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REPLY TO
ATTENTION OF
Regulatory Law Office

January 10, 2013

AZ CORP COMMISSION
DOCKET CONTROL

2013 JAN 11 PM 12 19

Subject: In The Matter Of The Application Of Tucson Electric Power Company For The Establishment of Just and Reasonable Rates and Charges Designed to Realize A Reasonable Rate Of Return On The Fair Value Of Its Operations Throughout The State Of Arizona. Arizona Corporation Commission Docket No. E-01933A-12-0291.

VIA OVERNIGHT DELIVERY
Docket Control Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007-2927

Dear Clerk:

Attached hereto is the United States Department of Defense and all other Federal Executive Agencies' Original Notice of filing of the Prepared Direct Testimony of Dan L. Neidlinger, together with thirteen (13) copies of same, in the above referenced matter. A copy of same is being provided in accord with the service list in the Notice.

Thank you in advance for your assistance. Please call if there are any problems with this request. I can be reached at (703) 693-1274 or by E-mail at kyle.j.smith124.civ@mail.mil.

Regards,

Kyle J. Smith
General Attorney
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Arizona Corporation Commission
DOCKETED
JAN 11 2013
DOCKETED BY

Cc: All parties listed on Notice

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS:

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

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA	DOCKET NO. E-01933A-12-0291 **NOTICE OF FILING DIRECT TESTIMONY OF DAN L. NEIDLINGER**

Pursuant to the requirements of the September 6, 2012 Procedural Order in this matter, attached are the original and 13 copies of the Direct Testimony of Dan L. Neidlinger on behalf of the United States Department of Defense and all other Federal Executive Agencies ("DoD/FEA").

Dated this 10th day of January, 2013

Respectfully submitted,

Kyle J. Smith
Attorney for Dod/FEA

The original and thirteen (13) copies of the foregoing is being transmitted overnight delivery this 10th day of January 2013 to be received and Filed on the 11th day of January 2013 with:

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

A copy of same is being served by e-mail or first class mail this same date to:

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Kyle J. Smith

BEFORE THE ARIZONA CORPORATION COMMISSION

TUCSON ELECTRIC POWER COMPANY

DOCKET NO. E-01933A-12-0291

Direct Testimony of Dan L. Neidlinger

On Behalf of

The Department of Defense and All Other Federal Executive Agencies

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Electric Cost of Service and Rate Design

January 11, 2013

TABLE OF CONTENTS

Introduction....1

Class Revenue and Load Comparisons – 2006 vs 2011....4

CCOSS and Class Revenue Allocation....5

Rate Design....15

PPFAC....21

Statement of Qualifications....Attachment A

Historical Comparisons – 2006 vs 2011....Exhibit DLN-1

Customer Class 4CP Load Data....Exhibit DLN-2

Distribution Plant Allocation – 2006 vs 2011....Exhibit DLN-3

Rate Base and Operating Expense Allocations – 2006 vs 2011....Exhibit DLN-4

Demand Illustration – 4CP vs A&P....Exhibit DLN-5

Income Tax Allocations....Exhibit DLN-6

Proposed Changes to Rate Schedules LLP-90N and LLP-14....Exhibit DLN-7

APS Rate Schedule E-35

El Paso Electric Company – FPPCAC Rate No. 18 – New Mexico

APPENDIX:

Responses to DOD's First Set of Data Requests to TEP

Responses to DOD's Third Set of Data Requests to TEP

Responses to DOD's Fourth Set of Data Requests to TEP

Response to DOD 1.03 (4) – Retail System Peaks – Revised (Spreadsheet)

ARIZONA CORPORATION COMMISSION

TUCSON ELECTRIC POWER COMPANY

DOCKET NO. E-01933A-12-0291

Direct Testimony of Dan L. Neidlinger

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Dan L. Neidlinger. My business address is 3020 North 17th Drive, Phoenix, Arizona. I am President of Neidlinger & Associates, Ltd., a consulting firm specializing in utility rate economics.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS AND EXPERIENCE.

A. A summary of my professional qualifications and experience is included in the attached Statement of Qualifications (Attachment A). In addition to the Arizona Corporation Commission ("ACC" or "Commission"), I have presented expert testimony before regulatory commissions and agencies in Alaska, California, Colorado, Guam, Idaho, New Mexico, Nevada, Texas, Utah, Wyoming and the Province of Alberta, Canada.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of the Department of Defense and All Other Federal Executive Agencies, collectively referred to in this testimony as the "DOD". The major DOD installations in Arizona served by Tucson Electric Power Company ("TEP" or the "Company") are Davis Monthan Air Force Base ("DM") located in Tucson and Fort Huachuca ("Fort") located in Sierra Vista. Both DOD facilities currently receive service from TEP under Rate Schedule LLP-14. Another Federal agency, the Veterans

Administration ("VA") Hospital in Tucson, receives service under Rate Schedule LLP-90.

Q. WHAT IS THE COMBINED ANNUAL ELECTRIC USAGE OF THE FORT AND DM?

A. These military installations are two of the Company's largest customers. Combined annual electric usage for these DOD facilities is approximately 221 million kilowatt hours ("kWh"). Unlike most of TEP's customers, the Fort and DM own and operate their distribution systems.[1]

These DOD facilities have in the past and continue to implement energy efficient programs. DM has contracted for the installation of a 14.5 megawatt photovoltaic solar project which is scheduled for operation in 2013. The VA has installed a 4.5 megawatt solar system that is partially in operation at this writing. The Fort is currently evaluating the feasibility of large solar installation. As discussed later in this testimony, TEP's rate proposals will negatively impact the cost effectiveness of these solar projects thereby inhibiting DOD's energy efficiency efforts.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS MATTER?

A. The DOD customers of TEP that sponsor my testimony seek no subsidy from other customers of TEP, nor do they wish to subsidize these customers. Their request is straightforward - implement rates that are based on sound cost of service principles. In support of this position, my testimony addresses the following cost of service and rate design issues:

1. Changes in customer class revenues, loads and load factors since the 2006 rate case;

[1] The Fort's distribution system has been privatized and is operated by Sulphur Springs Valley Electric Cooperative.

