024	[26] 2025	[27] 2026
American Electric Power	AEP	$3.13	$3.25	$3.38	$3.52	$3.65	$3.80	$3.95	$4.12	$4.29	$4.48	$4.68	$4.89	$5.11	$5.34	$5.58	$5.84
Cleco Corp.	CNL	$2.59	$2.73	$2.88	$3.04	$3.21	$3.39	$3.57	$3.75	$3.94	$4.13	$4.32	$4.52	$4.73	$4.94	$5.16	$5.40
Empire District Electric	EDE	$1.31	$1.42	$1.53	$1.65	$1.79	$1.93	$2.08	$2.22	$2.36	$2.50	$2.63	$2.75	$2.87	$3.00	$3.14	$3.28
Entergy Corp.	ETR	$7.55	$7.70	$7.86	$8.01	$8.17	$8.34	$8.54	$8.78	$9.07	$9.40	$9.79	$10.23	$10.70	$11.18	$11.69	$12.22
Great Plains Energy Inc.	GXP	$1.25	$1.32	$1.40	$1.48	$1.57	$1.66	$1.75	$1.85	$1.94	$2.04	$2.14	$2.23	$2.33	$2.44	$2.55	$2.67
Hawaiian Electric	HE	$1.44	$1.57	$1.71	$1.86	$2.03	$2.21	$2.39	$2.57	$2.75	$2.91	$3.06	$3.20	$3.35	$3.50	$3.66	$3.83
IDACORP, Inc.	IDA	$3.36	$3.49	$3.63	$3.78	$3.93	$4.09	$4.26	$4.43	$4.62	$4.82	$5.04	$5.27	$5.51	$5.76	$6.02	$6.29
NV Energy	NVE	$0.69	$0.77	$0.85	$0.95	$1.06	$1.18	$1.30	$1.41	$1.53	$1.63	$1.72	$1.80	$1.88	$1.97	$2.06	$2.15
Pinnacle West Capital	PNW	$2.99	$3.15	$3.32	$3.50	$3.69	$3.89	$4.09	$4.30	$4.51	$4.73	$4.95	$5.18	$5.41	$5.66	$5.92	$6.19
PNM Resources	PNM	$1.08	$1.22	$1.38	$1.56	$1.76	$1.99	$2.22	$2.45	$2.66	$2.86	$3.03	$3.17	$3.31	$3.46	$3.62	$3.78
Portland General	POR	$1.95	$2.05	$2.15	$2.26	$2.37	$2.49	$2.61	$2.74	$2.87	$3.00	$3.14	$3.28	$3.43	$3.59	$3.75	$3.92
Southern Co.	SO	$2.57	$2.70	$2.85	$2.99	$3.15	$3.32	$3.49	$3.66	$3.84	$4.02	$4.21	$4.40	$4.60	$4.81	$5.03	$5.25
Westar Energy	WR	$1.79	$1.90	$2.02	$2.14	$2.27	$2.41	$2.55	$2.70	$2.84	$2.98	$3.13	$3.27	$3.42	$3.57	$3.74	$3.91

Projected Annual Data
Dividend Payout Ratio

Company	Ticker	[28] 2012	[29] 2013	[30] 2014	[31] 2015	[32] 2016	[33] 2017	[34] 2018	[35] 2019	[36] 2020	[37] 2021	[38] 2022	[39] 2023	[40] 2024	[41] 2025	[42] 2026
American Electric Power	AEP	60.00%	59.50%	59.00%	58.50%	58.00%	58.00%	58.00%	58.00%	58.00%	58.00%	58.00%	58.00%	58.00%	58.00%	58.00%
Cleco Corp.	CNL	52.00%	52.00%	52.00%	52.00%	52.00%	52.00%	52.00%	52.00%	52.00%	52.00%	52.00%	52.00%	52.00%	52.00%	52.00%
Empire District Electric	EDE	80.00%	77.00%	74.00%	71.00%	68.00%	68.00%	68.00%	68.00%	68.00%	68.00%	68.00%	68.00%	68.00%	68.00%	68.00%
Entergy Corp.	ETR	62.00%	61.75%	61.50%	61.25%	61.00%	61.00%	61.00%	61.00%	61.00%	61.00%	61.00%	61.00%	61.00%	61.00%	61.00%
Great Plains Energy Inc.	GXP	66.00%	64.50%	63.00%	61.50%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%
Hawaiian Electric	HE	77.00%	74.00%	71.00%	68.00%	65.00%	65.00%	65.00%	65.00%	65.00%	65.00%	65.00%	65.00%	65.00%	65.00%	65.00%
IDACORP, Inc.	IDA	43.00%	45.75%	48.50%	51.25%	54.00%	54.00%	54.00%	54.00%	54.00%	54.00%	54.00%	54.00%	54.00%	54.00%	54.00%
NV Energy	NVE	49.00%	52.75%	56.50%	60.25%	64.00%	64.00%	64.00%	64.00%	64.00%	64.00%	64.00%	64.00%	64.00%	64.00%	64.00%
Pinnacle West Capital	PNW	63.00%	63.25%	63.50%	63.75%	64.00%	64.00%	64.00%	64.00%	64.00%	64.00%	64.00%	64.00%	64.00%	64.00%	64.00%
PNM Resources	PNM	42.00%	42.50%	43.00%	43.50%	44.00%	44.00%	44.00%	44.00%	44.00%	44.00%	44.00%	44.00%	44.00%	44.00%	44.00%
Portland General	POR	55.00%	54.75%	54.50%	54.25%	54.00%	54.00%	54.00%	54.00%	54.00%	54.00%	54.00%	54.00%	54.00%	54.00%	54.00%
Southern Co.	SO	73.00%	72.00%	71.00%	70.00%	69.00%	69.00%	69.00%	69.00%	69.00%	69.00%	69.00%	69.00%	69.00%	69.00%	69.00%
Westar Energy	WR	70.00%	68.25%	66.50%	64.75%	63.00%	63.00%	63.00%	63.00%	63.00%	63.00%	63.00%	63.00%	63.00%	63.00%	63.00%

Projected Annual Data
Dividends per Share & Terminal Market Value

Company	Ticker	[43] 2012	[44] 2013	[45] 2014	[46] 2015	[47] 2016	[48] 2017	[49] 2018	[50] 2019	[51] 2020	[52] 2021	[53] 2022	[54] 2023	[55] 2024	[56] 2025	[57] 2026	[58] Terminal Price	[59] Terminal P/E Ratio
American Electric Power	AEP	$1.95	$2.01	$2.07	$2.14	$2.20	$2.29	$2.39	$2.49	$2.60	$2.71	$2.83	$2.96	$3.10	$3.24	$3.39	$71.54	12.26
Cleco Corp.	CNL	$1.42	$1.50	$1.58	$1.67	$1.76	$1.85	$1.95	$2.05	$2.15	$2.25	$2.35	$2.46	$2.57	$2.69	$2.81	$68.64	12.90
Empire District Electric	EDE	$1.13	$1.18	$1.22	$1.27	$1.31	$1.41	$1.51	$1.61	$1.70	$1.79	$1.87	$1.95	$2.04	$2.13	$2.23	$38.19	11.64
Entergy Corp.	ETR	$4.77	$4.85	$4.93	$5.01	$5.08	$5.21	$5.36	$5.53	$5.74	$5.97	$6.24	$6.53	$6.82	$7.13	$7.46	$120.59	9.87
Great Plains Energy Inc.	GXP	$0.87	$0.90	$0.93	$0.96	$1.00	$1.05	$1.11	$1.17	$1.22	$1.28	$1.34	$1.40	$1.46	$1.53	$1.60	$37.91	14.22
Hawaiian Electric	HE	$1.21	$1.27	$1.32	$1.38	$1.44	$1.56	$1.67	$1.78	$1.89	$1.99	$2.08	$2.18	$2.28	$2.38	$2.49	$48.05	12.56
IDACORP, Inc.	IDA	$1.50	$1.66	$1.83	$2.01	$2.21	$2.30	$2.39	$2.50	$2.60	$2.72	$2.84	$2.97	$3.11	$3.25	$3.40	$75.89	12.06
NV Energy	NVE	$0.38	$0.45	$0.54	$0.64	$0.75	$0.83	$0.90	$0.98	$1.04	$1.10	$1.15	$1.20	$1.26	$1.32	$1.38	$31.07	14.46
Pinnacle West Capital	PNW	$1.99	$2.10	$2.22	$2.35	$2.49	$2.62	$2.75	$2.89	$3.03	$3.17	$3.31	$3.47	$3.62	$3.79	$3.96	$86.57	13.99
PNM Resources	PNM	$0.51	$0.59	$0.67	$0.77	$0.88	$0.98	$1.08	$1.17	$1.26	$1.33	$1.39	$1.46	$1.52	$1.59	$1.66	$35.08	9.27
Portland General	POR	$1.13	$1.18	$1.23	$1.29	$1.34	$1.41	$1.48	$1.55	$1.62	$1.70	$1.77	$1.85	$1.94	$2.02	$2.12	$45.76	11.67
Southern Co.	SO	$1.97	$2.05	$2.13	$2.21	$2.29	$2.40	$2.52	$2.65	$2.77	$2.90	$3.04	$3.17	$3.32	$3.47	$3.63	$81.63	15.54
Westar Energy	WR	$1.33	$1.38	$1.42	$1.47	$1.52	$1.61	$1.70	$1.79	$1.88	$1.97	$2.06	$2.15	$2.25	$2.35	$2.46	$51.05	13.07
																		12.58
																		12.56

Projected Annual Data
Investor Cash Flows

Company	Ticker	[60] Initial Outflow	[61] 4/30/12	[62] 10/30/12	[63] 10/30/13	[64] 10/30/14	[65] 10/30/15	[66] 10/30/16	[67] 10/30/17	[68] 10/30/18	[69] 10/30/19	[70] 10/30/20	[71] 10/30/21	[72] 10/30/22	[73] 10/30/23	[74] 10/30/24	[75] 10/30/25	[76] 10/30/26
American Electric Power	AEP	($38.82)	$0.00	$1.95	$2.01	$2.07	$2.14	$2.20	$2.29	$2.39	$2.49	$2.60	$2.71	$2.83	$2.96	$3.10	$3.24	$74.93
Cleco Corp.	CNL	($36.98)	$0.00	$1.42	$1.50	$1.58	$1.67	$1.76	$1.85	$1.95	$2.05	$2.15	$2.25	$2.35	$2.46	$2.57	$2.69	$72.44
Empire District Electric	EDE	($20.20)	$0.00	$1.13	$1.18	$1.22	$1.27	$1.31	$1.41	$1.51	$1.61	$1.70	$1.79	$1.87	$1.95	$2.04	$2.13	$40.42
Entergy Corp.	ETR	($67.66)	$0.00	$4.77	$4.85	$4.93	$5.01	$5.08	$5.21	$5.36	$5.53	$5.74	$5.97	$6.24	$6.53	$6.82	$7.13	$128.05
Great Plains Energy Inc.	GXP	($20.27)	$0.00	$0.87	$0.90	$0.93	$0.96	$1.00	$1.05	$1.11	$1.17	$1.22	$1.28	$1.34	$1.40	$1.46	$1.53	$39.51
Hawaiian Electric	HE	($25.19)	$0.00	$1.21	$1.27	$1.32	$1.38	$1.44	$1.56	$1.67	$1.78	$1.89	$1.99	$2.08	$2.18	$2.28	$2.38	$50.54
IDACORP, Inc.	IDA	($40.06)	$0.00	$1.50	$1.66	$1.83	$2.01	$2.21	$2.30	$2.39	$2.50	$2.60	$2.72	$2.84	$2.97	$3.11	$3.25	$79.29
NV Energy	NVE	($15.47)	$0.00	$0.38	$0.45	$0.54	$0.64	$0.75	$0.83	$0.90	$0.98	$1.04	$1.10	$1.15	$1.20	$1.26	$1.32	$32.45
Pinnacle West Capital	PNW	($46.02)	$0.00	$1.99	$2.10	$2.22	$2.35	$2.49	$2.62	$2.75	$2.89	$3.03	$3.17	$3.31	$3.47	$3.62	$3.79	$90.53
PNM Resources	PNM	($17.46)	$0.00	$0.51	$0.59	$0.67	$0.77	$0.88	$0.98	$1.08	$1.17	$1.26	$1.33	$1.39	$1.46	$1.52	$1.59	$36.74
Portland General	POR	($24.51)	$0.00	$1.13	$1.18	$1.23	$1.29	$1.34	$1.41	$1.48	$1.55	$1.62	$1.70	$1.77	$1.85	$1.94	$2.02	$47.88
Southern Co.	SO	($43.76)	$0.00	$1.97	$2.05	$2.13	$2.21	$2.29	$2.40	$2.52	$2.65	$2.77	$2.90	$3.04	$3.17	$3.32	$3.47	$85.25
Westar Energy	WR	($27.31)	$0.00	$1.33	$1.38	$1.42	$1.47	$1.52	$1.61	$1.70	$1.79	$1.88	$1.97	$2.06	$2.15	$2.25	$2.35	$53.51

EXHIBIT SKB-10

Blue Chip Financial Forecasts®

Top Analysts' Forecasts Of U.S. And Foreign Interest Rates, Currency Values And The Factors That Influence Them

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EXECUTIVE EDITOR:
RANDELL E. MOORE
3663 Madison Ave.
Kansas City, MO 64111
Phone (816) 931-0131
Fax (816) 931-0430
E-mail: *randy.moore@wolterskluwer.com*

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Marketing Director: Dom Cervi

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Consensus Still Sees Modest Economic Growth, But Downside Risks Are High

Domestic Commentary Consensus forecasts of U.S. economic growth this quarter and next increased during the past month but expectations for growth over the remainder of the forecast horizon were little changed. Most panelists continue to anticipate modest but gradually improving growth over the forecast horizon but acknowledge the existence of downside risks given the deteriorating situation in Europe, signs of slowing activity in Asia and the potential for greater-than-anticipated fiscal retrenchment in the U.S.

Based on our November 22nd-23rd survey, the consensus now predicts real GDP growth of 2.7% (saar) in the current quarter, 0.7 of a percentage point greater than estimated a month ago. That compares with downwardly revised growth of 2.0% in Q3, according to the government's second estimate. The downward revision stemmed from lower than initially reported business inventories. Indeed, inventories are now reported to have contracted by $8.5 billion versus an initially reported $5.4 billion increase. Estimated Q3 growth in real final sales (GDP minus inventories) remained at 3.6%. Modest downward revisions in personal consumption and fixed business investment were offset by a narrower net export deficit. Real government spending and investment was downwardly revised to show a 0.1% contraction. That marked the fourth consecutive quarterly decline, the first such occurrence since the beginning of the Vietnam War wind-down in 1971. A contraction this quarter would mark the first five-quarter string of declines since the end of the Korean War.

Discouragingly, real disposable personal income is now reported to have contracted 2.1% in Q3. Moreover, based on revised estimates of wages and salaries, personal taxes, and contributions to government social insurance for April through June, the government revised its Q2 estimate of real DPI from an increase of 0.6% to a contraction of 0.5%. As a consequence, real gross domestic income (GDI), arguably a better indicator of an economy's health than GDP, rose just 0.2% in Q2 and 0.4% in Q3.

GDP growth in the current quarter is likely to be supported by real PCE growth on par with that in Q3 but much slower growth in business spending on equipment and structures. Purchases of consumer goods, aided by better vehicle sales, will likely be stronger in Q4 than in Q3. However, consumer spending on services is likely to be slower given that such spending in Q3 was the fastest seen in some years. While the level of real PCE in September was comfortably above its Q2 average, suggesting solid momentum going into Q4, the 0.1% gain in October was a disappointment, causing some analysts to pare their estimates of growth during the final quarter of the year.

Analysts' estimates of business investment in Q4 have come down. October core capital goods orders, a leading indicator of capital spending, fell 1.8%, the biggest monthly drop since January. Moreover, core capital goods shipments, an input into GDP, contracted 1.1% after falling 1.0% in September. That marked the first back-to-back monthly declines since January and February of this year.

A rebound in business inventories will likely be the biggest contributor to GDP in current quarter, but some of the increase may turn out to be unintended. A further narrowing of the trade deficit also should add to GDP in Q4. However, real final sales during the quarter should fall well short of the 3.6% advance registered last quarter.

Looking beyond the current quarter, the consensus predicts real GDP will grow 2.0% in Q1 2012, 0.2 of a point stronger than forecast last month. Growth of 2.1% and 2.4% is forecast for Q2 and Q3 of next year, unchanged from a month earlier. The consensus forecast of real GDP growth in the final quarter of next year rose 0.1 of a percentage point this month to 2.7% but the forecast of growth in Q1 2013 slipped by 0.2 of a point to 2.6%.

Critical to the outlook for growth in the first half of next year is whether Congress approves an extension of this year's two percentage point reduction in workers' payroll taxes and/or the long-term unemployment benefits program, both of which expire at the end of December. The recent failure by the so-called "Super committee" to come up with a $1.5 trillion long-term debt reduction plan, likely reduced the odds that these programs will be extended. Nonetheless, most analysts' estimates of economic growth next year still assume that Congress will act in the next couple of weeks to at least extend the payroll tax holiday. Absent such action, growth in DPI and PCE next year is likely to fall well short of current consensus assumptions.

In the longer-run, the failure of the Super Committee to strike a deal triggers automatic discretionary and defense cuts of $1.2 trillion over 9 years, beginning in January 2013. While some politicians are already devising ways to circumvent the cuts, the President and leaders of the House and Senate have so far signaled their intention to stick to the original deal. Each are likely posturing given it is an election year, but further fiscal restraint in 2013 seems highly likely.

As expected, the Federal Open Market Committee left policy unchanged at its November 1st-2nd meeting but left the door ajar to further stimulus given an unemployment rate that remained "elevated," and "significant downside risks to the economic outlook, including strains in global financial markets." The unchanged policy stance comes in the wake of the Fed's conditional promise in August to leave its federal funds rate target at 0%-0.25% until at least mid-2013 and the announcement in September of plans to sell $400 billion of shorter duration assets on its balance sheet, replacing them with an equal amount of longer maturity Treasury notes by next June.

Minutes of the November meeting did reveal further discussions on ways to improve Fed communication of its policy intentions. Among the options discussed was conditional guidance on policy based upon "numerical thresholds" for inflation and unemployment. Also discussed was the idea of targeting nominal GDP as an intermediate policy objective, but this idea did not seem to garner much support. While no decisions were made in November on a revamped communications strategy we may see something come out of the FOMC's December 13th meeting.

Some influential FOMC members continue to talk up the possibility of additional quantitative easing (most likely purchases of mortgage-backed securities), but a near-term move in that direction seems unlikely unless the economy is shocked by events in Europe or failure to extend the payroll tax holiday. Rapid deterioration of the situation in Europe that evolved into a global credit crunch also would likely prompt the Fed to reactivate some of the liquidity enhancing mechanisms successfully employed during the second half of 2008 and first half of 2009.

Along those lines, the Fed recently launched its third round of bank stress tests, forcing the largest institutions to gauge whether they could withstand a sharp deterioration in the economy characterized by plunging equity markets, a sharp widening of credit spreads and a significant jump in the unemployment rate. The results will determine whether regulators will allow the banks to boost dividends and/or announce share buy-backs in the coming year. Banks are required to submit their plans to the Fed by January 9th. Full results of the tests will be released in March.

Consensus Forecast The FOMC is expected by the consensus to leave its fed funds target unchanged until mid-2013. Additional quantitative easing by the Fed is assumed by about half of our panelists. The economy is expected to grow modestly over the forecast horizon but downside risks remain considerable. Inflation is expected to ease in 2012 *(see page 2).*

Special Questions On page 14 are results of our twice-yearly long-range survey results with forecasts for the years 2013 through 2017 and averages for the 5-year periods 2013-2017 and 2018-2022.

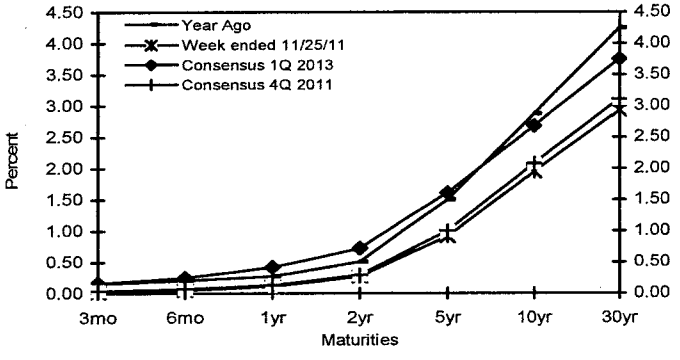
Consensus Forecasts Of U.S. Interest Rates And Key Assumptions[1]

	History								Consensus Forecasts-Quarterly Avg.					
	Average For Week Ending				Average For Month			Latest Q	4Q	1Q	2Q	3Q	4Q	1Q
Interest Rates	Nov.25	Nov.18	Nov.11	Nov.4	Oct.	Sep.	Aug.	3Q 2011	2011	2012	2012	2012	2012	2013
Federal Funds Rate	0.08	0.08	0.08	0.08	0.07	0.08	0.10	0.08	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.2**
Prime Rate	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**
LIBOR, 3-mo.	0.51	0.47	0.45	0.43	0.41	0.35	0.29	0.30	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.5**
Commercial Paper, 1-mo.	0.10	0.10	0.11	0.11	0.09	0.08	0.11	0.09	**0.1**	**0.1**	**0.2**	**0.2**	**0.2**	**0.3**
Treasury bill, 3-mo.	0.02	0.01	0.01	0.01	0.02	0.01	0.02	0.02	**0.0**	**0.0**	**0.1**	**0.1**	**0.1**	**0.2**
Treasury bill, 6-mo.	0.05	0.04	0.04	0.04	0.05	0.04	0.06	0.06	**0.1**	**0.1**	**0.1**	**0.2**	**0.2**	**0.3**
Treasury bill, 1 yr.	0.11	0.11	0.10	0.12	0.11	0.10	0.11	0.13	**0.1**	**0.2**	**0.2**	**0.3**	**0.3**	**0.4**
Treasury note, 2 yr.	0.27	0.26	0.25	0.23	0.28	0.21	0.23	0.28	**0.3**	**0.3**	**0.4**	**0.5**	**0.6**	**0.7**
Treasury note, 5 yr.	0.91	0.90	0.90	0.91	1.06	0.90	1.02	1.15	**1.0**	**1.1**	**1.2**	**1.3**	**1.5**	**1.6**
Treasury note, 10 yr.	1.95	2.02	2.05	2.07	2.15	1.98	2.30	2.43	**2.1**	**2.2**	**2.3**	**2.4**	**2.6**	**2.7**
Treasury note, 30 yr.	2.93	3.04	3.08	3.07	3.13	3.18	3.65	3.70	**3.1**	**3.2**	**3.3**	**3.5**	**3.7**	**3.8**
Corporate Aaa bond	3.85	3.89	3.88	3.84	3.98	4.09	4.37	4.46	**4.0**	**4.0**	**4.1**	**4.2**	**4.3**	**4.4**
Corporate Baa bond	5.13	5.16	5.12	5.11	5.37	5.27	5.36	5.46	**5.2**	**5.2**	**5.3**	**5.4**	**5.5**	**5.5**
State & Local bonds	4.07	4.09	4.02	4.02	4.13	4.01	4.02	4.18	**4.0**	**4.1**	**4.1**	**4.2**	**4.3**	**4.3**
Home mortgage rate	3.98	4.00	3.99	4.00	4.07	4.11	4.27	4.31	**4.0**	**4.1**	**4.1**	**4.2**	**4.4**	**4.5**
	History								Consensus Forecasts-Quarterly					
	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q
Key Assumptions	2009	2010	2010	2010	2010	2011	2011	2011	2011	2012	2012	2012	2012	2013
Major Currency Index	72.8	74.8	77.6	75.9	73.0	71.9	69.6	69.9	**71.8**	**72.1**	**72.3**	**72.0**	**72.0**	**72.2**
Real GDP	3.8	3.9	3.8	2.5	2.3	0.4	1.3	2.0	**2.7**	**2.0**	**2.1**	**2.4**	**2.7**	**2.6**
GDP Price Index	1.1	1.5	1.5	1.4	1.9	2.5	2.5	2.5	**1.8**	**1.9**	**1.9**	**2.0**	**2.0**	**2.1**
Consumer Price Index	2.7	1.3	-0.5	1.4	2.6	5.2	4.1	3.1	**1.8**	**2.1**	**2.1**	**2.3**	**2.2**	**2.3**

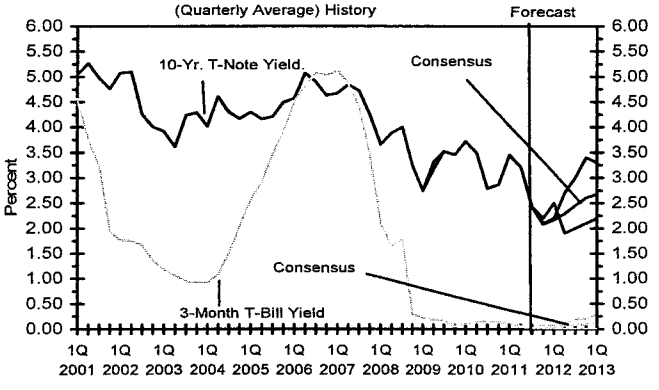
Forecasts for interest rates and the Federal Reserve's Major Currency Index represent averages for the quarter. Forecasts for Real GDP, GDP Price Index and Consumer Price Index are seasonally-adjusted annual rates of change (saar). Individual panel members' forecasts are on pages 4 through 9. Historical data for interest rates except LIBOR is from Federal Reserve Release (FRSR) H.15. LIBOR quotes available from *The Wall Street Journal*. Interest rate definitions are the same as those in FRSR H.15. Treasury yields are reported on a constant maturity basis. Historical data for the Fed's Major Currency Index is from FRSR H.10 and G.5. Historical data for Real GDP and GDP Chained Price Index are from the Bureau of Economic Analysis (BEA). Consumer Price Index (CPI) history is from the Department of Labor's Bureau of Labor Statistics (BLS).

U.S. Treasury Yield Curve

Week ended November 25th, 2011 and Year Ago vs.
4Q 2011 and 1Q 2013 Consensus Forecasts

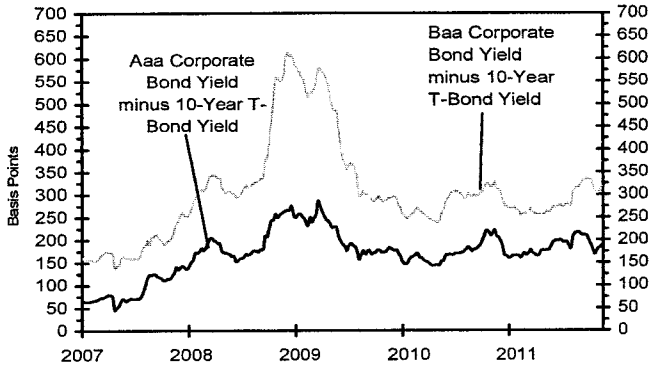


U.S. 3-Mo. T-Bills & 10-Yr. T-Note Yield



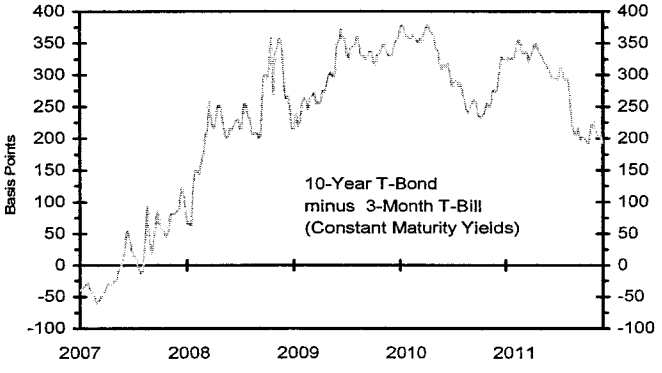
Corporate Bond Spreads

As of week ended November 25th, 2011



U.S. Treasury Yield Curve

As of week ended November 25th, 2011



----------3-Month Interest Rates[1]----------

	History			Consensus Forecasts Months From Now:		
	Latest:	Month Ago:	Year Ago:	3	6	12
U.S.	0.71	0.55	0.65	**0.44**	**0.39**	**0.39**
Japan	0.40	0.21	0.33	**0.24**	**0.24**	**0.24**
U.K.	1.15	1.02	0.75	**0.88**	**0.77**	**0.77**
Switzerland	0.23	0.20	0.50	**0.10**	**0.10**	**0.10**
Canada	1.30	1.69	1.62	**1.13**	**0.93**	**0.95**
Australia	4.70	4.95	4.96	**4.50**	**4.30**	**4.43**
Eurozone	1.55	1.76	1.16	**0.85**	**0.80**	**0.82**

----------10-Yr. Government Bond Yields[2]------

	History			Consensus Forecasts Months From Now:		
	Latest:	Month Ago:	Year Ago:	3	6	12
U.S.	1.97	2.13	2.91	**2.04**	**2.23**	**2.64**
Germany	2.25	2.06	2.71	**1.87**	**2.07**	**2.28**
Japan	1.04	1.02	1.16	**1.05**	**1.08**	**1.17**
U.K.	2.51	2.51	3.36	**2.31**	**2.42**	**2.73**
France	3.69	3.19	3.14	**4.09**	**4.08**	**4.31**
Italy	7.37	5.96	4.44	**6.20**	**6.30**	**6.30**
Switzerland	0.90	1.03	1.68	**0.95**	**1.10**	**1.27**
Canada	2.11	2.28	3.16	**2.36**	**2.53**	**3.02**
Australia	3.91	4.48	5.50	**4.37**	**4.51**	**4.94**
Spain	6.71	5.54	5.20	**6.43**	**6.49**	**6.47**

----------Foreign Exchange Rates[1]----------

	History			Consensus Forecasts Months From Now:		
	Latest:	Month Ago:	Year Ago:	3	6	12
U.S.	72.289	70.876	73.185	**72.5**	**71.8**	**71.0**
Japan	76.930	76.100	83.490	**77.7**	**77.4**	**79.5**
U.K.	1.5783	1.5945	1.5961	**1.57**	**1.59**	**1.64**
Switzerland	0.9159	0.8852	0.9979	**0.92**	**0.92**	**0.92**
Canada	1.0260	1.0090	1.0226	**1.01**	**0.99**	**0.97**
Australia	1.0036	1.0330	0.9846	**1.00**	**1.01**	**1.04**
Euro	1.3521	1.3873	1.3654	**1.33**	**1.34**	**1.37**

	Consensus 3-Month Rates vs. U.S. Rate			Consensus 10-Year Gov't Yields vs. U.S. Yield	
	Now	In 12 Mo.		Now	In 12 Mo.
Japan	-0.31	**-0.14**	Germany	0.28	**-0.36**
U.K.	0.44	**0.38**	Japan	-0.93	**-1.47**
Switzerland	-0.48	**-0.29**	U.K.	0.54	**0.10**
Canada	0.59	**0.56**	France	1.72	**1.67**
Australia	3.99	**4.04**	Italy	5.40	**3.66**
Eurozone	0.84	**0.44**	Switzerland	-1.07	**-1.37**
			Canada	0.14	**0.38**
			Australia	1.94	**2.30**
			Spain	4.74	**3.83**

Forecasts of panel members are on pages 10 and 11. Definitions of variables are as follows: [1]Three month rate on interest-earning money market deposits denominated in selected currencies. [2]Government bonds are yields to maturity. Foreign exchange rate forecasts for U.K., Australia and the Euro are U.S. dollars per currency unit. For the U.S dollar, forecasts are of the U.S. Federal Reserve Board's Major Currency Index.

International Commentary The Eurozone's debt crisis intensified sharply over the past month as global money mangers dumped holdings of European government and bank debt. Especially troubling was the rapid spread of the crisis from periphery members to the zone's core. The selling pushed 10-year government note yields in Italy to well in excess of 7% and yield curves are now inverted in Italy, Ireland, Greece and Portugal – a historically accurate harbinger of recession. Meanwhile, French, Dutch, Austrian and German government yields have turned skyward, the latter in part because of a failed auction that forced the Bundesbank to step in and buy bunds. Wholesale bank lending for Europe is effectively drying up as firms fret about counter-party risks, forcing increasing numbers of institutions to rely on the ECB for their day-to-day funding requirements. Ominously, the forced selling of debt and surging borrowing costs in Europe are increasingly reminiscent of the months leading up to the financial crisis in the fall of 2008 and are prompting some analysts to openly speculate about an inevitable break-up of the Eurozone.

Despite the intensifying crisis, Germany so far remains opposed to issuance of Eurobonds backed by all member states or massive purchases of sovereign debt by the European Central Bank until real fiscal union is achieved by way of treaty changes that impose strict budgetary rules on member states and automatic sanctions if those rules are broken. Hopes that the upcoming December 9th European Summit might produce definitive solutions to the crisis are fading. So, too, have hopes that the European Financial Stability Fund might at least buy time for needed reforms since it is not yet operational, is unlikely to be sufficiently leveraged to do much good, and might itself have difficulty issuing debt. While the International Monetary Fund recently announced a new rapid-fire credit line aimed at "breaking the chains of contagion," and is rumored to have readied a massive loan to finance Italy over the next 12 to 18 months while it implements budget cuts and growth-boosting reforms, the U.S. and other IMF members are unlikely to pony up the vast sums of money actually needed to solve what is seen as Europe's problem.

In the short run, the ECB is likely to continue its purchases of sovereign debt in limited amounts, follow-up its November 3rd cut in interest rates with another 25 basis point reduction in the refi rate on December 8th, and possibly announce an extended liquidity operation for banks in conjunction with a broadening of eligible collateral. While real GDP in the Eurozone managed to increase 0.9% *(saar)* in Q3, the currency zone likely lapsed into recession beginning this quarter, easing ECB policymaker's inflationary concerns and likely paving the way for further interest rate cuts during the first half of 2012.

At its November meeting, the Bank of England left the repo rate at its historic low of 0.5% and the size of its quantitative easing program at GBP 75 billion. Minutes from the meeting were less dovish than expected by some analysts but a further expansion of the BoE's QE program is likely early next year if the Eurozone's debt crisis continues to intensify, U.K. GDP ends up contracting in the current quarter, and inflation continues to slide from its September peak as the influence of the temporary factors recedes and downward pressure from unemployment and spare capacity persists.

The Reserve Bank of Australia cut its cash rate 25 basis points to 4.5% on November 1st. Minutes revealed that "material changes" to the inflation outlook, combined with downside risks to the global economy, prompted the RBA's shift to a more neutral policy setting.

The Bank of Canada policy shifted to neutral in late October by abandoning mention of the potential need for removal of policy stimulus and by downgrading its economic growth and inflation outlook. Given the uncertain outlook for global growth, BoC policy is likely to remain on hold for the foreseeable future with its overnight policy rate stuck at 1.0% *(see pages 10-11 for individual panelists' forecasts).*

Fourth Quarter 2011

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum – Average For Quarter															Avg. For Qtr.	(Q-Q % Change) (SAAR)		
	Short-Term							Intermediate-Term				Long-Term							
	1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR Rate 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	A. Fed's Major Currency $ Index	B. Real GDP	C. GDP Price Index	D. Cons. Price Index
Bank of Toyko-Mitsubishi UFJ	0.3 H	3.3	0.5	0.2 H	0.1	0.1	0.2	0.3	1.0	2.1	3.2	4.2	5.4 H	3.9	4.0	71.0	3.0	2.2	1.0
Swiss Re	0.3 H	3.3	0.3	0.1 L	0.0 L	0.1	0.2	0.3	1.0	2.0	3.0	4.0	5.3	na	4.0	na	2.5	0.8	1.0
Scotiabank Group	0.3 H	3.3	na	na	0.0 L	na	na	0.3	1.0	1.8 L	2.9 L	na	na	na	na	na	2.3	1.5	2.9
Cycledata Corp.	0.2	3.3	0.4	0.1 L	0.0 L	0.1	0.2	0.3	1.0	2.2	3.1	4.0	5.3	4.0	4.0	71.0	2.7	1.9	3.0
Fannie Mae	0.2	3.3	na	na	0.0 L	na	na	na	na	2.1	3.2	4.0	na	na	4.1	na	2.5	1.8	1.8
JPMorgan Private Banking	0.2	3.3	0.5	0.1 L	0.0 L	0.1	0.1 L	0.3	1.1	2.2	3.2	4.1	5.4 H	4.0	4.1	72.3	3.0	2.0	2.1
Naroff Economic Advisors	0.2	3.3	0.5	0.1 L	0.0 L	0.1	0.1 L	0.3	1.0	2.1	3.1	4.0	5.3	4.1	4.0	72.0	3.6	2.5	3.1
J.W. Coons Advisors LLC	0.1 L	3.3	0.5	0.2 H	0.0 L	0.1	0.1 L	0.3	1.0	2.1	3.1	3.9	5.2	na	4.1	70.4	1.8 L	2.2	2.3
BMO Capital Markets	0.1 L	3.3	0.4	0.1 L	0.0 L	0.1	0.1 L	0.3	0.9 L	2.1	3.0	3.9	5.2	4.1	4.1	72.0	3.0	1.0	1.8
Economist Intelligence Unit	0.1 L	3.3	0.3	0.1 L	0.0 L	0.1	0.1 L	0.3	0.9 L	2.0	3.0	na	na	na	4.0	na	2.0	na	1.1
Bank of America Merrill Lynch	0.1 L	na	0.5	na	0.1	na	na	0.2 L	1.0	2.3 H	na	na	na	na	na	na	3.0	1.6	1.5
J.P. Morgan Chase	0.1 L	na	0.4	na	0.0 L	na	na	0.3	0.9 L	2.0	2.9 L	na	na	na	na	na	3.0	1.0	0.7
UBS	0.1 L	na	0.4	na	0.1	na	na	0.2 L	1.0	1.9	3.0	na	na	na	na	na	2.0	1.0	0.6 L
GLC Financial Economics	0.1 L	3.3	0.4	0.1 L	0.0 L	0.1	0.1 L	0.3	1.0	2.1	3.1	3.9	5.3	4.1	4.0	72.2	1.8 L	1.8	1.9
SunTrust Banks	0.1 L	3.3	0.4	0.1 L	0.1	0.2	0.3 H	0.4	1.2 H	2.3 H	3.3	4.1	5.2	4.5 H	4.0	na	3.1	2.8	3.7 H
Barclays Capital	0.1 L	3.3	0.5	0.2 H	0.0 L	0.0 L	0.1 L	0.3	1.1	2.3 H	3.3	4.0	5.1	4.2	4.2 H	na	2.5	1.9	1.2
RDQ Economics	0.1 L	3.3	0.5	0.1 L	0.0 L	0.0 L	0.1 L	0.4	1.0	2.2	3.2	4.0	5.3	4.1	4.0	71.8	3.0	2.2	1.5
Wells Fargo	0.1 L	3.3	0.5	0.2 H	0.0 L	0.0 L	0.1 L	0.3	1.0	2.0	3.0	3.9	5.2	4.1	4.0	74.0	3.1	2.2	1.5
Goldman Sachs & Co.	0.1 L	3.3	0.5	na	0.3 H	na	na	0.3	1.1	2.3 H	3.0	3.5 L	na	na	3.9 L	na	2.0	1.6	1.9
Daiwa Capital Markets America	0.1 L	3.3	0.5	0.1 L	0.1	0.1	0.2	0.3	1.0	2.1	3.3	3.9	5.3	4.0	4.0	72.0	2.3	1.5	2.5
MacroFin Analytics	0.1 L	3.3	0.5	0.1 L	0.0 L	0.1	0.1 L	0.3	1.0	2.1	3.1	3.9	5.1	4.1	4.0	71.5	2.4	1.8	2.5
Nat'l Assn. of Realtors	0.1 L	3.3	0.5	0.2 H	0.0 L	0.0 L	0.1 L	0.3	1.0	2.1	3.2	4.0	5.3	4.2	4.1	na	2.9	2.2	2.8
Woodworth Holdings	0.1 L	3.3	0.5	0.1 L	0.0 L	0.1	0.1 L	0.3	0.9 L	2.1	3.1	3.9	5.2	4.1	4.0	73.0	2.0	1.6	1.0
Action Economics	0.1 L	3.3	0.5	0.1 L	0.0 L	0.1	0.1 L	0.3	1.0	2.1	3.1	4.0	5.2	4.0	4.0	72.0	3.0	0.5 L	1.7
Mesirow Financial	0.1 L	3.3	0.4	0.1 L	0.0 L	0.5 H	0.1 L	0.3	1.0	2.1	3.2	4.0	5.2	4.0	4.1	74.8	2.4	1.7	1.8
Wintrust Wealth Management	0.1 L	3.3	0.4	0.2 H	0.1	0.1	0.1 L	0.3	0.9 L	2.0	3.0	3.9	5.2	3.9	3.9 L	69.1 L	2.6	1.2	1.9
Russell Investments	0.1 L	3.3	0.4	0.2 H	0.1	0.1	0.1 L	0.3	1.0	2.0	3.1	3.9	5.2	4.0	4.1	72.1	2.8	2.3	2.2
Thredgold Economic Assoc.	0.1 L	3.3	0.3	0.1 L	0.1	0.1	0.1 L	0.3	1.0	2.2	3.2	4.1	5.1	3.8	4.1	70.0	2.0	1.9	2.2
Kellner Economic Advisers	0.1 L	3.3	0.2	0.2 H	0.1	0.1	0.1 L	0.3	1.2 H	1.9	2.9 L	3.9	4.9 L	4.2	4.0	70.0	3.0	2.0	2.2
Georgia State University	0.1 L	3.3	na	na	0.1	0.1	0.2	0.3	1.1	2.0	3.2	3.9	5.4 H	na	4.0	na	2.2	1.4	2.5
RidgeWorth Investments	0.1 L	3.3	0.5	0.1 L	0.0 L	0.1	0.1 L	0.3	1.0	2.0	3.2	4.0	5.3	3.7 L	4.0	71.9	3.0	1.8	0.9
Wells Capital Management	0.1 L	3.3	0.5	0.1 L	0.0 L	0.1	0.1 L	0.3	1.0	2.1	3.0	3.8	5.1	4.1	4.0	71.9	3.9 H	2.3	2.0
PNC Financial Services Corp.	0.1 L	3.3	0.5	na	0.0 L	0.0 L	0.1 L	0.2 L	1.0	2.1	na	na	na	4.0	4.0	69.3	2.5	1.3	1.5
Oxford Economics	0.1 L	3.3	0.4	na	0.0 L	0.1	0.1 L	0.3	0.9 L	2.1	3.3	4.0	na	na	4.1	72.9	2.6	2.5	2.9
The Northern Trust Company	0.1 L	3.3	0.0 L	na	0.0 L	na	0.2	0.3	1.1	2.1	3.1	na	na	na	na	na	2.2	1.4	1.6
RBS Securities	0.1 L	3.3	0.6 H	0.1 L	0.0 L	0.1	0.1 L	0.3	1.0	2.1	3.1	3.9	5.2	4.1	4.0	72.5	3.2	3.0 H	1.6
ClearView Economics	0.1 L	3.3	0.5	0.1 L	0.0 L	0.1	0.1 L	0.3	1.0	2.1	3.1	3.9	5.3	4.1	4.0	71.5	2.6	1.5	1.0
Chmura Economics & Analytics	0.1 L	3.3	0.5	0.1 L	0.0 L	0.1	0.1 L	0.3	1.0	2.1	3.1	3.9	na	na	4.0	75.1 H	2.6	2.1	2.0
Moody's Analytics	0.1 L	3.3	0.5	0.2 H	0.0 L	0.1	0.3 H	0.6 H	1.2 H	2.3 H	3.7 H	4.3 H	5.4 H	na	4.0	na	2.6	2.6	1.0
DePrince & Associates	0.1 L	3.3	0.5	0.1 L	0.0 L	0.1	0.1 L	0.3	1.0	2.1	3.1	3.9	5.2	4.0	4.0	71.3	3.2	2.0	1.7
Pierpont Securities	0.1 L	3.3	0.5	0.1 L	0.0 L	0.1	0.1 L	0.3	1.0	2.1	3.1	3.9	5.2	4.1	4.0	72.6	3.1	2.0	1.0
Loomis, Sayles & Company	0.1 L	3.3	0.5	0.1 L	0.0 L	0.0 L	0.1 L	0.3	1.0	2.0	3.1	3.9	5.2	4.0	4.0	71.3	3.0	1.7	1.7
Nomura Securities, Inc.	0.1 L	3.3	0.4	0.1 L	0.0 L	0.1	0.1 L	0.3	1.0	2.1	3.1	3.9	5.3	na	4.0	71.4	3.0	1.2	1.2
Stone Harbor Investment Partners	0.1 L	3.3	0.4	0.1 L	0.0 L	0.1	0.1 L	0.3	1.0	2.0	3.0	3.9	5.2	na	4.2 H	71.0	2.6	1.9	1.9
Comerica Bank	0.1 L	3.3	0.4	na	0.0 L	0.1	0.1 L	0.3	1.1	2.2	3.2	na	na	na	4.1	na	3.1	2.3	2.6
Societe Generale	0.1 L	3.3	0.4	0.1 L	0.0 L	0.1	0.1 L	0.2 L	0.9 L	2.0	3.0	4.1	5.3	na	3.9 L	na	2.5	1.8	0.8
Moody's Capital Markets Group	0.1 L	3.3 L	0.5	0.1 L	0.0 L	0.1	0.2	0.3	1.0	2.0	3.0	3.9	5.3	4.0	4.0	71.7	2.8	1.5	1.5
December Consensus	**0.1**	**3.3**	**0.4**	**0.1**	**0.0**	**0.1**	**0.1**	**0.3**	**1.0**	**2.1**	**3.1**	**4.0**	**5.2**	**4.0**	**4.0**	**71.8**	**2.7**	**1.8**	**1.8**
Top 10 Avg.	0.2	3.3	0.5	0.2	0.1	0.1	0.2	0.4	1.1	2.2	3.3	4.1	5.3	4.2	4.1	73.1	3.2	2.5	2.9
Bottom 10 Avg.	0.1	3.3	0.3	0.1	0.0	0.0	0.1	0.2	0.9	2.0	3.0	3.8	5.1	3.9	4.0	70.4	2.0	1.1	0.9
November Consensus	0.1	3.3	0.4	0.1	0.0	0.1	0.2	0.3	1.1	2.2	3.2	4.1	5.4	4.1	4.1	71.1	2.0	1.8	1.8
Number of Forecasts Changed From A Month Ago:																			
Down	11	0	2	12	16	15	16	18	34	30	34	32	24	13	24	6	1	12	21
Same	34	44	10	15	26	21	21	22	9	11	6	6	6	9	9	7	8	18	10
Up	2	0	31	8	5	4	4	6	3	6	5	1	4	6	9	16	38	16	16
Diffusion Index	40 %	50 %	84 %	44 %	38 %	36 %	35 %	37 %	16 %	24 %	18 %	10 %	21 %	38 %	32 %	67 %	89 %	54 %	45 %

First Quarter 2012

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum – Average For Quarter															Avg. For	(Q-Q % Change) (SAAR)		
	Short-Term							Intermediate-Term				Long-Term							
	1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR Rate 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	A. Fed's Major Currency $ Index	B. Real GDP	C. GDP Price Index	D. Cons. Price Index
Bank of Toyko-Mitsubishi UFJ	0.3 H	3.3 H	0.5	0.2	0.1	0.1 L	0.2	0.3	1.3	2.6	3.6	4.3	5.7 H	4.0	4.4	70.0	2.8	2.4	2.5
Swiss Re	0.3 H	3.3	0.3	0.1 L	0.1	0.1 L	0.2	0.3	1.0	2.2	3.2	4.1	5.4	na	4.2	na	-0.3 L	0.2 L	0.2 L
Scotiabank Group	0.3 H	3.3	na	na	0.1	na	na	0.4	1.2	1.9	3.0	na	na	na	na	na	1.5	1.6	2.2
Cycledata Corp.	0.2	3.3	0.4	0.1 L	0.0 L	0.1 L	0.2	0.3	1.0	2.2	3.1	4.0	5.3	4.0	4.0	72.0	0.8	1.9	3.0
Georgia State University	0.2	3.3	na	na	0.1	0.2	0.2	0.3	1.2	2.3	3.6	4.4	5.5	na	4.1	na	1.5	0.9	1.3
Fannie Mae	0.2	3.3	na	na	0.1	na	na	na	na	2.2	3.3	4.2	na	na	4.1	na	1.3	1.3	2.0
Wells Capital Management	0.2	3.3	0.6 H	0.2	0.1	0.1 L	0.3	0.4	1.1	2.2	3.1	3.7	4.8	4.1	4.2	71.8	2.8	2.5	2.7
JPMorgan Private Banking	0.2	3.3	0.5	0.1 L	0.0 L	0.1 L	0.1 L	0.3	1.1	2.2	3.2	4.1	5.4	4.0	4.1	72.4	0.8	1.9	2.0
Naroff Economic Advisors	0.2	3.3	0.5	0.2	0.1	0.1 L	0.2	0.4	1.1	2.0	3.1	4.0	5.3	4.1	4.0	71.0	2.8	2.4	2.8
SunTrust Banks	0.2	3.3	0.4	0.1 L	0.1	0.3 H	0.5 H	0.7 H	1.4	2.4	3.4	4.3	5.0	4.8 H	4.1	na	3.4 H	2.7	4.0 H
BMO Capital Markets	0.1 L	3.3	0.5	0.1 L	0.0 L	0.1 L	0.1 L	0.3	0.9	2.0	3.0	3.9	5.2	4.1	4.0	72.5	1.7	2.6	2.8
GLC Financial Economics	0.1 L	3.3	0.5	0.1 L	0.0 L	0.1 L	0.1 L	0.3	1.0	2.1	3.1	4.0	5.3	4.1	4.0	72.0	1.4	1.9	2.1
J.W. Coons Advisors LLC	0.1 L	3.3	0.4	0.1 L	0.1	0.1 L	0.2	0.3	1.1	2.1	3.1	4.0	5.2	na	4.1	71.0	1.5	2.3	2.5
Economist Intelligence Unit	0.1 L	3.3	0.3	0.1 L	0.0 L	0.1 L	0.1 L	0.3	0.9	2.0	3.0	na	na	na	4.0	na	1.2	na	2.0
Oxford Economics	0.1 L	3.3	0.3	na	0.0 L	0.1 L	0.2	0.3	1.0	2.2	3.4	4.1	na	na	4.1	74.2	2.2	3.1 H	2.5
J.P. Morgan Chase	0.1 L	na	0.5	na	0.0 L	na	na	0.3	1.1	2.3	3.3	na	na	na	na	na	0.5	1.0	0.9
Bank of America Merrill Lynch	0.1 L	na	0.5	na	0.1	na	na	0.3	1.1	2.5	na	na	na	na	na	na	1.8	1.4	1.4
UBS	0.1 L	na	0.4	na	0.1	na	na	0.3	1.1	2.1	3.3	na	na	na	na	na	2.0	2.0	1.4
Barclays Capital	0.1 L	3.3	0.6 H	0.2	0.1	0.1 L	0.2	0.3	1.3	2.8 H	4.0 H	4.3	5.5	4.2	4.2	na	2.5	2.5	2.5
PNC Financial Services Corp.	0.1 L	3.3	0.5	na	0.0 L	0.1 L	0.1 L	0.3	1.0	2.0	na	na	na	3.8	3.7 L	68.8	2.7	1.7	2.0
Wells Fargo	0.1 L	3.3	0.5	0.2	0.0 L	0.1 L	0.2	0.3	1.0	2.1	3.1	3.9	5.2	4.0	4.0	75.0	1.7	1.1	1.7
RDQ Economics	0.1 L	3.3	0.5	0.1 L	0.1	0.1 L	0.3	0.6	1.4	2.5	3.6	4.4	5.5	4.4	4.4	71.8	2.7	2.3	2.2
Nat'l Assn. of Realtors	0.1 L	3.3	0.5	0.2	0.0 L	0.1 L	0.1	0.5	1.2	2.3	3.4	4.2	5.4	4.3	4.3	na	2.3	2.7	3.5
Chmura Economics & Analytics	0.1 L	3.3	0.5	0.1 L	0.0 L	0.1 L	0.1 L	0.3	1.1	2.3	3.3	4.1	na	na	4.2	76.6 H	2.1	2.4	1.7
Woodworth Holdings	0.1 L	3.3	0.5	0.1 L	0.0 L	0.1 L	0.1 L	0.3	0.9	2.1	3.1	3.9	5.2	4.1	4.0	74.0	1.5	1.5	1.2
RidgeWorth Investments	0.1 L	3.3	0.5	0.2	0.1	0.1 L	0.2	0.3	1.0	2.1	3.3	4.0	5.2	3.6 L	4.0	71.0	1.5	1.8	1.8
Daiwa Capital Markets America	0.1 L	3.3	0.5	0.1 L	0.1	0.1 L	0.2	0.3	1.2	2.2	3.3	4.0	5.4	4.0	4.0	72.0	2.4	1.6	1.9
MacroFin Analytics	0.1 L	3.3	0.5	0.2	0.0 L	0.1 L	0.1 L	0.3	1.1	2.2	3.2	4.1	5.3	4.1	4.1	72.0	2.1	1.6	2.4
Action Economics	0.1 L	3.3	0.5	0.2	0.0 L	0.1 L	0.1 L	0.5	1.4	2.4	3.4	4.1	5.4	4.1	4.1	71.7	2.5	2.6	2.9
Nomura Securities, Inc.	0.1 L	3.3	0.4	0.2	0.1	0.1 L	0.1 L	0.3	0.9	2.1	3.1	3.9	5.3	na	4.0	71.0	2.1	0.7	1.2
Comerica Bank	0.1 L	3.3	0.4	na	0.0 L	0.2	0.2	0.5	1.2	2.4	3.5	na	na	na	4.1	na	2.9	2.2	2.1
Mesirow Financial	0.1 L	3.3	0.4	0.1 L	0.1	0.1 L	0.2	0.4	1.1	2.2	3.3	4.1	5.2	4.1	4.3	76.5	2.1	1.1	1.9
Goldman Sachs & Co.	0.1 L	3.3	0.4	na	0.2 H	na	na	0.3	1.1	2.3	3.0	3.5	na	na	4.0	na	0.5	1.9	1.9
Wintrust Wealth Management	0.1 L	3.3	0.4	0.2	0.1	0.1 L	0.1 L	0.3	1.1	2.1	3.2	4.1	5.4	4.1	4.1	68.5 L	2.7	1.9	2.2
Russell Investments	0.1 L	3.3	0.4	0.2	0.1	0.2	0.2	0.3	1.2	2.2	3.4	3.9	5.0	4.0	4.1	72.2	2.9	2.2	2.8
Stone Harbor Investment Partners	0.1 L	3.3	0.4	0.2	0.0 L	0.1 L	0.1 L	0.2 L	0.7 L	1.4 L	2.5 L	3.4 L	4.6 L	na	3.7	72.0	0.7	1.8	1.8
Thredgold Economic Assoc.	0.1 L	3.3	0.3	0.2	0.1	0.1 L	0.2	0.3	1.1	2.3	3.3	4.2	5.2	3.8	4.2	70.0	2.1	2.0	2.2
Kellner Economic Advisers	0.1 L	3.3	0.2	0.2	0.1	0.1 L	0.2	0.4	1.3	2.0	2.9	3.9	4.9	4.3	4.0	70.0	3.1	2.1	2.2
The Northern Trust Company	0.1 L	3.3	0.1 L	na	0.1	na	0.2	0.3	1.2	2.1	3.1	na	na	na	na	na	1.5	1.7	1.9
Pierpont Securities	0.1 L	3.3	0.6 H	0.1 L	0.0 L	0.1 L	0.1 L	0.3	1.1	2.1	3.1	4.0	5.4	4.2	4.2	74.0	3.2	2.5	2.4
RBS Securities	0.1 L	3.3	0.6 H	0.1 L	0.0 L	0.1 L	0.1 L	0.3	0.8	1.9	2.9	3.8	5.0	3.9	3.9	73.5	2.5	2.7	2.3
ClearView Economics	0.1 L	3.3	0.5	0.1 L	0.0 L	0.1 L	0.1 L	0.3	0.9	2.1	3.1	3.9	5.2	4.1	4.0	72.0	2.4	1.7	2.0
Loomis, Sayles & Company	0.1 L	3.3	0.5	0.1 L	0.0 L	0.1 L	0.1 L	0.3	1.0	2.0	3.0	3.9	5.2	3.9	3.9	72.1	1.9	0.6	2.6
DePrince & Associates	0.1 L	3.3	0.4	0.2	0.1	0.1 L	0.2	0.4	1.0	2.1	3.2	4.0	5.0	3.7	4.1	72.1	2.1	2.0	2.2
Societe Generale	0.1 L	3.3	0.4	0.1 L	0.0 L	0.1 L	0.1 L	0.2 L	0.9	2.0	3.0	4.1	5.3	na	3.9	na	2.5	1.8	0.8
Moody's Analytics	0.1 L	3.3	0.4	0.3 H	0.0 L	0.1 L	0.3	0.5	1.6 H	2.7	4.0 H	4.6 H	5.6	na	4.5 H	na	2.1	1.5	1.8
Moody's Capital Markets Group	0.1 L	3.3 L	0.5	0.1 L	0.0 L	0.1 L	0.2	0.3	1.0	2.1	3.0	3.9	5.6	4.0	3.8	72.4	1.6	1.4	1.3
December Consensus	**0.1**	**3.3**	**0.4**	**0.1**	**0.0**	**0.1**	**0.2**	**0.3**	**1.1**	**2.2**	**3.2**	**4.0**	**5.2**	**4.1**	**4.1**	**72.1**	**2.0**	**1.9**	**2.1**
Top 10 Avg.	0.2	3.3	0.5	0.2	0.1	0.2	0.3	0.5	1.3	2.5	3.6	4.3	5.5	4.3	4.3	74.1	2.9	2.6	3.0
Bottom 10 Avg.	0.1	3.3	0.3	0.1	0.0	0.1	0.1	0.2	0.9	1.9	2.9	3.8	5.0	3.9	3.9	70.3	0.8	1.0	1.1
November Consensus	0.1	3.3	0.4	0.2	0.1	0.1	0.2	0.3	1.2	2.3	3.3	4.1	5.4	4.1	4.1	71.2	1.8	1.9	2.2
Number of Forecasts Changed From A Month Ago:																			
Down	8	0	3	14	16	16	18	19	25	25	26	23	18	11	21	5	8	12	14
Same	37	44	12	17	30	22	20	20	17	18	12	13	11	10	15	8	14	25	21
Up	2	0	29	5	1	2	3	7	4	4	7	3	6	8	6	18	25	9	12
Diffusion Index	44 %	50 %	80 %	38 %	34 %	33 %	32 %	37 %	27 %	28 %	29 %	24 %	33 %	45 %	32 %	71 %	68 %	47 %	48 %

Second Quarter 2012

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter																Avg. For Qtr.	(Q-Q % Change) (SAAR)		
	Short-Term							Intermediate-Term				Long-Term								
	1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR Rate 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	A. Fed's Major Currency $ Index	B. Real GDP	C. GDP Price Index	D. Cons. Price Index
Bank of Toyko-Mitsubishi UFJ	0.3 H	3.3 H	0.5	0.2	0.1	0.1 L	0.2	0.4	1.6	2.9	3.7	4.4	5.9	4.2	4.6	69.0	3.0	2.6	3.0
Swiss Re	0.3 H	3.3	0.3	0.2	0.1	0.1 L	0.2	0.6	1.2	2.3	3.3	4.2	5.5	na	4.3	na	-0.2 L	0.9	1.1
Scotiabank Group	0.3 H	3.3	na	na	0.1	na	na	0.7	1.4	2.2	3.2	na	na	na	na	na	1.2	1.6	1.8
SunTrust Banks	0.2	3.3	0.5	0.3	0.1	0.5 H	0.9 H	1.0 H	1.6	2.5	3.3	4.4	4.9	5.0 H	4.0	na	3.6 H	2.7 H	4.1 H
Cycledata Corp.	0.2	3.3	0.4	0.1 L	0.0 L	0.1 L	0.2	0.3	1.1	2.3	3.2	4.2	5.5	4.0	4.0	72.0	1.0	1.9	3.0
Georgia State University	0.2	3.3	na	na	0.1	0.2	0.2	0.3	1.3	2.5	3.8	4.5	5.6	na	4.1	na	1.5	0.3 L	0.9
Fannie Mae	0.2	3.3	na	na	0.1	na	na	na	na	2.3	3.4	4.2	na	na	4.1	na	1.3	1.4	1.8
Wells Capital Management	0.2	3.3	0.6	0.2	0.1	0.2	0.3	0.4	1.3	2.5	3.4	4.0	5.0	4.4	4.4	71.9	2.5	2.4	2.5
JPMorgan Private Banking	0.2	3.3	0.5	0.2	0.0 L	0.1 L	0.1 L	0.3	1.1	2.2	3.2	4.1	5.5	4.1	4.1	72.3	1.5	1.9	2.1
Naroff Economic Advisors	0.2	3.3	0.4	0.2	0.2 H	0.2	0.2	0.5	1.2	2.0	3.1	3.9	5.1	4.0	4.0	69.0	3.2	2.6	2.7
BMO Capital Markets	0.1 L	3.3	0.5	0.1 L	0.0 L	0.1 L	0.2	0.4	1.0	2.0	2.9	3.9	5.1	4.1	4.0	73.0	2.0	2.5	2.9
GLC Financial Economics	0.1 L	3.3	0.5	0.2	0.0 L	0.1 L	0.1 L	0.2 L	1.0	2.2	3.2	4.0	5.4	4.2	4.1	71.9	1.9	2.3	2.5
J.W. Coons Advisors LLC	0.1 L	3.3	0.4	0.2	0.1	0.2	0.2	0.4	1.2	2.2	3.1	4.1	5.3	na	4.1	70.9	2.0	2.2	2.5
Economist Intelligence Unit	0.1 L	3.3	0.4	0.1 L	0.0 L	0.1 L	0.2	0.3	1.0	2.1	3.2	na	na	na	4.1	na	1.2	na	2.1
Oxford Economics	0.1 L	3.3	0.3	na	0.0 L	0.1 L	0.2	0.3	1.1	2.3	3.6	4.1	na	na	4.1	74.2	2.2	2.6	2.1
Bank of America Merrill Lynch	0.1 L	na	0.5	na	0.1	na	na	0.4	1.3	2.8	na	na	na	na	na	na	1.8	1.3	1.5
J.P. Morgan Chase	0.1 L	na	0.4	na	0.1	na	na	0.3	1.3	2.5	3.6	na	na	na	na	na	1.5	1.2	1.2
UBS	0.1 L	na	0.4	na	0.1	na	na	0.3	1.3	2.2	3.5	na	na	na	na	na	2.5	1.5	1.0
DePrince & Assoc.	0.1 L	3.3	0.4	0.3	0.1	0.2	0.4	0.5	1.1	2.3	3.3	4.1	5.0	3.5	4.2	73.2	2.6	2.0	2.3
Pierpont Securities	0.1 L	3.3	0.5	0.1 L	0.0 L	0.1 L	0.1 L	0.4	1.2	2.4	3.4	4.2	5.6	4.5	4.3	74.0	3.2	2.3	2.9
Barclays Capital	0.1 L	3.3	0.7 H	0.2	0.1	0.1 L	0.2	0.4	1.4	2.8	4.0	4.5	5.5	4.3	4.3	na	2.5	2.6	1.2
Wells Fargo	0.1 L	3.3	0.5	0.2	0.1	0.1 L	0.2	0.4	1.1	2.2	3.2	4.0	5.3	4.0	4.0	76.0	1.7	2.0	1.8
Nat'l Assn. of Realtors	0.1 L	3.3	0.5	0.2	0.1	0.1 L	0.2	0.6	1.5	2.6	3.6	4.4	5.6	4.6	4.4	na	2.5	2.5	3.4
Chmura Economics & Analytics	0.1 L	3.3	0.5	0.1 L	0.1	0.1 L	0.2	0.3	1.2	2.4	3.4	4.2	na	na	4.3	76.7	2.2	2.1	2.8
MacroFin Analytics	0.1 L	3.3	0.5	0.2	0.1	0.1 L	0.1 L	0.4	1.2	2.2	3.3	4.2	5.4	4.3	4.2	72.5	2.5	1.5	2.1
Nomura Securities, Inc.	0.1 L	3.3	0.5	0.2	0.1	0.1 L	0.1 L	0.3	1.0	2.2	3.2	4.0	5.4	na	4.1	72.0	2.6	1.1	0.9
Woodworth Holdings	0.1 L	3.3	0.5	0.1 L	0.0 L	0.1 L	0.1 L	0.3	0.9	2.1	3.1	3.9	5.2	4.1	4.0	75.0	1.5	1.4	1.3
Daiwa Capital Markets America	0.1 L	3.3	0.5	0.1	0.1	0.1 L	0.2	0.4	1.3	2.3	3.3	4.0	5.4	4.0	4.1	73.0	2.7	1.6	1.8
Action Economics	0.1 L	3.3	0.5	0.2	0.1	0.1 L	0.1 L	0.6	1.6	2.7	3.7	4.1	5.4	4.2	4.2	71.3	2.8	2.5	3.3
PNC Financial Services Corp.	0.1 L	3.3	0.4	na	0.0 L	0.1 L	0.1 L	0.3	1.0	2.0	na	na	na	3.8	3.7	68.8	2.7	1.7	2.0
Comerica Bank	0.1 L	3.3	0.4	na	0.0 L	0.2	0.3	0.7	1.5	2.6	3.8	na	na	na	4.3	na	2.7	2.2	2.0
RidgeWorth Investments	0.1 L	3.3	0.4	0.2	0.1	0.1 L	0.2	0.3	1.0	2.1	3.3	3.8	4.9	3.3 L	3.9	70.0	2.0	1.8	1.8
Wintrust Wealth Management	0.1 L	3.3	0.4	0.2	0.1	0.1 L	0.2	0.4	1.2	2.2	3.3	4.2	5.5	4.2	4.2	67.8 L	2.9	1.9	2.3
RDQ Economics	0.1 L	3.3	0.4	0.2	0.1	0.1 L	0.4	0.8	1.9 H	3.0	4.2	4.9	6.0	4.9	4.8	72.4	2.9	2.4	2.5
Russell Investments	0.1 L	3.3	0.4	0.2	0.1	0.2	0.3	0.5	1.4	2.3	3.6	4.0	4.9	4.1	4.2	71.9	2.8	2.3	2.2
Mesirow Financial	0.1 L	3.3	0.4	0.1 L	0.1	0.2	0.3	0.5	1.2	2.3	3.5	4.2	5.2	4.1	4.4	77.5 H	2.4	1.3	1.1
Goldman Sachs & Co.	0.1 L	3.3	0.3	na	0.1	na	na	0.4	1.2	2.5	3.3	3.5	na	na	4.1	na	1.5	1.3	2.1
Stone Harbor Investment Partners	0.1 L	3.3	0.3	0.2	0.1	0.1 L	0.1 L	0.2 L	0.8 L	1.5 L	2.6 L	3.3 L	4.8 L	na	3.8	74.0	1.3	2.2	2.1
Kellner Economic Advisers	0.1 L	3.3	0.3	0.3 H	0.1	0.2	0.3	0.5	1.4	2.0	3.0	4.0	5.0	4.4	4.0	70.0	3.2	2.2	2.2
Thredgold Economic Assoc.	0.1 L	3.3	0.3	0.2	0.1	0.1 L	0.2	0.4	1.2	2.4	3.4	4.3	5.3	3.9	4.3	70.0	2.2	2.0	2.3
The Northern Trust Company	0.1 L	3.3	0.1 L	na	0.1	na	0.2	0.3	1.2	2.1	3.1	na	na	na	na	na	2.0	1.5	1.7
ClearView Economics	0.1 L	3.3	0.5	0.1 L	0.0 L	0.1 L	0.1 L	0.3	0.9	2.1	3.1	3.9	5.2	4.1	4.0	72.5	2.3	1.8	2.3
Loomis, Sayles & Company	0.1 L	3.3	0.4	0.1 L	0.0 L	0.1 L	0.1 L	0.3	1.0	2.1	3.1	4.0	5.3	3.9	4.0	72.5	1.6	1.1	2.9
RBS Securities	0.1 L	3.3	0.4	0.1 L	0.0 L	0.1 L	0.1 L	0.3	0.8 L	1.9	2.9	3.7	4.9	3.8	3.8	72.0	2.7	2.2	2.6
Societe Generale	0.1 L	3.3	0.4	0.1 L	0.0 L	0.1 L	0.1 L	0.2 L	0.8 L	1.9	2.8	3.9	4.8 L	na	3.6 L	na	0.8	1.5	-0.3 L
Moody's Capital Markets Group	0.1 L	3.3	0.5	0.1 L	0.1	0.1 L	0.2	0.3	1.1	2.1	3.0	3.9	5.6	3.8	3.8	73.1	1.6	1.2	0.7
Moody's Analytics	0.1 L	3.3 L	0.4	0.3 H	0.0 L	0.1 L	0.3	0.6	1.8	3.2 H	4.5 H	5.1 H	6.1 H	na	5.0 H	na	2.9	1.5	1.7
December Consensus	**0.1**	**3.3**	**0.4**	**0.2**	**0.1**	**0.1**	**0.2**	**0.4**	**1.2**	**2.3**	**3.3**	**4.1**	**5.3**	**4.1**	**4.1**	**72.3**	**2.1**	**1.9**	**2.1**
Top 10 Avg.	0.2	3.3	0.5	0.2	0.1	0.2	0.4	0.6	1.6	2.7	3.8	4.5	5.7	4.5	4.5	74.7	3.1	2.5	3.1
Bottom 10 Avg.	0.1	3.3	0.3	0.1	0.0	0.1	0.1	0.2	0.9	1.9	2.9	3.7	4.9	3.8	3.8	69.9	1.1	1.1	0.9
November Consensus	0.1	3.3	0.4	0.2	0.1	0.2	0.3	0.5	1.3	2.4	3.4	4.2	5.4	4.1	4.2	71.2	2.1	1.9	2.2
Number of Forecasts Changed From A Month Ago:																			
Down	7	0	5	9	14	15	19	17	25	22	23	21	16	10	20	5	14	14	17
Same	38	44	14	22	32	23	20	24	18	22	15	16	11	8	16	10	15	25	20
Up	2	0	25	5	1	2	2	5	3	3	7	2	4	7	6	16	18	7	10
Diffusion Index	45 %	50 %	73 %	44 %	36 %	34 %	29 %	37 %	26 %	30 %	32 %	26 %	31 %	44 %	33 %	68 %	54 %	42 %	43 %

