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BEFORE THE ARIZONA CORPORATION COMMISSION

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IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	Docket No. E-01933A-12-0291

NOTICE OF FILING

The Residential Utility Consumer Office ("RUCO") hereby provides notice of filing the Redacted Supplemental Direct Testimony of Frank Radigan and Paul Goetz and the Supplemental Direct Testimony of Robert Mease, the Direct Testimony of Robert Mease on Rate Design and the Direct Testimony on Energy Efficiency Resource Plan, in the above-referenced matter.

RESPECTFULLY SUBMITTED this 11th day of January, 2013.

Daniel Pozefsky
Chief Counsel

Arizona Corporation Commission
DOCKETED

JAN 11 2013

DOCKETED BY

AN ORIGINAL AND THIRTEEN COPIES
of the foregoing filed this 11th day
of January, 2013 with:

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

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By Cheryl Fraulob
Cheryl Fraulob

TUCSON ELECTRIC POWER COMPANY

DOCKET NO. E-01933A-12-0291

REDACTED SUPPLEMENTAL DIRECT TESTIMONY

OF

FRANK W. RADIGAN

AND

PAUL GOETZ

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JANUARY 11, 2013

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Based on our examination of additional construction program information provided by Tucson Electric power Company, we have revised our original recommendation on the appropriate level of utility plant in service that should be recovered in rates.

RUCO recommends that distribution plant in service for 2011 be reduced by $70 million, which results in a reduction in required revenue of approximately $8.4 million compared to RUCO's original recommendation of $21 million.

INTRODUCTION

Q. PLEASE STATE YOUR FULL NAMES AND ADDRESSES.

A. My name is Frank W. Radigan. I am a principal in the Hudson River Energy Group and my office address is 237 Schoolhouse Road, Albany, New York 12203. My name is Paul Goetz. I am a partner in the firm of Bollam, Sheedy, Torani, & CO. LLP, CPAs and my office address is 26 Computer Drive West, Albany, NY

Q. ARE YOU THE SAME FRANK RADIGAN AND PAUL GOETZ THAT PREVIOSULY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes. When RUCO submitted initial testimony it stated that it continued to gather information on the Company's budget process and supporting justification for its construction program. RUCO further stated that it wanted the opportunity to revise the adjustment to plant in service when rate design testimony was filed if RUCO received acceptable supporting documentation from the Company.

Q. HAVE YOU PREPARED ANY EXHIBITS IN SUPPORT OF YOUR RECOMMENDATIONS?

A. Yes, RUCO has prepared the following exhibits:

Exhibit_FWR-PG-18 Planning Memorandum on New Substations

Exhibit_FWR-PG-19 Lateral 7.5 Transformer Upgrade

Exhibit_FWR-PG-20 Drexel C-44 Reconductor

Exhibit_FWR-PG-21 Excerpt from UNS 2011 10-K Report

Exhibit_FWR-PG-22 Fitch Ratings Report on Bonus Depreciation

FINDINGS AND RECOMMENDATIONS

Q. HAVE YOU HAD THE OPPORTUNITY TO CONTINUE YOUR INVESTIGATION INTO THE REASONABLENESS OF THE COMPANY'S CONSTRUCTION PROGRAM?

A. Yes, through further information exchange the Company was able to provide additional information on the justification for many projects. After submission of initial testimony, the Company was able to provide the justification for the projects done at the generating stations since the last rate case. The work orders are reasonable and support the money expended. The Company was also able to provide one year of a complete construction budget from the time it was initially reviewed by management up to the presentation to the Board of Directors in December of 2010. Finally, the Company provided a spreadsheet summarizing the expenditures by year for each of its budget categories in sufficient detail so as to be able to tie them back to a significant number of the planning memoranda already provided. All of this material was adequate to confirm that the Company has a reasonable planning process.

That said, RUCO still believes that a reduction to rate base is appropriate to reflect the fact that the Company has had an aggressive construction program in anticipation of load that has not materialized and probably will not materialize anytime soon.

Q. PLEASE EXPLAIN WHY A REDUCTION IN RATE BASE IS APPORPRIATE

A. [BEGIN CONFIDENTIAL

END CONFIDENTIAL].

[BEGIN CONFIDENTIAL

END CONFIDENTIAL].

Q. PLEASE DISCUSS THE IMPLICATIONS OF THIS OVERCAPACITY SITUATION.

A. Building a new substation takes time; from the siting, planning and construction, it may take anywhere from 3-5 years. Transformers are sized in certain increments and cannot be changed out in tiny increments as load grows. Because of this, substations are sized to not only meet current load needs, but future load needs as well. This is also true for production plants and transmission plants. As such, substation construction results in a "step function" between available capacity and load served. In the utility business this is referred to as "lumpiness" of capacity and is generally acceptable, as it is more economic to make room for excess capacity to accommodate growth in the future. There is, however, a point where the lumpiness cannot be justified under current conditions and the regulator must ascertain how much of the cost can be allowed in rates.

Another way to look at this is how it relates to risk. Should the regulator consider the Company's request to include the overcapacity, then it is the ratepayer who bears the risk of future growth. In other words, the current ratepayers will be paying for growth that may or may not occur. It is not fair, nor reasonable, to shift the risk onto the ratepayer.

From a strict regulatory standpoint, the current ratepayer should not pay for plant that is not being used. This is a basic regulatory principle. Excess plant capacity that is not being used should not be paid for by current ratepayers. Of course, the question of whether building this much capacity was even prudent is another and separate issue.

The Company's methodology for planning new substations is to review the zoning in the area and develop an estimate of what the load would be assuming that the area was fully developed. The Company's planning assumption is that one residential customer could use up to 5 kVA of substation capacity, so a 100 MVA substation can serve 20,000 homes. When the substation was planned, the load in the area was projected to grow at an annual rate of 2 MVA per year. Even considering that subdivisions bring a large amount of load all at once, this new substation was built to accommodate many years of growth.

[BEGIN CONFIDENTIAL

END CONFIDENTIAL]. The planning memorandum for each of these substations is attached as Exhibit__FWR-PG-18

Q. IN REVIEWING THE COMPANY'S CONSTRUCTION PROGRAM, IS IT EASY TO DISCERN WHICH PROJECTS WERE DONE FOR PURELY FORECASTED LOAD GROWTH?

A. Not always; some projects are recorded for multiple reasons while others are simply placed in a separate budget category (other than "New Business") that is not typically associated with forecasts or projected growth. Also, the project descriptions do not always fully explain why the work is being done. [BEGIN CONFIDENTIAL

END CONFIDENTIAL]. The project justification memorandum is attached as Exhibit__FWR-PG-19

.

[BEGIN CONFIDENTIAL

END CONFIDENTIAL].

[BEGIN CONFIDENTIAL

END CONFIDENTIAL]. The project planning memorandum is attached as Exhibit__FWR-PG-20.

Q. COULD THE UTILITY PUT ANY OF THESE SUBSTATION PROJECTS ON HOLD WHEN CUSTOMER GROWTH WAS ANTICIPATED?

A. Yes, easily. As explained previously, the actual completion of a substation from initial planning to commercial operation can be a long process, but that does not mean the actual construction is time-consuming. A brand new substation has standardized plans and specifications with parts that can be used in almost any modern [ear substations] that the Company owns. The previously discussed Canoa Ranch substation took a matter of months to construct. As such, the construction could be delayed a year or two without any material impact on the system. For example, the Cienega substation was first contemplated to be in-service in June 2008 but was delayed until July 2010.

Q. ARE THERE ANY OTHER FACTORS YOU KNOW OF THAT WOULD INFLUENCE THE UTILITY TO ACCELERATE CONSTRUCTION?

A. Yes, provisions included in the 2010 Federal Tax Relief Act provided for a 100% bonus depreciation deduction for qualified property placed in service between 9/8/2010 and 1/1/2012. Provisions also provide for a 50% bonus deprecation deduction for property placed in service in 2012. For 2011, there were no limits on the amount of qualified property placed in service that would be eligible for the accelerated deduction. UNS (as well as other utilities throughout the United States) took advantage of the accelerated depreciation deduction in 2011 as disclosed in its Form 10-K for 2011 (See Exhibit__FWR-PG-21 Excerpt from UNS 2011 10-K).

The 100% bonus depreciation deduction effectively provides for the expensing of qualified purchases rather than recovering the cost of such assets over their respective tax lives. The use of the bonus depreciation deduction has no impact on book depreciation amounts. The benefit of utilizing the deduction is to reduce current taxes by deferring income tax payments to future years. Cash flow accelerated as tax payments are delayed. For book purposes, deferred tax liabilities are created for the tax impact of the additional tax depreciation over book depreciation. Such differences would equal out over the book depreciation lives of the respective assets. The use of the accelerated depreciation may result in

Net Operating Losses (NOLs) that can be carried forward to offset taxable income in future periods.

FitchRatings issued a special report – *Bonus Depreciation in the U.S. Utility Industry* on March 7, 2011. The report noted that the bonus depreciation would result in the "significant acceleration of cash flow" due to the deferral of cash taxes. Fitch also notes that in rate-regulated utilities, the effect of bonus depreciation is to shift regulatory revenue requirements from current years to future years. Fitch also noted that bonus depreciation is anticipated to significantly improve funds from operations (FFO) and associated credit ratios (e.g. FFO interest coverage and FFO-to-debt) for certain utility and power companies in 2011 and 2012 as a result of the associated tax deferrals. (See Exhibit__FWR-PG-22 FitchRatings Report).

As disclosed in the Unisource 10-K for 2011, the use of bonus depreciation in 2011 resulted in a no taxes paid for TEP in 2011 and the Company anticipated no taxes being paid in 2012 as well. Capital spending in 2011 was $343 million for TEP compared to $278 million for 2010 and compared to the 2007-2010 four year average of $240 million.

Q. HOW DO YOU PROPOSE TO MAKE AN ADJUSTMENT TO THE COMPANY'S PLANT IN SERVICE TO REFLECT THE OVER CAPACITY THAT YOU DISCUSSED PREVOUSLY?

A. RUCO recommends that distribution plant in service for 2011 be reduced by $70 million. This adjustment was arrived at by reducing by one-half the plant additions related to new substations and the budget categories Load Redistribution, Reliability Improvements, New Business, and Equipment Replacement Substations. It is these budget categories that contain the projects discussed above and are mostly related to forecast new load. [BEGIN CONFIDENTIAL

END CONFIDENTIAL]. This adjustment is not meant to reflect the elimination of any one substation project or any one project under the other budget categories, though a case could be made that such adjustments could be done. [BEGIN CONFIDENTIAL

END CONFIDENTIAL]. To do such adjustments, however, would take a great deal more time and would require full access to all of the Company's complete budget material (which is not available). Rather, this adjustment is meant to reflect an elimination of a portion, but not an insignificant portion, of plant additions where a material amount of money has been invested in projects designed around optimistic growth assumptions and where such investments will not be fully used and useful for a long time into the future.

Q. ARE YOU CHANGING YOUR ADJUSTMENT TO RATEBASE FROM YOUR DIRECT POSITION?

A. Yes. As explained above in direct testimony RUCO was still looking at information and would supplement the initial testimony with its rate design filing. Based on responses to Data Requests, meetings with the Company and additional analysis, RUCO is modifying its rate base adjustments to reflect the updated and new information.

Q. WHAT IS THE FINANCIAL IMPACT ON THE UTILITY FROM YOUR RECOMMNEDED ADJUSTMENT?

A. The revenue requirement impact on this case is a reduction of approximately $8.4 million (compared to our original recommendation of $21 million). The adjustments themselves will be supplemented, detailed and identified in the supplemental schedules being filed with RUCO's rate design testimony. As RUCO discussed in initial testimony, this is not a permanent financial impact to the utility because when customer growth comes back, the utility will benefit from increased revenues. [BEGIN CONFIDENTIAL

END CONFIDENTIAL]. Seen from this perspective, the Company will be made whole when its load projections come to fruition.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

EXHIBITS
FWR-PG-18 THRU FWR-PG-20
CONFIDENTIAL

EXHIBIT_FWR-PG-21

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

[X] **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2011
OR

[ ] **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from _________to ________.

Commission File Number	Registrant; State of Incorporation; Address; and Telephone Number	IRS Employer Identification Number
1-13739	**UNISOURCE ENERGY CORPORATION** (An Arizona Corporation) 88 E. Broadway Boulevard Tucson, AZ 85701 (520) 571-4000	86-0786732
1-5924	**TUCSON ELECTRIC POWER COMPANY** (An Arizona Corporation) 88 E. Broadway Boulevard Tucson, AZ 85701 (520) 571-4000	86-0062700

Securities registered pursuant to Section 12(b) of the Exchange Act:

Registrant	Title of Each Class	Name of Each Exchange on Which Registered
UniSource Energy Corporation	**Common Stock, no par value**	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Exchange Act:

Registrant	Title of Each Class	Name of Each Exchange on Which Registered
Tucson Electric Power Company	**Common Stock, without par value**	**N/A**

Indicate by check mark if the registrant is a well known seasoned issuer, as defined in Rule 405 of the Securities Act of 1933.

UniSource Energy Corporation Yes __X__ No____
Tucson Electric Power Company Yes _____ No_X_

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934 (Exchange Act).

UniSource Energy Corporation Yes _____ No_X__
Tucson Electric Power Company Yes ____ No_X_

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

UniSource Energy Corporation Yes __X__ No____
Tucson Electric Power Company Yes__X__ No____

(9) In January 2012, UniSource Energy redeemed $35 million of its convertible senior notes. Pursuant to the redemption, substantially all of the notes were converted into approximately 1 million shares of UniSource Energy Common Stock.

We have reviewed our contractual obligations and provide the following additional information:

- We do not have any provisions in any of our debt or lease agreements that would cause an event of default or cause amounts to become due and payable in the event of a credit rating downgrade.
- None of our contracts or financing arrangements contains acceleration clauses or other consequences triggered by changes in our stock price.

Dividends on Common Stock

On February 24, 2012, UniSource Energy declared a first quarter cash dividend of $0.43 per share on its common stock. The first quarter dividend, totaling approximately $16 million, will be paid March 22, 2012 to shareholders of record at the close of business March 12, 2012. The table below summarizes UniSource Energy's dividends paid in 2009 through 2011.

	2011	2010	2009
Quarterly Dividend Per Common Share	$0.42	$0.39	$0.29
Annual Dividend Per Common Share	$1.68	$1.56	$1.16
Common Stock Dividends Paid	$62 million	$57 million	$41 million

Income Tax Position

As of December 31, 2011, UniSource Energy and TEP had the following carry-forward amounts:

	UniSource Energy		TEP	
	Amount	Expiring Year	Amount	Expiring Year
	-Amounts in Millions of Dollars-			
Capital Loss	$ 8	2015	$ -	-
Federal Net Operating Loss	230	2031	212	2031
State Net Operating Loss	-	2016	13	2016
State Credits	1	2016	2	2016
AMT Credit	43	None	25	None

The 2010 Federal Tax Relief Act includes provisions that make qualified property placed into service between September 8, 2010 and January 1, 2012 eligible for 100% bonus depreciation for tax purposes. The same law makes qualified property placed in service during 2012 eligible for 50% bonus depreciation for tax purposes. This is an acceleration of tax benefits UniSource Energy otherwise would have received over 20 years. As a result of these provisions, UniSource Energy did not pay any federal income taxes for the tax year 2011 and does not expect to pay any federal income taxes for 2012.

TUCSON ELECTRIC POWER COMPANY

RESULTS OF OPERATIONS

Executive Summary

TEP's financial condition and results of operations are the principal factors affecting the financial condition and results of operations of UniSource Energy. The following discussion relates to TEP's utility operations, unless otherwise noted.

2011 Compared with 2010

TEP recorded net income of $85 million in 2011 compared with $108 million in 2010. The following factors contributed to the decrease in TEP's net income:

EXHIBIT_FWR-PG-22

Utilities, Power, & Gas
U.S.
Special Report

Bonus Depreciation in the U.S. Utility Industry

Analysts

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Bonus Depreciation: Following the Cash

For U.S. companies in the utilities sector with substantial qualifying assets entering commercial service in 2011, bonus depreciation, if elected, will result in a significant acceleration of cash flow because of associated deferrals of cash taxes. A U.S. federal economic and job stimulus bill passed in December 2010 permits taxpayers to depreciate 100% of the cost of eligible, newly installed equipment after Sept. 8, 2010 and before Jan. 1, 2012. The first-year depreciation rate will fall to 50% of the cost of equipment that enters service in 2012. For a full explanation, see the Background of Bonus Depreciation on page 3.

The effect of bonus depreciation is to shift forward cash flow by deferring tax payments to later years. Bonus depreciation increases after-tax cash flow in the year that the cost of the new equipment is taken as a tax deduction, and it decreases after-tax cash flows in later years as deferred tax liabilities are reduced and cash tax payments increased. All other things being equal, the sum of cash flows over time is unchanged, but the timing of the receipt of the cash flow is more front-loaded and lumpier with enhanced cash flow at the beginning and subsequently more tax payment outflows. This is illustrated in the Hypothetical Bonus Depreciation Example table on page 4.

Bonus depreciation is anticipated to significantly improve funds from operations (FFO) and associated credit ratios (e.g. FFO interest coverage and FFO-to-debt) for certain utility and power companies in 2011 and 2012 as a result of the associated tax deferrals. In later years, FFO credit metrics and cash flow could become pressured as deferred taxes payable become cash taxes. Fixed income investors should watch out for these potential boomerangs.

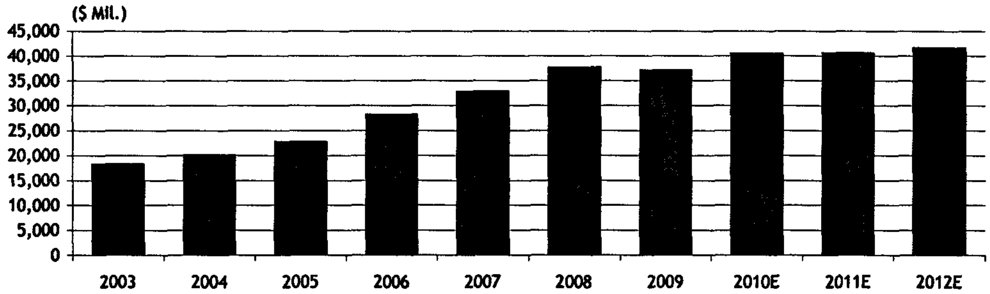
Some additional guideline credit ratios that Fitch normally reviews are based on earnings before interest, tax, depreciation, and amortization (EBITDA). EBITDA credit measures are not affected by tax filings using bonus depreciation and provide a more normalized point of view that excludes the impacts of large early cash inflow or longer term cash outflows that are associated with bonus depreciation. When Fitch compares both sets of ratios, it makes more visible the effects of various tax shelter mechanisms such as bonus depreciation, investment tax credits, and net operating loss carry-forwards and carry-backs.