2. The class cost of service study ("CCOSS") supporting the filing;
3. The Company's proposed class revenue allocations;
4. The Company's proposed rate designs for large customers served under its Large General Service and Large Light & Power rates including time of use ("TOU") rates; and
5. The Company's proposed voltage adjustments incorporated in its revised purchased power and fuel adjustment clause ("PPFAC").

I. CLASS REVENUE AND LOAD COMPARISONS – 2006 VS 2011

Q. DID YOU REVIEW THE CHANGES IN CLASS MEGAWATT HOUR ("MWH") SALES AND RELATED REVENUES SINCE THE LAST RATE CASE IN 2006?

A. Yes. A summary of changes in key class revenue and load statistics is provided on the attached Exhibit DLN-1. Over this five year period, megawatt hour ("MWH") sales have remained essentially unchanged or slightly lower for all customer classes except for the mining class. Mining sales increased by 17%. Revenues for the non-mining classes increased due to the 2008 rate increase, the fuel and purchased power increases reflected in the 2011 test year filing and a small increase in customer count.

Q. HAVE THERE BEEN ANY SIGNIFICANT CHANGES IN CLASS PEAK LOADS OR LOAD FACTORS SINCE 2006?

A. Again, except for the mining class, class peak loads and load factors in 2011 are comparable to 2006 experience. I revised the class load data shown on Exhibit DLN-1 to correct for the faulty load data used by TEP in its CCOSS. These revisions are discussed in more detail later in this testimony.

Q. WHAT DO YOU CONCLUDE FROM THESE COMPARISONS?

A. I conclude that TEP's costing in this case should parallel the costing performed by Mr. Bentley Erdwurm, TEP's cost of service and rate design witness in the 2006 case. Rate base is significantly greater in this case but the same demand allocation method, 4CP Average & Peaks ("A&P"), was used in both cases. Accordingly, one would expect to see very similar CCOSS results, relatively speaking. Inexplicably, TEP's CCOSS filing in this case does not meet this expected result.

II. CCOSS AND CLASS REVENUE ALLOCATION

Q. WHY SHOULD ELECTRIC RATES BE PRIMARILY BASED UPON COST OF SERVICE?

A. In a regulated environment, cost of service is the single-most important criterion in the development of revenues by customer class and the development of rates that will produce those revenues. If rates are not cost-based, the inevitable results are subsidies among classes of customers and customers within a class. Although other factors, such as continuity, simplicity and stability, are valid considerations in the rate design process, the primary guideline should be cost of service. Rates developed based on cost of service considerations are equitable because each customer pays its fair share of the utility's total costs.

Q. WHAT ARE THE PROBABLE CONSEQUENCES OF SETTING ELECTRIC RATES PRIMARILY ON NON-COST CONSIDERATIONS?

A. In addition to the inequities previously discussed, basing rates on non-cost considerations can lead to unnecessary departure of large commercial and industrial customers. Additionally, inequitable rate structures may result in uneconomic decision-making with respect to energy use and energy alternatives. Utilities with tilted rate structures and obsolete rate designs find themselves scrambling to keep their current commercial and industrial customers on the system without offering special contract rates that are significantly lower than standard rate schedules.

Q. THE COMPANY IS REQUIRED UNDER ACC RULES TO FILE A CCOSS. HOW IMPORTANT DOES THE COMPANY VIEW COST OF SERVICE IN SETTING RATES?

A. In response to a DOD data request[2], the Company said that it viewed cost of service as "a very important guide" in the ratemaking process. However, it gave no specifics as to how this guide was used in adjusting class revenues in this case. As discussed later in this testimony, proposed adjustments to class revenues were made in some instances based on faulty costing. In other instances, the Company's proposals fall well short of revenue adjustments needed in this case to ultimately achieve rates that are at or near cost of service.

Q. DID YOU FILE DIRECT TESTIMONY ON COST OF SERVICE AND RATE DESIGN IN THE COMPANY'S LAST RATE PROCEEDING, DOCKET NOS. E-01933A-05-650 AND 07-0402, ON BEHALF OF THE DOD?

A. Yes.

Q. WHAT WAS YOUR CONCLUSION AT THAT TIME WITH RESPECT TO TEP'S RATE STRUCTURE?

A. I stated in that testimony[3] that there was significant imbalance in the rate structure due to large variances in class returns, particularly with respect to the Residential and General Service ("GS") classes. TEP's CCOSS in that case showed a negative return for the Residential class of $24.8 million and a positive return of $28 million for the GS class. These two customer classes accounted for over 84% of TEP's total retail sales in 2006.

Q. WAS THE DOD A SIGNATORY TO THE 2008 SETTLEMENT AGREEMENT IN THE LAST RATE CASE?

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[2] Response to DOD data request 4.1

[3] Direct Testimony of Dan L. Neidlinger filed in Dockets 05-0650 and 07-0402 on March 13, 2008

A. Yes. The 2008 Settlement Agreement ("Agreement") provided for a 6.1% across-the-board revenue increase. I stated in my testimony[4] supporting the Agreement that the across-the-board rate adjustments were "contra to the results of the class cost of service analyses discussed in detail in my direct testimony" but that the major rate design changes incorporated in the Agreement out-weighed the cost of service deficiencies.

Q. DOES TEP'S RATE STRUCTURE REMAIN UNBALANCED IN THIS CASE?

A. Yes. With the exception of the mining class, the sales and load statistics for the major classes in the current 2011 test year mirror comparable data for 2006. Accordingly, one would expect to see comparable CCOSS results. However, the Company's revised[5] CCOSS is heavily skewed in favor of the Small GS class and not comparable to the results shown in the 2006 CCOSS.

Q. DID YOU REVIEW AND ANALYZE THE COMPANY'S CCOSS TO DETERMINE THE REASONS FOR THIS NONCOMPARABILITY?

A. Yes. I reviewed and analyzed all aspects of the Company's CCOSS including functionalization assumptions, allocation methods and assumptions and underlying allocation data. Based on this review, I have concluded that the Company's CCOSS, as revised on October 5, 2012, cannot be relied upon to set class revenues in this case or used as a guide in designing cost-based rates.