Third Quarter 2012

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter															Avg. For	(Q-Q % Change) (SAAR)		
	Short-Term							Intermediate-Term				Long-Term				Qtr.			
	1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	A. Fed's Major Currency $ Index	B. Real GDP	C. GDP Price Index	D. Cons. Price Index
Bank of Toyko-Mitsubishi UFJ	0.3 H	3.3 H	0.5	0.2	0.1	0.1	0.2	0.7	1.9	3.2	3.9	4.6	6.0	4.4	4.9	67.0	3.3	2.8 H	2.8
Swiss Re	0.3 H	3.3	0.3	0.2	0.2 H	0.2	0.3	0.8	1.5	2.4	3.4	4.4	5.6	na	4.4	na	2.7	1.6	1.8
Scotiabank Group	0.3 H	3.3	na	na	0.1	na	na	0.9 H	1.6	2.6	3.6	na	na	na	na	na	1.4	1.8	1.8
SunTrust Banks	0.2	3.3	0.5	0.3 H	0.1	0.6 H	1.1 H	0.9 H	1.5	2.3	3.0	4.3	4.8	4.9	3.8	na	3.4	2.6	4.1 H
Cycledata Corp.	0.2	3.3	0.4	0.1 L	0.0 L	0.1 L	0.2	0.3	1.1	2.4	3.3	4.3	5.6	4.0	4.0	72.0	1.5	2.0	3.1
Russell Investments	0.2	3.3	0.4	0.2	0.2 H	0.3	0.4	0.7	1.6	2.5	3.7	4.0	4.8	4.2	4.3	72.2	2.6	2.3	2.4
Naroff Economic Advisors	0.2	3.3	0.4	0.3	0.2 H	0.2	0.3	0.6	1.4	2.0	3.1	4.0	5.2	4.1	4.2	65.0 L	4.2 H	2.8 H	2.6
DePrince & Associates	0.2	3.3	0.3	0.3	0.2 H	0.3	0.5	0.7	1.2	2.4	3.5	4.2	5.1	3.5	4.3	72.1	3.2	2.1	2.5
Georgia State University	0.2	3.3	na	na	0.2 H	0.2	0.3	0.5	1.7	3.0	4.2	5.0	6.1	na	4.5	na	1.7	1.1	0.6 L
Fannie Mae	0.2	3.3	na	na	0.2 H	na	na	na	na	2.4	3.4	4.3	na	na	4.1	na	1.4	1.1	1.6
MacroFin Analytics	0.2	3.3	0.5	0.2	0.1	0.2	0.3	0.5	1.3	2.3	3.4	4.3	5.7	4.5	4.2	73.0	2.6	1.4	2.0
Wells Capital Management	0.2	3.3	0.8 H	0.3	0.2 H	0.2	0.4	0.5	1.4	2.8	3.6	4.1	5.1	4.6	4.7	72.4	2.3	2.2	2.4
JPMorgan Private Banking	0.2	3.3	0.5	0.2	0.0 L	0.1 L	0.2	0.3	1.1	2.2	3.2	4.1	5.5	4.1	4.2	72.0	2.0	2.0	2.0
Chmura Economics & Analytics	0.2	3.3	0.5	0.1 L	0.1	0.1 L	0.2	0.4	1.2	2.5	3.5	4.2	na	na	4.4	75.6	2.8	2.3	2.6
Pierpont Securities	0.1	3.3	0.5	0.2	0.0 L	0.1 L	0.2	0.5	1.5	2.8	3.9	4.5	5.8	4.8	4.6	74.5	3.4	2.5	3.2
Economist Intelligence Unit	0.1	3.3	0.5	0.2	0.1	0.1 L	0.2	0.4	1.2	2.2	3.4	na	na	na	4.2	na	1.6	na	2.0
GLC Financial Economics	0.1	3.3	0.5	0.2	0.0 L	0.1 L	0.1 L	0.2	1.1	2.3	3.3	4.1	5.5	4.3	4.3	71.6	2.3	2.8 H	2.9
J.W. Coons Advisors LLC	0.1	3.3	0.5	0.2	0.1	0.2	0.3	0.4	1.3	2.2	3.2	4.2	5.4	na	4.1	70.7	2.8	2.3	2.5
BMO Capital Markets	0.1	3.3	0.5	0.1 L	0.0 L	0.1 L	0.3	0.5	1.2	2.1	3.0	4.0	5.2	4.2	4.1	72.5	2.4	2.1	2.3
Oxford Economics	0.1	3.3	0.3	na	0.0 L	0.1 L	0.2	0.4	1.3	2.5	3.9	4.3	na	na	4.2	74.5	2.4	2.3	1.9
Bank of America Merrill Lynch	0.1	na	0.5	na	0.1	na	na	0.6	1.5	3.0	na	na	na	na	na	na	1.3 L	1.3	1.5
J.P. Morgan Chase	0.1	na	0.4	na	0.2 H	na	na	0.3	1.3	2.5	3.6	na	na	na	na	na	2.5	1.3	1.3
UBS	0.1	na	0.4	na	0.1	na	na	0.3	1.5	2.3	3.7	na	na	na	na	na	2.5	2.5	3.5
Wells Fargo	0.1	3.3	0.5	0.2	0.1	0.2	0.3	0.4	1.2	2.2	3.2	4.0	5.3	4.1	4.0	76.5	1.9	2.0	1.8
Nat'l Assn. of Realtors	0.1	3.3	0.5	0.3	0.2 H	0.2	0.3	0.8	1.7	2.9	3.9	4.7	5.9	4.8	4.6	na	2.5	2.3	3.2
Barclays Capital	0.1	3.3	0.5	0.2	0.1	0.1 L	0.2	0.5	1.5	2.8	4.0	4.8	5.5	4.3	4.3	na	3.0	2.7	3.7
Nomura Securities, Inc.	0.1	3.3	0.5	0.2	0.1	0.1 L	0.1 L	0.3	1.2	2.4	3.3	4.1	5.5	na	4.2	73.0	2.4	1.6	1.4
Woodworth Holdings	0.1	3.3	0.5	0.1 L	0.0 L	0.1 L	0.1 L	0.3	0.9	2.1	3.1	3.9	5.2	4.1	4.0	75.0	2.0	1.3	1.2
Action Economics	0.1	3.3	0.5	0.2	0.1	0.1 L	0.2	0.7	1.8	2.8	3.9	4.2	5.4	4.3	4.2	70.7	3.1	1.8	3.0
Comerica Bank	0.1	3.3	0.4	na	0.0 L	0.2	0.4	0.8	1.7	2.7	4.1	na	na	na	4.4	na	2.5	1.7	2.5
Daiwa Capital Markets America	0.1	3.3	0.4	0.1 L	0.1	0.1 L	0.2	0.4	1.4	2.4	3.4	4.1	5.4	4.0	4.3	73.0	2.8	1.7	1.8
Wintrust Wealth Management	0.1	3.3	0.4	0.2	0.1	0.1 L	0.2	0.5	1.3	2.3	3.4	4.3	5.6	4.3	4.3	67.1	3.1	2.0	2.2
RDQ Economics	0.1	3.3	0.4	0.2	0.1	0.2	0.5	0.9	2.2 H	3.5	4.7	5.3	6.4 H	5.3 H	5.2	73.1	3.1	2.5	2.7
Mesirow Financial	0.1	3.3	0.4	0.1 L	0.2 H	0.2	0.3	0.6	1.4	2.5	3.5	4.3	5.2	4.0	4.4	76.6 H	2.0	1.4	1.8
RidgeWorth Investments	0.1	3.3	0.4	0.2	0.1	0.2	0.2	0.3	1.0	2.1	3.3	3.6	4.7	3.1 L	3.9	69.0	2.5	1.8	1.8
RBS Securities	0.1	3.3	0.4	0.1 L	0.1	0.1 L	0.2	0.3	0.8 L	1.7 L	2.8 L	3.5 L	4.6 L	3.7	3.5 L	72.5	2.1	2.0	2.4
PNC Financial Services Corp.	0.1	3.3	0.3	na	0.1	0.1 L	0.2	0.5	1.3	2.4	na	na	na	4.0	4.0	67.7	2.4	2.0	2.3
Kellner Economic Advisers	0.1	3.3	0.3	0.3	0.1	0.2	0.4	0.6	1.5	2.1	3.0	4.0	5.0	4.4	4.1	70.0	3.3	2.3	2.2
Thredgold Economic Assoc.	0.1	3.3	0.3	0.2	0.1	0.2	0.3	0.5	1.4	2.5	3.5	4.4	5.4	3.9	4.4	70.0	2.3	2.0	2.3
Goldman Sachs	0.1	3.3	0.3	na	0.0 L	na	na	0.4	1.3	2.5	3.3	3.6	na	na	4.2	na	2.0	1.4	1.8
Stone Harbor Investment Partners	0.1	3.3	0.3	0.2	0.1	0.1 L	0.2	0.3	0.9	1.8	2.9	3.6	4.8	na	3.9	72.0	1.7	2.7	2.2
The Northern Trust Company	0.1	3.3	0.1 L	na	0.1	na	0.2	0.3	1.2	2.2	3.2	na	na	na	na	na	2.3	1.7	1.9
Loomis, Sayles & Company	0.1	3.3	0.4	0.1 L	0.0 L	0.1 L	0.1 L	0.3	1.1	2.4	3.4	4.2	5.5	4.0	4.1	72.6	2.1	0.6 L	2.6
ClearView Economics	0.1	3.3	0.5	0.1 L	0.0 L	0.1 L	0.1 L	0.3	0.9	2.1	3.1	3.9	5.2	4.1	4.0	73.0	2.7	2.0	2.6
Societe Generale	0.1	3.3	0.4	0.1 L	0.0 L	0.1 L	0.1 L	0.2 L	0.9	2.2	3.2	4.0	4.9	na	3.7	na	1.6	2.4	3.5
Moody's Capital Markets Group	0.1	3.3	0.4	0.1 L	0.1	0.1 L	0.3	0.4	1.2	2.3	3.0	3.9	5.6	3.8	3.8	73.8	2.0	1.8	1.7
Moody's Analytics	0.0 L	3.3 L	0.3	0.3 H	0.0 L	0.1 L	0.4	0.6	2.1	3.7 H	4.9 H	5.4 H	6.4 H	na	5.5 H	na	3.1	2.1	2.1
December Consensus	**0.1**	**3.3**	**0.4**	**0.2**	**0.1**	**0.2**	**0.3**	**0.5**	**1.3**	**2.4**	**3.5**	**4.2**	**5.4**	**4.2**	**4.2**	**72.0**	**2.4**	**2.0**	**2.3**
Top 10 Avg.	0.2	3.3	0.5	0.3	0.2	0.3	0.5	0.8	1.8	3.0	4.1	4.7	5.9	4.6	4.7	74.6	3.3	2.6	3.3
Bottom 10 Avg.	0.1	3.3	0.3	0.1	0.0	0.1	0.1	0.3	1.0	2.0	3.0	3.8	4.9	3.8	3.9	68.9	1.6	1.3	1.5
November Consensus	0.1	3.3	0.4	0.2	0.1	0.2	0.3	0.5	1.4	2.5	3.6	4.3	5.5	4.2	4.3	71.1	2.4	2.0	2.3
Number of Forecasts Changed From A Month Ago:																			
Down	6	1	3	11	13	14	18	16	23	19	22	19	15	9	14	6	19	8	16
Same	39	43	18	21	32	24	20	26	19	25	20	15	16	13	20	10	17	25	21
Up	2	0	23	4	2	2	3	4	4	3	3	5	4	7	8	15	11	13	10
Diffusion Index	46 %	49 %	73 %	40 %	38 %	35 %	32 %	37 %	29 %	33 %	29 %	32 %	34 %	47 %	43 %	65 %	41 %	55 %	44 %

Fourth Quarter 2012

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: Short-Term 1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR Rate 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	Intermediate-Term 8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	Long-Term 12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	Avg. For Qtr. A. Fed's Major Currency $ Index	(Q-Q % Change) (SAAR) B. Real GDP	C. GDP Price Index	D. Cons. Price Index
Bank of Toyko-Mitsubishi UFJ	0.3 H	3.3	0.5	0.2	0.1	0.1 L	0.2	1.3 H	2.1	3.4	4.0	4.7	6.1	4.5	5.1	68.0	3.5	3.0	2.5
Naroff Economic Advisors	0.3 H	3.3	0.4	0.4 H	0.3 H	0.3	0.5	0.8	1.7	2.2	3.2	4.3	5.3	4.1	4.2	65.0 L	4.2 H	2.8	2.6
Swiss Re	0.3 H	3.3	0.3	0.3	0.2	0.3	0.4	0.9	1.7	2.5	3.5	4.5	5.7	na	4.5	na	2.7	1.0	1.2
Scotiabank Group	0.3 H	3.3	na	na	0.2	na	na	1.1	1.7	3.0	4.0	na	na	na	na	na	1.9	1.8	2.2
SunTrust Banks	0.2	3.3	0.5	0.3	0.1	0.7 H	1.2 H	1.0	1.5	2.3	3.0	4.2	4.7	4.9	3.8	na	3.1	2.4	3.8 H
Georgia State University	0.2	3.4 H	na	na	0.2	0.2	0.3	0.5	1.7	3.1	4.2	5.1	6.3	na	4.7	na	1.8	1.4	1.5
Wells Fargo	0.2	3.3	0.5	0.2	0.2	0.2	0.3	0.5	1.2	2.3	3.3	4.1	5.4	4.2	4.0	77.0	2.0	2.0	1.9
MacroFin Analytics	0.2	3.3	0.6	0.3	0.2	0.3	0.5	0.7	1.5	2.4	3.5	4.4	5.8	4.7	4.3	73.5	2.8	1.5	2.0
Russell Investments	0.2	3.3	0.4	0.3	0.2	0.4	0.4	0.9	1.8	2.6	4.0	4.1	4.8	4.3	4.4	72.2	2.5	2.4	2.2
Cycledata Corp.	0.2	3.3	0.4	0.1 L	0.1	0.1 L	0.3	0.4	1.2	2.4	3.4	4.4	5.6	4.1	4.0	73.0	1.5	2.1	3.1
DePrince & Assoc.	0.2	3.3	0.3	0.3	0.2	0.4	0.6	0.8	1.3	2.6	3.6	4.3	5.2	3.6	4.5	72.2	2.5	2.1	2.4
Fannie Mae	0.2	3.3	na	na	0.2	na	na	na	na	2.5	3.5	4.3	na	na	4.2	na	1.6	1.4	1.7
Wells Capital Management	0.2	3.3	0.9 H	0.4 H	0.2	0.3	0.5	0.7	1.5	3.1	3.8	4.4	5.2	4.9	4.9	73.3	2.8	1.9	2.5
JPMorgan Private Banking	0.2	3.3	0.5	0.2	0.0 L	0.1 L	0.2	0.4	1.1	2.2	3.3	4.2	5.5	4.1	4.2	71.5	1.9	1.9	2.1
Chmura Economics & Analytics	0.2	3.3	0.5	0.1 L	0.1	0.2	0.2	0.5	1.3	2.6	3.6	4.3	na	na	4.5	74.1	3.0	2.5	2.3
Pierpont Securities	0.1	3.3	0.5	0.2	0.1	0.1 L	0.2	0.7	1.8	3.3	4.5	4.9	6.2	5.3	5.0	76.0	3.9	2.7	3.4
J.W. Coons Advisors LLC	0.1	3.3	0.6	0.3	0.2	0.3	0.3	0.5	1.4	2.3	3.2	4.3	5.4	na	4.2	70.4	3.0	2.2	2.5
GLC Financial Economics	0.1	3.3	0.5	0.2	0.0 L	0.1 L	0.1 L	0.2 L	1.0	2.3	3.4	4.2	5.6	4.5	4.4	71.2	2.7	2.5	2.7
Economist Intelligence Unit	0.1	3.3	0.5	0.2	0.1	0.1 L	0.2	0.5	1.4	2.3	3.8	na	na	na	4.4	na	1.7	na	2.1
BMO Capital Markets	0.1	3.3	0.4	0.1 L	0.0 L	0.1 L	0.4	0.8	1.5	2.3	3.1	4.2	5.3	4.2	4.3	71.5	2.7	1.7	1.7
Oxford Economics	0.1	3.3	0.3	na	0.0 L	0.1 L	0.2	0.5	1.5	2.7	4.2	4.4	na	na	4.3	74.5	3.1	1.9	1.8
Bank of America Merrill Lynch	0.1	na	0.5	na	0.1	na	na	0.8	1.8	3.3	na	na	na	na	na	na	1.0 L	1.0	1.4
UBS	0.1	na	0.4	na	0.2	na	na	0.4	1.7	2.4	3.8	na	na	na	na	na	3.0	2.0	2.0
Nat'l Assn. of Realtors	0.1	3.3	0.6	0.4 H	0.3 H	0.4	0.5	1.1	2.0	3.2	4.3	5.1	6.1	5.1	4.9	na	2.8	2.2	2.9
Barclays Capital	0.1	3.3	0.5	0.2	0.1	0.1 L	0.2	0.5	1.5	2.8	4.0	4.8	5.5	4.3	4.3	na	3.0	2.7	2.8
Nomura Securities, Inc.	0.1	3.3	0.5	0.2	0.1	0.1 L	0.1 L	0.3	1.3	2.5	3.5	4.2	5.7	na	4.3	73.0	2.6	1.3	1.3
Woodworth Holdings	0.1	3.3	0.5	0.1 L	0.0 L	0.1 L	0.1 L	0.3	0.9	2.1	3.1	3.9	5.2	4.1	4.0	76.0	2.0	1.2	1.1 L
Action Economics	0.1	3.3	0.5	0.2	0.1	0.2	0.4	0.9	2.0	3.1	4.1	4.3	5.5	4.3	4.3	70.4	3.4	2.0	2.9
Comerica Bank	0.1	3.3	0.4	na	0.0	0.3	0.5	0.9	1.8	2.9	4.3	na	na	na	4.5	na	2.5	1.9	2.7
Wintrust Wealth Management	0.1	3.3	0.4	0.2	0.1	0.1 L	0.2	0.5	1.4	2.4	3.5	4.4	5.7	4.4	4.4	66.5	3.2	2.1	2.1
Thredgold Economic Assoc.	0.1	3.3	0.4	0.3	0.1	0.3	0.4	0.6	1.6	2.6	3.6	4.5	5.5	4.1	4.5	70.5	2.4	2.0	2.4
Kellner Economic Advisers	0.1	3.3	0.4	0.4 H	0.2	0.3	0.5	0.3	1.6	2.1	3.1	4.1	5.1	4.5	4.1	70.0	3.4	2.3	2.4
RDQ Economics	0.1	3.3	0.4	0.2	0.1	0.2	0.6	1.0	2.5 H	4.0	5.3	5.8 H	6.8 H	5.8 H	5.7	73.5	3.1	2.5	2.8
Daiwa Capital Markets America	0.1	3.3	0.4	0.1 L	0.1	0.1 L	0.2	0.5	1.4	2.5	3.5	4.2	5.5	4.0	4.4	74.0	3.0	1.8	2.0
RidgeWorth Investments	0.1	3.3	0.4	0.2	0.1	0.2	0.2	0.3	1.0	2.2	3.6	3.6	4.7	3.0 L	4.0	69.0	2.5	1.9	2.4
PNC Financial Services Corp.	0.1	3.3	0.3	na	0.1	0.1 L	0.2	0.6	1.5	2.6	na	na	na	4.2	4.1	67.2	2.5	2.1	2.5
Mesirow Financial	0.1	3.3	0.3	0.1 L	0.2	0.3	0.4	0.8	1.5	2.6	3.6	4.3	5.2	4.0	4.5	77.6 H	2.4	1.3	1.7
RBS Securities	0.1	3.3	0.3	0.1 L	0.1	0.1 L	0.2	0.3	0.8 L	1.7 L	2.8 L	3.2 L	4.2 L	3.6	3.4 L	71.5	2.8	1.8	2.0
Goldman Sachs & Co.	0.1	3.3	0.3	na	0.0 L	na	na	0.5	1.5	2.8	3.5	3.7	na	na	4.3	na	2.5	1.4	1.8
Stone Harbor Investment Partners	0.1	3.3	0.3	0.2	0.1	0.1 L	0.2	0.6	1.4	2.5	3.7	4.2	5.2	na	4.5	70.0	2.0	3.2 H	2.5
The Northern Trust Company	0.1	3.3	0.1 L	na	0.1	na	0.2	0.3	1.2	2.5	3.6	na	na	na	na	na	2.8	2.1	2.3
ClearView Economics	0.1	3.3	0.5	0.1 L	0.0	0.1 L	0.1 L	0.3	0.9	2.1	3.1	3.9	5.2	4.1	4.0	73.5	2.8	2.1	2.6
Loomis, Sayles & Company	0.1	3.3	0.3	0.1 L	0.0 L	0.1 L	0.1 L	0.3	1.3	2.6	3.6	4.4	5.6	4.1	4.3	72.8	2.4	0.6 L	2.6
Societe Generale	0.1	3.3	0.4	0.1 L	0.0 L	0.1 L	0.1 L	0.2 L	0.9	2.3	3.3	4.0	4.9	na	3.7	na	2.7	2.0	1.9
Moody's Capital Markets Group	0.1	3.3	0.4	0.1 L	0.1	0.1 L	0.3	0.6	1.3	2.4	3.1	3.9	5.5	3.5	3.9	74.6	3.0	1.8	1.9
Moody's Analytics	0.0 L	3.3 L	0.3	0.4 H	0.0 L	0.1 L	0.4	0.8	2.4	4.2 H	5.4 H	5.7	6.7	na	6.0 H	na	3.6	2.4	2.2
December Consensus	**0.1**	**3.3**	**0.4**	**0.2**	**0.1**	**0.2**	**0.3**	**0.6**	**1.5**	**2.6**	**3.7**	**4.3**	**5.5**	**4.3**	**4.4**	**72.0**	**2.7**	**2.0**	**2.2**
Top 10 Avg.	0.2	3.3	0.6	0.3	0.2	0.4	0.6	1.0	2.0	3.4	4.4	4.9	6.1	4.8	5.0	75.1	3.5	2.7	3.0
Bottom 10 Avg.	0.1	3.3	0.3	0.1	0.0	0.1	0.1	0.3	1.0	2.1	3.1	3.8	4.9	3.8	3.9	68.7	1.7	1.2	1.5
November Consensus	0.1	3.3	0.4	0.2	0.1	0.2	0.4	0.6	1.6	2.7	3.7	4.4	5.6	4.3	4.4	71.1	2.6	2.0	2.2
Number of Forecasts Changed From A Month Ago:																			
Down	6	1	5	11	12	15	15	16	20	18	20	16	14	6	14	6	13	9	11
Same	38	41	23	20	33	23	23	26	21	25	20	18	17	15	19	10	18	27	23
Up	2	2	15	5	1	2	3	3	4	3	4	5	4	8	9	15	15	9	12
Diffusion Index	46 %	51 %	62 %	42 %	38 %	34 %	35 %	36 %	32 %	34 %	32 %	36 %	36 %	53 %	44 %	65 %	52 %	50 %	51 %

First Quarter 2013

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum – Average For Quarter															Avg. For	(Q-Q % Change) (SAAR)		
	Short-Term							Intermediate-Term				Long-Term							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	A.	B.	C.	D.
	Federal Funds Rate	Prime Bank Rate	LIBOR 3-Mo.	Com. Paper 1-Mo.	Treas. Bills 3-Mo.	Treas. Bills 6-Mo.	Treas. Bills 1-Yr.	Treas. Notes 2-Yr.	Treas. Notes 5-Yr.	Treas. Notes 10-Yr.	Treas. Bond 30-Yr.	Aaa Corp. Bond	Baa Corp. Bond	State & Local Bonds	Home Mtg. Rate	Fed's Major Currency $ Index	Real GDP	GDP Price Index	Cons. Price Index
Bank of Toyko-Mitsubishi UFJ	0.8 H	3.8 H	1.2 H	0.9 H	0.9 H	1.0 H	1.2	2.0 H	2.6 H	3.5	4.1	5.0	6.3	4.5	5.1	69.0	3.4	2.9	2.7
Nat'l Assn. of Realtors	0.3	3.3 L	0.6	0.5	0.4	0.6	0.8	1.5	2.4	3.4	4.5	5.3	6.3	5.2	5.1	na	3.0	2.3	3.0
Naroff Economic Advisors	0.3	3.3 L	0.4	0.5	0.4	0.5	0.7	0.9	1.9	2.4	3.5	4.6	5.6	4.2	4.4	65.5	2.6	2.6	2.8
Pierpont Securities	0.3	3.3 L	0.6	0.3	0.2	0.3	0.4	1.2	2.4	3.8	5.2	5.3	6.6	5.7 H	5.5	78.0 H	4.2 H	3.0 H	3.6
J.W. Coons Advisors LLC	0.3	3.3 L	0.6	0.3	0.3	0.4	0.4	0.7	1.5	2.4	3.3	4.4	5.6	na	4.3	70.5	2.6	2.2	2.5
Swiss Re	0.3	3.3 L	0.3 L	0.3	0.2	0.3	0.4	0.9	1.9	2.7	3.6	4.6	5.8	na	4.6	na	3.0	0.5 L	0.5 L
SunTrust Banks	0.2	3.3 L	0.6	0.4	0.1	0.9	1.6 H	1.5	1.9	2.6	3.4	4.5	5.0	5.2	4.1	na	2.6	2.4	3.7 H
Georgia State University	0.2	3.4	na	na	0.2	0.2	0.3	0.5	1.7	3.1	4.2	5.1	6.3	na	4.7	na	1.8	1.4	1.5
Wells Fargo	0.2	3.3 L	0.5	0.2	0.2	0.3	0.4	0.5	1.3	2.4	3.4	4.2	5.5	4.2	4.1	77.5	1.4	2.1	2.0
MacroFin Analytics	0.2	3.3 L	0.6	0.3	0.2	0.3	0.6	0.9	1.7	2.5	3.6	4.5	6.0	4.8	4.5	74.0	3.0	1.5	2.0
Russell Investments	0.2	3.3 L	0.5	0.3	0.2	0.4	0.5	1.0	2.1	2.8	4.0	4.3	5.0	4.4	4.5	72.1	2.4	2.3	2.1
RidgeWorth Investments	0.2	3.3 L	0.5	0.3	0.1	0.3	0.4	0.4	1.3	2.4	3.9	3.7	4.8	2.9 L	4.2	72.0	2.5	2.0	2.4
Wintrust Wealth Management	0.2	3.3 L	0.4	0.3	0.2	0.3	0.3	0.6	1.6	2.5	3.6	4.5	5.8	4.5	4.3	65.1 L	3.3	2.1	2.2
Thredgold Economic Assoc.	0.2	3.3 L	0.4	0.3	0.2	0.4	0.5	0.7	1.7	2.7	3.7	4.5	5.5	4.2	4.6	70.5	2.5	2.0	2.4
Cycledata Corp.	0.2	3.3 L	0.4	0.1 L	0.1	0.1 L	0.3	0.4	1.3	2.5	3.6	4.5	5.7	4.2	4.1	73.0	1.5	2.2	3.1
DePrince & Assoc.	0.2	3.3 L	0.3 L	0.3	0.2	0.4	0.6	0.8	1.4	2.7	3.8	4.4	5.4	3.6	4.6	72.5	3.1	2.2	2.5
Fannie Mae	0.2	3.3 L	na	na	0.3	na	na	na	na	2.5	3.5	4.4	na	na	4.3	na	1.9	1.5	1.5
Wells Capital Management	0.2	3.3 L	0.9	0.4	0.3	0.3	0.5	0.8	1.5	3.3	4.2	4.6	5.4	5.3	5.1	74.0	3.0	2.1	2.4
JPMorgan Private Banking	0.2	3.3 L	0.5	0.2	0.0 L	0.1 L	0.2	0.4	1.2	2.3	3.3	4.2	5.6	4.1	4.2	71.0	2.0	1.9	2.0
Chmura Economics & Analytics	0.2	3.3 L	0.5	0.1 L	0.1	0.2	0.3	0.5	1.4	2.7	3.7	4.4	na	na	4.5	73.0	2.9	2.6	2.8
Comerica Bank	0.2	3.3 L	0.5	na	0.0 L	0.3	0.6	1.1	2.0	3.0	4.4	na	na	na	4.6	na	3.0	2.0	2.6
Economist Intelligence Unit	0.1	3.3 L	0.6	0.2	0.1	0.2	0.3	0.8	1.5	2.5	4.0	na	na	na	4.6	na	2.1	na	2.1
GLC Financial Economics	0.1	3.3 L	0.5	0.2	0.0 L	0.1 L	0.1 L	0.2	1.1	2.5	3.7	4.5	6.0	4.3	4.7	71.1	2.9	2.6	2.8
BMO Capital Markets	0.1	3.3 L	0.3 L	0.2	0.0 L	0.1 L	0.6	1.1	1.7	2.4	3.3	4.3	5.4	4.3	4.4	71.0	2.3	2.1	2.3
Oxford Economics	0.1	3.3 L	0.3 L	na	0.0 L	0.1 L	0.3	0.6	1.8	3.0	4.5	4.6	na	na	4.4	75.7	2.5	1.7	1.6
UBS	0.1	na	0.4	na	0.2	na	na	0.5	1.7	2.5	3.9	na	na	na	na	na	2.7	2.0	2.8
RBS Securities	0.1	3.3 L	0.3 L	0.2	0.1	0.1 L	0.2	0.3	0.8 L	1.8 L	2.9 L	3.1 L	4.0 L	3.5	3.4 L	73.0	2.6	2.8	2.1
Nomura Securities, Inc.	0.1	3.3 L	0.5	0.2	0.1	0.1 L	0.1 L	0.3	1.4	2.6	3.5	4.2	5.7	na	4.3	73.0	2.5	1.6	1.3
Woodworth Holdings	0.1	3.3 L	0.5	0.1 L	0.0 L	0.1 L	0.1 L	0.3	0.9	2.1	3.1	3.9	5.2	4.1	4.0	77.0	2.5	1.1	1.0
Action Economics	0.1	3.3 L	0.5	0.2	0.1	0.2	0.6	1.2	2.2	3.3	4.3	4.5	5.6	4.4	4.3	70.1	3.5	2.8	3.2
Kellner Economic Advisers	0.1	3.3 L	0.4	0.5	0.3	0.4	0.6	0.8	1.6	2.2	3.1	4.1	5.1	4.5	4.2	70.0	3.5	2.3	2.4
PNC Financial Services Corp.	0.1	3.3 L	0.3 L	na	0.1	0.2	0.3	0.7	1.6	2.8	na	na	na	4.4	4.3	66.9	2.6	2.1	2.3
Mesirow Financial	0.1	3.3 L	0.3 L	0.1 L	0.3	0.4	0.5	0.9	1.7	2.7	3.7	4.4	5.3	4.1	4.5	76.6	2.5	1.8	1.9
Daiwa Capital Markets America	0.1	3.3 L	0.3 L	0.1 L	0.1	0.1 L	0.2	0.5	1.4	2.5	3.5	4.2	5.5	3.8	4.4	74.0	3.2	1.9	2.1
Stone Harbor Investment Partners	0.1	3.3 L	0.3 L	0.2	0.1	0.1 L	0.2	0.9	1.8	3.0	4.2	4.7	5.5	na	4.8	68.0	2.1	2.8	2.5
ClearView Economics	0.1	3.3 L	0.5	0.1 L	0.0 L	0.1 L	0.1 L	0.3	0.9	2.1	3.1	3.9	5.2	4.1	4.0	74.0	3.0	2.2	2.7
Loomis, Sayles & Company	0.1	3.3 L	0.3 L	0.1 L	0.0 L	0.1 L	0.1 L	0.3	1.3	2.8	3.8	4.6	5.7	4.1	4.4	73.0	1.7	1.8	2.3
Societe Generale	0.1	3.3 L	0.4	0.1 L	0.0 L	0.1 L	0.1 L	0.2 L	0.9	2.3	3.4	4.0	4.9	na	3.7	na	1.1 L	2.0	1.8
Moody's Capital Markets Group	0.1	3.3 L	0.4	0.2	0.2	0.2	0.5	0.7	1.4	2.4	3.0	3.8	5.1	3.2	4.0	75.3	3.5	1.9	1.9
Moody's Analytics	0.0 L	3.3 L	0.3 L	0.4	0.0 L	0.1 L	0.4	0.8	2.4	4.2 H	5.4 H	5.7 H	6.7 H	na	6.3 H	na	3.5	2.6	2.4
December Consensus	**0.2**	**3.3**	**0.5**	**0.3**	**0.2**	**0.3**	**0.4**	**0.7**	**1.6**	**2.7**	**3.8**	**4.4**	**5.5**	**4.3**	**4.5**	**72.2**	**2.6**	**2.1**	**2.3**
Top 10 Avg.	0.3	3.3	0.7	0.4	0.3	0.5	0.8	1.2	2.2	3.3	4.5	4.9	6.2	4.8	5.0	75.6	3.4	2.7	3.0
Bottom 10 Avg.	0.1	3.3	0.3	0.1	0.0	0.1	0.2	0.3	1.1	2.2	3.2	3.9	4.9	3.7	4.0	68.7	1.8	1.5	1.5
November Consensus	0.2	3.3	0.4	0.3	0.2	0.3	0.5	0.8	1.7	2.8	3.8	4.5	5.6	4.3	4.5	71.5	2.8	2.1	2.3
Number of Forecasts Changed From A Month Ago:																			
Down	4	2	2	7	11	13	13	13	17	18	17	15	15	8	13	5	16	6	12
Same	35	34	25	23	27	24	23	23	20	19	19	15	14	13	20	10	17	21	17
Up	1	3	11	4	2	1	2	3	2	3	3	6	4	6	6	15	7	12	11
Diffusion Index	46 %	51 %	62 %	46 %	39 %	34 %	36 %	37 %	31 %	31 %	32 %	38 %	33 %	46 %	41 %	67 %	39 %	58 %	49 %

International Interest Rate And Foreign Exchange Rate Forecasts

United States

Blue Chip Forecasters	3 Mo. Interest Rate %			10 Yr. Gov't Bond Yield %			Fed's Major Currency $ Index		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Scotiabank Group	na	na	na	1.90	2.20	3.00	na	na	na
Moody's Analytics	na	na	na	2.67	3.24	4.21	na	na	na
Nomura Securities	0.50	0.50	0.50	2.10	2.25	2.40	72.0	73.0	75.0
Mizuho Research Institute	0.40	0.20	0.20	1.90	2.00	2.10	71.9	70.3	69.1
Wells Fargo	0.45	0.45	0.45	2.30	2.40	2.50	na	na	na
ING Financial Markets	0.40	0.40	0.40	1.80	1.80	2.00	73.5	72.1	68.9
Societe Generale	na	na	na	1.60	1.75	2.25	na	na	na
December Consensus	**0.44**	**0.39**	**0.39**	**2.04**	**2.23**	**2.64**	**72.5**	**71.8**	**71.0**
High	0.50	0.50	0.50	2.67	3.24	4.21	73.5	73.0	75.0
Low	0.40	0.20	0.20	1.60	1.75	2.00	71.9	70.3	68.9
Last Months Avg.	0.41	0.37	0.39	2.20	2.28	2.68	72.3	72.6	68.2

Japan

Blue Chip Forecasters	3 Mo. Interest Rate %			10 Yr. Gov't Bond Yield %			Yen/USD		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Scotiabank Group	na	na	na	na	na	na	81.3	82.7	84.7
Moody's Analytics	na	na	na	1.15	1.16	1.16	81.7	83.5	87.3
Nomura Securities	na	na	na	na	na	na	79.0	80.0	85.0
Mizuho Research Institute	0.33	0.33	0.33	0.95	0.95	1.05	75.0	73.0	77.0
Wells Fargo	0.20	0.20	0.20	1.04	1.06	1.10	na	na	na
ING Financial Markets	0.20	0.20	0.20	1.10	1.10	1.30	73.0	70.0	70.0
Societe Generale	na	na	na	1.00	1.15	1.25	76.0	75.0	73.0
December Consensus	**0.24**	**0.24**	**0.24**	**1.05**	**1.08**	**1.17**	**77.7**	**77.4**	**79.5**
High	0.33	0.33	0.33	1.15	1.16	1.30	81.7	83.5	87.3
Low	0.20	0.20	0.20	0.95	0.95	1.05	73.0	70.0	70.0
Last Months Avg.	0.24	0.24	0.24	1.07	0.93	1.15	77.6	78.1	80.5

United Kingdom

Blue Chip Forecasters	3 Mo. Interest Rate %			10 Yr. Gilt Yields %			USD/Pound Sterling		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Scotiabank Group	na	na	na	na	na	na	1.61	1.62	1.64
Moody's Analytics	na	na	na	2.78	3.04	3.59	1.56	1.57	1.60
Nomura Securities	na	na	na	na	na	na	1.55	1.58	1.65
Mizuho Research Institute	0.90	0.60	0.60	2.20	2.30	2.40	na	na	na
Wells Fargo	0.75	0.70	0.70	2.60	2.70	3.30	na	na	na
ING Financial Markets	1.00	1.00	1.00	2.20	2.30	2.50	1.59	1.58	1.62
Societe Generale	na	na	na	1.75	1.75	1.88	1.54	1.59	1.67
December Consensus	**0.88**	**0.77**	**0.77**	**2.31**	**2.42**	**2.73**	**1.57**	**1.59**	**1.64**
High	1.00	1.00	1.00	2.78	3.04	3.59	1.61	1.62	1.67
Low	0.75	0.60	0.60	1.75	1.75	1.88	1.54	1.57	1.60
Last Months Avg.	0.83	0.70	0.70	2.43	2.51	2.84	1.52	1.52	1.57

Switzerland

Blue Chip Forecasters	3 Mo. Interest Rate %			10 Yr. Gov't Bond Yield %			CHF/USD		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Scotiabank Group	na	na	na	na	na	na	0.87	0.86	0.86
Moody's Analytics	na	na	na	1.25	1.31	1.50	0.85	0.86	0.86
Nomura Securities	na	na	na	na	na	na	na	na	na
Mizuho Research Institute	na	na	na	na	na	na	na	na	na
Wells Fargo	na	na	na	na	na	na	na	na	na
ING Financial Markets	0.10	0.10	0.10	0.90	0.90	1.00	0.92	0.92	0.87
Societe Generale	na	na	na	0.70	1.10	1.30	1.02	1.05	1.08
December Consensus	**0.10**	**0.10**	**0.10**	**0.95**	**1.10**	**1.27**	**0.92**	**0.92**	**0.92**
High	0.10	0.10	0.10	1.25	1.31	1.50	1.02	1.05	1.08
Low	0.10	0.10	0.10	0.70	0.90	1.00	0.85	0.86	0.86
Last Months Avg.	0.10	0.10	0.10	1.05	1.08	1.18	0.88	0.88	0.90

Canada

Blue Chip Forecasters	3 Mo. Interest Rate %			10 Yr. Gov't Bond Yield %			CAD/USD		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Scotiabank Group	na	na	na	2.20	2.40	2.90	1.01	0.99	0.98
Moody's Analytics	na	na	na	2.73	2.85	3.15	1.01	1.00	0.99
Nomura Securities	na	na	na	2.80	3.00	3.30	0.95	0.95	0.96
Mizuho Research Institute	na	na	na	na	na	na	na	na	na
Wells Fargo	1.15	1.15	1.20	2.50	2.75	3.30	na	na	na
ING Financial Markets	1.10	0.70	0.70	2.00	2.00	2.40	1.05	1.01	0.97
Societe Generale	na	na	na	1.90	2.15	3.05	1.03	1.00	0.97
December Consensus	**1.13**	**0.93**	**0.95**	**2.36**	**2.53**	**3.02**	**1.01**	**0.99**	**0.97**
High	1.15	1.15	1.20	2.80	3.00	3.30	1.05	1.01	0.99
Low	1.10	0.70	0.70	1.90	2.00	2.40	0.95	0.95	0.96
Last Months Avg.	1.20	1.18	1.40	2.51	2.66	3.10	1.00	1.00	0.98

International Interest Rate And Foreign Exchange Rate Forecasts

Australia

Blue Chip Forecasters	3 Mo. Interest Rate %			10 Yr. Gov't Bond Yield %			USD/AUD		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Scotiabank Group	na	na	na	na	na	na	1.02	1.04	1.08
Moody's Analytics	na	na	na	5.12	5.34	5.66	1.01	1.00	0.98
Nomura Securities	4.60	4.90	5.25	na	na	na	0.98	1.00	1.05
Mizuho Research Institute	na	na	na	na	na	na	na	na	na
Wells Fargo	na	na	na	na	na	na	na	na	na
ING Financial Markets	4.40	3.70	3.60	4.00	4.00	4.40	0.98	1.00	1.05
Societe Generale	na	na	na	4.00	4.20	4.75	na	na	na
December Consensus	**4.50**	**4.30**	**4.43**	**4.37**	**4.51**	**4.94**	**1.00**	**1.01**	**1.04**
High	4.60	4.90	5.25	5.12	5.34	5.66	1.02	1.04	1.08
Low	4.40	3.70	3.60	4.00	4.00	4.40	0.98	1.00	0.98
Last Months Avg.	4.80	4.90	5.00	4.55	4.91	5.43	1.00	1.01	1.03

Eurozone

Blue Chip Forecasters	3 Mo. Interest Rate %			USD/EUR		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Scotiabank Group	na	na	na	1.41	1.42	1.40
Moody's Analytics	na	na	na	1.40	1.37	1.32
Nomura Securities	0.94	0.94	0.94	1.30	1.32	1.35
Mizuho Research Institute	0.90	0.70	0.80	1.27	1.30	1.35
Wells Fargo	0.65	0.65	0.65	na	na	na
ING Financial Markets	0.90	0.90	0.90	1.30	1.30	1.38
Societe Generale	na	na	na	1.30	1.33	1.40
December Consensus	**0.85**	**0.80**	**0.82**	**1.33**	**1.34**	**1.37**
High	0.94	0.94	0.94	1.41	1.42	1.40
Low	0.65	0.65	0.65	1.27	1.30	1.32
Last Months Avg.	1.26	1.00	1.01	1.36	1.35	1.35

Blue Chip Forecasters	10 Yr. Gov't Bond Yields %											
	Germany			France			Italy			Spain		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
ING Financial Markets	1.80	1.80	2.00	4.70	4.40	4.20	6.80	6.80	6.60	6.80	6.80	6.60
Mizuho Research Institute	1.80	1.90	2.00	na	na	na	na	na	na	na	na	na
Moody's Analytics	2.39	2.67	3.00	3.48	3.76	4.41	5.60	5.80	6.00	6.06	6.17	6.33
Societe Generale	1.50	1.90	2.10	na	na	na	na	na	na	na	na	na
December Consensus	**1.87**	**2.07**	**2.28**	**4.09**	**4.08**	**4.31**	**6.20**	**6.30**	**6.30**	**6.43**	**6.49**	**6.47**
High	2.39	2.67	3.00	4.70	4.40	4.41	6.80	6.80	6.60	6.80	6.80	6.60
Low	1.50	1.80	2.00	3.48	3.76	4.20	5.60	5.80	6.00	6.06	6.17	6.33
Last Months Avg.	2.06	2.15	2.38	3.21	3.09	3.12	5.74	5.71	5.82	5.73	5.64	5.67

	Consensus Forecasts 10-year Bond Yields vs U.S. Yield			
	Current	In 3 Mo.	In 6 Mo.	In 12 Mo.
Japan	-0.93	-0.99	-1.15	-1.47
United Kingdom	0.54	0.27	0.18	0.10
Switzerland	-1.07	-1.09	-1.13	-1.37
Canada	0.14	0.32	0.29	0.38
Australia	1.94	2.33	2.28	2.30
Germany	0.28	-0.17	-0.17	-0.36
France	1.72	2.05	1.85	1.67
Italy	5.40	4.16	4.07	3.66
Spain	4.74	4.39	4.25	3.83

	Consensus Forecasts 3 Mo. Deposit Rates vs U.S. Rate			
	Current	In 3 Mo.	In 6 Mo.	In 12 Mo.
Japan	-0.31	-0.19	-0.63	-0.14
United Kingdom	0.44	0.45	0.38	0.38
Switzerland	-0.48	-0.34	-0.29	-0.29
Canada	0.59	0.69	0.54	0.56
Australia	3.99	4.06	3.91	4.04
Eurozone	0.84	0.41	0.41	0.44

Viewpoints:

A Sampling of Views on the Economy, Financial Markets and Government Policy Excerpted from Recent Reports Issued by our Blue Chip Panel Members and Others

The Q3 GDP Revision: News for Optimists and Pessimists

The government's estimate of real GDP growth for 3Q11 was revised down to 2.0% (from a first print of 2.5%). But the two most conspicuous details of the report are positive for near-term growth. The composition of GDP in 3Q11 now shows an unrevised 3.6% saar final sales growth and an outright decline in inventories, a combination that can be expected to lead to a positive turn in the inventory cycle soon. Indeed, the forecast improvement to 3.0% real GDP growth this quarter incorporates an increase in the inventory contribution to annualized growth from -1.6%-pt in 3Q11 to 0.8%-pt in 4Q11 (with about half this shift offset by a decline in the contribution from net exports, largely reflecting the part of the inventory boost that is supplied by foreign sources). In addition, the first report on corporate profits shows earnings continue to rise more quickly than GDP. Margins from domestic non-financial activity reached their highest level since the late 1960s.

However, other important details of the revision are more negative. The deterioration in state and local finances, as federal aid from the stimulus legislation runs down, points to further tightening from this sector in coming quarters. The significant downward revision to wage and salary income and to real disposable income accentuates the previously-reported disconnect between spending growth and income growth and the resulting plunge in the saving rate. Such declines, especially against the backdrop of soft asset prices and weak confidence readings, are often followed by retrenchment. Because of weak personal income, growth of national income has been running well below GDP growth over the past two quarters. Fed research suggests that early reports on national income are often more reliable estimates of economic growth than GDP.

The combination of relatively strong growth in final sales and little or no growth in inventories is as usual viewed as a positive for near-term real GDP growth as it points to a positive turn in the inventory cycle that will boost domestic manufacturing. Moreover, the detail of the report showing a split between inventory growth for durables and non-durables helps identify where this help should come from. Inventories in the durable goods industries rose 4.2% saar in 3Q11, in line with the recent trends. The stall in inventory accumulation is concentrated in nondurables, -3.5% saar, and extends to manufacturing (-$8.4 billion saar), wholesale industries (-$12.6 billion), and the farm sector (-$10.8 billion). Monthly source data detail indicates that the maximum de-stocking in nondurable inventories occurred in August.

This suggests that the boost to growth from the turn in the inventory cycle should be coming in the nondurable goods industries and could have started as soon as September. IP growth for nondurable manufacturing averaged 0.25% per month in September and October after a small net decline on average over the previous four months, some improvement but not enough to provide much of a major boost to overall GDP growth yet.

The second important positive news in the GDP report is the first look at 3Q11 profits. Total adjusted profits of US firms increased 8.5% saar in 3Q11, again outpacing overall GDP growth. And while in past quarters, profits had been boosted by earnings from abroad, foreign earnings declined in 3Q11. Profits from domestic operations increased 9.3% saar last quarter. And the 6.6% growth pace for domestic non-financial profits allowed margins for this sector to reach their highest levels since the late 1960s.

Real business fixed investment was revised slightly lower in 3Q11, but at 14.8% saar growth it is still the major growth sector of the economy. Strong profits growth provides some support for the view that strong double-digit growth in business spending will be maintained this quarter. But the latest monthly news on capital spending has been disappointing. Core capital goods shipments, source data for estimating equipment spending, declined about 1% in both September and October. (However, the IP report sends a different message. Production of business equipment increased 0.6% in September and 1.0% in October.)

As has been the case through most of the expansion, upbeat news on corporate profits has been accompanied by disappointing growth of labor income. The first revision to GDP includes revisions to prior quarter labor income based on the more reliable income data in the Quarterly Census of Employment and Wages (QCEW). Wage and salary income for 2Q11 was revised down to growth of only 2.4% saar (from 4.9%) and 3Q11 growth was revised down to 1.5% growth (from 2.0%), at odds with expectations that upward revisions to August and September payroll employment would lead to an upward revision of income growth.

Real disposable income has been revised down accordingly and now shows declines in each of the last two quarters while real consumer spending posted gains of 0.7% saar and 2.4% for the two quarters. The apparent disconnect between falling income and rising spending is squared via a sharp decline in the saving rate, down to 3.8% in 3Q11 from 4.8% the prior quarter and 5.0% in 1Q11. The decline in the saving rate is probably a warning of spending caution ahead, especially against the backdrop of recent trends in asset prices and consumer confidence. The saving rate can decline because higher tax payments (pe haps on capital gains) are holding down disposable income relative to total income. But this was not the case last quarter. Saving as a share of disposable income declined 1.0%-pt in 3Q11, and the saving rate redefined as a share of total household income declined 0.9%-pt, only slightly less.

The period of consumer retrenchment may have already started. Real consumer spending slowed to a 0.1% gain in October following increases averaging 0.3% the prior three months, despite help in October from falling prices. Research at the Fed indicates that early estimates of gross domestic income (GDI) may tend to be more reliable growth measures than estimates of GDP. In this light, it is worth noting that revised data show real GDI increasing less than 0.5% saar in each of the last two quarters.

Another feature of the first revision is the complete set of revenue and outlay tables for the state and local government sector. The overall balance tends to be volatile from quarter to quarter but these data show that state and local governments, in aggregate, had managed to bring borrowing requirements back toward normal by mid-2010 through a combination of spending cuts, tax increases, deferred maintenance, and increased federal aid. With the economy now growing, it would seem that state and local finances might be able to loosen a bit in coming quarters. But this does not appear to be the case. Federal aid that had been temporarily lifted as part of the stimulus *(continued on next page)*

Viewpoints

A Sampling of Views on the Economy, Financial Markets and Government Policy Excerpted from Recent Reports Issued by our Blue Chip Panel Members and Others

package is now starting to run off. These federal grants declined by $57.1 billion saar in 3Q11, and fully account for the widening budget imbalance of the sector last quarter. Further scheduled cuts in aid will put continued pressure on finances in the quarters ahead.

Robert Mellman, JPMorgan Chase Bank, New York, NY

A Super Flop

Members of the Joint Select Committee on Deficit Reduction (JSCDR) failed to meet the requirement of the Budget Control Act (BCA) of 2011 directing this so-called "Super Committee" to agree on (by 23 November) and then present to Congress (for passage by 23 December) a plan to cut $1.2 trillion from the projected 10-year budget deficitUnder another provision of the BCA this failure will trigger the "sequestration" (automatic reduction) of scheduled spending on both defense and non-defense discretionary programs in January 2013

This legislative failure has little direct effect on our forecast for the US economy. We had not expected the JSCDR to propose substantive changes that would affect the 2012 outlook, and we continue to believe that fiscal policies for 2013 will not be set before late next year. The immediate aftermath of the 2012 presidential and congressional elections should be anopportune time to strike a long-run budget compromise that would incorporate significant reforms to both taxes and spending. It is important to recognize that, under current law, very large automatic tax increases and spending cuts will take effect at the beginning of 2013. Like a sword of Damocles hanging over the US government, the prospect of such a severe fiscal restraint seems likely to, eventually, compel action.

As noted, the JSCDR's failure to act will likely have no direct effect on fiscal measures in the year ahead. The Congressional Budget Office (CBO) and Joint Committee on Taxation (JCT) estimate that under current law a combination of BCA spending caps, the partial withdrawal from military operations in Iraq and Afghanistan, and other expiring tax provisions amount to $69 billion in 2012 – a "drag" of just 0.4% of the CBO's estimate of fiscal 2012 GDP. However, we continue to believe that Congress will act soon to counteract all of that drag – and to provide some modest net stimulus to 2012 growth.

Despite the latest "process failure," we expect a bi-partisan majority to agree to take action before year-end to prevent the scheduled expiration of the two percentage point (pp) cut in payroll taxes enacted a year ago as a "temporary" fiscal boost. We judge that, with the economy still faltering, policymakers will deem it ill-advised to risk the effects of a sizeable tax increase of roughly $120bn that would result from the restoration of the usual payroll tax rates. Moreover, we think that Congress will also act to extend the life of the emergency unemployment compensation (EUC) program. Congress must enact, by mid-December, legislation (the "omnibus" spending bill) to authorize on-going government operations for fiscal 2012. That "must-pass" legislation would likely be the most suitable vehicle for extending the payroll tax cut and the EUC program. Both are subject to "pay-go" rules requiring tax or spending offsets over a 10-year time horizon, but these rules could be waived as they were last year. However, the politics surrounding the "Super Committee's" failure will make enactment of these measures more contentious.

The looming sequestration would greatly magnify the 2013 tightening of fiscal policy that is embedded in current law. Beyond a modest fiscal drag in 2012, the fiscal drag in 2013 under current policy grows substantially. The spending caps enacted in the BCA would reduce projected discretionary spending in 2013 by about $49bn but the sequestration now set to be triggered in January 2013 would add cuts of more than twice that amount -- roughly $111bn. In addition, CBO estimates that reductions in troop deployment would shave about $53bn more from outlays – for total spending cuts of $214bn, or 1.3% of GDP. On the revenue side, the expiration of the Bush-era tax cuts, failure to index the AMT (alternative minimum tax) for inflation, and other expiring tax provisions total approximately $314 billion, or 1.9% of GDP. The combined spending cuts and revenue from expiring tax provisions create a total fiscal drag of about 3.3% of GDP in 2013.

With the failure of the JSCDR, the BCA mandates a "sequestration" procedure that results in automatic cuts in both defense and non-defense discretionary spending. The BCA directs the Office of Management and Budget (OMB) to impose cuts through a specific formula and to be spread evenly over FY2013-21. They would also be divided evenly between the defense and non-defense programs, including entitlements. However, cuts to Medicare and certain health care programs would be capped at 2% for each fiscal year.

Sequestration would shave more than 7% from planned defense spending over the decade ahead but other defense spending cuts associated with reductions in troop deployment would cut another 6% from defense outlays over the 10-year budget horizon. Defense Secretary Leon Panetta and Senator John McCain have warned of dire national security consequences resulting from such deep cuts. Resistance to the mandated cuts in non-defense programs is likely to be equally intense. In our view, averting sequestration's deep cuts will become a priority for many in Congress but doing so will require the sort of sober realignment of budgetary priorities that eluded the Super Committee. The debt ratings agencies, which have indicated that the Committee's failure will not lead to a quick downgrade of US debt, may recognize this prospect.

Our baseline forecast of the economy in 2013 assumes Congress acts to offset most, but not all, of these automatic changes after the presidential election in November 2012. While we retain the assumption that fiscal drag in 2013 will be greater than in 2012, we remain confident that it will be substantially less than current law would require.

The economic cost of procrastination creates a powerful incentive to finally take up the sorts of tax and entitlement reforms that will ultimately be needed to set US fiscal policy on a sustainable path. The sequestration process triggered by the failure of the Super Committee magnifies the incentive to act. Both this summer's debt ceiling debate and now the failure of the Super Committee may seem to reveal a dysfunctional government. But behind it all, a consensus now appears to recognize the necessity for reform. We believe that consensus will eventually produce significant progress toward these long-overdue reforms shortly after the 2012 election in order to avert the frightening consequences of sequestration and other current-law budget changes scheduled to take effect early in 2013.

David Resler and Ellen Zentner, Nomura Securities, New York NY

Long-Range Forecasts:

The table below contains results of our semi-annual long-range CONSENSUS survey. There are also Top 10 and Bottom 10 averages for each variable. Shown are estimates for the years 2013 through 2017 and averages for the five-year periods 2013-2017 and 2018-2022. Apply these projections cautiously. Few economic, demographic and political forces can be evaluated accurately over such long time spans.

		----------Average For The Year----------					Five-Year Averages	
Interest Rates		**2013**	**2014**	**2015**	**2016**	**2017**	**2013-2017**	**2018-2022**
1. Federal Funds Rate	**CONSENSUS**	**0.5**	**1.8**	**2.8**	**3.4**	**3.7**	**2.4**	**3.7**
	Top 10 Average	0.9	2.9	4.0	4.3	4.6	3.4	4.7
	Bottom 10 Average	0.2	0.9	1.6	2.2	2.6	1.5	2.6
2. Prime Rate	**CONSENSUS**	**3.6**	**4.8**	**5.8**	**6.5**	**6.7**	**5.5**	**6.7**
	Top 10 Average	4.0	6.0	7.1	7.5	7.7	6.4	7.7
	Bottom 10 Average	3.3	3.9	4.7	5.3	5.6	4.5	5.5
3. LIBOR, 3-Mo.	**CONSENSUS**	**0.8**	**2.2**	**3.2**	**3.8**	**4.0**	**2.8**	**4.0**
	Top 10 Average	1.3	3.5	4.3	4.8	4.9	3.8	4.9
	Bottom 10 Average	0.4	1.2	2.0	2.6	2.9	1.8	3.0
4. Commercial Paper, 1-Mo.	**CONSENSUS**	**0.6**	**1.9**	**2.8**	**3.4**	**3.7**	**2.5**	**3.7**
	Top 10 Average	1.1	2.9	4.0	4.4	4.6	3.4	4.6
	Bottom 10 Average	0.2	1.0	1.8	2.3	2.7	1.6	2.7
5. Treasury Bill Yield, 3-Mo.	**CONSENSUS**	**0.5**	**1.7**	**2.7**	**3.3**	**3.6**	**2.3**	**3.5**
	Top 10 Average	1.0	2.8	3.9	4.3	4.4	3.3	4.5
	Bottom 10 Average	0.1	0.8	1.6	2.2	2.6	1.4	2.5
6. Treasury Bill Yield, 6-Mo.	**CONSENSUS**	**0.6**	**1.8**	**2.8**	**3.4**	**3.7**	**2.5**	**3.7**
	Top 10 Average	1.2	3.0	4.1	4.5	4.6	3.5	4.6
	Bottom 10 Average	0.2	0.9	1.7	2.0	2.6	1.5	2.6
7. Treasury Bill Yield, 1-Yr.	**CONSENSUS**	**0.8**	**2.1**	**3.1**	**3.6**	**3.9**	**2.7**	**3.8**
	Top 10 Average	1.4	3.2	4.4	4.6	4.8	3.7	4.8
	Bottom 10 Average	0.4	1.1	1.9	2.5	2.8	1.7	2.8
8. Treasury Note Yield, 2-Yr.	**CONSENSUS**	**1.2**	**2.4**	**3.3**	**3.9**	**4.1**	**3.0**	**4.1**
	Top 10 Average	1.9	3.5	3.2	4.8	5.0	3.6	5.0
	Bottom 10 Average	0.7	1.5	2.2	2.8	3.0	2.0	3.0
10. Treasury Note Yield, 5-Yr.	**CONSENSUS**	**2.2**	**3.1**	**3.9**	**4.3**	**4.4**	**3.6**	**4.4**
	Top 10 Average	3.1	4.0	4.8	5.2	5.3	4.5	5.3
	Bottom 10 Average	1.5	2.3	2.8	3.3	3.4	2.6	3.3
11. Treasury Note Yield, 10-Yr.	**CONSENSUS**	**3.2**	**4.0**	**4.6**	**4.8**	**4.9**	**4.3**	**4.8**
	Top 10 Average	4.1	4.7	5.3	5.5	5.7	5.1	5.7
	Bottom 10 Average	2.4	3.2	3.7	4.0	4.1	3.5	3.9
12. Treasury Bond Yield, 30-Yr.	**CONSENSUS**	**4.2**	**4.8**	**5.3**	**5.5**	**5.6**	**5.1**	**5.5**
	Top 10 Average	5.1	5.7	6.2	6.4	6.4	6.0	6.4
	Bottom 10 Average	3.3	4.0	4.3	4.5	4.6	4.2	4.4
13. Corporate Aaa Bond Yield	**CONSENSUS**	**4.7**	**5.4**	**5.8**	**6.2**	**6.2**	**5.7**	**6.1**
	Top 10 Average	5.5	6.2	6.6	7.1	7.1	6.5	7.1
	Bottom 10 Average	3.9	4.5	5.0	5.2	5.3	4.8	5.1
13. Corporate Baa Bond Yield	**CONSENSUS**	**5.7**	**6.4**	**6.8**	**7.1**	**7.2**	**6.6**	**7.0**
	Top 10 Average	6.5	7.2	7.6	8.1	8.1	7.5	8.0
	Bottom 10 Average	5.0	5.6	6.0	6.2	6.2	5.8	6.0
14. State & Local Bonds Yield	**CONSENSUS**	**4.7**	**5.3**	**5.5**	**5.7**	**5.8**	**5.4**	**5.6**
	Top 10 Average	5.5	6.1	6.3	6.5	6.5	6.2	6.3
	Bottom 10 Average	3.9	4.5	4.8	4.9	5.1	4.6	4.9
15. Home Mortgage Rate	**CONSENSUS**	**4.8**	**5.6**	**6.0**	**6.3**	**6.4**	**5.8**	**6.3**
	Top 10 Average	5.7	6.4	6.8	7.1	7.2	6.6	7.2
	Bottom 10 Average	4.2	4.8	5.2	5.4	5.5	5.0	5.4
A. FRB - Major Currency Index	**CONSENSUS**	**73.4**	**74.0**	**74.8**	**75.5**	**75.9**	**74.7**	**75.6**
	Top 10 Average	77.0	78.9	79.3	79.8	80.3	79.1	80.6
	Bottom 10 Average	70.1	69.5	70.5	71.2	71.6	70.6	71.0
		----------Year-Over-Year, % Change----------					Five-Year Averages	
		2013	**2014**	**2015**	**2016**	**2017**	**2013-2017**	**2018-2022**
B. Real GDP	**CONSENSUS**	**2.8**	**2.8**	**2.9**	**2.9**	**2.8**	**2.8**	**2.6**
	Top 10 Average	3.3	3.5	3.4	3.3	3.2	3.3	2.9
	Bottom 10 Average	2.2	2.1	2.5	2.4	2.4	2.3	2.3
C. GDP Chained Price Index	**CONSENSUS**	**2.1**	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**	**2.1**
	Top 10 Average	2.6	2.9	2.7	2.7	2.7	2.7	2.6
	Bottom 10 Average	1.5	1.6	1.8	1.7	1.8	1.7	1.7
D. Consumer Price Index	**CONSENSUS**	**2.3**	**2.4**	**2.4**	**2.4**	**2.3**	**2.4**	**2.3**
	Top 10 Average	2.9	3.2	3.0	3.0	2.9	3.0	2.8
	Bottom 10 Average	1.8	1.8	1.9	1.9	1.9	1.9	2.0

Databank:

2011 Historical Data

Monthly Indicator	Jan	Feb	Mar	Apr	May	Jun	Jly	Aug	Sep	Oct	Nov	Dec
Retail and Food Service Sales (a)	0.8	1.3	0.8	0.2	-0.1	0.2	0.4	0.3	1.1	0.5		
Auto & Light Truck Sales (b)	12.64	13.24	13.02	13.13	11.68	11.51	12.20	12.09	13.05	13.21		
Personal Income (a, current $)	1.1	0.5	0.5	0.4	0.3	0.1	0.1	-0.1	0.1	0.4		
Personal Consumption (a, current $)	0.4	0.8	0.6	0.3	0.2	-0.2	0.9	0.2	0.7	0.1		
Consumer Credit (e)	2.2	3.2	2.2	2.8	3.0	5.6	5.8	-4.7	3.6			
Consumer Sentiment (U. of Mich.)	74.2	77.5	67.5	69.8	74.3	71.5	63.7	55.7	59.4	60.9		
Household Employment (c)	117	250	291	-190	105	-445	-38	331	398	277		
Non-farm Payroll Employment (c)	68	235	194	217	53	20	127	104	158	80		
Unemployment Rate (%)	9.0	8.9	8.8	9.0	9.1	9.2	9.1	9.1	9.1	9.0		
Average Hourly Earnings (All, cur. $)	22.86	22.88	22.89	22.93	23.02	23.01	23.12	23.08	23.14	23.19		
Average Workweek (All, hrs.)	34.2	34.3	34.3	34.4	34.4	34.3	34.3	34.2	34.3	34.3		
Industrial Production (d)	5.8	5.2	5.3	4.5	3.4	3.3	3.6	3.4	3.2	4.0		
Capacity Utilization (%)	76.9	76.5	77.0	76.7	76.7	76.7	77.5	77.4	77.3	77.8		
ISM Manufacturing Index (g)	60.8	61.4	61.2	60.4	53.5	55.3	50.9	50.6	51.6	50.8		
ISM Non-Manufacturing Index (g)	59.4	59.7	57.3	52.8	54.6	53.3	52.7	53.3	53.0	52.9		
Housing Starts (b)	.636	.518	.593	.549	.553	.615	.615	.585	.630	.628		
Housing Permits (b)	.568	.534	.574	.563	.609	.617	.601	.625	.589	.653		
New Home Sales (1-family, c)	310	281	305	316	308	303	297	296	313			
Construction Expenditures (a)	-1.4	-1.0	-0.2	0.7	2.5	1.6	-3.3	1.7	0.2			
Consumer Price Index (nsa., d)	1.6	2.1	2.7	3.2	3.6	3.6	3.6	3.8	3.9	3.5		
CPI ex. Food and Energy (nsa., d)	1.0	1.1	1.2	1.3	1.5	1.6	1.7	2.0	2.0	2.1		
Producer Price Index (n.s.a., d)	3.6	5.4	5.6	6.6	7.1	6.9	7.2	6.5	6.9	5.9		
Durable Goods Orders (a)	4.0	-1.1	4.6	-2.5	2.0	-1.2	4.2	0.7	-1.6	-0.7		
Leading Economic Indicators (g)	0.2	0.9	0.7	-0.3	0.7	0.3	0.6	0.3	0.1	0.9		
Balance of Trade & Services (f)	-47.9	-45.7	-46.4	-43.2	-50.2	-51.6	-45.6	-44.9	-43.1			
Federal Funds Rate (%)	0.17	0.16	0.14	0.10	0.09	0.09	0.07	0.10	0.08	0.07		
3-Mo. Treasury Bill Rate (%)	0.15	0.13	0.10	0.06	0.04	0.04	0.04	0.02	0.01	0.02		
10-Year Treasury Note Yield (%)	3.39	3.58	3.41	3.46	3.17	3.00	3.00	2.30	1.98	2.15		

2010 Historical Data

Monthly Indicator	Jan	Feb	Mar	Apr	May	Jun	Jly	Aug	Sep	Oct	Nov	Dec
Retail and Food Service Sales (a)	0.4	0.3	2.2	0.6	-0.8	-0.2	0.3	1.0	1.0	1.3	0.7	0.6
Auto & Light Truck Sales (b)	10.81	10.42	11.69	11.28	11.55	11.25	11.53	11.52	11.78	12.14	12.24	12.46
Personal Income (a, current $)	0.8	0.2	0.5	0.7	0.6	0.1	0.4	0.5	0.0	0.5	0.1	0.5
Personal Consumption (a, current $)	0.2	0.4	0.6	0.1	0.3	0.0	0.4	0.6	0.3	0.6	0.4	0.4
Consumer Credit (e)	3.2	-3.8	-2.5	-6.4	-1.2	-0.9	-2.7	-2.5	0.0	3.9	0.7	2.3
Consumer Sentiment (U. of Mich.)	74.4	73.6	73.6	72.2	73.6	76.0	67.8	68.9	68.2	67.7	71.6	74.5
Household Employment (c)	551	187	254	430	-29	-261	-101	276	111	-294	-175	297
Non-Farm Payroll Employment (c)	-39	-35	192	277	458	-192	-49	-59	-29	171	93	152
Unemployment Rate (%)	9.7	9.7	9.7	9.8	9.6	9.5	9.5	9.6	9.6	9.7	9.8	9.4
Average Hourly Earnings (All, cur. $)	22.44	22.48	22.48	22.52	22.57	22.57	22.61	22.67	22.70	22.77	22.76	22.77
Average Workweek (All, hrs.)	34.0	33.4	34.1	34.1	34.2	34.1	34.2	34.2	34.2	34.3	34.2	34.3
Industrial Production (d)	0.2	1.0	3.4	4.6	7.2	7.8	7.6	6.8	6.3	5.9	6.0	6.8
Capacity Utilization (%)	71.9	72.2	72.8	73.2	74.3	74.5	75.3	75.5	75.7	75.7	75.8	76.8
ISM Manufacturing Index (g)	58.3	57.1	60.4	59.6	57.8	55.3	55.1	55.2	55.3	56.9	58.2	58.5
ISM Non-Manufacturing Index (g)	50.7	52.7	54.1	54.6	54.8	53.5	53.7	52.8	53.9	54.6	56.0	57.1
Housing Starts (b)	.615	.603	.626	.687	.580	.539	.550	.606	.597	.539	.551	.526
Housing Permits (b)	.636	.655	.688	.632	.582	.585	.575	.575	.562	.555	.564	.630
New Home Sales (1-family, c)	346	344	385	420	281	307	279	278	316	282	287	331
Construction Expenditures (a)	-0.1	-3.0	1.0	2.3	-2.8	0.1	-2.6	-1.0	1.2	1.1	0.2	-2.5
Consumer Price Index (s.a., d)	2.6	2.1	2.3	2.2	2.0	1.1	1.2	1.1	1.1	1.2	1.1	1.5
CPI ex. Food and Energy (s.a., d)	1.6	1.3	1.1	0.9	0.9	0.9	0.9	0.9	0.8	0.6	0.8	0.8
Producer Price Index (n.s.a., d)	4.5	4.2	5.9	5.4	5.1	2.7	4.1	3.3	3.9	4.3	3.4	3.8
Durable Goods Orders (a)	4.9	0.5	0.1	2.9	-0.7	-0.2	1.2	-0.8	4.9	-3.1	-0.1	-0.7
Leading Economic Indicators (g)	0.6	0.4	1.5	-0.1	0.5	-0.2	0.2	0.1	0.7	0.2	1.2	0.8
Balance of Trade & Services (f)	-37.5	-41.0	-41.1	-41.5	-42.2	-46.9	-41.6	-45.5	-44.0	-39.5	-38.8	-40.5
Federal Funds Rate (%)	0.11	0.13	0.16	0.20	0.20	0.18	0.18	0.19	0.19	0.19	0.19	0.18
3-Mo. Treasury Bill Rate (%)	0.06	0.11	0.15	0.16	0.16	0.12	0.16	0.16	0.15	0.13	0.14	0.14
10-Year Treasury Note Yield (%)	3.73	3.69	3.73	3.82	3.42	3.20	3.01	2.70	2.65	2.54	2.76	3.29

(a) month-over-month % change; (b) millions, saar; (c) thousands, saar; (d) year-over-year % change; (e) annualized % change; (f) $ billions; (g) level. Most series are subject to frequent government revisions. Use with care.