Despite any concerns about increasing cash tax payments in future years, Fitch notes that there may be some offsetting favorable credit implications for companies electing bonus depreciation, depending upon the uses of the near-term cash flow from temporarily reduced tax payments. There is a small positive net present value impact of bonus depreciation for many companies. On balance, Fitch anticipates no rating upgrades as a result of the temporary improvement in FFO credit metrics that will result from bonus depreciation.

High Sector Capital Spending Produces Opportunities for Bonus Depreciation

The regulated utilities sector is one the most capital intensive sectors of the economy. Sector capital spending increased significantly in the prior decade and is anticipated to remain relatively elevated in 2011 and 2012. Much of the capital spending, including maintenance capital spending and new qualifying assets that enter service, is eligible for bonus depreciation.

35 Operating Utilities Capex Summary



E – Estimate.
Source: Fitch Ratings.

Good, Bad, or Mixed for Credit Ratings?

From a credit ratings perspective, one of the key considerations relating to bonus depreciation is how related cash is utilized. If the cash is used to reduce debt issuance, pre-fund the pension plan, or partially fund capital spending for the core business, that would be considered neutral to positive for credit. On the other hand, credit rating concerns may emerge if the cash is used disproportionately for share buybacks or other shareholder-friendly initiatives as eventually the tax bills will become due. If there were no balance sheet improvements or capital spending that produced cash flow with the bonus depreciation cash proceeds, then this may be a rating concern. Fitch analysts will track if the use of the cash is used for credit or equity friendly purposes. See Appendix 2 for a summary of 2010 issuer earnings call disclosures on bonus depreciation amounts and use of proceeds.

Analysts must also consider whether and how the utilization of bonus depreciation changes the leverage of individual issuers within a corporate group. For example, bonus depreciation at an operating subsidiary could change the timing of its individual tax payments and influence upstream dividend payment amounts. This would result in higher or lower parent debt than would otherwise be expected.

For rate-regulated utilities in many states, the effect of bonus depreciation is to shift regulatory revenue requirements and revenues from current years to later years. In certain states, calculation of regulatory rate base requires deducting deferred taxes from net utility assets. Thus, for a regulated utility facing a near-term base rate case or earnings review, the high tax deferrals associated with 100% bonus tax depreciation in the test year could reduce rate base and the related revenue requirement in a single year. Then in subsequent years, as the tax deferral is amortized, the rate base and regulated revenue requirements would gradually increase. In this case the revenue requirements are to later years. This is not a consideration for those utilities that have multi-year rate settlements in effect and are not contemplating a rate filing until 2012–2013, nor is it a consideration for companies in the power and gas sector that are not utilities and not subject to regulated tariffs.

Bonus depreciation will make it more difficult to discern a company's sequential FFO trends and to perform peer comparisons because of bonus depreciation FFO distortions. It is important that credit analysts understand the significance of bonus-deprecation-related cash flow to total cash flow; or, said another way, how much of the 2011 and 2012 total cash flow is nonrecurring and how much FFO-based credit metrics will decline when the cash inflows from bonus depreciation are no longer available and deferred taxes become payable in cash. Other tax considerations such as net operation loss (NOL) carry-forwards may also influence FFO. For issuers with NOLs, the net cash effect of bonus depreciation would extend the period of time that the issuer will benefit from an NOL position and pay less cash taxes.

Background of Bonus Depreciation

Bonus depreciation is an increasingly common form of tax relief and economic stimulus. It has been implemented several times on a national level and also in targeted geographic regions, such as to provide stimulus in the Gulf Coast region after Hurricane Katrina. The power sector has opportunities to use depreciation due to its high capital intensity. Environmental compliance and renewable mandates and investments for system growth and reliability will keep capital spending elevated

The most recent round of bonus depreciation stems from the U.S. Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010 (2010 Tax Relief Act) that was signed into law on Dec. 17, 2010. The Tax Relief Act provides up to 100% bonus depreciation through 2011 and reverts to 50% bonus depreciation for 2012. To be eligible for bonus deprecation under the Tax Relief Act, a qualifying asset property must be acquired or placed in service between Sept. 8, 2010 and Dec. 31, 2011 and have a useful life of 20 years or less. There remains some uncertainty regarding the particulars of bonus deprecation, which is anticipated to be clarified by IRS guidance expected to be released in March 2011. As a result, some companies' guidance on the amount of related cash flow includes wide ranges.

Prior to the Tax Relief Act, the American Recovery and Reinvestment Act of 2009 also provided for bonus depreciation. While there have been sequential rounds of tax relief via bonus depreciation over the past 10 years, Fitch recognizes the temporary nature of the incremental cash flow from this source.

Appendix 1

Hypothetical Bonus Depreciation Example

Assume that Company purchases an asset for $100 in Year 1. Further assume Company purchases another asset for $100 in Year 2. Both assets have a book life of 10 years and a tax life of five years.

The tables below show selected line items from the income statement, cash flow, and balance sheet with and without bonus depreciation. The key point is that there is no difference in the cumulative amount of cash flow over time from bonus depreciation, except for the net present value effect of tax deferrals. Cash flow is accelerated and tax payments are delayed.

Hypothetical Bonus Depreciation Example

Assume that Company purchases an asset for $100 in Year 1. Further assume Company purchases another asset for $100 in Year 2. Both assets have a book life of 10 years and a tax life of five years.

	Without Bonus								With Bonus							
	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total
Assumptions																
Asset 1 — Put in Service	100	—	—	—	—	—	—	—	100	—	—	—	—	—	—	—
Asset 2 — Put in Service	—	100	—	—	—	—	—	—	—	100	—	—	—	—	—	—
Tax Rate (%)	35	35	35	35	35	35	35	—	35	35	35	35	35	35	3	—
Regular Tax Depreciation Asset 1[a]	(20)	(32)	(19)	(12)	(12)	(6)	—	(100)	—	—	—	—	—	—	—	—
Bonus Tax Depreciation Asset 1	—	—	—	—	—	—	—	—	(100)	—	—	—	—	—	—	(100)
Regular Tax Depreciation Asset 2[a]	—	(20)	(32)	(19)	(12)	(12)	(6)	(100)	—	—	—	—	—	—	—	—
Bonus Tax Depreciation Asset 2	—	—	—	—	—	—	—	—	—	(100)	—					(100)
Total Tax Depreciation	**(20)**	**(52)**	**(51)**	**(31)**	**(23)**	**(17)**	**(6)**	**(200)**	**(100)**	**(100)**	—	—	—	—	—	**(200)**
Income Statement																
Revenues	200	200	200	200	200	200	200	—	200	200	200	200	200	200	200	—
Expenses	(30)	(30)	(30)	(30)	(30)	(30)	(30)	—	(30)	(30)	(30)	(30)	(30)	(30)	(30)	—
Book Depreciation	(10)	(20)	(20)	(20)	(20)	(20)	(20)	—	(10)	(20)	(20)	(20)	(20)	(20)	(20)	—
Pretax Book Income	160	150	150	150	150	150	150	1,060	160	150	150	150	150	150	150	1060
Current (Cash) Tax Expense	(53)	(41)	(42)	(49)	(51)	(53)	(57)	(347)	(25)	(25)	(60)	(60)	(60)	(60)	(60)	(347)
Deferred Tax Expense	(4)	(11)	(11)	(4)	(1)	1	5	(25)	(32)	(28)	7	7	7	7	7	(25)
Total Tax Expense	**(56)**	**(53)**	**(53)**	**(53)**	**(53)**	**(53)**	**(53)**	**(371)**	**(56)**	**(53)**	**(53)**	**(53)**	**(53)**	**(53)**	**(53)**	**(371)**
Net Income	104	98	98	98	98	98	98	689	104	98	98	98	98	98	98	689
Effective Tax Rate (%)	35	35	35	35	35	35	35	—	35	35	35	35	35	35	35	—
Balance Sheet																
Cash	118	246	375	496	614	731	844	—	146	291	402	512	623	733	844	—
Asset	100	200	200	200	200	200	200	—	100	200	200	200	200	200	200	—
Accumulated Book Depreciation	(10)	(30)	(50)	(70)	(90)	(110)	(130)	—	(10)	(30)	(50)	(70)	(90)	(110)	(130)	—
Total Assets	**208**	**416**	**525**	**626**	**724**	**821**	**914**	—	**236**	**461**	**552**	**642**	**733**	**823**	**914**	—
Deferred Tax Liability	4	15	26	29	30	29	25	—	32	60	53	46	39	32	25	—
APIC	100	200	200	200	200	200	200	—	100	200	200	200	200	200	200	—
Retained Earnings	104	202	299	397	494	592	689	—	104	202	299	397	494	592	689	—
Total Liabilities and Equity	**208**	**416**	**525**	**626**	**724**	**821**	**914**	—	**236**	**461**	**552**	**642**	**733**	**823**	**914**	—
Cash Flows — Indirect Method																
Net Income	104	98	98	98	98	98	98	689	104	98	98	98	98	98	98	689
Remove Non-Cash Items:																
Book Depreciation	10	20	20	20	20	20	20	130	10	20	20	20	20	20	20	130
Deferred Taxes	4	11	11	4	1	(1)	(5)	25	32	28	(7)	(7)	(7)	(7)	(7)	25
Total Cash Flows	**118**	**129**	**128**	**121**	**119**	**117**	**113**	**844**	**146**	**146**	**111**	**111**	**111**	**111**	**111**	**844**
Cash Flow Difference Bonus Case vs. No Bonus Case								28	17	(18)	(11)	(8)	(6)	(2)	0	—
Difference in Current (Cash) Tax Bonus Case vs. No Bonus Case								28	17	(18)	(11)	(8)	(6)	(2)	0	—
Unexplained Difference								—	—	—	—	—	(0)	(0)	—	—

[a]Based on five-year MACRS (modified accelerated cost recovery system).
Source: Fitch Ratings.

Appendix 2

Examples of Company Disclosures from 2010 Earnings Calls

Issuer/(IDR, Outlook)	Estimated Amount	Use of Cash Proceeds	Other Comments
Alliant Energy Corp. (Not Rated)	Not disclosed.	Not disclosed.	Due to bonus depreciation and mixed service cost, no material federal cash tax payments expected through 2015.
American Electric Power Co. (BBB, Stable)	$1.2 billion between 2011 and 2013.	Invest proceeds in growth capex, reduce need for debt financing, fund pension and lawsuit settlement payment.	—
Black Hills Corp. (BBB, Stable)	Not disclosed.	Not disclosed.	Due to bonus depreciation, BKH accelerated $40 million of capex from 2011 into 2010. Fitch assumes significant bonus depreciation benefit given $500 million of spending for two generation projects to be in service by year-end 2011.
Centerpoint Energy, Inc. (BBB–, Stable)	Up to $500 million in 2011 and more than $50 million in 2012.	Fund capital expenditure program.	—
CMS Energy (BB+, Stable)	Not disclosed.	Not disclosed.	NOLs at the parent are significant source of tax reduction. Bonus depreciation will extend the life of NOLs.
Dominion Resources, Inc. (BBB+, Stable)	$1.6 billion–$2.5 billion between 2011 and 2013.	Share buyback $400 million–$700 million in 2011; reduce need for debt issuance in 2012.	—
DTE Energy Corp. (BBB, Stable)	$100 million–$200 million over 2011–2012.	No equity funding needs in 2011.	—
Entergy Corp (Not Rated)	$500 million over several years.	Not disclosed.	NOLs at the parent are significant source of tax reduction. Bonus depreciation will extend the life of NOLs. Some offsetting reduction in rate base and regulated revenue requirements is expected.
Exelon Corp (BBB+, Stable)	$850 million in 2011; $170 million in 2012.	Pension funding.	—
FirstEnergy Corp. (BBB, Negative)	Up to $500 million through 2012.	Retain cash; reduce need to issue debt.	—
Hawaiian Electric (Not Rated)	$55 million in 2011 and $30 million in 2012.	Not disclosed.	Awaiting rules on definition of eligible property.
Northeast Utilities (BBB, RWP)	$250 million in 2011 and in aggregate $450 million–$550 million from 2011 through 2013.	Reduce debt.	Reduce interest expense by $5 million in 2011, partially offset by $2 million reduction in earnings due to reduced rate base and lower regulatory revenue requirements.
PEPCO Holdings (BBB, Stable)	No impact until later years due to NOL position.	Not disclosed.	The cash flow benefit from bonus depreciation will be delayed until after NOLs are used. Some offsetting reduction in rate base and revenue requirements may occur in later years, but not immediately in 2011–2012 due to use of NOLs.
PPL Corp. (BBB, Stable)	$700 million between Sept. 9, 2010 and end of 2012.	Eliminate need for equity funding until end of 2011 at the earliest.	Adverse effect on EPS.
SCANA Corp (BBB+, Stable)	$50 million in 2011. (Note: New nuclear investment will not be eligible for bonus depreciation, since it will not enter service in the relevant years.)	Mitigate external funding needs.	Utility will experience reduced rate base due to netting of deferred taxes. Not likely to affect rates charged to consumers, but it is incorporated in quarterly monitoring reports provided to South Carolina regulators.
Sempra Energy (A–, Negative)	Not disclosed.	Not disclosed.	As a result of bonus depreciation and other factors, SRE will not be paying any cash federal taxes for several years. The utilities will have a small reduction in earnings (example given in the area of $25 million–$40 million annually), but it is minor relative to the cash flow effects.
Southern Co. (A/Stable)	$500 million–$600 million in 2011; $250 million–$300 million in 2012.	Reduce external debt and equity funding needs in 2011–2012.	—
TECO Energy Inc. (BBB–, RWP)	$200 million tax benefit from 2008 through 2012.	Use the incremental cash flow in the utility.	Extends the period in which TECO will not pay any cash taxes on a consolidated basis due to NOL position.
Westar Energy, Inc. (BBB–, Positive)	Not likely to use bonus depreciation to the extent that it would eliminate use of other more permanent forms of tax incentives.	Not relevant.	—
Wisconsin Energy Co. (A–, Stable)	$100 million in 2011; $200 million in 2012.	Increase dividend payout.	Some offsetting reduction in regulated revenues is expected.

NOL – Net operation loss.
Source: CallStreet earnings call transcripts, Fitch.

TUCSON ELECTRIC POWER COMPANY

DOCKET NO. E-01933A-12-0291

SUPPLEMENTAL DIRECT TESTIMONY

OF

ROBERT B. MEASE

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JANUARY 11, 2013

TABLE OF CONTENTS

SUPPLEMENTAL DIRECT TESTIMONY ON REVENUE REQUIREMENTS AND ENERGY EFFICIENCY RESOURCE PLAN

EXECUTIVE SUMMARY

Tucson Electric Power Company ("TEP" or "Company") is a Class A public utility and is a wholly owned operating subsidiary of UNS Energy Corporation. TEP is an electric utility serving approximately 404,000 retail customers in the Tucson metropolitan area of Pima County as well as parts of Cochise County. TEP also sells electricity to other utilities and power marketing entities in the western United States.

On July 2, 2012, the Company filed a general rate application requesting a revenue increase of $127.8 million or approximately a 15.3 percent increase over test year adjusted revenues of $837 million. The average residential customer would see their monthly bill increase from $85.17 to $95.82, a monthly increase of $10.65. RUCO is recommending a revenue increase of $46.4 million, an increase of 5.5 percent over test year revenues.

The Company is also proposing an Original Cost Rate Base (OCRB) of $1,519,073 and a Rate of Return of 8.52% while RUCO is proposing an OCRB of $1,321,544 and a Rate of Return of 7.28%.

In addition to an increase in rates for all classes of TEP's customers the Company is also requesting modifications to its Purchase Power and Fuel Adjustment Clause (PPFAC) and a modified approach to funding the cost of its energy efficiency (EE) and demand side management (DSM) programs. The Company is also seeking to establish a lost fixed cost recovery program related to energy efficiency and renewable generation requirements and an environmental cost recovery mechanism.

INTRODUCTION

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

A. My Name is Robert B. Mease. I am the Associate Chief of Accounting and Rates for the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Have you filed any prior testimony in this case on behalf of RUCO?

A. Yes, on December 21, 2012, I filed direct testimony presenting RUCO's required revenue recommendations for TEP.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present RUCO's revised required revenue recommendations based on the findings of RUCO consultants Frank Radigan and Paul Goetz. I will also present RUCO's recommendations on the Company-proposed energy efficiency plan and RUCO's recommended rate design.

As described in Mr. Radigan's testimony filed on December 21, 2012, the Company failed to justify the increase in plant in service since the last rate case and Mr. Radigan recommended that gross utility plant in service be reduced by approximately $230.1 million and test year depreciation expense by approximately $26.3 million. It was further stated that RUCO leaves open the possibility to revise this adjustment to plant in service when it files its direct testimony on rate design on January 11, 2013 if it receives acceptable supporting documentation from the Company. The Company has provided additional information and RUCO is now recommending that plant in service be reduced by $138.6 million and depreciation expense be reduced by $23.7 million. Based on the information provided RUCO has made adjustments to its original schedules filed and has revised its testimony accordingly. The revisions to plant and related accounts are discussed on pages 2 through 7.

In addition, as discussed in Mr. Mease's testimony, the Energy Efficiency Resource Plan ("EERP") was to be discussed in testimony submitted with the rate design being filed on January 11, 2013. See RUCO's discussion on TEP's Energy Efficiency Resource Plan on pages 1 through 22 at the end of this document.

RATE BASE ADJUSTMENT SUMMARY

<u>Rate Base Adjustment No. 1 – Gross Utility Plant in Service</u>

RUCO is recommending reduction of Gross Utility Plant in Service by <u>$138,614,227</u> as explained in the direct testimony of RUCO consultant, Frank Radigan.