Q. PLEASE EXPLAIN YOUR CONCLUSION THAT TEP'S CCOSS SHOULD BE REJECTED.

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[4] Settlement Testimony of Dan L. Neidlinger filed on June 10, 2008
[5] October 5, 2012 revised CCOSS

A. The Company's CCOSS is replete with major errors in underlying load data and errors in the application of load data. Further, in some instances plant and operating costs were misallocated based on notions of "equity" and "fairness" rather than on fact or cost causation. These errors produce a cost of service result that is completely unacceptable, specious and of little value for ratemaking in this case.

Q. DID YOU PREPARE A REVISED CCOSS WITH CORRECTED ALLOCATION METHODS AND FACTORS?

A. No, I did not. Preparing such a study is a major undertaking and beyond the scope of my assignment in this case. It is my understanding that at least one other party to this proceeding, intervenor AECC, is preparing an alternative CCOSS for consideration by the Commission. I have, however, prepared a series of exhibits that clearly demonstrate the flawed nature of the Company's study.

Q. PLEASE DISCUSS THE ERRORS IN THE COMPANY'S LOAD DATA.

A. Accurate load data is a critical input to a CCOSS for an electric utility. Load data is needed to properly assign demand-related plant and costs to customer classes. These demand-related costs represent approximately 65% of TEP's total costs. An electric class cost of service study cannot be properly performed without this load data. TEP was unable to accurately determine class coincident peak demands and decided to apportion differences between class load research results and measured system peak demands among all classes[6]. This apportioning process produced overstated 4CP demands for all customer classes except the Small GS class where demands were understated.

Q. WHAT IS THE MAGNITUDE OF THESE ERRORS?

[6] Responses to AECC's data requests 3.1 and 6.1

A. As shown on Exhibit DLN-2, the errors are significant and readily observable. For instance, the 59% load factor for the Small GS class, which includes low load factor pumping loads, is greater than the 51% load factor for the Large GS class – an illogical finding. The low load factors for the Large Light & Power ("LL&P") class and the Mining class of 67% and 80%, respectively, also fail the reasonableness test. As indicated on DLN-1, the 2006 load factor for the LL&P class was 81% or 14% greater than TEP's calculated load factor for this class in this case. There is no logical explanation for this precipitous drop in load factor for these large customers. Similarly, mining is a 24/7 process industry that typically experiences load factors that exceed 90%.

Q. PLEASE EXPLAIN THE REVISED CLASS LOAD FACTORS SHOWN ON EXHIBIT DLN-2.

A. The revised class load factors shown on Exhibit DLN-2 are provided for comparative purposes. Loss-adjusted loads were used for all classes with demand meters (Large GS, LL&P and Mining). The residential 4CP load of 1,082 megawatts ("MW") was calculated assuming a 41% load factor which is comparable to the 2006 residential load factor. As a result of these adjustments, the 4CP load for the Small GS class was increased from 420 MW to 648 MW thereby reducing the load factor from 59% to 38%. A 38% load factor for this class is not unreasonable considering the fact that pumping loads have been included in the Small GS class in this case.

Q. DID YOU DISCOVER ANY INSTANCES WHERE ALLOCATIONS WERE MADE BASED ON PERCEPTIONS OF "EQUITY" RATHER THAN FACTUAL FOUNDATION?

A. Yes. One example is distribution plant. Distribution plant and related expenses were initially allocated by TEP using a 12 month coincident peak average rather than a non-coincident peak ("NCP") method which was used in 2006 and recognized throughout the electric utility industry as the accepted method for allocating distribution plant. TEP changed its allocation using NCP data and refilled its CCOSS on October 5, 2012. However, the revised CCOSS included NCP errors for the Large GS and LL&P classes.[7]

TEP allocated distribution plant to the LL&P and Mining classes without first determining the extent to which customers in these classes actually use TEP's distribution system. In many instances, these large industrial customers, including the Fort and DM, own and operate their own distribution systems and accordingly, use little if any of TEP's distribution plant. By ignoring this fact TEP has over-allocated this component of TEP's utility plant to the larger customer classes.

Q. IS THIS ALLOCATION ERROR SIGNIFICANT?

A. Yes. Exhibit DLN-3 compares the percentage of total distribution plant allocated to the LL&P and Mining classes in 2006 with the percentage allocated in this case to each of these classes. In 2006, the distribution plant allocated to the Mining class was essentially zero. The current CCOSS allocates $49 million or 3.98% of total distribution plant to the Mining class. The percentage of total distribution plant allocated to the LL&P class more than doubled from 2.18% to 4.99%. Based on 2006 relationships, the over-allocation of distribution plant to the LL&P class in this case is approximately $35 million.

Q. DID THE ERRORS IN CLASS LOAD DATA AND DISTRIBUTION PLANT ALLOCATIONS DISTORT THE OVERALL RESULTS OF THE COMPANY'S CCOSS?

A. Yes. These errors are largely responsible for the aberrant results shown on Exhibit DLN-4. This comparative analysis shows the downward skewing of rate base and operating expenses allocated to the GS class and upward increases to the LL&P and Mining classes. The increase-multiples provided in the last column of that exhibit

[7] Responses to DOD's data request 3.2

quantify the magnitude of the distortion in the current CCOSS results. Rate base increase-multiples for the LL&P and Mining classes are 2.59 and 2.89, respectively compared with an overall increase multiple of 1.55. Corresponding increase-multiples for operating expenses for these classes are 1.28 and 1.59 compared with an overall increase multiple of 1.13. These results must be deemed unreasonable and unacceptable considering the fact that, with one exception, there have been no significant changes in class kWh sales or load profiles since 2006. The mining load is the exception. This exception, however, cannot adequately explain the almost tripling of rate base allocated to the Mining class in this proceeding.

Q. WHAT IS YOUR VIEW OF THE A&P DEMAND ALLOCATION METHOD USED BY THE COMPANY IN BOTH THE 2006 CASE AND THIS CASE?

A. The A&P demand allocation method is technically flawed since it double-counts average demand: once in the energy component of the formula and again in the 4CP component of the formula. Accordingly, high load factor customers are allocated a disproportionate share of fixed production plant and related costs under the A&P method. Considering the predominance of TEP's summer peak, the 4CP method is the most appropriate method for allocating these costs. This method equitably apportions the annual fixed costs incurred by the Company to meet this peak.