Calendar Of Upcoming Economic Data Releases

Monday	Tuesday	Wednesday	Thursday	Friday
November 28 New Home Sales (Oct)	**29** S&P/Case-Shiller Home Price Index (Sep) Consumer Confidence (Nov, Conference Board) ABC Consumer Comfort Index Weekly Store Sales	**30** ADP Employment (Nov) Challenger Survey (Nov) Chicago PMI (Nov) Pending Home Sales (Oct) Beige book for Dec. 13 FOMC meeting Agricultural Prices (Nov) EIA Crude Oil Stocks Mortgage Applications	**December 1** ISM Manufacturing (Nov) Vehicle Sales (Nov) Construction Spending (Oct) Weekly Jobless Claims Weekly Money Supply	**2** Employment Report (Nov)
5 ISM Non-Manufacturing (Nov Factory Orders (Oct))	**6** ABC Consumer Comfort Index Weekly Store Sales	**7** Consumer Credit (Oct) Mortgage Applications EIA Crude Oil Stocks	**8** Wholesale Inventories (Oct) ICSC Chain Store Sales (Nov) Weekly Jobless Claims Weekly Money Supply	**9** Trade Balance (Oct) Consumer Sentiment (Dec, Preliminary, University of Michigan)
12 U.S. Budget (Nov)	**13** **FOMC Meeting** Retail Sales (Nov) Business Inventories (Oct) Weekly Store Sales ABC Consumer Comfort Index	**14** Import Prices (Nov) EIA Crude Oil Stocks Mortgage Applications	**15** Philadelphia Fed Survey (Dec) Empire Survey (Dec) Industrial Production (Nov) Producer Price Index (Nov) TIC data (oct) Current Account (Q3) Weekly Jobless Claims Weekly Money Supply	**16** Consumer Price Index (Nov)
19 NAHB Housing Market Index (Dec)	**20** Housing Starts (Nov) Weekly Store Sales ABC Consumer Comfort Index	**21** Existing Home Sales (Nov) EIA Crude Oil Stocks Mortgage Applications	**22** GDP (Q3, Final) Consumer Sentiment (Dec., Final, University of Michigan) Leading Economic Indicators (Nov) Weekly Jobless Claims Weekly Money Supply	**23** Personal Income and Consumption (Nov) New Home Sales (Nov) Durable Goods (Nov)
26 **Christmas Day Observed** **Markets Closed**	**27** S&P/Case-Shiller Home Price Index (Oct) Consumer Confidence (Dec, Conference Board) ABC Consumer Comfort Index Weekly Store Sales	**28** EIA Crude Oil Stocks Mortgage Applications	**29** Pending Home Sales (Oct) Weekly Jobless Claims Weekly Money Supply	**30** Chicago PMI (Dec)
January 2 **New Year's Day (observed)** **Markets Closed**	**3** ISM Manufacturing (Jan) Construction Spending (Nov) FOMC Minutes (Dec. 13 meeting) ABC Consumer Comfort Index Weekly Store Sales	**4** ADP Employment (Dec) Vehicle Sales (Dec) Factory Orders (Dec) Mortgage Applications EIA Crude Oil Stocks	**5** ISM Non-Manufacturing (Jan) ICSC Chain Store Sales (Dec) Weekly Jobless Claims Weekly Money Supply	**6** Employment Report (Dec)

BLUE CHIP FORECASTERS

CONTRIBUTORS TO DOMESTIC SURVEY

Action Economics, LLC, Boulder, CO
Michael Englund

Bank of America Merrill Lynch, New York, NY
Ethan Harris

Bank of Tokyo-Mitsubishi UFJ, Ltd., New York, NY
Christopher S. Rupkey

Barclays Capital, New York, NY
Dean Maki

BMO Capital Markets Economics, Toronto, Canada
Sherry Cooper and Douglas Porter

Chmura Economics & Analytics, Richmond, VA
Christine Chmura and Dr. Xiaobing Shuai

ClearView Economics, LLC, Cleveland, OH
Kenneth T. Mayland

Comerica, Dallas, TX
Robert A. Dye

Cycledata Corp., San Diego, CA
Robert S. Powers

Daiwa Capital Markets America, New York, NY
Michael Moran

Economist Intelligence Unit, New York, NY
Leo Abruzzese and Jan Friederich

DePrince & Associates, Murfreesburo, TN
Albert E. DePrince Jr.

Fannie Mae, Washington, DC
Douglas Duncan

Georgia State University, Atlanta, GA
Rajeev Dhawan and Emin Hajiyev

GLC Financial Economics, Providence, RI
Gary L. Ciminero

Goldman, Sachs & Co., New York, NY
Jan Hatzius

J.P. Morgan Chase, New York, NY
Bruce Kasman and Robert Mellman

JPMorgan Private Wealth Management, New York, NY
Anthony Chan

J.W. Coons Advisors, LLC, Columbus, OH
James W. Coons

Kellner Economic Advisers, Port Washington, NY
Irwin L. Kellner

Loomis, Sayles & Company, L.P., Bloomfield, MI
Brian Horrigan and David Sowerby

MacroFin Analytics, Wayne, NJ
Parul Jain

Mesirow Financial, Chicago, IL
Diane Swonk

Moody's Capital Markets Group, New York, NY
John Lonski

Moody's Analytics, West Chester, PA
Mark M. Zandi

Naroff Economic Advisors, Philadelphia, PA
Joel L. Naroff

National Association of Realtors, Washington, DC
S. Lawrence Yun

Nomura Securities International, Inc., New York, NY
David H. Resler

Oxford Economics, Wayne, PA
Lea Tyler

Pierpont Securities, Stamford, CT
Stephen Stanley

PNC Financial Services Group, Pittsburgh, PA
Stuart G. Hoffman

RBS, Greenwich, CT
Michelle Girard

RDQ Economics, New York, NY
John Ryding and Conrad DeQuadros

RidgeWorth Capital Management, Richmond, VA
Alan Gayle

Russell Investments, Seattle, WA
Michael Dueker

Scotiabank Group, Toronto, Canada
Aron Gampel and Dr. Warren Jestin

Societe Generale, NY, New York
Stephen W. Gallagher

Standard & Poor's Corp., New York, NY
Beth Ann Bovino

Stone Harbor Investment Partners, LP, New York, NY
Brian Keyser

SunTrust Banks, Inc., Atlanta, GA
Gregory L. Miller

Swiss Re, New York, NY
Kurt Karl

The Northern Trust Company, Chicago, IL
Paul L. Kasriel and Asha G. Bangalore

Thredgold Economic Associates, Salt Lake City, UT
Jeff K. Thredgold

UBS, New York, NY
Maury Harris, Samuel Coffin and Kevin Cummins

Wintrust Wealth Management., Chicago, IL
William B. Hummer

Wells Capital Management, San Francisco, CA
Gary Schlossberg

Wells Fargo, Charlotte, NC
John Silvia and Mark Vitner

Woodworth Holdings, Ltd., Summit, NJ
Jay N. Woodworth

CONTRIBUTORS TO INTERNATIONAL SURVEY

Barclays Capital, New York, NY

ING Financial Markets, London, England

Mizuho Research Institute, Tokyo, Japan

Moody's Analytics, West Chester, PA

Moody's Capital Markets Group, New York, NY

Nomura Securities International, New York, NY

Scotiabank Group, Toronto, Canada

Societe Generale, New York, NY

UBS, New York, NY

Wells Fargo, Charlotte, NC

EXHIBIT SKB-11

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENT RESPONSE TO STAFF'S FIFTEENTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291
October 29, 2012

STF 15.2

With reference to JJR-4, pages 2 through 8 provide an explanation and all underlying data for support of the data in Column [10] labeled "Long-Term Growth Est."

RESPONSE: **October 23, 2012**

Please see TEP Direct Workpapers 06.21.xlsx [located in TEP's electronic data room in TEP Testimony\Direct\Reed – Direct Testimony Workpapers\TEP Direct Workpapers 06.21 (Zip file)], specifically in tabs numbered 5, 5a and 5b, and 19,22,47_BCFF1211email.pdf, Bates Nos. TEP(0291)010302-010320 (located in TEP's electronic data room in TEP Testimony\Direct\Reed – Direct Testimony Workpapers\Citations), for the requested information.

RESPONDENT:

John J. Reed

WITNESS:

John J. Reed

SUPPLEMENTAL RESPONSE: **October 29, 2012**

Dr. Berry requested that TEP supplement this response to include the definition of the Bloomberg field. Please see below in response to his request:

The Long Term Growth rate shown in Column [10] of Exhibit JJR-4 is the Bloomberg data field "Best_Est_Long_term_Growth" which is defined by Bloomberg as follows:

> Long Term Growth Forecasts are received directly from contributing analysts, they are not calculated by BEst. While different analysts apply different methodologies, the Long Term Growth Forecast generally represents an expected annual increase in operating earnings per share over the Company's next full business cycle. In general, these forecasts refer to a period of between three to five years.

"BEst" is the acronym that Bloomberg uses to refer to their internally generated estimates.

RESPONDENT:

John J. Reed

WITNESS:

John J. Reed

Exhibit SKB-12

Yields on Long Term TIPS

Time Period	TIPS Yield (%)
2003	2.54
2004	2.21
2005	1.94
2006	2.27
2007	2.34
2008	2.20
2009	2.24
2010	1.72
2011	1.19

Average **2.07**

Source: Federal Reserve

BEFORE THE ARIZONA CORPORATION COMMISSION

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

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

PUBLIC

DIRECT

TESTIMONY

OF

MICHAEL J. MCGARRY, SR.

ON BEHALF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

DECEMBER 21, 2012

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EXECUTIVE SUMMARY
TUSCON ELECTRIC POWER COMPANY
DOCKET NO. E-01933A-12-0291

ENERGY EFFICIENCY RESOURCE PLAN ("EERP")

Tucson Electric Power Company ("TEP" or "Company") is proposing an alternative approach to Energy Efficiency Standard ("EES") compliance. This alternative approach includes a three-year pilot program that the Company maintains will allow them to invest in and deliver cost effective Energy Efficiency ("EE") programs to its customers. The Company would recover the cost of its EE investments, including a return on those costs, through TEP's existing Demand-Side Management ("DSM") Surcharge ("DSMS"). TEP is proposing that the EERP will include the same type of program-related costs that are currently being recovered through the DSMS including the costs of developing, implementing, and administering DSM/EE measures and programs along with a return on TEP's investments in DSM/EE.

TEP's 2011-2012 Energy Efficiency Implementation Plan is currently being litigated in Arizona Corporation Commission Docket No. E-01933A-11-0055. In that case, a resolution of the issues and Commission approval of the plan has not yet occurred as the issue of whether the Company will be able to achieve the efficiency goals for 2012 and 2013 as required by Arizona Administrative Code ("A.A.C.") R14-2-2404 is still outstanding.

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

The Company also argues that its proposal would reduce and stabilize the rate impacts to customers, better synchronize the benefits of EE with their associated costs, provide a base level of certainty to program offerings, and eliminate the need to provide a performance incentive.

The Company is requesting that the Commission approve a three-year forward-looking budget that totals $79,640,355, which includes $24,739,192, $27,044,908, and $27,856,255 for 2014 through 2016, respectively. This results in average annual incremental costs of $26.5 million to TEP's customers. Additionally, TEP is requesting that the Weighted Average Cost of Capital used be based on the debt and capital structure approved by the Commission in this proceeding. The Company is seeking an overall weighted cost of capital of 7.74%, which includes a cost of equity (ROE) of 10.75%. However, the Company is requesting that the ROE should be increased by 200 basis points or 12.75%.

Staff has a number of regulatory and policy concerns that lead them to the conclusion that the Commission should reject the Company's proposed EERP:

(1) The Commission should reject the forward-looking concept proposed by TEP.
(2) The 200-basis-point increase to the ROE is excessive, unnecessary, and should be rejected.
(3) Since cost recovery would be virtually secured, it is unclear that the proposed EERP would provide incentives to maximize the results of the program and, at the same time, provide cost-effective and efficient implementation of the programs.
(4) The Company's proposal would require that the Commission issue one or more waivers of the various requirement of A.A.C. R14-2, including:
    - A.A.C. R14-2-2405 – annual implementation plan
    - A.A.C. R14-2-2410 – monitoring plan
(5) While not specifically mentioned by the Company, the EERP is an apparent attempt by TEP to mitigate the effects of regulatory lag.

In place of the Company's plan, Staff recommends that the Commission adopt the concept of establishing a regulatory asset for approved EE implementation costs that TEP incurs to achieve the Commission's energy efficiency goal. The Commission should allow the Company to earn a return on that investment of no greater than what the Commission approves for the weighted cost of capital in this proceeding. The amortization period for this regulatory asset will be seven years on a rolling basis and will be trued up each year and adjustments made to the Company's DSMS to reflect any under or over recoveries. This seven-year period is based on a composite weighted average of the useful life of the various measures that are included in the Company's proposed EE Implementation Plan.

Over the short term, Staff believes that ratepayers will be burdened less under its recommended plan than under the Company's proposal. At the same time, the Company will have a suitable level of funding to implement cost-effective programs to meet the Commission's goals.

ENVIRONMENTAL COMPLIANCE ADJUSTOR ("ECA")

TEP is proposing the ECA to provide for the recovery of and return on capital investments and associated costs related to environmental investments made by TEP and not already recovered in base rates or recovered through another Commission-approved mechanism. The ECA will be calculated annually based on the ECA Qualified Investments closed to plant-in-service and ECA Qualified Investments included in Construction Work in Progress ("CWIP") during the preceding calendar year.

The Company believes the ECA is necessary to allow TEP to recover the significant costs required to meet environmental compliance standards imposed by federal or other governmental agencies. TEP states that the rules to meet compliance standards will require increased capital spending for the installation of additional equipment with corresponding increases in O&M costs associated with the installation and operation of such equipment or implementation of new

environmental protocols at TEP's facilities. The capital investments will reduce the plant capacity because of the increased station power need for the equipment.

Further, the Company believes that it will be likely that most of the compliance-associated expenditures will occur between rate cases. The inability to recover the significant environmental compliance costs as they are incurred, according to TEP, places the Company and its customers in an untenable position. With respect to TEP, these environmental mandates will result in reduced cash flow and increased capital and O&M expenditures without recovery of those costs through increased revenue because of the extended time between the adjudication of TEP rate cases. This will be detrimental to TEP's financial health and may adversely impact its access to capital on reasonable terms. TEP's customers will be negatively impacted by the extended timeframe between rate cases because the accumulated capital costs and increased O&M will result in larger rate increases. The Company believes it is preferable to recover these mandate costs over time and not as established in rate cases, leading to more moderate annual rate increases without causing the Company to suffer any financial harm.

Staff, however, disagrees that a need for a cost-tracker does, in fact, exist. Staff asserts that the Company offers no evidence that its cash flows are unable to sustain the needed capital requirements for the potential mandate compliance. Further, while given the opportunity to do so, the Company did not provide any evidence beyond a hypothetical explanation of financial consequences to the Company should they be required to make the investments for complying with the mandates before recovery of prudently incurred costs are allowed in base rates. Additionally, there is no evidence that the normal regulatory treatment (i.e., Allowance for Funds Used During Construction ("AFUDC") of large capital expenditures such as these would financially harm the Company. Contrary to the Company's claims, the ECA appears to be proposed only as a means to mitigate regulatory lag because the Company has offered no evidence to show that it would, in fact, be substantially harmed from the financial consequences of the needed capital outlays.

Staff recommends that the Commission reject the ECA as currently proposed by the Company as too broad and includes capital investments that are not as of yet mandated or whose compliance date is well outside the timeframe in which the Company is likely to request another base rate increase. Trackers are implicitly an interim measure to provide relief to a utility for costs which are mandated, significant, potentially volatile, and out of the utility's control. A tracker is not intended as a permanent fix to make up for the regulatory lag in the ratemaking process. The Company has not demonstrated a need that warrants the extraordinary action of their proposed ECA tracker.

Since the Company has several major projects that it must meet in the next 2-3 years and to be consistent with the treatment that APS received in Docket No. E-0139A-11-0221, Staff recommends that, if the Commission should decide to order some type of environmental tracker, that tracker should mirror the Environmental Improvement Surcharge ("EIS") granted to Arizona Public Service Company ("APS") in Decision No. 73183 (May 24, 2012). It should include a cap to mitigate ratepayer impacts. Finally, as part of any settlement discussions, the parties should acknowledge that the EIS is a contributing factor to the length of any proposed "stay-out," as was done in the recent APS Decision.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Michael J. McGarry, Sr. I am President and CEO of Blue Ridge Consulting Services, Inc. My business address is 2131 Woodruff Road, Suite 2100, PMB 309, Greenville, SC 29607.

BACKGROUND AND QUALIFICATIONS

Q. Please state your experience and educational background.

A. I have been President of Blue Ridge Consulting Services, Inc. since 2004. In my career, I have overseen or been part of numerous rate case audits, prudency reviews, and management and operational audits. I have worked with clients to manage various aspects of the regulatory and rate case process; prepared supporting analyses and testimony for submission to regulatory bodies and interveners; prepared revenue requirement and cost of service analyses; and developed complex revenue requirement models to present alternative positions to utilities' proposed rate requests. Prior to assuming my present position, I was Vice President of East Coast Operations from July 2003 to June 2004 with Hawks, Giffels & Pullin (HGP), Inc. In that position, I was responsible for developing and overseeing client engagements in utility regulatory affairs, management audits, and rate case management. From August 2001 to July 2003, I was an independent consultant working on a number of different projects, including a renewal/update of delivery service tariffs for Illinois Power and several utility street lighting cost benefit assessment projects. From June 2000 until August 2001, I was a senior consultant with Denali Consulting, Inc., a utility supply chain and e-procurement strategy and implementation firm. From October 1997 through June 2000, I was employed by Navigant Consulting, Inc. and several of its predecessors or acquired firms, working on a number of different projects, including a management audit of Southern Connecticut Gas Company and the original delivery

service tariff filing for Illinois Power. From July 1985 through October 1997, I was employed by the New York State Department of Public Service ("NYSDPS") in its Utility Operational Audit Section in which the staff conducted focused operational audits in many facets of utility operations for all sectors of the utility industry, including gas, electric, telecommunications, and water. Prior to my employment with the NYSDPS, I was a rate analyst with Orange and Rockland Utilities (1981 to 1983) and then with Seminole Electric Cooperative (1983 to 1985). I received my Masters of Business Administration from the State University of New York at Buffalo in 1996 and a Bachelor of Arts in Economics from Potsdam College (SUNY) in 1981.

Q. Have you prepared an attachment summarizing your educational background and regulatory experience?

A. Yes. Attachment MJM-1 provides details concerning my experience and qualifications.

Q. Have you previously testified before the Arizona Corporation Commission?

A. Yes. I recently testified in Arizona Public Service Company's base rate filing in Docket No. E-01345A-11-0224, where I proffered testimony on APS's proposed infrastructure tracking mechanism, power supply adjustor, and tariffs.

Q. Have you testified before commissions in other jurisdictions?

A. Yes. I have testified in Delaware, Illinois, Maine, Maryland, Michigan, Missouri, New York, North Dakota, Nova Scotia, Ohio, and Utah. These proceedings included testimony involving revenue requirements, power supply costs, management decisions and prudence impacts, operations and maintenance expenses, capital investments, and project management. A complete list is included in Attachment MJM-1.

I have also presented topics before staff groups from regulatory commissions, NARUC sub-committee groups, and as a program faculty member for the Institute of Public Utilities at Michigan State University. Topics presented include management auditing and prudence reviews, service company costs and allocations, forecasting methodology and modeling, revenue requirements, rate base, and price regulation theory.

PURPOSE OF TESTIMONY

Q. On whose behalf are you testifying?

A. I am appearing on behalf of the Arizona Corporation Commission ("Commission") Utilities Division Staff ("Staff").

Q. What is the purpose of the testimony you are presenting?

A. I am presenting the Staff's position with respect to (1) Tucson Electric Power Company's ("TEP" or "Company") proposed Energy Efficiency Resource Plan ("EERP") and (2) Environmental Compliance Adjustor ("ECA").

Q. Was this testimony and the supporting analyses prepared by you or under your direct supervision?

A. Yes, it was.

Q Please briefly describe the information you reviewed in preparation for your testimony.

A. I have reviewed the Company's testimony and exhibits and data request responses provided by the Company to the various parties to this proceeding.

ENERGY EFFICIENCY RESOURCE PLAN ("EERP")

Q. Please describe the EERP proposed by the Company.

A. The Company is proposing what it describes as an alternative and "improved approach to Energy Efficiency Standard ("EES") compliance."[1] This "improved approach" includes a three-year pilot program that the Company maintains will allow them to invest in and deliver cost effective Energy Efficiency ("EE") programs to its customers. The Company would recover the cost of its EE investments, including a return on those costs, through TEP's existing Demand-Side Management ("DSM") Surcharge ("DSMS"). TEP is proposing that the EERP will include the same type of program-related costs that are currently being recovered through the DSMS including the costs of developing, implementing, and administering DSM/EE measures and programs along with a return on TEP's investments in DSM/EE.[2]

Q. Does the EERP include a performance incentive?

A. No. The Company has eliminated the performance incentive in this plan.

Q. **Is there any background information that would be useful to mention for the Commission?**

A. Yes. Arizona Corporation Commission Docket No. E-01933A-11-0055 is where TEP's 2011-2012 Energy Efficiency Implementation Plan is being litigated. The overall goal of that proceeding is for the parties to that proceeding to review and comment on TEP's proposed 2011-2012 EE implementation plan leading to Commission approval. On January 31, 2011, pursuant to A.A.C. R14-2-2405, TEP filed with the Commission its application for approval of the Company's Energy Efficiency Implementation Plan for 2011-2012 ("Implementation Plan"). On August 22, 2011, TEP filed updated information

[1] Hutchens Direct at 15: 4-5.
[2] Hutchens Direct at 15:19-22.

to its Implementation Plan. In the Implementation Plan, the Company proposed, for the 2011-2012 program years, DSM programs and measures with budgets totaling $18,182,475 in 2011 and $24,759,193 for 2012; a modification of the Performance Incentive structure (resulting in payments of $16.4 million for two years); a form of a lost fixed cost recovery mechanism entitled an "Authorized Revenue Requirement True-up" ("ARRT") mechanism which was intended to recover revenue requirement associated with energy efficiency kWh savings; and a DSMS of $0.006343 per kWh.[3] From that timeframe (i.e., January 2011 up to August, 2012), the parties have been litigating the Company's Implementation Plan. However, as of the drafting of this testimony, a resolution of the issues and Commission approval of the plan has not occurred.

Q. Why is not yet having resolution of the plan significant?

A. One of the outstanding issues that is in the Company's proposed plan is whether the Company will be able to achieve the efficiency goals for 2012 and 2013 as required by A.A.C. R14-2-2404. I further address the significance of this later in this testimony.

Q. What does TEP proffer as the benefits of the Company's proposed plan?

A. Company Witness David G. Hutchens states, "TEP's proposal provides an alternative solution for financing the cost of complying with the EE Rules that would reduce and stabilize the rate impacts to our customers, better synchronize the benefits of EE with their associated costs, provide a base level of certainty to program offerings and eliminate the need to provide a performance incentive."[4] The rate that customers would be charged would be based on a three-year planning horizon for TEP's EE programs. The Company is proposing that the DSMS rate would be set in advance and recover the cost of the TEP's investment plus a return, resulting in "moderate, predictable year-over-year increases to

[3] Recommended Opinion & Order at 2, Docket No. E-01933A-11-0055, August 21, 2012.
[4] Hutchens Direct at 16:21-22.

ease customers into the increasing costs of EES compliance."[5] Witness Hutchens argues, "The most efficient way to provide cost-effective EE is to treat it like any other resource in our IRP process."[6] As Witness Hutchens states, "Under TEP's proposal, the Company would determine the most cost-effective EE option appropriate for its particular system, invest its capital to procure that resource, and recover the associated costs – including the amortization expense and an appropriate return on investment – through the DSMS."[7] Witness Hutchens points out that the capital invested in such programs will be considered a regulatory asset and amortized over a four-year term.[8] Witness Hutchens adds that the Company believes that the proposed EERP is "a win-win proposition for all stakeholders."[9] He argues that customers benefit from "a predictable DSMS that allows them to plan for their energy expenses while gaining greater assurance that TEP's EE programs will be available over a multi-year timeframe."[10] Further, he adds that local contractors who manage the various programs will "enjoy greater certainty regarding program funding levels." "The Commission and its Staff would benefit from a reduction in the administrative burden associated with annual reviews of TEP's EE Implementation Plans."[11] Witness Hutchens concludes, "TEP will have more certainty about the energy savings to incorporate into its resource and system planning and will realize a reasonable return from its EE investments."[12]

Q. What are the EE plan costs that are being proposed for inclusion in the plan?

A. As mentioned above, the Company is requesting that the Commission approve a three-year ***forward-looking budget*** that totals $79,640,355, which includes $24,739,192,

[5] Hutchens Direct at 17:1-2.
[6] *Id.* at 17:5-6.
[7] *Id.* at 17: 6-9.
[8] *Id.* at 17:11-12.
[9] Hutchens Direct at 17:16.
[10] *Id.* at 17:16-19.
[11] *Id.* at 17:19-22.
[12] *Id.* at 17: 22-24.

$27,044,908, and $27,856,255 for 2014 through 2016, respectively.[13] This results in average annual incremental costs of $26.5 million to TEP's customers.

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

A. TEP is requesting the Weighted Average Cost of Capital used be based on the debt and capital structure approved by the Commission in this proceeding. The Company is seeking an overall weighted cost of capital of 7.74%, which includes a cost of equity (ROE) of 10.75%.[14] However, the Company is requesting that the ROE should be increased by 200 basis points or 12.75% to "reflect the nature of the investment."[15] To support this 200-basis-point increase, Witness Hutchens states:

> Unlike its investments in power plants, buildings, computers and other assets with independent market value, TEP's EE expenditures produce only intangible assets with no value outside of the Commission's rules. That is why the creation of a regulatory asset – the value of which is derived solely from the Commission's authorization – is required to allow TEP to recover and earn a return on its EE investment. The nature of this investment justifies this higher rate of return, since intangible assets do not necessarily provide TEP with the same financial benefits as tangible, saleable assets.[16]

Q. Has the Company provided an estimate of the revenue requirement associated with this forward-looking plan?

A. Yes. Included as Exhibit CAJ-7 to Company Witness Craig A. Jones's Direct Testimony is the Company's proposed Plan of Administration ("POA") for the EERP. Within that document is Attachment D, which shows the revenue requirement calculation for each year for 2014 through 2016 and includes the going-forward portion of recovery of the

[13] Jones Direct at 65, Table 1 – Costs included in DSMS with EE Resource Plan. Note: the 1st year covers the period August 1, 2013 through December 31, 2014 (a 17 month period) while 2015 and 2016 costs are for a calendar year basis.
[14] TEP Application at 6:12-15.
[15] Hutchens Direct at 17:27–18: 3.
[16] *Id.* at 18:3-10.

regulatory asset through 2019. I have summarized the incremental impact in Table 1 below.

Table 1
Total EE Program Expenditures, Revenue Requirement and Cumulative Impact
2014 - 2019

Line No.	Description	2014	2015	2016	2017	2018	2019	Source
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
1	Total EE Program Expenditures ($MM)	$ 24.74	$ 27.04	$ 27.86	$ -	$ -	$ -	
2	Gross Revenue Requirement for 2014 ($MM)	$ 7.97	$ 7.35	$ 6.89	$ 6.42	$ -	$ -	Exhibit CAJ-7 Attachment D
3	Gross Revenue Requirement for 2015 ($MM)	$ -	$ 8.72	$ 8.04	$ 7.53	$ 7.02	$ -	Exhibit CAJ-7 Attachment D
4	Gross Revenue Requirement for 2016 ($MM)	$ -	$ -	$ 8.98	$ 8.28	$ 7.75	$ 7.23	Exhibit CAJ-7 Attachment D
5	Cummulative Impact ($MM) (sum of line 2, 3 & 4)	$ 7.97	$ 16.07	$ 23.90	$ 22.23	$ 14.77	$ 7.23	

Q. Does the Company argue that its proposed plan reduce the cost on customer's bills?

A. Yes. Witness Hutchens argues concerning the EERP that, because the costs of the program are amortized over four years, the DMS surcharge would be lower than if each years' full program costs are recovered in the surcharge.[17] Table 2 shows what the Company claims would be the average customer bill impact under the current methodology and the proposed EERP.

Table 2[18]

	Average Residential Bill Impact	
Year	Current	Proposed
2014	$ 2.04	$ 0.81
2015	$ 2.69	$ 1.46
2016	$ 2.74	$ 2.16

[17] Hutchens at 18:13-17.
[18] *Id.* at 18:19-26.

Witness Hutchens provides a chart that shows that to recover the full cost of the first three years of the program, the bill impact to customers continues on from 2017 through 2019 at $1.99, $1.31, and $.064, respectively.[19]

Q. Does the Company provide any support for the 4-year amortization period?

A. The Company provides three reasons that it argues supports the four-year amortization: (1) four years is a balanced approach between needing timely recovery of the costs and customer desires to have moderate rate increases, (2) accounting rules provide criteria for deferring costs so long as those costs are deemed "probable" for recovery, and four years in the Company's opinion meets this accounting criteria, and (3) the Company believes a four-year recovery period is reasonable and appropriate in order to maintain a moderately sized regulatory asset over time. The Company argues that longer amortization periods will produce larger regulatory assets and by inference more costs to customers (presumably by interest costs).[20]

Q. What does the Company conclude regarding its proposed EE Resource Plan?

A. Witness Hutchens makes the following statement:

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

[19] Hutchens Direct at 19, chart.
[20] *Id.* at 20:12-27.

> By "putting our skin in the game" the Company is taking on additional risk by investing in a regulatory asset that derives value only as a result of an order of the Commission authorizing TEP to recover its costs from customers.[21]

Q. Do you agree that the EERP as proposed by the Company is in the best interest of the customer?

A. No.

Q. Please explain your concerns.

A. I have a number of regulatory and policy concerns that I believe the Commission should consider that lead me to the conclusion that the Commission should reject the Company's EERP as proposed.

(1) The Commission should reject the forward-looking concept proposed by TEP.

(2) The 200-basis-point increase to the ROE is excessive, unnecessary, and should be rejected.

(3) Since cost recovery would be virtually secured, it is unclear that the proposed EERP would provide incentives to maximize the results of the program and, at the same time, provide cost-effective and efficient implementation of the programs.

(4) The Company's proposal would require that the Commission issue one or more waivers of the various requirement of Arizona Administrative Code R14-2, including:

- A.A.C. R14-2-2405 – annual implementation plan
- A.A.C. R14-2-2410 – monitoring plan

(5) While not specifically mentioned by the Company, the EERP is an apparent attempt by TEP to mitigate the effects of regulatory lag.

[21] *Id.* at 22:14-25

Q. Please explain each of your concerns and how they lead you to the conclusion that the Commission should reject the Company's proposed EE plan.

A. With respect to the first concern (the Commission should reject the forward-looking concept proposed by TEP), the Company is asking the Commission to approve a three-year budget that would be trued up at the end of the three years and only to the extent that TEP would reconcile the balance in the regulatory asset to true-up for under-recovered costs, which would take place either in a subsequent rate filing or as part of a second EE resource plan filing.[22]

Q. **Why is this a problem?**

A. There are two problems of note. First, if a program proves to be ineffective or not cost beneficial and is terminated or scaled back, the Company will recover the full amount of the program costs that are included in the three-year budget until the true-up in the next rate case or EE resource plan filing. While this concept is no different from other types of expenses that the Company might experience between rate cases (i.e., various O&M accounts can be over or under during the rate effective period from the amounts at which rates were established), the difference here is that those costs will continue to be recovered, are being capitalized and accruing interest at a premium (i.e., the 200-basis-point adder to the ROE). As such, the Company will not only be collecting program costs that are possibly no longer benefiting ratepayers, but TEP will be earning interest on it as well. While the true-up **may** make the ratepayer whole, since no preset time will be established for the next rate case or EE filing, ratepayers absorb the burden for the excess costs. The Company acknowledged that it would earn a return during all periods regardless of whether it underperforms and/or does not meet the EE standards. In

[22] Jones Direct at 67:21 –68: 7.

response to a RUCO data request, the Company stated, "TEP agrees that if the EERP is approved as proposed, that TEP would earn a return on its EE investments."[23]

Second, pre-approving three years of program plans and costs would require that the Commission provide a waiver of certain sections of the Commission's regulations. Specifically, as required by A.A.C. R14-2-2410, sub-section a.1, the Commission must approve a DSM program or DSM measure **before** it is implemented. In response to a data request, the Company acknowledged, "If the Commission approves the Company's proposal as part of the rate case Order, the Commission would have effectively provided a waiver from the specific requirements set forth in A.C.C R14-2-2410, sub-section A.1."[24] Issuing of waivers to this Commission's directives is, in my opinion, not sound regulatory policy.

Q. What are your concerns with the Company's request for a 200-basis-point premium on the ROE that will be used to calculate the return for investors for the regulatory asset that will be used to recover the EE Plan costs?

A. I believe that the Company has provided weak and inconsistent support for it, and, as such, it should be rejected.

Q. Please explain.

A. The Company attempts to position this 200-basis-point premium as necessary because the "investment" in EE is riskier than its investment in more tangible assets such as power plants, buildings, computers, and other assets.[25] The Company states in response to a data request, "Unlike investments in utility plant, such as power plants, buildings, computers and other assets with an independent market value, TEP's EE expenditures produce intangible assets

[23] Exh. 2, RUCO 3.21.
[24] Exh. 3, STF 3.04.
[25] Hutchens Direct at 18: 2-10.

with no external value outside the creation of a regulatory asset by order of the Commission. A 200 basis point increase on these projects, therefore, reflects the increased risk associated with TEP's investment in these intangible assets."[26] In response to a data request, the Company cites a Nevada Decision in which that commission included in its rules a provision that utilities could include an additional 5% (500 basis points) on the authorized rate of return to the Company for conservation and demand management program costs included in a regulatory asset.[27] However, the Company did not provide a complete picture. In 2010, that provision of the Nevada Administrative Code was deleted.[28] In fact, the current language in the Nevada Administrative Code associated with what rate to apply reads, "*The electric utility shall apply a carrying charge at the rate of 1/12 of the authorized overall rate of return to the unamortized balance in the subaccounts of FERC Account No. 182.3.*"[29] It is interesting that the Company is using as support an administrative code that was removed more than two years ago. Further, the Company's other support for the premium is as lukewarm to the concept as the Nevada Commission apparently was. The Company, in response to a data request, provided a March 2012 Regulatory Assistance Project ("RAP") report titled, "Regulatory Mechanisms to Enable Energy Provider Delivered Energy Efficiency," in which it does mention rate of return premiums as a means to promote energy efficiency and address the possible financial management problems associated with the regulatory asset.[30] While the report acknowledges the Nevada code, it states that this provision was eliminated when the Nevada Commission introduced a net lost revenue adjustment. The report goes on to say, "Few other jurisdictions have offered this type of incentive mechanism."[31] Finally, it is also interesting that the RAP report also makes the

[26] Exh. 4, STF 3.02.
[27] Exh. 5, RUCO 4.01.
[28] Exh. 6, *ADOPTED REGULATION OF THE PUBLIC UTILITIES COMMISSION OF NEVADA*, LCB File No. R042-10, July 22, 2010.
[29] Exh. 7, Nevada Administrative Code § 704.9523 (4)(b).
[30] Exh. 4, Attachment at 38, STF 3.02 RAP Report.
[31] Exh. 4 Attachment at 39, STF 3.02 RAP Report.

following statement: "To ensure that the financial return rewards productive expenditures, regulators should require energy providers to demonstrate that the resulting programs have achieved performance targets."[32] So, the very document that the Company is relying on for support of its 200-basis-point premium calls this mechanism a "reward" and something that could be used to "promote" energy efficiency, yet, conversely, the Company states that its EERP does not include a performance incentive. Also, and at the same time, the Company is seeking approval of a lost fixed cost recovery mechanism which is that with which the Nevada Commission replaced the 5% bonus in its jurisdiction. The Company's support here is very weak. Therefore, the Commission should reject the concept of a premium on the return associated with the regulatory asset for energy efficiency.

Q. What are your concerns with the Company's incentive to implement its energy efficiency plan in a cost efficient and effective manner?

A. As mentioned earlier, I believe that since cost recovery would be virtually secured under the Company proposed plan, it is unclear that the proposed EERP would provide incentives to maximize the results of the program and at the same time provide cost-effective and efficient implementation of the programs. Since the EERP would in essence pre-approve the EE program cost budgets, a certain amount of "good-faith" would have to be assumed that the Company would implement the programs in a cost-effective and efficient manner. One concern would be whether the Company would have incentive to look for ways to improve program implementation and thereby reduce those costs.

[32] Exh. 4, Attachment at 38, STF 3.02 RAP Report.

Q. **What are your concerns with respect to the implementation of the EERP requiring waivers from the Commission?**

A. As a general rule, I believe that waivers from requirements of commission rules should be held to a high standard of review for the necessity of that waiver. I do believe that TEP's proposed EERP rises to that standard. The Commission's rules require a pre-approval of energy efficiency programs for up to two years subject to whether the Commission finds that the proposed plan meets the energy efficiency goals.[33] These rules were carefully crafted to balance the needs of the stakeholders in the process, and any deviation should not be taken lightly. In this case, TEP is proposing at least two waivers. The first is to A.C.C R14-2-2405 which states, "*Except as provided in R14-2-2418, on June 1 of each odd year, or annually at the election of each affected utility, each affected utility shall file with Docket Control, for Commission review and approval, an implementation plan describing how the affected utility intends to meet the energy efficiency standard for the next one or two calendar years, as applicable, except that the initial implementation plan shall be filed within 30 days of the effective date of this Article.*" In response to a data request which asked whether the Company's proposed implementation plan was in compliance with section 2405, the Company responded:

> The purpose of the EERP is to create an alternative mechanism that will fulfill the spirit and objectives of the Electric Energy Efficiency Standard set forth in A.A.C. R14-2-2404. If the Commission approves the Company's proposal as part of the rate case Order, the Commission will have effectively provided a waiver from the specific requirements set forth in A.A.C. R14-2-2405[34]

[33] A.A.C. R14-2-2407.
[34] Exh. 8, STF 3.01.

As such, the Company would only file updates to the existing plan, not a full request for approval of a new plan which identifies how the Company intends to meet the energy efficiency standards as specified in A.C.C. R14-2-2403. In addition, the Company was unclear whether addressing DSM programs or measures which are found not to be cost-effective that need to be modified or terminated in the annual implementation plan filing would be compliant with R14-2-2410 (c). In Exhibit 3 the Company stated:

> Because the program or measure was determined to be cost effective during the planning and implementation stage, all allowable costs incurred for the program up to the actual date of termination will be collected under the DSM surcharge. This satisfies the requirement under A.A.C. R14-2-2410 (c).

This response does not indicate how the DSMS would be adjusted during the three-year plan period.

Q. What do you conclude with respect to these waivers and open issues related to complying with the Commission's rules and regulations and being in the interest of ratepayers?

A. For all the reasons mentioned above, I recommend that the Commission reject the Company's EE Implementation Plan for not being compliant with the Commission's Energy Efficiency rules and regulations and for not being in the public interest.

Q. You mentioned that you believe that the EERP is an attempt to mitigate regulatory lag. Is that correct?

A. Yes.

Q. What leads you to this opinion?

A. The Company does not overtly state that the proposed rate mechanism and upfront collection of costs is being proposed to mitigate regulatory lag. However, these cost recovery mechanisms are intended to provide additional cash flows for costs that the utility is attempting to recover *before* they are reviewed by the Commission in a formal rate case setting. The mechanism is designed to ensure recovery between rate cases, and that would, from the utility's perspective, mitigate regulatory lag.

Q. Are you recommending an alternative plan?

A. Yes. However, there are components of the Company's plan that I believe are salvageable.

Q. **Please continue.**

A. There are two parts to my recommendation. First, I am recommending that the existing DSMS be eliminated once all unrecovered costs, including any *actual* incentive earned, are accounted for and recovered over a one-year period beginning with the effective date of the Commission approved rates in this proceeding. Second, I am recommending that the Commission adopt the concept of establishing a regulatory asset for approved EE implementation costs that TEP incurs to achieve the Commission's energy efficiency goal. I am also recommending that the Commission allow the Company to earn a return on that investment of no greater than what the Commission approves for the weighted cost of capital in this proceeding. The amortization period for this regulatory asset will be seven years on a rolling basis and will be trued up each year and adjustments made to the Company's DSMS to reflect any under or over recoveries. This seven-year period is based in part on a composite weighted average of the useful life of the various measures

that are included in the Company's proposed EE Implementation Plan and on balancing the interests of stakeholders.

Q. The Company claims that four years is a reasonable period to amortize the regulatory asset. How do you respond?

A. The Company points to U.S. Generally Accepted Accounting Principles ("GAAP") and its own judgment in determining what the amortization period should be and arrives at the conclusion that four years is appropriate. The Company offers no substantive proof that a long amortization period is either riskier or is detrimental to ratepayers. In fact, in response to a staff data request, the Company stated, "Accounting standards do not prohibit the Commission from setting longer (or shorter) amortization periods."[35] I believe that a seven-year period is reasonable and balances the need to recover the principle of the regulatory asset while the EE measures are achieving the savings claimed by the Company and providing the benefits to ratepayers with the need to mitigate rate impacts to customers.

Q. Would your plan include projected costs as proposed by TEP?

A. No. I recommend that the Commission allow only those costs that have been actually incurred and verified to their effectiveness per the Commission's verification regulations as specified in R14-2-2415; Monitoring, Evaluation, and Research.

Q. Please explain the first part of your proposal?

A. At the present, the Company's EE programs are subject to the terms and conditions established in its last base rate case settlement in 2008 as approved in Commission Decision 70628. The Company currently is collecting $0.001294 per kWh for all its

[35] Exh. 9, STF.3.06.

customers except those customers who take service under the Residential Lifeline Discount or Residential Lifeline/Medical Life-Support Discount pricing plans.[36] These revenues are being used to pay for the Company's current EE efforts. The EE plan currently in effect includes costs and a performance incentive that TEP is entitled to collect, assuming the costs are reasonable and prudent. The first part of my proposed plan would allow the Company to recover any unrecovered costs that the current DSMS surcharge does not cover. The Company would be permitted to include the actual unrecovered costs and the actual performance incentive that it earned up through the effective date of the Commission approved rates in this case. This would require a full accounting to be provided as part of the Company's compliance filing with the Commission's order in this case. The existing DSMS surcharge tariff would then be used to collect these funds based on the approved sales forecast in this case for the twelve months of the rate effective period, which is anticipated to be July 1, 2013, to June 30, 2014. While this surcharge is in effect, and assuming a decision in Docket E-01345A-11-0055, the Company would also be incurring its EE Plan costs for the remainder of 2013. On April 1, 2014, the Company would file its proposed EE Plan for 2014 *plus* an accounting of the actual EE program costs for those *actual* costs incurred after July 1, 2013, through the end of the year, December 31, 2013. The Commission's rules allow for the parties to review and comment in a proceeding before the Commission with the Commission making a decision to approve or modify within 180 days of the filing. I would recommend that, to the extent possible, the review process be expedited or even a new rule issued that shortens that period to 120 days, such that the new rate would be effective on or about July 1 of each year. This would be possible in that the prospective part of the plan would be for informational purposes only and that only approved programs would be subject to the accounting for actual costs.

[36] TEP Tariff Rider R-2 - Demand Side Management Surcharge (DSMS) Effective June 1, 2010.

Q. Does this mean that during the first year after approval of your plan that the Company will not have a surcharge in place since the costs have yet to be incurred?

A. No. As I previously mentioned, during the first year of the plan, the Company would be allowed to recover the unrecovered balance of costs from the current DSMS as of the effective date of the rates approved by the Commission in this proceeding. However, my proposal does envision that the Company will incur the program costs **BEFORE** TEP is allowed to recover them in the surcharge. I acknowledge that because of the review and approval process as required by the Commission's rules and regulations, there could be ten months between the time the last of the costs are incurred and when recovery is allowed to begin. However, to recognize this lag, I am not opposing the carrying cost rate at the Company's approved weighted cost of capital and would recommend that the Commission allow the Company to accrue the carrying cost from the date the costs are incurred starting with the effective date of the Commission order in this case. In addition, I am recommending that the Commission expedite, to the extent possible, the review and approval schedule with the filings from 180 days to 120 days, as allowed by Commission rules.

Q. Should the Commission accept your recommendation, how would the Company comply with your proposed plan?

A. The Company would be required, as part of its compliance filing for this case, to provide a schedule which shows the unrecovered costs balance as of the anticipated rate effective date including the actual performance incentive earned. Included as Exhibit 15 is an illustrative example of the derivation of the Company DSMS rate for the period July 2013 through June 2014. I have estimated the unrecovered balance at approximately $22.5 million, which is the $4.5 million of unrecovered costs included in Company Witness

Jones's testimony plus $18 million of estimated unrecovered costs[37] for the period since the last rate for DSMS was approved in 2010. This estimate would have to be updated. With this assumption and with applying Staff's recommended cost of capital, I estimate that the DSMS will be $.00XXX per kWh from July 1, 2013, until June 30, 2014.

Q. **Would the current Rider R-2 Demand Side Management Surcharge ("DSMS") stay in place during this period?**

A. Yes. However, it would have to be modified to accommodate the 2nd part of my recommendation.

Q. **Please explain the second part of your recommendation.**

A. According to the requirements of R14-2-2409, on April 1, 2014, the Company will file its annual implementation plan and include the actual expenditures that it incurred from when it begins implementation of the EE Plan as will be ordered in Docket No. E-0139A-11-0055. At present, Staff is recommending in that proceeding that the program costs needed to meet the Commission energy efficiency standards for 2012 and 2013 is $23 million. I defer to Staff Witness Julie McNeely-Kirwan on the specific recommendations concerning the programs that TEP was proposing for 2012 and 2013. In that filing on April 1, 2014, the Company would provide all the requirements of R14-2-2409 showing the **ACTUAL** expenditures and results for July 1 to December 31, 2013.

Modeling the schedules that Company Witness Craig Jones sponsored in Attachment D in the Company's proposed plan of administration, I have prepared Exhibit 15 Staff Derivation of Alternative Plan Revenue Requirement for EERP. My intention is to show this as an illustrative example of what the potential revenue requirement impact will be

[37] Unrecovered costs would be the sum of actual EE Plan expenses plus the actual incentive less the revenues collected from the existing DSMS rate.

along with a comparative analysis to the proposed DSM surcharge rates that are included in the Company filing. I have modified the methodology slightly to simplify the calculation and have eliminated the long-debt component. As mentioned above, I am recommending a regulatory asset similar to that proposed by the Company and I am recommending that asset to accrue interest at the Company's allowed overall rate of return. My analysis reflects the 7.0% overall return proposed by Staff Witness Dr. Berry.

Q. **What were the results of your analysis?**

A. Based on the information contained in Exhibit 15, Table 3 below shows the comparative results for the rate per kWh to customers for my recommended implementation plan versus the Company's plan.

Table 3 – EERP DSMS Rates Comparative Results

Year	Per Company	Per Staff	Difference	Percent
2014	$ 0.000916	$ 0.000565	$ (0.000351)	-38.32%
2015	$ 0.001664	$ 0.000868	$ (0.000796)	-47.84%
2016	$ 0.002454	$ 0.001468	$ (0.000986)	-40.18%
2017	$ 0.002265	$ 0.002044	$ (0.000221)	-9.76%
2018	$ 0.001492	$ 0.001912	$ 0.000420	28.15%
2019	$ 0.000723	$ 0.001589	$ 0.000866	119.78%

Q. What do you conclude from this analysis?

A. Over the short term, ratepayers will be burdened less that under the Company's proposal and, at the same time, the Company will have a suitable level of funding to implement cost-effective programs to meet the Commission's goals.

Q. Does this conclude your testimony on the EERP?

A. Yes, it does.

ENVIRONMENTAL COMPLIANCE ADJUSTOR ("ECA")

Q. Please describe the ECA proposed by the Company.

A. The Company is proposing the ECA to provide for the recovery of and return on capital investments and associated costs related to environmental investments made by TEP and not already recovered in base rates or recovered through another Commission-approved mechanism. The ECA will be calculated annually based on the ECA Qualified Investments closed to plant-in-service and ECA Qualified Investments included in Construction Work in Progress ("CWIP") during the preceding calendar year.

Q. Why does the Company believe that an ECA is necessary?

A. Company Witness Hutchens states that the ECA is necessary for the following reason:

> It will allow TEP to recover the significant costs required to meet environmental compliance standards imposed by federal or other governmental agencies. The availability of an adjustor to recover theses costs ***as they are incurred*** would moderate the impact on our customers, avoiding the large rate increases that would result from deferring these costs to a future rate filing.[38]

Further, Witness Hutchens offers why TEP is proposing it in this rate case by stating:

> TEP is proposing the implementation of the ECA in this rate case in response to an ever increasing number of rules creating more stringent environmental standards that require the Company to invest an unprecedented amount of capital in its generation resource portfolio over the next five years. The EPA and other federal agencies (e.g. Office of Surface Mining) recently have mandated through various rulemakings that certain electric utility generating facilities install, upgrade, and revise environmental control measures and practices. These rules include, but are not limited to, EPA final rules and proposed rules that will likely become final in the foreseeable future.39

[38] Hutchens Direct at 23:11-15.
[39] *Id.* at 23: 21 –24:2.

Q. What proposed rules does the Company believe will be enacted that will impact the capital requirements for compliance?

A. Witness Hutchens provides two categories: Final Rules and Proposed Rules. The final rules[40] include the following:

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

The proposed rules[41] include these elements:

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

Witness Hutchens states that these rules "will require increased capital spending for the installation of additional equipment with corresponding increases in O&M costs associated with the installation and operation of such equipment or implementation of new environmental protocols at TEP's facilities."[42] He provides an approximate breakdown of the possible investments:

- $200 million capital & $3-6 million in O&M for San Juan Generating Station for BART
- $86 million capital & $2-4 million in O&M for Navajo Generating Station for Bart and MATS
- $36 million capital and $2-4 million in O&M for Four Corners Power Plan for BART and MATS

[40] Hutchens Direct at 24: 4-7.
[41] *Id.* at 24:10-15.
[42] *Id.* at 24:17-20.

- $5 million capital and $3 million in O&M for Springerville Generating for MATS[43]

Witness Hutchens states that these capital investments will reduce the plant capacity because of the increased station power need for the equipment. He opines that the total capital outlay could reach $400 million and that TEP "will not be able to phase-in or control the timing of these costs, as the compliance deadlines are mandated exclusively by the EPA and judicial rulings."[44]

Q. What impact does the Company say complying with mandates will have on its customers?

A. Witness Hutchens opines:

> It is likely that most of the expenditures discussed above will occur between rate cases. The inability to recover the significant environmental compliance costs as they are incurred, places TEP and its customers in an untenable position. With respect to TEP, these environmental mandates will result in reduced cash flow and increased capital and O&M expenditures without recovery of those costs through increased revenue because of the extended time between the adjudication of TEP rate cases. This will be detrimental to TEP's financial health and may adversely impact its access to capital on reasonable terms. TEP's customers will be negatively impacted by the extended timeframe between rate cases because the accumulated capital costs and increased O&M will result in larger rate increases.[45]

Witness Hutchens maintains that the Company believes it is "preferable" to recover these mandate costs over time and not as established in rate cases. He argues that this will lead to more moderate annual rate increases and not cause the Company to suffer any financial harm.[46] He concludes that ECA treatment will enable the Company to "meet governmental mandates, especially environmental requirements given their significant impact on TEP and its generation resource portfolio."[47]

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[43] *Id.* at 24: 21 –25:25.
[44] *Id.* at 25:11-15.
[45] *Id.* at 25:19 –26: 2.
[46] *Id.* at 26: 4-7.
[47] *Id.* at 26:13-15.

Q. Do you agree that TEP *needs* a cost-tracker mechanism such as the proposed ECA at this time?

A. No. I do not agree that the Company *needs* a cost-tracker such as the one proposed. The Company offers no evidence that its cash flows are unable to sustain the needed capital requirements for the potential mandate compliance. Further, despite being given the opportunity to do so, the Company did not provide any evidence beyond a hypothetical explanation of financial consequences to the Company should they be required to make the investments for complying with the mandates before recovery of prudently incurred costs are allowed in base rates. In a response to a Staff data request, the Company was asked to fully explain Witness Hutchens's statement in his direct testimony: "*This will be detrimental to TEP's financial health and may adversely impact its access to capital on reasonable terms.*" The Company responded:

> TEP would be investing hundreds of millions of dollars over the course of several years but would be precluded from any recovery of that investment until years later. Investing the equivalent of approximately 30 percent of TEP's rate base for several years without receiving any return on that investment would put pressure on the Company's ability to maintain its current credit ratings.
>
> If TEP's credit ratings were to be lowered due to weakening cash flows resulting from the Company's inability to earn a return on and of the significant amount invested between rate cases, TEP's cost of debt would increase, thus increasing costs to ratepayers. Weakening financial metrics would likely put downward pressure on UNS's stock price, which would also increase the cost of equity financing available to TEP.[48]

However, despite the theoretical claim to the contrary, there is no evidence that the normal regulatory treatment (i.e., AFUDC) of large capital expenditures such as these would financially harm the Company. Contrary to the Company's claims, it is my opinion that the ECA is a mitigation to regulatory lag because the Company has offered no evidence to show that it would, in fact, be substantially harmed from the financial consequences of the

[48] Exh. 10, STF 3.13.

needed capital outlays despite being given the opportunity to do so in Staff 3.13.

Q. The Company claims that its ECA is "similar" to the EIS mechanism recently approved in the Arizona Public Service Company ("APS") base rate proceeding, but TEP tailored it to meet its needs and that of its customers. Do you agree?

A. The Company certainly tailored its proposed ECA. However, I disagree that TEP's ECA is tailored according to the APS EIS. Rather, in my opinion, the ECA is more reflective of what APS originally proposed as its "Environmental and Reliability Account" ("ERA") in Docket No. E-01933A-11-0224.

Q. Please explain.

A. As I testified in the APS case, APS's ERA was designed to recover "both the return ***on*** the capital investment as well as the return ***of*** the investment through depreciation expense. In addition, APS proposed to include the revenue requirement components for the qualified investments, including income and property taxes, deferred taxes, tax credits where appropriate, and operations and maintenance expenses ("O&M")."[49] In the approved settlement in that case, the Company withdrew its ERA proposal and the existing EIS was modified in settlement to include capital carrying costs associated with government-mandated environmental controls, subject to a cap.[50] TEP's proposed ECA does not include a cap and more importantly includes most, if not all, of the categories' cost that APS originally requested in its ERA. Therefore, TEP's proposed ECA is not similar to the approved APS EIS.

[49] Exh. 11 at 6:3-7, McGarry Direct, Docket No. E-01345A-11-0224.
[50] Exh. 14, Decision No. 73183 at 15: 15-19, Docket No. E-01345A-11-0224.

Q. What types of mandates and investments is TEP proposing to include in the ECA?

A. In a data request, TEP provided a list of the projects and the dates that the expected mandates became or would become final and when the Company would be expected to comply. In addition, the Company provided its capital budget for these projects for the period 2013-2019. In response to STF 18.2 (a confidential response),[51] the Company provided a list of dates for both the final rules and proposed rules. [redacted]

[redacted]

From this information, some relief may be warranted for those projects that are expected to be in-service in the next 2-3 years.

[51] Exh. 12, STF 18.3 (CONFIDENTIAL).
[52] [redacted]

Q. If adopted as proposed, how will the ECA work?

A. TEP Witness Craig A. Jones sponsored the Plan of Administration ("POA") which describes how the ECA will be implemented and monitored. Each March 1, the POA indicates that TEP will file with the Commission its proposed ECA rate for the previous year and include supporting data and schedules. The Commission Staff and interested parties would then have an opportunity to review the ECA filing and supporting data. The ECA would become effective May 1 unless the Commission acted to suspend the filing by May 1. Once approved, the ECA would be in effect for a twelve-month period.[53]

Q. How would TEP propose to define "Qualified Environmental Compliance Projects"?

A. In a data request, TEP provided a list of the projects and the dates that the expected TEP would define a qualified investment for purposes of inclusion in the ECA as follows:

> Those projects designed to comply with current or prospective environmental standards required by federal, state, tribal, or local laws and regulations. In general, these environmental standards apply, but are not limited to the following: sulfur dioxide, nitrogen oxide, carbon dioxide, ozone, particulate matter, volatile organic compounds, mercury and other toxics, coal ash and other combustion residuals and water intake.[54]

TEP would include the follow specific accounts when determining the costs that would flow through the ECA:

> Steam Production: FERC Accounts 310 to 316
> Other Production: FERC Accounts 340 to 346
> Completed Construction not Classified: FERC Account 106
> Construction Work In Progress – Electric: FERC Account 107

[53] Jones Direct, Exh. CAJ-6 – Plan of Administration – Environmental Compliance Adjustor.
[54] *Id.*, Exhibit CAJ-6, Environmental Compliance Adjustor ("ECA") Plan of Administration, 2. Definitions Page 1

Q. Does the Company propose to recover just capital costs and the carrying costs associated with those investments?

A. No. The POA includes a full revenue requirements calculation for all the costs for these projects including CWIP. It includes depreciation expense, income taxes, property taxes, deferred taxes and tax credits, and O&M expense.[55]

Q. In your opinion, is the ECA intended as a form of interim rate relief between rate cases?

A. Yes. This rate mechanism is intended to provide additional revenues to the Company that it would otherwise not be entitled to outside the normal litigated rate case process.

Q. Are there circumstances in which the Commission should consider allowing a utility to recover significant capital costs outside the normal regulatory process (i.e., base rate cases)?

A. Yes.

Q. What issues should the Commission consider when deciding whether to approve a cost tracker such as the ERA?

A. As I have previously testified to before the Commission, to allow a cost tracker which provides a utility the opportunity to collect additional revenues outside the normal rate case process should be based on individual utility circumstances and not on a one-plan fits all method. Any utility would want a cost tracker as it avoids and mitigates the impact that the regulatory process, often referred to as regulatory lag, has on a utility's ability to earn its allowed rate of return. A tracker has the ability to provide additional funds for operation, which may reduce the need for short-term debt, thus saving ratepayers interest

[55] *Id.*, CAJ-6, Environmental Compliance Adjustor ("ECA") Plan of Administration, 2. Definitions Page 2

costs. However, these reasons alone are not sufficient to circumvent the regulatory process. There are significant downsides to cost trackers.

Q. What are the downsides of a cost tracker such as the ERA?

A. The disadvantages related to cost tracker overuse include the following:

- Weakening the incentive of a utility to control costs
- Undercutting the positive effects of regulatory lag
- Biasing a utility's technological and investment decisions
- Motivating utilities to shift more costs to functions subject to trackers, diluting frequency and quality of cost reviews
- Having the tendency to be more complicated and burdensome to both the Commission staff and to consumers
- Producing a negative perception by consumers due to more frequent press reports of "rate increase"

Q. Under what circumstances might the Commission approve a tracker such as the ECA?

A. The primary circumstance in which the Commission should consider approving a tracker such as the ECA would be when the utility is mandated to make significant capital expenditures to meet mandates of others on the utility. As such, federal, state, local, tribal, and other mandates involving significant or extraordinary capital investment to meet environmental statutes, rules, and/or regulations that could significantly harm the utility's financial well-being would be one reason for a tracker. However, the Commission should also consider the ability of the utility to fund the investment either by its own internal cash or financing before asking ratepayers to incur the additional hardship a tracker would place on them. Another important variable would be whether the costs are expected to be volatile, unpredictable, and outside the utility's control and thereby potentially causing significant financial harm to the utility and ultimately its ratepayers. The Commission's Power Supply Adjustor ("PSA") fits into this category. The costs are significant and can

be volatile, and price spikes from unforeseen events (such as a major hurricane in the Gulf of Mexico) can have a significant impact on the financial health of a utility while also negatively impacting its ratepayers.

Q. Do you recommend that the Commission approve the ECA proposed by TEP?

A. No. The Commission should reject the ECA as currently proposed by the Company.

Q. Why?

A. The ECA as presented by TEP is too broad and includes capital investments that are not as of yet mandated or whose compliance date is well outside the timeframe in which I believe the Company will request another base rate increase. It also includes other types of costs that are not capital in nature, such as CWIP, O&M and property taxes. Trackers are implicitly an interim measure to provide relief to a utility for costs which are mandated, significant, potentially volatile, and out of the utility's control. A tracker is not intended as a permanent fix to make up for the regulatory lag in the ratemaking process.

Q. Are you aware of any extraordinary events in which the Commission dealt with the possible effects of a federal mandate that could have had considerable negative impact on a group of utilities?

A. Yes. As I testified to in the APS case, such an example is the circumstances surrounding the arsenic water remediation cases in Arizona.[56] It is my understanding that both Staff and ultimately the Commission were concerned that if the water utilities in Arizona were not provided interim rate relief in the form of a tracker, the financial consequences could have been staggering, even to the point of one or more of the utilities filing for bankruptcy. Even worse was the possibility that if a water utility was unable to comply

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Exh. 13, Decision No. 66400, Docket No. W-01445A-00-0962 (October 14, 2003).

with the EPA mandates, the EPA could have shut down the utility forcing its customers to find other sources of water. A tracker was implemented for water utilities to meet the federal mandates associated with water utilities' ability to install the capital equipment necessary to meet the new and more stringent requirements related to arsenic in Arizona welis which were based on specific circumstances and conditions.[57]

Q. What were those conditions?

A. The conditions under which the Commission approved the tracker included the following:

- The tracker was temporary and had a two-step filing process.[58]
- The tracker was focused on only those projects related to arsenic remediation.[59]
- The tracker included limited amounts of O&M with a deferral mechanism set up to recover costs at a later date.[60]
- The Company would set a specific date for the next rate filing.[61]
- The EPA mandates had severe and significant consequences.[62]

Q. Are the proposed ECA and the Arsenic water mandates similar?

A. No. Both are intended to provide the utilities interim relief between rate cases for capital expenditures that are legally mandated. However, TEP's proposed ECA differs significantly in that it may include costs for projects that are not yet mandated (only anticipated) and includes non-capital costs not typically included, such as depreciation, taxes, and O&M. Notably, TEP's tracker would appear to be a permanent tracker updated annually, which is unlike the arsenic water cases which were temporary and included specific timeframes for rate filings. Finally, the ECA does not afford customers any

[57] *Id.*
[58] Id at 21:27-28:28.
[59] Id. at 22:1-2.
[60] Id. at 6:23-25; 7:1-2; and 19:26-28.
[61] Id. at 10:8-10.
[62] *Id.* at 3:26; 4:1-4 .

prescribed protection from substantial rate increases as the result of the tracker and its updates in the form of a cap.

Q Should the Commission approve the ECA as proposed by the Company?

A. No. I recommend that the Commission reject the ECA proposed by TEP as the Company has not demonstrated that circumstances warrant an extraordinary action as was the case with the arsenic problem for water utilities.

Q. What do you recommend?

A. Since the Company has several major projects that it must meet in the next 2-3 years and to be consistent with the treatment that APS received in Docket No. E-0139A-11-0224, I recommend that the Company modify its request and submit a proposal that mirrors the EIS approved by the Commission. This proposal would include a revised plan of administration that would state that the Company would collect only actual capital costs for the environmental mandates that it is required to install plus the carrying costs (at the approved weighted costs of capital). I would recommend that the Company adopt the following language as part of a revised plan of administration:

Calculation of EIS Capital Carrying Costs

EIS capital carrying costs used in calculating the EIS $ per kWh rate will include the following: (1) return on EIS Qualified Investments based on the Company's Weighted Average Cost of Capital ("WACC") approved by the Commission in Decision No. 73183, (2) depreciation expense, (3) income taxes, (4) property taxes, (5) deferred income taxes and tax credits where appropriate, and (6) associated O&M. EIS Qualified Projects and the EIS capital carrying costs calculation will be submitted by the Company to the ACC in the form of Schedule 1 and Schedule 2, as attached to this document.

In addition, any approval for such a mechanism should alleviate the need for frequent base rate increases as a result of these capital outlays. The Company would be recovering the mandated capital investment plus carrying costs before the next base rate proceeding. It is important to note that the parties to the settlement in the APS case acknowledged that the revised EIS was a contributing factor to the length of the "stay-out" provision to which APS agreed.[63] I would expect that any settlement in this case would include a similar recognition. Finally, at the Company's next base rate proceeding, any unrecovered balance of capital investments for this tracker would be moved to base rates and the rate reset to zero.

Q. **The EIS in the APS case included a cap. Do you propose such a cap in this proceeding?**

A. Yes. I believe a cap is a reasonable mechanism to mitigate ratepayer impacts. Absent a similar cap such as that which exists with APS, I believe that a cap that increases the customer and delivery charges portion of the customer's bill by no more than 1% is reasonable.

Q. Does this conclude your testimony related to ECA?

A. Yes. It does

[63] Exh. 14, Decision No. 73183 at 25:25-26.

EXHIBIT 1

Experience and Qualification of Michael J. McGarry, Sr.

Summary

Mr. McGarry's professional experience spans thirty-one years within the private and public sectors. He has conducted over thirty comprehensive management and operational audits of investor-owned energy, telecommunications, and water utilities. These audits have included comprehensive management audits and/or operational audits on most utility functions including corporate governance, strategic planning, internal auditing, capital and operating budget process and practices, distribution operations and maintenance, fuel procurement, supply chain management, demand side management, crew operations, affiliates transactions, commodity trading, and construction program practices.

Project Management

Mr. McGarry's experience includes management of multi-discipline teams for a wide range of client engagements, development and implementation of detailed work plans and project schedules. He has analyzed and planned interdivisional resource utilization; supervised, developed and coached interdivisional team members; and created numerous executive reports, briefings, and presentations.

Regulatory and Rate Case Management

Mr. McGarry has worked with clients to manage all aspects of the regulatory and rate case process. He has developed efficient processes to prepare supporting analyses and testimony for submission to the regulatory bodies and interveners. He is a seasoned project manager and has analytical expertise to respond to interrogatories and data requests from all rate case interveners in a timely manner. Mr. McGarry has assisted a number of clients in preparing revenue requirement and cost of service analyses. He has also developed rate structure and billing determinant information analyses, time of day and interruptible rates analyses, fuel and purchased power reports, and annual wholesale rates for member cooperatives. He has developed complex revenue requirement models to present alternative positions to a utility's proposed rate request.

Testimony and Witness Preparation

Mr. McGarry has proffered and/or supported testimony in Arizona, Colorado, Delaware, Illinois, Maine, Maryland, Michigan, Missouri, New York, North Dakota, Nova Scotia, Ohio, Pennsylvania and Utah. These proceedings included testimony involving management decision and prudence impacts, operations and maintenance expenses, capital investments, revenue requirements, project management, and others.

Utility Management and Operational Audits

Mr. McGarry has conducted over thirty comprehensive management and operational audits of investor-owned energy and telecommunications utilities. These audits have included comprehensive management audits and/or operational audits on most functions within the utility environment including corporate governance, strategic planning, internal auditing, capital and operating budget processes and practices, distribution operations and maintenance, fuel procurement, supply chain management, demand side management, crew operations, affiliates transactions, commodity trading, and construction program practices.

Restructuring, Unbundling, and Cost Allocation

Mr. McGarry has developed the supporting analyses and regulatory filing requirements needed to support unbundling rates for utilities. This has included detailed studies where the company's plant-in-service and depreciation reserve was allocated to each unbundled function. He has assessed utility management actions to prepare the company for competition, including the processes and practices used by the utility to prepare to enter new markets and offer new services.

Training and Public Speaking

Mr. McGarry has presented topics before Commission staff groups, NARUC sub-committee groups, and as a program faculty member (2010 & 2011) for the Institute of Public Utilities at Michigan State University. Topics presented include management auditing and prudence reviews, service company costs and allocations, forecasting methodology and modeling, revenue requirements, rate base, price regulation theory, and cost trackers.

Education

Potsdam College, B.A., Economics, 1981
University at Buffalo School of Management, MBA, 1996

Regulatory Experience

Before the Arizona Corporation Commission (AZCC)
Docket No. 12-0291 *Application of Tucson Electric Power Company for Just and Reasonable rates and charges to realize a reasonable rate of return in Arizona*, before the AZCC. August 2012 - present
Project Manager and Testifying Witness. Oversaw analysis and assessment of the company's proposed cost of service and rate design, cost of capital and return on equity, and energy efficiency mechanisms. Will provide written testimony in support of Staff's position regarding energy efficiency mechanisms and environmental compliance adjustor.

Docket No. 11-0224 *Arizona Public Service Company Rate Case*, before the AZCC. July 2011-March 2012
Project Manager and Testifying Witness. Analyzed the company's proposed Infrastructure Tracking Mechanism, power supply adjustor, and tariffs. Testimony filed November 2011.

Before the Connecticut Public Utilities Regulatory Authority (PURA)

Docket 10-02-13 *Application of Aquarion Water Company to Amend its Rate Schedules*
On behalf of the PURA. April-August 2010
Project Manager. Oversaw rate case analysis and assessment of the company's proposed revenue requirement specifically related to cash working capital and test year expenses. Assisted with analysis of specific issues and preparation of Commission's recommended decision.

Docket 07-07-01 *Diagnostic Management Audit of Connecticut Light & Power Company.*
On behalf of the Staff of the PURA. July 2008-June 2009
Project Manager. Performed overall day to day project management responsibilities to conduct a diagnostic management audit of the Connecticut Light & Power Company (CL&P). Managed a project team of accountants, engineers and industry specialists who were responsible for evaluating the effectiveness of the management and operations of all aspects of the company. In addition, managed a focused prudency review of Northeast Utilities' (CL&P's parent company) development and implementation of a $122 million customer information system known as CustomerCentral or C2.

Before the Delaware Public Service Commission (DEPSC)

Docket No. 11-528 *On behalf of the Staff of the DEPSC in the matter of the application Delmarva Power & Light Company (DPL) for approval of modifications to its electric base rates.* January-July 2012
Project Manager and Testifying Witness. Oversaw rate case analysis and assessment of the company's proposed inter-company allocations. Provided expert testimony regarding the impact of the sale of Conectiv Energy on inter-company allocations and the resulting impact on revenue requirements.

Docket No. 09-414 *On behalf of the Staff of the DEPSC in the matter of the application of Delmarva Power & Light Company (DPL) for approval of modifications to its electric base rates.* September 2009-May 2010
Project Manager. Oversaw rate case analysis and assessment of the company's proposed revenue requirement. Assisted with analysis of specific issues and preparation of witness testimony.

Docket No. 07-239F *On behalf of the Staff of the DEPSC in the matter of the application DPL for approval of modifications to its gas cost rates.* October 2007-April 2008
Project Manager and Testifying Witness. Oversaw review of DPL gas hedging program and testified to the findings and conclusions.

Docket No. 06-287 *On behalf of the Staff of the DEPSC in the matter of Chesapeake Utilities Corporation's implementation of a Gas Hedging program.* June-August 2007
Project Manager. Provided industry expertise and suggestions to the Commission on a proposal plan to implement a gas hedging procurement program at the company.

Docket No. 06-284 *On behalf of the Staff of the DEPSC in the matter of DPL's request for a $15M increase in gas base rates.* October 2006-March 2007
Project Manager and Testifying Witness. Testified on several rate base and revenue requirement issues. Recommended Commission reduce proposed rate increase request to $8.4M (56%).

Before the District of Columbia Public Service Commission (DCPSC)

Formal Case No. 1093 *In the Matter of the Investigation into the Reasonableness of Washington Gas Light Company's (WGL) Existing Rates and charges for Gas Service*

On Behalf of the DCPSC. June 2012-present
Project Manager and Lead Consultant. Managed team of consultants providing advisory services to Commissioners and Staff on proposed revenue requirements, rate base, and rate design. Led analysis of revenue requirements, fuel costs, uncollectibles, environmental issues affecting rate base, inventory adjustments, plant in service, construction work in progress, research and development issues, safety initiatives, affiliate allocations, and energy funds.

Formal Case No. 1087 *In the Matter of the Application of the Potomac Electric Power Company (PEPCO) for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service*

On Behalf of the DCPSC. September 2011-present
Project Manager and Lead Consultant. Advised Commissioners and Staff on proposed revenue requirements, rate base, rate design, reliability projects, and cost recovery mechanism.