Rate Base Adjustment No. 2 – Accumulated Depreciation

As explained in the direct testimony of RUCO consultant, Frank Radigan, RUCO is recommending reducing the Accumulated Depreciation Account by $126,516,244.

Rate Base Adjustment No. 6 – Allowance For Working Capital

Cash Working Capital should be decreased by $4,507,000 based on adjustments to various operating expense accounts.

OPERATING INCOME ADJUSTMENT SUMMARY

Operating Income Adjustment No. 2. – Depreciation Expense

RUCO is recommending a reduction in test year depreciation expense by $23,731,458. RUCO consultant Frank Radigan will provide testimony on this adjustment.

Operating Income Adjustment No. 13 – Property Tax Expense

An adjustment to property tax expense, of $1,352,038 is being proposed by RUCO due to the proposed reduction in the Company's rate base.

Operating Income Adjustment No. 14 – Income Tax Adjustment

RUCO is proposing that current year's income tax expense be increased by $17,513,996.

REVENUE REQUIREMENTS

Q. Please summarize the results of RUCO's analysis of the Company's filing and identify RUCO's recommended revenue increase, operating income requirement as well as the Company's Original Cost Rate Base (OCRB) and Fair Value Rate Base (FVRB).

A. RUCO is recommending a revenue increase as follows:

000's	TEP	RUCO	DIFF.
Increase in gross revenue	$127,765	$ 46,370	($ 81,395)
Increase in revenues required	15.27%	5.54%	(9.73%)

RUCO is recommending operating income levels as follows:

000's	TEP	RUCO	DIFF.
Required operating income	$129,484	$104,229	($ 25,255)

RUCO is recommending OCRB and FVRB as follows:

000's	TEP	RUCO	DIFF.
Original Cost Rate Base	$1,519,073	$1,321,544	($ 197,529)
Fair Value Rate Base	$2,280,216	$2,039,707	($ 240,509)

RATE BASE

Rate Base Adjustment No. 1 – Gross Utility Plant in Service

Q. Can you please explain RUCO's proposed adjustment to Gross Utility Plant in Service?

A. RUCO is recommending reduction of Gross Utility Plant in Service by <u>$138,614,237</u> based on the recommendation of RUCO consultant Frank Radigan.

<u>Rate Base Adjustment No. 2 – Accumulated Depreciation</u>

Q. What adjustments has RUCO recommended to the Company's Accumulation Depreciation accounts?

A. Based on the recommendation of RUCO consultant, Frank Radigan, RUCO is recommending reducing the Accumulated Depreciation Account by <u>$126,516,244</u>.

<u>Rate Base Adjustment No. 6 – Cash Working Capital</u>

Q. Please explain RUCO's adjustment to Cash Working Capital.

A. RUCO is recommending a Cash Working Capital decrease of <u>$4,507,000</u>. The adjustment is the result of RUCO's proposed expense reductions.

OPERATING INCOME

<u>Operating Income Adjustment No. 2. – Depreciation Expense</u>

Q. Can you please explain your adjustment to depreciation expense?

A. RUCO is recommending a reduction in test year depreciation expense by <u>$23,731,458</u> as explained by Mr. Radigan in his testimony.

Operating Income Adjustment No. 12 – Miscellaneous General Expense

Q. What adjustment is RUCO proposing for miscellaneous expense expenses?

A. RUCO is recommending an additional test year expense of $5,820,875 based on Mr. Radigan's adjustment for market based rents applicable to commercial property.

Operating Income Adjustment No. 13 – Property Tax Expense

Q. Does RUCO accept the Company's methodology in calculating property tax expense?

A. Yes. The method used by the TEP in this rate case is consistent with prior cases as filed and has been accepted by RUCO.

Q. Why is RUCO making an adjustment to the Company's property taxes as filed?

A. RUCO is proposing a reduction in gross plant in service by $138,614,237, as discussed in Rate Base Adjustment No. 1. As a consequence of excluding plant from rate base the property taxes associated with the proposed reduction in plant is also reduced. The reduction in allowable property taxes based on the recalculated expense is $1,352,038.

<u>Operating Income Adjustment No. 14 – Income Tax Expense</u>

Q. Has RUCO made an adjustment to Income Tax Expense as filed by the Company?

A. Yes. RUCO has adjusted this expense based upon the methodology that is used in all rate applications reviewed by RUCO.

Q. Can you explain the method utilized in calculating income tax expense both for the test year adjustment as well as the method used in calculating the tax effects of proposed revenue adjustments?

A. When calculating income tax expense for rate making purposes RUCO begins with operating income before taxes and from that amount will deduct Arizona income taxes due and interest synchronization. (Interest synchronization is calculated as follows: Adjusted ACC Jurisdictional Rate Base X Weighted Cost of Debt) The two results, Arizona income taxes and interest synchronization, are multiplied by the statutory Federal Income Tax Rate. In this case RUCO has used 35 percent as the statutory Federal Income Tax Rate.

Q. When applying this methodology to the RUCO's proposed test year operating income what was the result?

A. There was an additional income tax expense proposed by RUCO of <u>$17,513,996</u> and added to the Company's operating expenses.

Q. Was there an adjustment to income tax expense after RUCO's final revenue requirement was determined in this rate filing?

A. Yes. The increase in income tax expense related to RUCO's additional revenue requirement is $18,392,609.

Q. Does this conclude your testimony?

A. Yes.

Tucson Electric Power Company
Docket No. E-01933A-12-0291
Test Year Ended December 31, 2011 **REVISED**

TABLE OF CONTENTS TO RUCO FINAL SCHEDULES

Tucson Electric Power Company
Docket No. E-01933A-12-0291
Test Year Ended December 31, 2011

REVISED

REVENUE REQUIREMENT
ACC JURISDICTIONAL
(Thousands of Dollars)

LINE NO.	DESCRIPTION	(A) COMPANY ORIGINAL COST	(B) COMPANY RCND	(C) COMPANY FAIR VALUE	(D) RUCO ORIGINAL COST	(E) RUCO RCND	(F) RUCO FAIR VALUE
1	Adjusted Rate Base	$ 1,519,073	$ 3,041,359	$ 2,280,216	$ 1,321,544	$ 2,757,869	$ 2,039,707
2							
3	Adjusted Operating Income (Loss)	$ 52,471	$ 52,471	$ 52,471	$ 76,251	$ 76,251	$ 76,251
4							
5	Current Rate Of Return (Line 3 / Line 1)	3.45%	1.73%	2.30%	5.77%	2.76%	3.74%
6							
7	Required Operating Income (Line 13 X Line 1)	$ 129,484	$ 129,484	$ 129,484	$ 104,229	$ 104,229	$ 104,229
8							
9	Weighted Average Cost of Capital	7.74%	7.74%	7.74%	7.28%	7.28%	7.28%
10							
11	Fair Value Adjustment	0.78%	-3.48%	-2.06%	0.61%	-3.50%	-2.17%
12							
13	Required Rate of Return	8.52%	4.26%	5.68%	7.89%	3.78%	5.11%
14							
15	Operating Income Deficiency (Line 7 - Line 3)	$ 77,013	$ 77,013	$ 77,013	$ 27,978	$ 27,978	$ 27,978
16							
17	Gross Revenue Conversion Factor (Schedule RBM-1, page 2)	1.6590	1.6590	1.6590	1.6574	1.6574	1.6574
18							
19	Increase In Gross Revenue Requirement (Line 15 X Line 17)	$ 127,765	$ 127,765	$ 127,765	$ 46,370	$ 46,370	$ 46,370
20							
21	Adjusted Test Year Revenue	$ 836,938	$ 836,938	$ 836,938	$ 836,938	$ 836,938	$ 836,938
22							
23	Proposed Annual Revenue Requirement (Line 19 + Line 21)	$ 964,703	$ 964,703	$ 964,703	$ 883,308	$ 883,308	$ 883,308
24							
25	Required Percentage Increase In Revenue (Line 19 / Line 21)	15.27%	15.27%	15.27%	5.54%	5.54%	5.54%
26							
27	Rate Of Return On Common Equity	10.75%	10.75%	10.75%	10.00%	10.00%	10.00%

References:
Columns (A) Thru (C): Company Schedule A-1, C-1 and D-1
Column (D): Schedules RBM-1, Page 2, RBM-2, RBM-7 and RBM-22
Column (E): Schedule RBM-2, Column (F)
Column (F): Average of Column (D) + Column (E)

Tucson Electric Power Company
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REVISED

GROSS REVENUE CONVERSION FACTOR

LINE NO.	DESCRIPTION	REFERENCE	(A)
	CALCULATION OF GROSS REVENUE CONVERSION FACTOR:		
1	Revenue		100.00%
2	Less: Uncollectibles	Per Company Workpapers	0.25%
3	Subtotal	Line 1 - Line 2	99.75%
4	Less: Combined Federal And State Tax Rate	Line 16	39.42%
5	Subtotal	Line 3 - Line 4	60.34%
6	**Revenue Conversion Factor**	Line 1 / Line 5	1.6574
7			
8	CALCULATION OF EFFECTIVE TAX RATE:		
9	Arizona Taxable Income		100.0%
10	Arizona State Income Tax Rate		6.968%
11	Federal Taxable Income	Line 9 - Line 10	93.0%
12	Applicable Federal Income Tax Rate		35.0%
13	Effective Federal Income Tax Rate	Line 11 X Line 12	32.5%
14	Subtotal	Line 10 + Line 13	39.5%
15	Revenue Less Uncollectibles	Line 3	99.8%
16	Combined Federal And State Income Tax Rate	Line 14 X Line 15	39.4%
17			
18			
19			
20			
21			
22	Operating Income Deficiency	Sch RBM-1 Ln 15	$ 27,978
23	Gross Income Conversion Fzctor	Column (A) Ln 6	1.6574
24	Increase in Gross Revenue		$ 46,370
25			
26	Increase in Income Tax Expense	Ln 24 - Ln 22	$ 18,393
27			
28			

$ 18,392.609

Tucson Electric Power Company
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REVISED

FAIR VALUE RATE BASE
ACC JURISDICTIONAL
(Thousands of Dollars)

LINE NO.	DESCRIPTION	(A) COMPANY OCRB	(B) COMPANY RCND	(C) COMPANY FVRB	(D) OCRB/RCND % DIFF.	(E) RUCO OCRB	(F) RUCO RCND	(G) RUCO FVRB
1	Gross Utility Plant In Service	$ 3,199,453	$ 6,655,502	$ 4,927,478	208.02%	$ 3,060,840	$ 6,367,159	$ 4,713,999
2	Accumulated Depreciation	(1,411,639)	(3,005,492)	(2,208,566)	212.91%	(1,285,123)	(2,736,129)	(2,010,626)
3	Net Utility Plant In Service	$ 1,787,814	$ 3,650,010	$ 2,718,912		$ 1,775,717	$ 3,631,030	$ 2,703,373
4								
5	Plant Held For Future Use	$ -	$ -	$ -	100.00%	$ -	$ -	$ -
6								
7	Total Net Utility Plant	$ 1,787,814	$ 3,650,010	$ 2,718,912		$ 1,775,717	$ 3,631,030	$ 2,703,373
8								
9	Deductions:							
10	Cust. Advances For Const.	$ (8,924)	$ (13,182)	$ (11,053)	147.71%	$ (8,924)	$ (13,182)	$ (11,053)
11	Customer Deposits	(23,743)	(23,743)	(23,743)	100.00%	(23,743)	(23,743)	(23,743)
12	Def'd Credit - Cont'd Plt & Retm't Oblig.	(15,832)	(15,773)	(15,803)	99.63%	(15,832)	(15,773)	(15,803)
13	Acc. Deferred Income Taxes	(284,654)	(620,365)	(452,510)	217.94%	(351,705)	(766,494)	(559,100)
14	Total Deductions	$ (333,153)	$ (673,063)	$ (503,108)		$ (400,204)	$ (819,192)	$ (609,698)
15								
16	Allowance - Working Capital	$ 53,323	$ 53,323	$ 53,323	100.00%	$ 48,816	$ 48,816	$ 48,816
17								
18	Regulatory Assets	$ 11,089	$ 11,089	$ 11,089	100.00%	$ -	$ -	$ -
19								
20	Regulatory Liability	$ -	$ -	$ -	100.00%	$ (102,785)	$ (102,785)	$ (102,785)
21								
22								
23	**TOTAL TEST YEAR RATE BASE**	$ 1,519,073	$ 3,041,359	$ 2,280,216		$ 1,321,544	$ 2,757,869	$ 2,039,707

References:
Columns (A) (B) (C): Company Schedule B-1
Column (D): Column (B) / Column (A)
Column (E): Schedule RBM-3 page 1, Column (C)
Column (F): Column (D) X Column (E)
Column (G): Average Of Column (E) + Column (F)

Tucson Electric Power Company
Docket No. E-01933A-12-0291
Test Year Ended December 31, 2011

REVISED

ORIGINAL COST RATE BASE - ACC JURISDICTIONAL

LINE NO.	DESCRIPTION	(A) COMPANY FILED AS OCRB		(B) RUCO ADJUSTMENTS	(C) RUCO ADJUSTED AS OCRB
1	Gross Utility Plant In Service	$ 3,199,454		$ (138,614)	$ 3,060,840
2	Accumulated Depreciation	(1,411,639)		126,516	(1,285,123)
3	Net Utility Plant In Service	$ 1,787,815		$ (12,098)	$ 1,775,717
4					
5	Plant Held For Future Use	$ -		$ -	$ -
6					
7	Total Net Utility Plant	$ 1,787,815	0	$ (12,098)	$ 1,775,717
8					
9	Deductions:				
10	Cust. Advances For Const.	$ (8,924)		$ -	$ (8,924)
11	Customer Deposits	(23,743)		-	(23,743)
12	Def'd Credit - Cont'd Plt & Retm't Oblig.	(15,832)		-	(15,832)
13	Acc. Deferred Income Taxes	(284,654)		(67,051)	(351,705)
14	Total Deductions	$ (333,153)		$ (67,051)	$ (400,204)
15					
16	Allowance - Working Capital	$ 53,323		$ (4,507)	$ 48,816
17					
18	Regulatory Assets	$ 11,089		$ (11,089)	$ -
19					
20	Regulatory Liability	$ -		$ (102,785)	$ (102,785)
21					
22					
23	TOTAL OCRB	$ 1,519,074		$ (197,530)	$ 1,321,544

References:
Column (A): - Company Schedule B-2. Also see RBM-3 page 2 Col. A
Column (B): - RUCO Adjustments (See RBM-3 page 2, Columns (B) thru (G))
Column (C): - Sum Of Columns (A) and (B)

Tucson Electric Power Company
Docket No. E-01933A-12-0291
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Schedule RBM-3
Page 2 of 3

SUMMARY ORIGINAL COST RATE BASE - RUCO ADJUSTMENTS
(Thousands of Dollars)

LINE NO.	DESCRIPTION	(A) COMPANY FILED AS OCRB	(B) Adjustment No. 1 Gross Utility Plant	(C) Adjustment No. 2 Accumulated Depreciation	(D) Adjustment No.3 Accu Deferred Income Taxes	(E) Adjustment No.4 Regulatory Liabilities	(F) Adjustment No.5 Sahuarita-Nogales Trans. Line	(G) Adjustment No. 5	(H) RUCO ADJUSTED AS OCRB
1	Gross Utility Plant In Service	$ 3,199,454	$ (138,614)	-		$ -	$ -	$ -	$ 3,060,840
2	Accumulated Depreciation	(1,411,639)	-	126,516	-	-	-	-	(1,285,123)
3	Net Utility Plant In Service	$ 1,787,815	$ (138,614)	$ 126,516	$ -	$ -	$ -	$ -	$ 1,775,717
4									
5	Plant Held For Future Use	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6									
7	Total Net Utility Plant	$ 1,787,815 0	$ (138,614)	$ 126,516	$ -	$ -	$ -	$ -	$ 1,775,717
8									
9	Deductions:								
10	Cust. Advances For Const.	$ (8,924)	$ -	$ -	$ -	$ -	$ -	$ -	$ (8,924)
11	Customer Deposits	(23,743)	-	-	-	-	-	-	(23,743)
12	Def'd Credit - Plt & Retm't	(15,832)	-	-	-	-	-	-	(15,832)
13	Acc. Deferred Income Taxes	(284,654)	-	-	(67,051)	-	-	-	(351,705)
14	Total Deductions	$ (333,153)	$ -	$ -	$ (67,051)	$ -	$ -	$ -	$ (400,204)
15									
16	Allowance - Working Capital	$ 53,323	$ -	$ -	$ -	$ -	$ -	$ (4,507)	$ 48,816
17									
18	Regulatory Assets	$ 11,089	$ -	$ -			$ (11,089)	$ -	$ -
19									
20	Regulatory Liability	$ -	$ -	$ -	$ -	$ (102,785)	$ -	$ -	$ (102,785)
21									
22									
23	TOTAL OCRB	$ 1,519,074	$ (138,614)	$ 126,516	$ (67,051)	$ (102,785)	$ (11,089)	$ (4,507)	$ 1,321,544

References:
Column (A): Company Schedule B-1
Columns (B) Thru (G): RUCO Rate Base Adjustment Nos. 1 thru 5
Column (H): Sum Of Columns (A) Through (G)

Tucson Electric Power Company
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RATE BASE ADJUSTMENT NO. 1
GROSS UTILITY PLANT IN SERVICE
(Thousands of Dollars)

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Gross Utility Plant in Service	$ 3,199,454	$ (138,614)	3,060,840
2				
3				
4				
5				
6				
7				
8	Gross Utility Plant Reduction	$ 70,642,900	See RBM-5 page 1 Ln 44	
9			and FWR Testimony	
10	ACC Jurisdictional Costs of New Building	67,971,337		
11				
12	TOTAL ADJUSTMENTS	$ 138,614,237		
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23	References:			
24	Column (A) Ln 1 - Company Workpapers			
	Column (A) Ln 10 - Company Response to Staff Data Request 23.6			