Q. DID THE COMPANY USE THE 4CP METHOD FOR ITS JURISDICTIONAL COST STUDY?

A. Yes. The wholesale segment of the Company's business should be viewed as another customer class, irrespective of regulatory jurisdiction. If the 4CP method is appropriate for jurisdictional purposes, it is also appropriate for ACC retail costing.

Q. PLEASE EXPLAIN THE ILLUSTRATION PROVIDED ON EXHIBIT DLN-5.

A. The illustration shown on Exhibit DLN-5 compares the results of a demand allocation using the 4CP method and the A&P method for a hypothetical utility with two customer classes. In the base case, both classes are allocated 50 units of demand under the 4CP method. Under the A&P method, Class A receives an allocation of 45 units and Class B an allocation of 55 units – a demand greater than it actually experienced. In the second example, the only change is an increase in B's load factor from 60% to 80%. Under the 4CP method, there is no change in the demand allocation between the two classes. However, under the A&P method, Class B's allocation increases by 5 units of demand to 60. Class B has become more efficient in its use of the utility's production facilities but is penalized whereas Class A, which has not changed its behavior, receives a lower allocation of demand costs. A costing method, such as the A&P method, that discourages the efficient use of a utility's resources should be rejected.

Q. IS THERE A TECHNICALLY VALID DEMAND ALLOCATION METHOD THAT CONSIDERS AVERAGE ENERGY USAGE IN THE CALCULATION OF CLASS ALLOCATION FACTORS?

A. The Average & Excess ("A&E") method is a recognized demand allocation method that considers both average demands, or energy use, and class peak demands. Unlike the A&P method, however, the A&E method does not penalize high load factor customers since there is no double-counting of average demand. The peak demand component of the calculation uses the maximum NCP for each class. Demand allocation results under the A&E method are normally comparable to the results under a 4CP method except for off-peak loads. The Company should have selected the A&E method if it wanted to reflect load diversity in its demand allocations.

Q. IN ADDITION TO THE ERRORS IN LOAD DATA AND DISTRIBUTION PLANT ALLOCATIONS AND THE FLAWED DEMAND ALLOCATION METHOD, DID THE COMPANY ALSO INCORRECTLY ALLOCATE INCOME TAXES AMONG CUSTOMER CLASSES?

A. Yes. The Company inexplicably allocated income taxes at present rates and at proposed rates using two different allocation methods. Both methods are incorrect. At present rates, income taxes were allocated based on plant in service[8]. At proposed rates, income taxes were allocated based on total class revenues[9]. These errors in the Company's CCOSS add another element of distortion to the indicated class returns shown on Schedules G-1 and G-2.

Income tax expense, or credit in the case of losses, should be allocated based on taxable income or loss, not methods based on perceived equity among the classes.

Q. DID YOU RECALCULATE INCOME TAXES BASED ON TAXABLE INCOME OR LOSS?

A. Revised income tax allocations are provided on Exhibit DLN-6. There are large differences in class allocated income taxes at both present and proposed rates. Corresponding changes in percentage returns on rate base are also large.

Q. GIVEN THE DEFICIENCIES IN THE COMPANY'S CCOSS, ARE THE COMPANY'S PROPOSED CLASS REVENUE ADJUSTMENTS ACCEPTABLE?

A. No. There is no cost of service foundation upon which to accurately evaluate class revenue levels at present rates. The Company's proposed revenue adjustments to supposedly move classes closer to cost of service are based on faulty information. Mr. Craig A. Jones states on Page 4 of his direct testimony: "It (the CCOSS) shows that the

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[8] Responses to AECC data request 3.4

[9] Responses to AECC data request 4.1

residential and large light & power customers are being subsidized by the general service class" This conclusion is incorrect at least with respect to subsidies provided by the Small GS class and subsidies received by the LL&P class.

Q. THE CCOSS ERRORS YOU DISCUSSED SEEM TO INVALIDATE THE RELATIVE DIRECTION OF CLASS REVENUE ADJUSTMENTS PROPOSED BY THE COMPANY. WOULD YOU AGREE?

A. Yes. The load data and allocation errors tend to understate the returns provided by the Large GS, LL&P and Mining classes of customers and overstate the returns provided by the Residential and Small GS classes. The Company is asking for an increase in the combined revenues for the Large GS, LL&P and Mining classes of 24.4% compared with an increase in the combined revenues of all other customer classes of only 11.9%. Based on my analysis, these proposals are opposite of the direction that revenue adjustments should take in this case.

The Company cannot achieve its goal of recovering total fixed costs by misallocation of class revenue responsibility. There should be a reasonable expectation that every new customer added to the system will bear its fair share of system costs. That expectation is not being met under the current rate structure and will continue to be unfulfilled under TEP's class revenue proposals in this case.

III. RATE DESIGN

Q. WHAT IS YOUR OVERALL ASSESSMENT OF THE COMPANY'S RATE DESIGN PROPOSALS?

A. My general impression of the Company's proposed rates, at least with respect to the rate proposals for the larger customers, is that they are not cost-based. The proposed consolidation of rates, where possible, is a positive step. However, the proposed shifting of revenue responsibility for larger customers into 100% ratcheted demand charges is not a positive step. The 100% demand ratchet is merely an indiscriminate fixed-cost recovery mechanism that fails to properly match price with cost.

Q. DOESN'T THE 100% RATCHET PROPOSAL COMPOUND THE ERRORS CREATED IN THE ALLOCATION OF DEMAND COSTS UNDER THE A&P METHOD?

A. Yes. As previously discussed, the A&P method over-allocates demand costs to high load factor customer classes. TEP then seeks to guarantee recovery of these costs through the application of a 100% demand ratchet. TEP is also asking the Commission to approve a Lost Fixed Cost Recovery adjustment clause as additional insurance for fixed cost recovery in this case.

Q. WHAT IS A DEMAND RATCHET?

A. A demand ratchet is a proxy for seasonal rates for utilities that exhibit wide divergences in seasonal loads. The ratchet establishes a customer's minimum monthly demand charge based on the customer's maximum monthly peak demand during a consecutive 12 month period. TEP is a summer peaking system. In 2011, TEP's average summer peak (June-September) of 2,262 MW exceeded the average winter peak

(November-February) of 1,341 MW by 921 MW or 69%.[10] Utilities with demonstrative peaking characteristics, such as TEP, often include demand ratchet provisions in their tariffs to insure that customers pay demand charges during the off-peak season consistent with seasonal load relationships. The current demand ratchet included in LL&P rates is 66.7% - a percentage comparable to the 69% experienced in 2011. Accordingly, there is no cost justification for increasing the current demand ratchet to 100%.