Formal Case No. 1076 *In the Matter of the Application of PEPCO for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service.*
On Behalf of the DCPSC. July 2009-June 2010
Project Manager. Advised Commission Staff on the company's and intervener's filings and testimony regarding revenue requirements, rate base, cost of service, rate design, bill stabilization, and depreciation.

Formal Case No. 1053 - *Technical consultant for the DCPSC in the matter of PEPCO's request for a $50.4 million increase in base rates.* February 2007-June 2008
Project Manager. Provided technical expertise to Commission in evaluating PEPCO's rate case filing. Commission accepted adjustments which reduced the allowed increase by a significant percentage.

Formal Case No. 1032 *In the Matter of the Investigation into PEPCO's Distribution Service Rates*

On Behalf of the DCPSC. January-March 2005
Project Manager. Review and evaluation of PEPCO compliance filings for class cost of service and revenue requirements for distribution service pursuant to a settlement approved in May 2002. Provided analysis and recommended adjustments to Staff on 23 designated issues and 13 company proposed adjustments. Proceeding was settled in anticipation of a full rate case for rates to be effective August 8, 2007.

Formal Case No. 1016 *In the Matter of the Application of Washington Gas Light Company (WGL), District of Columbia Division, for Authority to Increase Existing Rates and Charges for Gas Service*

On Behalf of the DCPSC. June-December 2003
Project Manager and Consultant to Commissioners and Staff. Project Manager for the analysis of WGL's rate filings. Provided analysis and recommended adjustments to the DCPSC Staff on WGL's proposed increase to base rates. Advised the Commission during deliberations on party positions and possible recommendations.

Before the Hawaii Public Utilities Commission

Docket No. 05-0075 *In the matter of a proceeding to investigate Kauai Island Utility Coop's Proposed Revised Integrated Resource Plan and Demand Side Management Framework.* June 2005-January 2006
Project Manager. Managed a team of consultants responsible for evaluating the impact of the changes proposed by the company.

Before the Illinois Commerce Commission (ILCC)

Case: 05-0597 *On behalf of the Illinois Citizens Utility Board, Cook County States Attorney's Office and City of Chicago.* November 2005-May 2006
Project Manager and Testifying Witness. Provided analysis and recommended adjustments in the general rate increase of 20.1% or $320 million filed by ComEd.

Consultant to Illinois Power Company. Conducted mandated compliance filing to un-bundle utility's rate tariffs. Prepared filing requirements and all support schedules analysis to justify allocation of generation, transmission and distribution. Prepared testimony on behalf of the company's controller.

Consultant to Illinois Power Company. Prepared 2001 required update filing for the ILCC compliance filing to un-bundle utility's rate tariffs. Prepared filing requirements and all support schedules analysis to justify allocation of generation, transmission and distribution. Prepared testimony on behalf of the company's controller.

Before Maine Public Utilities Commission (MEPUC)

Case No 2008-151 *MEPUC Investigation into Maintenance and Replacement Program for Northern Utilities Inc.'s Cast Iron Facilities (Phase II)*

On behalf of Maine Public Advocate. July 2008-July 2010
Project Manager and Testifying Witness. Litigated proceeding and led a consultant team to assist the State of Maine Public Advocate to follow-up on investigation for the need for the program and the company's management of the repair or replacement of its cast iron facilities.

Case No 2004-813 *MEPUC Investigation into Maintenance and Replacement Program for Northern Utilities Inc.'s Cast Iron Facilities (Phase I)*

On behalf of Maine Public Advocate. November 2004-March 2005
Project Manager and Testifying Witness. Litigated proceeding and led a consultant team to assist the State of Maine Public Advocate to investigate the need for the program and the company's management of the repair or replacement of its cast iron facilities. Participated in panel testimony regarding cost and risk of the program.

Before the Maryland Public Service Commission

Case No. 9092/9093 (Phase II) *On behalf of the Staff of the Commission in Base Rate Proceeding for PEPCO and Delmarva Power & Light Company.* December-March 2008
Project Manager and Testifying Witness. Provided rebuttal testimony on behalf of the Commission related to the reasonableness of the costs and charges of Pepco Holdings, Inc. Service Company.

Case No. 9092 *On behalf of the Staff of the Commission in Base Rate Proceeding for PEPCO.* January-June 2007
Project Manager. Reviewed and analyzed the company's base increase request and all pro formas, adjustments to test year revenue requirement and supported witness testimony. Commission approved less than 20% of the company's original request.

Case No. 9062 *On behalf of the Maryland Office of People's Counsel in the matter of the application of Chesapeake Utilities Corporation for authority to revise its rates and charges for gas service.* May-August 2006
Project Manager. Managed a project team responsible for providing expert witness testimony in the areas of revenue requirements, rate base, cost of service, revenue allocation, rate design, revenue normalization, and cost of capital.

Before the Massachusetts Department of Public Utilities (MADPU)

Case No. D.P.U. 08-110 *On behalf of the MDPU regarding the Petition and Complaint of the Massachusetts Attorney General for an Audit of New England Gas Company.* February-August 2010
Project Manager. Managed a project team of accountants and industry specialists who were responsible for evaluating the accuracy of the accounting records, practices and procedures used in the development of the company's revenue requirements calculations in the company's base rate request.

Before the Michigan Public Service Commission

Case No. U-16655 *On behalf of the Attorney General of the State of Michigan (MIAG) in the matter of the application of Consumers Energy Company (CECO) for authority to reconcile its renewable energy plan (REP) costs associated with the plan approved in Case No. U-15805 and Case No. U-16543.* September 2012-present
Project Manager and Testifying Witness. Review the company's REP Cost Reconciliation for 2011 to ensure the adherence to approved processes and reasonable and prudent costs. Testified regarding the company's methodology used to calculate its proposed PSCR expense.

Case No. U-16656 *On behalf of the MIAG in the matter of the application of The Detroit Edison Company (DetEd) for authority to reconcile its REP costs associated with the amended plan approved in Case No. U-16582.* September 2012-present
Project Manager and Testifying Witness. Reviewed the company's REP Cost Reconciliation for 2011 to ensure the adherence to approved processes and reasonable and prudent costs. Expected to testify at upcoming hearing.

Case No. U-16434-R *On behalf of the MIAG in the matter of the Application of DetEd for reconciliation of its 2011 power supply cost recovery (PSCR) plan.* June 2012-present
Project Manager and Testifying Witness. Reviewed PSCR plan requirements and provided analysis and testimony concerning prior year under-recovery of power supply costs, over-refund of the company's residual Self-Implementation Refund, the company's claimed credit to PSCR costs related to credit claimed by affiliate, RARS asset and liability balance resulting in over recovery, and Reduced Emissions Fuel (REF) prudency and calculation of REF impacts.

Case No. U-17026 *On behalf of the MIAG in the matter of the application of Indiana Michigan Power Company for a certificate of necessity pursuant to MCL 460.6s and related accounting authorizations* June-September 2012
Project Manager. Managed review of certificate of necessity, evaluation of company's prudency in obtaining alternative power supply options, and review of the company's implementation of and prudency in management of its nuclear plant Life Cycle Management project in comparison to industry standards.

Case No. U-16892 *On behalf of the MIAG in the matter of the application of DetEd for reconciliation of its PSCR plan for 2010.* November 2011-May 2012
Project manager and Testifying Witness. Reviewed PSCR plan requirements and testified to appropriateness of specific components of that factor.

Case No. U-16047-R *On behalf of the MIAG in the matter of the application of DetEd for its PSCR plan for 2011.* August 2011-March 2012
Project Manager and Testifying Witness. Reviewed PSCR plan requirements and provided analysis and testimony concerning prior year under-recovery of power supply costs, under-recovery of cumulative Pension Equalization Mechanism costs, and the over-refund of the company's residual Self-Implementation Refund.

Case No. U-16432 *On behalf of the MIAG in the matter of CECO's Application to Implement a PSCR Plan for 2011.* February-June 2011
Project Manager. Reviewed cost recovery plan requirements and provided analysis concerning prior year under-recovery, generation dispatch and purchased power, purchased power agreements, emission control expenses including appropriateness of mercury filter expenses as part of PSCR process.

Case No. U-16434 *On behalf of the MIAG in the matter of DetEd's Application to Implement a PSCR Plan for 2011.* February-June 2011
Project Manager and Testifying Witness. Reviewed PSCR plan requirements and provided analysis concerning prior year under-recovery, generation dispatch and purchased power, purchased power agreements, emission control expenses including appropriateness of coal refinement expenses as part of PSCR process.

Case No. U-16472 *On behalf of the MIAG in the matter of the application of DetEd 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.* February-June 2011
Project Manager and Testifying Witness. Review of Advanced Metering Infrastructure program cost benefits and tariffs filed and testifying witness to same.

Case No. U-16407 *On behalf of the MIAG in the matter of the application of Michigan Consolidated Gas Company (MichCon) for approval of a detailed plan for main renewal, including a long-term plan to significantly reduce the amount of cast iron main in its system.* October 2010-May 2011
Project Manager and Testifying Witness. Reviewed the company's proposed plan with respect to whether a cost recovery mechanism can be designed to minimize the impact on ratepayers. Testified as to the reasonableness of cost benefit of replacements as well as to the capital cost recovery as it affects future rate cases.

Case No. U-16300 *On behalf of the MIAG in the matter of the application of CECO for authority to reconcile its REP costs associated with the plan approved in Case No. U-15805.* November 2010-January 2011
Project Manager and Testifying Witness. Reviewed the company's REP Cost Reconciliation for 2009 to ensure the adherence to approved processes and reasonable and prudent costs. Testified as to significant concerns with respect to the transfer price for renewable energy resources proposed by the company.

Case No. U-16356 *On behalf of the MIAG in the matter of the application of DetEd for authority to reconcile its REP costs associated with the plan approved in Case No. U-15806-RPS.* October 2010-March 2011
Project Manager and Testifying Witness. Reviewed the company's REP Cost Reconciliation for 2009 to ensure adherence to approved processes and reasonable and prudent costs and testified to those issues.

Case No. U-15675-R *On behalf of the MIAG in the matter of the application of CECO for the reconciliation of PSCR costs and revenues for the calendar year 2009.* October 2010-January 2011
Project Manager and Testifying Witness. Reviewed PSCR plan requirements and testified to transfer price, replacement power costs, and reasonableness of including excess fuel and variable O&M expenses proffered by various intervenors.

Case No. U-15677-R *On behalf of the MIAG in the matter of the application of DetEd for reconciliation of its PSCR plan for the calendar year 2009.* September-December 2010
Project Manager and Testifying Witness. Reviewed PSCR reconciliation and testified with respect to the transfer price for renewable energy source flowing into the PSCR proposed by the company.

Case No. U-16047 *On behalf of the MIAG in the matter of the application of DetEd for authority to implement a PSCR Plan in its rate schedules for 2010 metered jurisdictional sales of electricity.* January-May 2010
Project manager and Testifying Witness. Reviewed PSCR plan requirements and testified to appropriateness of specific components of that factor.

Case No. U-15415-R *On behalf of the MIAG in the matter of the application of CECO for the reconciliation of PSCR costs and revenues for the calendar year 2008 and for other relief related to pension and OPEB costs.* May-November 2009
Project Manager and Testifying Witness. Reviewed PSCR reconciliation, provided analysis of potential issues, and developed recommendations including basis, past precedence, and/or industry expertise. Testified regarding Karn 1 outage delay and Rate E-1 discount recovery.

Case No. U-15806/U-15890 *On behalf of the MIAG in the matter of DetEd's and MichCon's compliance with Public Acts 286 and 296 regarding their REP and Energy Optimization Plan (EOP).* March-June 2009
Project Manager and Testifying Witness. Reviewed the EOPs of both companies and provided analysis and testimony regarding issues and shortcomings concerning the plans in relation to the specifications of the Act and the benefit to customers.

Case No. U-15805/15889 *On behalf of the MIAG in the matter of CECO to comply with Public Acts 286 and 295 regarding its REP and EOP.* March-June 2009
Project Manager and Testifying Witness. Reviewed the company's EOP and provided analysis and testimony of issues and shortcomings concerning the plans in relation to the specifications of the Act and the benefit to customers.

Case No. U-15677 *On behalf of the MIAG in the matter of the application of DetEd for authority to implement a PSCR plan in its rate schedules for 2009 metered jurisdictional sales of electricity.* January-June 2009
Project manager. Reviewed PSCR plan requirements for appropriateness of specific components of that factor.

Case No. U-15415 *On behalf of the MIAG in the matter of the application of CECO for approval of a PSCR plan and for authorization of monthly PSCR factors for the year 2008.* January-March 2008
Project Manager. Reviewed PSCR plan requirements and provided summary briefing to Michigan Attorney General.

Case No. U-15320 *On behalf of the MIAG in the matter of the application of Midland Cogeneration Venture Limited Partnership (MCV) for the Commission to eliminate the "availability caps" which limit CECO's recovery of capacity payments with respect to its power purchase agreement with MCV.* October 2007-June 2008
Project Manager. Oversaw project to provide industry expertise to evaluate issue in case and recommend alternative arguments.

Case No. U-15245 *On behalf of the MIAG in the matter of the application of CECO for authority to increase its rates for the generation and distribution of electricity and for other relief.* July 2007-April 2008
Project Manager and Testifying Witness. Provided expert testimony on partial and interim rate relief, CECO's decision to acquire Zeeland Power Company from Broadway Gen Funding, LLC. Provided testimony in permanent phase to reduce the company's net operating income to more closely reflect the expected costs in 2008.

Case No U-15244 *On behalf of the MIAG in the matter of the application of DetEd for authority to increase its electric base rates.* September 2007-October 2008
Project Manager and Testifying Witness. Testified regarding revenue requirements.

Case No U-15190 *On behalf of the MIAG in Base Rate Proceeding for CECO.* March-September 2007
Project Manager. Reviewed the revenue decoupling proposal and supported the witness testimony.

Case No U-15040 *On behalf of the MIAG in GCR 2007/08 Plan proceeding of Michigan Gas Utilities Corporation.* March-August 2007
Project Manager and Testifying Witness. Reviewed GCR plan requirements and provided analysis of the potential benefits of gas procurement hedging program. Testified regarding the GCR clause plan 2007-08.

Case No. U-14231 *On behalf of the MIAG in the matter, on the Commission's own motion, to commence an investigation into future capacity requirements*. February-May 2007
Project Manager. Reviewed and provided a formal written report on the Michigan Public Service Commission's 21st Century Energy Plan Report.

Case No. U-15001 *On behalf of the MIAG in PSCR 2007/08 Plan proceeding.* November 2006-August 2007
Project Manager and Testifying Witness. Reviewed PSCR plan requirements and testified regarding the company's projected PSCR under-recoveries for 2005 and 2006.

Case No. U-14701-R *On behalf of the MIAG in PSCR 2006/07 reconciliation proceeding.* June-November 2007
Project Manager and Testifying Witness. Reviewed PSCR reconciliation and testified to eliminate some expenses used in the company's calculation of its under-recovery PSCR reconciliation for 2006.

Case No. U-14547 *On behalf of the MIAG in the matter of the application of CECO for authority to increase rates for the distribution of natural gas and for other relief.* December 2005-April 2006
Expert Witness and Project Manager. Provided analysis, recommended adjustments, and filed testimony for the Attorney General on CECO's proposed increase to base rates.

Case No. U-14347 *On behalf of the MIAG in the matter of the application of CECO for authority to increase its rates for the generation and distribution of electricity and for other relief.* April-September 2005.
Project Manager. Managed project team and supported testimony on cost of service, revenue allocation and rate design issues.

Before the Missouri Public Service Commission (MOPSC)

Veolia Energy Company (Veolia) 2011 and 2012 Request for Authority to Increase Electric Rates in Missouri (Case No. HR-2011-0241). July-September 2011
Project Manager and Testifying Witness. Led a team of consultants engaged to review Veolia's proposed adjustments, rate base, revenues and expenses, affiliate transactions and allocations, revenue requirement, cost of capital, and cost of service and rate design. Evaluated Veolia's proposed revenue requirement and testified before the MOPSC to proposed adjustments to the revenue requirements filed by the company in its application.

Consultant to Ameren UE. Conducted revenue requirement analysis in preparation of Missouri Public Service Commission compliance filing to un-bundle utility's rate tariffs. Prepared the filing requirements and all support schedules analysis to justify allocations of generation, transmission and distribution.

New Mexico Public Regulation Commission (NMPRC)

Special Case Study: Public Service Company of New Mexico (PNM) NM PRC Docket No. 10-00086-UT. August 2010
Blue Ridge worked with QSI Consulting, Inc. to conduct a training session for the NMPSC Staff and develop training materials for presentation to Staff on the basic elements of future test year proceedings, how those may differ from traditional rate cases, and how to apply and interpret the forecasting methodologies and modeling that will come into play; and analyze the pending PNM rate case and provide an analytic framework for Staff to apply to the forecasting issues in the case.

Before the North Dakota Public Service Commission (NDPSC)

Northern States Power Company (NSP) 2011 and 2012 Request for Authority to Increase Electric Rates in North Dakota (Case No. PU-10-657/PU-11-55). April-Ocotber 2011
Project Manager and Testifying Witness. Led a team of consultants engaged to review NSP's proposed adjustments, rate base, revenues and expenses, affiliate transactions and allocations, revenue requirement, cost of capital, and cost of service and rate design. Evaluated NSP's proposed revenue requirement and testified before the NDPSC to proposed adjustments to the revenue requirements filed by the company in its application.

Before the Nova Scotia Utility and Review Board
Case No. P-888 *On behalf of the Consumer Advocate of the Province of Nova Scotia in the base rate proceeding of Nova Scotia Power.* December 2006-March 2007
Project Manager and Testifying Witness. Provided an evaluation of a management audit of Nova Scotia Power and that report's usefulness to assess the company's management performance and operational efficiency within the context of that proceeding.

Before the Public Utilities Commission of Ohio (PUCO)

Case No. 11-5428-EL-RDR *On behalf of the Staff of the Public Utilities Commission of Ohio In the matter of the application of Delivery Capital Recovery (DCR) Rider Contained in the Tariffs of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company (collectively, Companies).* November 2011-April 2012
Project Manager and Expert Witness. Led a team of consultants engaged to audit and attest to the accuracy and reasonableness of the Companies' compliance with their Commission-approved DCR Riders with regard to the return earned on plant-in-service since the Companies' last distribution rate case.

Case No. 08-0917-EL-SSO *On behalf of the Ohio Hospital Association in the matter of the Application of American Electric Power of Ohio for authority to increase rates for distribution of electric service.* (Hired by Ohio Hospital Association's attorney for utility matters, Bricker and Eckler, to provide expertise in negotiating rate with American Electric Power). September 2008-March 2009
Evaluated revenue and rate impact on member hospitals.

On behalf of the Staff of the PUCO:

- Case #08-0072-GA-AIR Columbia Gas of Ohio for an increase in gas rates, April-August 2008
- Case #07-0829-GA-AIR Dominion East Ohio for an increase in gas rates, November 2007-July 2008
- Case #07-0589-GA-AIR Duke Energy Ohio for an increase in gas rates, November 2007-Februrary 2008

Project Manager. Oversaw multi-discipline team of accountants, auditors, engineers and analysts to conduct a comprehensive rate case audit of the company's gas base rate filing. Primary goal of project was to validate information in filing, provide findings conclusions and recommendations concerning the reliability of information and data in the filing and support Staff in its evaluation of the reasonableness of the filing.

Case No. 07-0551-EL-UNC *On behalf of the Ohio Schools Council in the matter of the Application of FirstEnergy Ohio (and its operating companies Ohio Edison, Cleveland Electric and Toledo Edison) for authority to Increase rates for distribution service, modify certain accounting practices and for tariff approval.* August 2007-April 2008
Project Manager. Hired by Ohio Schools Council's attorney for utility matters (Bricker and Eckler, LLP) to provide industry expertise in reviewing FirstEnergy's application with respect to cost of service and rate design and the resulting impact on Council's member school systems' energy costs.

Case No. 06-0986-EL-UNC *On behalf of the City of Cincinnati in the matter of the Application of Duke Energy Ohio, Inc., to modify its market-based Standard service offer.* May-August 2007
Project Manager. Hired by City of Cincinnati's Water and Sewer District attorney for utility matters (Bricker and Eckler, LLP) to provide industry expertise in reviewing the company's proposal and impact on City's project energy costs.

Oregon Public Utility Commission (OPUC)

Docket No UP205 *Examination of NW Natural's Rate Base and Affiliated Interests Issues* Co-sponsored between NW Natural, Staff, Northwest Industrial Gas Users, Citizens Utility Board. August 2005-January 2006
Project Manager. Led a team that conducted a management audit of NW Natural Gas that included an evaluation of rate base issues for Financial Instruments (gas and financial hedging) Deferred Taxes, Tax Credits, Cost for a Distribution System, Security Issuance Costs and AFUDC calculations as well as Affiliate Transactions for Cost Allocations and Transfer Pricing, Labor Loading, Segregation of Regulated Rate Base and Subsidiary Investments and Properties, and validation of tax paid from/to affiliates are proper. Audit was to ensure the company's compliance with orders, rules and regulations of the OPUC, with company policy and with Generally Accepted Accounting Principles.

Utah Division of Public Utilities

Docket No. 09-035-23 *In the Matter of the Application of Rocky Mountain Power (RMP) 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.* June-December 2009
Project Manager and Testifying Witness. Verified the reasonableness of the revenue requirements as provided by the company in its application and testified before the Public Service Commission of Utah.

Docket No. 09-035-15 *In the Matter of the Application of RMP for Approval of its Proposed Energy Cost Adjustment Mechanism (ECAM) - Net Power Cost Evaluation (NPC), RMP 2009 General Rate Case.* July-December 2009
Project Manager and Testifying Witness. Analyzed the reasonableness and technical accuracy of the RMP's NPC request, performed a comprehensive review of the company's NPC estimate and developed recommendations to ensure an accurate baseline for the ECAM, analyzed special issues addressed in the NPC portion of the case, analyzed the company's fuel price hedging policies and provided recommendations appropriate for the ECAM, and reviewed intervener NPC issues as well as analyzing additional issues as raised by the company and testified to hedging issues.

Before the Washington Utilities and Transportation Commission (WUTC)

Independent Third-Party Evaluation of Puget Sound Energy's (PSE) Conservation Incentive Mechanism (ECIM) under the co-direction of PSE and the WUTC Staff. Phase I: July-October 2009; Phase II: October 2009-September 2010
Project Manager. Assess the extent to which the design and implementation of the incentive mechanism addressed key issues and objectives required by the Commission: accuracy of implementation in calculations of incentives or penalties, compliance with the conditions and requirements of the pilot program, proper use of the calculation methodology, and which assumptions or methods were used to calculate and verify the savings report.

Before the Public Utilities Commission of the State of Colorado (COPUC)

Docket No. 04A-050E *Review of the Electric Commodity Trading Operations of Public Service Company of Colorado (PSCo)*
On behalf of the COPUC Staff. March-September 2004
Project Manager. Focused operational audit within the bounds of a litigated proceeding to determine if ratepayers were subsidizing or negatively impacted by PSCo's energy trading function.

South Carolina State Senator

Advised Senator on regulatory process for requesting States Public Service Commission for a comprehensive review of Duke Power Company's storm and restoration and right of way management. Reviewed and advised Senator of results of report finding.

Southern Connecticut Gas

Consultant. As part of a team that conducted a comprehensive management audit of the management and operations of the company, completed the capital budgeting area of the audit.

Before the New York Public Service Commission

Case: 94-C-0657
Commission Staff. Proceeding to evaluate the compliance of NYNEX with Commission rules and orders related to operational support system costs to competitors. Part of staff panel to facilitate discussion between the company and potential competitors (i.e., users of operational support systems) and report back to Commission.

Focused review of the preparedness of Rochester Gas and Electric (RG&E) and Consolidated Edison (ConEd) for competition in the electric industry. Evaluated all aspects of the company's management actions to prepare for competition including strategic planning, goals and objectives and senior management's attention to the company operations in a de-regulated industry.

Case: 97-M-0567
Commission Staff. Litigated proceeding to determine the benefits of a proposed merger of Long Island Lighting Company (LILCO)/Brooklyn Union Gas. Analyzed proposed synergy savings.

Case: 96-E-0132 *Show Cause Proceeding Regarding Rate Relief for Ratepayers of LILCO*
Commission Staff and Testifying Witness. Litigated proceeding where Staff proffered testimony containing a benchmark study showing that LILCO's operations and maintenance expenses were excessive compared to a peer group of 24 utilities. Panel testimony concerning the findings and conclusions resulting from the benchmark study.

Case: 96-M-0858 *Prudence Investigation into the Scrap Handling Practices in the Western Division of Niagara Mohawk Power Company (NIMO)*
Commission Staff and Testifying Witness. Litigated proceeding as a result of allegations of bribery and corruption in company practices related to a specific vendor who purchased company scrap metal. Lead team of 10 staff examiners to quantify the extent to which the company paid excessive rates to this vendor. Testified to the findings of the analysis. Case settled with ratepayers receiving a credit to bills.

Case: 91-C-0613 *Operational Audit of the Outside Plant Construction and Rehabilitation Program of New York Telephone Company*
Commission Staff. Comprehensive operational audit of the company's management and implementation of a $150M capital program to rehabilitate the outside plant distribution network. Served as Staff Examiner responsible for crew supervision, goals monitoring, contractor oversight, and report preparation.

Case: 91-W-0583 *Prudence Proceeding of the Operations and Management of Jamaica Water*
Commission Staff and Testifying Witness. Litigated proceeding as a result of audit to determine extent to which management inattention and inappropriate practices resulted in excessive costs to rate payers. Testified on a Staff panel to the excessive costs associated with management's inattention to sound business practices related to the design, purchase and installation of the company customer information system.

Case: 92-W-0030 *Operational Audit of Jamaica Water Operations and Management*
Commission Staff. Comprehensive management audit of company operations. Responsible for work plan development, and specific topics areas including engineering, contracting, and information technology. Findings led to prudence proceeding.

Case: 92-M-0973 *Management Audit of RG&E*
Commission Staff. Comprehensive management audit of company operations. Responsible for work plan development, supervision of staff and specific topics areas including purchasing and internal controls.

Case: 93-E-0918 *Operational Audit of the Demand Side Management Function at RG&E*
Commission Staff. Comprehensive operational audit of the demand side management function including program planning, management and energy savings verification. Developed and supervised the implementation of the work plan.

Case: 88005 *Operational Audit of Materials and Supply Function at National Fuel Gas*
Commission Staff. Comprehensive operational audit of the materials and supplies function including warehouse operations, inventory control and procurement. Developed and implemented the work plan for this project.

Operational Audit of the Fuel Procurement and Contracting of LILCO
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Provided research and data evaluation expertise to the project.

Operational Audit of the Fuel Procurement and Contracting of ConEd
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Provided research and data evaluation expertise to the project

Case: 90007 Operational Audit of the Fuel Procurement and Contracting of Central Hudson Gas and Electric
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Provided research and data evaluation expertise to the project

Operational Audit of Fuel Procurement and Contracting of Orange & Rockland Utilities
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Provided research and data evaluation expertise to the project

Operational Audit of the Fuel Procurement and Contracting of RG&E
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on nuclear fuel. Provided research and data evaluation expertise.

Case: 88-E-115 *Prudence Proceeding to Investigate the Construction Costs Associated with the Homer City Coal Cleaning Plant (HCCCP)*
Commission Staff and Testifying Witness. Litigated proceeding as a result of audit to determine extent to which management inattention and inappropriate practices resulted in excessive construction charges related to the HCCCP. Testified on a Staff panel to the

fuel price differential costs resulting from the failure of the coal cleaning plant to function as designed as well as surrebuttal testimony on the cost of a flu-gas de-sulfurization plant and ancillary equipment and facilities. Case settled. Customers received $125M credit.

Case: 87003 *Operational Audit of the HCCCP*
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on the construction of the HCCCP jointly owned by New York State Electric and Gas (NYSEG) and Penelec. Responsible for fuel and construction costs analysis, benchmarking costs and alternative methods for meeting EPA Clean air restrictions, contracting practices and report preparation.

Case: 87003 *Operational Audit of the Fuel Procurement and Contracting of NYSEG*
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Responsible for fuel cost analysis, benchmarking costs, contracting practices and report preparation.

Case: 86007 *Operational Audit of the Field Crew Supervision and Utilization of NYSEG*
Commission Staff. Comprehensive operational audit to determine effectiveness of field crew utilization and supervision. Staff examiner responsible for verifying supervisor activities, reporting, goals attainment and report preparation.

Case: 86005 *Prudence Proceeding to Investigate the Fuel Procurement and Contracting Practices at NIMO*
Commission Staff. Litigated proceeding as a result of audit to determine extent to which management inattention and inappropriate practices resulted in excessive fuel charges to customers. Responsible for fuel cost analysis and benchmarking costs, contracting practices, and testimony preparation. Case settled with customers receiving $66M credit.

Case: 86005 *Operational Audit of the Fuel Procurement and Contracting of NIMO*
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Responsible for fuel cost analysis and benchmarking costs, contracting practices and report preparation.

Case: 85001 *Operational Audit of the Research and Development Function of ConEd*
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on R&D activities. Staff examiner on the project responsible for reviewing projects documentation and control, outside contracting a report preparation.

Testimony filed by Mr. McGarry

Before the Arizona Corporation Commission

- Arizona Public Service Company - Docket No. E-01345A-11-0224

Before the Delaware Public Service Commission

- Delmarva Power and Light Company - Docket No. 11-528
- Delmarva Power and Light Company - Docket No. 07-239F
- Delmarva Power and Light Company - Docket No. 06-284

Before the Illinois Commerce Commission

- Commonwealth Edison - Case: 05-0597

Before Maine Public Utilities Commission

- Northern Utilities Inc. - Case No. 2008-151
- Northern Utilities Inc. - Case No. 2004-813

Before the Maryland Public Service Commission

- PEPCO and Delmarva Power and Light Company - Case No. 9092/9093

Before the Michigan Public Service Commission

- Consumers Energy Company - Case No. U-16655
- Detroit Edison Company - Case No. U-16434-R
- Detroit Edison Company - Case No. U-16047-R
- Detroit Edison Company - Case No. U-16434
- Detroit Edison Company - Case No. U-16892
- Detroit Edison Company - Case No. U-16472
- Michigan Consolidated Gas Company - Case No. U-16407
- Detroit Edison Company - Case No. U-16356
- Consumers Energy Company - Case No. U-16300
- Detroit Edison Company - Case No. U-16047
- Detroit Edison Co. and Michigan Consolidated Gas - Case No. U-15806/U-15890
- Consumers Energy Company - Case No. U-15805/15889
- Detroit Edison Company - Case No. U-15677-R
- Consumers Energy Company - Case No. U-15675-R
- Consumers Energy Company - Case No. U-15415-R
- Consumers Energy Company - Case No. U-15245
- Detroit Edison Company - Case No. U-15244
- Michigan Gas Utilities Corporation - Case No. U-15040
- Consumers Energy Company - Case No. U-15001
- Consumers Energy Company - Case No. U-14701-R
- Consumer Energy Company - Case No. U-14547

Before the Missouri Public Service Commission

- Veolia Energy Company - Case No. HR-2011-0241

Before the New York Public Service Commission

- Long Island Lighting Company - Case: 96-E-0132
- Niagara Mohawk Power Company - Case: 96-M-0858
- Jamaica Water - Case: 91-W-0583
- New York State Electric & Gas Homer City Prudence Review - Case: 88-E-115

Before the North Dakota Public Service Commission

- Northern States Power Company - Case Nos. PU-10-657 and PU-11-55

Before the Nova Scotia Utility and Review Board

- Nova Scotia Power - Case No. P-888

Before the Utah Division of Public Utilities

- Rocky Mountain Power - Docket No. 09-035-23

Speaking Engagements

National Association of Regulatory Utility Commissioners - Before the NARUC sub-committee on Accounting and Finance, CAPEX Trackers, March 28, 2012.

Institute of Public Utilities, Michigan State University, East Lansing, MI; Advanced Regulatory Studies Program, training session on Management Audits and Prudency Reviews; September 27, 2011, and September 30, 2010.

National Association of Regulatory Utility Commissioners - Before the NARUC sub-committee on Accounting and Finance, service company costs and allocations to regulated entities, September 15, 2010.

New Mexico Public Regulation Commission Staff, Santa Fe, NM - In cooperation with QSI Consulting; service companies and related cost allocations, benchmarking, and rate case planning; June 29, 2010.

Colorado Public Utilities Commission Staff – In cooperation with QSI Consulting; future of regulation and deregulation, revenue requirements, rate base, rate of return, cost of service, determining net operating income, cost of capital, staff audits, and affiliate transactions; June 22, 2006.

EXHIBIT 2

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
RUCO'S THIRD SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
September 25, 2012

RUCO 3.21

Energy Efficiency – If the EERP is approved as proposed, admit that TEP would continue to earn a return on its EE investments during all periods – even years that it underperforms and/or does not meet the EE standard.

RESPONSE:

TEP agrees that if the EERP is approved as proposed, that TEP would earn a return on its EE investments.

RESPONDENT:

Denise Smith

WITNESS:

David Hutchens

Arizona Corporation Commission ("Commission")
Federal Energy Regulatory Commission ("FERC")
Open Access Transmission Tariff ("OATT")
Tucson Electric Power Company ("TEP" or the "Company")
UNS Energy Corporation fka UniSource Energy Corporation ("UNS")
UniSource Energy Services ("UES")
UniSource Energy Development Company ("UED")
UNS Electric, Inc. ("UNS Electric")
UNS Gas, Inc. ("UNS Gas")

EXHIBIT 3

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S THIRD SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291 September 17, 2012

STF 3.04

Energy Efficiency. Reference David G. Hutchens Direct Testimony, Page 19, Lines 17-22. Please fully explain how the proposed 3 year pilot is consistent with A.C.C R14-2-2410, sub-section A, B & C which state (in part),

a. An affected utility may recover the costs that it incurs in planning, designing, implementing, and evaluating a DSM program or DSM measure if the DSM program or DSM measure is all of the following:
   1. Approved by the Commission before it is implemented,
   2. Implemented in accordance with a Commission-approved program proposal or implementation plan, and
   3. Monitored and evaluated for cost-effectiveness pursuant to R14-2-2415.
b. An affected utility shall monitor and evaluate each DSM program and DSM measure, as provided in R14-2-2415, to determine whether the DSM program or DSM measure is cost-effective and otherwise meets expectations.
c. If an affected utility determines that a DSM program or DSM measure is not cost-effective or otherwise does not meet expectations, the affected utility shall include in its annual DSM progress report filed under R14-2-2409 a proposal to modify or terminate the DSM program or DSM measure.
d. How would the Company's plan comply with Sections A-3, B and C? If a program were deemed not cost effective and terminated, how would the rate treatment be affected during this three year period?

RESPONSE:

The purpose of the EERP is to create an alternative mechanism that will fulfill the spirit and objectives of the Electric Energy Efficiency Standard ("Standard"). If the Commission approves the Company's proposal as part of the rate case Order, the Commission would have effectively provided a waiver from the specific requirements set forth in A.C.C R14-2-2410, sub-section A.1. The Company will continue to monitor and evaluate each DSM program and measure as provided in R14-2-2415, to comply with R14-2-2410, Subsections A.3 and B.

In accordance with the proposed EERP Plan of Administration ("POA"), Exhibit CAJ-7, if an evaluation determines that a previously cost-effective DSM program is no longer cost-effective, the Company will terminate that program and report it in the March 1 DSM progress report, as required under R-14-2-2409. Because the program or measure was determined to be cost effective during the planning and implementation stage, all allowable costs incurred for the program up to the actual date of termination will be collected under the DSM surcharge. This satisfies the requirement under A.A.C. R14-2-2410.C.

RESPONDENT:

Denise Smith

WITNESS:

David Hutchens and Craig A. Jones

Arizona Corporation Commission ("Commission")
Demand-Side Management ("DSM")
Energy Efficiency ("EE")
Energy Efficiency Resource Plan ("EERP")
Tucson Electric Power Company ("TEP" or the "Company")
UNS Energy Corporation fka UniSource Energy Corporation ("UNS")
UniSource Energy Services ("UES")
UniSource Energy Development Company ("UED")
UNS Electric, Inc. ("UNS Electric")
UNS Gas, Inc. ("UNS Gas")

EXHIBIT 4

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
STAFF'S THIRD SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
September 17, 2012

STF 3.02

Energy Efficiency. Reference David G. Hutchens Direct Testimony, Page 18, lines 2-3. Please explain the basis for selecting 200 basis points for the premium on the return of the EE costs on TEP's ROE. Provide all studies, analysis, and/or industry research that support this level of premium.

RESPONSE:

The 200 basis point addition to the Company's return on equity for EERP projects reflects the increased risk from the EERP investment. Unlike investments in utility plant, such as power plants, buildings, computers and other assets with an independent market value, TEP's EE expenditures produce intangible assets with no external value outside the creation of a regulatory asset by order of the Commission. A 200 basis point increase on these projects, therefore, reflects the increased risk associated with TEP's investment in these intangible assets. It should be noted that Nevada Power has had been granted a 500 basis point increase to its return on equity for EE investments.

Please see STF 3.02 RAP report.pdf, Bates Nos. TEP\019515-019586, from the Regulatory Assistance Project, which illustrates an example of this alternative to a traditional performance incentive. See specifically 6.2.3 on page 38.

RESPONDENT:

Denise Smith

WITNESS:

David Hutchens and Craig A. Jones

Arizona Corporation Commission ("Commission")
Demand-Side Management ("DSM")
Energy Efficiency ("EE")
Energy Efficiency Resource Plan ("EERP")
Tucson Electric Power Company ("TEP" or the "Company")
UNS Energy Corporation fka UniSource Energy Corporation ("UNS")
UniSource Energy Services ("UES")
UniSource Energy Development Company ("UED")
UNS Electric, Inc. ("UNS Electric")
UNS Gas, Inc. ("UNS Gas")

EXHIBIT 5

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S FOURTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
October 11, 2012, 2012

RUCO 4.01

Energy Efficiency – In regard to the Company's response to STF 3.02, please provide a copy of the Public Utilities Commission of Nevada decision that granted a 500 basis point increase to Nevada Power's return on equity for EE investments.

RESPONSE:

Please see the link below to the original Decision that granted Nevada Power an extra 500 basis points on its return on equity.

http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2001_THRU_2004/2002-5/10716.pdf

The related language that was in the Nevada Administrative Code § 704.9523 (3)(e)(4) is as follows:

> (4) To calculate revenue requirements, the utility must base the rate of return to be applied to the balance in the subaccounts of FERC Account 182.3 for each conservation or demand management program that the utility has carried out on the authorized return of equity plus 5 percent.

RESPONDENT:

Denise Smith

WITNESS:

David Hutchens and Craig A. Jones

EXHIBIT 6

ADOPTED REGULATION OF THE

PUBLIC UTILITIES COMMISSION OF NEVADA

LCB File No. R042-10

Effective July 22, 2010

EXPLANATION – Matter in *italics* is new; matter in brackets [~~omitted material~~] is material to be omitted.

AUTHORITY: §§1, 2, 5-14 and 16, NRS 704.741 and 704.785; §§3, 4 and 15, NRS 704.785.

A REGULATION relating to public utilities; prescribing the requirements for electric utilities to recover certain amounts based on the measurable and verifiable effects of the implementation of energy efficiency and conservation programs approved by the Public Utilities Commission of Nevada; amending various provisions concerning the information which an electric utility must include in the resource plan filed with the Commission; and providing other matters properly relating thereto.

Section 1. Chapter 704 of NAC is hereby amended by adding thereto the provisions set forth as sections 2, 3 and 4 of this regulation.

Sec. 2. *"Energy efficiency" means a modification of energy use patterns which results in the greater productive use of energy or a reduction in the consumption of electric power.*

Sec. 3. *1. An electric utility may recover an amount based on the measurable and verifiable effects of the implementation by the electric utility of energy efficiency and conservation programs described in the demand side plan of the electric utility and approved by the Commission pursuant to NAC 704.9494 as part of the action plan of the electric utility. The amount recovered must include:*

(a) The costs reasonably incurred by the electric utility in implementing and administering the energy efficiency and conservation programs, which are recovered pursuant to NAC 704.9523; and

(b) The measurable and verifiable effects on the revenue of the electric utility caused or created by the implementation of the energy efficiency and conservation programs, which are recovered pursuant to section 4 of this regulation.

2. Upon the request of an electric utility or intervening party or upon a motion of the Commission, the Commission may authorize an electric utility to include in the amount recovered pursuant to subsection 1 for an individual energy efficiency or conservation program financial incentives to support the promotion of the participation of the customers of the electric utility in the energy efficiency or conservation program.

3. The Commission will consider the effect of any recovery pursuant to this section on the rates of the customers of the electric utility.

Sec. 4. *1. An electric utility may recover an amount based on the measurable and verifiable effects on the revenue of the electric utility which are caused or created by the implementation of energy efficiency and conservation programs described in the demand side plan of the electric utility and approved by the Commission pursuant to NAC 704.9494 as part of the action plan of the electric utility.*

2. To recover an amount pursuant to subsection 1, an electric utility must:

(a) Establish and maintain a separate subsidiary record of the subaccounts of FERC Account No. 182.3 (Other Regulatory Assets) for the tracking, calculation and recovery of the lost revenue associated with the energy efficiency and conservation programs that are described in the demand side plan of the electric utility and approved by the Commission pursuant to NAC 704.9494 as part of the action plan of the electric utility.

(b) At the time the utility files an annual deferred energy accounting adjustment application pursuant to subsection 3 of NRS 704.187, apply to the Commission to establish the following period-specific rates:

(1) A prospective base lost revenue rate which is determined by allocating lost revenue to each customer class in the manner approved by the Commission in the most recent general rate case of the electric utility. The prospective base lost revenue rate for a customer class is an amount equal to the lost revenue allocated to the customer class pursuant to this subparagraph divided by the projected kilowatt hour sales for that class for the relevant period.

(2) A deferred lost revenue rate to clear the period-specific balance over 12 months. The deferred lost revenue rate is an amount equal to the period-specific balance in the subaccount of FERC Account No. 182.3 for lost revenue associated with energy efficiency and conservation programs for each class of customers divided by the applicable test period kilowatt hour sales.

3. An electric utility shall account for period-specific lost revenue associated with a program for energy efficiency and conservation and revenue received from the period-specific base lost revenue rate in the following manner:

(a) On a monthly basis, the electric utility shall:

(1) Calculate the deferred lost revenue;

(2) Calculate the recorded revenue attributable to the base lost revenue rate; and

(3) Record in the subaccount of FERC Account No. 182.3 the difference between estimated lost revenues and recorded revenue attributable to the base lost revenue rate.

(b) The electric utility shall apply a carrying charge at the rate of 1/12 of the authorized overall rate of return to the unamortized balance in the lost revenue subaccount of FERC Account No. 182.3.

4. An electric utility shall:

(a) Perform by program by month by class the monitoring and verification of actual kilowatt hour and demand savings required by NAC 704.9522;

(b) Include with the demand side plan submitted by the utility pursuant to NAC 704.934 the information described in paragraph (a) for review and approval by the Commission; and

(c) Make any adjustments to the balancing account for lost revenue, including, without limitation, carrying charges, as are necessary to reflect the results of the review by the Commission of the information submitted pursuant to paragraph (b).

Sec. 5. NAC 704.9057 is hereby amended to read as follows:

704.9057 "Demand side plan" means the programs proposed by a utility to promote *energy efficiency and* conservation . ~~[and demand management.]~~

Sec. 6. NAC 704.9215 is hereby amended to read as follows:

704.9215 1. A utility's resource plan must be accompanied by a summary that is suitable for distribution to the public. The summary must contain easily interpretable tables, graphs and maps and must not contain any complex explanations or highly technical language. The summary must be approximately 30 pages in length.

2. The summary must include:

(a) A brief introduction, addressed to the public, describing the utility, its facilities and the purpose of the resource plan, and the relationship between the resource plan and the strategic plan of the utility for the duration of the period covered by the resource plan.

(b) The forecast of low growth, the forecast of high growth and the forecast of base growth of the peak demand for electric energy and of the annual electrical consumption, for the next 20 years, commencing with the year following the year in which the resource plan is filed, both with and without the impacts of programs for ***energy efficiency and*** conservation ~~[and demand management]~~ and an explanation of the economic and demographic assumptions associated with each forecast.

(c) A summary of the demand side plan listing each program and its effectiveness in terms of costs and showing the 20-year forecast of the reduction of demand and the contribution of each program to this forecast.

(d) A summary of the preferred plan showing each planned addition to the system for the next 20 years, commencing with the year following the year in which the resource plan is filed, with its anticipated capacity, cost and date of beginning service.

(e) A summary of renewable energy showing how the utility intends to comply with the portfolio standard and listing each existing contract for renewable energy and each existing contract for the purchase of renewable energy credits and the term and anticipated cost of each such contract.

(f) A summary of:

(1) The energy supply plan for the next 3 years setting out the anticipated cost, price volatility and reliability risks of the energy supply plan;

(2) The risk management strategy;

(3) The fuel procurement plan; and

(4) The purchased power procurement plan.

(g) A summary of the activities, acquisitions and costs included in the action plan of the utility.

(h) An integrated evaluation of the components of the resource plan which relates the preferred plan to the objectives of the strategic plan of the utility, and any other information useful in presenting to the public a comprehensive summary of the utility and its expected development.

Sec. 7. NAC 704.925 is hereby amended to read as follows:

704.925 1. A utility's resource plan must include forecasts of energy consumption and the peak demand for summer and winter for the system, disaggregated by rate schedule, for the 20-year period beginning with the year following the year in which the resource plan is filed. The utility may combine rate schedules if necessary to protect the confidentiality of individual customers.

2. The utility shall identify components of residential and commercial energy and demand for which initiatives for ***energy efficiency and*** conservation ~~[and demand management]~~ are applicable. The utility shall include in its forecast an assessment of the impacts of such initiatives on the identified components and on overall levels of energy consumption and demand by residential and commercial customers.

3. The utility's forecast must include:

(a) Estimated annual losses of energy on the system for the 20-year period of the resource plan; and

(b) Estimated annual energy to be used by the utility for the 20-year period of the resource plan.

4. The utility shall consider the impact of applicable new technologies and the impact of applicable new governmental programs or regulations.

5. The utility shall consider the impact of distributed generation and customers who acquire energy pursuant to NRS 704.787 or chapter 704B of NRS.

6. The utility shall provide a reasonable estimate of the demand from interruptible loads and the total demand of each type of interruptible load.

7. The utility shall identify all standby loads and the total demand of each type of standby load and include an analysis of the likelihood and effect of incurring such demands at the time of the system peak of the utility.

8. All forecast values for the entire system of the utility must be reported. The utility shall separately estimate the contribution to peak demand and energy consumption for the components of the system located within the State of Nevada and for the components of the system located outside the State of Nevada.

9. A resource plan must contain a graphical representation of projected load duration curves for the year following the year in which the resource plan was filed and every fifth year thereafter for the remainder of the period covered by the resource plan.

10. To verify and complete the final forecasts, the utility may evaluate the forecasts with the results of alternative forecasting methods.

11. Any change in the methodology of forecasting used by the utility from that used in the utility's previous resource plan must be identified in the current resource plan of the utility.

Sec. 8. NAC 704.934 is hereby amended to read as follows:

704.934 1. As part of its resource plan, a utility shall submit a demand side plan.

2. The demand side plan must include:

(a) An identification of end-uses for programs for ***energy efficiency and*** conservation . ~~[and demand management.]~~

(b) An assessment of savings attributable to technically feasible programs for ***energy efficiency and*** conservation , ~~[and demand management,]~~ as determined by the utility. The programs must be ranked in a list according to the level of savings in energy or reduction in demand, or both.

(c) An assessment of technically feasible programs to determine which will produce benefits in peak demand or energy consumption. The utility shall estimate the cost of each such program. The methods used for the assessment must be stated in detail, specifically listing the data and assumptions considered in the assessment.

3. In creating its demand side plan, a utility shall consider the impact of applicable new technologies on current and future ~~[demand side]~~ ***energy efficiency and conservation*** options. The consideration of new technologies must include, without limitation, consideration of the potential impact of advances in digital technology and computer information systems.

4. A utility shall include in its demand side plan an energy efficiency program for residential customers which reduces the consumption of electricity or any fossil fuel. The energy efficiency program must include, without limitation, the use of new solar thermal energy sources.

5. The demand side plan must provide a list of the programs for which the utility is requesting the approval of the Commission. The list must include, without limitation:

(a) An estimate of the reduction in the peak demand and energy consumption that would result from each proposed program, in kilowatt-hours and kilowatts saved. The programs must be listed according to their expected savings and their contribution to a reduction in peak demand

and energy consumption based upon realistic estimates of the penetration of the market and the average life of the programs.

(b) An assessment of the costs of each proposed program and the savings produced by the program. If the program can be relied upon to reduce peak demand on a firm basis, the assessment must include the savings in the costs of transmission and distribution.

(c) An assessment of the impact on the utility's load shapes of each proposed and existing program for ***energy efficiency and*** conservation . ~~[and demand management.]~~

(d) If a program is an educational program, the projected expenses of the utility for the educational program.

6. For any ***energy efficiency or*** conservation ~~[or demand management]~~ program which reduces the consumption of electricity or any fossil fuel, a utility shall include in its demand side plan a complete life-cycle analysis of the costs and benefits of the program using the Total Resource Cost Test.

7. The utility shall include with its demand side plan a report on the status of all programs for ***energy efficiency and*** conservation ~~[and demand management]~~ that have been approved by the Commission. The report must include tables for each such program showing, for each year, the planned and achieved reduction in kilowatt-hours, the reduction in kilowatts and the cost of the program.

8. On or before ~~[August 15]~~ ***July 1*** of each year following the filing of its resource plan, the utility shall file with the Commission a copy of the complete analysis that the utility used in determining for the upcoming year which ***energy efficiency and*** conservation ~~[and demand management]~~ programs are to be continued and which programs are to be cancelled. ~~[The]~~ ***Within 180 days after the analysis is filed, the*** Commission will ~~[process this]~~ ***accept the***

analysis ~~[in the same manner as an amendment filed pursuant to NAC 704.9503.]~~ ***as filed, accept the analysis with modification or reject the analysis.***

9. As used in this section:

(a) "New solar thermal energy sources" means energy sources which are installed after the effective date of the utility's energy efficiency program and which reduce the consumption of electricity or any fossil fuel by using solar radiation to heat water or to provide space heating or cooling.

(b) "Total Resource Cost Test" means a method of determining the overall economic efficiency of a demand management program from the perspective of society by measuring the net costs of the program based on its total costs, including, without limitation, the costs to both participants and the utility.

Sec. 9. NAC 704.945 is hereby amended to read as follows:

704.945 1. A utility shall include in its resource plan a table of loads and resources for each supply plan analyzed. The table must include the following data for each year of the resource plan:

(a) The capacity provided by each supply resource;

(b) The total expected capacity of all resources;

(c) The forecasted peak demand;

(d) The estimated impact of new programs for ***energy efficiency and*** conservation ***;*** ~~[and demand management;]~~

(e) The expected capacity and energy provided by renewable resources, categorized by type;

(f) The required planning reserves;

(g) The total capacity required;

(h) The excess or deficiency of capacity without additional resources; and

(i) The excess or deficiency of capacity with additional planned resources.

2. A graph must be included for the preferred plan of the utility showing, over the 20-year planning period:

(a) The total resources requirements;

(b) The total demand without new programs for ***energy efficiency and*** conservation ***;*** ~~[and demand management;]~~

(c) The total demand with new programs for ***energy efficiency and*** conservation ***;*** ~~[and demand management;]~~

(d) The total capacity with additional planned resources; and

(e) The total capacity without additional resources.

3. A graph must be included for the preferred plan that shows, for each year of the 20-year planning period, the excess or required capacity both with and without the additional planned resources.

4. A graph or table must be provided that shows the allocation of the capacity of the transmission system of the utility between bundled retail transmission customers, unbundled retail transmission customers and wholesale transmission customers.

Sec. 10. NAC 704.9475 is hereby amended to read as follows:

704.9475 1. A utility shall conduct an analysis of sensitivity for all major assumptions and estimates used in its resource plan. The analysis must include the:

(a) Forecast of peak demand and energy consumption;

(b) Dates when proposed acquisitions will be in service;

(c) Unit availability;

(d) Costs of power plants;

(e) Prices of fuel;

(f) Amounts of purchased power and corresponding costs;

(g) Schedule, impact and costs of programs for ***energy efficiency and*** conservation ***;*** ~~[and demand management;]~~

(h) Capacity of plants in megawatts;

(i) Discount rates;

(j) Rate of inflation;

(k) Cost of capital;

(l) Environmental costs; and

(m) Economic benefit.

2. The utility shall state the ranges and consequences of uncertainty for each of the assumptions and describe methods of combining various uncertainties.

Sec. 11. NAC 704.9489 is hereby amended to read as follows:

704.9489 1. Each resource plan of a utility must include a detailed action plan based on an integrated analysis of the demand side plan and supply plan of the utility. In its action plan, the utility shall specify all its actions that are to take place during the 3 years commencing with the year following the year in which the resource plan is filed. The action plan must contain:

(a) An introductory section that explains how the action plan fits into the longer-term strategic plan of the utility.

(b) A list of actions for which the utility is seeking the approval of the Commission.

(c) A schedule for the acquisition of data, including planned activities to update and refine the quality of the data used in forecasting.

(d) A specific timetable for acquisition of options for the supply of electric energy and for programs for ***energy efficiency and*** conservation . ~~[and demand management.]~~

(e) If changes in the methodology are being proposed, a description fully justifying the proposed changes, including an analysis of the costs and benefits. Any changes in methodology that are approved by the Commission must be maintained for the period described in the action plan.

(f) A section describing any plans of the utility to acquire additional modeling instruments.

(g) A section for the utility's program for ***energy efficiency and*** conservation , ~~[and demand management.]~~ including:

(1) A description of continued planning efforts;

(2) A plan to carry out and continue selected measures for ***energy efficiency and*** conservation ~~[and demand management]~~ that have been identified as desirable; and

(3) Any impacts of imputed debt calculations associated with energy efficiency contracts in the preferred plan.

(h) A section for the utility's program for acquisition of resources for the supply of electric energy for the period covered by the action plan, including:

(1) The immediate plans of the utility for construction of facilities or long-term purchases of power;

(2) The expected time for construction of facilities and acquisition of long-term purchases of power identified in subparagraph (1);

(3) The major milestones of construction; and

(4) Any impacts of imputed debt calculations associated with renewable energy contracts or energy efficiency contracts in the preferred plan.

2. The action plan must contain an energy supply plan.

3. The action plan must contain a budget for planned expenditures suitable for comparing planned and achieved expenditures. Expenses must be listed in a format that is consistent with the categories and periods to be presented in subsequent filings. The budget must be organized in the following categories:

(a) Forecasting of loads;

(b) ~~[Conservation and demand management;]~~ ***Energy efficiency and conservation;***

(c) Plan for supply; and

(d) Financial plan.

4. The action plan must contain schedules suitable for comparing planned and actual activities and accomplishments. Milestones and points of decision committing major expenditures must be shown.

Sec. 12. NAC 704.9494 is hereby amended to read as follows:

704.9494 1. The Commission will issue an order:

(a) Approving the action plan of the utility as filed; or

(b) If the plan is not approved as filed, specifying those parts of the action plan the Commission considers inadequate.

2. Approval by the Commission of an action plan constitutes a finding that the programs and projects contained in that action plan, other than the energy supply plan, are prudent, including, without limitation, construction of facilities, purchased power obligations, programs for ***energy efficiency and*** conservation ~~[and demand management]~~ and impacts of imputed debt calculations associated with renewable energy contracts or energy efficiency contracts. If the Commission subsequently determines that any information relied upon when issuing its order approving the

action plan was based upon information that was known or should have been known by the utility to be untrue or false at the time the information was presented, the Commission may revoke, rescind or otherwise modify its approval of the action plan.

3. If, at the time that the Commission approves the action plan of the utility, the Commission determines that the elements of the energy supply plan are prudent, the Commission will specifically include in the approval of the action plan its determination that the elements contained in the energy supply plan are prudent. For the Commission to make a determination that the elements of the energy supply plan are prudent:

(a) The energy supply plan must not contain any feature or mechanism that the Commission finds would impair the restoration of the creditworthiness of the utility or would lead to a deterioration of the creditworthiness of the utility.

(b) The energy supply plan must optimize the value of the overall supply portfolio for the utility for the benefit of its bundled retail customers.

(c) The utility must demonstrate that the energy supply plan balances the objectives of minimizing the cost of supply, minimizing retail price volatility and maximizing the reliability of supply over the term of the plan.

➥ Failure by a utility to demonstrate that its energy supply plan is prudent in accordance with this subsection does not otherwise affect approval of the action plan, including the energy supply plan, and the utility may subsequently seek a determination that the energy supply plan is prudent in the appropriate deferred energy proceeding.

4. A utility may recover all costs that it prudently and reasonably incurs in carrying out an approved action plan in the appropriate separate rate proceeding. A utility may recover all costs that are prudently and reasonably incurred in carrying out the approved energy supply plan,

including deviations pursuant to subsection 1 of NAC 704.9504 approved by the Commission in the appropriate deferred energy application filed pursuant to NAC 704.023 to 704.195, inclusive.

Sec. 13. NAC 704.9498 is hereby amended to read as follows:

704.9498 1. Not earlier than 15 months and not later than 21 months after the date on which the utility files its action plan, the utility shall file a report on the progress of its action plan with the Commission and serve a copy of the progress report on all parties of record. The progress report must include:

(a) Information concerning the status of planned facilities approved by the Commission, including any cost or schedule variances;

(b) Information concerning the status of all programs for ***energy efficiency and*** conservation , ~~[and demand management,]~~ including planned and achieved reductions in kilowatt-hours and reduction in demand in kilowatt-hours;

(c) A comparison of budgeted and actual costs for the entire action plan;

(d) An identification of and justification for any significant deviation from the approved action plan, including supporting information;

(e) An updated forecast of energy consumption and peak demand; and

(f) An updated table for loads and resources for the remaining years covered by the 20-year plan.

2. The progress report must be in the same form as the action plan and will be assigned a new docket number by the Commission.

3. The utility or any party of record may request a hearing on the progress report, specifying in its request the reason the utility or party believes a hearing is required. Upon a finding of good cause, the Commission will order a hearing on the matter.

Sec. 14. NAC 704.9522 is hereby amended to read as follows:

704.9522 1. A utility provider shall propose a measurement and verification protocol for all energy efficiency ***and conservation*** measures submitted pursuant to NAC 704.9005 to 704.9525, inclusive.

2. The utility provider shall comply with, and shall ensure that all energy efficiency ***and conservation*** contracts entered into by the utility provider comply with, the most recent measurement and verification protocol approved by the Commission . ~~[at the time an energy efficiency measure is implemented.]~~

Sec. 15. NAC 704.9523 is hereby amended to read as follows:

704.9523 1. All costs of implementing programs for ***energy efficiency and*** conservation ~~[and demand management]~~ must be accounted for in the books and records of ~~[a]~~ ***an electric*** utility separately from amounts attributable to any other activity. All accounts must be maintained in a manner that will allow costs attributable to specific programs to be readily identified.

2. ~~[Except as otherwise provided in subsection 4, a]~~ ***An electric*** utility may, pursuant to subsection 3, recover all ~~[prudent and reasonable]~~ ***reasonably incurred*** costs ~~[incurred in]~~ ***of*** implementing programs for ***energy efficiency and*** conservation ~~[and demand management]~~ that have been ***described in the demand side plan of the electric utility and*** approved by the Commission ***pursuant to NAC 704.9494*** as part of the action plan of the ***electric*** utility, including, without limitation, the costs for labor, overhead, materials, incentives paid to customers, advertising, marketing , ***monitoring*** and evaluation. ~~[The utility may recover approved costs associated with monitoring and evaluating these programs through a general rate case.]~~

3. To recover ***the reasonably incurred*** costs ~~[incurred in]~~ ***of*** implementing programs for ***energy efficiency and*** conservation ~~[and demand management, a]~~ ***, an electric*** utility must:

(a) ~~[Calculate, on a monthly basis, the costs incurred in implementing each program since the end of the test period or period of certification in its last proceeding to change general rates.~~

~~(b) Record the cost of implementing each program, as calculated pursuant to paragraph (a), in a]~~ ***Establish and maintain*** separate ~~[subaccount]~~ ***subsidiary records of the subaccounts*** of FERC Account No. 182.3 (Other Regulatory Assets) for each program ~~[and record an offset in the appropriate subaccount of other FERC accounts.~~

~~(c) Maintain subsidiary records of the subaccounts of FERC Account No. 182.3 for each program.]~~ ***described in the demand side plan of the electric utility and approved by the Commission pursuant NAC 704.9494 as part of the action plan of the electric utility.*** These records must clearly delineate all costs incurred by the ***electric*** utility in implementing each program approved by the Commission ~~[.~~

~~(d) Apply]~~ ***and be maintained by program by month by rate effective period.***

(b) At the time the electric utility files an annual deferred energy accounting adjustment application pursuant to subsection 3 of NRS 704.187, apply to the Commission to establish the following period-specific rates:

(1) A prospective base program cost rate which is determined by allocating in the manner approved by the Commission in the most recent general rate case of the electric utility the total cost of programs for energy efficiency and conservation that are described in the demand side plan approved by the Commission. The prospective base program cost rate for a customer class is an amount equal to the cost allocated to that customer class pursuant to this

subparagraph divided by the projected kilowatt hour sales for that class for the relevant period.

(2) A deferred program cost rate to clear the period-specific balance over 12 months. The deferred program cost rate is an amount equal to the period-specific balance in the subaccount of FERC Account No. 182.3 for the cost of energy efficiency and conservation programs divided by the applicable test period kilowatt hour sales.

4. An electric utility shall account for period-specific costs incurred to implement a program for energy efficiency and conservation and revenues received from the period-specific prospective base program cost rate in the following manner:

(a) On a monthly basis, the electric utility shall record in a subaccount of FERC Account No. 182.3 the program costs incurred and the revenues received from the prospective base program cost rate for the energy efficiency and conservation program.

(b) The electric utility shall apply a carrying charge at the rate of 1/12 of the authorized overall rate of return to the *unamortized* balance in the subaccounts of FERC Account No. 182.3 . ~~If for each program not included in the rate base.~~

~~(c) Clear any balance accumulated in the subaccounts of FERC Account No. 182.3 for each program as a component of an application by the utility to change general rates as follows:~~

~~(1) The Commission will adjust the rate to amortize the balance over a 3-year period, unless otherwise specified by the Commission.~~

~~(2) The utility must begin amortizing costs on the date that the change in general rates becomes effective.~~

~~(3) The utility must include the balance in the subaccounts of FERC Account No. 182.3 for each program, including carrying charges, in the rate base as of the date that ends the test~~

~~period used in the utility's application to change general rates or as of the date that ends the period of certification, whichever is later.~~

~~(4) To calculate revenue requirements, the utility must base the rate of return to be applied to the balance in the subaccounts of FERC Account No. 182.3 for each conservation or demand management program that the utility has carried out on the authorized return on equity plus 5 percent.~~

~~4. Costs incurred in implementing a dispatchable direct load control program must be recovered pursuant to subsection3, except for the costs of incentives paid to customers which are treated as fuel and purchased power expense pursuant to NAC 704.023 to 704.195, inclusive.~~

~~5. As used in this section, "dispatchable direct load control program" means a program offered by a utility pursuant to which customers may agree to allow the utility remotely to interrupt or cycle electrical equipment and appliances, including, without limitation, air conditioners, water heaters and space heaters.]~~

Sec. 16. NAC 704.9056 is hereby repealed.

TEXT OF REPEALED SECTION

704.9056 "Demand management" defined. (NRS 703.025, 704.210, 704.741) "Demand management" means a deliberate reshaping of customers' patterns of use to shift the time of use of electric energy and reduce consumption during the period of the utility's peak load.

NOTICE OF ADOPTION OF REGULATION

The Public Utilities Commission of Nevada adopted regulations assigned LCB File No. R042-10 which pertain to Chapter 704 of the Nevada Administrative Code on June 30, 2010. A copy of the regulations as adopted is attached hereto.

LEGISLATIVE REVIEW OF ADOPTED REGULATIONS AS REQUIRED BY NRS 233B.066 LCB FILE R042-10 (DOCKET NO. 09-07016)

The following informational statement is submitted for adopted amendments to Nevada Administrative Code Chapter 704.

1. **A description of how public comment was solicited, a summary of public response, and an explanation how other interested persons may obtain a copy of the summary.**

Copies of the proposed regulations, notice of intent to act upon the regulation and notice of workshop and hearing were sent by U.S. mail and email to persons who were known to have an interest in the subject of electric utility decoupling. These documents were also made available at the website of the Public Utilities Commission ("PUC"), http://puc.nv.gov, mailed to all county libraries in Nevada, published in the following newspapers:

Elko Daily Free Press
Las Vegas Review Journal
Nevada Appeal
Reno Gazette Journal
Tonopah Times-Bonanza,

and posted at the following locations:

Public Utilities Commission
1150 East William Street
Carson City, Nevada 89701

Public Utilities Commission
101 Convention Center Drive, Suite 250
Las Vegas, Nevada 89109

First Judicial District Court
885 East Musser Street
Carson City, Nevada 89701

Second Judicial District Court
75 Court Street
Reno, Nevada 89501

Eighth Judicial District Court
Regional Justice Center
200 Lewis Avenue
Las Vegas, Nevada 89155

Informal workshops were held on October 1, 2009, October 26, 2009, November 24, 2009, and March 12, 2010, at which time the participants discussed potential regulation language

and other issues related to the rulemaking process. Thereafter, the proposed regulation language was sent to LCB on March 16, 2010.

An additional formal workshop was held on June 10, 2010 and a public hearing was held on June 11, 2010. At that workshop and hearing, Nevada Power Company and Sierra Pacific Power Company, d/b/a NV Energy, the Regulatory Operations Staff, MGM/Mirage, Newmont Mining, Barrick Goldstrike Mines and the Attorney General's Bureau of consumer Protection all generally agreed that they were satisfied with the language and that the proposed regulation met the intent of the statute.

A copy of the transcript of the proceedings is available for review at the offices of the PUC, 1150 East William Street, Carson City, Nevada 89701 and 101 Convention Center Drive, Suite 250, Las Vegas, Nevada 89109.

2. **The number of persons who:**
(a) Attended each hearing: June 10, 2010 - 8; June 11, 2010 - 9
(b) Testified at each hearing: June 10, 2010 - 7; June 11, 2010 - 8
(c) Submitted to the agency written comments: 31

3. **A description of how comment was solicited from affected businesses, a summary of their response, and an explanation how other interested persons may obtain a copy of the summary.**

Comments were solicited from affected businesses in the same manner as they were solicited from the public.

The summary may be obtained as instructed in the response to question #1.

4. **If the regulation was adopted without changing any part of the proposed regulation, a summary of the reasons for adopting the regulation without change.**

The permanent regulations were adopted on June 30, 2010. It was not revised as the participants in the Workshop and Hearing and the Commission believed the regulation met the intent of the statute.

5. **The estimated economic effect of the adopted regulation on the businesses which it is to regulate and on the public. These must be stated separately, and each case must include:**
(a) Both adverse and beneficial effects; and
(b) Both immediate and long-term effects.

(a) Both adverse and beneficial effects:

The adopted regulation will have little or no economic impact on the public, aside from informing them of how to dispose of and/or recycle certain electronic waste (such as compact fluorescent light bulbs). Prior to adoption of the regulation, electric utilities

were required to send semi-annual notices to customers containing information on a number of issues. The adopted regulation requires said mailing to include information regarding disposal and/or recycling of certain waste. Including additional information in the previously required mailings, as required by the adopted regulation will not significantly increase the cost to the electric utilities.

(b) Both immediate and long-term effects:

See Item # 5(a).

6. **The estimated cost to the agency for enforcement of the adopted regulation.**

There is no additional cost to the agency for enforcement of these regulations.

7. **A description of any regulations of other state or government agencies which the proposed regulation overlaps or duplicates and a statement explaining why the duplication or overlapping is necessary. If the regulation overlaps or duplicates a federal regulation, the name of the regulating federal agency.**

These regulations do not overlap or duplicate any federal, state, or local regulations.

8. **If the regulation includes provisions that are more stringent than a federal regulation which regulates the same activity, a summary of such provisions.**

N/A

9. **If the regulation provides a new fee or increases an existing fee, the total annual amount the agency expects to collect and the manner in which the money will be used.**

N/A

10. **If the proposed regulation is likely to impose a direct and significant economic burden upon a small business or directly restrict the formation, operation or expansion of a small business? What methods did the agency use in determining the impact of the regulation on a small business?**

The PUC has determined that the proposed regulations do not impose a direct and significant economic burden upon a small business or restrict the formation, operation or expansion of a small business. In making this determination, the PUC adopted the findings of Staff, which conducted a Delphi Method exercise to determine the impacts. The Delphi Method is a systematic, interactive, forecasting method based on independent inputs of selected experts.

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Rulemaking to adopt, amend, or repeal regulations regarding electric utility decoupling and other related utility matters in accordance with Senate Bill 358 (Section 11.3).	)))))	Docket No. 09-07016

At a general session of the Public Utilities Commission of Nevada, held at its offices on June 30, 2010.

PRESENT: Chairman Sam A. Thompson
Commissioner Rebecca D. Wagner
Commissioner Alaina Burtenshaw
Assistant Commission Secretary Nancy Krassner

ORDER

The Public Utilities Commission of Nevada ("Commission") makes the following findings of fact and conclusions of law:

1. The Public Utilities Commission of Nevada ("Commission") voted to open a rulemaking to adopt, amend, or repeal regulations regarding electric utility decoupling and other related utility matters in accordance with Senate Bill 358 (Section 11.3), passed during the 2009 legislative session. This matter has been designated as Commission Docket No. 09-07016.

2. This matter is being conducted by the Commission pursuant to the Nevada Revised Statutes and the Nevada Administrative Code ("NAC") Chapters 233B, 703, and 704.

3. On September 9, 2009, the Commission issued a Notice of Rulemaking, Request for Comments and Proposed Regulations and Notice of Workshop. Comments, some including suggested regulation language, were filed at various times by the Regulatory Operations Staff ("Staff") of the Commission, Nevada Power Company d/b/a/ NV Energy and Sierra Pacific Power Company d/b/a/ NV Energy (collectively referred to as "NV Energy"), the Attorney

General's Bureau of Consumer Protection ("BCP"), the Southwest Energy Efficiency Project ("SWEEP"), Newmont Mining Corporation ("Newmont"), MGM/Mirage Corporation ("MGM"), and Barrick Goldstrike Mines ("Barrick"). Informal workshops were held on October 1, 2009, October 26, 2009, November 24, 2009 and March 12, 2010.

4. On March 23, 2010, the Commission issued a Procedural Order. The proposed regulations were attached. Staff was directed to conduct an investigation pursuant to NRS 233B.0608 to determine whether the proposed regulations were likely to: (a) impose a direct and significant economic burden upon a small business; or (b) directly restrict the formation, operation or expansion of a small business.

5. On March 16, 2010, the Commission sent the proposed regulations to the Legislative Counsel Bureau ("LCB"). The LCB designated the proposed regulations as LCB File No. R042-10.