REVISED

RATE BASE ADJUSTMENT NO. 2
ACCUMULATED DEPRECIATION

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Accumulated Depreciation	$ (1,411,638,679)	$ 126,516,244	$ (1,285,122,435)
2				
3				
4				
5				
6				
7				
8				
9				
10				
11	RUCO Proposed Adjustments			
12				
13	Reduction of A/D due to disallowance of plant in service		$ -	RBM-5 page 1, Ln 44
14	Reduction of A/D due to depreciation expense increase			
15	resulting from reclassification of plant		1,288,484	RBM-5 page 1, Ln 36
16	Reduction of A/D due to disallowance of new office building		1,885,760	RBM-5 page 2, Ln 17
17	Reduction of A/D due to the return of depreciation			
18	reserve to ratepayers		20,557,214	RBM-4 page 4, Ln 10
19	Reclassification of A/D to Regulatory Liability			
20	($123,342,000 - $20,557,000)		102,784,786	RBM-4 page 4, Ln 8
21				
22				
23			$ 126,516,244	
24				

References:
Comumn (A) Company Schedule B-1

Tucson Electric Power Company
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RATE BASE ADJUSTMENT NO. 6
ALLOWANCE FOR WORKING CAPITAL
(Thousands of Dollars)

LINE NO.	DESCRIPTION	REFERENCE		(A) AMOUNT
1	Cash Working Capital Per TEP	TEP SCH. B-5, Page 1	$	(19,359)
2	Cash Working Capital Per RUCO	RBM-6		(23,866)
3	Adjustment	Line 2 - Line 1	$	(4,507)
4				
5	Fuel Inventory Per TEP	TEP SCH. B-5, Page 1	$	25,307
6	Fuel Inventory Per RUCO	TEP SCH. B-5, Page 1		25,307
7	Adjustment	Line 6 - Line 5	$	-
8				
9	Materials And Supplies Per TEP	TEP SCH. B-5, Page 1	$	42,837
10	Materials And Supplies Per RUCO	TEP SCH. B-5, Page 1		42,837
11	Adjustment	Line 10 - Line 9	$	-
12				
13	Prepayments Per TEP	TEP SCH. B-5, Page 1	$	4,538
14	Prepayments Per RUCO	TEP SCH. B-5, Page 1		4,538
15	Adjustment	Line 14 - Line 13	$	-
16				
17	TOTAL ADJUSTMENT - WORKING CAPITAL	Sum Lines 3, 7, 11, 15)	$	(4,507)
18				
19				
20				
21				
22				

Tucson Electric Power Company
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Schedule RBM-5
REVISED Page 1 of 2

TEST YEAR PLANT ADJUSTMENTS

Line	Acct.	2006 Gross Plant	2006 Depre Reserve	2006 Net Plant	2011 Gross Plant	2011 Depre Reserve	2011 Net Plant	Depre Rate	RUCO ADJUSTED 2011 Gross Plant	Depr Res on 2006 Balance	Growth in Reserve Balance	Total Depre Reserve	Net Plant	Prop Depre Rate	Depreciation Expense Company	Depreciation Expense RUCO	Difference
	Steam Production Plant																
1	310	$ 4,603	$ 2,243	$ 2,360	$ 4,603	$ 3,874	$ 729	5.34%	$ 4,603	$ 3,874	$ -	$ 3,874	$ 729	1.58%	73	73	-
2	311	111,087	62,031	49,056	168,247	97,520	70,727	5.16%	168,247	97,520	-	97,520	70,727	2.32%	3,903	3,903	-
3	312	652,151	332,664	319,487	1,020,623	489,561	531,062	3.87%	1,020,623	489,561	-	489,561	531,062	3.03%	30,925	30,925	-
4	314	206,960	101,243	105,717	300,048	140,860	159,188	3.79%	300,048	140,860	-	140,860	159,188	3.67%	11,012	11,012	-
5	315	71,511	38,182	33,329	116,382	59,751	56,631	3.24%	116,382	59,751	-	59,751	56,631	3.66%	4,260	4,260	-
6	316	19,281	10,338	8,943	22,314	13,826	8,488	3.88%	22,314	13,826	-	13,826	8,488	2.73%	609	609	-
7	317	70	56	14	-		-		9	-	-	-				-	
8																	
9		$ 1,065,663	$ 546,757	$ 518,906	$ 1,632,217	$ 805,392	$ 826,825										
10									$ 1,632,226	$ 805,392	$ -	$ 805,392	$ 826,825		50,781	50,781	-
11	**Distribution Plant**																
12																	
13	360	$ 7,991	$ 2,895	$ 5,096	$ 8,018	$ 3,543	$ 4,475	1.43%	8,012	3,466	7	3,473	4,539	1.43%	115	115	(0)
14	361	6,282	1,745	4,537	11,107	2,122	8,985	1.63%	9,973	2,257	(12)	2,245	7,728	1.72%	191	172	(20)
15	362	95,451	63,750	31,701	138,343	42,910	95,433	1.46%	128,263	70,718	(2,503)	68,215	60,048	1.53%	2,117	1,962	(154)
16	364	112,985	80,761	32,224	159,393	51,948	107,445	1.63%	148,487	89,969	(3,422)	86,547	61,940	1.74%	2,773	2,584	(190)
17	365	106,758	59,379	47,379	152,686	55,045	97,641	1.47%	141,893	67,226	(1,096)	66,129	75,764	1.63%	2,489	2,313	(176)
18	366	49,342	15,411	33,931	53,276	23,337	29,939	1.42%	52,352	18,914	398	19,312	33,040	1.35%	719	707	(12)
19	367	213,374	46,664	166,710	268,486	104,292	164,194	1.89%	255,535	66,828	3,372	70,200	185,335	1.87%	5,021	4,779	(242)
20	368	77,837	35,429	42,408	103,782	47,865	55,917	1.84%	97,685	42,590	475	43,065	54,620	1.87%	1,941	1,827	(114)
21	368	125,291	44,936	80,355	164,679	71,693	92,986	2.52%	155,423	60,723	987	61,710	93,713	2.09%	3,442	3,248	(193)
22	369	12,050	4,425	7,625	15,071	5,414	9,657	1.62%	14,361	5,401	1	5,402	8,959	1.85%	279	266	(13)
23	369	79,968	38,184	41,784	98,682	33,223	65,459	1.50%	94,284	44,182	(986)	43,195	51,089	1.52%	1,500	1,433	(67)
24	370	32,881	11,285	21,596	45,714	14,857	30,857	2.99%	42,698	16,201	(121)	16,080	26,618	3.29%	1,504	1,405	(99)
25	373	9,334	5,835	3,499	11,173	4,814	6,359	1.74%	10,741	6,647	(165)	6,482	4,259	1.77%	198	190	(8)
26	374	216	183	33	-		-	0.00%	51	-							
27																	
28		$ 929,760	$ 410,882	$ 518,878	$ 1,230,410	$ 461,063	$ 769,347										
29									$ 1,159,758	$ 495,121	$ (3,065)	$ 492,056	$ 667,651		$ 22,288	$20,999	$ (1,288)
30	Total	$ 1,995,423	$ 957,639	$ 1,037,784	$ 2,862,627	$ 1,266,455	$ 1,596,172										
31									$ 2,791,984	$ 1,300,513	$ (3,065)	$ 1,297,448	$1,494,476		$ 73,069	$71,780	$ (1,288)
32																	

Line	ADJUSTMENT TO GROSS UTILITY PLANT	
33	**ADJUSTMENT TO GROSS UTILITY PLANT**	
34		
35	Steam Plant as Submitted by Company	$ 1,632,217
36	Steam Plant Recomputed by RUCO	$ 1,632,226
37	Decrease in Gross Value Steam Plant	$ (9)
38		
39	Distribution Plant as Submitted by Company	$ 1,230,410
40	Distribution Plant Recomputed by RUCO	$ 1,159,758
41	*Decrease in Gross Value Dist. Plant*	$ 70,652
42		
43		
44	Total Reduction in Plant	$ 70,642,900

DEPRECIATION EXPENSE ADJUSTMENT

$ (1,288,484)

BUILDING COSTS ALLOCATED TO AFFILIATES

Line	Description		(A)		Sq FT	$ per sq foot		Annual Revenue Requirment ($ millions)
1	Investment in Land-downtown HQ	$	8,549,938					
2	Investment in Office Facilities		71,430,308					
3	Investment in Furniture & Equipment		50,023					
4	Less: Accumulated Depreciation		(901,025)					
5	Less: Accumulated Depreciation		(1,176,718)					
6	Less: Accumulated Deferred Income Taxes		-					
7	Net Investment in Office Facilities		77,952,526					
8	Multiplied by: Current Regulated Rate of Return		8.03%					
9								
10	Required Return on Office Facilities and F&E		6,259,588					
11								
12	Add:							
13	O&M Expenses Applicable to Office Facilities and F&E		2,100,000	RBM-19				
14	PC/Lan Expenses		-					
15	Property Taxes Applicable to Office Facilities		1,000,000	RBM-20				
16	Insurance Costs Applicable to Office Facilities		-					
17	Book Depreciation on Office Facilities		1,885,760	RBM-10				
18	Income Taxes on Equity Portion of Return **		2,225,597					
19								
20	Revenue Requirement for Office Facilities and F&E		13,470,945		232,835	57.86	$	13,470,945
21								
22	Diveded by: Number of Employees - Excluding SPG		539			25.00	$	5,820,875
23								
24	Cost Per Employee	$	24,992	Calculated IncomeAffects of Bldg			$	(7,650,070)
25								
26	Divided by: Annual Labor Hrs.		2,080					
27								
28	Facilities Cost Per Hour	$	12.02					
29								
30	**							
31	Net Investment in Office Facilities	$	77,952,526					
32	Regulated Rate of Return - Equity Component		4.36%					
33	Equity Component of Return on Office Facilities		3,398,730					
34	Divide by 1- Combined Tax Rate		60.4291%					
35			5,624,327					
36	Multiply by Combined Tax Rate		39.5709%					
37	Income Taxes on Equity Portion of Return	$	2,225,597					
38								

References:
Company Data Response
See FWR Testimony

Tucson Electric Power Company
Docket No. E-01933A-12-0291 **REVISED** Schedule RBM-6
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ALLOWANCE FOR WORKING CAPITAL
LEAD/LAG DAY SUMMARY

LINE NO.	DESCRIPTION	(A) COMPANY EXPENSES AS FILED	(B) RUCO Adj	(C) RUCO Adjusted Results	(D) Revenue Lag Days	(E) Exp Lag Days	(F) Net Lag Days	(G) Lead Lag Factor	(H) Cash Working Capital Requirements
	OPERATING EXPENSES					-	-	-	-
	Non-Cash Expenses:								
1	Bad Debts Expense	$ 2,080,293	$ (2,080,293)	-			-		$ -
2	Depreciation	119,580,496	$ (119,580,496)	-			-		-
3	Amortization	3,481,610	$ (3,481,610)	-			-		-
4	Deferred Income Taxes	12,803,088	$ (12,803,088)	-			-		-
5	Total Non-Cash Expenses	$ 137,945,487	$ (137,945,487)	$ -					$ -
	Other Operating Expenses:								
6	Salaries & Wages	$ 71,991,108	$ (1,470,721)	$ 70,520,387	36.47	10.46	26.01	7.13%	$ 5,025,302
7	Incentive Pay	6,247,890	(2,530,620)	3,717,270	36.47	259.50	(223.03)	-61.10%	(2,271,404)
8	Fuel Expense	285,386,416	-	285,386,416	36.47	29.50	6.97	1.91%	5,449,708
9	Lease Expense	101,812,888	-	101,812,888	36.47	94.33	(57.86)	-15.85%	(16,139,435)
10	Remote Generating Plant O & M	47,385,627	(4,883,016)	42,502,611	36.47	(6.90)	43.37	11.88%	5,050,242
11	Office Supplies and Expenses	9,594,745	-	9,594,745	36.47	12.46	24.01	6.58%	631,150
12	Outside Services	10,520,391	-	10,520,391	36.47	44.51	(8.04)	-2.20%	(231,737)
13	Property Insurance	2,271,746	(289,320)	1,982,426	36.47	-	36.47	9.99%	198,080
14	Injuries and Damages	2,278,506	-	2,278,506	36.47	(13.27)	49.74	13.63%	310,501
15	Pensions and Benefits	17,449,591	-	17,449,591	36.47	13.03	23.44	6.42%	1,120,598
16	Misc. General Expenses	4,285,497	3,681,859	7,967,356	36.47	(2.00)	38.47	10.54%	839,737
17	Rents	375,864	-	375,864	36.47	(40.51)	76.98	21.09%	79,271
18	Property Taxes	39,148,092	(1,352,038)	37,796,054	36.47	213.78	(177.31)	-48.58%	(18,360,598)
19	Payroll Taxes	7,830,466	$ (272,631)	7,557,835	36.47	16.53	19.94	5.46%	412,886
20	Current Income Taxes	7,016	22,763	29,779	36.47	62.05	(25.58)	-7.01%	(2,087)
21	Other Taxes	46,168	-	46,168	36.47	91.37	(54.90)	-15.04%	(6,944)
22	Interest on Customer Deposits	(2,439)	-	(2,439)	36.47	182.50	(146.03)	-40.01%	976
23	Other Operations and Maint.	63,312,707	(149,998)	63,162,709	36.47	11.99	24.48	6.71%	4,236,228
24	Total Other Operating Exp.	$ 669,942,279	$ (7,243,724)	$ 662,698,555					$ (13,657,527)
25									
26	Other Cash Working Capital Elements:								
27	Interest on Long-Term Debt	$ 54,838,713	$ -	54,838,713	36.47	86.20	(49.73)	-13.62%	$ (7,471,587)
28	Rev. Taxes and Assessments	85,440,494	-	85,440,494	36.47	48.16	(11.69)	-3.20%	$ (2,736,437)
29	Total Other Cash Working Cap.	$ 140,279,207	$ -	$ 140,279,207					$ (10,208,023)
30									
31	TOTAL CASH WORKING CAPITAL	$ 948,166,973		$ 802,977,762					$ (23,865,550)
32									
33									
34									
35									

36 References:
37 Column (A): - Company Schedule B-5
38 Column (B): RUCO Operating Income Adjustments (See RBM-8)
39 Column (C): Column (A) + (B)
40 Column (D): Company Schedule B-5, Page 3
41 Column (E): Column (C) X Column (D)

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Schedule RBM-7
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OPERATING INCOME STATEMENT
(Thousands of Dollars)

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO TEST YEAR ADJM'TS	(C) RUCO TEST YEAR AS ADJ'D	(E) RUCO PROPOSED ACC JURID'L	(F) RUCO RECOM'D ACC JURID'L
1	Operating Revenues:					
2	Electric Retail Revenues	$ 836,938	$ -	$ 836,938	$ 46,370	$ 883,308
3	Sales for Resale	-	-	-		
4	Other Operating Revenue	$ 29,183	6,961	36,144	-	$ 36,144
5						
6	TOTAL OPERATING REVENUES	$ 866,121	$ 6,961	$ 873,082	$ 46,370	$ 919,452
7						
8	Operating Expenses:					
9	Fuel, Purchased Power and Trans	$ 292,188	(6,692)	$ 285,496		$ 285,496
10	Other Operations and Maintenance Exp	381,988	(2,286)	379,702		379,702
11	Depreciation and Amortization	97,311	(23,731)	73,580		73,580
12	Taxes Other than Income Taxes	35,142	(1,625)	33,517		33,517
13	Income Taxes	7,019	17,514	24,533	18,393	42,926
14	Rounding Differences	-	2	2		2
15	TOTAL OPERATING EXPENSES	$ 813,648	$ (16,817)	$ 796,831	$ 18,393	$ 815,223
16						
17	OPERATING INCOME (LOSS)	$ 52,473	$ 23,778	$ 76,251	$ 27,978	$ 104,229

References:
Column (A) Per Company Filing
Column (B) Schedule RBM-8
Column (E) Schedule RBM-1 page 2

References:
Column (A): Company Schedule C-1
Column (B): Testimonies, RLM & MDC And Schedule RLM-8, Pages 1 Thru 6
Column (C): Column (A) + Column (B)
Column (D): Column (C) X Jurisdictional Factor
Column (E): See Schedule RLM-1
Column (F): Column (D) + Column (E)

Tucson Electric Power Company
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Schedule RBM-10
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OPERATING EXPENSE ADJUSTMENT NO. 2
DEPRECIATION / AMORTIZATION

Line No.	Acct	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Various	Total Depreciation Expense	$ 97,310,414	$ (23,731,458)	$ 73,578,956
2	407.3	Regulatory Asset Amortization	2,982,638	(2,982,638)	$ -
3					
4					
5		Total Other Operating Income	$ 100,293,052	$ (26,714,096)	$ 73,578,956
6					
7					
8					
9	Total Plant Depreciation Adjustments				
10		Depreciation adjustment due reduction in Gross Plant		$ 1,288,484	See RBM Sch 5-1
11		Depreciation adjustment related to removing office bldg.		1,885,760	See RBM Sch 5-2
12		Depreciation reduction due to return to ratepayers			
13		of excess depreciation reserve		20,557,214	FWR Testimony
14		Total Depreciation rduction		$ 23,731,458	
15					
16					
17					
18					
19					
20					
21					
22					
23	References:				
24		Column (A) Company Schedules			
		Column (B) RUCO Adjustments Total Depreciation Expense See Lns 10, 11, and 12			
		Column (B) RBM-5			
		Column (B) Company Schedules			

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Schedule RBM-19
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OPERATING INCOME ADJUSTMENT NO. 12
MISCELLANEOUS GENERAL EXPENSES

Line No.	CONTRIBUTIONS		(A) RUCO ADJUSTMENTS
1	Rental Expense Based on Marker Rates for Corporate Building		$ (5,820,875)
2	Operating Expense of Corporate Building		2,100,000
3	Charitable Contributions		39,016
4			
5			$ (3,681,859)
6			
7			
8	Charitable Contributions	$ 1,250	
9	United Way of Northern Arizona	6,714	
10	United Way of Tuscon and Southern Arizona	14,232	
11	Boys and Girls Club of Tuscon	950	
12	Charitable Contributions	3,060	
13	Charitable Contributions	1,000	
14	Society for Human Reso	165	
15	Charitable Contributions	240	
16	Charitable Contributions	1,500	
17	Thomas Alva Edison Foundation	15,000	
18			
19	TOTAL CONTRIBUTIONS IDENTIFIED	$ 44,111	
20			
21	ACC JURISDICTIONAL	88.45%	
22			
23	TOTAL RUCO ADJUSTMENT FOR CONTRIBUTIONS	$ 39,016	
24			
25			
26			
27			
28	Reference:		
29	Column (A) Ln 1 Sch RBM-5		
30	Column (A) Ln 2 Sch RBM-5 page 2 Ln 1		
31	Ln 8 through Ln 17 - See response to RUCO Data Request 8.09		
32			
33			
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37			