Q. DID TEP PROVIDE ANY COST JUSTIFICATION FOR THE 100% DEMAND RATCHET?

A. No. In response to a DOD data request[11] seeking cost justification for the 100% demand ratchet, the Company stated: "The Company objects to this request as vague and ambiguous".

The request was straightforward. TEP's answer was non-responsive and evasive. Every rate proposed by a utility should be cost-justified. Rate changes must be supported by cost changes. TEP has not provided any cost justification supporting a 100% demand ratchet.

Q. DURING YOUR MANY YEARS OF CONSULTING, HAVE YOU EVER ENCOUNTERED AN ELECTRIC UTILITY CASE WHEREBY THE APPLICANT HAS PROPOSED A 100% DEMAND RATCHET?

A. No. In my experience, demand ratchet provisions typically include percentages ranging from 60% to 75%. The ratchet percentage in the Large GS class is currently 50% and, as previously mentioned, the ratchet percentage in the LL&P class is 66.7%.

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[10] Response to DOD data request 1.3
[11] Response to DOD data request 1.8

Q. UNDER THE COMPANY'S DEMAND RATCHET PROPOSAL, WOULDN'T THERE BE LESS INCENTIVE TO THE CUSTOMER TO MANAGE ITS LOAD ON A YEAR AROUND BASIS?

A. Yes. The load management incentive would be significantly reduced since monthly demand charges would not change for 11 months after a peak has been set. Under the current 67.7% demand ratchet, the Fort and DM are paying ratcheted demand charges during only three months of the year thereby providing incentives to manage load during the other nine months.

Q. WOULD THE RATCHET ALSO BE APPLICABLE TO WINTER PEAKING LOADS?

A. Yes. The current ratchet provision is also applicable to winter-peaking loads but at the much lower 67.7% percentage. The Commission recently approved an 80% ratchet for large customers[12] of Arizona Public Service Company ("APS"). However, the ratchet is only applicable to on-peak demands set during the six summer months of May through October.

Q. HOW WOULD THE 100% DEMAND RATCHET AFFECT THE ECONOMICS OF LARGE SOLAR PROJECTS CURRENTLY IN PLACE OR IN THE PLANNING STAGES FOR DOD INSTALLATIONS?

A. This single rate change increases annual combined power costs to the Fort and DM by over $2 million. These higher costs will, in all likelihood, continue to be incurred after these solar projects become operational and will most assuredly negatively impact the economics of solar systems installed at the VA and the solar system soon to be constructed at DM. If approved, it would also impair the economic feasibility of a solar project that is in the planning stages at the Fort.

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[12] Rate Schedule E-34, Extra Large General Service

Q. IS THE COMPANY PROPOSING A 100% ENERGY RATCHET FOR ITS NON-DEMAND METERED CUSTOMERS, NAMELY RESIDENTIAL AND SMALL COMMERCIAL CUSTOMERS?

A. No, but an energy ratchet for residential and small commercial customers would be consistent with the Company's "guaranteed revenues" rate design philosophy evident in this filing. Both the Company and the Commission are well aware of the customer backlash that would occur should an energy ratchet be imposed on residential and small commercial customers. Demand ratchets, even at current percentages, are very much an irritant to demand-metered customers and a similar backlash would occur should a 100% demand ratchet be implemented.

Q. IS THERE ANY JUSTIFICATION, IN YOUR VIEW, TO CHANGE THE CURRENT 67% DEMAND RATCHET PERCENTAGE FOR THE LL&P CLASS?

A. No. The current 67% reasonably reflects TEP's seasonal demand characteristics and related costs.

Q. HAS THE COMPANY'S ZEAL TO FIX REVENUE LEVELS PRODUCED OTHER RATE DESIGN PROPOSALS THAT ARE NOT COST RELATED?

A. Yes. One example is the proposed rate, LGS-13, for the Large GS class – a rate that is almost identical to the proposed rate for the LL&P customer class. The proposed demand charge (ratcheted at 100%) of $21 per kilowatt ("kW") is approximately double the current rate of $10.35 per kW with corresponding proposed reductions in energy rates. These higher demand/lower energy rate components are appropriate for the LL&P class but not for the Large GS class which exhibits much greater load diversity among its customers. The average summer usage per bill for the LL&P class is over 8,000,000 kWh compared with an average summer usage per bill for the Large GS class of only 184,000 kWh. The redesigned LGS-13 rate will create significant intra class inequities unless the class is split into more than one rate. APS has a Medium GS rate (100kW-400kW) that provides a bridge between low and high load factor commercial customers. The rate incorporates voltage level, declining block demand charges. This is a rate design concept that should be applied to TEP's rate structure.

A small increase in the current 50% demand ratchet for rate LGS-13 might be reasonable assuming the current demand/energy relationship in the rate is maintained. However, there is no justification for a 100% ratchet for this class. APS's Medium GS rate has no demand ratchet.

Q. PLEASE EXPLAIN THE PROPOSED CHANGES TO THE LLP-90N TOU RATE AND THE LLP-14 RATE SHOWN ON EXHIBIT DLN-7.

A. In addition to the change in the ratchet from 67.7% to 100%, there are other significant changes proposed for these rates. The incentives to shift load to off-peak periods under the LLP-90N rate have been reduced. Shifting load will not reduce demand charges since the proposed off-peak demand charge is the same as the on-peak demand charge and both ratcheted at 100%. In addition, the difference in seasonal demand rates has been reduced from $4 per kW to $3 per kW. Further, the differential in on-peak/off-peak energy rates has been decreased for both the summer and winter seasons.

The proposed LLP-14 rate includes a 10% increase in the demand rate, a 21% increase in the summer energy rate and a 43% increase in the winter energy rate. Should these increases be approved, the Fort and DM, both currently served under LLP-14, would likely opt for the LLP-90N rate in spite of its diminished incentives to shift load.