6. On April 8, 2010, the LCB returned the proposed regulations to the Commission in revised form. The returned regulation is attached hereto as Attachment No. 1, and incorporated herein by this reference.

7. On April 9, 2010, the Commission issued a Notice of Intent to Act Upon a Regulation, Notice of Workshop and Notice of Hearing.

8. On April 22, 2010, following Staff's recommendation at Agenda 06-10, the Commission issued an Order finding that the proposed regulations do not impose a direct and significant economic burden upon a small business, nor do they directly restrict the formation, operation or expansion of a small business.

9. A duly noticed Workshop and Hearing were held on June 10 and 11, 2010, respectively. Appearances were made by Staff, NV Energy, BCP, Newmont, Barrick and MGM.

10. The participants agreed with the proposed regulation and felt it accomplished the legislative intent of section 11.3 of SB 358.

11. Because the proposed regulations contemplate a new filing establishing collection of a base amount to offset against potential lost revenues, the Commission and the participants discussed the transition phase. NV Energy proposed a plan for the transition phase which was filed on June 11, 2010, a copy of which is attached hereto as Attachment No. 2 and incorporated herein by this reference.

12. The participants agreed that the procedure outlined in Attachment No. 2 was acceptable, and the Commission hereby cites it with approval.

13. The Commission finds that it is in the public interest to adopt as permanent the proposed regulations.

THEREFORE, based on the foregoing findings of fact and conclusions of law, it is hereby ORDERED that:

1. The proposed regulations, attached hereto as Attachment No. 1 are ADOPTED AS PERMANENT pursuant to NRS 233B.063.

2. The Commission retains jurisdiction for the purpose of correcting any errors which may have occurred in the drafting or issuance of this order.

By the Commission,

/s/
SAM A. THOMPSON
Chairman and Presiding Officer

/s/
REBECCA D. WAGNER
Commissioner

/s/
ALAINA BURTENSHAW
Commissioner

Attest: /s/
NANCY KRASSNER,
Assistant Commission Secretary

Dated: Carson City, Nevada
7-2-2010
(SEAL)

EXHIBIT 7

NAC 704.9523 Accounting for and recovery of costs of implementing programs for energy efficiency and conservation. (NRS 703.025, 704.210, 704.785)

1. All costs of implementing programs for energy efficiency and conservation must be accounted for in the books and records of an electric utility separately from amounts attributable to any other activity. All accounts must be maintained in a manner that will allow costs attributable to specific programs to be readily identified.

2. An electric utility may, pursuant to subsection 3, recover all reasonably incurred costs of implementing programs for energy efficiency and conservation that have been described in the demand side plan of the electric utility and approved by the Commission pursuant to NAC 704.9494 as part of the action plan of the electric utility, including, without limitation, the costs for labor, overhead, materials, incentives paid to customers, advertising, marketing, monitoring and evaluation.

3. To recover the reasonably incurred costs of implementing programs for energy efficiency and conservation, an electric utility must:

(a) Establish and maintain separate subsidiary records of the subaccounts of FERC Account No. 182.3 (Other Regulatory Assets) for each program described in the demand side plan of the electric utility and approved by the Commission pursuant to NAC 704.9494 as part of the action plan of the electric utility. These records must clearly delineate all costs incurred by the electric utility in implementing each program approved by the Commission and be maintained by program by month by rate effective period.

(b) At the time the electric utility files an annual deferred energy accounting adjustment application pursuant to subsection 3 of NRS 704.187, apply to the Commission to establish the following period-specific rates:

(1) A prospective base program cost rate which is determined by allocating in the manner approved by the Commission in the most recent general rate case of the electric utility the total cost of programs for energy efficiency and conservation that are described in the demand side plan approved by the Commission. The prospective base program cost rate for a customer class is an amount equal to the cost allocated to that customer class pursuant to this subparagraph divided by the projected kilowatt hour sales for that class for the relevant period.

(2) A deferred program cost rate to clear the period-specific balance over 12 months. The deferred program cost rate is an amount equal to the period-specific balance in the subaccount of FERC Account No. 182.3 for the cost of programs for energy efficiency and conservation divided by the applicable test period kilowatt hour sales.

4. An electric utility shall account for period-specific costs incurred to implement a program for energy efficiency and conservation and revenues received from the period-specific prospective base program cost rate in the following manner:

(a) On a monthly basis, the electric utility shall record in a subaccount of FERC Account No. 182.3 the program costs incurred and the revenues received from the prospective base program cost rate for the program for energy efficiency and conservation.

(b) The electric utility shall apply a carrying charge at the rate of 1/12 of the authorized overall rate of return to the unamortized balance in the subaccounts of FERC Account No. 182.3.

(Added to NAC by Pub. Utilities Comm'n by R004-04, eff. 5-25-2004; A by R162-07, 6-17-2008; R051-09, 1-28-2010; R042-10, 7-22-2010)

EXHIBIT 8

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
STAFF'S THIRD SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
September 17, 2012

STF 3.01

Energy Efficiency. Reference David G. Hutchens Direct Testimony, Page 15, lines 4-5, Please fully explain how the Company's 3 year proposal is compliant with A.A.C R14-2-2405 which states, "*Except as provided in R14-2-2418, on June 1 of each odd year, or annually at the election of each affected utility, each affected utility shall file with Docket Control, for Commission review and approval, an implementation plan describing how the affected utility intends to meet the energy efficiency standard for the next one or two calendar years, as applicable, except that the initial implementation plan shall be filed within 30 days of the effective date of this Article.*"

RESPONSE:

The purpose of the EERP is to create an alternative mechanism that will fulfill the spirit and objectives of the Electric Energy Efficiency Standard set forth in A.A.C. R14-2-2404. If the Commission approves the Company's proposal as part of the rate case Order, the Commission will have effectively provided a waiver from the specific requirements set forth in A.A.C. R14-2-2405.

Because the Company will not be filing annual implementation plans, the most recent Commission-approved Energy Efficiency Implementation Plan will be used as the initial document for the EERP. The Company will then file any updates or changes to programs as part of its March 1 DSM progress report required by A.A.C. R-14-2-2409.

RESPONDENT:

Denise Smith

WITNESS:

David Hutchens and Craig A. Jones

Arizona Corporation Commission ("Commission")
Demand-Side Management ("DSM")
Energy Efficiency ("EE")
Energy Efficiency Resource Plan ("EERP")
Tucson Electric Power Company ("TEP" or the "Company")
UNS Energy Corporation fka UniSource Energy Corporation ("UNS")
UniSource Energy Services ("UES")
UniSource Energy Development Company ("UED")
UNS Electric, Inc. ("UNS Electric")
UNS Gas, Inc. ("UNS Gas")

EXHIBIT 9

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
STAFF'S THIRD SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
September 17, 2012

STF 3.06

Energy Efficiency. Reference David G. Hutchens Direct Testimony, Page 20, lines 16-22 Assuming that the Commission approves a regulatory asset, specifically identify and fully explain what accounting standards would prohibit the Commission from setting a longer (or shorter amortization period). If the Commission sets a 5 year amortization, would the accounting standards make it such that the regulatory asset was less likely to be fully recovered? Please fully explain your answer.

RESPONSE:

Accounting Standard Codification ("ASC") under U.S. Generally Accepted Accounting Principles ("GAAP") 980-340-25-1 Recognition of Regulatory Assets allows the deferral of costs as long as it is probable that those specific costs are subject to recovery in future revenues. Accounting standards do not prohibit the Commission from setting a longer (or shorter) amortization period. TEP's EERP is a 3-year pilot program. TEP is requesting recovery over 4 years. Recovery periods that extend over a longer time frame should be carefully evaluated, considering the nature of the related cost. If the Commission sets a 5-year amortization period, application of accounting standards could make it such that the regulatory asset is less likely to be fully recovered.

ASC-980-340-25-1 requires a supportable conclusion that the recovery of regulatory assets is probable. Cost of service regulation is based on implicit presumptions that (1) operating expenses should normally be recovered in the period in which the expenses are incurred, and (2) an allowance for a return on investment should normally be recovered in the period during which the investment is used to provide services to customers. Departure from those norms requires professional judgment in the determination of the appropriate recovery period. Subjective decisions regarding a longer recovery period introduces risk and uncertainty about whether past regulatory actions will be upheld due to potential changes in the political or regulatory climate.

RESPONDENT:

Georgia Hale and Annette Candelaria

WITNESS:

Karen Kissinger and David Hutchens

EXHIBIT 10

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
STAFF'S THIRD SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
September 17, 2012

STF 3.13

Energy Cost Adjustor. Reference David G. Hutchens Direct Testimony, Page 25, lines24-26, please fully explain your statement, "*this will be detrimental to TEP's financial health and may adversely impact its access to capital on reasonable terms.*"

RESPONSE:

As stated in Mr. Hutchens' direct testimony, most major compliance projects take a significant time to design, permit and construct. For example, the SCR facilities at San Juan require investments over four to five years before the projects are complete. As a result, TEP would be investing hundreds of millions of dollars over the course of several years but would be precluded from any recovery of that investment until years later. Investing the equivalent of approximately 30 percent of TEP's rate base for several years without receiving any return on that investment would put pressure on the Company's ability to maintain its current credit ratings.

If TEP's credit ratings were to be lowered due to weakening cash flows resulting from the Company's inability to earn a return on and of the significant amount invested between rate cases, TEP's cost of debt would increase, thus increasing costs to ratepayers. Weakening financial metrics would likely put downward pressure on UNS's stock price, which would also increase the cost of equity financing available to TEP.

RESPONDENT:

Jo Smith

WITNESS:

Kevin Larson

EXHIBIT 11

BEFORE THE ARIZONA CORPORATION COMMISSION

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

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	DOCKET NO. E-01345A-11-0224

DIRECT

TESTIMONY

OF

MICHAEL J. MCGARRY, SR.

ON BEHALF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

NOVEMBER 18, 2011

service tariff filing for Illinois Power. From July 1985 through October 1997, I was employed by the New York State Department of Public Service ("NYSDPS") in its Utility Operational Audit Section in which the staff conducted focused operational audits in many facets of utility operations for all sectors of the utility industry, including gas, electric, telecommunications, and water. Prior to my employment with the NYSDPS, I was a rate analyst with Orange and Rockland Utilities (1981 to 1983) and then Seminole Electric Cooperative (1983 to 1985). I received my Masters of Business Administration from the State University of New York at Buffalo in 1996 and a Bachelor of Arts in Economics from Potsdam College (SUNY) in 1981.

Q. Have you prepared an attachment summarizing your educational background and regulatory Experience?

A. Yes. Attachment MJM-1 provides details concerning my experience and qualifications.

Q. Have you previously testified before the Arizona Corporation Commission?

A. No.

Q. Have you testified before commissions in other jurisdictions?

A. Yes. I have presented or supported testimony in Colorado, Delaware, Illinois, Maine, Maryland, Michigan, Missouri, New York, North Dakota, Nova Scotia, Ohio, Pennsylvania, and Utah. These proceedings included testimony involving revenue requirements, power supply costs, management decisions and prudence impacts, operations and maintenance expenses, capital investments, and project management. A complete list is included in Attachment MJM-1.

EXHIBIT 12

CONFIDENTIAL

EXHIBIT 13

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

MARC SPITZER, Chairman
JIM IRVIN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
MIKE GLEASON

Arizona Corporation Commission
DOCKETED
OCT 14 2003
DOCKETED BY

IN THE MATTER OF THE APPLICATION OF ARIZONA WATER COMPANY, AN ARIZONA CORPORATION, FOR ADJUSTMENTS TO ITS RATES AND CHARGES FOR UTILITY SERVICE FURNISHED BY ITS NORTHERN GROUP AND FOR CERTAIN RELATED APPROVALS.

DOCKET NO. W-01445A-00-0962

DECISION NO. 66400

OPINION AND ORDER
PHASE II (ARSENIC TREATMENT COST RECOVERY MECHANISM)

DATES OF HEARING: October 3 and 18, 2002; June 26, 2003

PLACE OF HEARING: Phoenix, Arizona

ADMINISTRATIVE LAW JUDGE: Dwight D. Nodes

APPEARANCES: Mr. Norman James, FENNEMORE CRAIG, on behalf of Arizona Water Company;

Mr. Daniel W. Pozefksy, Attorney, on behalf of the Residential Utility Consumer Office;

Ms. Kay Bigelow, City Attorney, on behalf of the City of Casa Grande;

Mr. Walter W. Meek, on behalf of the Arizona Utility Investors Association, Inc.; and

Mr. David Ronald, Staff Attorney, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission.

BY THE COMMISSION:

I. INTRODUCTION

Arizona Water Company's ("Arizona Water" or "Company") Northern Group serves approximately 16,000 customers under five different sets of rate schedules (Sedona, Pinewood, Rimrock, Lakeside, and Overgaard). In November 2000, Arizona Water filed an application with the Arizona Corporation Commission ("Commission") for rate increases for the five Northern Group systems. In its application, Arizona Water also sought approval to reorganize these systems into two

O&M costs whether the Company leases or operates the facilities itself. Ms. Diaz Cortez testified that RUCO's recommendation could be accomplished by requiring lease payments to be broken out into capital costs and O&M costs, and allowing the Company to recover a return on, and depreciation of, the incremental arsenic plant. However, under RUCO's recommendation, all O&M costs associated with the arsenic treatment facilities would require examination in a full rate case prior to being afforded recovery (RUCO Ex. 2, at 6-7)[7].

After considering the arguments regarding the O&M recovery issue, we believe the modified ACRM proposed by Staff and the Company is a reasonable compromise of the positions previously advocated by those parties. In addition to providing a mechanism for recovery of capital costs incurred by Arizona Water, which costs are not opposed even by RUCO, the modified ACRM offers the Company an opportunity to recover limited verifiable O&M costs in a timely manner. The proposed ACRM also treats leasing and owning arsenic treatment facilities on an equal basis, thereby affording Arizona Water the flexibility to negotiate the least-cost means of complying with federal arsenic limit mandates. However, the recovery of O&M expenses is confined to specific and narrowly defined costs in order to enable Staff and other parties to more easily audit expenditures incurred by the Company for the treatment facilities. The Company also retains the opportunity to file a general rate application.

B. Number of Step Increases

The parties also disagree regarding the number of step increases that should be permitted prior to the Company's next full rate case in 2007. Arizona Water proposed that it should be entitled to three step increases, while Staff and RUCO recommend that each affected system be limited to two step increases (Ex. A-1, at 10; Ex. S-1, at 11, RUCO Ex. 1, at 5). Arizona Water argues that the ability to request three step increases will allow the Company greater flexibility and will enable it to better match operating income with debt service costs. Arizona Water also contends that three step increases will be preferable for customers because the increases will be implemented in smaller increments. The Company claims smaller increases will be even more important if the Commission

[7] RUCO also raised the argument that the modified ACRM exceeds the scope of the Commission's legal authority with respect to approval of automatic adjustment mechanisms. RUCO's legal arguments are addressed below.

EXHIBIT 14

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

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

Arizona Corporation Commission
DOCKETED
MAY 24 2012
DOCKETED BY

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, AND TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.

DOCKET NO. E-01345A-11-0224

DECISION NO. 73183

OPINION AND ORDER

DATES OF HEARING:	July 18, 2011 (Procedural Conference); October 7, 2011 (Public Comments – Sun City, Arizona); December 16, 2011 (Special Open Meeting); January 19, 2012 (Public Comments – Phoenix, Arizona); January 19, 2012 (Pre-Hearing Conference); January 26, 27, 30, 31, February 1, 2, and 3, 2012.
PLACE OF HEARING:	Phoenix, Arizona
ADMINISTRATIVE LAW JUDGE:	Lyn Farmer
IN ATTENDANCE:	Gary Pierce, Chairman Bob Stump, Commissioner Sandra D. Kennedy, Commissioner Paul Newman, Commissioner Brenda Burns, Commissioner
APPEARANCES:	Ms. Meghan H. Grabel and Mr. Thomas L. Mumaw, Law Department, PINNACLE WEST CAPITAL CORPORATION, on behalf of the Applicant; Mr. Michael M. Grant, GALLAGHER & KENNEDY, PA, on behalf of Arizona Investment Council; Mr. Craig A. Marks, CRAIG A. MARKS, PLC, on behalf of AARP; Mr. Timothy M. Hogan, ARIZONA CENTER FOR LAW IN THE PUBLIC INTEREST; on behalf of Southwest Energy Efficiency Project, Western Resource Advocates, Arizona School Boards Association, and Arizona Association of School Business Officials;

updated annually documenting program and measure savings assumptions and incremental costs.

X. Rate Treatment Related to any Acquisition by APS of Southern California Edison's Share of Four Corners Units 4-5 – This Section provides that this docket will remain open until December 31, 2013, for APS to file a request to adjust its rates to reflect the rate base and expense effects associated with (1) the acquisition of Southern California Edison's ("SCE") ownership interest in Four Corners Units 4 and 5, and (2) the retirement of Units 1-3, as well as any cost deferral authorized in the Commission's Decision in the Four Corners acquisition docket; that APS is authorized to request amendments to the PSA Plan of Administration to include the post-acquisition Operations and Maintenance expense associated with Four Corners Units 1-3 as a cost of producing off-system sales until closure of Units 1-3, provided that such costs do not exceed off-system sales revenue in any given year; that any filing seeking a rate adjustment must include specific schedules and any proposed adjustment rider must spread the costs on an equal percentage basis across all rate schedules and will not become effective before July 1, 2013; and that rates are adjusted only if the Commission finds the Four Corners transaction to be prudent.

XI. Modification to Environmental Improvement Surcharge – This Section withdraws the proposed ERA mechanism; revises the existing Environmental Improvement Surcharge ("EIS") to recover the capital carrying costs associated with government-mandated environmental controls, subject to a cap; resets the existing EIS to zero; and revises the EIS Plan of Administration to implement these changes.

XII. Cost Deferral Related to Changes in Arizona Property Tax Rate – This Section allows APS to defer without interest for future recovery: 25 percent of the prorated property tax rate increase in 2012, 50 percent in 2013, and 75 percent each year thereafter, and 100 percent of all property tax rate decreases; recovery will begin after the next general rate case with recovery of a positive balance spread over 10 years and a negative balance over three years; and the signatories may review the deferrals for reasonableness and prudence.

XIII. Transmission Cost Adjustment Mechanism – This Section provides that the current level of transmission costs in base rates will remain in base rates; APS will file its revised TCA tariff and supporting documents by May 15 of each year, and the annual TCA adjustment will become effective

June 1 of each year unless Staff requests review or the Commission orders otherwise; and the TCA Plan of Administration is modified to include the new provisions.

XIV. Low Income Programs – This Section provides that funds remaining in the bill assistance program approved in Decision No. 69663 may be used to assist customers whose incomes are less than or equal to 200 percent of the Federal Poverty Income Guidelines; and that the billing method for low income customers will be simplified by including PSA and the Demand Side Management Adjustor Charge ("DSMAC") charges to their rate schedule and then applying a discount to the total bill, such that there will be no bill impact to low income customers as a result of the billing method change.

XV. Service Schedule 3 (Line Extensions) – This Section provides that Version 12 of Service Schedule 3, as approved in Decision No. 72684 (November 18, 2011), will become effective on the date that rates set herein are effective.

XVI. Bill Presentation – This Section provides that APS will initiate stakeholder meetings within 90 days that will address issues related to making APS' bill easier for customers to understand and requires APS to file an application for any authorization needed to modify its bill presentation and explain how stakeholder input during the process was included.

XVII. Rate Design – This Section provides that APS' proposed Experimental Rate Schedule AG-1, a buy-through rate for large commercial and industrial customers (that does not address the subject of retail competition), should be approved as modified and set forth in Attachment J; that if there are any unmitigated lost fixed generation costs related to the AG-1 Experimental Rate in APS' next rate case, APS should explain why and shall not propose to recover such costs from residential customers; that APS shall file a study in its next rate case to support costs of various charges in Service Schedule 1, taking into account the impact Smart Grid technology may have on the costs; the request to establish Service Schedule 9, an economic development schedule is withdrawn in favor of the use of Commission-approved special contracts; and other rate design issues are resolved in Attachment K.

XVIII. Compliance Matters – This Section provides that within ten days of this Decision, APS shall file compliance schedules for Staff's review and that subject to that review, the schedules

will become effective on the effective date of new rates; that on or before May 31 each year, APS shall file a report with the Commission that identifies the extent of the challenges regarding workforce planning, the specific actions that APS is taking to address the issue, and the progress it is making toward meeting those goals; and provides that the rating agencies communications report filing requirement found in Decision No. 70667 is eliminated.

XIX. Force Majeure Provision – This Section sets out the conditions whereby APS, the Commission, or a signatory may request a change in or review of base rates.

XX. Commission Evaluation of Proposed Settlement – This Section provides that if the Commission fails to issue an order adopting all material terms of the Settlement Agreement, any or all of the signatories may withdraw from the agreement and pursue without prejudice their respective remedies at law; provides that for purposes of the Settlement Agreement, whether a term is material is in the discretion of the signatory choosing to withdraw from the Settlement Agreement, and if a signatory withdraws from the Settlement Agreement and files an application for rehearing, the other signatories except for Staff, shall support the application for rehearing.

XXI. Miscellaneous Provisions – This Section provides that the signatories shall support and defend the Settlement Agreement and shall make reasonable and good faith efforts to obtain a Commission order approving the Settlement Agreement; and that to the extent any provision of the Settlement Agreement is inconsistent with any existing Commission order, rule, or regulation, the Settlement Agreement shall control and that each term is in consideration of all other terms and the terms are not severable.

Benefits of the Settlement Agreement as Identified by the Parties

Staff

Staff finds that the provisions of the proposed Settlement Agreement are in the public interest and that the Commission should approve it. Staff explains that the goal of the 2009 settlement agreement approved by the Commission was to improve APS' standing in the investment community, provide predictability with rate case filings and timing, and establish a strong

commitment to Arizona's energy future.[44] This Settlement Agreement is designed to build upon the progress toward those goals while preserving the Commission's flexibility to implement policy objectives in energy efficiency and renewables. Staff believes that the Settlement Agreement was the product of a transparent and open process involving a diverse group of stakeholders, and that the end result balances APS' financial stability with benefits to customers.

Those benefits include:

- An overall zero dollar base rate increase;
- A zero percent bill impact for the remainder of 2012 (Commission-approved adjustors (including the possibility of a Four Corners rider pursuant to paragraph 10.3 of the Agreement) may increase customer bills after December 31, 2012);
- An increase in rate stability, including a four year period without base rate increases;
- A buy-through rate for industrial and large commercial customers that holds residential customers harmless in the event that there are stranded fixed costs;
- A narrowly-tailored Lost Fixed Cost Recovery ("LFCR") mechanism that supports energy efficiency ("EE") and distributed generation ("DG") at any level or pace set by the Commission;
- An opt-out rate design for residential customers who choose not to participate in the LFCR;
- A process for simplifying customer bills; and
- Bill assistance for additional low income customers at shareholder expense.[45]

Staff explains that the Signatories intended to provide the Commission with maximum flexibility in setting EE and DG policy and therefore, there are no specific EE or RES targets or requirements built into the Settlement Agreement. Staff noted that there are components of the Settlement Agreement that will allow continued improvement in APS' financial standing, including; the settlement itself, which reflects "the positive climate of the Commission's process;"[46] the inclusion of 15 months of post test year plant; a 10 percent return on equity; the LFCR; and the other parts of the Settlement Agreement that support the Company's ability to accept a four year stay out.

[44] Staff's Opening Brief at 5.
[45] Staff Opening Brief at 6.
[46] Tr. at 26, AIC Opening Statement.

Staff argues that the Settlement Agreement appropriately balances consumer and shareholder interests and identifies the following provisions that will benefit consumers:

1) Rate Case Filing Moratorium – Staff believes that the four year stay-out whereby APS will not file its next general rate case before May 31, 2015 and new base rates will not take affect before July 1, 2016, will provide customers with rate stability while also providing APS with sufficient revenue to provide safe and reliable electric service. Staff disagrees with SWEEP's argument that the stay out provision should be shortened to three years, because Staff believes that stay-out provisions encourage utilities to control costs, which can lead to lower rates in future rate cases. Staff also believes that the Settlement Agreement was "crafted to permit maximum flexibility to the Commission in the implementation of new policy while providing a means to make the Company whole."[47]

2) No Base Rate Increase – Staff notes that although APS initially proposed a $95.49 million total rate increase, the proposed Settlement Agreement provides no base rate increase. The change to base rates includes a non-fuel base rate increase of $116.3 million (including post test year plant in service as of March 31, 2012), a fuel base rate decrease of $153.1 million, and a transfer of cost recovery from the RES to base rates in the amount of approximately $36.8 million. The base cost of fuel and purchased power will decrease from $0.037571 per kWh to $0.032071 per kWh. Staff believes that even though adjustor mechanisms may continue to fluctuate and increase bills, "the fact that base rates will remain constant for a four-year period is a significant benefit to customers."[48]

3) A Bill Impact of Zero or Slightly Negative Once New Rates Take Effect for the Remainder of 2012 - APS has agreed to delay recovery of a portion of its fuel and purchased power costs until early 2013 and this delay will allow a zero or slightly negative bill impact until February 1, 2013.[49] This benefits customers by not increasing base rates during the summer when usage is typically higher and by decreasing the frequency of bill impacts associated with the reset of fuel and purchased power costs which would have occurred in July 2012.

4) A Rate of Return on Equity that is 100 Basis Points Below APS' Existing Return on

[47] Staff Opening Brief at 38.
[48] *Id.* at 13.
[49] The PSA reset will occur in February 2013 and true-up its recovery of fuel and purchased power expenses.

5) Rate Treatment Related to APS Proposed Acquisition of Four Corners – Staff explained that APS believes that this provision is essential to the four year rate moratorium, noting that the non-fuel related annual revenue requirement associated with the Four Corners transaction amounts to approximately $70 million annually. Staff also explained that the Settlement Agreement would lower the balance of the cost deferrals, because the costs would begin to be collected sooner.[65] Any recovery of costs would occur only upon a finding by the Commission that the transaction and costs were prudent.

6) Elimination of the 90/10 Sharing Is In the Public Interest – Staff believes that the elimination of the 90/10 sharing provision and two new PSA provisions will produce benefits for customers when there are lower fuel prices and will provide incentives for APS to manage its PSA balance. The PSA is "a cost tracking mechanism designed to allow APS to recover costs associated with obtaining power supplies in a more effective manner due to the short-term volatility in power costs" and tracks how much actual fuel and purchased power costs deviate from the amount recovered through APS' base cost of fuel and purchased power collected in base rates.[66] The 90/10 sharing provision splits the over or under collection of fuel costs between ratepayers and the Company. When actual fuel costs exceed base fuel rates, APS can collect 90 percent of those costs, and when actual fuel costs are less than base fuel rates, APS can keep 10 percent of those savings. The PSA sharing mechanism is designed to give APS a financial incentive to prudently plan for and acquire its purchased power and fuel. Under the Settlement Agreement, the 90/10 sharing provision is replaced with periodic audits of APS' fuel and power procurement, with the first audit for calendar year 2014; and with the application of interest rates that vary depending upon whether there is an under or over collection of the PSA balance. Staff believes that these provisions will produce benefits for customers when fuel prices are lower and will provide incentives for APS to better manage its PSA balances.

7) The EIS and Property Tax Deferrals Were Important In Achieving A Longer Stay-Out And Are In the Public Interest As Well - Staff believes that the changes to the EIS are in the public

[65] Staff Opening Brief at 27.
[66] Staff Ex. 4, Solganick November 18, 2011 Direct Testimony at 17.

interest because now APS will invest its own funds to pay for government-mandated environmental controls, and the EIS will only collect the capital carrying costs, subject to a cap equal to the charge currently in place for the EIS. The EIS will be reset to zero on the effective date of new rates adopted in this Decision. The property tax deferral was an important component of APS' ability to agree to a four year stay out, and as Staff explains, the amount to be deferred is limited and any positive balance will be recovered over 10 years while any negative balance will be refunded over 3 years.

Staff believes that the Settlement Agreement results in just and reasonable rates and that the impact on customers' bills will be reasonable. Staff notes the following bill impacts from adopting the Settlement Agreement, and also from various adjustors and surcharges:

- A modest reduction across customer classes, generally around one percent on the effective date of the new rates, expected to be July 1, 2012, resulting from delaying the reset of the existing PSA to reflect new base fuel rates;
- In early 2013 when the PSA resets, average residential customer bills will increase by approximately 6.4 percent;
- If the Four Corners transaction closes in 2012, there would be a reduction in the PSA forward component, resulting in a negative 2.9 percent PSA impact, and the February 2013 PSA reset would be approximately 3.5 percent instead of 6.4 percent;
- When the first LFCR adjustment is approved by the Commission, a 0.2 percent adjustment to bills would occur on March 1, 2013;
- If the Four Corners transaction closes, then no earlier than July 2013, a 3 percent nonfuel increase to the average residential customer bill is possible if approved by the Commission; and
- Other adjustor charges could impact customer bills, including the DSMAC, the TCA, and the RES.[67]

. . .

[67] Staff Opening Brief at 31-32. These are estimates and not rates adopted in this Decision.

EXHIBIT 15

Exhibit___MJM-13 - Staff Derivation of Alternative plan Revenue Requirement for EERP

Line	Description	Amount	Comment
1	Original Cost	$11,500,000.00	Estimate - Actual amount would be recorded here. Used Staff proposed budget from E-01933A-11-0055 for 6 months
2	Asset Life	7	Based on average usefulful life of measures - see Exhibit____ MJM-XX, Line 4
3	Income Tax Rate	39.57%	
4	Nominal Return	7.0000%	Per Staff Witness S.Keith Berry, Ph.D
5	Gross Conversion Factor	1.659	TEP Schedule C-3

		Comment	2014 **	2015	2016	2017	2018	2019	2020	2021	2022	2023
6	Regulatory Assest Amortization	Original Cost ÷ Years	$ 1,642,857	$ 1,642,857	$ 1,642,857	$ 1,642,857	$ 1,642,857	$ 1,642,857	$ 1,642,857	$ -	$ -	$ -
7	Tax Depreciation	Original Cost	$ 11,500,000									
8	Net Book basis (end of year)	Line 7 minus Line 6	$ 9,857,143	$ 8,214,286	$ 6,571,429	$ 4,928,571	$ 3,285,714	$ 1,642,857	$ -	$ -	$ -	$ -
9	Tax basis (end of year)											
10	ADIT (end of year) Book basis minus tax basis) times tax rate)	Line 8 * income tax rate (line 3)	$ 3,900,471	$ 3,250,393	$ 2,600,314	$ 1,950,236	$ 1,300,157	$ 650,079	$ -	$ -	$ -	$ -
11	Rate Base, end of year											
12	Regulatory Asset	Line 1	$ 11,500,000	$ 11,500,000	$ 11,500,000	$ 11,500,000	$ 11,500,000	$ 11,500,000	$ 11,500,000	$ 11,500,000	$ 11,500,000	$ 11,500,000
13	Accumulated Amortization	Sum Line 6 to 2014 to YTD	$ (1,642,857)	$ (3,285,714)	$ (4,928,571)	$ (6,571,429)	$ (8,214,286)	$ (9,857,143)	$ (11,500,000)	$ (11,500,000)	$ (11,500,000)	$ (11,500,000)
14	ADIT	Line 10	$ (3,900,471)	$ (3,250,393)	$ (2,600,314)	$ (1,950,236)	$ (1,300,157)	$ (650,079)	$ -	$ -	$ -	$ -
15	Unamortized ITC		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	Rate Base, end of year	Sum lines 12-15	$ 5,956,671	$ 4,963,893	$ 3,971,114	$ 2,978,336	$ 1,985,557	$ 992,779	$ (0)	$ (0)	$ (0)	$ (0)
17	Revenue Requirement											
18	Carrying Costs	Line 16 * Nominal Return	$ 416,967	$ 347,473	$ 277,978	$ 208,484	$ 138,989	$ 69,495	$ (0)	$ (0)	$ (0)	$ (0)
19	O&M		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	Revenue Requirement before Taxes	Sum lines 18+19	$ 416,967	$ 347,473	$ 277,978	$ 208,484	$ 138,989	$ 69,495	$ (0)	$ (0)	$ (0)	$ (0)
21	Gross Up Conversion	Line 5	$ 691,748	$ 576,457	$ 461,166	$ 345,874	$ 230,583	$ 115,291	$ (0)	$ (0)	$ (0)	$ (0)
22	Amortization	Line 6	$ 1,642,857	$ 1,642,857	$ 1,642,857	$ 1,642,857	$ 1,642,857	$ 1,642,857	$ 1,642,857	$ -	$ -	$ -
23												
24	Total Revenue Requirement -2014 Plan Costs	Sum lines 20-23	$ 2,334,605	$ 2,219,314	$ 2,104,023	$ 1,988,731	$ 1,873,440	$ 1,758,149	$ 1,642,857	$ (0)	$ (0)	$ (0)
25	Total Revenue Requirement -2015 Plan Costs	Tab 2015	$ -	$ 5,022,283	$ 4,774,264	$ 4,526,245	$ 4,278,226	$ 4,030,208	$ 3,782,189	$ 3,534,170	$ (0)	$ (0)
26	Total Revenue Requirement -2016 Plan Costs	Tab 2016	$ -	$ -	$ 5,490,364	$ 5,219,230	$ 4,948,096	$ 4,676,961	$ 4,405,827	$ 4,134,693	$ 3,863,558	$ -
27	Total Revenue Requirement -2017 Plan Costs	Tab 2017	$ -	$ -	$ -	$ 5,655,075	$ 5,375,807	$ 5,096,538	$ 4,817,270	$ 4,538,002	$ 4,258,733	$ 3,979,465
28	Total Revenue Requirement	Sum Line 24-27	$ 2,334,605	$ 7,241,597	$ 12,368,651	$ 17,389,281	$ 16,475,569	$ 15,561,856	$ 14,648,143	$ 12,206,865	$ 8,122,292	$ 3,979,465
29	Forecast Sales (MWhrs)	CAJ-8, 2014 annualized from amount shown o 2021 thru 2023 estimated based on growth rate trend 2014 to 2020	4,790,031	9,658,045	9,739,655	9,813,955	9,902,221	10,002,707	11,045,242	11,102,686	11,140,265	11,163,859
30	DSMS Rate per kWh	Line 28 ÷ Line 29	$ 0.0004870	$ 0.0007500	$ 0.0012700	$ 0.0017720	$ 0.0016640	$ 0.0015560	$ 0.0013260	$ 0.0010990	$ 0.0007290	$ 0.0003560
31	Current DSMS Rate (per TEP Tariffs)	Previous years rate	$ 0.0012490	$ 0.0004870	$ 0.0007500	$ 0.0012700	$ 0.0017720	$ 0.0016640	$ 0.0015560	$ 0.0013260	$ 0.0010990	$ 0.0007290
32	Change	Line 30 minus line 31	$ (0.0007620)	$ 0.0002630	$ 0.0005200	$ 0.0005020	$ (0.0001080)	$ (0.0001080)	$ (0.0002300)	$ (0.0002270)	$ (0.0003700)	$ (0.0003730)
33	TEP Proposed Rate	Exhibit CAJ-8 TEP EERP POA Attachm	$ 0.0009160	$ 0.0016640	$ 0.0024540	$ 0.0022650	$ 0.0014920	$ 0.0007230	NA	NA	NA	NA
34	Change Staff versus Company	line 30 minus line 33	$ (0.0004290)	$ (0.0009140)	$ (0.0011840)	$ (0.0004930)	$ 0.0001720	$ 0.0008330	NA	NA	NA	NA
35	Percent Change	line 34 ÷ line 35	$ (0.4683406)	$ (0.5492788)	$ (0.4824776)	$ (0.2176600)	$ 0.1152815	$ 1.1521438	NA	NA	NA	NA

Exhibit___MJM-13 - Staff Derivation of Alternative plan Revenue Requirement for EERP

2015

Line	Description	Amount	Comment
1	Original Cost	$ 24,739,192.00	Estimate - Actual amount would be recorded here. Used Staff proposed budget from E-01933A-11-0055 for 6 months
2	Asset Life	7	Based on average usefulful life of measures - see Exhibit___ MJM-XX, Line 4
3	Income Tax Rate	39.57%	
4	Nominal Return	7.0000%	Per Staff Witness S.Keith Berry, Ph.D
5	Gross Conversion Factor	1.659	TEP Schedule C-3

		Comment	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
6	Regulatory Assest Amortization	Original Cost ÷ Years		$ 3,534,170	$ 3,534,170	$ 3,534,170	$ 3,534,170	$ 3,534,170	$ 3,534,170	$ 3,534,170	$ -	$ -
7	Tax Depreciation	Original Cost		$ 24,739,192								
8	Net Book basis (end of year)	Line 7 minus Line 6	$ -	$ 21,205,022	$ 17,670,851	$ 14,136,681	$ 10,602,511	$ 7,068,341	$ 3,534,170	$ -	$ -	$ -
9	Tax basis (end of year)											
10	ADIT (end of year) Book basis minus tax basis) times tax rate	Line 8 * income tax rate (line	$ -	$ 8,390,827	$ 6,992,356	$ 5,593,885	$ 4,195,414	$ 2,796,942	$ 1,398,471	$ -	$ -	$ -
11	Rate Base, end of year											
12	Regulatory Assest	Line 1		$ 24,739,192	$ 24,739,192	$ 24,739,192	$ 24,739,192	$ 24,739,192	$ 24,739,192	$ 24,739,192	$ 24,739,192	$ 24,739,192
13	Accumulated Amortization	Sum Line 6 to 2014 to YTD	$ -	$ (3,534,170)	$ (7,068,341)	$ (10,602,511)	$ (14,136,681)	$ (17,670,851)	$ (21,205,022)	$ (24,739,192)	$ (24,739,192)	$ (24,739,192)
14	ADIT	Line 10	$ -	$ (8,390,827)	$ (6,992,356)	$ (5,593,885)	$ (4,195,414)	$ (2,796,942)	$ (1,398,471)	$ -	$ -	$ -
15	Unamortized ITC											
16	Rate Base, end of year	Sum lines 12-15	$ -	$ 12,814,195	$ 10,678,496	$ 8,542,796	$ 6,407,097	$ 4,271,398	$ 2,135,699	$ (0)	$ (0)	$ (0)
17	Revenue Requirement											
18	Carrying Costs	Line 16 * Nominal Return	$ -	$ 896,994	$ 747,495	$ 597,996	$ 448,497	$ 298,998	$ 149,499	$ (0)	$ (0)	$ (0)
19	O&M											
20	Revenue Requirement before Taxes	Sum lines 18+19	$ -	$ 896,994	$ 747,495	$ 597,996	$ 448,497	$ 298,998	$ 149,499	$ (0)	$ (0)	$ (0)
21	Gross Up	Line 5	$ -	$ 1,488,112	$ 1,240,094	$ 992,075	$ 744,056	$ 496,037	$ 248,019	$ (0)	$ (0)	$ (0)
22	Amortization	Line 6	$ -	$ 3,534,170	$ 3,534,170	$ 3,534,170	$ 3,534,170	$ 3,534,170	$ 3,534,170	$ 3,534,170	$ -	$ -
23	Prior Years Unrecovered Costs											
24	Total Revenue Requirement -2015 Plan Costs	Sum lines 21+22+23	$ -	$ 5,022,283	$ 4,774,264	$ 4,526,245	$ 4,278,226	$ 4,030,208	$ 3,782,189	$ 3,534,170	$ (0)	$ (0)

Exhibit___MJM-13 - Staff Derivation of Alternative plan Revenue Requirement for EERP

2016

Line	Description	Amount	Comment
1	Original Cost	$ 27,044,908.00	Estimate - Actual amount would be recorded here. Used Staff proposed budget from E-01933A-11-0055 for 6 months
2	Asset Life	7	Based on average usefulful life of measures - see Exhibit___ MJM-XX, Line 4
3	Income Tax Rate	39.57%	
4	Nominal Return	7.0000%	Per Staff Witness S.Keith Berry, Ph.D
5	Gross Conversion Factor	1.659	TEP Schedule C-3

		Comment	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
6	Regulatory Assest Amortization	Original Cost ÷ Years		$ -	$ 3,863,558	$ 3,863,558	$ 3,863,558	$ 3,863,558	$ 3,863,558	$ 3,863,558	$ 3,863,558	$ -
7	*Tax Depreciation*	Original Cost		$ -	$ 27,044,908							
8	Net Book basis (end of year)	Line 7 minus Line 6	$ -	$ -	$ 23,181,350	$ 19,317,791	$ 15,454,233	$ 11,590,675	$ 7,727,117	$ 3,863,558	$ -	$ -
9	Tax basis (end of year)											
10	ADIT (end of year) Book basis minus tax basis) times tax rate)	Line 8 * income tax rate (line 3)	$ -	$ -	$ 9,172,860	$ 7,644,050	$ 6,115,240	$ 4,586,430	$ 3,057,620	$ 1,528,810	$ -	$ -
11	Rate Base, end of year											
12	Regulatory Assest	Line 1			$ 27,044,908	$ 27,044,908	$ 27,044,908	$ 27,044,908	$ 27,044,908	$ 27,044,908	$ 27,044,908	$ 27,044,908
13	Accumulated Amortization	Sum Line 6 to 2014 to YTD	$ -	$ -	$ (3,863,558)	$ (7,727,117)	$ (11,590,675)	$ (15,454,233)	$ (19,317,791)	$ (23,181,350)	$ (27,044,908)	$ (27,044,908)
14	ADIT	Line 10	$ -	$ -	$ (9,172,860)	$ (7,644,050)	$ (6,115,240)	$ (4,586,430)	$ (3,057,620)	$ (1,528,810)	$ -	$ -
15	Unamortized ITC											
16	Rate Base, end of year	Sum lines 12-15	$ -	$ -	$ 14,008,490	$ 11,673,741	$ 9,338,993	$ 7,004,245	$ 4,669,497	$ 2,334,748	$ (0)	$ (0)
17	Revenue Requirement											
18	Carrying Costs	Line 16 * Nominal Return	$ -	$ -	$ 980,594	$ 817,162	$ 653,730	$ 490,297	$ 326,865	$ 163,432	$ (0)	$ (0)
19	O&M											
20	Revenue Requirement before Taxes	Sum lines 18+19	$ -	$ -	$ 980,594	$ 817,162	$ 653,730	$ 490,297	$ 326,865	$ 163,432	$ (0)	$ (0)
21	*Gross Up*	Line 5	$ -	$ -	$ 1,626,806	$ 1,355,672	$ 1,084,537	$ 813,403	$ 542,269	$ 271,134	$ (0)	$ (0)
22	Amortization	Line 6	$ -	$ -	$ 3,863,558	$ 3,863,558	$ 3,863,558	$ 3,863,558	$ 3,863,558	$ 3,863,558	$ 3,863,558	$ -
23	Prior Years Unrecovered Costs		$ -									
24	Total Revenue Requirement -2016 Plan Costs	Sum lines 21+22+23	$ -	$ -	$ 5,490,364	$ 5,219,230	$ 4,948,096	$ 4,676,961	$ 4,405,827	$ 4,134,693	$ 3,863,558	$ (0)

Exhibit___MJM-13 - Staff Derivation of Alternative plan Revenue Requirement for EERP

2017

Line	Description	Amount	Comment
1	Original Cost	$ 27,856,255.00	Original Cost
2	Asset Life	7	Asset Life
3	Income Tax Rate	39.57%	Income Tax Rate
4	Nominal Return	7.0000%	Nomial Return
5	Gross Conversion Factor	1.65900	Gross Conversion

		Comment	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
6	Regulatory Assest Amortization	Original Cost ÷ Years		$ -	$ -	$ 3,979,465	$ 3,979,465	$ 3,979,465	$ 3,979,465	$ 3,979,465	$ 3,979,465	$ 3,979,465
7	Tax Depreciation	Original Cost		$ -	$ -	$ 27,856,255						
8	Net Book basis (end of year)	Line 7 minus Line 6	$ -	$ -	$ -	$ 23,876,790	$ 19,897,325	$ 15,917,860	$ 11,938,395	$ 7,958,930	$ 3,979,465	$ -
9	Tax basis (end of year)											
10	ADIT (end of year) Book basis minus tax basis) times tax ra	Line 8 * income tax rate (line 3)	$ -	$ -	$ -	$ 9,448,046	$ 7,873,372	$ 6,298,697	$ 4,724,023	$ 3,149,349	$ 1,574,674	$ -
11	Rate Base, end of year											
12	Regulatory Assest	Line 1			$ -	$ 27,856,255	$ 27,856,255	$ 27,856,255	$ 27,856,255	$ 27,856,255	$ 27,856,255	$ 27,856,255
13	Accumulated Amortization	Sum Line 6 to 2014 to YTD	$ -	$ -	$ -	$ (3,979,465)	$ (7,958,930)	$ (11,938,395)	$ (15,917,860)	$ (19,897,325)	$ (23,876,790)	$ (27,856,255)
14	ADIT	Line 10	$ -	$ -	$ -	$ (9,448,046)	$ (7,873,372)	$ (6,298,697)	$ (4,724,023)	$ (3,149,349)	$ (1,574,674)	$ -
15	Unamortized ITC											
16	Rate Base, end of year	Sum lines 12-15	$ -	$ -	$ -	$ 14,428,744	$ 12,023,953	$ 9,619,163	$ 7,214,372	$ 4,809,581	$ 2,404,791	$ -
17	Revenue Requirement											
18	Carrying Costs	Line 16 * Nominal Return	$ -	$ -	$ -	$ 1,010,012	$ 841,677	$ 673,341	$ 505,006	$ 336,671	$ 168,335	$ -
19	O&M											
20	Revenue Requirement before Taxes	Sum lines 18+19	$ -	$ -	$ -	$ 1,010,012	$ 841,677	$ 673,341	$ 505,006	$ 336,671	$ 168,335	$ -
21	Gross Up	Line 5	$ -	$ -	$ -	$ 1,675,610	$ 1,396,342	$ 1,117,073	$ 837,805	$ 558,537	$ 279,268	$ -
22	Amortization	Line 6	$ -	$ -	$ -	$ 3,979,465	$ 3,979,465	$ 3,979,465	$ 3,979,465	$ 3,979,465	$ 3,979,465	$ 3,979,465
23	Prior Years Unrecovered Costs		$ -									
24	Total Revenue Requirement -2017 Plan Costs	Sum lines 21+22+23	$ -	$ -	$ -	$ 5,655,075	$ 5,375,807	$ 5,096,538	$ 4,817,270	$ 4,538,002	$ 4,258,733	$ 3,979,465

Year	Tariff (per kWh)		Avg. Res. Bill	
	Current	Proposed	Current	Proposed
2014	$ 0.002315	$ 0.000916	$ 2.04	$ 0.81
2015	$ 0.003052	$ 0.001664	$ 2.69	$ 1.46
2016	$ 0.003117	$ 0.002454	$ 2.74	$ 2.16

Line No.	Description	2014	2015
	(a)	(b)	(c)
1	**Total EE Program Expenditures ($MM)**	$ 24.74	$ 27.04
2	**Gross Revenue Requirement for 2014 ($MM)**	$ 7.97	$ 7.35
3	**Gross Revenue Requirement for 2015 ($MM)**	$ -	$ 8.72
4	**Gross Revenue Requirement for 2016 ($MM)**	$ -	$ -
5	**Cummulative Impact ($MM) (sum of line 2, 3 & 4)**	$ 7.97	$ 16.07

2016	2017	2018	2019	Source
(d)	(e)	(f)	(g)	
$ 27.86	$ -	$ -	$ -	
$ 6.89	$ 6.42	$ -	$ -	Exhibit CAJ-7 Attachment D
$ 8.04	$ 7.53	$ 7.02	$ -	Exhibit CAJ-7 Attachment D
$ 8.98	$ 8.28	$ 7.75	$ 7.23	Exhibit CAJ-7 Attachment D
$ 23.90	$ 22.23	$ 14.77	$ 7.23	

Exhibit____MJM-12 - Staff Derivation of DSMS July 2013 through June 2014

Line No.	Month	Unrecovered Balance (1)	1/12th	Carrying Charge	monthly	Carrying Costs	Recovered amount	Cummulative
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
1	7/1/2013	$ 22,452,182	$ 1,871,015	7.0000%	0.5833%	$ 130,971.06	$ 2,001,986.23	$ 2,001,986.23
2	8/1/2013	$ 20,581,167	$ 1,871,015			$ 120,056.81	$ 1,991,071.97	$ 3,993,058.20
3	9/1/2013	$ 18,710,152	$ 1,871,015			$ 109,142.55	$ 1,980,157.72	$ 5,973,215.92
4	1-Oct	$ 16,839,137	$ 1,871,015			$ 98,228.30	$ 1,969,243.46	$ 7,942,459.38
5	11/1/2013	$ 14,968,121	$ 1,871,015			$ 87,314.04	$ 1,958,329.21	$ 9,900,788.59
6	12/1/2013	$ 13,097,106	$ 1,871,015			$ 76,399.79	$ 1,947,414.95	$ 11,848,203.54
7	1/1/2014	$ 11,226,091	$ 1,871,015			$ 65,485.53	$ 1,936,500.70	$ 13,784,704.24
8	2/1/2014	$ 9,355,076	$ 1,871,015			$ 54,571.28	$ 1,925,586.44	$ 15,710,290.68
9	3/1/2014	$ 7,484,061	$ 1,871,015			$ 43,657.02	$ 1,914,672.19	$ 17,624,962.87
10	1-Apr	$ 5,613,046	$ 1,871,015			$ 32,742.77	$ 1,903,757.93	$ 19,528,720.80
11	5/1/2014	$ 3,742,030	$ 1,871,015			$ 21,828.51	$ 1,892,843.68	$ 21,421,564.48
12	6/1/2014	$ 1,871,015	$ 1,871,015			$ 10,914.26	$ 1,881,929.42	$ 23,303,493.90
13	Total		$ 22,452,182			$ 851,312	$ 23,303,494	
14	Forecast Retail Sales (MWhrs) (2)						9,580,062	
15	Estimated DSMS Rate per kWh (July 1, 2013 - June 30, 2014)						$ 0.00243	

Notes:

(1) Unrecovered Beginning Balance at 7/1/2013 estimated at $4,452,182 included in filing plus $18M expected program plan expenses in 2013

(2) Forecast Retail Sales based on 13,571,755 for period 8/13 to 12/14 annualized

BEFORE THE ARIZONA CORPORATION COMMISSION

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

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

(PUBLIC)

DIRECT

TESTIMONY

OF

W. MICHAEL LEWIS, P.E.

ON BEHALF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

DECEMBER 21, 2011

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EXECUTIVE SUMMARY
TUCSON ELECTRIC POWER
DOCKET NO. E-01933A-12-0291

The Direct Testimony of W. Michael Lewis of W. M. Lewis and Associates, Inc. provides the results of engineering investigations of Tucson Electric Power Company ("TEP" or "Company") as authorized by the Arizona Corporation Commission ("Commission") pursuant to requests and direction from the Commission's Utility Division Staff ("Staff" or "ACC Staff"). The engineering investigations were undertaken by Mr. Lewis of W.M. Lewis and Associates, Inc. and Mr. Strobl of Technical Associates, Inc. Field inspections of selected facilities and technical projects under the direction and operation of the Company in Arizona, reviews and analyses of the TEP Application and other TEP documentation, as well as discussions with TEP personnel comprised the engineering investigations for this case.

The inspections and reviews were performed by Messrs. Lewis and Strobl on October 29 through November 1, along with Mr. Prem Bahl of the ACC Staff on October 29 and November 1, and included discussions with TEP technical, management, and systems operations personnel. Data requests to TEP regarding performance indices, maintenance practices and design standards, and the in-service status of construction and design projects were also prepared and submitted to TEP. Within the investment projects requested by TEP for inclusion in rate base, the Solon solar project and the San Juan equipment upgrading and replacement project were of particular interest. This was the case because the dollar value of these two (2) projects is about $24 million of TEP's total post test-year request of about $42 million claimed by TEP to be in-service by December 31, 2012. TEPs responses to data requests, in-person meetings with TEP personnel, and observations of project activities during the field investigations formed the basis for the discussions, conclusions and recommendations in this testimony.

The major elements of the engineering analysis focused on TEP's service quality, distribution system reliability indices, the operational status of five (5) of the major plant and equipment project investments which constituted about 70 percent of the total TEP requested for inclusion in rate base, and the maintenance and operational procedures undertaken by TEP to support electric services to Arizona customers. TEP claims that its request that post test-year investments be included in rate base are based on the investments having been in-service or that the investments will be placed in-service by year-end 2012. Objectives during the field investigations were to observe some of these projects, and to discuss these projects, as well as other aspects of TEP's operations with personnel responsible for the development and/or management of TEP projects and operations.

Quality of Service/ Distribution System Indices. Our evaluation centered upon metrics of TEP's System Average Interruption Frequency Index ("SAIFI"), System Average Interruption Duration Index ("SAIDI"), and Customer Average Interruption Duration Index ("CAIDI"). The methodology is set by IEEE 1366 "Guide for Electric Power Distribution Reliability Indices". This method is followed by TEP as well as most of the investor-owned electric utilities in the U.S. and most of the larger Municipal and Federal agency utilities.

Based upon discussions with the TEP personnel responsible for the calculation and presentation of outage data and observations of how the data is collected, TEP's performance is excellent. TEP should determine "Target Values" for SAIDI and SAIFI to be maintained as a minimum by TEP, irrespective of their ranking in the reported industry results.

Facilities Investment/In-Service Operations. The field investigations included observing the new Solon solar project and the project undertaken to underground 13.8 kV distribution feeder circuits that had been underbuilt on poles carrying TEP's 138 kV distribution system conductors. The observations of these projects were coordinated and conducted by TEP personnel responsible, at least in part, for the completion and integration of these projects into TEP's distribution system. The utility scale Solon solar project recently placed in-service will be remotely monitored by TEP, with routine and fault correction maintenance work done by TEP crews. The undergrounding of the 13.8 kV distribution feeder circuits project was completed and recently energized.

The remaining three (3) investment projects of the five (5) major projects were thoroughly discussed with project responsible TEP personnel regarding the timetable for investment and timelines for integration of projects into TEP operations. The San Juan project is an on-going program of upgrades and replacements of aging equipment, and of new facilities and upgrades to meet environmental compliance standards. Additional phases (beyond Phase I) of the MAXIMO software implementation project remains in the planning stage, but could become part of TEP requests in the future. Additionally, TEP personnel provided information and reports pertaining to the transmission link project to confirm the in-service operations of each.

TEP Call Center. TEP Call Center operations are located at the Sundt Power Station site, and serve TEP, UNS Electric and UNS Gas customers in Arizona. The TEP Call Center, in conjunction with the Outage Management System ("OMS") mapping of the TEP system electrical components and customer interfaces, is the first-line communications link between TEP and its customers. The TEP Call Center is a 24/7 operation manned with personnel who have access to billing information and other service data in order to respond to customer outage notifications and/or customer requests for other information such as bill payment status.

With regard to TEP electrical network outages, recognition is through Call Center notification and OMS mapping prompts as to equipment level faults affecting one or more customers. This evaluation procedure allows TEP to initially analyze the problem(s) and to dispatch field maintenance personnel to the location(s) of the fault(s) in the network.

TEP Outage Management System. TEP operates an Outage Management System that combines Geographic Information System ("GIS") mapping and computer-generated single-line representations of the distribution system. The system operates down to an individual customer level and includes circuit features such as switches and transformers. Upon notification of an outage by either the Call Center or by Supervisory Control and Data Acquisition ("SCADA") in the case of a feeder circuit breaker operation, the operators can locate the outage and direct the repair crew to the location. The system acts to derive the outage information necessary for indices determination by recording the duration of the outage and the number of customers affected. It also provides the probable cause or source of the outage based upon the number and

location of the interrupted customers. Further, the Outage Management System provides the Call Center with confirmation of service restoration when repairs or corrections are completed by the field personnel. The system is suitable for TEP's use.

Distribution System (4.16 kV to 13.8 kV). Staff is concerned that the 4.16 kV ("4 kV") system represents a source of greater losses to serve comparable customers as compared to that of the 13.8 kV circuits. At present the 4 kV circuits are supplying about 84,000 customers with a combined load of about 440 MW. The aim would be to reduce the line losses required to serve this load by an upgrade to 13.8 kV. The load and power factor remaining constant, this increase in circuit voltage would decrease the current in the lines by a factor of 4.16/13.8 or about 30 percent of the equivalent 4kV current levels. As line losses vary by the square of the current, line losses could decrease to about 10 percent of the 4 kV values. This could represent significant savings in terms of the costs of energy lost and in reduced peak demand.

There are significant costs in such a conversion including the replacement of the distribution transformers, possible insulator replacements, increased phase wire clearances, and a question as to the conversion of the substation to supply a 13.8 kV source. Staff is recommending that TEP initially perform a study of the potential loss reductions and an estimate of the costs required to convert 1 to 3 selected 4 kV circuits. Staff's recommendation to the Commission is for TEP to perform a cost-benefit study followed by a pilot program as discussed above with a report of the results.

Customer Metering. In response to STF 6.09, TEP stated that about 42 percent of its customer meters are AMR. Subsequent discussion with TEP personnel revealed that there are very few AMI meters currently in use. Generally speaking "AMR" meters provide for remote reading while an "AMI" meter, sometimes referred to as a "Smart" meter, can provide for two-way communication and can be provided with control features for customer appliance management and can provide service connection and disconnects remotely. Future movement to a "Smart Grid" will require customer metering by "AMI" meters. Other advantages of an AMI meter is the ability to re-program its metering set-ups of time-varying rates remotely on a customer specific basis.

Staff recommends that the Commission order TEP to move toward an AMI metering system.

Distribution System Analysis/Losses. Staff had inquired in a Data Request (STF 6.04) as to the frequency that TEP performs load-flow analysis of the distribution system. In response, TEP stated that these are performed only when a problem is known to exist or to review proposed switching routines that are suspected to create problems. Staff think that periodic load-flow analysis to review the effects of system demand changes, fault levels, and as a check on circuit loading, can identify problems in loading and losses prior to such occurring. Also, periodic load-flow results can be checked for agreement with actual measurements of the system loading to correct problems with the system circuit model that the program is using for its base results.

Staff would recommend that TEP set up a routine of periodic load-flow analysis of its system and confirm that the model is accurate.

TEP Distribution System Outage of November 9, 2012. Staff have reviewed this incident and the following is our understanding of the cause and resulting effects on the system. On the date stated at about 0700 hrs, TEP's distribution system suffered an outage of several 46 kV and 138 kV distribution substations. The outage coincided with the scheduled removal from service of an Arizona Public Service Company transmission line. The substations were tripped by a load shedding action of TEP's Local Area Protection Scheme. As a result, about 46,645 customers were affected with a loss of service. The majority, about 40,581 of the outages were restored to service in about 3 minutes. Another 4,569 in 25 minutes, and the remaining 1,495 in about 80 minutes. Staff believes that the load shedding operation was not due to the TEP operations failing to provide sufficient local generation, but was primarily due to an incorrect setting of TEP's Tie Open Load Shed system.

Staff also believe that the cause of the outage was an incorrect set-up of the Tie Open Load Shed System for the outage of the 500 kV transmission line. No written procedure was necessary or customary for the varying of TEP's local generation. There were some positive outcomes of the incident in that an error in the SCADA display was revealed and a missing 46 kV breaker indication was noted on the load shed restoration display. TEP's initiation of a procedure for the setting of the Load Shedding is proper and should help to prevent any repeat of the incident. Staff's only suggestion is that during any future circuit breaker operation in the distribution substations, an effort should be made to confirm the correct indication appears on the SCADA display of breaker positions.

Recommendations:

Staff recommends that TEP management consider allocating funding to increase the number of distribution circuits to be addressed with upgrades from the current one circuit per-year rate;

As explained in the Direct Testimony of Ralph Smith, Staff has made a policy recommendation that post-test year plant additions that can be confirmed as in service by December 31, 2012 be included in rate base. Staff recommends the inclusion in rate base of those post-test year plant additions.

Based on Staff's evaluation, TEP's Call Center performs effectively and efficiently in response to outage notifications as well as customer bill inquiries.

Based on Staff's evaluation, TEP's Outage Management System appropriate to TEP and is suitable for TEP's use.

Staff recommends that TEP initially perform a study of potential line loss reductions for upgrading one to three 4 kV circuits prior to implementing a broad distribution system upgrade. If the study indicates long-term positive benefits, then a pilot program would be appropriate for the upgrade of a select circuit to determine actual costs and develop construction and outage management procedures that will be involved in the upgrade process.

Staff recommends that TEP continue upgrading toward AMI meters.

Staff recommends that TEP move toward equipping its feeder circuits with meters to provide comparable data to what is provided by the circuit metering on TEP's distribution circuits.

Staff recommends that TEP establish a routine of periodic load-flow analyses of its distribution system and confirm that the system circuit model is accurate.

Staff recommends that, after the November 9, 2012 outage, that TEP use any future circuit breaker operation in the distribution system to confirm that the correct indication appears on the SCADA display of breaker positions.

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is William Michael Lewis. My business address is 934 Valley Street, Wheelersburg, Ohio 45694.

Q. What is your present employment?

A. I am employed by the firm of W. M. Lewis and Associates, Inc. ("WML&A"). I am the President of the firm.

Q. Please describe the nature of the firm.

A. WML&A is a Consulting Engineering firm which provides various engineering services, primarily in areas of electrical power and electric utility operation, to a range of clients including investor-owned electric utilities, municipal utilities, international investment organizations, and regulatory bodies. The firm was established in 1958.

Q. Please describe your background, education, and experience.

A. I have been employed by WML&A since 1979. My prior employment was with Goodyear Atomic Corp. and Westinghouse Electric. Positions that I have held at WML&A include Senior Engineer, Manager of Engineering, Vice-President, and President. I hold a BSEE degree from Ohio State University and an MBA from Ohio University. For the past 20 years, much of my work has involved foreign assignments on behalf of the Asian Development Bank and the World Bank regarding project post-evaluation, feasibility studies, and reviews of operation and maintenance of various generating stations, urban and rural transmission and distribution systems, and utility management. Additional tasks included the design of facilities and preparation of agreements for the interconnection of utilities, preparing operating agreements between utilities and independent power producers, and various tasks related to the privatization of electric utilities in the South Asian area. Additional aspects of my experience and education are presented in my resume, which is included in the Attachment to this testimony.

Q. Are you filing Direct Testimony on behalf of the Arizona Corporation Commission ("Commission") Utilities Division Staff ("ACC Staff")?

A. Yes.

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

A. My testimony describes and presents evaluations, observations and recommendations regarding aspects of the Tucson Electric Power Company ("TEP" or "Company") Application before the Arizona Corporation Commission ("ACC" or "Commission") in Docket No. E-01933A-12-0291. Specifically, I address investigations for the ACC Staff of engineering analyses of certain aspects of TEP's Application, including requests for the inclusion of post test-year plant additions in rate base and evaluations of TEP's distribution system service quality indices.

Q. What is the major focus of your investigations?

A. The major focus of my investigations was field investigations of certain TEP facilities throughout Arizona, including discussions with TEP personnel. Field investigations were made on October 29 through November 1 by myself and Kenneth C. Strobl of Technical Associates, Inc. and were coordinated and accompanied by TEP personnel. Mr. Prem Bahl of the ACC Staff accompanied us as well on October 29 and November 1.

The purpose of these field investigations was two-fold. First was to visit and review a number of the major construction projects included in the as-filed $42 million of total gross post-test year plant investment additions that the Company is requesting be included in rate base in this case. The second was to discuss with TEP personnel these projects and the other operational influences on the current and projected quality of electrical services to TEP customers in Arizona.

Q. Please describe the major elements of your investigations.

A. The major elements of our investigations are directed at TEP's distribution system service quality indices, the construction and operations of selected plant facilities currently in-service and/or expected to be in-service in the next few months, and the general

capabilities and operations of TEP's network assets to provide electric services to its Arizona customers. The field investigations and reviews of project developments included discussions with TEP engineering and other technical personnel in charge of, or participating in, the construction, operations, and development of network facilities and network monitoring systems. In addition to these field activities, we reviewed portions of TEP's prefiled Application and testimony in this case, as well as documents such as TEP's Federal Energy Regulatory Commission ("FERC") Form No. 1, and its critical circuit analyses/patrol program reports.

We also prepared data requests to the Company, the bulk of which addressed service quality and distribution system indices, and post test-year plant investments that are proposed by TEP for inclusion in rate base in this case. Our reviews of TEP's responses to these data requests were a major influence on the development of the itinerary for the field investigations and the contents of this testimony.

Q. What are the impacts of your efforts on behalf of ACC Staff?

A. The field investigations, the discussions with TEP personnel and the reviews and analyses of TEP filed testimony and responses to data requests in this case provided some perspective and understanding of the Company's installations and operations of its electric network facilities and monitoring systems in Arizona. The remainder of this testimony discusses these observations and evaluations, and provides recommendations for the Commission's consideration regarding these matters. This testimony also contains comments regarding the capabilities of the TEP personnel we met in our field visits that are charged with ensuring that facilities and systems are safe, reliable, and operate in an effective manner to meet the electrical service needs of TEP customers in Arizona.

Q. Please Briefly Describe What Is Addressed In Your Testimony?

A. The following general topics and issues are addressed, at least to some extent, in this testimony:

(A) Quality of Service/Distribution Indices --- refers to the operational quality and electric service performance satisfaction provided to TEP customers, including electrical power quality complaints.

(B) Post Test-Year Plant Additions --- relates to the Company's requested inclusion of investments in new and replacement plant and equipment system components.

(C) TEP Call Center --- reflects the procedures and operations of the central facility for the receipt of customer outage calls and general customer service informational inquiries.

(D) TEP Outage Management System --- relates to TEP's monitoring and responses to distribution system operations, outages, and repairs/betterments of network electrical components.

(E) Distribution System Upgrade (4.16 kV to 13.8 kV) --- refers to the on-going maintenance, replacement and operation of TEP's 4.16 kV distribution system in terms of the cost, reliability and loss reduction compared to its typical 13.8 kV distribution system.

(F) Customer Metering --- relates to TEP's efforts and plans associated with its approach and implementation of advanced metering systems.

(G) Distribution System Analysis/Losses --- addresses the monitoring and potential electrical improvement in the operations of TEP's electrical distribution network.

(H) TEP Distribution System Outage --- relates to November 9, 2012 outage of several 46 kV and 138 kV distribution substations.

These topics and issues are addressed by this testimony in a general manner. The scope of these topics is too great to be addressed in a completely comprehensive manner within the schedule allotted for the processing of this rate case application.

Q. What is your general perspective of the operations of TEP facilities and TEP personnel that you have had an opportunity to witness in your field visit?

A. Generally speaking, the Company's plant facilities, network systems and operations appear to reflect thoughtful planning, and appear to be effectively utilized and maintained. The Company's operating practices, including its preventative maintenance planning and outage response practices, which are currently developing new software support for system operations (an adaptation of MAXIMO), as well as the technical and administrative personnel involved, demonstrate an acceptable level of competence and quality of expertise.

II. WORK EFFORT AND EVALUATIONS

Q. Please describe your evaluations and the role of your field investigations in this work effort.

A. Our work effort commenced with reviews and analyses of TEP's Application and filed testimony in this proceeding. To supplement the information in TEP's Application and prefiled testimony, we reviewed a variety of documentation filed in support of its Application.

Additional information was acquired and analyses were made based on TEP's responses to data requests issued by ACC Staff, most notably Staff Set STF 6.1 through 6.42, STF 27.0, and TEP's supplemental responses to STF 6.13, 6.14, 6.35, 6.37 and 6.42. TEP responses to Staff data requests STF 6.39 through STF 6.42 address the Company's plant investment projects including those being requested for inclusion in rate base in this case. A breakdown of the individual construction project investments and corresponding actual and estimated in-service dates for the projects in excess of $500,000 claimed by TEP as post-test year additions was provided by TEP in response to data request STF 6.42.

Data requests STF 6.15, 6.16 and 6.35 addressed TEP's claims and calculations regarding customer service complaints and electric service reliability and quality. The latter reflecting TEP's evaluations of Customer Average Interruption Duration Index (CAIDI), System Average Interruption Duration Index (SAIDI), and System Average Interruption Frequency Index (SAIFI).

A. Quality of Service/Distribution Indices

Q. What was your method of assessing the service reliability and service quality of TEP's distribution system?

A. Our evaluation centered upon metrics of TEP's System Average Interruption Frequency Index ("SAIFI"), System Average Interruption Duration Index ("SAIDI"), and Customer Average Interruption Duration Index ("CAIDI").

Q. What are the characteristics of SAIFI, SAIDI, and CAIDI and what is the basis for using these indices as an indication of system reliability?

A. Electric utilities record and report information on system outage events using a variety of methods which, taken together, provide a measure of system quality of service as reflected by the frequency and duration of power outages to the average customer. These three (3) indices are the more useful indications of reliability and the most commonly reported. The characteristics can be inferred by the descriptions above. SAIFI (on an annual basis) is the sum of the number of customers interrupted divided by the total number of customers served. SAIDI is the total of customer interruption durations (in minutes) divided by the total number of customers served. CAIDI can be calculated by SAIDI/SAIFI which is then an indication of the interruptions and duration of such interruptions experienced by the average customer served by the distribution system on an annual basis.

Q. What sets the basis and methodology for the indices described above?

A. The methodology is set by Institute of Electrical and Electronics Engineers ("IEEE") 1366 "Guide for Electric Power Distribution Reliability Indices". This method is followed by

TEP as do most of the investor-owned electric utilities in the USA as well as most of the larger Municipal and Federal agency utilities.

Q. Are the indices reflective of all interruptions?

A. No. Utility practice is to develop the data for the calculation of the indices on "sustained interruptions" which are defined as those interruptions of five (5) minutes or more. TEP employs this time measure for its evaluations.

Q. What has been TEP's recent performance as indicated by its indices?

A. At page six of the Direct Testimony of Mr. DeConcini, there was presented a discussion of the recent results and a comparison to other utilities, comparable to TEP in size and service area. In response to STF 6.35, TEP furnished spread sheets of month and year end results for the indices for calendar years 2007-2011.[1] We have reviewed these as to the quality of data and calculations and found them to be accurately calculated and properly presented. A summary of the provided results for the years 2009-2011 is as follows:

In the above data, SAIDI and CAIDI are in minutes and the values include major event days ("MEDs").

Q. What is a MED?

A. A MED is a day or a portion of a 24 hour time period where the service area is subjected to extreme or unusual conditions.

[1] Exh. 1 (Confidential).

Q. Are MEDs another consideration as to what constitutes and outage to be included in the calculation of these indices?

A. Yes. In addition to the five minute threshold, IEEE-1366 defines the impact of various aspects of weather (storms, high winds, temperature variances, etc.) as designated MEDs. The indices are calculated on an annual basis (or for a given time period) with and without the effect of outages occurring during MEDs. In the response to STF 6.35, TEP provided both sets of indices for the periods listed above.

Q. What can be said as to these results?

A. Considering the values of the indices which are inclusive of MEDs, TEP has good reliability in its distribution system. I would consider a given distribution system to exhibit very good reliability if the annual SAIFI has a value of 1.00 and a corresponding SAIDI of about 90 minutes. That would mean that the average customer experiences one outage per year with a duration of 90 minutes. TEP's results are not significantly below those values and the results listed do include the effects of MEDs. TEP's indices for 2011 were significantly affected by three (3) MEDs.