Tucson Electric Power Company
Docket No. E-01933A-12-0291
Test Year Ended December 31, 2011

Schedule RBM-20
Page 1 of 1

REVISED

OPERATING INCOME ADJUSTMENT NO. 13
PROPERTY TAX EXPENSE

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Property Tax Expense - Steam Production	$ 15,733,923	$ -	$ 15,733,923
2	Property Tax Expense - Distribution	13,054,052	$ (1,371,818)	11,682,234
3	Property Tax Expense - General	1,719,601	$ 19,780	1,739,381
4				
5	Total Property Tax Expense	$ 30,507,576	$ (1,352,038)	$ 29,155,538
6				
7				
8				
9				
10	**ADJUSTMENT TO EXPENSE**	Steam	Distribution	General
11				
12	Reduction in Plant in Service	$ -	$ 70,642,900	$ -
13	Less: Accumulated Depreciation	-	(1,288,484)	(1,000,000)
14	Net Book Value	-	69,354,416	(1,000,000)
15				
16	Less: Assessment Ratio	19.50%	19.50%	19.50%
17				
18	Taxable Value	$ -	$ 13,524,111	$ (195,000)
19				
20	Average Tax Rate	10.1435%	10.1435%	10.1435%
21				
22	Property Tax Reduction	$ -	$ 1,371,818	$ (19,780)
23				
24				
25				
26	References:			
27				
28	Column (A) Provided in Company Workpapers			
29	Column (C) Ln 13 - RUCO's reduction in property tax related to new office building			
30	Provided by Company. See Schedule RBM-5 Page 1			
31	Column (A) and (B) Lns 12 and 13 See Schedule RBM-5			
32				
33				
34				
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37				

Tucson Electric Power Company
Docket No. E-01933A-12-0291
Test Year Ended December 31, 2011

REVISED

OPERATING INCOME ADJUSTMENT NO. 14
INCOME TAX EXPENSE

(Thousands of Dollars)

LINE NO.	DESCRIPTION	(A) REFERENCE		(B) AMOUNT
1	FEDERAL INCOME TAXES:			
2				
3	Operating Income Before Taxes	Schedule RBM-7, Column (C), Line 17 + Line 13	$	100,784
4	LESS:			
5	Arizona State Tax	Line 21		(4,325)
6	Interest Expense	Line 46		(38,721)
7	Federal Taxable Income	Sum Of Lines 1, 2 & 3	$	57,738
8				
9	Federal Tax Rate	Schedule RBM-1, Page 2, Column (A), Line 12		35.00%
10	Federal Income Tax Expense	Line 4 X line 5	$	20,208
11				
12	STATE INCOME TAXES:			
13				
14	Operating Income Before Taxes	Line 3	$	100,784
15	LESS:			
16	Interest Expense	Line 21		(38,721)
17	State Taxable Income		$	62,063
18				
19	State Tax Rate	Tax Rate		6.97%
20				
21	State Income Tax Expense	Line 17 X Line 19	$	4,325
22				
23	TOTAL INCOME TAX EXPENSE:			
24				
25	Federal Income Tax Expense	Line 10	$	20,208
26	State Income Tax Expense	Line 21		4,325
27	Total Income Tax Expense Per RUCO	Sum Of Lines 12 & 13	$	24,533
28	Total Income Tax Expense Per Company Filing (Schedule C-1)			7,019
29				
30	Difference	Line 27 - Line 28	$	17,514
31				
32	RUCO ADJUSTMENT TO INCOME TAX EXPENSE (See RBM 7, Column (C), Line 13)	Line 30	$	17,514
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	NOTE (A):			
43	Interest Synchronization:			
44	Adjusted ACC Jurisdiction Rate Base (Schedule RBM-3, Column (D), Line 14)	$ 1,321,544		
45	Weighted Cost Of Debt (Schedule RBM-22, Column (F), Line 1 + Line 2)	2.93%		
46	Interest Expense (Line 18 X Line 19)	$ 38,721		

REVISED

OPERATING INCOME ADJUSTMENT NO. 13
PROPERTY TAX EXPENSE

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32
33
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TUCSON ELECTRIC POWER COMPANY

DOCKET NO. E-01933A-12-0291

DIRECT TESTIMONY

OF

ROBERT B. MEASE

ON

RATE DESIGN

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JANUARY 11, 2013

TABLE OF CONTENTS – RATE DESIGN

EXECUTIVE SUMMARY

Based on RUCO's analysis of TEP's rate application the average residential customer will see their monthly bill increase from $85.17 to $89.85, a monthly increase of $4.68, or 5.5 percent.

RUCO's proposal is based on total revenue requirements of $883.3 million which includes a recommended revenue increase of $46.4 million.

RUCO is also recommending several changes to TEP's lifeline customers as proposed by the Company, however, is further proposing limiting any rate increase to the lifeline customer to the same percentage increase proposed for all other residential ratepayers.

INTRODUCTION

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

A. My name is Robert B. Mease. I am Associate Chief of Accounting and Rates employed by the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Please state your educational background and qualifications in the utility regulation field.

A. Appendix 1, which is attached to this testimony, describes my educational background, work experience and regulatory matters in which I have participated. In summary, I joined RUCO in October of 2011. I graduated from Morris Harvey College in Charleston, WV and attended Kanawha Valley School of Graduate Studies. I am a Certified Public Accountant and currently licensed in the state of West Virginia. My years of work experience include serving as Vice President and Controller of Energy West, Inc. a public utility and energy company located in Great Falls, Montana. While with Energy West I had responsibility for all utility filings and participated in several rate case filings on behalf of the utility. As Energy West was a publicly traded company listed on the NASDAQ Exchange I also had responsibility for all filings with the Securities and Exchange Commission.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present RUCO's recommendations regarding TEP's cost of service (CCOS) allocation and rate design and recommend appropriate changes.

Q. Mr. Mease, did you perform a detailed cost of service study?

A. No. While I did do a cursory review, I did not perform an indepth detailed study.

Q. Based on the review you did perform, did you see make any adjustments to the cost of service?

A. No. I did not make any adjustments.

RATE DESIGN OBJECTIVES

Q. Can you please explain the Company's objectives in this rate? application for simplification of the existing rate structure?

A. The Company's proposed rate design objectives are to consolidate, simplify, and modernize the existing rate structure.

...

Q. Why does TEP feel it necessary to consolidate and simplify the existing rate structure?

A. Currently the Company has over 50 retail service rates with multiple variations in many classes. Many of these rates provide little if any incremental benefits through the numerous options. The numerous options to customers add unnecessary confusion for many customers, and increase costs associated with necessary modifications to the billing system and require additional education of both internal personnel and customer base. By consolidating many of the existing rates TEP hopes to reduce the customer confusion and encourage customers to consider all options available to them.

TEP is proposing to eliminate "frozen" rates. The frozen rates do not accurately reflect the costs associated with the rate and the longer the increase is postponed the larger the impact on the customer when the rate is adjusted.

MARGIN ANALYSIS BY RATE CLASSIFICATION

Q. Can you please provide an analysis or breakdown of the margins for the various classes for TEP ratepayers?

A. Yes. Please see attached chart.

RATE CLASS	RUCO PROPOSED MARGIN	RUCO PROPOSED PPFAC	RUCO PROPOSED PPFAC	Percentage Margin
Residential Service	$ 262,215,394	$ 118,425,580	$380,640,974	44.36%
Residential Time Of Use	7,269,795	4,388,547	11,658,341	1.23%
Small General Service	133,185,475	62,017,156	195,202,631	22.53%
Small General Service Time of Use	7,679,515	4,109,473	11,788,988	1.30%
Irrigation & Water Pumping	4,217,005	3,248,547	7,465,552	0.71%
Large General Service	81,182,089	33,283,559	114,465,648	13.73%
Large General Service Time of Use	9,952,379	7,157,860	17,110,240	1.68%
Large Light & Power Service	18,722,540	10,401,627	29,124,167	3.17%
Large Light & Power Service Time of Use	22,234,423	16,041,270	38,275,693	3.76%
Mining Service	41,115,648	31,928,918	73,044,566	6.96%
Traffic Signals & Lighting Service	3,343,776	1,181,323	4,525,100	0.57%
	$ 591,118,038	$ 292,183,861	$883,301,900	100.00%

Q. Does RUCO propose any significant adjustments between the different classes of ratepayers?

A. No. RUCO believes that the current classification of ratepayers is sufficient and proposes no reclassifications

RESIDENTIAL RATES

Q. What has TEP proposed for an increase in the monthly charges for residential rate class R-01, which represents approximately 85 percent of the customer base and generates approximately 42 percent of the system margin?

A. The Company is proposing to increase residential customer charges from the current $7.00 per month to $12.00 per month for the standard residential customer and $15.00 for all residential TOU customers. This represents an increase of approximately 71 percent for non-TOU ratepayers and approximately 114 percent for TOU ratepayers.

Q. Why is TEP increasing the monthly fixed charges for the largest group of company and residential ratepayers?

A. As stated in Mr. Jones testimony, page 33, the proposed customer charge is still only 22 percent of the customer and demand charges identified in the CCOS for the residential customer and the charge is still well below the monthly customer charges that the Commission has previously approved for other electric customers.

Q. Does RUCO agree with this large increase in monthly charges for the residential ratepayer?

A. RUCO believes that the increase as proposed by the Company is excessive and provides a disincentive for the ratepayer to be energy efficient. With a higher monthly fixed charge the volumetric charges consequently are reduced. This in effect does not provide the customer with an incentive to be conservative.

Q. Has TEP proposed substantial changes in the monthly volumetric charges in the R-01 class of ratepayer?

A. Yes. Currently there are three tiers (0 – 500 kWh, 501 – 3,500 kWh and >3,500 kWh) for energy charges and the Company is proposing to eliminate the >3,500 kWh tier. The Company does not believe that the tier is necessary as this tier makes the rate overly complex and captures less than one percent of the overall usage of this class.

Q. **Does RUCO agree with eliminating this tier for residential rate payers?**

A. No. RUCO does not agree with eliminating this tier. Even though the Company indicates that this tier generates less than one percent of the usage in R-01 residential class, this explanation does not provide sufficient reasoning for elimination. By having the higher tier, the residential ratepayer would have the tendency to be more conservative in order to keep their monthly billing to a minimum.

Q. **Has the Company identified those residential rates that they are proposing to eliminate and/or blend with other residential classes of rates?**

A. Yes. The Company has identified twenty six residential rates, including lifeline rates, that they are proposing to eliminate and/or blend into existing rates.

...

Q. Does RUCO agree with the Company's proposal?

A. Yes. RUCO agrees with the elimination and blending of the rates identified by the Company. RUCO would expect to see a substantial reduction in administrative expenses as a result of this proposal.

Q. Can you please provide a summary of the Company's existing residential rates as well as the rates being proposed in this filing?

A. See chart below for TEP's R-01 residential classification of ratepayers which is approximately 85 percent of all TEP ratepayers.

	PRESENT	TEP	RUCO
RESIDENTIAL - R-01	RATES	PROPOSED	PROPOSED
Customer Charge - Single-Phase	$ 7.00	$ 12.00	$ 10.20
Summer			
1st 500 kWhs	$ 0.0469	$ 0.0617	$ 0.0496
Next 3,000 kWhs	$ 0.0690	$ 0.0837	$ 0.0703
3,501 kWhs and above	$ 0.0890	$ 0.0837	$ 0.0928
Winter			
1st 500 kWhs	$ 0.0473	$ 0.0467	$ 0.0477
Next 3,000 kWhs	$ 0.0673	$ 0.0687	$ 0.0731
3,501 kWhs and above	$ 0.0873	$ 0.0687	$ 0.0807
Purchased Power & Fuel			
Summer kWh	$ 0.0332	$ 0.0331	$ 0.0331
Winter kWh	$ 0.0257	$ 0.0307	$ 0.0307

LIFELINE RATES

Q. Can you please describe TEP's current concerns related to the existing lifeline ratepayers and rate structure?

A. The Company's low income rates are defined as lifeline rates. TEP indicates that the existing rate design is overly burdensome and unreasonable. TEP is concerned that other customers have to pay the subsidies created by the multiple rate options as well as the cost of administration. TEP believes that the complexities associated with the existing rates results in additional costs to serve lifeline customers, and the additional costs are being absorbed by the remaining ratepayers.

Q. What is the current rate structure for TEP's lifeline ratepayers?

A. The current tariff configuration and discount applications are overly complex and confusing. They contribute to the over 300 possible variations of residential rates that must be accommodated in the Company's billing system and tested any time a rate change occurs. Lifeline rates that were set as far back as Decision No. 56781 in 1990 have become confusing and are no longer cost justified. While multiple additional groups of customers and levels of discounts have been created since 1990, the lifeline rates have only been increased once in 20 years. Some rates have been frozen, so as to not impact a customer, even though they are no longer based on cost of service.

Additionally, the Company was required to allow these frozen rates to be portable, and eligible customers remain on 20 year old out-of-date rates. Allowing the rate to be mobile prevents these old obsolete rates from fading away, even through attrition.

The cumulative effect of past rate cases has created a situation where similar lifeline customer's are paying significantly different rates and the approximately 23,000 lifeline customers are being served on 20 different rates.[1]

Q. What is TEP proposing in this rate case related to lifeline ratepayers?

A. First, existing lifeline ratepayers on R-04, R-05 and R-08 will be moved to a new lifeline rate designed to offer a 25 percent discount on all volumetric charges and the existing R-06 ratepayers (approximately 70 percent of lifeline ratepayers) will receive a flat $10.00 per month discount. Second, lifeline ratepayers will no longer be exempt from PPFAC or DSMS charges. Third, TEP is proposing to eliminate the option to make a lifeline rate mobile. Fourth, lifeline ratepayers will be subject to annual requalification at the Company's request. Fifth, lifeline rates will be limited to ratepayers who qualify as below the 150 percent federally

[1] See Craig Jones testimony pages 69 to 71

defined poverty level. Lifeline ratepayers in the senior or medical category will receive the same discount as other lifeline ratepayers.[2]

Q. Does RUCO agree with the changes as proposed by TEP for lifeline rates?

A. Not entirely. RUCO agrees with TEP that lifeline rates can be consolidated into a more efficient rate structure. Consolidating rates for lifeline customers would not only create a less complex structure for the Company but would also be less confusing to the lifeline ratepayer. RUCO also agrees with the Company that annual requalification is necessary under certain circumstances and will prevent customers from taking advantage of reduced rates when not entitled to this benefit. RUCO agrees with the Company's proposal to eliminate the mobility option and that customers will qualify for the lifeline rate structure only if they are below the 150 percent federally defined poverty level. Finally, RUCO agrees that lifeline ratepayers should be subject to PPFAC or DSMS adjustments as other ratepayers.

Q. Does RUCO take exception to any of the changes the Company has proposed for lifeline ratepayers?

A. Yes. In reviewing the Company's proposed rate increases there are several cases where lifeline rate increases are in excess of 50 percent.

[2] See Craig Jones testimony page 71 and 72

RUCO believes that in these cases the increases the Company has proposed for lifeline rates are excessive. Any changes in rates for one class of customers should not exceed the percentage change for other residential ratepayers.

Q. Can you please provide a summary of the proposed rate increase to the different rate classes of lifeline ratepayers?

A. Yes. See the following chart.

		No. of Customers	Lifeline Proposed Inc. PPFAC	Discount Compared to Standard Rate	Calculated Discount	Percent Change to Annual Billing	Caculculated Current Rate	Limit to Lifeline Rate	Recalculated Increase Based on Limitation
Residential R-01									
Residential Lifeline	R-04-01	819	$ 795.87	$ 217.29	$ 177,961	24.8%	$ 637.72	6.00%	$ 675.98
Residential Lifeline	R-05-01	1,722	795.87	217.29	374,173	9.7%	725.50	6.00%	769.03
Residential Lifeline	R-08-01	1,046	795.85	217.29	227,285	39.7%	569.69	6.00%	603.87
Residential Lifeline	R-06-01	13,373	893.16	120.00	1,604,760	14.4%	780.73	6.00%	827.58
Residential TOU R-21F									
Residential Lifeline	R-04-21F	4	865.01	120.88	484	49.3%	579.38	6.00%	614.14
Residential Lifeline	R-05-21F	4	865.01	120.88	484	31.3%	658.80	6.00%	698.33
Residential Lifeline	R-08-21F	9	865.01	120.88	1,088	67.4%	516.73	6.00%	547.74
Residential Lifeline	R-06-21F	25	889.89	96.00	2,400	38.6%	642.06	6.00%	680.58
Residential TOU R-70F									
Residential Lifeline	R-04-70F	6	865.01	120.88	725	39.0%	622.31	6.00%	659.65
Residential Lifeline	R-05-70F	16	865.01	120.88	1,934	22.2%	707.86	6.00%	750.34
Residential Lifeline	R-08-70F	24	865.02	120.88	2,901	56.0%	554.50	6.00%	587.77
Residential Lifeline	R-06-70F	109	889.89	96.00	10,464	27.8%	696.31	6.00%	738.09
Residential TOU R-201AF									
Residential Lifeline	05-201AF	3	860.25	58.35	175	29.1%	666.34	6.00%	706.32
Residential Lifeline	08-201AF	12	860.25	58.35	700	63.6%	525.83	6.00%	557.37
Residential Lifeline	06-201AF	336	890.64	27.96	9,395	36.6%	652.01	6.00%	691.13
Residential TOU R-201BF									
Residential Lifeline	05-201BF	-	778.59	105.63	-	24.7%	624.37	6.00%	661.83
Residential Lifeline	06-201BF	12	778.22	96.00	1,152	30.8%	594.97	6.00%	630.67

This chart identifies the excessive increase in lifeline rates. As previously stated, RUCO proposes that the lifeline customer rate increases be limited to the rate increase being proposed for the residential ratepayer class taken as a whole.