Q. DIDN'T THE COMMISSION RECENTLY APPROVE A TOU RATE FOR THE LARGE CUSTOMERS OF APS THAT PROVIDES FOR EXPLICIT INCENTIVES TO SHIFT LOAD TO OFF-PEAK PERIODS?

A. Yes. A copy of APS's recently approved Rate Schedule E-35, Extra Large General Service Time of Use, rate is attached. The rate is illustrative of the TOU attributes that need to be incorporated in TEP's TOU rates. The rate provides for large monetary incentives to reduce demand charges by shifting load to off-peak periods. It also properly recognizes differences in the cost to serve customers at secondary, primary and transmission voltages.

Q. WHAT ABOUT THE PROPOSED CHANGE IN THE POWER FACTOR ADJUSTMENT FOR THE LLP-90N AND LLP-14 RATES?

A. The Company is proposing to convert the current 1.3 cents per kW credit for each 1% lagging power factor[13] greater than 90% into a 1.3 cent charge for each 1% less than 100% power factor. Although the monetary impact is not large relative to other proposed rate adjustments, the Company's proposal is not well reasoned. Utilities typically benchmark power factors for large loads at 90%. Penalties are assessed customers with power factors less than 90% but are not penalized if power factor is 90% or greater since losses are very small in the 90% to 100% power factor range. Accordingly, there is no material cost support for the proposed 1.3 cent per kW charge for each 1% in this range. However, losses accelerate for each percentage drop in power factor below 90% and penalties greater than 1.3 cents per kW are probably justified for power factors below this threshold.

[13] Power factor is true power, KW, divided by apparent power, KVAR.

IV. PPFAC

Q. HAVE YOU REVIEWED THE PROPOSED REVISONS TO THE CURRENT PPFAC?

A. I have reviewed briefly the Company's proposed revisions to its PPFAC. I do not have any specific recommendations on the PPFAC at this time except as related to the voltage level line and transformation loss adjustment factors. The Company proposed PPFAC provides for energy loss adjustment factors for customers taking service at transmission voltages, 138 KV or higher, but not for customers served at primary voltages.

Q. DIDN'T YOU SUGGEST IN THE LAST PROCEEDING, DOCKET 07-0402, THAT THE PPFAC PROPOSED IN THAT CASE INCORPORATE LINE LOSS FACTORS BASED ON VOLTAGE LEVEL OF SERVICE?

A. Yes. I suggested in that case that the PPFAC should include loss factors for customers taking service at both primary and transmission voltages. The Company's loss adjustment proposal is limited to customers served at 138 KV transmission voltage levels. I recommend that loss adjustment factors be expanded to also include customers served at primary voltages.

Recognition of line-loss cost differentials in fuel and purchased power adjustors is not a new concept. El Paso Electric Company has incorporated these voltage-level factors for its New Mexico customers for some time. A copy of its current tariff in that regard is provided on the attached FPPCAC Rate No. 18 (Exhibit 4, Page 57 of 94).

Q. GIVEN THE EXTREMELY HIGH LEVEL OF DEMAND CHARGES PROPOSED BY TEP IN THIS CASE, SHOULDN'T ADJUSTMENTS TO

DEMAND RATES ALSO BE MADE TO REFLECT VOLTAGE LEVEL OF SERVICE?

A. Yes. All of APS's recently approved general service tariffs for demand metered customers include separate demand charges for secondary, primary and transmission voltage levels. These differentials, based on cost of service, should also be recognized in TEP's tariffs.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

ATTACHMENT A

DAN L. NEIDLINGER

SUMMARY STATEMENT OF QUALIFICATIONS

I. General:

Mr. Neidlinger is President of Neidlinger & Associates, Ltd., a Phoenix consulting firm specializing in utility rate economics and financial management. During his consulting career, he has managed and performed numerous assignments related to utility ratemaking and energy management.

II. Education:

Mr. Neidlinger was graduated from Purdue University with a Bachelor of Science degree in Electrical Engineering. He also holds a Master of Science degree in Industrial Management from Purdue's Krannert Graduate School of Management. He is a licensed Certified Public Accountant in Arizona and Ohio.

III. Consulting Experience:

Mr. Neidlinger has presented expert testimony on financial, accounting, cost of service and rate design issues in regulatory proceedings throughout the western United States involving companies from every segment of the utility industry. Testimony presented to these regulatory bodies has been on behalf of commission staffs, applicant utilities, industrial intervenors and consumer agencies. He has also testified in a number of civil litigation matters involving utility ratemaking and once served as a Special Master to a Nevada court in a lawsuit involving a Nevada public utility.

Mr. Neidlinger has performed feasibility studies related to energy management including cogeneration, self-generation, peak shaving and load-shifting analyses for clients with large electric loads. In addition, he has consulted with U.S. Army installations on privatization of utility systems and assisted these and other consumer clients in contract negotiations with utility providers of electric, gas and wastewater service.

Mr. Neidlinger has extensive experience in the costing and pricing of utility services. During his consulting career, he has been responsible for the design and implementation of utility rates for numerous electric, gas, water and wastewater utility clients ranging in size from 50 to 30,000 customers.

IV. Professional Affiliations:

Professional affiliations include the American Institute of Certified Public Accountants.

EXHIBIT DLN-1

TUCSON ELECTRIC POWER COMPANY
Docket No. E-01933A-12-0291
Electric Cost of Service and Rate Design

Historical Comparisons - 2006 vs 2011
$(000)

	2006		2011		Percentage Increase (Decrease)	
Customer Class (1)	**Revenues**	**MWH Sales**	**Revenues**	**MWH Sales**	**Revenues**	**MWH Sales**
Residential	$307,535	3,864,352	$370,954	3,887,304	20.62%	0.59%
General Service (2)	288,212	3,539,638	342,681	3,401,960	18.90%	-3.89%
Large Light & Power	53,837	948,945	56,796	922,341	5.50%	-2.80%
Mining	37,790	924,898	62,304	1,083,071	64.87%	17.10%
Total	$687,374	9,277,833	$832,735	9,294,676	21.15%	0.18%
Rate Per kWh	$0.07409		$0.08959		20.93%	

	2006		2011		Percentage Increase (Decrease)	
Customer Class (1)	**Average 4CP Demand (3)**	**Load Factor (4)**	**Average 4CP Demand (3)**	**Load Factor (4)**	**Average 4CP Demand**	**Load Factor**
Residential	1,061	41.58%	1,082	41.00%	1.98%	-0.58%
General Service (2)	899	44.95%	891	43.58%	-0.89%	-1.37%
Large Light & Power	134	80.84%	134	78.44%	0.00%	-2.40%
Mining	99	106.65%	130	94.81%	31.31%	-11.84%
Total	2,193	48.30%	2,237	47.41%	2.01%	-1.84%

NOTES:
(1) Excluding Lighting Class
(2) Includes OPA
(3) Average of class 4 coincident summer peak demand (4CP) - Megawatts. See EXHIBIT DLN-2 for 2011 4CP class demands.
(4) Annual load factor calculated based on average 4CP demand.