Q. You did not mention the relative ranking of TEP compared to comparable utilities. Do you consider the relative ranking of a given utility's indices to determine if its distribution reliability performance is adequate, good, or very good?

A. No. At first blush, that kind of determination may be adequate but there are too many variances that, in my opinion, can make such an evaluation misleading. These include such considerations as the nature of a given utility's service area, the mix of radial versus networked feeders, the proportion of underground services, customer density, relative length of feeders, distances from service centers, lightning and wind conditions of the service area, etc. Also, the reporting and data collection quality across the reporting utilities can vary greatly. I would prefer that the values of the indices, with and without MED consideration, were the primary consideration.

Q. You mentioned the quality of data collection and reporting varies among utilities. How would you characterize TEP's performance?

A. Based upon discussions with the TEP personnel responsible for the calculation and presentation of outage data and observations of how the data is collected, I would characterize TEP's performance as excellent in that regard.

Q. You indicated that you consider TEP's distribution reliability to be "good". What would you recommend that the Commission consider in future evaluations of TEP reliability and what actions on the part of TEP are appropriate at this point in time?

A. I would recommend that the Commission evaluate TEP's reliability on the basis of the indices being maintained at present levels as a minimum. Our discussions and review of TEP's outage management and data collection indicate that TEP places a high degree of effort in monitoring outages, causes, and outage durations as well as the number of customers affected. This should be maintained at current levels and TEP management should continue to use the indices as a prime indicator of its quality of service and as a guide to maintenance and improvement activities aimed at the distribution system.

Further, TEP should determine "Target Values" for SAIDI and SAIFI to be maintained as a minimum by TEP, irrespective of their ranking in the reported industry results.

Q. Did you consider aspects of how TEP responds to customer outages and what provisions in staffing of repair personnel are maintained?

A. Yes. We prepared a Data Request in the form of STF 6.22 along those lines and then discussed TEP's response during our field observations.

Q. Would you say that TEP provides adequate and timely responses to outages?

A. Yes. TEP's response to STF 6.22 indicates that it provides 24/7 coverage of outages for repair with properly equipped service crews.[2] TEP has about 61 crews available for responses to outages. The journeymen Linemen designated as "Troublemen" are equipped

[2] Exh. 2.

with one-man bucket trucks which they take to their homes which allows for 15 minute (in most cases) response to outages and by being dispatched from their residences provides for generally good area coverage of outages. For major outages that require multiple crews and the larger equipment, crews report to the main Irvington campus where major equipment and materials are stored. TEP can also have such delivered to the outage site.

Q. Are you satisfied that TEP's staffing and outage response are providing a good degree of reliability as far as minimizing outage durations?

A. Based upon the above description of staffing and methodology and our observations of actual outage response during our field visits, I am satisfied that TEP is providing prompt response to customer outages and reasonably minimizing outage durations.

Q. What have been the major causes of distribution outages in recent years?

A. As a part of our investigations, we requested a listing of service interruptions that affected 200 or more customers and had an outage duration of more than four (4) hours over the past four (4) years. This was per STF 6.15.[3] A review of the provided confidential response indicated that a major cause of significant outages was due to pole failures that resulted in removing complete feeder circuits from service. We discussed this with TEP personnel during our field observations and visits as to TEP's analysis of the cause and what preventive measures are being taken to limit such in future.

TEP has initiated a program for the replacement of wooden poles that are observed to be in a weakened condition with steel poles. Further, wood poles in mid-span of feeders are also being replaced with steel poles to limit the extent of feeder failures. In addition, TEP will be using steel poles exclusively for all new construction and for replacement of failed wood poles.

[3] Exh. 3 (Confidential).

Q. Do you agree that this program of "steel only" will result in increasing the reliability of the distribution system?

A. Yes. In my opinion, this program is a good response to what has been a considerable problem and should result in increased reliability in the future.

Q. What other efforts does TEP employ to maintain and improve the distribution system?

A. During our discussions with TEP personnel, we were informed of a program TEP employs to survey the system feeders on an annual basis, rank them as to repair and/or improvement status, and then provide upgrades and preventive maintenance to the highest ranked feeder circuits. The ranking system utilizes the feeder circuits' individual reliability indices as a part of the formula that produces a "score" for each circuit. This is referred to as "Critical Circuit Ranking" developed by TEP Distribution Engineering. TEP provided a description of how this planning is applied and the resulting rankings. We have included it here as Exhibit 10.

Q. What is your assessment of this program?

A. In my opinion this is an excellent program and indicates that TEP is putting significant effort into improving its distribution system quality prior to failure and the ranking recognizes the value of the distribution indices on an individual circuit basis as an indicator of required preventive maintenance and/or upgrades.

Q. Do you have any comments as to the method or implementation of this program?

A. I think one concern is that there is a mention that funding for the determined upgrades and repairs may be limited to the point that only one circuit per year may be pursued. Given the number of distribution circuits, that could delay some circuits-depending on their ranking-for long periods. I would urge TEP management to consider allocating sufficient funding to increase the number of circuits to be addressed on an annual basis.

Q. Are you making that a recommendation here?

A. Yes, I recommend that TEP work toward increasing the pace of upgrading critical circuits that are in need of preventative maintenance or upgrades within its distribution system.

Q. What other aspects of the distribution reliability and performance did you consider?

A. We reviewed the number of distribution transformer failures and replacement over recent year, the system power factor performance and corrective measures pursued, the penetration of underground services, metering aspects, planned system improvements as regards the older 4 kV circuits, and the determination of the distribution system losses.

Q. What were you able to conclude about these items?

A. We have concluded that the distribution transformer failure rate is within expected range and that TEP has studied and continues to monitor the distribution system power factor and has provided the required correction of such by the installation of capacitors. The present level of under grounding is at 67 percent (STF 6.32) on a customer –served basis and this appears to be reasonable and increasing.[4] Aspects of metering types and applications are discussed hereafter as are planned system improvements and loss determination.

B. Post-Test Year Plant Additions

Q. Please Discuss TEP's Post-Test Year Plant Additions Being Requested For Inclusion In Rate Base In This Case.

A. Schedule B-2 of TEP's Application identifies the post-test year gross jurisdictional utility plant investment additions of $42.480 million being requested for inclusion in rate base in this case. TEP's response to data request STF 6.42 provided a list of projects each of which is in excess of $500,000 totaling $37.066 million that are included in TEPs post-test year request.[5]

[4] Exh. 4.
[5] Exh. 5 (Confidential)

The projects provided in response to STF 6.42 represent about 87% of the total post-test year amount requested by TEP. The project list provided the basis for the projects we scheduled for visit in the field and to discuss with TEP personnel. The list of projects provided in TEP's response to STF 6.42 is provided as Exhibit 5 to this testimony.

Q. Please Identify The Projects In TEP's Response To STF 6.42 That You Observed And/Or Discussed With TEP Personnel During Your Field Investigation To Arizona?

A. The following are the projects observed and/or discussed with TEP personnel, including the project investment amounts and TEP's proposed in-service dates:

Each of the above projects was observed and/or discussed with TEP personnel directly responsible for the project. With regard to the San Juan project, discussions with personnel directly in charge of oversight and implementation of the project were undertaken at TEP facilities at the Sundt generating station site. It should be noted that with regard to the San Juan project, the current TEP request represents a portion of on-going sub-project upgrades and rebuilds that have been underway for a couple of years and will continue into the future. This is the case because of the age of the San Juan facilities and the need for certain environmental compliance investment.

Our objectives regarding the reviewing of these projects were two-fold: (1) to either confirm a project was in-service or would be in-service by December 31, 2012; and (2) to ascertain the operational relevance and usefulness in providing electric services to TEP customers in Arizona.

Q. Please Continue and Briefly Discuss Each Of These Projects.

A. With regard to the projects listed above, we confirmed the current operational nature of the projects and/or the operational nature by TEP's claimed date of December 31, 2012. As mentioned previously, we did not visit the San Juan facility, but were assured by the TEP personnel in-charge that the plant and equipment that is reflected in TEP's requested [redacted] of post-test year additions is in-service at this time.

The following is a brief discussion of the projects reviewed and reflects our observations of each based on the meetings with TEP personnel responsible for the requirements and expenditures associated with the specific project.

(1) Solon UASTP-D11PD34 --- this project is referred to by TEP as the Prairie Fire project and represents a utility-scale photo-voltaic solar power generating facility that has now become operational. This site consists of a fixed-tilt photo-voltaic system generating about 5 MW of electric power. This site is in close proximity to TEP's solar equipment test site in which there are several vendors and other participants such as Arizona State University working with TEP. The purpose of the test site is to monitor and evaluate the electric output performances of various photo-voltaic panel configurations.

The Prairie Fire project is a Solon Energy design–build facility owned and operated by TEP. The project includes all necessary photo-voltaic panels, inverters, switch gear and interconnection equipment allowing TEP to integrate this electric generation source (about 5MW) into its electric network.

(2) San Juan-CBOAD00 --- San Juan is an approximate 1,800 MW (gross output) power station located in New Mexico which is 19.8% owned by TEP and consists of four (4) coal-fired units. The age of the station and the necessity to meet environmental compliance standards has compelled TEP to undertake the upgrading and replacing of plant and equipment over the last couple years and continue into the future. Steam flow temperatures, ash erosion, and other operational circumstances have resulted in thermal fatigue and general corrosive and deterioration of components of the units. This has

created the need for performing upgrade and/or replacement work on the primary superheater, expansion joints and stack ceiling upgrade, among other sub-projects at San Juan.

With respect to the above, TEP personnel provided a breakdown of the [redacted] requested in this case as post-test year additions.

[redacted]

The in-service date for these upgrades and replacements was April 30, 2012.

(3) T&D Work Mtg.–D111WMC --- constitutes the completion and implementation of the first phase (Phase I) of a potential three (3) phase undertaking by TEP to develop a comprehensive computer software system compatible with TEP operations. The software system is to "take the place" of 12 or 13 work management systems that were in various phases of use and non-use by TEP because of the antiquated nature and/or current inapplicability of these programs with TEP operations and management processes. TEP's comprehensive system is an adaptation of Siemen's MAXIMO software that is currently in various stages of use by electric utilities throughout the country, such as Portland General, DUKE Power and Salt River Project. TEP's planning and development of Phase I of this project commenced in April 2011 and was completed in May 2012. Phases II and III are still in the conceptual stages and are yet to be presented to TEP's management for consideration.

The purpose of TEP's software system is to bring together operational and management aspects of monitoring and coordinating the functioning of TEP's electric network. The objective is to integrate the data and information associated with work management, asset

inventories, maintenance applications and so forth. For example, TEP personnel indicated that a major function of the software system is to provide preventive maintenance scheduling prompts on work that needs to be done. In this regard, TEP can then do a more efficient job of analyzing the staffing and equipment necessary to undertake work such as breaker maintenance, substation transformer testing and monitoring, tree trimming, and project construction management.

(4) Electronics/Comm. – CBOPC92 --- this project, completed and operational during the first week in November 2012, provides a telecommunications link between the northern operations; e.g., UNS Electric and Gas systems in the Kingman area, and TEP's Tucson operational centers. The telecommunications link is a microwave system with multiple repeater facilities on mountain tops to relay signals between the locations. The three (3) telecommunications paths effectively act as 3-OCSs and have replaced an old DS3 system. The longest link between repeaters in the new system is about 50-60 miles.

The telecommunications link in its entirety is used to transfer billing and other customer information and data (TEP, UNS Electric and UNS Gas) as well as for the transmission of supervisory information on network operations. TEP worked with the vendor, Alcatel, to establish what amounts to three (3) communications paths within the telecommunications link with "dynamic bandwidth" functionality. The latter provides the capability to transfer traffic among the communications paths to optimize the transmission use of all three (3) paths.

(5) El-Ro UG-D08LD52 --- this distribution system project was a public improvement project in cooperation with the City of Tucson. The project planning was started by the City in 2001, with TEP construction beginning in 2010, and in-service in July 2012. The public improvements consisted of the expansion of about 2 miles of roadway (East Loop to Roberts) from 2-lanes to 4-lanes.

TEP's construction consisted of the undergrounding of a 200 – Amp circuit and a 600 – Amp looped circuit in conduit. TEP does not do any direct burial of conductors in its

network. The City of Tucson undertook the joint-use trenching work for this project, wherein TEP's conduit (and conductors) shares the trench with telephone and cable lines. In addition to the typical administrative procedures that were necessary for the City to undertake for this public improvement project, the City also had to deal with archeological/historic site considerations that were present at this location.

C. TEP Call Center

The TEP Call Center is located at the Sundt Power Station site, and serves TEP, UNS Electric and UNS Gas customers. Our discussions with personnel and observations at the Call Center focused on the operations and functions that relate to outage notification and TEP responses to outage notifications and information requests from customers.

The TEP Call Center is a 24/7 operation with "after hours" crews responding to customer calls. The Call Center also has an Interactive Voice Recognition ("IVR") system should a customer choose to not speak, at least initially, with a person in the Call Center. The Call Center personnel have access to billing information and other service data when responding to a customer call. With regard to extended outages of electric service, Call Center personnel contact customers impacted by the outage as to the nature and estimated duration of the outage as that information becomes available.

Q. How Would You Assess The Call Center Operations Based On Your Visit?

A. We were satisfied that the Call Center effectively and efficiently responds to customers outage notifications, i.e., trouble calls, as well as calls from customers regarding billing and other inquiries.

Q. What Is Your Understanding Of The Coordination Of Activities Among The Call Center, Outage Management And Field Maintenance Personnel At TEP?

A. Call Center personnel receive outage calls from customers which also appears as an equipment level fault(s) in the electrical network on the Outage Management System and, therefore, alerts the maintenance crews (troublemen) that there is an electric service outage. Either the number of customer calls in a specific network area and/or the

appearance of equipment faults on the Outage Management System allows TEP to evaluate the extent of the service interruption; i.e., a single customer compared to multiple customers. This outage evaluation procedure allows TEP to dispatch field maintenance personnel in an efficient manner to the location(s) of the apparent fault(s) in the network.

D. TEP Outage Management System

Q. You previously discussed how TEP responds to identified service outages. Can you discuss the concerned system utilized and your assessment of it?

A. Yes. TEP operates an Outage Management System that combines Geographic Information System ("GIS") mapping and computer-generated single-line representations of the distribution system. The system operates down to an individual customer level and includes circuit features such as switches and transformers. Upon notification of an outage by either the Call Center or by Supervisory Control and Data Acquisition ("SCADA") in the case of a feeder circuit breaker operation, the operators can locate the outage and direct the repair crew to the location. The system acts to derive the outage information necessary for indices determination by recording the duration of the outage and the number of customers affected. It also provides the probable cause or source of the outage based upon the number and location of the interrupted customers. Further, the Outage Management System provides the Call Center with confirmation of service restoration when repairs or corrections are completed by the field personnel.

Observation of the system in real-time during several customer outages indicates that the system is functional and is providing the repair crews and the system operators with necessary data to provide for safe and prompt restoration of service.

Q. Would you say that TEP's Outage Management System is adequate for its assigned tasks and comparable to current levels of such systems in other electric utilities?

A. Yes, in my opinion, the system is suitable for TEP's use.

E. Distribution System Upgrade (4.16 kV to 13.8 kV)

Q. What are your concerns relative to the remaining 4.16 kV distribution feeders in the distribution system and why should they be upgraded to 13.8 kV. ?

A. My concern is that the 4.16 kV ("4 kV") system represents a source of greater losses to serve comparable customers as compared to that of the 13.8 kV circuits.

Q. So it is not a reliability concern?

A. No. The outage data provided by TEP indicates that on average, the 4 kV circuits tend to be more reliable, i.e., a lower value of SAIFI than the 13.8 kV circuits. This could be expected, assuming similar levels of maintenance as these circuits tend to be shorter and installed in more protected right-of-ways such as alleys where they are not subjected to damage from vehicles, lightning, etc. to the level of the 13.8 kV circuits. My concern is only related to the potential loss reduction that a conversion could accomplish.

Q. Can you elaborate?

A. Yes. At present the 4 kV circuits are supplying about 84,000 customers with a combined load of about 440 MW. The aim would be to reduce the line losses required to serve this load by an upgrade to 13.8 kV. The load and power factor remaining constant, this increase in circuit voltage would decrease the current in the lines by a factor of 4.16/13.8 or about 30 percent of the equivalent 4kV current levels. As line losses vary by the square of the current, line losses could decrease to about 10% of the 4 kV values. This could represent significant savings in terms of the costs of energy lost and in reduced peak demand.

Q. You keep using "line losses" as a possible reduction. Would all of the circuit losses be reduced?

A. No, the losses in the distribution transformers would remain about the same as would the losses in the substation transformer supplying the circuit.

Q. Are you recommending that the Commission require TEP to go forward with a conversion of all of the remaining 4 kV circuits?

A. No. There are significant costs in such a conversion including the replacement of the distribution transformers, possible insulator replacements, increased phase wire clearances, and a question as to the conversion of the substation to supply a 13.8 kV source. I am recommending that TEP initially perform a study of the potential loss reductions and an estimate of the costs required to convert 1 to 3 selected 4 kV circuits. If the long-term benefits are positive, then TEP would perform a pilot program to convert a selected circuit to determine the actual costs, develop construction and outage management procedures that will be involved in the upgrade. I am aware of the potential difficulties of such a conversion but the benefits appear to be attractive as energy costs rise and the potential demand reduction is also a consideration.

My recommendation to the Commission is for TEP to perform a cost-benefit study followed by a pilot program as discussed above with a report of the results.

F. Customer Metering

Q. What is the current status of TEP's customer metering?

A. In response to STF 6.09, TEP stated that about 42 percent of their customer meters are AMR.[6] Subsequent discussion with TEP personnel revealed that there are very few AMI meters currently in use.

Q. What is a general description of "AMR" and "AMI" meters and their differences?

A. Generally speaking "AMR" meters provide for remote reading while an "AMI" meter, sometimes referred to as a "Smart" meter can provide for two-way communication and can be provided with control features for customer appliance management and can provide service connection and disconnects remotely. Future movement to a "Smart Grid" will require customer metering by "AMI" meters. Other advantages of an AMI meter is the

[6] Exh. 6.

ability to re-program its metering set-ups of time-varying rates remotely on a customer specific basis.

Q. Is TEP moving toward a system-wide installation of these "Smart" meters?

A. No. TEP informed us during our discussion of this that it is planning to "move forward with caution" and "with the speed of value" toward a Smart Grid that would require such an installation. TEP has initiated several pilot programs evaluating aspects of smart grid applications other than metering such as direct load control, feeder temperature monitoring, etc.

Q. What did you understand TEP's reasoning for this to be?

A. My understanding is that TEP is concerned with "technology risk", i.e., that any move now toward a large number of the newer AMI meters has a risk of the meters they may install becoming outmoded and possibly combined with an non-compatible telemetry system in future.

Q. Do you share those concerns?

A. I can understand such concern as there is a significant cost impact to be considered and there is some chance of the meters becoming out-modeled at some point. But I think that concern can be overcome and the advantages of the "Smart" metering, even at present, out-weigh the concerns or risk involved.

Q. Can you elaborate?

A. Yes. I believe that any significant changes in "Smart" meter functionality in the future could be (and will be) overcome by a replacement of the processor ("chip") in whatever meters TEP would install in the near term. Further, merely the ability of the "Smart" meters to adjust rates and provide even limited control functions is a feature that should be acquired promptly. Given that the AMR penetration is currently at less than one-half of the customer base, it would seem prudent to begin to install the AMI meters in lieu of the AMR and then retrofit the installed AMR meters.

Q. What would you recommend on the metering question?

A. I would recommend that the Commission order TEP to continue upgrading to an AMI metering system.

Q. Do you have any other comments as to TEP metering practices?

A. We did discuss with TEP personnel as to its replacement and depreciation practice concerning customer metering. We were informed that TEP currently depreciates its customer meters on a basis of 27 years, while their current replacement cycle is about 20 years. We agree with the 27 year depreciation.

G. Distribution System Analysis/Losses

Q. What concerns or comments do you have about the analysis or the losses of the TEP distribution system?

A. We had inquired in a Data Request (STF 6.04) as to the frequency that TEP performs load-flow analysis of the distribution system. In response, TEP stated that these are performed only when a problem is known to exist or to review proposed switching routines that are suspected to create problems.[7] We think that periodic load-flow analysis to review the effects of system demand changes, fault levels, and as a check on circuit loading can identify problems in loading and losses prior to such occurring. Also, periodic load-flow results can be checked for agreement with actual measurements of the system loading to correct problems with the system circuit model that the program is using for its base results.

We would recommend that TEP set up a routine of periodic load-flow analysis of its system and confirm that the model is accurate.

Q. And your concern as to losses?

A. In a separate Data Request (STF 6.23), we inquired as to what is the current metering provided at the distribution substations and what parameters are available. TEP replied that all of the new or upgraded substations are equipped with metering on each

[7] Exh. 7.

distribution circuit breaker that can provide an array of power, Var, voltage, and current levels to the Energy Management System via SCADA.[8] Also, the circuit metering can provide Kwh and kVar data as well. Our interest is that the total energy usage by circuit can be determined and recorded to be compared to the sum of the customers' metered usage so that the system losses can be determined on a circuit-circuit basis. This would allow for determining if, for example, a certain circuit has high losses compared to expectations and measures could be then taken to correct these.

We would recommend that all of the feeder circuits be so equipped.

H. TEP Distribution System Outage of 11-9-2012

Q. We understand that TEP had a significant outage on the morning of November 9, 2012. Have you reviewed this incident and if so, what are your conclusions as to the cause and the effects of the outage?

A. We have reviewed this incident and the following is our understanding of the cause and resulting effects on the system. On the date stated at about 0700 hrs, TEP's distribution system suffered an outage of several 46 kV and 138 kV distribution substations. The outage coincided with the scheduled removal from service of an Arizona Public Service Company transmission line. The substations were tripped by a load shedding action of TEP's Local Area Protection Scheme. As a result, about 46,645 customers were affected with a loss of service. The majority, about 40,581 of the outages were restored to service in about 3 minutes. Another 4,569 in 25 minutes, and the remaining 1,495 in about 80 minutes.

Our initial impression of the nature of the event was based on discussions between TEP personnel and Commission Staff. These seemed to imply that an insufficient level of local TEP generation had been provided to offset the effect of a scheduled outage of the 500 kV Cholla-Saguaro transmission line and that was the cause of the load-shedding.

[8] Exh. 8.

Subsequently, we prepared a Data Request (STF 27.0) to TEP for clarification and additional information. TEP's response to STF 27.0 clarified the matter.[9]

The following is based on our review of TEP's responses to the 14 questions contained in STF 27.0. We believe that the load shedding operation was not due to the TEP operations failing to provide sufficient local generation, but was primarily due to an incorrect setting of TEP's Tie Open Load Shed system. If the lack of local generation levels was sufficient to cause the load-shedding action by itself, then an unscheduled trip of the Cholla-Saguaro would have also resulted in load shedding which we do not think is a planned action. Also, given that the bulk of the shed load was restored in about 3 minutes remotely via the SCADA, there was sufficient generation available to serve the system load.

The delay in restoring the remaining customers to service was due to one of the 46 kV circuit breakers tripping but not displaying on the Load Shed Restoration Display and one 13.8 kV breaker indicating it was closed on the SCADA when in fact it was actually open. We assume that both of these were verified by field personnel and that accounted for the bulk of the delay in returning those circuits to service.

TEP also clarified that the increased level of local generation was necessary to provide for the added contingency condition that the 500 kV line outage created. In addition, it also may have replaced purchased power during the line outage. This is a supposition, since TEP did not suggest that. TEP replied to our question as to whether there were any written procedures in place relating to increasing local generation, and if these had been violated. TEP stated that varying local generation does not entail a written procedure as the concerned parties are in close proximity to one another in the TEP control room. However, TEP did confirm that they are preparing a formal procedure for the Tie Open Load Shed System and it is under review for implementation.

[9] Exh. 9.

We believe that the cause of the outage was an incorrect set-up of the Tie Open Load Shed System for the outage of the 500 kV transmission line. No written procedure was necessary or customary for the varying of TEP's local generation. There were some positive outcomes of the incident in that an error in the SCADA display was revealed and a missing 46 kV breaker indication was noted on the load shed restoration display. TEP's initiation of a procedure for the setting of the Load Shedding is proper and should help to prevent any repeat of the incident. Our only suggestion is that during any future circuit breaker operation in the distribution substations, an effort should be made to confirm the correct indication appears on the SCADA display of breaker positions.

III. CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize Staff's recommendations.

A. Staff recommends that TEP management consider allocating funding to increase the number of distribution circuits to be addressed with upgrades from the current one circuit per-year rate;

As explained in the Direct Testimony of Ralph Smith, Staff has made a policy recommendation that post-test year plant additions that can be confirmed as in service by December 31, 2012 be included in rate base. Staff recommends the inclusion in rate base of those post-test year plant additions.

Based on Staff's evaluation, TEP's Call Center performs effectively and efficiently in response to outage notifications as well as customer bill inquiries.

Based on Staff's evaluation, TEP's Outage Management System appropriate to TEP and is suitable for TEP's use.

Staff recommends that TEP initially perform a study of potential line loss reductions for upgrading one to three 4 kV circuits prior to implementing a broad distribution system upgrade. If the study indicates long-term positive benefits, then a pilot program would be appropriate for the upgrade of a select circuit to determine actual costs and develop

construction and outage management procedures that will be involved in the upgrade process.

Staff recommends that TEP continue upgrading toward AMI meters.

Staff recommends that TEP move toward equipping its feeder circuits with meters to provide comparable data to what is provided by the circuit metering on TEP's distribution circuits.

Staff recommends that TEP establish a routine of periodic load-flow analyses of its distribution system and confirm that the system circuit model is accurate.

Staff recommends that, after the November 9, 2012 outage, that TEP use any future circuit breaker operation in the distribution system to confirm that the correct indication appears on the SCADA display of breaker positions.

Q. Does this conclude your Testimony?

A. Yes.

BACKGROUND & EXPERIENCE PROFILE
W. MICHAEL LEWIS, P.E.
PRESIDENT
W.M. LEWIS & ASSOCIATES, INC.

EDUCATION

1981 - 1988	Master of Business Administration, Ohio University, Athens Office
1971 - 1971	B.S., Electrical Engineering, Ohio State University, Columbus, Ohio
Special Courses:	Power Circuit Breakers, Ohio State University Modern Power System Analysis, University of Wisconsin Digital Electronics for Power Application, IEEE Modern Methods of Analysis and Protection of Electric Power Systems, IEEE Project Management and Planning, University of Wisconsin Construction Contract Administration, University of Wisconsin High Voltage Testimony, Pennsylvania State Lighting Solution and Design, IIT/AEE Cogeneration Theory and Design, University of Wisconsin Planning, Procurement, and Installation of SCADA Systems, University of Wisconsin, 1989
REGISTRATIONS	Registered Professional Engineer in Kentucky and Ohio Registered Consultant to the Asian Development Bank, Manila, Philippines

POSITIONS

1979 - Present	President and Manager of Engineering of W.M. Lewis & Associates, Inc.
1974 - 1979	Electric Power Engineer, Goodyear Atomic Corporation (now Martin Marietta Energy Systems)

EXPERIENCE

Summary -- Extensive experience in utility practice, including serving as an expert witness on topics of planning, design, construction, operation, and maintenance of high-voltage transmission lines and facilities, (overhead and underground); high-voltage transformer and circuit breaker loading, operation, and maintenance; working and design clearances on facilities at 230 kV and above and other aspects of utility practice before the State Corporation Commission of Virginia; and on aspects of electric utility design and operation before the Federal Energy Regulatory Commission. Also served as an expert witness in numerous electrical accident litigation concerning interpretation of the NESC, OSHA regulations, and the concept of "Prudent Utility Practice." Has performed reviews of rural electric utilities in 14 countries.

In addition to experience and expertise in engineering, operation, and code application, prepared operation manuals for client utilities and industries, prepared training curriculum for power operators, trained power operators and linemen, and prepared PM program criteria for utilities and industry. Experienced in HV and EH V testing techniques of transformers and cables and circuit breakers, including OCB and SF_6 designs.

Graduate level studies include concentrated studies of staffing level theory and the use of statistical techniques in electric rate design and preparation of tariffs for electric utilities. Training in safety audits and compliance plans.

EXHIBIT 1

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
STAFF'S SIXTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
September 25, 2012

STF 6.35

At Page 6 of the Direct Testimony of Mr. DeConcini is a table entitled "2008-2011 SAIDI/CAIDI Comparison". With respect to this table, please provide all the data, spreadsheets, calculations, etc. that show how each of the figures was determined. Please provide the response in hard copy and electronic, executable format, preferably Microsoft Excel.

RESPONSE:

THE FILES LISTED BELOW CONTAIN CONFIDENTIAL INFORMATION AND ARE BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT DATED JULY 6, 2012.

Please see the files listed below for the Excel spreadsheets prepared by TEP for the requested information. Additionally, TEP is in the process of obtaining permission from Edison Electric Institute ("EEI") to provide reliability reports prepared by EEI.

File Name	Bates Numbers
STF 6.35 2008 TEP Distribution Indices Calcs-Confidential.xls	N/A
STF 6.35 2009 TEP Distribution Indices Calcs-Confidential.xls	N/A
STF 6.35 2010 TEP Distribution Indices Calcs-Confidential.xls	N/A
STF 6.35 2011 TEP Distribution Indices Calcs-Confidential.xls	N/A

RESPONDENT:

Tyler Wallace

WITNESS:

Michael DeConcini

EXHIBIT 2

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
STAFF'S SIXTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
September 25, 2012

STF 6.22

Please provide the number of repair crews, i.e., personnel with vehicle, tools, replacement parts, assigned "on-call" after normal business hours on a daily basis. Please include in this response a detailed description of how the crews are stationed and how they are dispatched to the location of complaints and/or outages.

RESPONSE:

TEP has approximately 61 crews available for emergency response in the Transmission and Distribution Operations area. This includes crews of varying sizes in Line Construction, Substations, Relay, Communication and Metering.

The System Control & Reliability ("SC&R") office operates 24 hours a day, 7 days a week and receives the first notification of any outages or issues that require crew response. A SC&R Supervisor will contact the designated on-call Supervisor for the type of crew required (Substations, Line Construction, et cetera). The on-call Supervisor will review the outage/issue, determine the size of crew required to respond and perform the necessary employee callout. There is a backup on-call Supervisor in case the primary misses the call. If the primary and secondary on call supervisors miss the call, the area Superintendent receives the call.

The majority of the employees called on to respond to the outage or issue report to the Irvington campus. The equipment and material are also stored on the Irvington campus. Crews will take the necessary equipment to the problem location. Depending on the amount and size of material required, the responding crew will take the material, or the Warehouse will deliver the material to the job site.

Troublemen drive one-man bucket trucks home, so they can respond within 15 minutes of a 911 call. These Journeymen Linemen are dispatched based on the area of town they are assigned.

RESPONDENT:

Susan Gray

WITNESS:

Michael DeConcini

EXHIBIT 3

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
STAFF'S SIXTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
September 25, 2012

STF 6.15

For each of the past four calendar years (2008-2011) and for the first 6 months of 2012, please provide a listing of all service interruptions that had a duration of four (4) hours or more and affected more than 200 customers. Please include for each outage the date and time; the ascribed cause; the duration of the outage; the number of consumers affected; the feeder or feeders affected; and the nature of the remedial efforts including equipment replaced, if any. Please include in this response a description of how the information in this response was obtained and recorded. The reference to "duration" means from the initial outage report from either the customer or system diagnostics to the restoration of service to the customer. If the vast majority (e.g. 90-95%) of the affected customers had service restored significantly sooner than the remaining customers affected by the outage, please describe the circumstances for each such episode.

RESPONSE:

THE FILES LISTED BELOW CONTAIN CONFIDENTIAL INFORMATION AND ARE BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT DATED JULY 6, 2012.

Please see the files below for the requested information.

File Name	Bates Numbers
STF 6.15 2008 OUTAGES-Confidential.XLS	N/A
STF 6.15 2009 OUTAGES-Confidential.XLSX	N/A
STF 6.15 2010 OUTAGE-Confidential.XLSX	N/A
STF 6.15 2011 OUTAGES-Confidential.XLSX	N/A
STF 6.15 2012 OUTAGES-Confidential.xlsx	N/A

The information in this data response was obtained from the Commission customer-hour outage reports on file. The information used to complete the Commission customer-hour outage reports is derived from TEP's Outage Management System ("OMS").

RESPONDENT:

John Tolo

WITNESS:

Michael DeConcini

EXHIBIT 4

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
STAFF'S SIXTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
September 25, 2012

STF 6.32

Please state the percentage of TEP customers served by underground distribution facilities as of year-end 2011.

RESPONSE:

As of year-end 2011, 67% of TEP customers were served by underground distribution facilities.

RESPONDENT:

Ana Bustamante

WITNESS:

Michael DeConcini

EXHIBIT 5

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO STAFF'S SIXTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291
September 26, 2012

STF 6.42

With respect to the approximately $40 million of capital investments TEP expects to be in-service during 2012 referenced at Page 27, Lines 24 through 26 of Mr. DeConcini's Direct Testimony, please provide the following:

a. a list of the specific capital investment projects with estimated costs in excess of $500,000;

b. the current status of each of the capital investment projects; e.g., funds expended to date; funds remaining to be expended; expected in-service date; comments regarding project developments; etc.;

c. any updating of the amounts expected to be placed in-service in 2012, such as projected increases or decreases to any of the specific projects, additional projects and eliminated projects, and etc. to those provided in (a); and

d. the specific amount of the capital investment projects that TEP is requesting be included in its proposed revenue requirement in this case.

RESPONSE: September 25, 2012

TEP is in the process of gathering this information and will provide it as soon as possible.

RESPONDENT:

Michael Flores

WITNESS:

Michael DeConcini

SUPPLEMENTAL RESPONSE: September 26, 2012

THE FILE LISTED BELOW CONTAINS CONFIDENTIAL INFORMATION AND IS BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT DATED JULY 6, 2012.

a.-c. Please see STF 6.42 Certain post-test year adds-Confidential.xlsx, for the requested information.

d. Please see TEP's responses to RUCO 1.07 and 3.01.

RESPONDENT:

Michael Flores and Mark Alberston

WITNESS:

Michael DeConcini

EXHIBIT 6

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
STAFF'S SIXTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
September 25, 2012

STF 6.09

Please describe the penetration of AMR and AMI metering in the Company's distribution system as of 6/30/2012.

RESPONSE:

179,814 meters out of 429,496 meters (42%) are AMR.

RESPONDENT:

Ed Mansfield

WITNESS:

Michael DeConcini

EXHIBIT 7

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
STAFF'S SIXTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
September 25, 2012

STF 6.04

Please state if the Company performs periodic load-flow and short-circuit studies and analyses of its distribution system. If so, please state how often such studies are performed, what system parameters are studied, and how the study results are utilized in planning and maintenance.

RESPONSE:

Power-flows are only performed when a problem is known to exist, or when a proposed switching routine is suspected to have problems. Short-circuit studies are performed when customers request available fault current, and when modifications are made to the circuit protection scheme to ensure coordination.

RESPONDENT:

Steve Metzger and Donovan Sandoval

WITNESS:

Michael DeConcini

EXHIBIT 8

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
STAFF'S SIXTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
September 25, 2012

STF 6.23

Please describe the Company's metering currently installed at a typical distribution substation that monitors and records system parameters; the parameters that are measured by this metering; and the measurement data that are stored for later evaluation.

RESPONSE:

TEP uses a metering standard for all new or upgraded 138kV and 46kV distribution substations that utilizes the protective relays for each element (i.e. transformer, line, feeder) within the substation to provide metering information. The relay provides MW, MVar, kV (line to line avg. for each phase), and Amps (each phase) information. This information is provided to the TEP EMS system. The information is provided to the primary and backup EMS instances via the SCADA communications network. The EMS information is mirrored to the PI data historian for retention.

The main breaker on each distribution feeder switchgear lineup contains a meter. The meter provides the primary and backup EMS nodes MW, MVar, kV (line to neutral for each phase), and Amps (each phase). The EMS information is mirrored to the PI data historian for retention. The kWh_{in}, kWh_{out}, $kVar_{in}$, $kVar_{out}$ values from the meter are stored in our meter data management system for retention. The meter also has the ability to provide power quality information. The power quality (harmonics, sags, swells, etc.) and all the information that the meter can provide is stored in a database designed by the meter manufacture for retention.

RESPONDENT:

Jim Taylor

WITNESS:

Michael DeConcini

EXHIBIT 9

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
STAFF'S TWENTY-SEVENTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
December 10, 2012

RE: TEP Distribution System Outage 11-9-2012 @ 0707 Hrs.

The following questions refer to the referenced outage:

STF 27.01

Staff's understanding of the conditions that led to the referenced outage are as follows:

On 11-9-2012, at about 0700 Hrs. MST, APS initiated a scheduled outage of the Cholla-Saguaro 500 KV transmission line. Thereupon, TEP's Remedial Action Scheme operated shedding load at several 46 KV distribution substations. This resulted in outages to about 46,645 customers; 40,581 of which were restored in 3 minutes; about 4,569 in 25 minutes; and the remaining 1,495 were restored to service in about 80 minutes after the load shedding occurred. Prior to the outages, TEP Operations was increasing local generation to cover the expected loss of incoming supply as a result of the outage of the 500 KV transmission line. TEP's analysis of the cause for the Remedial Action Scheme activation is that Operations failed to sufficiently increase the Local Generation.

Please confirm if the above description is accurate. If not, please correct and add any other details that would more completely describe the cause of the outage and restoration actions.

RESPONSE:

TEP recommends two changes to the subject paragraph.

1. For the sentence beginning with "Thereupon, TEP's Remedial…", TEP recommends changing the sentence to: "Thereupon, TEP's Local Area Protection Scheme operated shedding load at various 138 kV and 46 kV distribution substations."

2. For the sentence beginning with "Prior to the outages, TEP Operations…", TEP recommends changing the sentence to: "Prior to the outages and based on system studies, TEP Operations was increasing local generation to be able to cover for the next unexpected transmission line loss along with the outage of the APS 500 KV transmission line. TEP's analysis of the cause for the Local Area Protection Scheme activation is that Operations failed to sufficiently increase the local generation, in a timely manner, prior to the APS 500 kV line coming out of service."

The rest of the paragraph is accurate.

RESPONDENT:

John Tolo

WITNESS:

Michael DeConcini

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
STAFF'S TWENTY-SEVENTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
December 10, 2012

STF 27.02

Please explain how the scheduled outage of the Cholla-Saguaro line differed from an unexpected trip on this line, i.e., would a trip of the same line under the same system conditions as those at the time of the outage have resulted in the same loss of distribution service?

RESPONSE:

The difference between the scheduled outage of the Cholla-Saguaro line versus an unexpected trip of the Cholla-Saguaro line is the way the Tie Open Load Shed ("TOLS") system recognizes lines initially out of service. Had the operator manually disabled the Cholla-Saguaro contingency within the TOLS system after he changed TOLS tables and prior to the line out of service, the TOLS system would not have tripped the load. With the correct TOLS table installed and sufficient local generation, a Cholla-Saguaro line trip would not trigger load shed.

RESPONDENT:

John Tolo

WITNESS:

Michael DeConcini

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
STAFF'S TWENTY-SEVENTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
December 10, 2012

STF 27.03

Immediately prior to the outage, was the transmission grid in normal status or were there any contingencies in effect?

RESPONSE:

TEP's Springerville-Greenlee 345 kV line was out of service.

RESPONDENT:

John Tolo

WITNESS:

Michael DeConcini

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
STAFF'S TWENTY-SEVENTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
December 10, 2012

STF 27.04

Immediately prior to the outage, what was the incoming MW and MVAR on the Cholla-Saguaro line?

RESPONSE:

588 MW were incoming from Cholla to Saguaro, and 76 MVARS were outbound from Saguaro to Cholla.

RESPONDENT:

John Tolo

WITNESS:

Michael DeConcini

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
STAFF'S TWENTY-SEVENTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
December 10, 2012

STF 27.05

Immediately prior to the outage, what was the TEP system load?

RESPONSE:

TEP system load was 1,304 MW.

RESPONDENT:

John Tolo

WITNESS:

Michael DeConcini

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
STAFF'S TWENTY-SEVENTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
December 10, 2012

STF 27.06

What parameters, i.e., under-voltage, under/over frequency, etc. initiated the Remedial Action Scheme operation?

RESPONSE:

TEP does not utilize a Remedial Action Scheme ("RAS"), instead the Company utilizes a TOLS, classified as a Local Action Plan Scheme ("LAPS"). However, none of the parameters referenced in the question initiated the TOLS scheme.

RESPONDENT:

John Tolo

WITNESS:

Michael DeConcini

STF 27.07

Given the bulk of the customers who lost service were restored in 3 minutes, is it correct to assume that this restoration was accomplished by remote operation of one or more circuit breakers or switching?

RESPONSE:

Correct, restoration was accomplished via Supervisory Control and Data Acquisition ("SCADA").

RESPONDENT:

John Tolo

WITNESS:

Michael DeConcini

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
STAFF'S TWENTY-SEVENTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
December 10, 2012

STF 27.08

Please explain why some customers' service required a more extended time to restore.

RESPONSE:

Some customers' service required a more extended time to restore because 1) the indication of one of the 46 kV breakers that tripped was not physically located on the load shed restoration display, and 2) per the SCADA system, a 14 kV feeder indicated closed on the Energy Management System ("EMS") display, but in the field it was actually open.

RESPONDENT:

John Tolo

WITNESS:

Michael DeConcini

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
STAFF'S TWENTY-SEVENTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
December 10, 2012

STF 27.09

Given the 3 minute restoration of most of the affected customers, is it correct to assume there was no lack of generation available to TEP as a result of the scheduled line outage?

RESPONSE:

Correct.

RESPONDENT:

John Tolo

WITNESS:

Michael DeConcini

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
STAFF'S TWENTY-SEVENTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
December 10, 2012

STF 27.10

What was the reason or need to have increased local generation as a result of the scheduled line outage?

RESPONSE:

For planned outages, TEP's Transmission Planning Department runs system studies based on a range of city load amounts and the number of local units on line at the time of the planned outage. As a result of those studies, there is a required amount of local generation at given city loads needed to protect against voltage instability and overloads for various single contingencies.

RESPONDENT:

John Tolo

WITNESS:

Michael DeConcini

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
STAFF'S TWENTY-SEVENTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
December 10, 2012

STF 27.11

What written procedures were or are in effect and available to the operators as to methods and ramp rates to increase local generation. Were such procedures violated by TEP Operations?

RESPONSE:

The request to increase local generation based on the TOLS tables is a verbal communication, since the transmission and generation desks are located in proximity to one another.

RESPONDENT:

John Tolo

WITNESS:

Michael DeConcini

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
STAFF'S TWENTY-SEVENTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
December 10, 2012

STF 27.12

What units of TEP were being increased prior to the outage?

RESPONSE:

Sundt units 3 and 4.

RESPONDENT:

John Tolo

WITNESS:

Michael DeConcini

STF 27.13

What actions have been taken or initiated by TEP to prevent such an occurrence in future?

RESPONSE:

TEP has drafted a formal procedure (*Operating Procedure for the Tie Open Load Shed System*) outlining the tasks and activities for the changing of TOLS tables. The draft procedure is currently being circulated for comment and will be implemented upon completion of the review. TEP has corrected the load shed restoration display as well as the incorrect indication of the 14 kV feeder breaker.

RESPONDENT:

John Tolo

WITNESS:

Michael DeConcini

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
STAFF'S TWENTY-SEVENTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
December 10, 2012

STF 27.14

Please submit a single-line diagram of the 46 KV affected by the Remedial Action Scheme and indicate what devices were activated and the subsequently affected distribution substation.

RESPONSE:

THE FILE LISTED BELOW CONTAINS CONFIDENTIAL INFORMATION AND IS BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT DATED JULY 6, 2012.

Please see STF 27.14 Loadshed Restore displays-Confidential.pdf, Bates No. TEP\030166-030168, for the requested information.

RESPONDENT:

John Tolo

WITNESS:

Michael DeConcini

EXHIBIT 10

Distribution Engineering Summary: Critical Circuit Rankings

To: Mike Flores, Tom McKenna
Cc: Ed Beck, Bill Darmitzel, David Thomas, John Tolo
From: Lauren Briggs
Date: April 10, 2008
Subject: A Justification for and Explanation of the Implementation of a Method for Critical Circuit Rankings at Tucson Electric Power

Background & Justification

The ranking of critical circuits is a method for a utility to determine which of its circuits is the most important and would benefit the most from maintenance. Several years ago, TEP had a critical circuit list that was used to rank circuits for outside studies, although it was not associated with a maintenance program.

In light of the numerical increase of UniSource's reliability indices in the past few years, Distribution Engineering, in conjunction with management, has developed a method for defining critical circuits that takes into account both a circuit's physical characteristics as well as its affect on the system-wide reliability indices. Using this method, TEP can implement a maintenance program that will target problems on circuits which contribute to a higher system SAIFI. This will allow TEP to get the most out of its maintenance dollars by addressing specific issues on circuits that have the most impact on our reliability.

Application

The new method for ranking critical circuits borrows from the previous method, but includes revisions that allow us to look at criticality factors with increased granularity. Refer to Appendix A for the walk-through of the critical circuit rankings.

Columns A, B and C: Substation, kV and Circuit Number

Column A contains the substation name, column B contains the voltage of the circuit, and column C contains the circuit number.

Column D: Customer Count

Column D contains the number of customers on the circuit as of December 31st, 2007. In order to maintain consistency between data fields, most data is from 2007.

Column E: Circuit Loading

Column E contains the loading on the circuit as a percentage of its capacity. A circuit with a capacity of 10 MVA but carrying 12.5 MVA will receive a percentage of 125%. A circuit of 10 MVA but carrying will 5 MVA is loaded only to 50%.

Column F: Ability to Restore

Column F contains the Ability to Restore rating. The current options for this column are *All*, *Part* and *None*, and were determined by the Distribution Supervisors in the Map Room. *All* indicates that, should the entire circuit lockout, the entirety of its load could be transferred to adjacent circuits within 2 tiers of switching. *Part* means that only one- to two-thirds of the circuit could be switched to adjacent circuits within 2 tiers of switching. *None* means that no load from the circuit could be switched to adjacent circuits in only 2 tiers of switching.

Column H: Customers Affected

Customers Affected is a column that contains a value between 0.5 and 2. The value is determined by the number of customers on the circuit (column D). This rating is applied as follows:

Customer Count	Customers Affected Rating
1000 or less	0.5
1001 to 1500	0.75
1501 to 2000	1.0
2001 to 2500	1.25
2501 to 3000	1.5
3001 to 3500	1.75
3501 or greater	2.0

This column acts as a multiplier within the critical circuit rankings. The total of other ranked fields will be multiplied by this number; if a circuit has an extremely large amount of customers, its criticality will increase. If the circuit has a low amount of customers, its criticality will be somewhat discounted.

Column I: Circuit Condition

Circuit condition is an even value anywhere between 0 and 20. Circuit condition is based on two factors: the age of underground cable, and the age of wood poles in the circuit. If the length of underground cable in the circuit is less than one-third the average circuit's length of underground cable, the age of underground cable is ignored and only the age of wood poles is considered. Likewise, if the length of overhead wire is less than one-third the average circuit's, then wood poles are ignored and only the age of underground cable is considered. A circuit's

wood poles are also ignored if over 50% of total poles in the circuit are steel. A rating is applied as follows:

Age of cable or wood poles	Percentage of cable or wood poles	Rating
Greater than 40 years	50% or more	10
Greater than 30 years	50% or more	8
Greater than 20 years	50% or more	6
Greater than 10 years	50% or more	4
Within past 10 years	50% or more	2
Within past 10 years	100%	0

Vail C-27, for example, has a Circuit Condition Rating of 8. This is because it had more than one-third the average overhead and underground miles than the average circuit on the system, so both its underground and overhead ratings were considered. Eighty-nine percent of the underground cable in VLA-27 was installed between 1998 and 2007, so it receives a rating of 2 for the underground portion. Fifty-eight percent of the wood poles in the circuit were installed in or before 1987, so the circuit receives a rating of 6 for the overhead portion. Adding those ratings together gives an overall circuit condition rating of 8.

If Vail C-27 had less than one-third the average length of overhead exposure, then its overhead rating would be ignored, and the underground rating would be doubled. In that instance, VLA-27's circuit condition rating would be a 4. This allows us to look at the condition of circuits that are predominantly overhead or underground on the same scale as circuits that have more evenly distributed exposures.

Column J: Redundancy Factor

Redundancy factor is a rating given based on the Ability to Restore field. If a circuit is given an All, it receives a rating of 5. If it is given a Part, it receives a rating of 10. If given a None, the circuit receives a rating of 20.

Column K: Percent Loading

The percent loading rating is based on column E.

Percent Loading	Rating
Greater than 100%	20
From 75 to 100%	15
From 50 to 74%	10
From 25 to 49%	5
From 0 to 24%	0

Column L: Critical Customers

The critical customer rating is for circuits that support critical customers or serve as backup to critical customers. A rating of 20 is given if the circuit supports one or more truly critical

customers (hospitals, police stations, etc) or multiple critical customers (usually industrial). A rating of 10 is given if the circuit supports only one critical customer. A rating of 5 is given if the circuit serves only as backup to one or more critical customers. If a circuit does not serve as the primary or backup feed for a critical circuit, it does not receive a rating.

Column M: Criticality Ranking

The criticality ranking is the total number obtained from all the fields which were rated in previous columns. This number is determined by adding the ratings from columns I through L and then multiplying the sum by the rating from column H.

$$\text{Circuit Ranking} = \text{Customers Affected Rating} \left(\text{Circuit Condition Rating} + \text{Redundancy Factor} + \text{Percent Loading Rating} + \text{Critical Customer Rating} \right)$$

The minimum criticality value that a circuit can receive is 2.5, because the minimum redundancy value is 5. The maximum value a circuit can receive is 160. However, for this to occur, the circuit would have to have over 3500 customers, have an infrastructure where 50% of the facilities were over 40 years old, have no options for backup, be over 100% loaded, and supply multiple critical customers. Since that scenario is extremely unlikely, most circuits should fall into the range of 20 to 60.

The circuits in Appendix A have been arranged by their Criticality Rankings. These four substations were chosen as an example because they are all in close proximity and have adjacent circuits; they also cover similar physical terrain as well as load types. The highest ranked circuit is Spanish Trail C-35, which has a score of 40, and the lowest ranked is Vail C-18, which has a score of 7. This serves as a good example of how circuits that seem similar can have vastly different criticality rankings.

Critical circuit ranking can indicate which circuits have important loads or aging infrastructures, and which circuits would benefit from maintenance. However, the ranking alone cannot tell us which circuits are contributing to increasing reliability indices. In order to determine which circuits are negatively impacting the system-wide SAIFI, a SAIFI must be calculated on a circuit-by-circuit basis.

Column N: Ckt SAIFI

The circuit SAIFI is calculated in the same way as the system SAIFI, except on a smaller scale. The SAIFI is the number of customers that experience a sustained outage divided by the

total number of customers, but only outages on a particular circuit, and that circuit's customer count, are used to calculate the circuit SAIFI.

In order to pinpoint circuits that have high outage rates due to issues that can be solved with maintenance, outages external to the distribution system have been excluded from the circuit SAIFI calculations. In this case, the IEEE 1366 definition for external is used; that is, outages that do not occur on the distribution system. So distribution outages caused by customer equipment, loss of source conditions, substation equipment (other than the getaways), and load shed events are not included. Crew caused outages were also excluded.

The exclusion of these outages will highlight circuits that have high incidences of equipment failure, storm- or animal-caused outages. Examining circuits with high SAIFIs after external outages have been removed could reveal patterns of failed equipment or corridors that need extra bird-guarding.

Column O: System SAIFI

This column contains the 2007 TEP system SAIFI. It is included for the calculation in the column P.

Column P: Ratio

The ratio column computes the ratio between the circuit SAIFI and the system SAIFI. If the ratio is less than 1, the circuit is not increasing the system SAIFI. If the ratio is more than one, then the circuit is contributing to an increase in TEP's system SAIFI.

Implementation

In order to determine which circuits to perform maintenance on, the Criticality Ranking of a circuit can be compared to its SAIFI ratio. If a circuit ranks high on the criticality list and has a ratio of greater than 1, that circuit's outages should be studied to determine what maintenance should be performed. If the Ranking is high but the Ratio is low, we may decide to skip that circuit and continue down the list to a circuit that is increasing the system SAIFI. Likewise, a circuit with a high ratio but a low criticality ranking may not warrant maintenance.

In order to use this system, TEP will need to determine how much money is available for maintenance and how many circuits maintenance can actually be performed on. Once these items are established, the Critical Circuit Rankings can be used to cycle through circuits that require maintenance on a yearly basis. Hopefully, with this process in place, circuits that receive maintenance will move down the list as we work to improve them. See Appendix B for an overview of the process.

Conclusion

The development of a new critical circuit list, in conjunction with a comparison to SAIFI ratios, should allow TEP to pinpoint problem circuits for maintenance. Using this method, maintenance will not be performed in random fashion, but rather used to address specific problems on important circuits that are experiencing high rates of sustained outages. This will enable us to get the most out of our maintenance dollars by increasing the strength of our infrastructure and decreasing our reliability indices.

BEFORE THE ARIZONA CORPORATION COMMISSION

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

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

(PUBLIC)

DIRECT

TESTIMONY

OF

EMILY S. MEDINE

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

DECEMBER 21, 2012

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EXECUTIVE SUMMARY
TUCSON ELECTRIC POWER COMPANY
DOCKET NO. E-01933A-12-0291

My testimony addresses the following issues:

- Review of proposed changes to Tucson Electric Power's ("TEP") Purchased Power and Fuel Adjustment Clause ("PPFAC") Filing
- Review of proposed changes to the PPFAC components
- Review of fuel and purchased power performance under the PPFAC since its inception
- TEP's fuel and purchased power policies and procedures
- TEP fuel and power procurement organization
- TEP power plant performance
- Inventory cost assumptions in base rates
- TEP outlook

A summary of each issue follows.

TEP has been recovering a portion of its fuel and purchased power costs through the PPFAC since January 2009. TEP makes monthly filings as agreed to in the Plan of Administration. With the exception of Schedules 9, 10, 11 and 12, the filing is non-confidential. From a management audit perspective, the confidential portion of the filing would be enhanced with greater fuel price detail for each station including delivered fuel prices (which is actually required in the current Plan of Administration), other recoverable costs per the PPFAC, and identification of non-recurring cost items. In addition, as part of any future rate proceedings, TEP should prepare and file testimony related to fuel and purchased power costs.

The costs recovered under the PPFAC are defined by the Plan of Administration. TEP has requested a number of changes to the PPFAC including the inclusion of brokerage fees, the inclusion of 100 percent of the proceeds from emission allowance sales, and an extension of the monthly filing period from 30 to 45 days. Staff agrees with TEP with respect to these requests. TEP has also requested changes which Staff considers to be either related to rate design and will be addressed by another Staff witness. Staff has identified two cost items related to the PPFAC that it proposes be handled in a manner that would require changes to the Plan of Administration. The first relates to proceeds related to the sale of Renewable Energy Credits ("RECs") not part of the TEP Renewable Energy Standards Tariff which the Plan of Administration does not address. As a result, TEP did not flow the proceeds from the sale of some RECs in 2009 through the PPFAC. The second item relates to the costs associated with a fire that occurred at the San Juan

mine on September 9, 2011. The San Juan mine supplies the San Juan power plant. TEP has represented that the fire is an insurable event. It is recommended that the costs associated with this type of insurable event not flow through the PPFAC until after the insurance coverage has been determined and such claim paid and then only if the non-insurable portion cannot be recovered in another manner and/or is deemed to be prudent. Consistent with this recommendation, it is recommended that these costs net of TEP's share of the deductible be removed from PPFAC recovery.

It is further recommended that the Plan of Administration be revised to incorporate the documentation recommendations from the Compliance Audit of the PPFAC conducted by the TEP internal audit services. Finally, it is recommended that the Plan of Administration be revised to require management audits be conducted, as required by Staff

I reviewed the fuel and power purchases since 2009 and found the costs to be prudently incurred based upon the respective energy markets and the prevailing policies. The one exception relates to TEP's decision to with regards to sulfur credits.

Following Decision No. 70628, TEP filed a Fuel Implementation Plan on March 2, 2009. TEP reported it had prepared a Fuel Management Manual. The Coal Procurement Procedure, which was the subject of the specific directive, was included in the filing. The Hedging Policy was also provided with the Fuel Implementation Plan. In response to data requests in the current case, TEP provided the most recent versions of the Fuels Department Manual, the Hedging Policy, and the Energy Trading Policy. The Fuels Department Manual is comprehensive and contains the correct information. As a document, it would benefit from either the removal of many of the inserts or the relocation of the inserts to an appendix. The Hedging Policy should be updated to reflect current market conditions and should produce a Hedging Plan consistent with the requirements of the Hedging Policy.

The number of personnel assigned to fuel and power procurement activities is generally appropriate to TEP's size. That being said, there is insufficient redundancy in the solid fuel area and that there are organizational issues with respect to the Risk Manager and the Risk Controller. Specifically, it is recommended that the Risk Manager not have any commercial duties and the Risk Manager and the Risk Controller have different reporting lines consistent with leading industry practices.

I reviewed TEP performance by reviewing plant availability rates, inventory management, coal plant capacity factors and heat rates versus other coal plants in Western Electricity Coordinating Council ("WECC"), and coal plant fuel costs. The gas plants generally had higher availability rates than the coal plants. Navajo had the best availability of the coal plants with Springerville not too far behind. TEP has not been very successful in managing its inventory levels. At Sundt, coal stockpiles have consistently run above target levels as the result of a strategic economic decision to burn gas. At Springerville, there was an extended period when inventory levels were below target amounts. Within WECC the relative rankings of the plants changed between years with Navajo and Four Corners competing for the lowest heat rates and highest capacity factors within the TEP system. Overall, with the exception of Sundt, the TEP plants generally performed in the top 50 percent of WECC coal plants. Within the TEP

system, Springerville, Navajo and Four Corners have the lowest coal costs while Sundt has the highest.

I reviewed the inventory levels TEP proposes to include in base rates. I agree with the methodology in the determination of tons but questions the associated coal prices. The coal costs for the San Juan generating plant appear to include non-recurring costs, such as an audit adjustment, as well as the costs associated with the mine fire. In addition, the San Juan costs include back end costs, e.g., ash disposal, which are costs that have not yet been incurred. Staff proposes to adjust the San Juan costs for these additional items and the price for ash disposal at the Sundt power plant.

There is enormous uncertainty as to the status of several coal plants in the TEP system because many of TEP's coal plants may be required to retrofit selective catalytic reduction to reduce emissions of nitrous oxide ("NOx") in order to comply with regional haze requirements. As a result, the future of one or more of units may be in jeopardy. To the extent that any of the units are retired early, there may be fuel-related cost consequences as the existing coal contracts may continue beyond the new plant retirement dates and/or the tonnage under the contracts will be lower which could affect certain unit costs. In order to limit TEP's exposure to additional coal costs, TEP will need to assert its rights in all contract renegotiations. TEP should develop a plan that addresses the potential costs and strategies for their mitigation.

I. INTRODUCTION

Q. Please state your names and business address.

A. My name is Emily S. Medine. My business address is 1901 N. Moore Street, Suite 1200, Arlington, VA 22209.

Q. By whom are you employed and what is your position?

A. I am employed by Energy Ventures Analysis, Inc. ("EVA"), where I am a principal.

Q. Please describe your duties and responsibilities in that position.

A. EVA is a consulting firm that engages in a variety of projects for private and public sector clients. These consulting projects are related to energy and environmental issues. In the energy area, much of our work is related to analysis of the electric utility industry, fuel markets, particularly coal, natural gas, oil, and petroleum coke, and the transportation thereof. Our clients in these areas include coal, oil and natural gas producers, electric utility and industrial energy consumers, and energy transporters. We also work for a number of public agencies, such as regulatory commissions and the U.S. Department of Energy, as well as intervenors in utility rate proceedings, such as consumer counsels and municipalities.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Arts degree from Clark University in 1976 and a Masters in Public Affairs from the Woodrow Wilson School of Public and International Affairs at Princeton University in 1978. I have been with EVA since 1987. Prior to that, I worked for Consolidation Coal Company (now CONSOL Energy), Energy and Environmental Analysis, Inc. ("EEA") and Brookhaven National Laboratory. I perform and manage a variety of fuels-related consulting work for the electric utility industry, including fuel supply strategy studies, market analyses and price forecasts. I also audit the management

and performance of electric utility fuel supply departments and provide testimony to public service commissions. My resume is included in Exhibit EVA-1.

Q. On whose behalf are you appearing?

A. I am appearing on behalf of the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff ("Staff").

Q. Have you previously filed testimony before the Arizona Corporation Commission?

A. Yes. I have filed testimony in the Matter of the Filing by Tucson Electric Power Company ("TEP" or "Company") on behalf of Staff to Amend Decision No. 62103 (Docket No. E-01933A-05-0659) and the Matter of the Application of TEP for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate on the Fair Value of its Operations Throughout the State of Arizona (Docket No. E-01933A-07-0402).

Q. In what other jurisdictions have you filed testimony?

A. I have filed testimony on multiple occasions before the Public Utilities Commission of Ohio, the West Virginia Public Service Commission, Indiana Utility Regulatory Commission and the Nova Scotia Utilities and Regulatory Board. I have also worked on several occasions for the seven regulatory commissions that are responsible for regulating PacifiCorp. The seven states are California, Idaho, Montana, Oregon, Utah, Washington, and Wyoming.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of the testimony is to present findings regarding the following issues:

The purpose of the testimony is to present findings regarding the following issues:

- TEP's PPFAC mechanism including any recommended revisions to the Plan of Administration.
- A prudence audit of TEP's PPFAC for all years since the PPFAC was initiated in 2009.
- TEP's fuel and purchased power procurement policies and procedures.
- Review of plant operating performance
- Review of system simulation model(s)
- Review of model used by day-ahead traders
- Review TEP's use of hedging for both natural gas and power
- Review of internal and external audit reports on the procurement of fuel and purchased power
- Review of Fuel Implementation Plan filed on March 2, 2009

Q. Please summarize your testimony.

A. TEP has been recovering a portion of its fuel and purchased power costs through the PPFAC since January 2009. The costs recovered under the PPFAC are defined by the Plan of Administration. TEP has requested a number of changes to the PPFAC including the inclusion of brokerage fees, the inclusion of 100 percent of the proceeds from emission allowance sales and an increase from 30 to 45 days for the monthly filings. Staff agrees with TEP with respect to these three items. Staff is recommending several changes to the PPFAC as well. The other requests qualify as rate design and will be addressed in ACC Staff's rate design testimony. . Staff notes that TEP is not fully compliant with respect to the Plan of Administration which requires among other things that TEP report fuel costs by plant (Section 9.2.A.5).

TEP's fuel and power purchases since 2009 were reviewed and the costs were found to be prudently incurred based upon the respective energy markets and the prevailing policies and procedures. Staff identified a component of fuel cost credits that it believes should

have flowed through the PPFAC unless TEP had received specific Commission approval for an alternative treatment. TEP received authorization for a PPFAC in its last rate case, Docket No. E-0193A-07-0402 that included coal costs, which TEP records in Account 501 but the approved PPFAC did not include lime expense, which TEP records in Account 502. In all periods prior to 2009, TEP had recorded sulfur credits as a reduction to coal expense in account 501. The sulfur credits represent a contractually-based adjustment that reduces the cost of coal when the coal delivered contains higher sulfur content. The higher the sulfur content of the coal, the higher the contractually based sulfur credits are. [redacted] Because TEP did not receive regulatory approval for this accounting change, and because sulfur credits are a contractual price adjustment to the cost of coal, EVA believes the sulfur credits for the period 2009 through 2012 that TEP recorded in Account 502 should have been recorded in Account 501 as a component of coal costs and should be applied to reduce the PPFAC costs for coal that TEP charged to ratepayers for those years. Moreover, the sulfur credits (which are a reduction to TEP's cost of coal) should be recorded in Account 501 and credited to PPFAC costs on a going forward basis.

During the three-year period, coal generation accounted for about 90 percent of TEP generation. On an absolute basis, generation from gas and renewables increased during this period. Also during this period, average coal prices increased while the prices for natural gas and purchased power declined.

TEP has a Fuels Department Manual, a Hedging Policy, and an Energy Trading Policy which guide most of the activities under the PPFAC. The Fuels Department Manual is comprehensive. The Hedging Manual should be updated to reflect current market conditions.

The number of personnel assigned to fuel and power procurement activities is generally appropriate to TEP's size. That being said, Staff believes there is insufficient redundancy in the solid fuel area and that there are organizational issues with respect to the Risk Manager and the Risk Controller.

Staff found the TEP gas plants to have higher availability rates than the coal plants. Navajo had the best availability of the coal plants with Springerville not too far behind. TEP has not been very successful in managing its inventory levels. At Sundt, coal stockpiles have consistently run above target levels, which is the result of a strategic economic decision to burn gas. At Springerville, there was an extended period when inventory levels were below target amounts. Within the Western Energy Coordinating Council ("WECC") the relative rankings of the TEP plants changed between years with Navajo and Four Corners competing for the lowest heat rates and highest capacity factors within the TEP system. Overall, with the exception of Sundt, the TEP plants generally performed in the top 50 percent of WECC coal plants. Within the TEP system, Springerville, Navajo and Four Corners have the lowest coal costs while Sundt has the highest.

Staff reviewed the inventory levels TEP proposes to include in base rates. Staff concurs with the methodology in the determination of tons but questions the associated coal prices. The San Juan coal price appears to include non-recurring costs and San Juan and Sundt prices appear to include identifiable back end costs, e.g., ash disposal. Staff also

recognizes that if the sulfur credits included in the calculation of the lime costs are moved to the PPFAC, the lime costs in the base rates will need to be restated.

There is enormous uncertainty as to the status of several coal plants in the TEP system as a result of Regional Haze requirements. There may be significant fuel cost consequences for TEP customers that need to be carefully considered. With respect to coal costs, there are existing coal contracts that could continue beyond plant operating dates or that will be restructured to reflect lower tonnage numbers.

Q. Please summarize your recommendations.

A. With respect to natural gas and purchased power, Staff recommends:

- TEP should prepare a complete natural gas hedging plan consistent with the requirements outlined in the Hedging Manual.
- TEP should revise its hedging strategy for natural gas and power to reflect the fundamental changes in the energy markets.
- The Risk Manager should not have any commercial duties.
- The Risk Controller and Risk Manager should have different reporting lines.

With respect to solid fuel, Staff recommends:

- TEP should return the sulfur credits it received under its coal supply agreement to Account 501 going forward [redacted] In the current rate case, TEP has reduced the lime costs that TEP recorded in Account 502 by the amount of sulfur credits. Consequently, this adjustment will also require a restatement of lime costs that are to be included as non-PPFAC O&M expenses in the development of TEP's base rates.
- TEP should maintain a separate accounting of *all* incremental fuel purchase costs associated with the San Juan fire except TEP's share of the [redacted] deductible. To

the extent such costs have already been recovered in the PPFAC, they should be refunded to customers. Subsequent to the insurance settlement, TEP should be allowed to then seek recovery of any unrecovered costs that were prudently incurred through the PPFAC.

- TEP should reduce the unit cost of coal in determining cost of coal in inventory by non-recurring costs and ash handling costs.
- TEP should add resources to the solid fuel group to develop additional support for current solid fuel activities.
- TEP should develop a plan to minimize solid fuel cost consequences of any decisions to retire plants in response to regional haze requirements.

With respect to the PPFAC, Staff recommends:

- TEP should comply with the Plan of Administration in its PPFAC filings with respect to the reporting of fuel costs by plant.
- TEP should expand the required representation letter required by the Plan of Administration to include a statement that no Company interpretations of PPFAC includable costs or accounting adjustments were made to increase the PPFAC without full disclosure to and approval by the Commission.

  Pperformance/management audits of the PPFAC may be required by Staff. The Company, at the direction of Staff, should fund the audits.
- The Plan of Administration should be modified to include proceeds from the sale of renewable energy credits ("RECs") that do not flow through Renewable Energy Standards Tariff to customers.
- The Plan of Administration should be changed to incorporate the documentation recommendations from the Compliance Audit of the PPFAC conducted by the internal audit services.

With respect to the cost of inventory to be included in base rates, Staff recommends:

- The coal prices for each plant should be adjusted to exclude non-recurring costs and identifiable back end costs that have not yet been incurred.

III. ORGANIZATION OF TESTIMONY

Q. How is your testimony organized?

A. The next section discusses the Fuel and Purchased Power Audit, which contains an overall summary of performance followed by discussions of coal, gas and power. The next section discusses performance benchmarking. The final section provides audit conclusions.

IV. FUEL AND PURCHASED POWER AUDIT

Q. Please describe TEP's generating system.

A. TEP owns all or part of 12 generating plants with a total owned capacity of about 22 gigawatts ("GW"). (Exhibit EVA-2) About 60 percent of TEP's capacity is coal. TEP operates the Springerville and Sundt coal plants; TEP owns a minority share in three other coal plants which are operated by other parties. The remaining capacity consists of three wholly-owned natural gas-fired combustion turbines, one jointly owned natural gas-fired combined cycle, and some solar.

Q. Please summarize generating performance between 2008 and 2011.

A. Exhibit EVA-3 provides generation by fuel type, power purchases, and average fuel costs for 2009, 2010, 2011, an average of the three years, 2008 results and the percentage change between the three-year average and 2008. While overall generation has increased in each of the last three years, it still remains below 2008 levels overall. Average coal generation for 2009 through 2011 is 9.5 percent below coal generation in 2008. Average

natural gas generation for the three years is up by 14.8 percent and average purchased power for the three years is up by 5.6 percent.

With respect to fuel costs, average coal costs for the three-year period are over five percent higher than 2008 costs. Both average natural gas costs and power purchase costs are materially below 2008 levels.

Q. How did each plant perform during the 2009 to 2011 period?

A. The performance by plant is summarized on Exhibit EVA-4. Springerville provided about half of in-system generation in each of the three years. The next most significant is San Juan which provided about 20 percent of in-system generation. Coal prices at all of the coal plants increased through the period with the exception of Sundt which experienced a large decline in coal price in 2011 due to the expiration of a high-price contract. San Juan's 2011 coal price was inflated because of several factors related to a mine fire and an audit adjustment.

Q. How is fuel procured for these plants?

A. Fuel procurement falls under the responsibilities of the Senior Vice President, Operations. As shown in Exhibit EVA-5, responsibility for power and gas lies with the Senior Director Wholesale Contracts and Administration; the responsibility for coal lies with the Director of Fuels and Wholesale Marketing.

Coal

Q. Please describe the relative importance of coal within the TEP system.

A. Most of TEP's installed generation is coal. As shown in Exhibit EVA-3, during the period 2009 through 2011, coal generation accounted for about 90 percent of generation. Coal generation has been disproportionate to its capacity because of its lower cost.