Q. Does this conclude your testimony on rate design?

A. Yes.

Tucson Electric Power Company
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RUCO PROPOSED RATE DESIGN - SUMMARY

LINE NO.	DESCRIPTION	(A) RUCO PROPOSED MARGIN	(B) RUCO PROPOSED PPFAC	(C) RUCO TOTAL REVENNUE REQUIREMENT	(D) PERCENTAGE PER MARGIN
1					
2	PER SCHEDULE H-1				
3					
4	Residential Service	$ 262,215,394	$ 118,425,580	$ 380,640,974	44.36%
5	Residential Time Of Use	7,269,795	4,388,547	11,658,341	1.23%
6	Small General Service	133,185,475	62,017,156	195,202,631	22.53%
7	Small General Service Time of Use	7,679,515	4,109,473	11,788,988	1.30%
8	Irrigation & Water Pumping	4,217,005	3,248,547	7,465,552	0.71%
9	Large General Service	81,182,089	33,283,559	114,465,648	13.73%
10	Large General Service Time of Use	9,952,379	7,157,860	17,110,240	1.68%
11	Large Light & Power Service	18,722,540	10,401,627	29,124,167	3.17%
12	Large Light & Power Service Time of Use	22,234,423	16,041,270	38,275,693	3.76%
13	Mining Service	41,115,648	31,928,918	73,044,566	6.96%
14	Traffic Signals & Lighting Service	3,343,776	1,181,323	4,525,100	0.57%
15					
16	TOTAL ADJUSTED REVENUES	$ 591,118,038	$ 292,183,861	$ 883,301,900	100.00%
17					

LINE NO.	DESCRIPTION	(A) TOTAL REVENUE	(B) PERCENTAGE PER TOTAL REVENUE	(C) CUSTOMER COUNT	(D) ADJUSTED SALES kWh
22					
23	Residential Service	$ 392,299,316	44.41%	367,409	3,829,031,022
24	Small General Service	214,457,172	24.28%	37,387	2,178,314,340
25	Large General Service	131,575,887	14.90%	622	1,261,678,481
26	Large Light & Power Service	140,444,426	15.90%	14	1,947,412,723
27	Lighting Service	4,525,100	0.51%	19,566	37,430,789
28					
29	TOTAL ADJUSTED REVENUES	$ 883,301,900	100.00%	424,998	9,253,867,355
30					

LINE NO.	DESCRIPTION	(A) MARGIN	(B) PPFAC	(C) CUSTOMER COUNT	(D) ADJUSTED SALES kWh
33	RESIDENTIAL SERVICE				
34					
35	R-01 - NEW	$ 257,489,149	$ 113,726,221	347,779	3,559,030,499
36	R-201 AN - NEW	$ 7,298,198	$ 4,336,602	10,756	136,224,933
37	RESIDENTIAL TIME-OF-USE				
38	TOU R-80 NEW	$ 6,774,843	$ 4,021,763	8,075	118,997,877
39	TOU R-201 BN NEW	$ 528,959	$ 366,784	798	10,926,086
40	COMMUNITY SOLAR R-01	$ -	$ 362,757	-	3,851,627
41	LIFELINES DISCOUNT NON-TOU	$ (2,571,953)			
42	LIFELINES DISCOUNT TOU	$ (34,007)			
43					
44	RUCO RESIDENTIAL TOTAL PER BILL COUNT	$ 269,485,189	$ 122,814,127	367,409	3,829,031,022
45					
46	COMPANY RESIDENTIAL PROPOSED TOTALS	$ 300,799,863	$ 122,814,127	367,409	3,829,031,022
47					
48	DIFFERENCE				
49					
50					

Tucson Electric Power Company
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RUCO PROPOSED RATE DESIGN - SUMMARY CONT'D

	DESCRIPTION	(A) RUCO PROPOSED MARGIN	(B) RUCO PROPOSED PPFAC	(C) CUSTOMER COUNT	(D) ADJUSTED SALES kWh
51	"OTHER" SERVICE				
52					
53	SMALL GENERAL SERVICE				
54	SGS-10-NEW	$ 131,452,301	$ 60,116,429	35,639	1,888,524,435
55	GS-11 - NEW	3,348,854	1,861,843	339	58,614,700
56	PS-40 DISCOUNT	$ (1,615,680)			
57	C-10 OMMUNITY SOLAR		$ 38,884		
58	SGS-76N-NEW	$ 7,679,515	$ 4,109,473	924	123,590,518
59	PS-43 NEW	$ 2,581,353	$ 1,597,081	339	50,179,432
60	PS-31 NEW	1,635,652	1,651,466	146	57,405,255
61					
62	LARGE GENERAL SERVICE				
63	LGS 13 NEW	$ 81,049,538	$ 33,233,464	535	1,045,063,814
64	CONTRACT PSR	$ 132,551	$ 50,095		
65	LGS 85N NEW	$ 9,952,379	$ 7,157,860	87	216,614,667
66					
67	LARGE LIGHT & POWER SERVICE				
68	I-14	$ 18,722,540	$ 10,401,627	4	351,454,280
69	LLP 90N NEW	$ 21,406,201	$ 15,189,457	8	512,887,038
70	I90 CONTRACT	$ 828,222	$ 851,813		
71	MINING SERVICE	$ 41,115,648	$ 31,928,918	2	1,083,071,404
72					
73	TRAFFIC SIGNAL & LIGHTING SERVICE				
74	PS 41	$ 1,491,582	$ 938,547	1,251	29,734,586
75	LIGHTING	$ 1,852,194	$ 242,776	18,316	7,696,203
76					
77	RUCO "OTHER" TOTALS PER BILL COUNT	$ 321,632,849	$ 169,369,734	57,589	5,424,836,333
78					
79	COMPANY "OTHER" PROPOSED TOTALS	$ 371,708,356	$ 169,375,574	57,589	5,425,012,991
80	DIFFERENCE				
81					
82					
83	RUCO GRAND TOTALS PER BILL COUNT	$ 591,118,038	$ 292,183,861	424,998	9,253,867,355
84					
85	COMPANY GRAND TOTALS PER PROPOSED DESIGN	$ 672,508,219	$ 292,189,701	426,983	9,254,044,013
86					
87	DIFFERENCE				
88	Customer Count Difference Of 1,985 Is Based On TEP Reduced Proposed Rate Charge To $0.00 For Residential Service R-02;				
89	Therefore It Is Appropriate To Remove These Customers From Bill Determinents.				

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Schedule RBM-1
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RUCO PROPOSED RATE DESIGN - SUMMARY CONT'D

LINE NO.	DESCRIPTION		(A)	(B)	(C)	(D)	(E)	(F)	(G)
			TEP TY ADJUSTED		TEP PROPOSED		RUCO PROPOSED		
1	**Residential Service**								
2	Total	$ 392,299,316	45%		44%		44%		
3	PPFAC							$ 122,814,127	
4	Fixed			12%		17%		$ 42,652,837	16%
5	Variable			88%		83%		226,832,352	84%
6	Margin	$ 269,485,189	46%	100%	45%	100%	46%	$ 269,485,189	100%
7									
8	**Small General Service**								
9	Total	$ 214,457,172	28%		27%		24%		
10	PPFAC							$ 69,375,177	
11	Fixed			3%		5%		$ 7,978,309	5%
12	Variable			97%		95%		137,103,686	95%
13	Margin	$ 145,081,995	31%	100%	28%	100%	25%	$ 145,081,995	100%
14									
15	**Large General Service**								
16	Total	$ 131,575,887	12%		14%		15%		
17	PPFAC							$ 40,441,419	
18	Fixed			4%		7%		$ 6,019,667	7%
19	Variable			96%		93%		85,114,801	93%
20	Margin	$ 91,134,468	12%	100%	14%	100%	15%	$ 91,134,468	100%
21									
22	**Large Light & Power Service**								
23	Total	$ 140,444,426	14%		15%		16%		
24	PPFAC							$ 58,371,815	
25	Fixed			0%		0%		$ 305,983	0%
26	Variable			100%		100%		81,766,627	100%
27	Margin	$ 82,072,610	11%	100%	13%	100%	14%	$ 82,072,610	100%
28									
29									
30	**Lighting Service**								
31	Total	$ 4,525,100	0%		1%		1%		
32	PPFAC							$ 1,181,323	
33	Fixed			55%		57%		$ 1,852,194	55%
34	Variable			45%		43%		1,491,582	45%
35	Margin	$ 3,343,776	1%	100%	1%	100%	1%	$ 3,343,776	100%
36	TOTAL REVENUES	$ 883,301,900	100%		100%		100%	$ 883,301,900	
37									
38	MARGIN REVENUES	$ 591,118,038	100%		100%		100%	$ 591,118,038	
39									
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1	**RESIDENTIAL- New**	**R-01 - NEW**						
2	Customer Charge - Single-Phase		4,169,631	-	4,169,631	$ 10.20	$ 42,527,897	
3	Customer Charge - Three-Phase		3,720	-	3,720	$ 15.30	$ 56,913	
4	Summer							$ 42,584,810
5	1st 500 kWhs		774,517,742	-	774,517,742	$ 0.049578	$ 38,398,719	
6	Next 3,000 kWhs		1,111,304,840	-	1,111,304,840	$ 0.070315	$ 78,141,400	
7	3,501 kWhs and above		25,660,435	-	25,660,435	$ 0.092754	$ 2,380,102	
8	Winter							
9	1st 500 kWhs		964,189,143	-	964,189,143	$ 0.047724	$ 46,015,085	
10	Next 3,000 kWhs		676,975,492	-	676,975,492	$ 0.073051	$ 49,453,932	
11	3,501 kWhs and above		6,382,846	-	6,382,846	$ 0.080701	$ 515,101	
12	Purchased Power & Fuel							$ 214,904,340
13	Summer kWh		1,911,483,017	-	1,911,483,017	$ 0.033075	$ 63,222,301	
14	Winter kWh		1,647,547,482	-	1,647,547,482	$ 0.030654	$ 50,503,921	
15								$ 113,726,221
16	TOTAL REVENUE - RESIDENTIAL- New							$ 371,215,371
17								
18	**RESIDENTIAL - Special Electric Service - New**	**R-201-AN-NEW**						
19	Customer Charge - Single Phase		129,075	-	129,075	$ 10.20	$ 1,316,497	$ 1,316,497
20	Summer							
21	1st 500 kWhs		27,210,039	-	27,210,039	$ 0.040712	$ 1,107,766	
22	Next 3,000 kWhs		38,863,107	-	38,863,107	$ 0.056256	$ 2,186,274	
23	3,501 kWhs and above		330,324	-	330,324	$ 0.058296	$ 19,256	
24	Winter							
25	1st 500 kWhs		36,548,595	-	36,548,595	$ 0.030809	$ 1,126,020	
26	Next 3,000 kWhs		33,098,403	-	33,098,403	$ 0.046353	$ 1,534,208	
27	3,501 kWhs and above		174,465	-	174,465	$ 0.046863	$ 8,176	
28	Purchased Power & Fuel							$ 5,981,701
29	Summer kWh		66,403,470	-	66,403,470	$ 0.03308	$ 2,196,295	
30	Winter kWh		69,821,463	-	69,821,463	$ 0.03065	$ 2,140,307	
31								$ 4,336,602
32	**TOTAL REVENUE - RESIDENTIAL Special Electric Service - New**							$ 11,634,800
33								
34	**RESIDENTIAL- Time-Of-Use - New**	**R-80 NEW**						
35	Customer Charge - Single Phase		96,901	-	96,901	$ 12.75	$ 1,235,414	$ 1,235,414
36	Summer On Peak kWh		38,269,931	-	38,269,931	$ 0.060494	$ 2,315,089	
37	Summer Off Peak kWh		26,030,842	-	26,030,842	$ 0.047248	$ 1,229,909	
38	Winter On Peak kWh		21,519,575	-	21,519,575	$ 0.036927	$ 794,652	
39	Winter Off Peak kWh		33,177,530	-	33,177,530	$ 0.036162	$ 1,199,779	
40	Purchased Power & Fuel							$ 5,539,429
41	Summer On Peak kWh		38,269,931	-	38,269,931	$ 0.038739	$ 1,482,539	
42	Summer Off Peak kWh		26,030,842	-	26,030,842	$ 0.030187	$ 785,797	
43	Winter On Peak kWh		21,519,575	-	21,519,575	$ 0.034305	$ 738,221	
44	Winter Off Peak kWh		33,177,530	-	33,177,530	$ 0.030599	$ 1,015,206	
45								$ 4,021,763
46	TOTAL REVENUE - RESIDENTIAL- Time-Of-Use							$ 10,796,605
47								
48								
49								
50								

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51	**RESIDENTIAL- Time-Of-Use Special Electric Service - New**	**TOU R-201-BN-NEW**						
52	Customer Charge - Single Phase		9,575	-	9,575	$ 12.75	$ 122,076	$ 122,076
53	Summer On Peak kWh		3,054,312	-	3,054,312	$ 0.043064	$ 131,532	
54	Summer Off Peak kWh		2,081,926	-	2,081,926	$ 0.042007	$ 87,455	
55	Winter On Peak kWh		2,280,693	-	2,280,693	$ 0.032865	$ 74,955	
56	Winter Off Peak kWh		3,509,155	-	3,509,155	$ 0.032185	$ 112,942	
57	Purchased Power & Fuel							$ 406,883
58	Summer On Peak kWh		3,054,312	-	3,054,312	$ 0.038739	$ 118,321	
59	Summer Off Peak kWh		2,081,926	-	2,081,926	$ 0.030187	$ 62,847	
60	Winter On Peak kWh		2,280,693	-	2,280,693	$ 0.034305	$ 78,238	
61	Winter Off Peak kWh		3,509,155	-	3,509,155	$ 0.030599	$ 107,377	
62								$ 366,784
63	TOTAL REVENUE - RESIDENTIAL- Time-Of-Use Special Electric Service							$ 895,743
64								
65	REVENUE - RESIDENTIAL- FIXED						$ 45,258,797	
66	REVENUE - RESIDENTIAL- VARIABLE						$ 226,832,352	
67	LIFELINE DISCOUNT Non-TOU						$ (2,571,953)	
68	LIFELINE DISCOUNT -TOU						$ (34,007)	
69	TOTAL REVENUE - RESIDENTIAL- MARGIN							$ 269,485,189
70	TOTAL REVENUE - RESIDENTIAL- PPFAC							$ 122,814,127
71	PPFAC DISCOUNT - Non-TOU							
72	PPFAC DISCOUNT -TOU							
73	**TOTAL RESIDENTIAL REVENUE**							$ 392,299,316
74								
75								
76	**Small General Service - New**	**SGS-10 NEW**						
77	Customer Charge - Single-Phase		215,020	-	215,020	$ 15.30	$ 3,289,625	
78	Customer Charge - Three-Phase		212,653	-	212,653	$ 20.40	$ 4,337,883	
79	Summer							$ 7,627,508
80	1st 500 kWhs		74,822,676	-	74,822,676	$ 0.058398	$ 4,369,500	
81	501 kWhs and above		844,467,249	-	844,467,249	$ 0.074777	$ 63,146,795	
82	Winter							
83	1st 500 kWhs		105,220,676	-	105,220,676	$ 0.043091	$ 4,534,020	
84	501 kWhs and above		864,013,835	-	864,013,835	$ 0.059929	$ 51,779,327	
85	Primary Metering Discount						$ (4,848)	$ 123,824,794
86	Purchased Power & Fuel							
87	Summer kWh		919,289,925	-	919,289,925	$ 0.033075	$ 30,405,514	
88	Winter kWh		969,234,510	-	969,234,510	$ 0.030654	$ 29,710,915	
89								$ 60,116,429
90	PS-40 Margin Discount							$ (1,615,680)
91	TOTAL REVENUE - Small General Service							$ 189,953,050
92								
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99								
100								

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101	**Small General Service - Time-Of-Use - New**	**SGS-76N NEW**						
102	Customer Charge - Single Phase		11,088	-	11,088	$ 17.85	$ 197,910	$ 197,910
103	Summer On Peak kWh		29,840,723	-	29,840,723	$ 0.073017	$ 2,178,872	
104	Summer Off Peak kWh		28,458,762	-	28,458,762	$ 0.065363	$ 1,860,149	
105	Winter On Peak kWh		26,052,011	-	26,052,011	$ 0.057327	$ 1,493,472	
106	Winter Off Peak kWh		39,239,023	-	39,239,023	$ 0.049673	$ 1,949,112	
107	Purchased Power & Fuel							$ 7,481,605
108	Summer On Peak kWh		29,840,723	-	29,840,723	$ 0.038739	$ 1,156,000	
109	Summer Off Peak kWh		28,458,762	-	28,458,762	$ 0.030187	$ 859,085	
110	Winter On Peak kWh		26,052,011	-	26,052,011	$ 0.034305	$ 893,714	
111	Winter Off Peak kWh		39,239,023	-	39,239,023	$ 0.030599	$ 1,200,675	
112								$ 4,109,473
113	TOTAL REVENUE - Small General Service - Time-Of-Use							$ 11,788,988
114								
115	**Mobile Home Park Service - New**	**GS-11 NEW**						
116	Customer Charge - Single Phase		3,722	-	3,722	$ 15.30	$ 56,938	
117	Customer Charge - Three Phase		346	-	346	$ 20.40	$ 7,066	$ 64,003
118	Summer All kWh		26,876,589	-	26,876,589	$ 0.064445	$ 1,732,049	
119	Winter All kWh		31,738,111	-	31,738,111	$ 0.049137	$ 1,559,517	
120	Primary Metering Discount						$ (3,285)	
121	Transformer Owned Discount						$ (3,430)	
122	Purchased Power & Fuel							$ 3,284,851
123	Summer kWh		26,876,589	-	26,876,589	$ 0.033075	$ 888,943	
124	Winter kWh		31,738,111	-	31,738,111	$ 0.030654	$ 972,900	
125								$ 1,861,843
126	TOTAL REVENUE - Mobile Home Park Service							$ 5,210,697
127								
128	**Firm Service Municipal Water Pumping Service - New**	**PS-43 NEW**						
129	Customer Charge		4,063	-	4,063	$ 15.30	$ 62,160	$ 62,160
130	Summer Delivery kWh		24,321,024	-	24,321,024	$ 0.058092	$ 1,412,855	
131	Winter Delivery kWh		25,858,408	-	25,858,408	$ 0.042784	$ 1,106,337	
132	Purchased Power & Fuel						$ -	$ 2,519,192
133	Summer kWh		24,321,024	-	24,321,024	$ 0.033075	$ 804,418	
134	Winter kWh		25,858,408	-	25,858,408	$ 0.030654	$ 792,664	
135								$ 1,597,081
136	TOTAL REVENUE - Firm Service Municipal Water Pumping Service							$ 4,178,434
137								
138	**Interruptible Agricultural Pumping - New**	**PS-31 NEW**						
139	Customer Charge		1,747	-	1,747	$ 15.30	$ 26,728	$ 26,728
140	Summer All kWh		31,079,701	-	31,079,701	$ 0.035304	$ 1,097,235	
141	Winter All kWh		26,325,555	-	26,325,555	$ 0.019437	$ 511,689	
142	Purchased Power & Fuel							$ 1,608,925
143	Summer kWh		31,079,701	-	31,079,701	$ 0.029768	$ 925,181	
144	Winter kWh		26,325,555	-	26,325,555	$ 0.027589	$ 726,285	
145								$ 1,651,466
146	TOTAL REVENUE - Interruptible Agricultural Pumping							$ 3,287,118
147								
148								
149								
150								