TUCSON ELECTRIC POWER COMPANY
Docket No. E-01933A-12-0291
Electric Cost of Service and Rate Design

Customer Class 4CP Load Data

		Per TEP CCOSS (1)		Revised (2)	
Customer Class	**MWH Sales**	**4CP Load (3)**	**Load Factor**	**4CP Load (3)**	**Load Factor**
Residential	3,887,304	1,231	36.05%	1,082	41.01%
Small General Service	2,179,138	420	59.23%	648	38.39%
Large General Service	1,222,822	275	50.76%	244	57.21%
Large Light & Power	922,341	157	67.06%	134	78.57%
Mining	1,083,071	155	79.77%	130	95.11%
Lighting	37,431	24	17.80%	24	17.80%
Total TEP Retail	9,332,107	2,262	47.10%	2,262	47.10%

NOTES:
(1) Source: TEP load research - 4CP A&P calculation worksheet
(2) Revised with 41% load factor for Residential class and use of measured 4CP demands for Large General Service, Large Light & Power and Mining classes.
(3) Average coincident peak load for the months of June, July, August and September in megawatts

TUCSON ELECTRIC POWER COMPANY
Docket No. E-01933A-12-0291
Electric Cost of Service and Rate Design

Distribution Plant Allocation - 2006 vs 2011

Rate Case CCOSS	Total Distribution Plant	LL&P Allocation	Allocation Percent	Mining Allocation	Allocation Percent
2006 CCOSS (1)	$931,635,151	$20,271,219	2.18%	$606	0.00%
2011 CCOSS (2)	$1,243,492,787	$62,017,016	4.99%	$49,435,410	3.98%

NOTES:
(1) Schedule G-1 Revised - Docket 07-0402
(2) Schedule G-1 - Revised CCOSS October 5, 2012

TUCSON ELECTRIC POWER COMPANY
Docket No E-01933A-12-0291
Electric Cost of Service and Rate Design

Rate Base and Operating Expense Allocations - 2006 vs 2011

	2006 CCOSS (1)		2011 CCOSS (2)		
Customer Class	Rate Base Allocation	Percent	Rate Base Allocation	Percent	Increase Multiple
Residential	$519,970,267	52.91%	$738,869,476	48.64%	1.42
General Service	377,124,533	38.38%	490,261,945	32.27%	1.30
Large Light & Power	43,778,851	4.45%	113,466,950	7.47%	2.59
Mining	32,521,487	3.31%	94,041,114	6.19%	2.89
Lighting	9,339,022	0.95%	82,433,877	5.43%	8.83
Total	$982,734,160	100.00%	$1,519,073,362	100.00%	1.55

	2006 CCOSS (1)		2011 CCOSS (2)		
Customer Class	Op. Expense Allocation (3)	Percent	Op. Expense Allocation (3)	Percent	Increase Multiple
Residential	$225,449,235	49.53%	$257,591,664	50.08%	1.14
General Service	171,789,113	37.74%	166,368,002	32.34%	0.97
Large Light & Power	30,185,502	6.63%	38,737,374	7.53%	1.28
Mining	24,972,235	5.49%	39,763,105	7.73%	1.59
Lighting	2,778,034	0.61%	11,934,656	2.32%	4.30
Total	$455,174,119	100.00%	$514,394,801	100.00%	1.13

NOTES:
(1) Schedule G-1 Revised - Docket 07-0402
(2) Schedule G-1 - Revised CCOSS October 5, 2012
(3) Operating expenses excluding fuel, purchased power and income taxes.

TUCSON ELECTRIC POWER COMPANY
Docket No. E-01933A-12-0291
Electric Cost of Service and Rate Design

Demand Illustration - 4CP vs A&P

BASE CASE

Customer Class	Average Demand	Demand Allocation 4CP Method (1)	Demand Allocation A&P Method (2)	Over (Under) Allocation
A	20	50	45	(5)
B	30	50	55	5
Total	50	100	100	0

CUSTOMER CLASS B INCREASES LOAD FACTOR

Customer Class	Average Demand	Demand Allocation 4CP Method (1)	Demand Allocation A&P Method (2)	Over (Under) Allocation
A	20	50	40	(10)
B	40	50	60	10
Total	60	100	100	0

NOTES:
(1) 4CP allocation formula: Class contribution to system 4CP demand
(2) A&P allocation formula: (SLF%)(AD%) + (1-SLF%)(4CP%) where SLF=System load factor, AD= class average demand and 4CP=Class contribution to system 4CP demand

TUCSON ELECTRIC POWER COMPANY
Docket No. E-01933A-12-0291
Electric Cost of Service and Rate Design

Income Tax Allocations

	Income Taxes at Present Rates				
	Per TEP			Percent Return on Rate Base	
Customer Class	CCOSS (1)	Revised (2)	Difference	Per TEP	Revised
Residential	$3,403,412	$88,450	-$3,314,962	-0.40%	0.05%
Small Commercial	1,456,159	12,546,149	11,089,990	20.43%	16.82%
Large Commercial	838,347	348,011	-490,336	0.52%	0.79%
Large Light & Power	518,850	-1,897,630	-2,416,480	-9.02%	-6.89%
Mining	440,302	-2,297,352	-2,737,654	-12.98%	0.05%
Lighting	361,297	-1,769,261	-2,130,558	-11.43%	-8.85%
Total	$7,018,367	$7,018,367	$0	1.90%	1.90%

	Income Taxes at Proposed Rates				
	Per TEP			Percent Return on Rate Base	
Customer Class	CCOSS (3)	Revised (2)	Difference	Per TEP	Revised
Residential	$25,365,954	$20,227,460	-$5,138,494	4.75%	5.45%
Small Commercial	15,468,140	21,695,800	6,227,660	24.74%	22.71%
Large Commercial	8,064,630	11,749,664	3,685,034	15.16%	13.14%
Large Light & Power	4,108,186	2,825,762	-1,282,424	0.22%	1.35%
Mining	4,443,464	2,588,824	-1,854,640	-1.75%	0.22%
Lighting	315,620	-1,321,516	-1,637,136	-9.76%	-7.77%
Total	$57,765,994	$57,765,994	$0	8.52%	8.52%

NOTES;
(1) Income taxes at present rates allocated to classes by TEP in its CCOSS based on plant in service.
(2) Income taxes allocated based on class operating income before income taxes
(3) Income taxes at proposed rates allocated to classes by TEP in its CCOSS based on class revenues.