Q. Please explain the overall coal supply for the TEP plants.

A. The coal supply for the TEP plants is summarized on Exhibit EVA-6. This coal supply is best understood in context.

The San Juan Basin is on the northeastern part of New Mexico and the adjoining part of southwestern Colorado. The San Juan Basin is divided into a number of individual coalfields. Coal production in New Mexico dates back to the 1880's but had all but disappeared by the late 1950's due to the change from the steam engine to diesel and increased use of natural gas.

In the second half of the twentieth century, high growth in electricity demand prompted the construction of coal-fired power plants in concert with the construction of new coal mines which supplied the plants under long-term contracts. Pittsburg & Midway opened the McKinley surface mine in 1962 (Arizona Public Service's Cholla plant started operating in 1962) and Utah International[1] opened the Navajo mine in 1963 (Four Corners power plant started operating in 1963) and the San Juan mine in late 1972 (San Juan power plant started operating in 1976). In 1982, the Lee Ranch mine began production (the Springerville plant started operating in 1985). The Lee Ranch mine which had been developed by Santa Fe Industries [2] was "traded" to Hanson, which ultimately became Peabody in 1994.

The coal industry in Arizona, unlike New Mexico, did not develop until utility plants were built and designed for it. The coal reserves in Arizona are concentrated in the Black Mesa region which is in Navajo country. Two large mines were developed on these reserves: the Black Mesa mine, which was developed to supply the now-closed Mohave generating

[1] BHP Billiton ("BHP") subsequently purchased Utah International from General Electric.
[2] Santa Fe Industries was the diversified parent company of the Atchison, Topeka and Santa Fe Railway. Its non-railroad operations included construction, real estate, and energy interests.

station and the Kayenta mine, which was developed to supply the Navajo Generating Station. The Kayenta mine started producing in 1973; Navajo #1 started operating in 1974.

Of the mines discussed above, only two (McKinley and Lee Ranch) developed commercial rail access. TEP initially looked to McKinley for the supply to Sundt (formerly Irvington) for the coal conversion. With the closure of McKinley and a competitive coal market in the Rockies, subsequent purchases for Sundt resulted in a varied coal supply.

The development of the Powder River Basin, which is a huge deposit of sub-bituminous coal lying in northern Wyoming and southeast Montana, changed the coal supply landscape in the western United States. From very little production in the 1970's, the Powder River Basin grew to an annual production rate of almost 500 million tons. The growth in production is attributed to three primary factors: cost, quality, and competitive transportation. The coal is not very deep and the use of super-sized equipment (e.g., draglines, haul trucks, etc.) kept coal mining costs relatively low. The coal in the Powder River Basin is very low in sulfur which made it an attractive fuel for many power plants in order to meet environmental requirements. Finally, the addition of a second railroad in the Powder River Basin in the 1980's resulted in significant rail competition and competitive rates to many markets including those in the eastern United States.

The Powder River Basin became part of TEP's coal supply when the Springerville expansion required TEP to commit to use Powder River Basin coal for the new units for environmental reasons.

Q. What changes have occurred in the U.S. coal industry since 2007?

A. The period between 2007 and 2012 has been a particularly turbulent one for coal prices as shown in Exhibit EVA-7.

In 2007/2008 strong global coal demand combined with a relatively weak U.S. dollar increased the price of U.S. coals.[3] The prices for Appalachian coals more than tripled between June 2007 and July 2008. As a result, Appalachian coal producers sought to divert coal supplies into the export market and eastern utilities looked to other sources of coal to "backfill" their demand. The prices for Rockies coal, which is the natural substitute for Central Appalachia coal because of its quality characteristics, also increased about three-fold although the increases lagged Appalachia prices.

The global financial crisis which started in the second half of 2008 caused coal demand to fall and prices to plummet. Utility coal burn declined by over 100 million tons in 2009 (as compared to 2008) as a result of reduced electricity demand. By the end of the first quarter of 2009, coal prices had fallen to almost their pre-surge levels. Pricing at that time did not mean too much, however, as the market was not very liquid as most utilities were in an over-committed position.

Economic recovery combined with metallurgical coal supply disruptions in Australia in early 2011 increased global prices for metallurgical coals which also strengthened the market for Appalachia coals. Prices did not rise to the levels experienced in 2008 but increased to levels above the historic trading range. Prices for other coals also firmed but did not rise by the same magnitude as Appalachian coals.

[3] Global coal trade is U.S. dollar denominated. As Australia is the largest exporter of coal, the relationship between the U.S. and Australian dollars affect the market price for coal. The weaker the U.S. dollar relative to the Australian dollar, the higher the coal price.

Since 2012, coal prices have fallen rapidly. The current softness in the market is primarily due to low natural gas prices which have allowed natural gas-combined cycle generation to displace considerable coal generation. In 2012, it is estimated as much as 200 million tons of coal will be displaced as a result of low natural gas prices. Many utilities, who were not expecting the change in the relative competitiveness of their coal-fired generation, found themselves over-contracted for supply. Similarly, coal producers found themselves over-produced. As a result, coal prices have fallen as the excess supply is addressed.

Q. Has TEP's coal supply been affected by the market changes you describe?

A. TEP is somewhat but not completely insulated from the market changes due to the nature of its coal supply. Most of the coal TEP purchases are pursuant to long-term contracts with pricing mechanisms. The exceptions are the Sundt plant which is supplied under short-term agreements which expose the plant to market pricing when the coal is purchased and Springerville 1 & 2 whose entire requirements are not satisfied by the underlying long-term contract but whose coal price [redacted]

The impact of the changing market is most apparent at Sundt. The delivered price of coal to Sundt fell by almost 40 percent between 2009 and 2011 due to the declining price of Rockies coal.

TEP's coal supply has been directly affected by low natural gas prices. Sundt, which is able to burn coal or natural gas, burned substantial quantities of natural gas in 2011and most of 2012. As a result, the coal purchased for Sundt for this period [redacted]. In addition, the coal burn at the other TEP plants declined year-to-date 2012 due to low natural gas prices.

Q. Are there any other coal industry issues that have or are expected to affect the coal supply to TEP plants?

A. There are at least two industry issues that have affected or are expected to affect the coal supply to TEP plants: safety and new environmental requirements.

Q. What are the issues related to mine safety?

A. Coal mine safety became a prominent issue in 2006 following the tragedies at the Sago and Aracoma mines in the east. In June 2006, Congress enacted the Mine Improvement and New Emergency Response Act of 2006 ("MINER Act") which amended the Federal Mine Safety and Health Act of 1977. The MINER Act requires each underground coal mine operator to have a written, approved, and regularly updated accident response plan that provides for the evacuation of all individuals in the mine in the case of an emergency and provides for the maintenance of any individuals trapped underground. Specifically, the plan must provide for (1) redundant means of communication, (2) a tracking system (consistent with commercially available technology) that allows for above ground personnel to determine the location of all underground personnel, (3) adequate caches of breathable air in 30 minute increments in the escape ways, (4) lifelines consisting of flame-resistant materials to direct personnel out of the mine, (5) training, and (6) coordination with local authorities. In addition, each underground mine with more than 36 employees had to have available two mine rescue teams.

Subsequent to the MINER Act, two other major industry accidents occurred. In August 2007, nine died (six miners and three rescue workers) at Crandall Canyon in Utah; in April 2010, 29 miners died following an explosion at Massey Energy's Upper Big Branch mine in West Virginia. Investigations into both accidents cite safety violations and inadequate enforcement by the Mine Safety and Health Administration ("MSHA") as factors.

A general consequence of the MINER Act and the subsequent Crandall Canyon and Upper Big Branch mine disasters has been increased underground mine safety requirements, increased underground mine safety inspections, and greater attention to potential pattern of violation all of which are reflected in mine productivity and production costs. MSHA's decision to have the San Juan mine sealed following the thermal event may have been a consequence of this new vigilance.

Q. What are the issues related to new environmental requirements?

A. The two most immediate issues are compliance with the Mercury and Air Toxics Standards ("MATS") and the Regional Haze rules.

Q. What are the compliance requirements for MATS?

A. According to TEP, mercury and/or particulate emission control equipment may be required at Navajo, Springerville, and Four Corners to comply with MATS. The exact costs depend upon the type of equipment. If only mercury controls are required, the capital costs are relatively modest. The baghouse, which may also be required at Navajo, could cost TEP about $43 million for its share of the plant.

Q. What are the Regional Haze requirements?

A. States are required to issue revisions to their State Implementation Plans ("SIPs") to address the requirements of the Clean Air Act ("CAA") and the Environmental Protection Agency ("EPA") rules that require states to prevent impairment of visibility in mandatory Class I areas caused by emissions of air pollutants from numerous sources, including coal-fired power plants.

Q. How are TEP's plants affected by the compliance requirements for Regional Haze?

A. According to TEP, regional haze regulations requiring emission control upgrades are not applicable to Springerville at this time and are not likely to impact Springerville operations until 2018 or later. TEP is unsure whether Sundt Unit 4 will be affected by regional haze compliance issues and is expecting a proposal from EPA in December 2012 to provide clarity on the matter. Given the size and age of Sundt Unit 4, it would be hard to justify significant capital investment for the unit to stay on coal given its natural gas firing capability.

At San Juan, "(t)he current federal plan from the EPA requires installation of selective catalytic reduction - SCRs on all four San Juan units by September 2016....In October of this year, the State of New, Mexico released a proposed modified plan that it presented to the EPA as an alternative to the federal implementation plan. The modified plan includes among other things the retirement of San Juan Units 1 and 2 by December 31, 2017 and the installation of selective non-catalytic reduction technology on San Juan Units 3 and 4.... The modified plan would require several actions by third parties before it can move forward as well as approval by our Board of Directors and the Arizona Corporation Commission. If San Juan Units 1 and 2 are retired by December 31, 2017, TEP would request Commission approval to recover over a reasonable term, all cost associated with the early retirement of those units." UNS Energy Chairman Paul Bonavia also noted that TEP is "evaluating various replacement service resources in the event San Juan 1 and 2 are retired early. That includes a possibility of exchanging part of TEP's ownership in San Juan one and two for a portion of San Juan 3 or San Juan 4 or both."[4,5]

[4] UNS Energy's CEO Discusses Q3 2012 Results - Earnings Call Transcript

[5] TEP has subsequently indicated that EPA has not favorably received this alternative plan. The State of New Mexico and the utilities are reportedly working on another option for EPA to consider.

A retirement of San Juan Units 1 and 2, whether TEP receives a share of Units 3 and 4, would decrease the tons required by San Juan with likely cost consequences to the remaining owners. It could also impact final mine reclamation costs.

Navajo and Four Corners are located on the Navajo Indian Reservation and therefore are not subject to state regulatory jurisdictions. The EPA oversees regional haze planning for these facilities.

At Navajo, Salt River Project ("SRP"), the operator of the plant, has indicated concern if SCR's are mandated. Currently, emissions from Navajo are controlled by hot-side electrostatic precipitators ("ESPs"), wet limestone scrubbers, and Low-NOx Burners and Separated Overfire Air ("LNB/SOFA"). The ESPs reduce particulate matter by 99 percent and the scrubbers reduce sulfur dioxide ("SO_2") emissions by more than 95 percent. LNB/SOFA, reduce NOx emissions by about 40 percent. SRP has indicated that if SCR retrofits are required, the plant is at risk. A decision by EPA is expected by year end 2012.

At Four Corners, the current plan is to retire Units 1-3. Arizona Public Service ("APS"), the plant operator, is in the process of buying Southern California Edison's ("SCE") 739 MW interest in Units 4 and 5. SCE is being forced to sell its interest in the plant by California's greenhouse gas emission policy. TEP owns a seven percent stake in Units 4 and 5 so its capacity is unaffected by the retirements of Units 1-3. TEP is likely affected with respect to the coal costs as the smaller tonnage under the contract is likely to result in higher prices. It is believed that remaining conditions precedent to closing are the renegotiation of the coal supply contract and FERC approval.

Q. What is the status of greenhouse gas requirements?

A. In March 2012, EPA proposed a new source performance standard ("NSPS") for carbon dioxide for new fossil-fuel generating units. This proposal stems from EPA's 2009 finding that emissions of greenhouse gases ("GHG") endanger both the public health and welfare. The proposal calls for applicable facilities to be subject to an output-based standard of 1,000 pounds of CO_2 per megawatt-hour. EPA established the standard based upon uncontrolled emissions from natural gas combined cycle plants. According to EPA, new solid fuel fired plants could meet the standard either by employing carbon capture and storage ("CCS") at start-up or through a 30-year averaging option. EPA states in its proposal that this NSPS obligation would not be triggered if the installation of pollution controls or for new plants which commence construction within 12 months of the proposal.

The form of the final rule may differ significantly from the proposal. Regardless, the final rule will be subject to significant legal challenges in such areas as to how the NSPS for solid fuel can be based upon gas combustion or on a technology that has not been deemed technically demonstrated for utility power plants. Any litigation on the NSPS will join a raft on pending litigation on other actions related to GHG including the endangerment finding, the GHG emission standards for motor vehicles, and the Tailoring Rule.

Q. Do you agree with TEP's proposal to pass the costs of compliance with GHG costs through the PPFAC?

A. No. TEP's primary motivation is that "it could incur GHG expenses prior to the filing of its next rate case." Given the fact that any costs are unknown at this time and potentially very significant, any such approval is premature.

Coal Procurement

Q. How is coal acquired by TEP for its units?

A. TEP acquires all of the coal for Sundt Unit 4 and Springerville Unit 1 and Unit 2. TEP was involved in the negotiations for Springerville Unit 3 and Unit 4 but the coal contracts themselves are bilateral agreements between Tri-State and Salt River Project and the coal suppliers, respectively. TEP participates with Public Service Company of New Mexico ("PNM") in negotiations related to San Juan as TEP is a co-signatory on the coal contract with PNM due to TEP's 50 percent ownership of Units 1 and 2. TEP sits on the fuels committee for the other jointly-owned stations.

Q. Who acquires the coal for TEP?

A. The professional coal procurement staff is relatively small consisting of a Fuels Manager and a Lead Fuels Analyst. The Fuels Manager reports to Senior Vice President of Operations. Agreements are signed by the appropriate representatives per TEP's signature level policies.

Q. Please explain the coal supply for each of the plants.

A. **Springerville**

Springerville receives coal under one long-term contract. This contract, which is summarized in Exhibit EVA-8, [redacted]

[redacted]

[6] Exhibit TEP 1 (Confidential)

[redacted]

[redacted]

Sundt

After the buy-out of the McKinley contract, TEP did not enter into a long-term contract for replacement coal. Rather it purchased coal on a short-term, annual, or spot basis. Deliveries in 2009 and 2010 were pursuant to a [redacted]

Sundt Unit 4 is unusual in its ability to burn coal or gas. In 1999, TEP started to move methane gas from the city of Tucson's Los Reales landfill through a 3.5 mile pipeline to

[7] Exhibit TEP 2 (Confidential)
[8] Exhibit TEP 3 (Confidential)

the Sundt plant where it is burned along with coal. The gas, which is delivered at a lower cost than the coal, displaces about 15,000 tons of coal per year. Natural gas is burned instead of coal when it is lower in cost.

San Juan

The San Juan station is a four-unit coal-fired plant which is operated by PNM. TEP owns 50 percent of Units 1 and 2 which represents about 19.8 percent of the entire station. TEP, along with PNM, is a co-signatory to the San Juan Coal Supply Agreement ("San Juan CSA") reflecting its ownership position at the time of the initial agreement.[9] The agreement, which is summarized in Exhibit EVA-10, is between TEP and PNM and the San Juan Coal Company ("SJCC"), a subsidiary of BHP.

The San Juan underground mine has performed erratically. Until the fourth quarter of 2011, quarterly production, as shown in Exhibit EVA-11, has ranged from just over 500,000 tons to over 2.5 million tons. The needed production varies based upon the status of the stockpile. Assuming no stockpile build, quarterly production should average 1.5 million tons.

On September 9, 2011, the mine experienced a fire at the longwall face. The mine was evacuated without incident and according to SJCC, the fire was extinguished within three hours of the event. Within 30 hours of the event, SJCC reported that all traces of the mine fire gases had disappeared completely from the mine ventilation. A representative of the Mine Safety and Health Administration ("MSHA), who coincidently was on site at the time, issued a "K" order which allowed MSHA to take control of the situation.[10] MSHA

[9] Exhibit TEP 4 (Confidential)

[10] Section 103(k) of the Mine Act provides:

> In the event of any accident occurring in a coal or other mine, an authorized representative of the Secretary, when present, may issue such orders as he deems appropriate to ensure the safety of any person in the coal or other mine, and the operator of such mine shall obtain the approval of such representative, in consultation

did not accept SJCC's findings that the fire had been contained and ordered SJCC to seal the longwall area. The sealing of the headgate, which occurred on October 21, 2011, started what BHP reported to be a 100 day required period. In November 2011, SJCC was allowed to recommence operations in another area of the mine with continuous miners which are used to develop the longwall panels and to recover the longwall.

In December 2011, SJCC provided a Cure Plan as required under Section 12.3 (E)(1) of the San Juan CSA.[11] The Cure Plan provides details of the Non-Normal Conditions ("NNC"), the plans for curing the NNC, and the costs associated with the NNC. Also as required, the Cure Plan explored alternative supply options. In my opinion, this portion of the analysis was weak. For example, SJCC used a price for Powder River Basin coal of

[redacted]

[redacted]

with appropriate State representatives, when feasible, of any plan to recover any person in such mine or to recover the coal or other mine or return affected areas of such mine to normal.

[11] Exhibit TEP 5 (Confidential)

[redacted]

[13] Exhibit TEP 6 (Confidential)

[redacted]

Four Corners

The Four Corners station is a five-unit coal-fired plant operated by APS. APS owns units 1- 3; Units 4 and 5 are jointly owned with a number of buyers of which TEP is one. TEP, along with the other owners of Four Corners, is a counter-party to the long-term agreement with BHP for coal from the Navajo mine. The agreement, which is summarized in Exhibit EVA-12, dates back to 2003 at which time the parties to Units 4 and 5 decided to restate and amend the Four Corners Fuel Agreement Number 2 rather than provide additional supplements to it.[14] [redacted]

This agreement is in the process of being renegotiated in concert with APS's purchase of SCE's interest in the plant. As discussed above, the renegotiation is reportedly a condition precedent to APS closing on the purchase of SCE's capacity.

Navajo Generating Station

The Navajo Generating Station is a three-unit station operated by Salt River Project. The coal for Navajo is supplied under a long-term contract with Peabody which dates back to 1977 and runs for 35 years from the date of first operation of Unit 3.[15] [redacted]

[14] Exhibit TEP 7 (Confidential)
[15] Exhibit TEP 8 (Confidential)

[redacted] The agreement is summarized in Exhibit EVA-13.

Q. Based upon this discussion, the only plants for which TEP currently purchases coal are Sundt and Springerville. How are these procurements accomplished?

A. For Sundt, TEP issues a request for proposal to the companies on its bid list. In order to be able to evaluate the bids, TEP solicits rates from the UP at the same time.

As noted above the current contract for Springerville was negotiated in 2003, prior to the introduction of the PPFAC. The contract was [redacted].

Q. How did TEP evaluate the bids for Sundt?

A. TEP evaluated the bids on a quality-adjusted delivered price basis, consistent with the Fuel Manual and industry practice.[16]

Q. How does the coal move to the power plants?

A. Sundt is served by the Union Pacific Railroad ("UP"). Springerville is served by the Burlington Northern Santa Fe Railway Company ("BNSF"). San Juan and Four Corners are mine mouth. Navajo receives its coal via the Black Mesa and Lake Powell Railroad, a dedicated 80-mile electrified railway.

[16] Exhibit TEP 9 (Confidential)

Q. Are there any changes with respect to the railroads that could affect TEP?

A. TEP's supply is somewhat insulated from the commercial rail market. The exceptions are Sundt and Springerville. Sundt's most recent purchases were [redacted]

Coal Contract Administration

Q. Who is responsible for administering the coal and transportation contracts?

A. The Fuels Group is responsible for administering the coal and transportation contracts. This is largely an oversight function with respect to the jointly-owned plants. TEP has primary responsibility for Sundt and Springerville.

Q. What are TEP's inventory targets?

A. TEP indicated that its target for Sundt is [redacted]

Q. How well has TEP done in achieving its target inventory levels?

A. As shown in Exhibit EVA-14, TEP's actual inventory levels at Sundt and Springerville have diverged from target levels throughout the 2009 to 2011 period.[17] At Sundt, the reasons are clear. A decision to burn gas reduced coal demand and coal burn and resulted in higher stockpiles. As the decision to purchase the coal was reasonable and the decision to burn gas was reasonable, TEP should not be faulted with the high inventory levels. That being said, alternative procurement strategies should be employed going forward that recognize the likelihood for unpredictable coal burn levels at Sundt. At Springerville, the

[17] Exhibit TEP 10 (Confidential)

inventory was [redacted]

Q. What is TEP proposing to include in its 2011 test year with respect to inventory levels?

A. TEP is proposing to include the dollars associated with target inventory tons at each plant and one month of diesel requirements for Springerville. The target inventory tons are the target days by plant times the plant's average daily burn in 2011. The dollars per ton reflect the average costs of the coal delivered to each plant in 2011. The target diesel inventory is based upon approximately average monthly burn.

Q. What is the inventory amount in the 2011 test year?

A. Based on the above, TEP is proposing [redacted] in fuel inventory expense.

Q. Do you agree with TEP's approach?

A. Yes, in general. I was not able to confirm exactly how the unit costs were developed. Given the units costs for Navajo and Four Corners are similar to reported costs, EVA is not proposing any adjustment to these. Staff is proposing an adjustment to the unit costs for San Juan as they appear to include non-recurring costs and identifiable back end costs, such as ash disposal. Staff is also proposing an adjustment to the Sundt unit costs to delete identifiable back end costs. The proposed adjustments are summarized on Exhibit EVA-15.

Q. How often does the Company conduct physical surveys of its stockpiles?

A. On an annual basis, the Company engages a third-party to measure the quantity of coal at the Sundt and Springerville stations. The physical survey consists of a volumetric survey and a density survey. Reports detailing approach and findings are provided to TEP.

Natural Gas and Power

Q. Please characterize TEP's need for gas and purchased power.

A. TEP generally needs to purchase gas for power generation from April through October and is short peak power generation capacity from June through September. During the winter months, load can be met from its own generation, and TEP can sell excess power from October through March. These generalities are subject to planned and unplanned maintenance, as well as other unforeseen events. Selling and buying of power in the real-time, day-ahead, balance-of-the-month, or next-month markets fall into the category that TEP calls Short-Term sales and revenues.

Q. How much power does TEP purchase?

A. In 2011, TEP purchased 2,917,504 MWh, which is 31.2 percent of its total power sales. The total associated expenditures for this purchased power was $137,534,106, averaging out to a cost of $47.14 per MWh.

Q. How does TEP hedge purchase power?

A. TEP's power hedging program can be divided into two key mechanisms – fixed or gas-indexed price contracts (for both the sale and purchase of power) and gas indexed call/put options.

Q. Can you explain how the fixed price contracts work?

A. Fixed price contracts allow TEP to purchase power at a fixed price per MWh. Indexed price contracts allow TEP to purchased power at an index to natural gas. [redacted]

Q. Can you explain how the call options work?

A. [redacted]

Operationally, TEP staff on the day-ahead desk determine, based on the terms of the existing call options, whether it makes sense for the next day to purchase power or to generate power. If TEP's options reach "in the money" status during day-ahead planning, the options are exercised and power is purchased from the scheduled counter-parties. These options are indexed to natural gas prices as well.

Q. How does TEP hedge natural gas?

A. Physical gas is purchased at index. TEP has a hedge policy to reduce gas price volatility which consists of "non-discretionary" or mandatory hedges using financial instruments. TEP outlines a hedge schedule to reach [redacted] of the gas volume forecast to be required for that given month. All non-discretionary purchases must be completed two months prior to physical

flow and must be executed "during the week of the 20th of each month." This is when natural gas bid week generally begins and market liquidity increases. Also the non-discretionary schedule does not require purchases during the months when hurricane activity is typically at its highest levels in the northern hemisphere. The effect is that TEP starts to hedge three years prior to its physical need and executes transactions during January through July and November through December.

Q. Is TEP's hedging policy documented?

A. Yes, in the Fuels & Wholesale Power Hedging Policy ("Hedging Policy").

Q. How are the risks associated with the hedging activity managed?

A. The Risk Management Committee ("RMC") is responsible for reviewing and approving TEP policies and overseeing the management of risk. The RMC approves the annual non-discretionary hedge plan for natural gas and purchased power prior to the start of each calendar year. The RMC also approves all discretionary hedges, as proposed, during the calendar year.

As of January 1, 2012, the members of the RMC as defined by title are:

- CFO & Treasurer (Chairman of the RMC)
- Controller & CCO
- General Counsel
- COO of TEP & UES
- President of UNS
- VP of Finance & Rates

Additionally, "staff" designated to the RMC, also defined by title are:

- Risk Manager(s) for TEP and UES
- Wholesale Senior Director for TEP and UES

- Risk Controller(s) for TEP and UES
- Corporate Credit Manager
- Director of Energy Procurement
- Corporate Accounting Manager
- Director of Resource Planning

Other staff is called upon as needed

Q. Is this structure appropriate?

A. While the structure of the risk management committee appears sound, there is an issue with the reporting lines of some key roles and responsibility within the Risk Management Committee. In prior testimony filed December 2008 by EVA on behalf of Staff, it was recommended that the designated risk manager be devoid of all commercial duties. TEP's response to this recommendation as indicated in Decision No. 70628 (December 1, 2008) was as follows:

> The TEP Risk Manager ("RM") is an employee in the Wholesale Energy department. The responsibilities of the RM, as identified in the Hedging Policy, include ensuring adherence to the hedge plan parameters, proper recording of transactions, and performance of portfolio evaluation. The TEP Risk Controller ("RC") is an employee in the Credit department. The responsibilities of the RC, or a Credit department employee under the direction of the RC, include reconciliation of internal transaction documentation with the electronic data system, gathering and validating forward price curves, and performing credit risk and market risk measurement. TEP believes the separation of the RM and the RC, both organizationally and in their respective duties, satisfies Commission Staff's expectation of having a Company employee independent of the Wholesale Energy department evaluate market risk related to fuel and purchased power. This

recommendation was implemented in TEP's revised Hedging Policy, referenced above.

Based on TEP's structure as of November 2012, this is no longer the case. Currently the RM and RC are both employees of the wholesale and fuels department.

Q. What recommendations would you make in terms of reconciling this organizational issue?

A. First, as previously recommended, the Risk Manager should not have any commercial duties so as to avoid conflict of interest. Second, it is critical that the reporting lines of the Risk Controller and Risk Manager be different (as TEP indicates that was the case in 2008). While that may have been the case at that time, it does not appear to be the case in 2012. Both of these actions will assist in preventing any long term conflicts of interest.

Q. Were any conflicts of interest stemming from this organizational structure discovered?

A. No. These recommendations are of a preventative nature and are not based upon discovery of conflicts of interest within the existing RMC structure.

Q. **Specifically, what activities were performed in order to evaluate the prudency of TEP's trading and hedging practices?**

A. A review was conducted in four distinct phases:

1. Document review
2. Q&A with TEP Staff
3. In person review of TEP trading practices
4. Review of historical transaction data

Q. What were your findings from your in person review of TEP's trading practices?

A. TEP's observed trading and hedging practices are in line with its policies and are effective. Staff is very knowledgeable and experienced and functions in a system where they are rotated between positions to ensure that they are capable traders and that they are exposed to all facets of a trading day. One highly beneficial side-effect of this practice is improved redundancy and coverage when staff members are on sick leave, take vacation or leave TEP.

In terms of process, TEP's day-ahead trading operations were evaluated, which share some operations with UNS Gas. I witnessed the assigned trader forecast load requirements and apply these data to determine generation requirements for the following day. Based on this information, the individual traded on both the gas and/or power markets consistent with whether which generation assets were "in the money" – or able to operate at a lower cost than purchasing power. In cases where available power prices were lower than costs of generation, the trader was able to purchase power (by exercising options) to meet necessary requirements.

Once the gas and power trades on the day-ahead market were completed, the orders were passed to the individual responsible for nominating the gas through TEP's pipeline contracts with El Paso.

Once the transactions are completed, they are entered into their online record keeping system, which is audited nightly for accuracy.

Q. What tools or mechanisms do traders use in order to conduct this trading process?

A. [redacted]

[redacted]

Q. What is the Intercontinental Exchange?

[redacted]

Q. Are there fees associated with using this service?

[redacted]

Q. Did you review these fees?

[redacted]

Q. All-in-all, are the tools that TEP uses reasonable and prudent?

A. In general, yes. Both [redacted] are widely used throughout the industry and the trading team has a strong expertise in the software. [redacted]

Q. Tell us about your review of the historical transaction data?

As part of the review of TEP's hedging practices, TEP provided historical physical and financial transactions on both gas and purchased power. From this, it was determined whether TEP's own hedging policies are being followed in its hedging practices.

Q. How did you go about this analysis?

A. Using transaction data from [redacted]

Q. Did you only look at floating swaps?

[redacted]

Q. What were the results of your analysis?

[redacted]

[redacted]

Q. Is TEP's performance a hedge policy violation?

No. Despite the fact that neither costs nor volatility were reduced as a result of TEP's hedging program in 2011, these results are not indicative of poor execution by TEP. Rather, this performance is an indicator of rapidly changing market conditions that worked against TEPs hedging program (as well as many other utilities).

The review of TEP's hedging transactions found full compliance with existing policies. What this analysis calls to light, however, is more a question of a soundness of existing policies (i.e. approach to hedging), than any issue around compliance or prudence. One way to potentially address this issue is by revising its hedge plan to address both market risk and volatility issues.

Q. What is a hedge plan, and what are its standard elements?

A. While there is no one specific definition of a hedge plan for a utility, TEP defines what it means in section 3.1 of its own Hedging Policy, dated January 1, 2012, as follows:

> "Each year, in the fourth quarter, the Hedge Team will make a recommendation for the next 3 year's Hedging Plan ("Plan") to the RMC. The Plan will include an overview of the specific risks faced by TEP and a detailed explanation of the hedge strategy to be employed to mitigate those risks. The Plan will also include the timing of expected hedge transactions, calendar trigger dates, and the types of hedges that will be made if the triggers are reached."

This description is in line with what is widely considered best practices within the industry.

Q. Does TEP have a Plan as defined in the Hedging Policy?

A. TEP's Plan does not fully meet the requirements set forth in its own policies. While a document exists and outlines "the timing of expected hedge transactions and calendar trigger dates", [redacted]

Q. Is TEP in violation of its own policies due to the weak nature of its hedge plan?

A. As stated, TEP has a hedge plan, and as such is not in violation of its own policies per se; however, TEP's hedge plan is incomplete. Despite the fact that much of TEP's hedging is mechanistic, the volatility inherent in the energy markets combined with the substantial changes that have taken place – specifically in the gas markets – over the last several years, warrant review by both the wholesale trading department and the Risk Management Committee. The critical takeaways from this hedge plan must be that 1) TEP understands the market environment and potential risks inherent in both the local and national energy markets and that 2) its hedging practices reflect this understanding. [redacted], the additional 30 percent allowed through discretionary hedging indicates that, in order to conduct these trades in a comprehensive and prudent way, market understanding is a necessity. It is Staff's recommendation that TEP review its existing hedge plan and improve its comprehensiveness.

Q. Given that TEP's hedge plan requires approval by the Risk Management Committee, how does TEP address suggested changes to its hedge plan?

A. As outlined in section 3.2 of TEP's Hedging Policy, dated January 1, 2012:

> "...No other hedge transactions may be placed nor any changes made to the [hedge] plan without prior approval from the RMC. If any component of the Plan cannot be carried out, the Risk Manager will notify the RMC and recommend any necessary change or correction to the Plan."

Q. Did you see evidence that the policies addressing changes to TEP's hedge plan were followed?

A. TEP produced evidence of prior hedges outside the scope of the existing hedge plan that were approved by the Risk Management Committee. The approval process, while not entirely comprehensive, appears to be adequate.

Q. When you say "not entirely comprehensive", what do you mean?

A. While I did not see all hedge plan modifications, TEP provided e-mails consisting of TEP Wholesale Trading Staff requesting permission to conduct a hedge outside of the hedge plan, with e-mail responses granting approval. While this is adequate given the strictest interpretation of the policy, it is also recommended that there be better documentation of hedge plan modifications.

Q. What would this better documentation look like?

A. It would most certainly be a part of the hedge plan, which should be a living document that is updated as changes are made. The documentation should include the specific changes made, when these changes were made, whose approval was given and the

rationale behind making these modifications. This should all be a supplement to what I recommend as a "new and improved" hedge plan.

Q. **Despite these suggested improvements, do you think TEP is compliant with its policies as it relates to hedge plan modification?**

A. Yes.

Q. Do you believe that TEP's current hedging policies are prudent and effective?

A. As shown above in the results of the document review, TEP's usage of purely mechanistic hedging has not yielded the results for which it was intended. While TEP is certainly not to blame for rapidly changing market conditions, it points to the weakness of mechanistic hedging through periods of significant price declines. While in some ways this issue cannot be helped, TEP's hedging policies contain many legacy provisions that given the substantial changes in the gas industry, should be reexamined and addressed.

Q. Are there any recommendations you would like to make in regards to reexamination?

A. Yes. Given the rapid changes that have taken place (and potentially will continue to take place going forward), that auditing both TEP's hedge plan as well as the effectiveness of the Company's hedging strategy should be done more frequently.

Q. Who would perform such an audit? And how frequently should it be done?

A. Because of the importance of having an outside perspective on the fuels industry as well as a firm understanding of the major changes in the market, it is recommended bringing in an outside firm rather than using the internal auditor. While the internal audit system currently in place is sufficient to meet its current mandate, evaluating the effectiveness of

trades and hedging as well as the quality of TEP's hedge plan is best left to expert or independent opinion with significant industry knowledge.

Q. Could you please explain the key market issues that resulted in a significant chance in gas prices?

A. Exhibit EVA-18 graphs historical weekly natural gas prices at Henry Hub from 1990 through today. One can see by looking at 2009 and on that prices have come down significantly during this period.

Q. What are the driving forces behind such a substantial change?

A. The chart has been divided into three key eras – the Era of Gas Bubble, High Priced Era and the Era of "Game Changing Shales". The relevant era for this discussion is the most recent period. From 2009 to the present, prices have been driven to historically low prices by the increase of new sources of gas production, i.e., unconventional production from shale. Combined with a plethora of additional drivers such as "held by production", joint venture financial arrangements that promote natural gas drilling and a large backlog of uncompleted wells, unconventional gas producers have flooded the U.S. market with production, driving prices downward to historical lows.

Q. Was this an issue that TEP could have or should have predicted?

A. Very few experts, if any, were able to predict the rapid rise of unconventional gas production in the U.S. – certainly the magnitude of its impact on the gas and power markets. In my more than 25 years of tracking U.S. and global gas markets, I have never seen a more dramatic shift in natural gas prices and production in such a short period of time.

Q. How would you suggest TEP change its hedging policies to better adapt to these market changes you have described?

A. As mentioned above, many of TEP's policies due to these recent changes in the gas markets are now out of date. [redacted]

Q. Could you please elaborate on this?

A. [redacted]

Q. What is the logic behind this blackout during hurricane season?

A. [redacted]

Q. What has changed that makes you believe that the blackout is no longer logical?

[redacted]

[redacted]

Q. What were the results from your review of TEP's power hedging program?

A. I looked at the results of both the fixed/index pricing contracts that TEP has engaged in for purchased power as well as purchased power options. Similar to natural gas, there are some concerns around their hedging practices; not in that they represented any sort of policy violation, but results raised some questions.

Q. Could you please elaborate?

A. [redacted]

[redacted]

Q. When revisiting this issue, what are the key factors that should be addressed?

A. TEP is best served to review historical generation and heat rate data to determine the implicit value of power purchase optionality. Additionally, TEP should review the associated costs with simply purchasing power on the spot market. Comparison of these costs must be viewed based on the "all-in" costs, meaning that they include the option value in the $/MWH calculation.

Q. How do these issues, both on natural gas and power, factor into TEP's overall hedging policies?

A. These are examples of one key underlying issue: TEP's hedging practices should be revisited. While some form of mechanistic hedging both on gas and power is necessary to reduce risk, TEP should focus on adapting to changing market conditions through the greater use of discretionary hedging. This approach is a best practice within the industry, and we believe would benefit TEP greatly. The exact mix in terms of volumes, timing and assorted instruments that are used in TEP's hedging process cannot be precisely quantified at this time, as it is important for TEP to use its hedging process as a way to not only reduce volatility but also increase benefits for all major stakeholders – including and especially ratepayers. Such a revision to TEP's hedging policy could be developed in parallel with the finalization of the development of TEP's new forecast modeling approach.

Q. How else could these two issues – hedging and future modeling – be co-developed in the future?

A. In order to enhance the feedback between TEP's hedging practices and modeling efforts, Staff recommends that TEP utilize "at risk" calculations such as value at risk ("VaR") on a routine basis to measure existing risk and measure performance from hedge planning efforts. This is done widely throughout the industry and is considered a best practice.

PPFAC Fuel Cost assumptions

Q. What is the PPFAC and how did it come into existence?

A. The PPFAC is a mechanism by which TEP recovers its prudently incurred purchased power and fuel costs. It was created during the prior rate case and started in 2009.

Q. What costs are currently recoverable through the PPFAC ?

A. The Plan of Administration states:

> The allowable PPFAC costs include incremental Fuel and Purchased Power Costs incurred to provide service to retail customers. Additionally, the prudent direct costs of contracts used for hedging system fuel and purchased power will be recovered under the PPFAC. The allowable cost components include the following FERC accounts:
>
> ☐ 501 Fuel (Steam)
>
> ☐ 547 Fuel (Other Production)
>
> ☐ 555 Purchased Power
>
> ☐ 565 Wheeling (Transmission of Electricity by Others)
>
> These accounts are subject to change if the FERC alters its accounting requirements or definitions.

Q. Did you review the review the Compliance Audit of the PPFAC conducted by Unisource Energy Audit Services?

A. Yes.[18]

[18] Exhibit TEP 11 (Confidential)

Q. What were the conclusions of the Compliance Audit and do you agree?

A. The audit concluded that the PPFAC Reports sent to the Commission during the 2009/2010 FFPAC year were "accurate, complete and prepared in accordance with Arizona Corporation Commission and the TEP Plan of Administration." The audit report noted however, "there were no documented procedures over the monitoring controls in regards to the PPFAC reports and Forecasting process. In addition, "not all PPFAC reports were reviewed in sufficient detail." TEP agreed to certain corrective actions and audit services indicated a follow-up audit had been scheduled.

Q. In your audit of the PPFAC filings, did you identify any issues?

. Yes, two issues were identified. The first is related to lime costs. The second is related to the San Juan mine fire.

Q. Please explain the issue with lime costs.

A. Lime is used by the scrubbers installed on Springerville Units #1/#2 to control emissions of SO_2. A review of lime costs determined that [redacted].

EVA does not dispute TEP's position that the cost of lime is tied to the sulfur content of the coal but believes [redacted]

[19] If the Supplier delivers coal with an SO_2 content above a certain amount, the coal price is reduced.

[redacted]

Q. What is the issue with respect to the San Juan fire?

A. As discussed above, TEP incurred higher fuel costs at San Juan related to the mine fire. The higher costs can be divided into two categories: direct fire-related costs and costs associated with consuming the mine stockpile.

The direct costs associated with the mine fire are charged to the cost of fuel, ultimately flowing through Account 501. As discussed above, BHP has indicated and TEP expects an insurance recovery related to these costs. TEP has indicated there is a [redacted]

With respect to the mine stockpile, TEP advised EVA that the parties had an agreement for BHP to build an initial stockpile of [redacted]

[20] TEP in its initial application for a PPFAC and in its current proposal is seeking to recover incremental lime costs through the PPFAC.

[redacted]

Q. Do you have any recommendations regarding recover of the direct fire-related costs?

A. Yes. I recommend that the only cost that should be recovered through the PPFAC is the [redacted]

Q. Do you have any recommendations regarding recovery of the deferred stockpile expense?

A. This issue is more complicated because there was no PPFAC in existence at the time this fuel cost expense was deferred. However, since TEP did not take ownership of the stockpile coal until it was delivered in 2011 and 2012, I believe it is appropriate for these costs to be flowed through the PPFAC at this time. I also believe that if this accounting treatment is adopted, it should be applied going forward as well. In other words, as the stockpile is rebuilt, the costs associated with the rebuilding of the stockpile should be deferred and not recoverable in the PPFAC until the coal is consumed.

[redacted]

Test Year Fuel Cost Assumptions

Q. Do you any issues with the 2011 Test Year numbers for coal?

A. Yes. The 2011 coal numbers are based upon 2011 purchase costs and have not been normalized for unusual and non-recurring events with respect to San Juan. As discussed above, the 2011 San Juan numbers include two types of costs associated with the mine fire: direct mine fire costs and pre-paid inventory costs that were passed through the PPFAC in 2011. Staff has no objection to recovery of the [redacted] or the pre-paid inventory expense but these as not recurring costs and should not be part of the 2011 Test Year. There are two additional costs included in the Test Year numbers for San Juan which Staff believes should be excluded from the Test Year. [redacted] Again, Staff has no objection to TEP recovering these costs through the PPFAC, just to their inclusion in the 2011 Test Year. [redacted] Staff did not find issues with coal costs for the other plants.

Q. Do you have any issues with the 2011 Test Year numbers for natural gas?

A. 2011 generally fits what would be described as a "normal" pattern of gas usage. As shown in Exhibit EVA-22, 2011 numbers for gas burn were 4.4 percent lower than 2010 and 7.0 percent lower than 2009, proving that 2011 is "indicative" with the other numbers for other fuels and purchased power

Q. Thus, do you believe that using the Test Year numbers is a reasonable way to develop the PPFAC?

A. Despite the indicative nature of 2011, one cannot emphasize enough the rapidly changing market conditions in the world of natural gas. In Exhibit EVA-22, Staff also included data through the first eight months of 2012. Gas burn during this time was 42.3 percent higher

than in the first eight months of 2011 due to rapidly falling prices and an increase in coal-to-gas switching (as shown in Exhibit EVA-23). While I do not believe that this high level of gas burn will become the new normal, it is important to note that TEP must understand rapidly changing market conditions in the natural gas supply market to better develop its PPFAC assumptions.

Q. Because of these rapidly changing market conditions, and due to their impact on 2012, how would you suggest TEP proceed?

A. TEP is very aware of how rapidly changing market conditions impact its PPFAC cost assumptions. Because of this, TEP conducts a comprehensive modeling effort to ensure that the costs feeding the PPFAC are representative of a more realistic future outlook rather than an anomalous year like 2012. This modeling effort takes into account the role of shifting market conditions on dispatch and fuel mix as well as the fuel costs.

Q. In that case, what is TEP's process for submitting the PPFAC filing to the ACC?

A. A great deal of time was spent talking to and working with TEP staff members responsible for estimating the PPFAC. In general, TEP estimates what its electric load requirements will be throughout the coming year for the PPFAC (which is part of a much larger forecast), and based on estimated costs of generation and purchased power, these costs are allocated to rate payers on a cents per kWh basis.

Q. What tools or approaches does TEP use to create its forecasted PPFAC filing?

A. TEP is in the process of revising its entire forecast process to become more robust and comprehensive. [redacted]

Q. Are these tools and approaches consistent with what is seen in the industry?

A. Yes. TEP's is moving away from using existing models (which no longer meet TEP's needs) to using models developed by premiere providers [redacted]. These models are widely used throughout the industry and most certainly are in line with what are considered best practices. While TEP has not completed the transition to its new software applications it is clear that TEP is focused on implementation and improvement of its current forecasting system.

Q. How does TEP determine what fuel costs will be in the future? Are these an output or an input into the modeling system?

A. [redacted]

Q. Do you believe this approach is prudent?

A. Yes. While many utilities develop their own in-house fuel price forecasts, [redacted] in concert with existing contracts is a prudent approach.

Q. How frequently is the model updated?

A. New forecasts are developed on a quarterly basis.

Q. Is this a reasonable frequency given the rapidly changing market conditions?

A. Yes.

Q. Have you reviewed TEP's forecasting models and their contents?

A. While I did not see TEP's models first-hand, I reviewed the data that was extracted from the models for the calculation of the forward component of the PPFAC for the previous three years – which included the Test Year.

Q. What were the results of your review?

A. The primary goal given was to review the assumed fuel costs and review 1) whether the assumed fuel costs were reasonable and 2) that the fuel costs being used flowed through the model properly to the PPFAC calculation. Upon review, both were revealed to be accurate and prudent.

Benchmarking

Q. Did you perform any benchmarking of TEP's performance?

A. Yes. I looked at the performance of TEP's coal plants with respect to heat rate and capacity factor. Exhibits EVA-24 and EVA-25 present 2009, 2010, and 2011 annual capacity factors and heat rates for the coal plants in the WECC. As shown, the best performers are Navajo and Four Corners with high capacity factors and low heat rates. The poorest performer in the group was Sundt which is as to be expected given its size and history. San Juan and Springerville fell in the middle.

Q. Did you look at availability?

A. Yes, availability was reviewed. The results are summarized on Exhibit EVA-26. The gas plants had higher availability than the coal plants as would be expected given the relative simplicity of gas versus coal plants. The coal plant with the best availability is Navajo.

Q. Do you benchmark TEP's coal costs?

A. Yes. Exhibit EVA-27 presents coal costs per kilowatt-hour for selected coal-fired plants in the southwest. Unfortunately, there is a very limited list of "comparables" particularly with the closure of Mohave and the fact that most of the large power plants in the southwest are jointly owned. Nevertheless, there was some range in fuel costs with Sundt not surprisingly being the most expensive in 2006 and Navajo the least.

V. CONCLUSIONS FOR KEY AUDIT SCOPE ITEMS

- Plan of Administration – The proposed changes to the PPFAC that Staff is willing to accept require minor changes to the Plan of Administration. Changes are as follows:
  - Change the filing requirements from 30 to 45 days
  - Change footnote 7 on Schedule 3 to 100%
  - Modify Section 10.B to include brokerage fees
  - Add a Section 10.C to defer San Juan mine fire costs above the insurance deductible.

- Audit of PPFAC since 2009 – The audit determined that TEP's fuel and purchased power costs were prudently incurred during this period based upon the prevailing market and TEP's procurement policies. One item was identified, sulfur credits, which are contractual reductions to the price of coal that occur when the sulfur content of the coal delivered is higher than contractual specifications, [redacted]

- TEP's fuel and purchased power procurement policies and procedures – I reviewed TEP's fuel and purchased power procurement policies and procedures. I found the policies and procedures related to natural gas and power hedging are in need of an update due to fundamental changes in the market since the policies were developed. As a result of the change in the fuel and power markets, the policies and procedures were less effective than intended.

- Operating performance – No material changes were identified with respect to the operating performance of the power plans.

- System simulation model(s) - TEP is in the process of switching its system simulation model which should improve both its forecasting and its ability to measure value-at-risk.

- Model used by day-ahead traders - One of TEP's core planning tools is an Excel-based model designed by the trader currently utilizing it. TEP must work to ensure both redundancy and going concern of this model in the case of employee turnover.

- Review TEP's use of hedging – TEP actively uses hedges for both natural gas and power (for capacity and heat rate) following its existing internal policies. Because of declining prices for natural gas, the hedges have resulted in higher prices during this period, some of which was due to the mechanistic nature of the hedging and some of which was due to how the hedging plans were designed.

- Internal and external audit reports on the procurement of fuel and purchased power – No external audits on the procurement of fuel and purchased power were conducted. One internal audit was conducted and TEP indicated its agreement to comply with the findings.

- Fuel Implementation Plan filed on March 2, 2009 – I reviewed the Fuel Implementation Plan and found it to be consistent with the Commission's directive.

Q. Does this conclude your Direct Testimony?

A. Yes.

EXHIBITS

Exhibit EVA-1. EMILY S. MEDINE RESUME

EDUCATIONAL BACKGROUND

M.P.A.	Woodrow Wilson School of Public and International Affairs, Princeton University, 1978
B.A.	Geography, Clark University, 1976 (magna cum laude, Phi Beta Kappa)

PROFESSIONAL EXPERIENCE

Current Position

Emily Medine, a Principal, has been with Energy Ventures Analysis since 1987. Her experience includes bankruptcy support, market strategy development, fuel procurement audits, fuel procurement, acquisition and investment analyses, strategic studies and forecasting. She has also provided expert testimony on utility fuel procurement practices. The types of projects in which she is involved are described below:

Fuel Procurement Audits

Manages and performs fuel procurement audits on behalf of regulatory commissions, utility management, and third-party interveners. She has performed over 20 audits of utilities regulated by the Public Utilities Commission of Ohio and testified in a number of proceedings. She also managed two major audits of the fuel procurement practices of PacifiCorp. In 2005, Ms. Medine performed a management/performance audit of the Fuel and Purchased Power costs of the Cincinnati Gas & Electric Company. On behalf of the Consumer Advocate of the State of West Virginia Ms. Medine audited Appalachian Power fuel procurement costs in 2006 and 2007 and Monongahela Power in 2007.

Fuel Procurement

Develops and implements fuel procurement strategies for utilities and independent power projects. Fuel procurement assistance has ranged from determining an appropriate contract/spot mix to soliciting bids and negotiating purchase agreements. Ms. Medine has negotiated fuel supply agreements for three qualifying facilities (QF's) and has worked on fuel supply arrangements for a number of other plants. Ms. Medine is an advisor to Nova Scotia Power on its fuel procurement activities. Ms. Medine is currently developing the fuel procurement strategy for a new solid-fuel power plant on the Great Lakes.

Forecasting

Develops forecasts of coal demand and prices for alternative coal types and market segments. These forecasts are provided to individual clients and are documented in various COALCAST reports including the regional reports and the Long-Term Regional Coal Price Forecast reports.

Acquisition and Investment

Ms. Medine was the agent for Lexington Coal Company in the sale of its assets in Indiana and Illinois. As part of this engagement, Ms. Medine was responsible for the sale of three mines to Peabody Energy. Ms. Medine also routinely evaluates the economics of potential projects or acquisitions for producers, developers, and industrials. For coal projects, this includes market and financial forecasts. Ms. Medine completed the sale of six idle mine assets and various other properties.

Bankruptcy Support

Ms. Medine was an advisor to the Horizon Natural Resource companies which operated as a debtor-in-possession in the development of a plan to accomplish reclamation on all permits not sold and transferred as part of the plan of reorganization. For a period of 15 months, Ms. Medine served as Executive Vice President of Centennial Resources, Inc., a debtor-in-possession, as part of EVA's contract to manage this company post-petition. In this capacity, she managed the day-to-day operations of the company as well as serving as the liaison between the company, state and county regulatory agencies, the bankruptcy court, and the lenders. This assignment ended upon the filing of Centennial's plan of reorganization. Ms. Medine had also served as the advisor to secured lenders in another coal industry bankruptcy. In this capacity, she reviewed and developed independent financial forecasts and operating plans of the debtor-in-possession.

Market Strategy Development

Assists clients in the development of marketing strategies on behalf of coal suppliers and transporters. She has helped to identify the high value markets and strategies for obtaining these accounts.

Expert Testimony

Prepares analyses and testimony in support of clients involved in regulatory and legal proceedings. Provides testimony in commission hearings on fuel procurement issues and arbitration proceedings on contract disputes.

Prior Experience

Prior to joining EVA, Ms. Medine held various positions at CONSOL including Assistant District Sales Manager – Chicago Sales Office and Strategic Studies Coordinator. Prior to CONSOL, Ms. Medine was a Project Manager at Energy and Environmental Analysis, Inc. where she directed two large government studies. For the Environmental Protection Agency, Ms. Medine directed an evaluation of the energy, environmental and economic impacts of New Source Performance Standards on Industrial Boilers. For the Department of Energy, Ms. Medine directed an evaluation of the financial impacts of requiring utilities with coal capable boilers to reconvert to coal. Ms. Medine worked as a Research Assistant at Brookhaven National Laboratory while she attended graduate school.

Exhibit EVA-2. TEP GENERATING ASSETS

Plant	Operator	Ownership (%)	Ownership Capacity (MW)	Prime Mover	Fuel Type	Year First in Service
Bright Tucson-UASTP Solar	Tucson Electric Power	100.00	1.2	Photovoltaic	Solar	2010
DeMoss Petrie CT2	Tucson Electric Power	100.00	83.3	Gas Turbine	Natural Gas	2001
Four Corners	Arizona Public Service	2.80	58.8	Steam Turbine	Bituminous Coal	1963
H. Wilson Sundt CT	Tucson Electric Power	100.00	49.0	Gas Turbine	Natural Gas	1972
H. Wilson Sundt Generating Station	Tucson Electric Power	100.00	423.0	Steam Turbine	Natural Gas	1958
Los Reales Landfill	-	100.00	5.0	Steam Turbine	Landfill Gas	1999
Luna Energy Facility	Public Service of NM	33.33	203.6	Combined Cycle	Natural Gas	2006
Navajo	Salt River Project	7.50	168.8	Steam Turbine	Bituminous Coal	1974
North Loop	Tucson Electric Power	100.00	94.5	Gas Turbine	Natural Gas	1972
San Juan	Public Service of NM	19.52	320.7	Steam Turbine	Subbituminous Coal	1973
Springerville	Tucson Electric Power	65.08	777.1	Steam Turbine	Subbituminous Coal	1985
Springerville Solar	Tucson Electric Power	100.00	6.9	Photovoltaic	Solar	2001
TOTAL			2191.9			

Exhibit EVA-3. TEP GENERATION, 2008 – 2011

	2011	2010	2009	Average 2009-2011	2008	Average vs. 2008
Coal-Fired Generation (1000 MWH)	9,946	9,481	9,272	9,566	10,573	-9.5%
Gas-Fired Generation (1000 MWH)	929	1,078	992	1,000	871	14.8%
Renewable Generation (1000 MWH)	37	32	30	33	34	-2.9%
Total	**10,912**	**10,591**	**10,294**	**10,599**	**11,478**	**-7.7%**
Purchased Power (1000 MWH)	2,687	2,846	3,810	3,114	2,948	5.6%
Total Resources (1000 MWH)	13,599	13,437	14,104	13,713	14,426	-4.9%
Less Line Losses and Company Use (1000 MWH)	795	876	941	871	955	-8.8%
Total Energy Sold	**12,804**	**12,561**	**13,163**	**12,843**	**13,471**	**-4.7%**
Fuel Cost (Cents/kwh generated)						
Coal	2.56	2.29	2.14	2.34	2.22	5.2%
Gas	5.99	5.58	7.66	6.40	8.49	-24.7%
Purchased Power	3.94	4.17	3.79	3.97	8.07	-50.8%

Exhibit EVA-2. TEP GENERATING ASSETS

Plant	Operator	Ownership (%)	Capacity (MW)	Prime Mover	Fuel Type	Year First in Service
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DeMoss Petrie CT2	Tucson Electric Power	100.00	83.3	Gas Turbine	Natural Gas	2001
Four Corners	Arizona Public Service	2.80	58.8	Steam Turbine	Bituminous Coal	1963
H. Wilson Sundt CT	Tucson Electric Power	100.00	49.0	Gas Turbine	Natural Gas	1972
H. Wilson Sundt Generating Station	Tucson Electric Power	100.00	423.0	Steam Turbine	Natural Gas	1958
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Fuel Cost (Cents/kwh generated)						
Coal	2.56	2.29	2.14	2.34	2.22	5.2%
Gas	5.99	5.58	7.66	6.40	8.49	-24.7%
Purchased Power	3.94	4.17	3.79	3.97	8.07	-50.8%

Exhibit EVA-4. TEP PLANT PERFORMANCE

2011	Sundt	Springerville	Sundt GT	Demoss Petrie GT	San Juan	Four Corners	Navajo	North Loop	Luna
Generation (MWH)	898,764,000	5,453,103,000	2,772,000	2,662,000	2,208,827,000	690,678,000	1,127,748,000	2,299,000	524,771,000
Coal Burn (Tons)	264,822	3,624,094			1,210,003	387,167	529,435		
Gas Burn (MCF)	4,923,919		54,132	54,519				51,350	3,561,062
Coal $/MMBtu	3.678	1.945			3.404	2.100	1.987		
Gas $/MMBtu	5.916		78.929	6.719				6.033	6.186
2010	**Sundt**	**Springerville**	**Sundt GT**	**Demoss Petrie GT**	**San Juan**	**Four Corners**	**Navajo**	**North Loop**	**Luna**
Generation (MWH)	839,815,000	5,157,138,000	1,139,000	6,585,000	2,162,337,000	659,880,000	1,088,332,000	605,000	644,741,000
Coal Burn (Tons)	220,317	2,917,576			1,188,082	362,391	509,874		
Gas Burn (MCF)	5,110,533		17,780	93,974				18,235	5,056,015
Coal $/MMBtu	5.789	1.764			2.768	1.698	1.896		
Gas $/MMBtu	4.852		309.491	6.782				6.316	5.595
2009	**Sundt**	**Springerville**	**Sundt GT**	**Demoss Petrie GT**	**San Juan**	**Four Corners**	**Navajo**	**North Loop**	**Luna**
Generation (MWH)	680,088,000	5,159,391,000	1,334,000	4,064,000	2,163,058,000	760,139,000	1,038,394,000	828,000	445,800,000
Coal Burn (Tons)	73,464	2,870,126			1,180,240	425,386	488,578		
Gas Burn (MCF)	6,290,954		48,280	59,329				13,212	3,500,636
Coal $/MMBtu	6.093	1.793			2.697	1.737	1.773		
Gas $/MMBtu	4.493		2.213	5.414				3.381	6.922

Source: Form 1

Exhibit EVA-5. TEP FUEL AND PURCHASED POWER ORGANIZATION

REDACTED

Exhibit EVA-6. TEP COAL SUPPLY

[redacted]

Exhibit EVA-6. HISTORICAL COAL PRICES

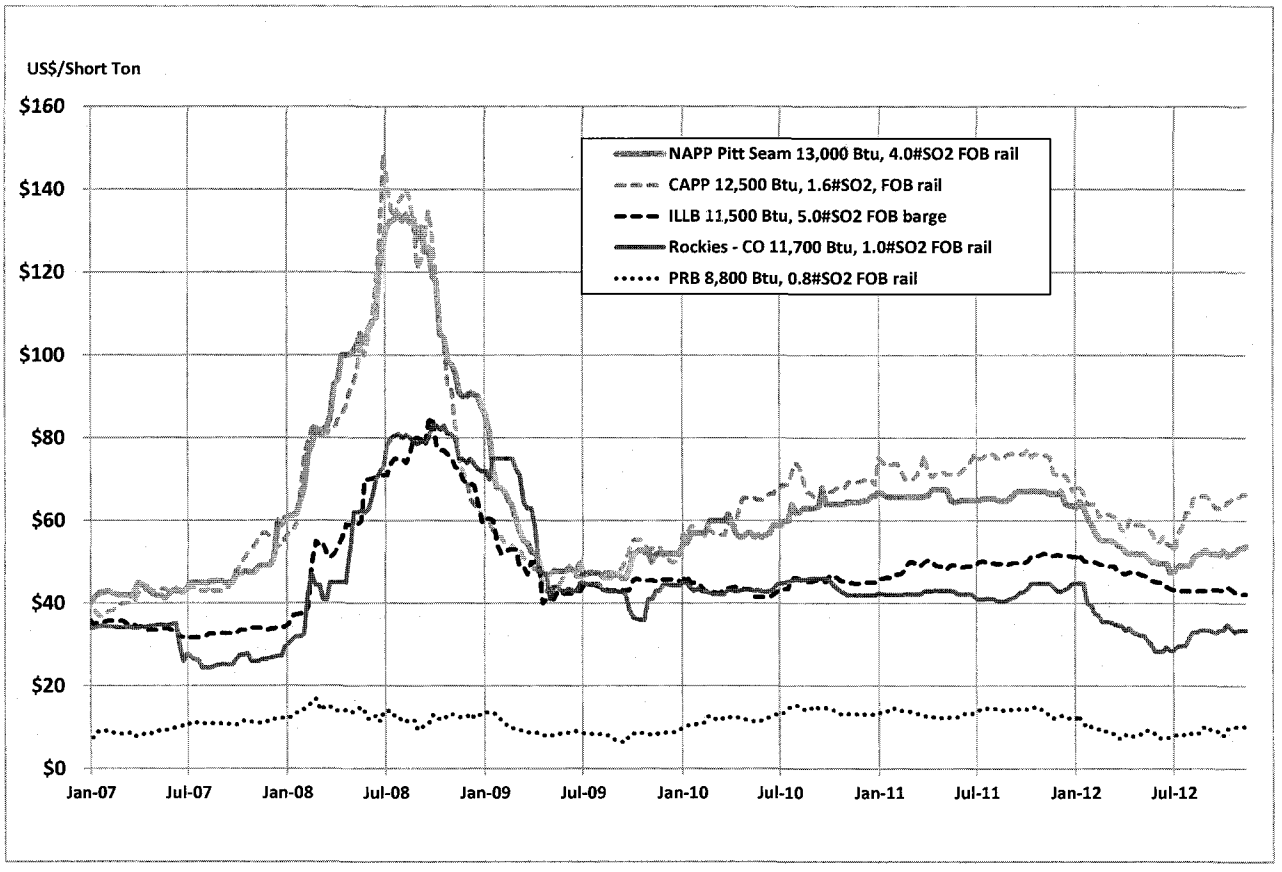


Exhibit EVA-8. SUMMARY OF SPRINGERVILLE AGREEMENT

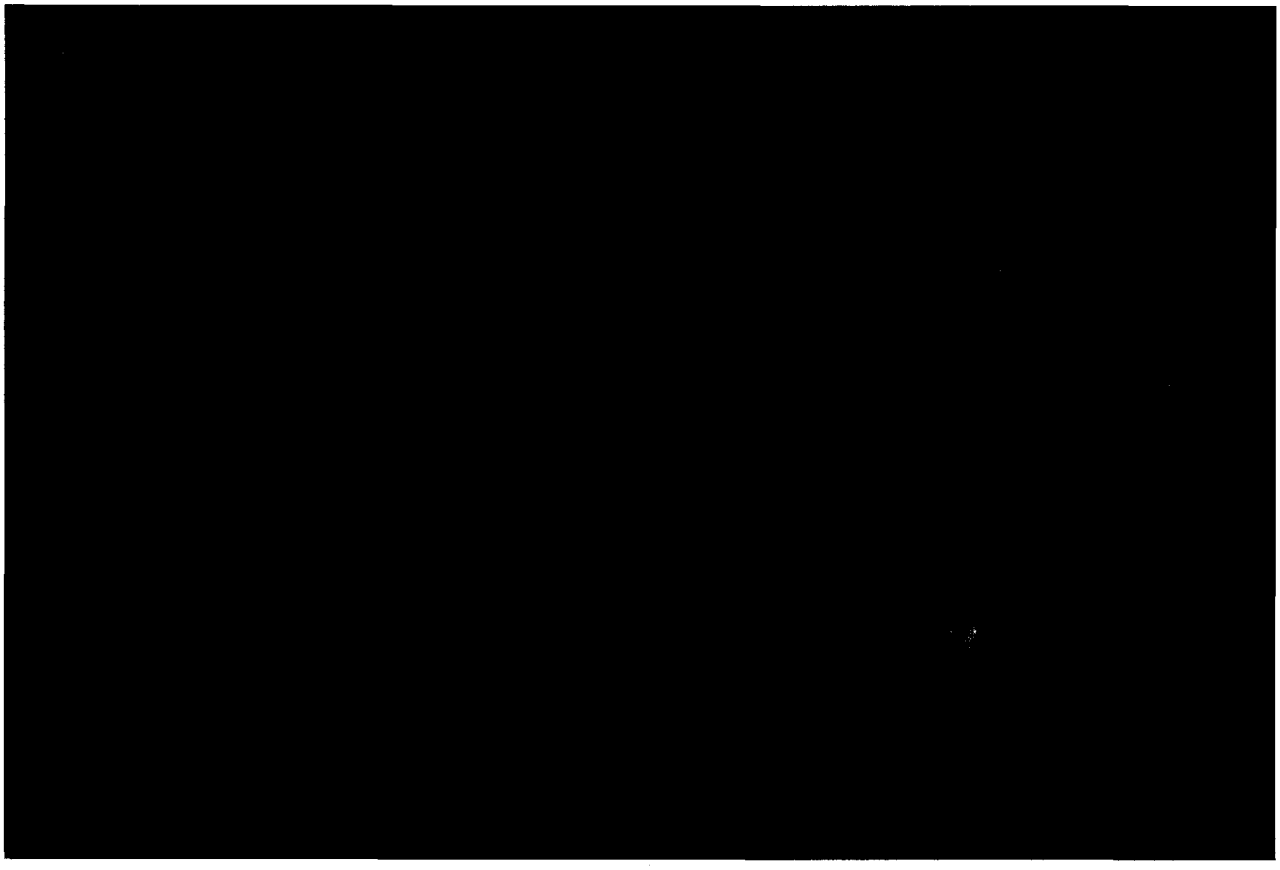


Exhibit EVA-9. SUMMARY OF SUNDT SUPPLY AGREEMENT

Exhibit EVA-10. SUMMARY OF SAN JUAN SUPPLY AGREEMENT

[redacted]

Exhibit EVA-11. QUARTERLY PRODUCTION FROM UNDERGROUND SAN JUAN MINE

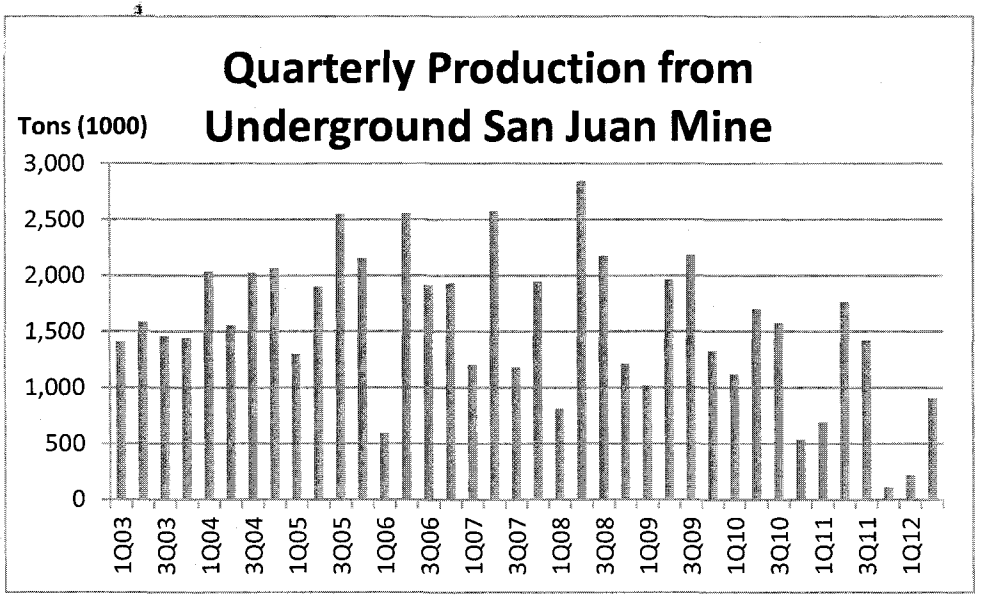


Exhibit EVA-12. SUMMARY OF FOUR CORNERS SUPPLY AGREEMENT

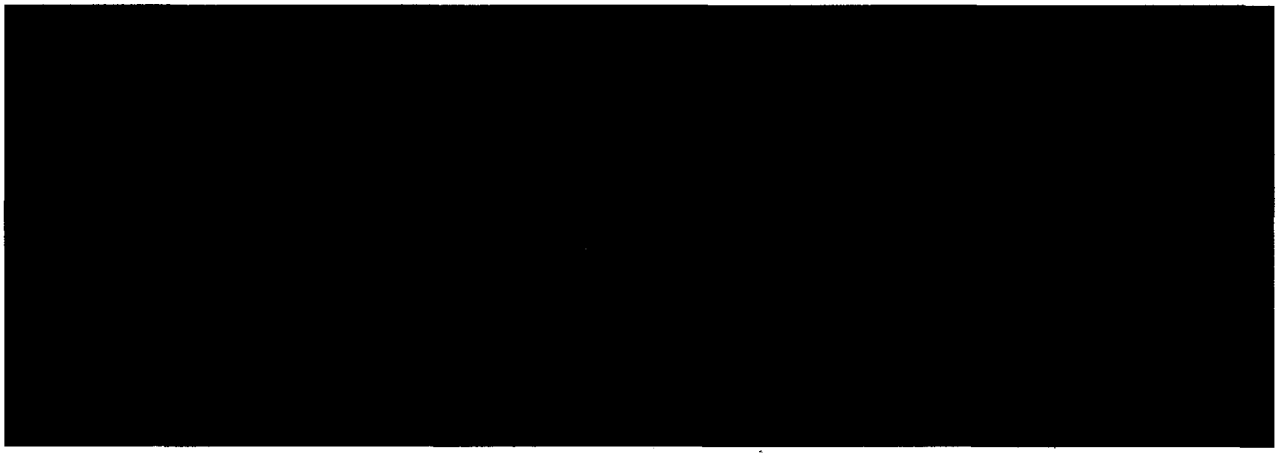


Exhibit EVA-13. SUMMARY OF NAVAJO SUPPLY AGREEMENT

Exhibit EVA-14. INVENTORY PERFORMANCE

[REDACTED]

Exhibit EVA-15. DOLLARS IN INVENTORY BASED UPON TARGETS

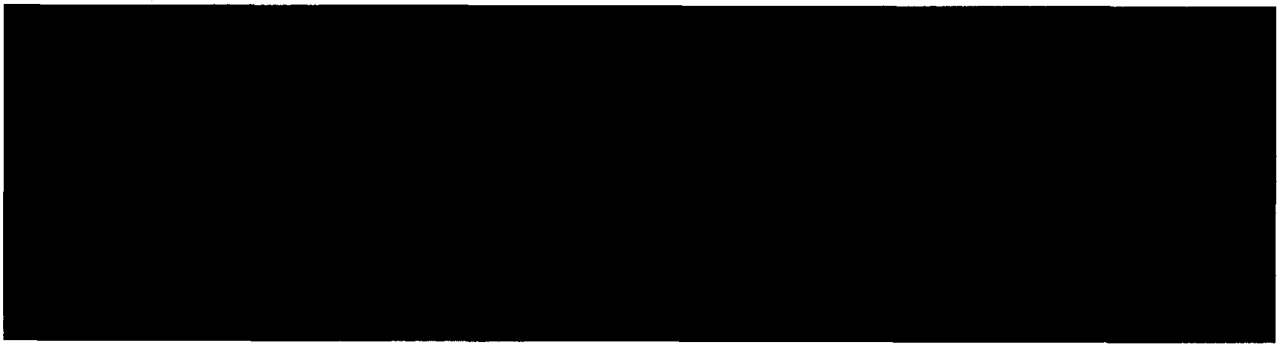


Exhibit EVA-16. SUMMARY OF NATURAL GAS HEDGES, 2011

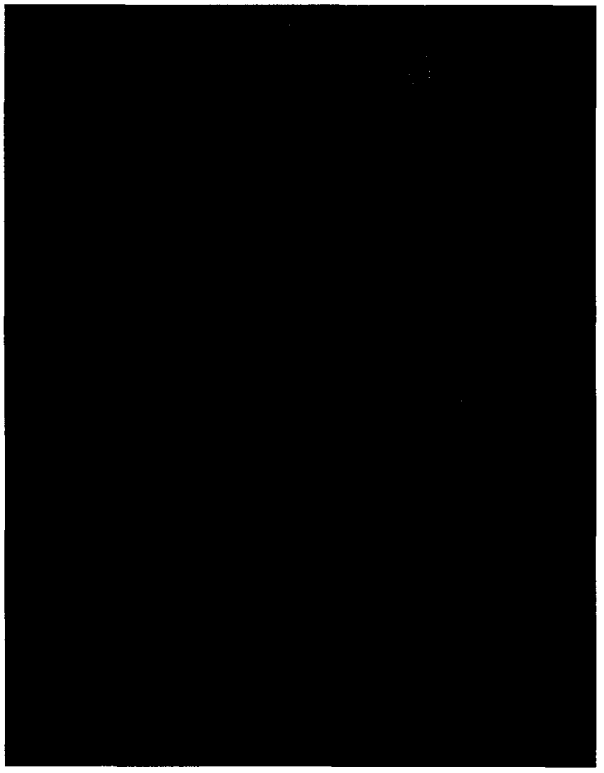
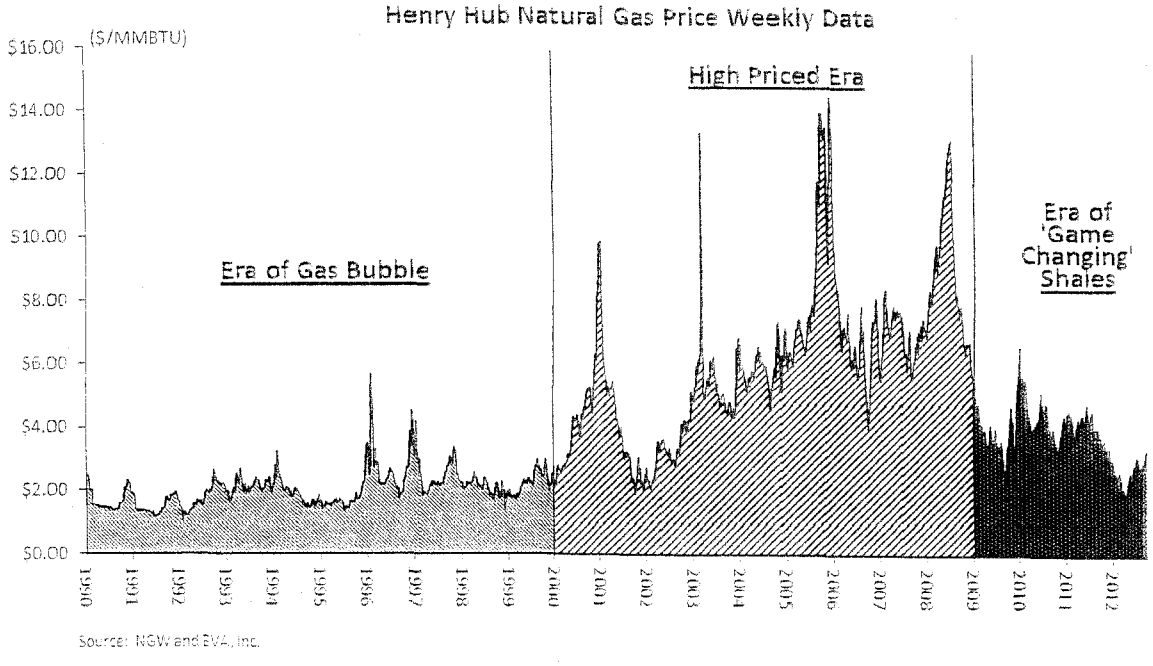


Exhibit EVA-17. COMPARISON OF NG HEDGE PRICES FOR 2011

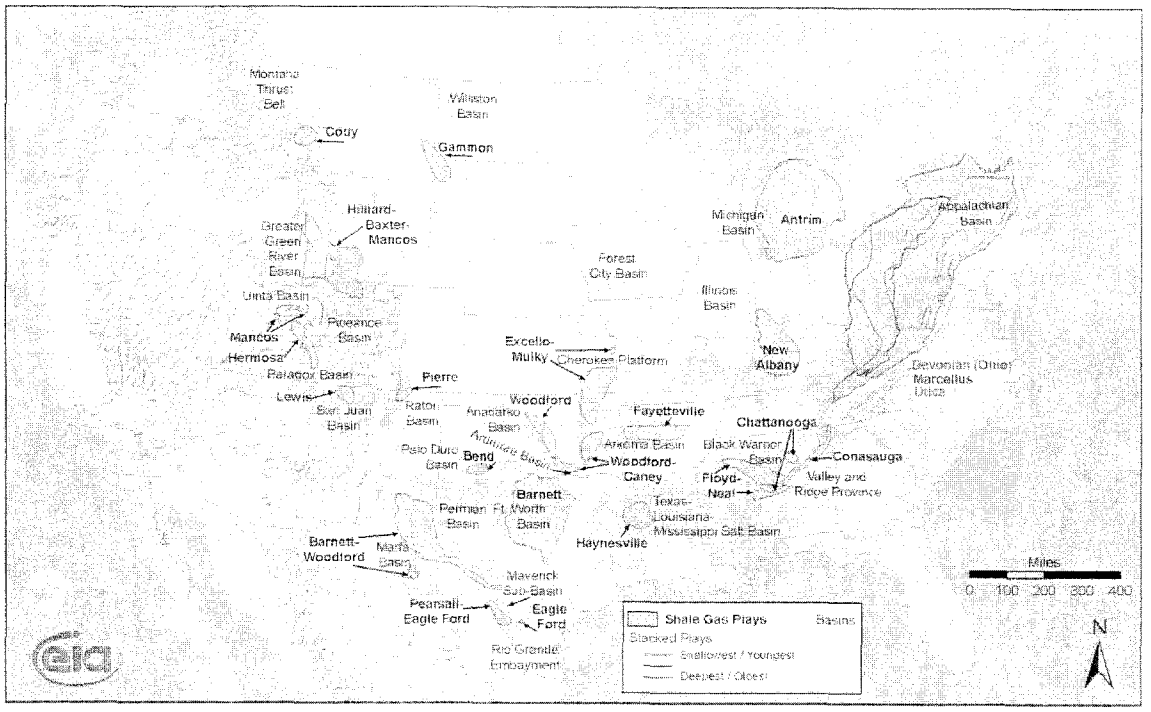
[redacted]

Exhibit EVA-18. HENRY HUB NATURAL GAS PRICE DATA



Source: NGW and EVA, Inc.