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151	**Large General Service - New**	**LGS-13 NEW**						
152	Customer Charge		6,420	-	6,420	$ 764.96	$ 4,911,030	$ 4,911,030
153	All Demand kW		3,277,679	-	3,277,679	$ 21.00	$ 68,831,262	
154	Energy							
155	Summer kWh		494,868,791	-	494,868,791	$ 0.007219	$ 3,572,681	
156	Winter kWh		550,195,023	-	550,195,023	$ 0.006902	$ 3,797,508	
157	Primary Metering Discount						$ (35,628)	
158	Transformer Owned Discount						$ (27,317)	
159	Purchased Power & Fuel							$ 76,138,508
160	Summer kWh		494,868,791	-	494,868,791	$ 0.033075	$ 16,367,785	
161	Winter kWh		550,195,023	-	550,195,023	$ 0.030654	$ 16,865,678	
162								$ 33,233,464
163	TOTAL REVENUE - Large General Service							$ 114,283,001
164								
165	**Large General Service - Time-Of-Use - New**	**LGS-85N NEW**						
166	Customer Charge		1,044	-	1,044	$ 934.95	$ 976,086	$ 976,086
167	Demand							
168	Summer On-Peak kW		190,618	-	190,618	$ 20.00	$ 3,812,361	
169	Summer Off-peak kW		131,265	-	131,265			
170	Winter On-Peak kW		257,042	-	257,042	$ 18.00	$ 4,626,749	
171	Winter Off-peak kW		161,933	-	161,933			
172	Energy							
173	Summer On-peak kWh		48,988,303	(39,915)	48,948,388	$ 0.003576	$ 175,048	
174	Summer Off-peak kWh		49,196,404	(40,084)	49,156,320	$ 0.002940	$ 144,540	
175	Winter On-peak kWh		40,905,653	(33,329)	40,872,324	$ 0.002305	$ 94,196	
176	Winter Off-peak kWh		77,700,944	(63,309)	77,637,635	$ 0.001589	$ 123,398	
177	Adjustment Reflects Difference Between TEP TY Ajusted & Proposed Bill Determinents. Commodity Count Is The Weight			(176,637)				
178	Purchased Power & Fuel							$ 8,976,293
179	Summer On-peak kWh		48,988,303	(39,915)	48,948,388	$ 0.038739	$ 1,896,212	
180	Summer Off-peak kWh		49,196,404	(40,084)	49,156,320	$ 0.030187	$ 1,483,889	
181	Winter On-peak kWh		40,905,653	(33,329)	40,872,324	$ 0.034305	$ 1,402,111	
182	Winter Off-peak kWh		77,700,944	(63,309)	77,637,635	$ 0.030599	$ 2,375,649	
183	Adjustment Reflects Difference Between TEP TY Ajusted & Proposed Bill Determinents. Commodity Count Is The Weight			(176,637)				
184								$ 7,157,860
185	TOTAL REVENUE - Time-Of-Use Large General Service							$ 17,110,240
186								
187	**Large Light & Power**	**I-14**						
188	Customer Charge		48	-	48	$ 1,699.91	$ 81,596	$ 81,596
189	All Demand kW		775,035	-	775,035	$ 21.00	$ 16,275,730	
190	Energy							
191	Summer kWh		164,577,383	-	164,577,383	$ 0.007152	$ 1,177,116	
192	Winter kWh		186,876,897	-	186,876,897	$ 0.006358	$ 1,188,098	
193	Purchased Power & Fuel							$ 18,640,944
194	Summer kWh		164,577,383	-	164,577,383	$ 0.030795	$ 5,068,161	
195	Winter kWh		186,876,897	-	186,876,897	$ 0.028540	$ 5,333,467	
196								$ 10,401,627
197	TOTAL REVENUE - Large Light & Power							$ 29,124,167
198								
199								
200								

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201	**Large Light & Power - Time-Of-Use - New**	**I-90N NEW**						
202	Customer Charge		96	-	96	$ 1,869.90	$ 179,510	$ 179,510
203	Demand							
204	Summer kW		389,779	-	389,779	$ 22.00	$ 8,575,130	
205	Winter kW		553,780	-	553,780	$ 19.00	$ 10,521,824	
206	Energy							
207	Summer On Peak kWh		110,511,318	(5)	110,511,314	$ 0.004848	$ 535,727	
208	Summer Off Peak kWh		122,033,912	(5)	122,033,907	$ 0.004053	$ 494,604	
209	Winter On Peak kWh		93,840,290	(4)	93,840,286	$ 0.004450	$ 417,623	
210	Winter Off Peak kWh		186,501,539	(8)	186,501,531	$ 0.003656	$ 681,784	
211	Adjustment Reflects Difference Between TEP TY Ajusted & Proposed Bill Determinents. Commodity Count Is The Weighted			(21)				
212	Purchased Power & Fuel							$ 21,226,691
213	Summer On Peak kWh		110,511,318	(5)	110,511,314	$ 0.034837	$ 3,849,883	
214	Summer Off Peak kWh		122,033,912	(5)	122,033,907	$ 0.027146	$ 3,312,732	
215	Winter On Peak kWh		93,840,290	(4)	93,840,286	$ 0.030849	$ 2,894,879	
216	Winter Off Peak kWh		186,501,539	(8)	186,501,531	$ 0.027517	$ 5,131,963	
217	Adjustment Reflects Difference Between TEP TY Ajusted & Proposed Bill Determinents. Commodity Count Is The Weighted			(21)				
218								$ 15,189,457
219	TOTAL REVENUE - Large Light & Power - Time-Of-Use - New							$ 36,595,658
220								
221	**Mining**							
222	Customer Charge		24	-	24	$ 1,869.90	$ 44,878	$ 44,878
223	Demand							
224	Summer On Peak kW		762,919	-	762,919	$ 22.00	$ 16,784,209	
225	Summer Off Peak kW							
226	Winter On Peak kW		1,043,162	-	1,043,162	$ 19.00	$ 19,820,073	
227	Winter Off Peak kW							
228	Energy							
229	Summer On Peak kWh		204,784,496	-	204,784,496	$ 0.004848	$ 992,736	
230	Summer Off Peak kWh		233,607,818	-	233,607,818	$ 0.004053	$ 946,813	
231	Winter On Peak kWh		214,192,112	-	214,192,112	$ 0.004450	$ 953,231	
232	Winter Off Peak kWh		430,486,978	-	430,486,978	$ 0.003656	$ 1,573,709	
233	Purchased Power & Fuel							$ 41,070,771
234	Summer On Peak kWh		204,784,496	-	204,784,496	$ 0.034837	$ 7,134,077	
235	Summer Off Peak kWh		233,607,818	-	233,607,818	$ 0.027146	$ 6,341,518	
236	Winter On Peak kWh		214,192,112	-	214,192,112	$ 0.030849	$ 6,607,612	
237	Winter Off Peak kWh		430,486,978	-	430,486,978	$ 0.027517	$ 11,845,710	
238								$ 31,928,918
239	TOTAL REVENUE - Mining							$ 73,044,566
240								
241	**Traffic Signal & Street Light Service**	**PS-41**						
242	Customer Charge		15,006	-	15,006			$ -
243	Summer All kWh		11,178,373	-	11,178,373	$ 0.060772	$ 679,328	
244	Winter All kWh		18,556,213	-	18,556,213	$ 0.043773	$ 812,254	
245	Purchased Power & Fuel							$ 1,491,582
246	Summer kWh		11,178,373	-	11,178,373	$ 0.033075	$ 369,725	
247	Winter kWh		18,556,213	-	18,556,213	$ 0.030654	$ 568,822	
248								$ 938,547
249	TOTAL REVENUE - Traffic Signal & Light Service							$ 2,430,129
250								

Tucson Electric Power Company
Docket No. E-01933A-12-0291
Test Year Ended December 31, 2011

Schedule RBM-2
Pages 1 Thru 6

RUCO PROPOSED RATE DESIGN

LINE NO.	DESCRIPTION	(A) RATE SCH.	(B) TEP PROPOSED BILL DETERMINENTS	(C) RUCO ADJUSTMENTS	(D) RUCO PROP'D BILL DETERM'TS	(E) RUCO PROP'D RATES AND CHARGES	(F) RUCO PROPOSED REVENUE CALCULATION	(G) RUCO PROPOSED REVENUE BY CUST. CLASS
251	**Lighting Service**							
252	55 Watt		1,428	-	1,428	$ 8.21	$ 11,726	
253	70 Watt		2,472	-	2,472	$ 8.21	$ 20,298	
254	100 Watt		121,283	-	121,283	$ 8.21	$ 995,871	
255	250 Watt		19,574	-	19,574	$ 12.32	$ 241,165	
256	400 Watt		3,904	-	3,904	$ 19.01	$ 74,198	
257	Underground		23,986	-	23,986	$ 15.57	$ 373,543	
258	Pole		47,144	-	47,144	$ 2.87	$ 135,394	
259								$ 1,852,194
260	Purchase Power & Fuel							
261	400 Watt							
262	Summer kWh		2,832,315	-	2,832,315	$ 0.03308	$ 93,679	
263	Winter kWh		4,863,888	-	4,863,888	$ 0.03065	$ 149,098	
264	TOTAL REVENUE - Lighting Service							$ 242,776
265								$ 2,094,971
266	TOTAL REVENUE - Community General Service Solar	GS-03-10					$ 38,884	
267								
268	REVENUE - OTHER- FIXED						$ 15,368,696	
269	REVENUE - OTHER- VARIABLE						$ 306,264,154	
270	REVENUE - OTHER - MARGIN							$ 321,632,849
271	REVENUE - OTHER - PPFAC							$ 169,369,734
272	**TOTAL OTHER REVENUE**							$ 491,002,584
273								
274	**TOTAL RESIDENTIAL REVENUE**							$ 392,299,316
275	Unreconciled Difference Between TEP TY Adjusted And TEP Proposed Bill Detrerminents							$ 6,389
276	**TOTAL RUCO PROPOSED REVENUE**							$ 883,308,288
277								
278								
279								
280	TOTAL TEP PROPOSED REVENUE							$ 883,308,288
281								
282								
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Tucson Electric Power Company
Docket No. E-01933A-12-0291
Test Year Ended December 31, 2011

TYPICAL RESIDENTIAL BILL ANALYSIS

LINE NO.	DESCRIPTION		(A) PRESENT RATES	(B) TEP PROPOSED	(C) RUCO PROPOSED		
1	**RESIDENTIAL - R-01 - New**						
2	Customer Charge - Single-Phase		$ 7.00	$ 12.00	$ 10.20		
3							
4	Summer						
5	1st 500 kWhs		$ 0.046925	$ 0.061700	$ 0.049578		
6	Next 3,000 kWhs		$ 0.068960	$ 0.083700	$ 0.070315		
7	3,501 kWhs and above		$ 0.088960	$ 0.083700	$ 0.092754		
8	Winter						
9	1st 500 kWhs		$ 0.047309	$ 0.046700	$ 0.047724		
10	Next 3,000 kWhs		$ 0.067309	$ 0.068700	$ 0.073051		
11	3,501 kWhs and above		$ 0.087309	$ 0.068700	$ 0.080701		
12	Purchased Power & Fuel						
13	Summer kWh		$ 0.033198	$ 0.033075	$ 0.033075		
14	Winter kWh		$ 0.025698	$ 0.030654	$ 0.030654		
15							
16							
17							
18							
19	**RESIDENTIAL BILL COMPARISONS**	KWH USED	PRESENT MONTHLY COSTS	TEP PROPOSED MONTHLY COSTS	RUCO PROPOSED MONTHLY COSTS	RUCO PROPOSED MONTHLY INCREASE	RUCO PROPOSED MONTHLY INCREASE
20							
21	Total Monthly Electric Bills at Different Usage Levels (Includes PPFAC)						
22							
23	Residential Service - R-01 - Summer	250	$27.03	$35.69	$30.86	$3.83	14.18%
24	Present Summer Months - May - October (6 Months)	500	$47.06	$59.39	$51.53	$4.46	9.49%
25	Proposed Summer Months - May - September (6 Months)	1,000	$98.14	$117.78	$103.22	$5.08	5.18%
26		2,000	$200.30	$234.55	$206.61	$6.31	3.15%
27		3,500	$353.54	$409.71	$361.70	$8.16	2.31%
28		5,000	$536.77	$584.88	$550.44	$13.67	2.55%
29							
30	Residential Service - R-01 - Winter	250	$25.25	$31.34	$29.79	$4.54	17.99%
31	Present Winter Months - November - April (5 Months)	500	$43.50	$50.68	$49.39	$5.89	13.53%
32	Proposed Winter Months - October - April (7 Months)	1,000	$93.76	$101.56	$102.45	$8.69	9.27%
33		2,000	$159.36	$176.36	$181.08	$21.72	13.63%
34		3,500	$322.52	$348.74	$360.50	$37.98	11.78%
35		5,000	$492.04	$497.77	$527.54	$35.50	7.22%
36							
37	The Average Residential R-01 Customer's Summer Bill	1,053	$103.55	$123.96	$108.70	$5.15	4.97%
38	The Average Residential R-01 Customer's Winter Bill	657	$61.86	$67.49	$66.88	$5.03	8.12%
39							
40							
41							

TUCSON ELECTRIC POWER COMPANY

DOCKET NO. E-01933A-12-0291

DIRECT TESTIMONY

OF

ROBERT B. MEASE

ON

ENERGY EFFICIENCY RESOURCE PLAN

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JANUARY 11, 2013

TABLE OF CONTENTS – ENERGY EFFICIENCY RESOURCE PLAN

INTRODUCTION

REVIEW OF TEP 2012 EE IMPLENTATION PLAN DOCKET

Q. Before getting into the details of the EERP, please provide a quick review TEP's current Energy Efficiency Plan.

A. TEP recovers dollar-for-dollar the costs of energy efficiency programs through its Demand Side Management Surcharge ("DSMS"). The Commission set TEP's current DSMS rate of $0.00129 per kWh in Decision No. 71720. The DSMS surcharge rate went into effect June 1, 2010. Decision No. 71720 allowed TEP to recover: (1) its estimated 2010 EE program expenses; (2) a 2009 Performance Incentive; and (3) some under recovery of previous years' program costs.[1] The current DSMS surcharge collects approximately $11 million per year.

In January 2011, TEP filed an Application for approval of expanded EE programs. For numerous reasons, there was significant delay relating to this docket, and ultimately this matter was sent to hearing. At hearing, RUCO joined TEP and other intervenors and supported

[1] See Docket No. E-01933A-11-0055 Recommended Opinion and Order, FOF 31, p. 9

TEP's "Updated Plan".[2] This was a 15 month plan beginning October 2012 and ending December 2013 with the following details:

	Updated Plan Oct. 2012 – Dec. 2013
PROGRAM COST	$18,532,606
PERFORMANCE INCENTIVE	
2010	$1,114,648
2011	$1,101,749
2012	$3,283,854
UNDERCOLLECTED BALANCE Thru 2011	$3,862,556[3]
TOTAL	**$27,894,412**[4]

The Updated Plan proposed to increase the DSMS to $0.002497 per kWh from $0.00129 per kWh for residential customers which increased the average residential bill to $2.20 from $1.10.[5]

Q. What is the status of the Updated Plan?

A. The matter is ready for Commission review at an Open Meeting. The ALJ has issued a Recommended Order and Opinion recommending approval of the Updated Plan. However, it is likely that this matter will not be placed on an Open Meeting agenda in the near future – due, in part, that

[2] Staff opposed the Updated Plan.
[3] TEP originally identified an under recovered balance of $13,440,236 through 2011. However, TEP agreed to accept a reduced unrecovered balance amount of $3,862,556. At the time of hearing TEP identified its under collected bank balance at $6.5 million (ROO at p. 10, ftnte 27). However, RUCO understands that as of October 2012, the balance is $5.5 million.
[4] TEP also requested the creation of a lost fixed cost recovery mechanism (AART). Through discussions with other parties, TEP agreed to eliminate its request for the mechanism.
[5] See Docket No. E-01933A-11-0055 Recommended Order and Opinion, FOF 50, p. 16.

the 2012 Updated Plan was intended to serve as a "bridge" until the next rate case, which is now before us.

Q. How does TEP plan to recover any under collected DSMS balance going forward?

A. Footnotes 7 and 8 on page 66 of Craig Jones's Direct Testimony leads RUCO to believe that TEP anticipated the possibility of a balance and would recover it beginning in 2013.

Q. Does RUCO agree with TEP's claim that it has faced "challenges" in implementing its EE Programs?

A. RUCO understands TEP's frustrations. The Company filed its Application in January 2011. Yet, as 2012 draws to a close, TEP still has no Plan in place to meet the EE Standard. TEP has scaled back DSM/EE programs to fit within the revenues collected under the 2010 DSMS rate.

TEP has an admirable track record of making a good faith effort to meet the ACC Energy Efficiency Standard despite incurring a significant under collected balance. And, from public comment, it appears that TEP has the overwhelming support of the community to provide enhanced, cost effective EE programs. RUCO is very appreciative of TEP's willingness to address RUCO's concerns in the 2012 EE Plan docket and to find compromise in that matter.

RUCO OPPOSES TEP'S ENERGY EFFICIENCY RESOURCE PLAN AS FILED IN THE PENDING RATE CASE

Q. Does RUCO believe that TEP's proposed EERP is the best way to alleviate those challenges?

A. No. RUCO respectfully opposes TEP's proposal and finds it not to be in the best interest of ratepayers. Yet, RUCO understands the motivations behind the EERP and is willing to investigate other possibilities to reduce administrative delay, set affordable DSMS rates, and provide program level certainty to the utility, its customers, and DSM/EE contractors.

Q. Please describe the EERP.

A. In summary, TEP proposes the EERP as a "pilot program" to address the "challenges the Company has faced in implementing its EE programs". The EERP:

1. Establishes a 3-year Plan period commencing August 1, 2013.
2. Sets annual EE budgets as follows:

Year 1	$24,739,192
Year 2	$27,044,908
Year 3	$27,856,255

3. Capitalizes the program costs of the Plan and amortizes recovery over a four (4) year period.

4. Applies a Performance Incentive to the amount spent on EE calculated as the authorized Rate of Return plus a 200 basis point premium added to the cost of equity and recovers it over the same four (4) year period.
5. Creates a regulatory asset for recovery of the revenues spent on EE programs.
6. Authorizes TEP to select and administer DSM/EE programs it independently determines to be cost effective over the three years of the EERP consistent with the approved annual budgets.
7. Eliminates annual Commission review and approval of EE plans.
8. Includes a Plan of Administration that includes a Societal Cost Test Template that TEP would use to determine cost effectiveness.

Q. In summary, why does RUCO oppose the EERP?

A. RUCO opposes the EERP because it is not in the best interest of ratepayers for the following reasons:

1. By capitalizing program costs and applying carrying costs, the ratepayers may end up paying more for the EE programs than if these costs were expensed.
2. The rate of return plus 200 basis points premium that is applied to the DSM/EE program costs constitutes a performance incentive that is not based on actual performance and rewards spending over EE savings.

3. The 3 year term unnecessarily binds future Commissions to spending levels and program structure.
4. The EERP eliminates significant Commission oversight.
5. The EERP commits the ratepayers to pay $96.6 million over six (6) years for a three (3) year program without any detail on what programs or measures the Company will implement.

EERP MAY COST RATEPAYERS MORE IN THE LONG RUN

Q. Since rate impact is an important consideration for RUCO, why doesn't RUCO support a methodology that reduces the DSMS rate while still providing adequate revenue to TEP to meet the EE Standard?

A. According to TEP, the 3 year EERP program costs equal $79,640,355. However, over the amortization period, ratepayers will pay a total of $96,619,255.[6] This is $16,978,900 over the actual costs of the DSM/EE program. The carrying costs plus premium associated with capitalizing the EE program increases costs in the long run.

RUCO has consistently supported ***cost effective*** energy efficiency programs. With that said, RUCO has also recommended that any EE goal be aggressive yet realistic. RUCO notes TEP's concern that the EE

[6] Craig Jones, Direct Testimony at p. 65.

Standard may not be achievable or may be so costly that compliance is unfeasible.

> "While TEP supports the underlying principles, the Company has continuously asserted that the EES goals may not be reasonably achievable and, as such, may create unintended consequences for utilities and customers. For instance EES compliance costs increase significantly each year as utilities are required to meet ever increasing annual and cumulative savings goals. Cost will escalate further as utilities exhaust the potential of the simplest and most cost effective measures and are forced to invest in less productive and more expensive programs." (Hutchens Direct Testimony, p. 16.)

If meeting the EE Standard is not "reasonably achievable", then the solution is not to exacerbate the problem by making the program costs more expensive over the long run. Furthermore, if TEP believes that "costs will escalate" and it will be "forced to invest in less productive and more expensive programs" then committing to a long term plan, eliminating Commission oversight and setting a performance incentive that is not based on performance is not in the best interest of ratepayers.

Q. Any other concern with capitalizing the DSMS costs?

A. Another consideration for RUCO is that the artificially reduced DSMS rate masks the true cost of EE.

Q. Which rate of return will TEP use in its performance incentive in the EERP?

A. TEP proposes to apply its Weighted Average Cost of Capital (WACC) and not the Fair Value Rate of Return (FVROR). Since the WACC is higher than the FVROR, applying the WACC instead of the FVROR further enriches the EERP's performance incentive. When adding an additional 200 basis points to the cost of equity using the WACC, TEP would receive a 8.67% return on its DSM/EE programs.

FVROR	5.68%
WACC	7.74%
EERP	8.67%

Q. Please discuss further why RUCO does not find value in paying carrying costs plus a premium for the benefit of a lower DSMS rate.

A. Mr. Jones's testimony compares the DSMS rate impact for the average residential ratepayer if costs are capitalized or expensed.

	2014	2015	2016	2017	2018	2019
Current Method	$2.04	$2.69	$2.74	$0	$0	$0
EERP Method	$0.81	$1.45	$2.16	$1.99	$1.31	$0.64
Difference	($1.23)	($1.23)	($0.58)	**$1.99**	**$1.31**	**$0.64**

Under the EERP proposal, ratepayers pay an extra $16,978,900 for the "benefit" of paying $1.23 ***less*** in 2014 and 2015, $0.58 ***less*** in 2016, but paying $1.99 ***more*** in 2017, $1.31 ***more*** in 2018 and $0.64 ***more*** in 2019. Moreover, these costs, beginning in 2017, would be ***in addition to*** whatever EE program costs the Commission approves in those years.

Q. Is RUCO's sole objection about the rate of return plus premium incentive the fact that $16.9 million is added to the EE budget?

A. No. RUCO understands that the proposed $79.6 million is only for the actual program costs. The $16.9 million, which is in addition to the $79.6 million, is not of value to ratepayers. Finally, the rate of return would also be in addition to the $79.6 million that the Company is requesting.

Q. What if, hypothetically, a performance-based incentive came out to be the same amount as the rate of return plus premium incentive? Would this overcome RUCO's objection?

A. Not really. First, RUCO believes that an incentive should be based on performance and not on the amount spent. Second, RUCO suspects that the rate of return plus premium incentive is more generous than a performance incentive.[7]

EERP CONTAINS A PERFORMANCE INCENTIVE TH AT REWARDS SPENDING OVER PERFORMANCE

[7] RUCO does not have the details of an alternative incentive mechanism in order to compare the two models.

Q. TEP claims its EERP eliminates the Performance Incentive. Yet, RUCO contends that the Performance Incentive still exists but has taken a different form. Please explain the difference of opinion.

A. It is well established that applying a rate of return to EE program costs is a type of incentive. There are three (3) major types of incentive mechanisms:[8]

1. performance target incentives.
2. shared savings incentives.
3. rate of return adders.

As the American Council for an Energy-Efficiency Economy (ACEEE) states:

> "While program cost and lost margin recovery mechanisms serve to mitigate the utility disincentive to invest in energy efficiency due to a reduction in sales, they do not necessarily provide an incentive for such investment. Even with a decoupling mechanism in place, investor-owned utilities often still have an incentive to make supply side investments because of the beneficial effect on stock price...***Because performance incentives are relatively easier to enact than decoupling, they are widely used by states that have mechanisms in place beyond program cost recovery...Several common approaches include: Performance target incentives, shared savings incentives and <u>rate of return incentives</u>***." (Emphasis added) (See Attachment B or go to http://aceee.org/sector/state-policy/toolkit/utility-programs/performance-incentives)

[8] See "Aligning Utility Incentives with Investment in Energy Efficiency: "A Resource of the National Action Plan for Energy Efficiency.", p. ES-3 http://www.epa.gov/cleanenergy/documents/suca/incentives.pdf

In a paper co-authored by Howard Geller of the Southwest Energy Efficiency Project (SWEEP), Mr. Geller identifies the various types of performance incentives:

> "Other states including Arizona, Connecticut, Massachusetts, Minnesota and Nevada have adopted performance incentives (also known as shareholder incentives) to reward utilities for implementing effective DSM programs and overcome their historical reluctance for doing so. ***Various approaches to performance incentives exist, including allowing utilities to earn a higher-than-normal rate of return*** on some or all DSM expenditures, allowing utilities to earn a bonus if they meet certain energy savings targets, or allowing utilities to keep a portion fo the net economic benefits resulting from their DSM programs." [9] (Emphasis added)

Q. What is the Performance Incentive – the entire rate of return plus the 200 basis point premium or solely the 200 basis points premium?

A. It could be argued that only the 200 basis points premium to the cost of equity is the performance incentive and that the rate of return covers the carrying costs necessary to compensate the utility for waiting four years for complete program cost recovery. However, RUCO finds that the entire rate of return plus the premium constitutes the performance incentive. RUCO comes to this conclusion because the entire rate applied to the DSM/EE programs is a bonus over and above the recovery of program costs and lost fixed costs needed to make the utility whole for its EE

[9] "Utah Energy Efficiency Strategy: Policy Options" http://www.swenergy.org/publications/documents/UT_Energy_Efficiency_Strategy.pdf)

programs. It is an even higher rate of return than the utility would have earned if it had placed new plant in service. And a performance incentive is intended, in part, to eliminate the financial disincentive to implement EE programs rather than to invest in new plant.

Q. Why should a utility even be given a performance incentive bonus? After all, in exchange for compliance with the EE Rules, the utility is made whole through recovery of program costs and is even afforded recovery of its lost fixed costs. In other words, what is the reason *the utility* supports a performance incentive?

A. In short, one purpose of a performance incentive is to eliminate the financial disincentive to choose energy efficiency over building new plant. Under traditional ratemaking principles, a utility earns a return (a profit) on capital invested in plant. Unless given an opportunity to earn a profit from its EE programs, there is an economic preference to invest in new plant rather than in EE programs because a utility is only made whole for its EE efforts but earns a return on capital investments.

Q. One purpose of a performance incentive is to eliminate the financial disincentive that favors adding plant over promoting energy efficiency. Isn't another equally – if not more important – objective of the performance incentive to incent superior performance in the

execution of cost efficient EE programs? In other words, what is the reason *the ratepayer* supports a performance incentive?

A. The ratepayer benefits when cost effective energy efficiency programs result in actual and sustained energy savings. When a utility selects EE programs that yield the greatest savings for the lowest cost, the ratepayers receive the maximum benefit. TEP's customers are captive – they have no choice but to receive service from TEP. A bonus structure that rewards the greatest results for the lowest costs is the best option for the ratepayer.

Q. Has the Commission expressed any guidance on how a performance incentive should be structured?

A. Yes. In the most recent APS rate case, the Commission ordered APS, Staff and stakeholders to develop a new performance incentive structure "*that optimizes the connection between energy efficiency, rates and utility business incentives that creates a clear connection between the level of performance incentive and achievement of cost-effective energy savings.*" (Decision. No. 73183)

Q. Does providing a rate of return plus premium as the incentive accomplish this purpose?

A. No. TEP's proposed rate of return plus premium incentive is tied to EE spending – not actual performance. There is no "clear connection between the level of performance incentive and achievement of cost-effective energy savings." TEP's proposed incentive is not in the ratepayers' interest because it: (1) incents the wrong behavior; (2) is not tied to cost effectiveness; (3) is not tied to results; and (4) rewards higher spending.

RUCO strongly believes that a performance incentive is appropriate when it is based on actual performance. This incents the utility to spend EE dollars on the most effective programs. TEP's proposal does not do this.

Under the EERP, TEP could fall short of meeting its energy efficiency objectives and still collect the full amount of the incentive. Alternatively, if TEP studiously selected the optimum programs and achieved greater EE savings, TEP would still receive the same incentive amount. Under TEP's proposal, there is no financial motivation to achieve excellence. There is also no financial incentive to meet the EE goal. As long as TEP selects programs, R&D projects and pilot programs that meet the criteria in the Plan of Administration, TEP receives the $16.9 million regardless of the amount of energy actually saved.

Under the terms of the EERP's Plan of Administration, the rate of return plus premium incentive will be added to the entire EE program costs. Some of the EE budget may be spent on programs that are unable to prove cost effectiveness, such as research and development and pilot programs. This is a further departure from a "clear connection between the level of performance incentive and achievement of cost-effective energy savings."

EERP's THREE YEAR TERM BINDS FUTURE COMMISSIONS

Q. Does RUCO have any concerns regarding the three year time period of the EERP?

A. Yes. RUCO has heard from the Commission on numerous occasions that it is opposed to long term commitments that set policy into the future and bind future Commissions. The EERP establishes a Plan of Administration and annual budgets for three (3) years. These elements of the EERP cement the EE policy of the Commission for TEP throughout that term. During the APS rate case hearing, on behalf of Chairman Pierce, CALJ Farmer stated:

> "One of the features of the proposed settlement agreement is that it allows the Commission to set public policy on DG and EE on an annual basis in the annual implementation plans. He says that he likes that flexibility ..." (APS Rate Case, Docket No. E-01345A-11-0224, Transcript Vol. II, p. 282)

Even if this particular Commission agrees that a multi-year plan is appropriate, in 2014, there will be a new Commission. Due to term limits, there will be at least one new Commissioner. That newly-constituted Commission will be bound by the EERP.

Q. What kind of changes could the Commission wish to make in the future?

A. While I can only speculate, it is reasonable to think that the Commission may wish to make – or, at a minimum, to have the option available to make – one or more of the following changes:

1. Change the level of EERP funding.
2. Change the inputs of the Societal Cost Test or switch to an entirely different test.
3. Require cost effectiveness at the measure level.
4. Require EE measures and programs to achieve a minimum cost effectiveness rating greater than 1.0.
5. Limit the amounts that may be spent on R&D programs.
6. Limit the amount that may be spent on pilot programs.

When DSM/EE Plans are approved on an annual basis, the Commission has the flexibility to make timely adjustments.

Q. But even if the Commission approved the 3-year EERP, doesn't it still retain the authority to open up the rate case and make a change?

A. Yes. It is possible but not simple. To go back and modify or terminate the EERP, the Commission would have to re-open the entire TEP rate case through a §40-252 procedure. Reopening the rate case, even for a specific, limited purpose, causes reactions on Wall Street and additional scrutiny from investment analysts. RUCO would argue that a §40-252 procedure brings greater regulatory uncertainty than having DSM/EE Plans approved on an annual basis.

There are further complications if the EERP is approved as part of a settlement agreement. First, altering the EERP would change a material provision of the agreement. Due process affords all parties to that agreement notice and an opportunity to be heard. Second, under standard settlement agreement terms, all parties who sign the agreement commit to support and defend all terms of the agreement. A settling party who, due to unforeseen circumstances at that time, may find the EERP ultimately to be adverse to its interests but would be bound by the terms of the agreement to continue to support a provision that it now sees as detrimental to its interests.

EERP ELIMINATES COMMISSION OVERSIGHT

Q. How does the EERP eliminate Commission oversight? After all, TEP states "the Commission and other interested parties *__may review the costs__* related to the EE investment with the annual DSM/EE

compliance filing and within the context of a rate case to determine prudency." (Jones Direct Testimony, p. 68)

A. The EERP takes control of the DSM/EE program out of the Commission's hands for the next three years. TEP states:

> "Rather than seeking Commission approval for annual stipends to support specific programs, we have proposed a three year pilot program that allows TEP to invest and recover the capital spent on cost effective energy efficiency measures..." (Bonavia Direct Testimony, p. 14)

Q. Who conducts the cost effectiveness test?

A. TEP

Q. Who selects the EE programs?

A. TEP.

Q. Will the Commission approve the measures and programs of the EERP?

A. No.

Q. What does "review of the costs" mean?

A. The Plan of Administration sets forth the inputs of the Societal Cost Test (SCT) and holds that as long as TEP applies these inputs and the programs or measure are cost effective, then "all costs will be fully recoverable" (Jones Direct Testimony, Exhibit CAJ-7, Plan of Administration, pp. 3-4) RUCO is doubtful that "review of costs" carries any meaningful authority.

EERP SEEKS APPROVAL OF A BUDGET WITHOUT PROVIDING PROGRAM SPECIFICS

Q. Could TEP spend the entire EERP budget on R&D or pilot programs that are not required to prove cost effectiveness?

A. While that is highly unlikely, the hypothetical proves a point. TEP has complete discretion to determine how to manage the overall EE budget. Under current practice, the Commission authorizes an itemized budget for individual programs and measures, for R&D and for any approved pilot programs.

The elimination of Commission oversight results in the possibility that EERP funds could be used in a manner consistent with the POA but contrary to the wishes of the Commission.

Q. Does RUCO have a concern with how "cost effectiveness" is defined?

A. Yes. The Plan of Administration states that "Any EE *measure* or *program* that passes the SCT as defined herein is determined to be cost-effective and all costs will be fully recoverable." While DSM measure is defined as a single practice, device or technology, a DSM program is "one or more DSM measures provided as part of a single offering to customers."[10]

Q. So what does that mean?

A. It means that cost effectiveness is effectively at the program level and not the measure level. This allows TEP to package or bundle measures that fall below 1.0 with measures that exceed 1.0 to come to a cumulative program cost effective score that is at least 1.0. The EERP allows for ratepayers to pay for less productive measures because they are bundled with some cost effective ones without Commission review and approval. And since the performance incentive is paid regardless of the level of energy savings, there is a heightened need for Commission approval of TEP's selected programs and measures.

Q. Does the EERP allow TEP to spend money on programs that are not cost effective?

A. Yes. Under the Plan of Administration, research and development and pilot programs are not required to demonstrate cost effectiveness. While the Commission has approved DSM funds for R&D and pilot programs in the past, because their cost effectiveness is difficult – if not impossible – to

[10] RUCO does not have the expertise to determine whether the Societal Cost Test inputs in the POA are similar to or more lenient than the cost effectiveness test inputs used by Staff. RUCO does not opine whether the inputs for the Societal Cost Test, the identified Avoided Environmental Costs, or the Net Lifetime Energy Savings are properly defined.

prove, the Commission has provided heightened analysis and has generally been cautious with the ratepayers' money for these categories. Without Commission oversight, TEP has no external constraints when deciding how much money to spend for R&D and pilot programs.

Q. While we know that ratepayers will be $96.6 million over six years for three years of EE, do we know which programs and measures the utility will administer?

A. Not at this time. TEP Direct Testimony did not provide any information on which EE programs and measures, or R&D programs or pilot programs it will administer in 2013, 2014 and 2015. All we know is that the Plan of Administration gives the utility complete discretion as long as it applies the inputs and methodology found in Attachment A to the Plan of Administration.

Q. Does that conclude your testimony on TEP's proposed Energy Efficiency Resource Plan?

A. Yes it does