Exhibit EVA-19. MAP OF U.S. SHALE GAS PLAYS – LOWER 48



Source: Energy Information Administration based on data from various published studies.
Updated: May 28, 2009

Exhibit EVA-20. SUMMARY OF POWER HEDGES AND COMPARISON TO COSTS OF POWER GENERATION, 2011

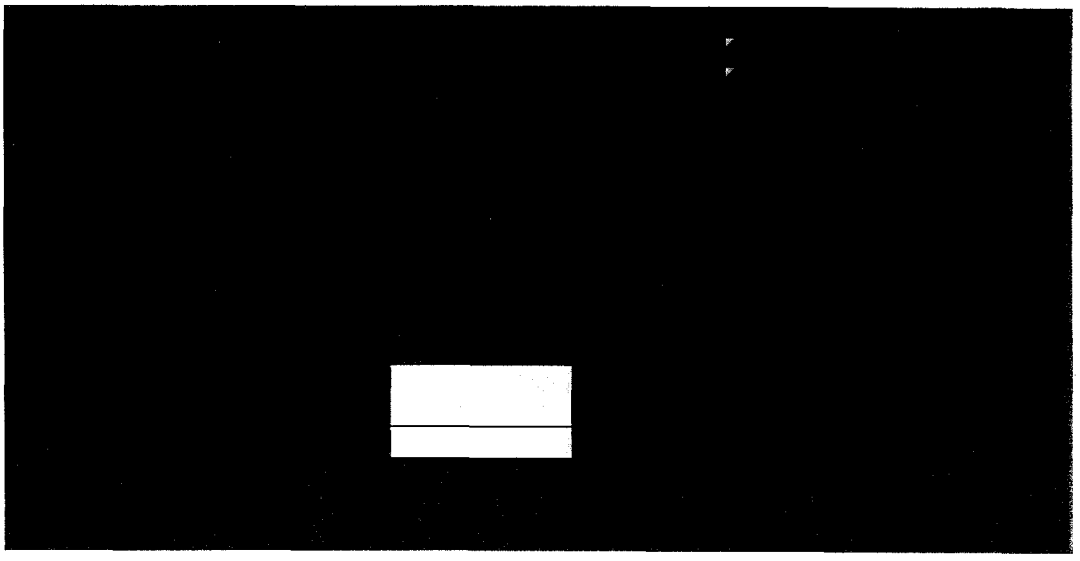


Exhibit EVA-21. SULFUR CREDITS APPLIED TO LIME COSTS

[redacted]

Exhibit EVA-22. TEP NATURAL GAS BURN – 2009 -2012

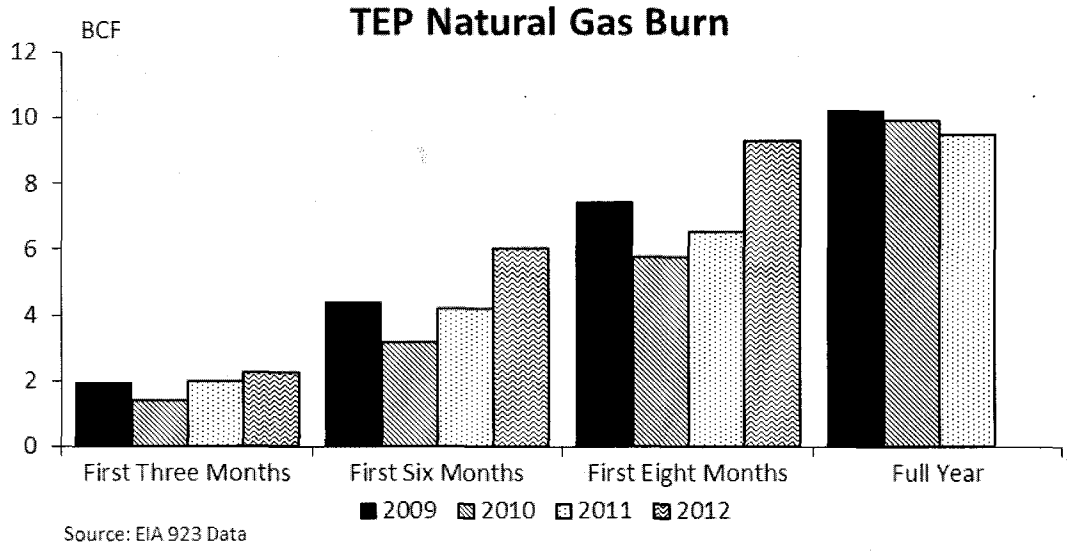
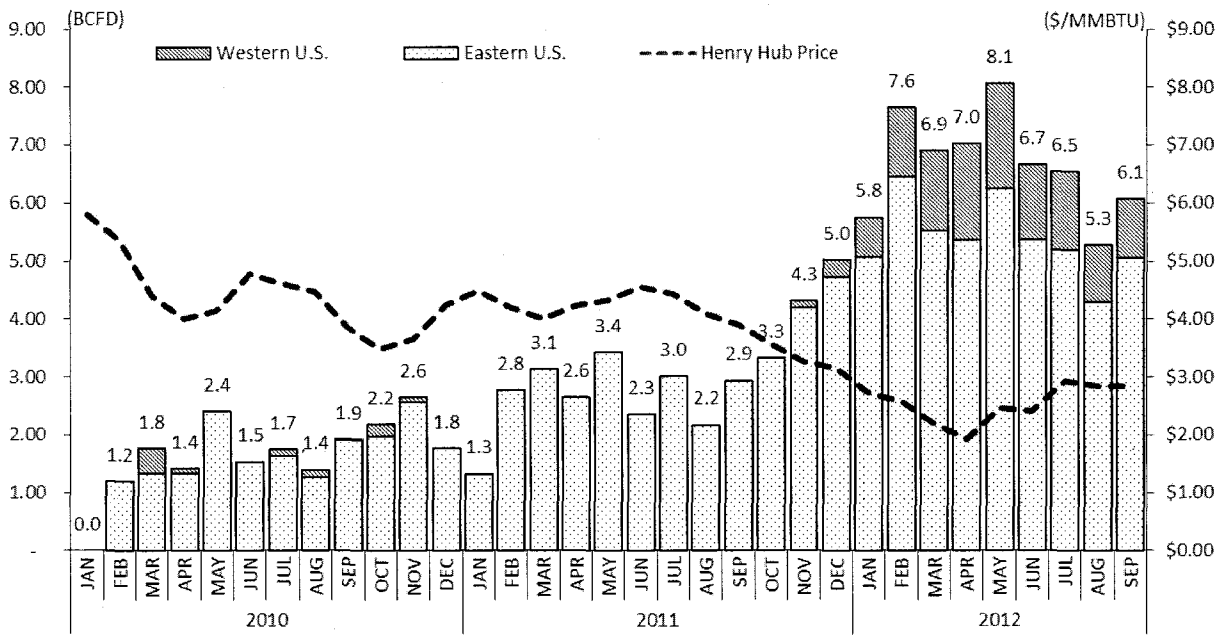


Exhibit EVA-23. COAL DISPLACEMENT BY NATURAL GAS


(BCFD)
($/MMBTU)
Western U.S.
Eastern U.S.
Henry Hub Price
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
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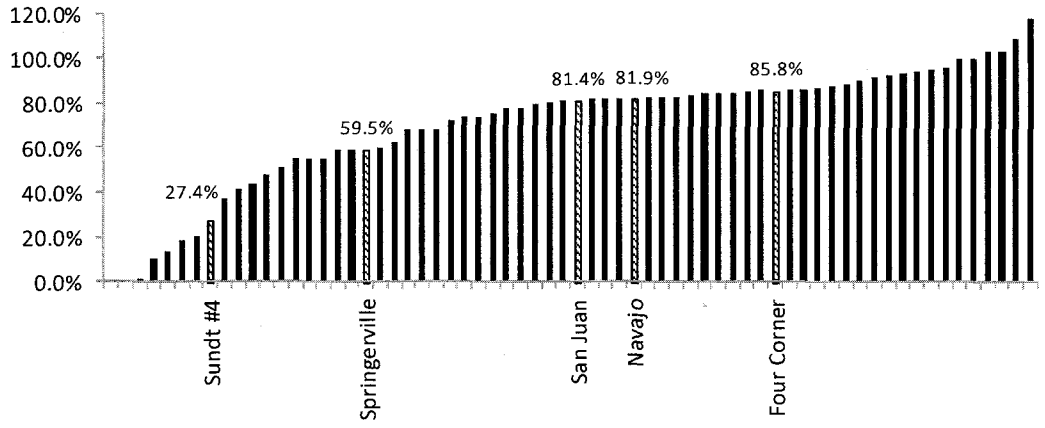
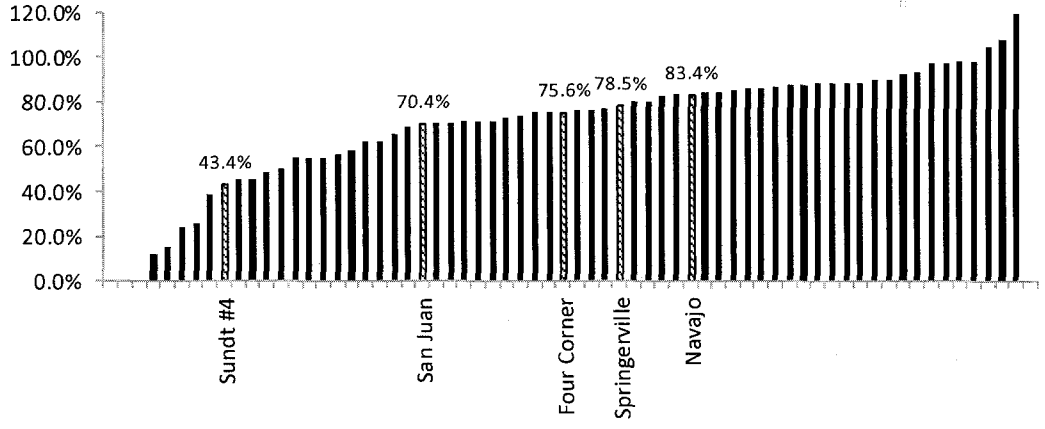
5.3
6.1
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
2010
2011
2012

Exhibit EVA-24. 2009, 2010, AND 2011 CAPACITY FACTORS FOR WSCC PLANTS

2009 Capacity Factor Benchmarking



2010 Capacity Factor Benchmarking



2011 Capacity Factor Benchmarking

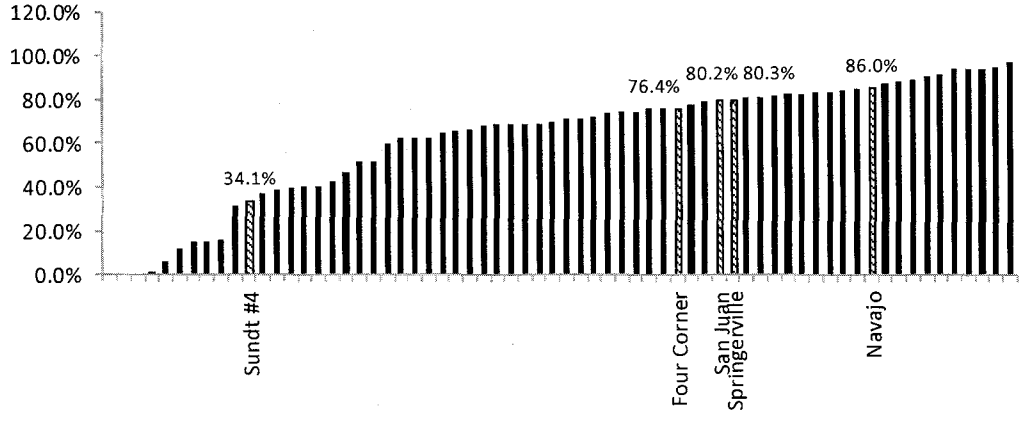
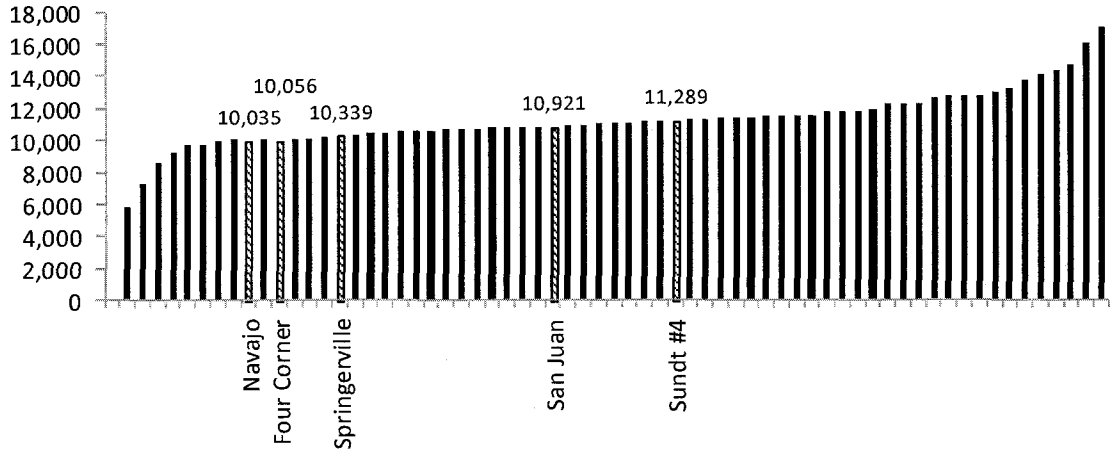
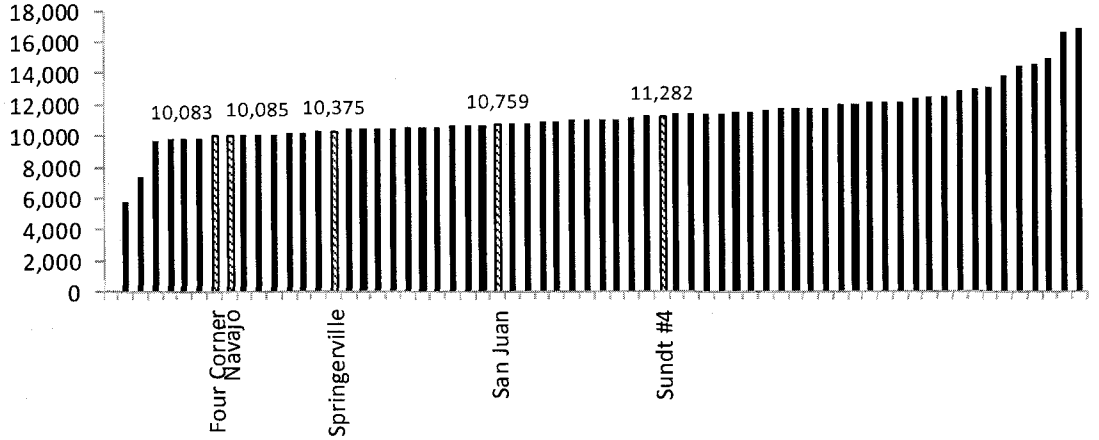


Exhibit EVA-25. ANNUAL HEAT RATES FOR WSCC PLANTS

2009 Heat Rate Benchmarking



2010 Heat Rate Benchmarking



2011 Heat Rate Benchmarking

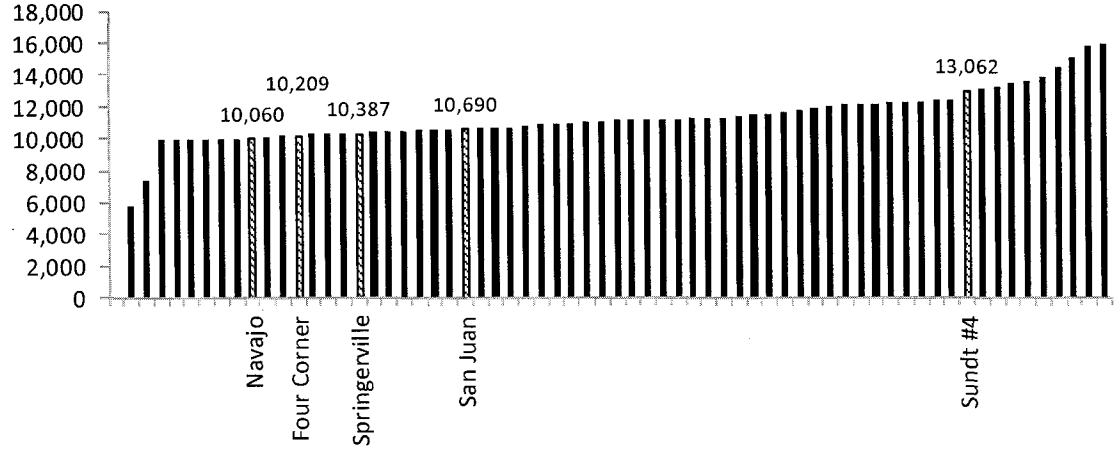
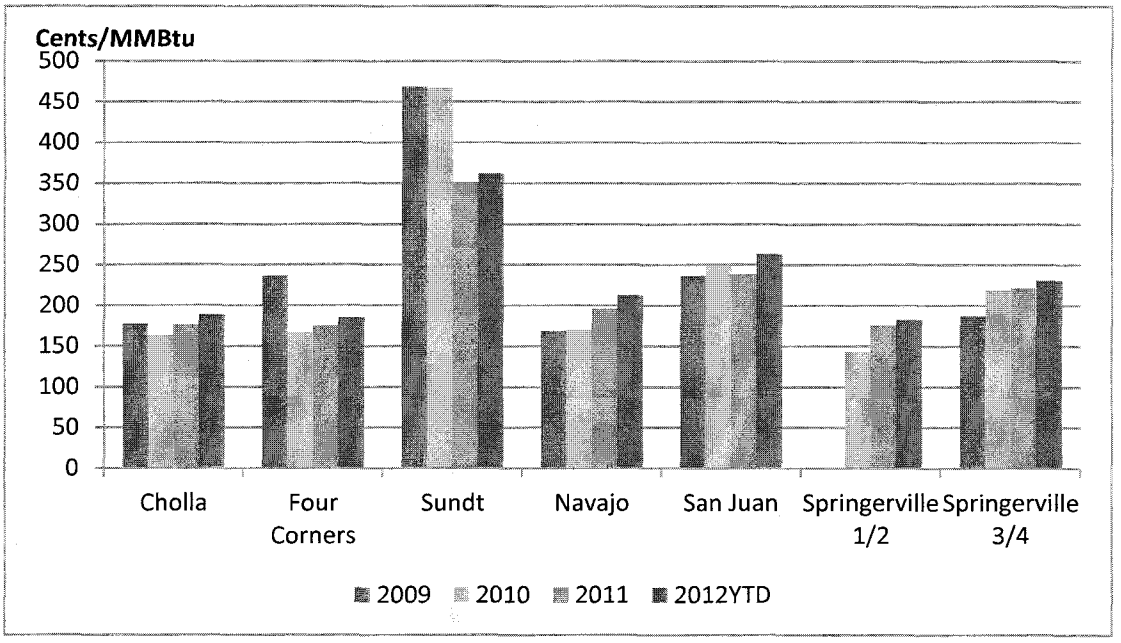


Exhibit EVA-26. EQUIPMENT AVAILABILITY AT TEP PLANTS

[REDACTED]

Exhibit EVA-27. DELIVERED COAL COSTS AT SELECTED PLANTS



Attachment I

Accounting for Sulfur Credits

ATTACHMENT 1 has been removed due to confidential information

EXHIBIT TEP 1 – 11

REMOVED DUE TO

CONFIDENTIAL INFORMATION

BEFORE THE ARIZONA CORPORATION COMMISSION

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

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

DIRECT

TESTIMONY

OF

HOWARD SOLGANICK

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

DECEMBER 21, 2012

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EXECUTIVE SUMMARY
TUCSON ELECTRIC POWER COMPANY
DOCKET NO. E-01933A-12-0291

My testimony reviews the Tucson Electric Power Company's ("Company") Lost Fixed Cost Recovery ("LFCR") proposal. Mr. Solganick is also providing a Rate Design Direct Testimony that will be filed on January 11, 2013.

Mr. Solganick's testimony presents Staff's recommendations based on a review of the Company's application and responses to Staff data requests. Staff recommends that the Commission modify the Company's LFCR proposal to (1) allow the Company to recover only distribution (delivery) service fixed charges, (2) cap the increased revenue allowed for each year at 1 percent, (3) recover the lost fixed cost revenue on a percentage of revenue basis, and (4) make the LFCR mechanism effective beginning with the rate effective date for this rate case.

INTRODUCTION

Q. **Please state your name, position and business address.**

A. My name is Howard Solganick. I am a Principal at Energy Tactics & Services, Inc. My business address is 810 Persimmon Lane, Langhorne, PA 19047. I am performing this assignment under subcontract to Blue Ridge Consulting Services, Inc.

Q. **Please summarize your qualifications and experience.**

A. I am licensed as a Professional Engineer in Pennsylvania (active) and New Jersey (inactive). I hold a Professional Planner's license (inactive) in New Jersey. I served on the Electric Power Research Institute's Planning Methods Committee and on the Edison Electric Institute Rate Research Committee. I have been appointed as an arbitrator in cases involving a pricing dispute between a municipal entity and an on-site power supplier and a commercial landlord-tenant case concerning submetering and billing. I also previously served on two New Jersey Zoning Boards of Adjustment as Chairman and member and a Pennsylvania Township Planning Commission as Chairman and member.

I have been actively engaged in the utility industry for over 35 years, holding utility management positions in generation, rates, planning, operational auditing, facilities permitting, and power procurement. I have delivered expert testimony in utility planning and operations, including rate design and cost of service, tariff administration, generation, transmission, distribution and customer service operations, load forecasting, demand side management, capacity and system planning, and regulatory issues.

I have also led and/or participated in consulting projects to develop, design, optimize, and implement both traditional utility operations and e-commerce businesses. These projects

focused on the marketing, sale and delivery of retail energy, energy related products and services, and support services provided to utilities and retailers.

I have been engaged by clients to review proposed distributed generation contracts and the operation and integration of generating assets within power pool operations, and have advised the Board of Directors of a public power utility consortium. For a period of four years I was engaged by a multiple site commercial real estate organization to manage its solicitation for the purchase of retail energy. As a subcontractor, I have performed management audits for the Connecticut Department of Public Utility Control and the Public Utilities Commission of Ohio. I also provide (as a subcontractor) support for the Staff and Commissioners of the District of Columbia Public Service Commission for electric and gas rate cases.

I have also been engaged (as a subcontractor) to review utility performance before, during and after outages resulting from major storms including Hurricane Ike and the two 2011 storms that affected New Jersey.

From 1994 to the present, I have been President of Energy Tactics & Services, Inc. From 1996 to 1998, I was a Managing Consultant for AT&T Solutions. From 1990 to 1994, I was Vice President of Business Development for Cogeneration Partners of America. In that position, I was responsible for the development of independent power facilities, most of which were fueled by natural gas and oil.

From 1978 to 1990, I held progressively increasing positions of responsibility with Atlantic City Electric Company in generation, regulatory, performance, planning, major procurement, and permitting areas.

From 1971 to 1978, I was an Engineer or Project Engineer for Univac, Soabar, Bickley Furnaces and deLaval Turbine, designing card handling equipment, tagging and printing machines, high temperature industrial furnaces, and utility and industrial power generation equipment, respectively.

I received a Bachelor of Science in Mechanical Engineering (minor in Economics) from Carnegie-Mellon University and a Master of Science in Engineering Management (minor in Law) from Drexel University. I have also taken courses on arbitration and mediation presented by the American Arbitration Association, scenario planning presented by the Electric Power Research Institute and load research presented by the Association of Edison Illuminating Companies. I have also taken courses in zoning and planning theory, practice and implementation in both New Jersey and Pennsylvania.

Q. Have you previously submitted testimony in regulatory proceedings?

A. Yes. I have testified and/or presented testimony (summarized in Exhibit HS-1) before the following regulatory bodies.

- Arizona Corporation Commission
- Delaware Public Service Commission
- Georgia Public Service Commission
- Jamaica (West Indies) Electricity Appeals Tribunal
- Maine Public Utilities Commission
- Maryland Public Service Commission
- Michigan Public Service Commission
- Missouri Public Service Commission
- New Jersey Board of Public Utilities
- Public Utilities Commission of Ohio

- Pennsylvania Public Utility Commission
- Public Utility Commission of Texas

PURPOSE AND SUMMARY OF TESTIMONY

Q. For whom are you appearing in this proceeding?

A. I am appearing on behalf of the Staff of the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff ("Staff").

Q. What is the purpose of your testimony?

A. My testimony analyzes Lost Fixed Cost Recovery ("LFCR") proposal of the Tucson Electric Power Company ("Company").

Based on my review of the Company's application, supporting testimony, and responses to data requests, I make the following recommendations:

- The Commission should modify the Company's LFCR proposal to
  - Allow the Company to receive recovery for only distribution and transmission (delivery) service fixed costs
  - Cap the increased revenue allowed for each year at 1%
  - Recover the lost fixed cost revenue on a percentage of revenue basis
  - Make the LFCR mechanism effective beginning with the rate effective date for this case

Q. What is revenue decoupling?

A. Decoupling is the term used to define a rate design that is designed to disconnect a utility's earnings or revenue from sales of energy or commodity. Decoupled rates can be

designed to eliminate or reduce the utility's disincentive to encourage energy conservation, impacts of the business cycle and/or the effects of weather.

Q. Have you reviewed specific decoupled rate design proposals in other jurisdictions?

A. I have reviewed proposals for decoupled electric and gas rate designs in Delaware for the Staff of the Delaware Public Service Commission where I also assisted in the pre-implementation education process. I have also reviewed decoupling proposals by gas utilities and offered testimony in Maryland for the People's Counsel and in Michigan for the Attorney General. In addition, I assisted the Staff of the District of Columbia Public Service Commission in the evaluation and implementation of a decoupled rate design for delivery of electricity. For Staff I also sponsored a LFCR mechanism in the recent APS case (Docket No. E-01345A- 11-0224).

Q. Please describe the Company's LFCR proposal.

A. The Company's proposal is to establish an LFCR mechanism focused on recovering its estimate of the fixed costs that are unrecovered due to energy efficiency and distributed generation. The Company's LFCR mechanism would exclude fuel and purchased power charges because those areas are already subject to an adjustment mechanism or annual formula.[1] Customer charges and 50% of demand-based charges would also be excluded.[2]

The Company's LFCR is proposed to include all customer classes except for street lighting and water pumping.[3] For calculation purposes the LFCR proposal uses four classes, residential, small general service, large general service and large light and power, which I call "super" classes for identification.

[1] Exhibit CAJ-5 – LFCR Plan of Administration, page 1, Delivery Revenue
[2] Exhibit CAJ-5 – LFCR Plan of Administration, page 1, Delivery Revenue
[3] Exhibit CAJ-5 – LFCR Plan of Administration, page 2, Excluded Rate Schedules and STF 1.087

The calculation of any lost fixed costs by class is based on the actual kWh metered (or estimated) at the distributed generation facilities (or sites)[4] and the estimated kWh not consumed based on an independent Measurement Evaluation and Research ("MER") of the Company's energy efficiency program[5].

To determine the Total Lost Fixed Cost Revenue the Company's LFCR mechanism uses a Lost Fixed Cost Rate ($/kWh)[6] multiplied by the Total Recoverable Energy Efficiency (or Distributed Generation) Savings (kWh).[7] This calculation is made individually for each of the four "super" classes. The LFCR mechanism would lump together all amounts from the "super" classes[8] add in any past over or under recovery[9] and recover the amount from all classes covered by the Company's LFCR on a per kWh basis.[10]

Although the Company's LFCR Plan of Administration refers to Delivery Revenue[11] and Delivery Charge[12] as inputs into the Company's LFCR mechanism and therefore might be interpreted as focusing on lost distribution costs, the Company's testimony[13] focuses on costs other than customer charge and power purchase and fuel.

The Company's LFCR mechanism annual cap would be 2%[14] (except during the initial period)[15] with the remaining balance plus interest carried to the next period.[16] Subject to

[4] Jones Direct 59:21
[5] Jones Direct 59:18
[6] Exhibit CAJ-5 – LFCR Plan of Administration, Schedule 4
[7] Exhibit CAJ-5 – LFCR Plan of Administration, Schedule 3
[8] Exhibit CAJ-5 – LFCR Plan of Administration, Schedule 2, line 4
[9] Jones Direct 57:23
[10] Exhibit CAJ-5 – LFCR Plan of Administration, Schedule 1, line3
[11] Exhibit CAJ-5 – LFCR Plan of Administration, page 1, Delivery Revenue
[12] Exhibit CAJ-5 – LFCR Plan of Administration, Schedule 5
[13] Jones Direct 57:19
[14] Jones Direct 58:1 and Data Response STF 1.087
[15] Jones Direct 61:14

the annual cap, the Company's LFCR mechanism aggregates all underrecovery or overrecovery on an annual basis and recovers or repays those sums over the following twelve-month period beginning July 1st.[17]

The Company is also proposing a fixed charge alternative for residential customers that may want a cost certain option. This alternative has a monthly cost of either $2.50 or $6.50 depending on whether the monthly consumption is less than 2,000 kWh or more than 2,000 kWh.[18] A gap (at exactly 2,000 kWh) exists on the proposed residential tariffs R-01, R-80, R-201AN and R-201BN.[19] This minor item will need to be addressed at implementation if the Company's LFCR mechanism is approved as proposed.

Q. Is the Company's LFCR mechanism the same as the LFCR mechanism approved by the Commission in Decision No. 73183?

A. No. The Company's testimony characterized the LFCR as "...very similar to the Commission-approved mechanisms in the APS and UNS Gas rate cases that were decided earlier this year."[20]

In response to a Staff data request, the Company further defined the differences as:[21]

- Recovery of lost revenues through a kWh charge instead of a percentage-based charge
- Use of a annual true-up mechanism
- A 2 percent cap
- Exclusion of the water pumping and lighting rate classes

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[16] Jones Direct 58:20
[17] Jones Direct 58:14
[18] Jones Direct 59:14
[19] Exhibit CAJ-10
[20] Jones Direct 57:9
[21] STF 1.087

In another response to a data request the Company further defined the difference as:[22]

- No reduction in the generation component in rates

Q. Are there other differences that were not enumerated by the Company?

A. Yes, there are:

- Lost revenue would be based on tail-block revenue[23] that includes generation costs
- An effective date at the end of the Test Year (1/1/12)[24] rather than the beginning of the rate effective period

Q. Has the Company estimated the impact of the LFCR mechanism?

A. The Company initially estimated the impact of its LFCR mechanism at approximately $36.6 million for 2012 and 2013.[25] In its initial response to a Staff data request, the Company estimated subsequent years at around $19 million.[26] To better understand the impact of the Company's LFCR mechanism, Staff and the Company had an informal technical conference and I had several telephone conferences with Mr. Jones. These communications focused on understanding and refining the definition of the Company's LFCR mechanism.

The Company worked collaboratively to develop a model that better answered the Staff data request and this information was provided to all parties as an update of STF 1.092 on December 5, 2012. The Company's estimate is attached as Exhibit HS-2. The Company's estimate of the impact of its LFCR mechanism is approximately $8.9 million in 2014, $10.3 million in 2015 and $11.8 million in 2016. The Company's proposed

[22] TEP Response to VSI 2.39
[23] Jones Direct 60:2
[24] Jones Direct 60:23
[25] Jones Direct 61:14
[26] STF 1.092

LFCR mechanism differentiates between lost fixed costs before and after the rate effective date by recognizing the different tail block rates effective before and after the expected rate change.

Q. Do you have a concern with STF 1.092?

A. Yes. The spreadsheet contains a note "Staff's APS position of using 50% of generation". Staff's position was that no generation component was appropriate in the LFCR mechanism.[27] The APS LFCR does not include a generation component.[28]

Q. Do you support the adoption of the Company's LFCR mechanism?

A. No. The Company's LFCR mechanism appears to have started with the recent Commission approved LFCR for APS but then adds on items that significantly raise costs to customers.

Q. What areas of the Company's revenue do not require some form of revenue decoupling to deal with the impact of energy efficiency programs and distributed generation?

A. The following cost areas do not require decoupling protection in whole or in part:

- Generation
- Energy
- Distribution *(partial)*
- Customer Management
    - Customer Accounts and Sales
    - Metering

[27] Direct Testimony of Howard Solganick (Docket No. E-01345A-11-0224) 11:8 dated November 18, 2011
[28] AZCC Decision No. 73183 13:6, 22:1 and 40:3

- Billing
- Meter Reading

Q. Is some form of revenue decoupling needed for transmission charges?

A. Absent an adjustment mechanism to true-up transmission charges some form of limited decoupling is appropriate.

Q. Is decoupling needed for distribution revenue?

A. Distribution costs are not as fungible, and some distribution assets cannot serve other customers within the short term. Therefore, a reduction in per customer sales may result in a shortfall in revenues to cover fixed costs. Decoupling is needed to recapture the portion of distribution costs that are collected on a volumetric (per kWh) basis. Some of the Company's rate schedules collect distribution costs using demand charges, which will remain constant or change slower than a straight volumetric rate.

Q. Why is revenue decoupling not necessary for the Customer Charges?

A. As a customer takes advantage of energy efficiency or distributed generation the Customer Charge is collected regardless of the customer's usage.

Q. Is the Company subject to an energy efficiency goal?

A. The rules[29] (the "Rules") set cumulative (and incremental) savings (based on prior year sales) as follows:

Year	Cumulative Savings %[30]	Incremental Savings %
2011	1.25	1.25
2012	3.00	1.75
2013	5.00	2.00
2014	7.25	2.25
2015	9.50	2.25

Q. Is energy efficiency cost effective for customers?

A. Yes. The analyses explored during the decoupling workshop proceedings forecast cost savings for customers as a result of a well designed, long-term energy efficiency program.

Q. Has the Company developed an energy efficiency forecast?

A. Yes. Exhibit HS-2 contains the Company's estimate of the results of its energy efficiency efforts under the title "EE related KWh".

Q. Has the Company developed a forecast of the impact of distributed generation?

A. Yes. Exhibit HS-2 contains the Company's estimate of the impact of distributed generation under the title "DG related KWh".

[29] Arizona Administrative Code R14-2-2401, et seq (effective January 1, 2011)
[30] Arizona Administrative Code R14-2-2404, Table 1 (effective January 1, 2011)

Q. Without some mechanism would the Company's Plan have a measureable impact on the Company's revenue?

A. Yes. The Rules require reductions in the Company's sales compared to each prior year. If the Company meets those goals then a portion of the Company's transmission and distribution revenue could be impacted.

Q. After reviewing the Company's LFCR mechanism what changes would you recommend?

A. I recommend changes to the Company's LFCR mechanism as follows:

- Remove the Company's recovery of generation charges
- Change the recovery basis from a $/kWh basis to a percentage of revenue basis
- Ensure that any transmission costs included in the LFCR mechanism are not double counted within a transmission adjustment
- Make the LFCR mechanism effective on the rate effective date of this case
- Reduce the annual cap to 1 percent
- Modify the Company's proposed fixed price option
- Develop and execute a customer education program

Q. Why is decoupling not necessary for generation?

A. The output of the Company's generating system is fungible. The generating system is not affected if energy is delivered to a new customer, an existing customer using slightly more energy, non-ACC jurisdictional customers or sold off-system. Therefore, the Company has many opportunities to sell the output of its generating system.

Q. What is the Company's forecast for sales?

A. The Company's Load Forecast shows a trend of increasing total sales to retail customers (without the effects of Energy Efficiency ("EE") and Distributed Generation ("DG")) and a generally level series of wholesale sales until current contract expiration.[31]

Year	Retail Sales (GWh)	Off System Sales (GWh)
2012	9,686	775
2013	10,033	772
2014	10,259	764
2015	10,477	745
2016	10,698	208

Q. What is a projection of net sales over that period?

A.

Year	Unrestricted Sales (GWh)	LFCR related Reductions (GWh)	Net Sales (GWh)
2012	10,461	222	10,239
2013	10,805	307	10,498
2014	11,023	419	10,604
2015	11,222	560	10,662
2016	10,906	721	10,185

Based on the Company's projected sales and its estimates of EE and DG for the period, the net sales still result in an increasing trend with the exception of 2016, which is driven by the Company's off-system sales situation.

Q. Does the LFCR approved for APS include generation costs?

A. No.

[31] TEP 2012 Integrated Resource Plan Table 7 (page 57)

Q. Why do you recommend that the LFCR mechanism collect the lost fixed costs on a percentage of base rate revenue basis?

A. The LFCR approved for APS and the Company's proposed LFCR mechanism require the same data and/or estimates. Lost fixed costs include both energy and demand impacts. The use of revenue-based recovery (rather than a per kWh basis) preserves the relationship between customer, demand and energy revenues collected from customers and therefore does not shift the LFCR impact towards high load factor customers.

Q. How should PPFAC costs be treated?

A. If the PPFAC is approved as the Company requested, then there is a separate mechanism to recover and adjust for the changes in the Company's sales and energy production. However, if the Company's request for full costs within the PPFAC is rejected then the "Delivery Charge" must be reduced by the amount of fuel and purchased power in base rates. The net effect is zero on the calculations made and impact to the Company.

Q. What concerns do you have about including transmission costs within the LFCR?

A. To avoid potential double recovery of lost transmission costs any changes to the transmission rate mechanism must recognize that a LFCR mechanism that includes transmission costs will protect the Company from cumulative lost sales.

Q. Is the Company's use of tail block rates appropriate?

A. No. Tail block rates are reasonable for the customers that use enough energy to reach their respective tail block. However, there are a significant number of customers that do not reach that point. Therefore, the "Delivery Charge" to be used should be a bill weighted average of each individual rate schedule. The cumulative bill information needed to make this calculation exists in the Company's bill frequency data. Using data

for Rate R-01 as an example 22.8 percent of the summer bills and 45.6% of the winter bills are priced within the initial 0-500 kWh rate block,[32] which is significantly lower than the tailblock. Without adjusting the Company's proposed "Delivery Charge" the Company will receive a windfall.

Q. Why are you recommending that the LFCR mechanism be implemented starting on the rate effective date of this case?

A. The Company's proposal to start the LFCR mechanism at the end of the Test Year recognizes the impact of only a single issue (cost or revenue item) rather than updating all inputs. For example, any labor or process productivity increases that the Company achieves after the end of the Test Year will flow to the stockholders; costs will change in both directions after a Test Year but the ratemaking formula does not usually include an adjustment mechanism, therefore singling out just the LFCR would be inappropriate. Additionally, as the Company has identified, the LFCR would need to have two different "Delivery Charges" to reflect rates before and after the rate effective date. Also, the LFCR approved for APS begins on the rate effective date.

Q. Why are you suggesting that the annual cap be reduced to 1%?

A. Using the information developed by the Company and provided in STF 1.092 the Company is now forecasting incremental impacts of less than 1.25%.[33]

I removed the recovery of generation costs and corrected the implementation point to reflect the rate effective date. With those changes I have calculated the impact of the LFCR and there is no need for a 2% cap and a 1% cap is more appropriate. An

[32] TEP file R-01 BF update for Howard 10-24-12.xls
[33] Exhibit HS-2 "Total LFCR $" and "% of Total Revenue"

appropriate calculation of the rate to be used in the LFCR rather than the suggested single tailblock will reduce this level further. My results are shown in Exhibit HS-3.

Q. What changes do you recommend for the proposed fixed charge option?

A. The Company has proposed a single break point for the fixed charge option. In the APS implementation there are multiple steps to the fixed price alternative. The Company apparently chose its two points using a bill impact methodology rather than a relationship to expected costs.[34]

I suggest a methodology be developed to determine the fixed price option for various steps. The methodology should use the midpoint of consumption for each of the steps and assume the number of years that the LFCR may be in effect. The amount should be based upon the expected LFCR over that period. The goal is to approximate the LFCR mechanism's expected results in the fixed charge.

Q. Do you recommend a customer education plan for the LFCR?

A. Yes. If an LFCR mechanism is approved for implementation, the Company should submit a plan to Staff and other parties for customer education. In my experience, this helps to make a significant rate change understandable and acceptable to customers. It is important to highlight the long-term benefits of EE and DG and the LFCR's short-term support for the Company to ensure that all parties are focused on cost-effective EE and DG as proscribed by the Rules.

[34] STF 1.090

The Company has indicated its willingness to receive input from all parties and I support that attitude.[35] Any customer education plan should use a variety of methods to deliver information to customers, as customers may be more receptive to one form or another. Some of the methods might include bill inserts, customer service representatives, energy advisors, website explanations and calculations as the Company suggests. I recommend additional approaches such as print and TV (both in paid advertisements and articles or features written by reporters), meeting with customers in small groups (Speaker's Bureau) and educating community leaders and organizations to further explain the concept.

Q. How would all of the changes that need to be accomplished to implement an LFCR be finalized?

A. At the resolution of any rate case, unless the Company was to receive its exact request, the Company has to file rates that conform to the Commission's decision. If a settlement occurs this calculation process occurs before the settlement is presented to the Commission. In either event, the Company has to prepare new rates for approval by the Staff as the result of a Commission decision or acceptance by the parties to the settlement document.

At present, the generation estimates in the Company's response to STF 1.092 appear inconsistent between residential and commercial and before and after the rate effective, date and this open issue should be resolved. Further, the Company's estimate of generation costs at $0.021 per kWh from STF 1.092 is not supported by the calculation of residential Production Demand divided by Total Throughput from STF 21.1 Unit Costs of $0.0407 per kWh.

[35] STF 1.086

Additionally, as the Company has noted for simplicity it has used Rate 10 for the commercial impact[36] although there are multiple rates for commercial customers and similar issues arise for the other classes. The filing should include both the new rates and all of the inputs needed to calculate the LFCR except the MER results and the DG metered data.

The Company's technical conferences have helped to set the stage for this final effort by opening the lines of communication.

Q Does the LFCR ensure that the Company cannot earn above its allowed rate of return?

A. An LFCR mechanism is designed to recoup the lost fixed costs for sales that no longer occur due to mandated energy efficiency and/or distributed generation. As shown above, the Company's sales forecast adjusted for its EE and DG efforts continues to growth through 2015. Positive economic conditions and/or above normal weather could increase sales during the rate effective period and potentially lead to an over earning situation. Further, as the positive effects of EE and DG take place future capital requirements should decline. Therefore the Company should still be subject to reviews of its financial performance at least annually even with the approval of an LFCR mechanism.

Q. **Does this conclude your testimony?**

A. Yes.

[36] Email dated November 21, 2012

Exhibit HS-1
Testimony - Howard Solganick

Arizona Corporation Commission
Case – Arizona Public Service Company Docket No. E-01345A-11-0224 (November 2011)
Client - Staff of the Arizona Corporation Commission
Scope - Testimony covered revenue decoupling, cost of service, revenue allocation, rate design and other related issues.

Public Service Commission of Delaware
Case - Delmarva Power & Light Company Docket No. 10-237 (October 2010)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization and miscellaneous charges.

Case - Delmarva Power & Light Company Docket No. 09-414 (February 2010)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization and weather normalization.

Case - Delmarva Power & Light Company Docket No. 09-277T (November 2009)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered an analysis of a straight fixed variable rate design for small gas customers and implementation issues.

Case - Delmarva Power & Light Company Docket No. 06-284 (January 2007)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization or normalization.

Georgia Public Service Commission
Case – Atlanta Gas Light Company Docket No. 31647 (August 2010)
Client – Public Interest Advocacy Staff of the Georgia Public Service Commission
Scope - Testimony covered revenue forecast, cost of service, revenue allocation, rate design and other related issues.

Case – Atmos Energy Corporation Docket No. 27163 (July 2008)
Client – Public Interest Advocacy Staff of the Georgia Public Service Commission
Scope - Testimony covered rate design and other related issues.

Jamaica (West Indies) Office of Utility Regulation

Case - Electricity Appeals Tribunal (August 2007)
Client - Jamaica public Service Company, Ltd.
Scope - "Witness Statement" on behalf of the Jamaica Public Service Company Limited. This Statement covered issues relating to recovery of expenses incurred due to Hurricane Ivan.

Maine Public Utilities Commission
Case - Northern Utilities, Accelerated Cast Iron Replacement Program Docket No. 2005-813 (2005)
Client - Public Advocate of the State of Maine
Scope - Testimony covered an analysis of the program's economics and implementation.

Public Service Commission of Maryland
Case - Chesapeake Utilities Corporation Case No. 9062 (August 2006)
Client - Office of the Maryland People's Counsel
Scope - Testimony covered cost of service, rate design and other related issues.

Case - Baltimore Gas & Electric's (1993)
Client - As president of the Mid Atlantic Independent Power Producers
Scope - Testimony covered BG&E's capacity procurement plans.

Michigan Public Service Commission
Case - Consumers Energy Company Case No. U-15245 (November 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered cost of service, rate design and revenue allocation.

Case - Consumers Energy Company Case No. U-15190 (July 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues related to Consumers Energy's gas revenue decoupling proposal.

Case - Consumers Energy Company Case No. U-15001 (June 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues related to Consumers Energy and the MCV Partnership.

Case - Consumers Energy Company Case No. U-14981 (September 2006)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues relating to the sale of Consumers interest in the Midland Cogeneration Venture.
Case - Consumers Energy Company Case No. U-14347 (June 2005)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)

Scope – Testimony covered cost of service and revenue allocation.

Missouri Public Service Commission
Case – AmerenUE Storm Adequacy Review (July 2008)
Client – KEMA/AmerenUE
Scope – Oral testimony covered KEMA's review of AmerenUE's system major storm restoration efforts.

Case – Veolia Energy Kansas City, Inc. File No. HR-2011-0241 (September 2011)
Client – City of Kansas City, Missouri
Scope – Testimony covered various aspects of the Company's tariff provisions and the impact on the City of Kansas City.

New Jersey Board of Public Utilities
Case - Cogeneration and Alternate Energy Docket # 8010-687 (1981)
Case - PURPA Rate Design and Lifeline Docket # 8010-687 (1981)
Case - Atlantic Electric Rate Case - Phases I & II Docket # 822-116 (1982)
Case - Power Supply Contract Litigation – Wilmington Thermal Systems Docket # 2755-89 (1989)
Case - NJBPU Atlantic Electric Rate Case - Phase II (1980-81) Docket # 7911-951 (Before the Commissioners of the New Jersey Board of Public Utilities)
Client - Employer was Atlantic City Electric Company.
Scope - The cases listed above covered load forecasting, capacity planning, load research, cost of service, rate design and power procurement.

Public Utilities Commission of Ohio
Case - The Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company Case 07-551-EL-AIR (January 2008)
Client - Ohio Schools Council
Scope - Testimony covers issues related to rate treatment of schools.

Case - The Application of the Columbus Southern Power Company 08-917-EL-SSO and the Ohio Power Company Case 08-918-EL-SSO (October 2008)
Client - Ohio Hospital Association
Scope - Testimony covers issues related to rates for net metering and alternate feed service and related treatment of hospitals.

Pennsylvania Public Utilities Commission
Case - York Water Company Docket No. R-00061322 (July 2006)
Client - Pennsylvania Office of Consumer Advocate
Subject - Testimony covered cost of service, rate design and other related issues, also supported the settlement process.

Case – Pennsylvania- American Water Company Docket No. R-2008-232689 (August 2010)
Client – Municipal Sewer Group
Subject - Testimony covered capacity planning, construction, treatment of future load and associated revenue, cost of service, rate design, capacity fee and other related issues.

Case – Pennsylvania- American Water Company Docket No. R-2008-232689 (August 2008)
Client – Municipal Sewer Group
Subject - Testimony covered cost of service, rate design, capacity fee and other related issues, also supported the settlement process.

Public Utilities Commission of Texas
Case – Determination of Hurricane Restoration Costs Docket No. 36918 (April 2009)
Client – CenterPoint Energy Houston Electric, LLC
Subject – Testimony covered the reasonableness of the client's Hurricane Ike restoration process for an outage covering over two million customers and a restoration period of 18 days

EE related KWh	Year	Residential	Commercial	Industrial	Other	Demand KW Commercial	Demand KW Industrial	EE or DG Goal	Total Lost kWh	Lost kWh as % of 9,285 GWh
Cummulative	2011	47,637,346	10,301,591	7,646,868	163,289	16,246	11,887	1.02%	65,749,093	0.7081%
Annual		47,637,346	10,301,591	7,646,868	163,289	16,246	11,887			
Cummulative	2012	106,381,459	22,438,136	26,663,305	959,822	37,285	44,330	2.44%	156,442,721	1.6849%
Annual		58,744,113	12,136,545	19,016,437	796,533	21,038	32,443			
Cummulative	2013	144,166,349	23,839,971	28,328,933	1,077,257	38,342	45,562	4.15%	197,412,510	2.1261%
Annual		37,784,890	1,401,836	1,665,628	117,436	1,058	1,232			
Cummulative	2014	211,410,864	37,873,577	38,372,988	1,308,898	61,514	62,102	6.11%	288,966,327	3.1122%
Annual		67,244,515	14,033,606	10,044,055	231,641	23,172	16,540			
Cummulative	2015	296,028,572	60,612,174	64,127,444	2,315,599	98,215	103,940	7.21%	423,083,769	4.5566%
Annual		84,617,708	22,738,597	25,754,455	1,006,701	36,701	41,838			
Cummulative	2016	384,870,273	88,337,055	94,546,051	3,399,979	142,802	152,859	9.24%	571,153,359	6.1514%
Annual		88,841,701	27,724,881	30,418,608	1,084,380	44,587	48,919			

DG related KWh	Year	Residential	Commercial	Industrial	Other	Demand KW Commercial	Demand KW Industrial
Existing	2011	26,774,143	12,781,661	4,000,000			8,000
Incremental		26,774,143	12,781,661	4,000,000	-		8,000
Existing	2012	34,056,137	25,375,000	6,625,000			16,000
Incremental		7,281,994	12,593,339	2,625,000			8,000
Existing	2013	47,965,612	34,125,000	27,125,000			35,000
Incremental		13,909,475	8,750,000	20,500,000			19,000
Existing	2014	54,880,008	48,125,000	27,125,000			43,000
Incremental		6,914,396	14,000,000	-			8,000
Existing	2015	61,570,040	48,125,000	27,125,000			43,000
Incremental		6,690,032	-	-			-
Existing	2016	74,508,361	48,125,000	27,125,000			43,000
Incremental		12,938,321	-	-			-

EE and DG percentage changes reflect adjustments for allowed credits

LFCR related KWh	Year	Residential	Commercial	Industrial	Other	Demand KW Commercial	Demand KW Industrial
Existing	2011	74,411,489	23,083,252	11,646,868	163,289	16,246	19,887
Incremental		74,411,489	23,083,252	11,646,868	163,289	16,246	19,887
Existing	2012	140,437,596	47,813,136	33,288,305	959,822	37,285	60,330
Incremental		66,026,107	24,729,884	21,641,437	796,533	21,038	40,443
Existing	2013	192,131,961	57,964,971	55,453,933	1,077,257	38,342	80,562
Incremental		51,694,365	10,151,836	22,165,628	117,436	1,058	20,232
Existing	2014	266,290,872	85,998,577	65,497,938	1,308,898	61,514	105,102
Incremental		74,158,911	28,033,606	10,044,055	231,641	23,172	24,540
Existing	2015	357,598,612	108,737,174	91,252,444	2,315,599	98,215	146,940
Incremental		91,307,740	22,738,597	25,754,455	1,006,701	36,701	41,838
Existing	2016	459,378,634	136,462,055	121,671,051	3,399,979	142,802	195,859
Incremental		101,780,022	27,724,881	30,418,608	1,084,380	44,587	48,919

Choose 1 for Company's position and 2 for Staff's APS position of using 50% of Generation

1

LFCR Rates	Year	Residential	Commercial	Industrial	Other	Demand KW Commercial	Demand KW Industrial
	2011	$ 0.065106	$ 0.077833	$ 0.024882	$ 0.065106		$ 19.02
	2012	$ 0.065106	$ 0.077833	$ 0.024882	$ 0.065106		$ 19.02
	2013	$ 0.065106	$ 0.077833	$ 0.024882	$ 0.065106		$ 19.02
	2014	$ 0.078100	$ 0.087900	$ 0.008500	$ 0.078100		$ 21.00
	2015	$ 0.078100	$ 0.087900	$ 0.008500	$ 0.078100		$ 21.00
	2016	$ 0.078100	$ 0.087900	$ 0.008500	$ 0.078100		$ 21.00

Generation Component in Rates	Year	Residential	Commercial	Industrial	Other	Demand KW Commercial	Demand KW Industrial
	2011	$ 0.031605	$ 0.027224	$ -	$ 0.031605		$ 12.83
	2012	$ 0.031605	$ 0.027224	$ -	$ 0.031605		$ 12.83
	2013	$ 0.031605	$ 0.027224	$ -	$ 0.031605		$ 12.83
	2014	$ 0.021000	$ 0.031800	$ -	$ 0.021000		$ 8.25
	2015	$ 0.021000	$ 0.031800	$ -	$ 0.021000		$ 8.25
	2016	$ 0.021000	$ 0.031800	$ -	$ 0.021000		$ 8.25

LFCR Revenues	Year	Residential	Commercial	Industrial	Other	Commercial	Industrial
Cummulative	2011	$ 4,844,634	$ 1,796,639	$ 289,797	$ 10,631	$ -	$ 378,244
Annual		$ 4,844,634	$ 1,796,639	$ 289,797	$ 10,631	$ -	$ 378,244
Cummulative	2012	$ 9,143,330	$ 3,721,440	$ 828,280	$ 62,490	$ -	$ 1,147,472
Annual		$ 4,298,696	$ 1,924,801	$ 538,482	$ 51,859	$ -	$ 769,228
Cummulative	2013	$ 12,508,943	$ 4,511,588	$ 1,379,805	$ 70,136	$ -	$ 1,532,283
Annual		$ 3,365,613	$ 790,148	$ 551,525	$ 7,646	$ -	$ 384,811
Cummulative	2014	$ 20,797,317	$ 7,559,275	$ 556,733	$ 102,225	$ -	$ 2,207,140
Annual		$ 5,791,811	$ 2,464,154	$ 85,374	$ 18,091	$ -	$ 515,345
Cummulative	2015	$ 27,928,452	$ 9,557,998	$ 775,646	$ 180,848	$ -	$ 3,085,737
Annual		$ 7,131,135	$ 1,998,723	$ 218,913	$ 78,623	$ -	$ 878,596
Cummulative	2016	$ 35,877,471	$ 11,995,015	$ 1,034,204	$ 265,538	$ -	$ 4,113,033
Annual		$ 7,949,020	$ 2,437,017	$ 258,558	$ 84,690	$ -	$ 1,027,296

Total LFCR $	Incremental	% of Total Rev Assume $950 mil	Total Accum lost revenues	Incremental Recovery rate	Accum Recovery rate per kWh
$ 7,319,945					
$ 7,319,945					
$ 14,903,012					
$ 7,583,066	7,583,066	0.80%			
$ 20,002,755					
$ 5,099,743	$ 5,099,743	0.54%	$20,365,876	$ 0.000549	$ 0.002183
$ 31,222,690					
$ 8,874,775	$ 8,874,775	0.93%	$41,823,461	$ 0.000956	$ 0.004504
$ 41,528,681					
$ 10,305,991	$ 10,305,991	1.08%	$73,687,036	$ 0.001110	$ 0.007936
$ 53,285,262					
$ 11,756,581	$ 11,756,581	1.24%	$117,307,193	$ 0.001266	$ 0.012634

notes:
- Initial filed rate and total dollars (assumes sales of 9,285,000,000 kWh)
- 2011 lost revenues are excluded from recovery amount , but included in accumulated lost kWh

The volumetric rates calculated for Res, Comm and Ind above are using the tail block revenues for both summer and winter divided by the combined kWh, resulting in a weighted average price.
This calculation was made for both the existing rates and the proposed rates. (Example: TY revenues for all usage >500 kWh was $81,431,764 + $2,268,588 summer and $34,390,624+$423,195 winter divided by equivelent combined volumes totaling 1,820,323,613 kWh)
This data can be found in the individual classes data provided in the file named "6. 2012 TEP Proposed Rates - Corrected". For Residential Standard reference Columns E, G and I lines 5, 6, 9 and 10.

EE related KWh	Year	Residential	Commercial	Industrial	Other	Demand KW Commercial	Demand KW Industrial	EE or DG Goal	Total Lost kWh	Lost kWh as % of 9,285 GWh
Cummulative	2011	47,637,346	10,301,591	7,646,868	163,289	16,246	11,887	1.02%	65,749,093	0.7081%
Annual		47,637,346	10,301,591	7,646,868	163,289	16,246	11,887			
Cummulative	2012	106,381,459	22,438,136	26,663,305	959,822	37,285	44,330	2.44%	158,442,721	1.6849%
Annual		58,744,113	12,136,545	19,016,437	796,533	21,038	32,443			
Cummulative	2013	144,166,349	23,839,971	28,328,933	1,077,257	38,342	45,562	4.15%	197,412,510	2.1351%
Annual		37,784,890	1,401,836	1,665,628	117,436	1,058	1,232			
Cummulative	2014	211,410,864	37,873,577	38,372,988	1,308,898	61,514	62,102	6.21%	288,966,327	3.1132%
Annual		67,244,515	14,033,606	10,044,055	231,641	23,172	16,540			
Cummulative	2015	296,025,572	60,612,174	64,127,444	2,315,599	98,215	103,940	7.21%	425,083,789	4.5966%
Annual		84,617,708	22,738,597	25,754,455	1,006,701	36,701	41,838			
Cummulative	2016	384,870,273	88,337,055	94,546,051	3,399,979	142,802	152,859	9.22%	571,153,359	6.1514%
Annual		88,841,701	27,724,881	30,418,608	1,084,380	44,587	48,919			

DG related KWh	Year	Residential	Commercial	Industrial	Other	Demand KW Commercial	Demand KW Industrial			
Existing	2011	26,774,143	12,781,661	4,000,000			8,000	0.35%	43,555,804	0.4691%
Incremental		26,774,143	12,781,661	4,000,000	-		8,000			
Existing	2012	34,056,137	25,375,000	6,625,000			16,000	0.70%	66,056,137	0.7114%
Incremental		7,281,994	12,593,339	2,625,000			8,000			
Existing	2013	47,965,612	34,125,000	27,125,000			35,000	1.05%	109,215,612	1.1763%
Incremental		13,909,475	8,750,000	20,500,000			19,000			
Existing	2014	54,880,008	48,125,000	27,125,000			43,000	1.40%	130,130,008	1.4015%
Incremental		6,914,396	14,000,000	-			8,000			
Existing	2015	61,570,040	48,125,000	27,125,000			43,000	1.75%	136,820,040	1.4736%
Incremental		6,690,032	-	-			-			
Existing	2016	74,508,361	48,125,000	27,125,000			43,000	2.10%	149,758,361	1.6129%
Incremental		12,938,321	-	-			-			

EE and DG percentage changes reflect adjustments for allowed credits

LFCR related KWh	Year	Residential	Commercial	Industrial	Other	Demand KW Commercial	Demand KW Industrial	
Existing	2011	74,411,489	23,083,252	11,646,868	163,289	16,246	19,887	109,354,897
Incremental		74,411,489	23,083,252	11,646,868	163,289	16,246	19,887	
Existing	2012	140,437,596	47,813,136	33,288,305	959,822	37,285	60,330	222,498,855
Incremental		66,026,107	24,729,884	21,641,437	796,533	21,038	40,443	
Existing	2013	192,131,961	57,964,971	55,453,933	1,077,257	38,342	80,562	306,628,122
Incremental		51,694,365	10,151,836	22,165,628	117,436	1,058	20,232	
Existing	2014	266,290,872	85,998,577	65,497,988	1,308,898	61,514	105,102	419,086,335
Incremental		74,158,911	28,033,606	10,044,055	231,641	23,172	24,540	
Existing	2015	357,598,612	108,737,174	91,252,444	2,315,599	98,215	146,940	559,903,829
Incremental		91,307,740	22,738,597	25,754,455	1,006,701	36,701	41,838	
Existing	2016	459,378,634	136,462,055	121,671,051	3,399,979	142,802	195,859	720,911,720
Incremental		101,780,022	27,724,881	30,418,608	1,084,380	44,587	48,919	

Choose 1 to retain Company's start position and 3 for Staff's start position

1.5

Choose 1 for Company's position and 3 for Staff's position of using 0% of Generation

3

LFCR Rates	Year	Residential	Commercial	Industrial	Other	Demand KW Commercial	Demand KW Industrial
	2011	$ -	$ -	$ -	$ -		$ -
	2012	$ -	$ -	$ -	$ -		$ -
	2013	$ 0.028550	$ 0.026050	$ 0.004250	$ 0.028550		$ 6.38
	2014	$ 0.057100	$ 0.056100	$ 0.008500	$ 0.057100		$ 12.75
	2015	$ 0.057100	$ 0.056100	$ 0.008500	$ 0.057100		$ 12.75
	2016	$ 0.057100	$ 0.056100	$ 0.008500	$ 0.057100		$ 21.00

Generation Component in Rates	Year	Residential	Commercial	Industrial	Other	Demand KW Commercial	Demand KW Industrial
	2011	$ 0.031605	$ 0.027224	$ -	$ 0.031605		$ 12.83
	2012	$ 0.031605	$ 0.027224	$ -	$ 0.031605		$ 12.83
	2013	$ 0.031605	$ 0.027224	$ -	$ 0.031605		$ 12.83
	2014	$ 0.021000	$ 0.031800	$ -	$ 0.021000		$ 8.25
	2015	$ 0.021000	$ 0.031800	$ -	$ 0.021000		$ 8.25
	2016	$ 0.021000	$ 0.031800	$ -	$ 0.021000		$ 8.25

LFCR Revenues	Year	Residential	Commercial	Industrial	Other	Commercial	Industrial
Cummulative	2011	$ -	$ -	$ -	$ -	$ -	$ -
Annual		$ -	$ -	$ -	$ -	$ -	$ -
Cummulative	2012	$ -	$ -	$ -	$ -	$ -	$ -
Annual		$ -	$ -	$ -	$ -	$ -	$ -
Cummulative	2013	$ 5,485,367	$ 1,625,917	$ 235,679	$ 30,756	$ -	$ 513,581
Annual		$ 1,475,874	$ 254,759	$ 94,204	$ 3,353	$ -	$ 178,979
Cummulative	2014	$ 15,205,209	$ 4,824,520	$ 556,733	$ 74,738	$ -	$ 1,340,049
Annual		$ 4,234,474	$ 1,572,685	$ 85,374	$ 13,227	$ -	$ 312,888
Cummulative	2015	$ 26,418,881	$ 8,300,155	$ 775,646	$ 132,221	$ -	$ 1,873,483
Annual		$ 5,213,672	$ 1,275,635	$ 218,913	$ 57,483	$ -	$ 533,434
Cummulative	2016	$ 36,230,520	$ 7,655,521	$ 1,034,204	$ 194,139	$ -	$ 4,113,033
Annual		$ 9,811,639	$ 1,555,366	$ 258,558	$ 61,918	$ -	$ 1,027,296

Total LFCR $	Incremental	% of Total Rev Assume $950 mil	Total Accum lost revenues	Incremental Recovery rate	Accum Recovery rate per kWh
$ -					
$ -					
$ -		0.00%			
$ 7,891,301					
$ 1,987,168	$ 1,987,168	0.21%	$1,987,168	$ 0.000214	$ 0.000214
$ 22,001,249					
$ 6,218,648	$ 6,218,648	0.65%	$10,192,985	$ 0.000670	$ 0.001098
$ 29,300,386					
$ 7,299,137	$ 7,299,137	0.77%	$25,697,938	$ 0.000786	$ 0.002768
$ 39,227,417					
$ 8,714,777	$ 8,714,777	0.92%	$49,917,669	$ 0.000939	$ 0.005376

notes: -Initial fixed rate and total dollars (assumes sales of 9,285,000,000 kwh)

-2013 lost revenues are excluded from recovery amount , but included in accumulated lost kWh

The volumetric rates calculated for Res, Comm and Ind above are using the tail block revenues for both summer and winter divided by the combined kWh, resulting in a weighted average price.

This calculation was made for both the existing rates and the proposed rates. (Example, TY revenues for all usage >500 kWh was $81,431,764 + $2,268,588 summer and $34,390,624+$43,195 winter divided by equivalent combined volumes totaling 1,820,323,618 kWh)

This data can be found in the individual classes data provided in the file named "6. 2012 TEP Proposed Rates - Corrected". For Residential Standard reference Columns E, G and I lines 5, 6, 9 and 10.

Staff has retained the Company's tailblock rate concept SOLELY for the purposes of calculation; see testimony for Staff's position.