TUCSON ELECTRIC POWER COMPANY
Docket No. E-01933A-12-0291
Electric Cost of Service and Rate Design

Proposed Changes to Rate Schedules LLP-90N and LLP-14

Rate Component	Present Rates (1)	Proposed Rates (1)	Rate Change
Rate Schedule LLP-90N:			
Customer Charge	$500.00	$2,200.00	$1,700.00
Summer Demand Charge - Per kW: (2)			
On-Peak	$20.03	$22.00	$1.97
Off-Peak (3)	$10.03	$22.00	$11.97
Summer Energy Charge - Per kWh:			
On-Peak Non-Fuel	$0.0011	$0.0061	$0.0050
On-Peak Fuel and Purchased Power	$0.0418	$0.0348	-$0.0069
Total On-Peak Energy Charge	$0.0429	$0.0409	-$0.0020
Off-Peak Non-Fuel	$0.0007	$0.0051	$0.0044
Off-Peak Fuel and Purchased Power	$0.0287	$0.0271	-$0.0016
Total Off-Peak Energy Charge	$0.0294	$0.0322	$0.0028
Winter Demand Charge - Per kW: (2)			
On-Peak	$15.03	$19.00	$3.97
Off-Peak (3)	$7.53	$19.00	$11.47
Winter Energy Charge - Per kWh:			
On-Peak Non-Fuel	$0.0007	$0.0056	$0.0049
On-Peak Fuel and Purchased Power	$0.0271	$0.0308	$0.0037
Total On-Peak Energy Charge	$0.0278	$0.0364	$0.0086
Off-Peak Non-Fuel	$0.0005	$0.0046	$0.0041
Off-Peak Fuel and Purchased Power	$0.0195	$0.0275	$0.0080
Total Off-Peak Energy Charge	$0.0201	$0.0321	$0.0121
Rate Schedule LLP-14:			
Customer Charge	$500.00	$2,000.00	$1,500.00
Demand Charge - Per kW (2)	$19.02	$21.00	$1.98
Summer Energy Charge - Per kWh:			
Non-Fuel	$0.0004	$0.0090	$0.0086
Fuel and Purchased Power	$0.0326	$0.0308	-$0.0018
Total Summer Energy Charge	$0.0330	$0.0398	$0.0068
Winter Energy Charge - Per kWh:			
Non-Fuel	$0.0004	$0.0080	$0.0076
Fuel and Purchased Power	$0.0251	$0.0285	$0.0035
Total Winter Energy Charge	$0.0255	$0.0365	$0.0110

NOTES:
(1) Corrected Schedule H-3, pages 9 and 10
(2) Demand ratchet of 67.7% at present rates; 100% at proposed rates
(3) Present Rates - Excess of 150% of on-peak demand.

aps

RATE SCHEDULE E-35
EXTRA LARGE GENERAL SERVICE
TIME OF USE

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access customers whose monthly maximum demand registers 3,000 kW or more for three (3) consecutive months in any continuous twelve (12) month period ending with the current month. Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by an individual customer contract.

This schedule is not applicable to breakdown, standby, supplemental, residential or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be three phase, 60 Hertz, at the Company's standard voltages that are available within the vicinity of the customer site.

Service under this schedule is generally provided at secondary voltage, primary voltage when the customer owns the distribution transformer(s), or transmission voltage.

RATES

The bill shall be computed at the following rates or the minimum rates, whichever is greater, plus any adjustments incorporated in this rate schedule:

Bundled Standard Offer Service

Basic Service Charge:

For service through Self-Contained Meters:	$ 1.183	per day, or
For service through Instrument-Rated Meters:	$ 1.795	per day, or
For service at Primary Voltage:	$ 3.881	per day, or
For service at Transmission Voltage:	$ 26.574	per day

Demand Charge:

Secondary Service:	$ 16.768	per On-Peak kW, plus
	$ 3.064	per Off-Peak kW, or
Primary Service:	$ 15.792	per On-Peak kW, plus
	$ 2.966	per Off-Peak kW, or
Transmission Service:	$ 10.755	per On-Peak kW, plus
	$ 2.462	per Off-Peak kW

The Demand Charge for military base customers taking primary service and served from dedicated distribution feeder(s) shall be reduced to $ 12.108 per On-Peak kW and $ 2.597 per Off-Peak kW.

RATES (cont)

Energy Charge:	$ 0.04076	per kWh during On-Peak hours, plus
	$ 0.03219	per kWh during Off-Peak hours

Bundled Standard Offer Service consists of the following Unbundled Components:

Unbundled Standard Offer Service

Customer Accounts Charge:	$ 0.601	per day
Revenue Cycle Service Charges:		
Metering:		
Self-Contained Meters:	$ 0.440	per day, or
Instrument-Rated Meters:	$ 1.052	per day, or
Primary:	$ 3.138	per day, or
Transmission:	$ 25.831	per day

These daily metering charges apply to typical installations. Customers requiring specialized facilities are subject to additional metering charges that reflect the additional cost of the installation, (for example, a customer taking service at 230 kV). Adjustments to unbundled metering components will result in an adjustment to the bundled Basic Service Charge.

Meter Reading:	$ 0.068	per day
Billing:	$ 0.074	per day
System Benefits Charge:	$ 0.00297	per kWh
Transmission Charge:	$ 1.776	per On-Peak kW
Delivery Charge:		
Secondary Service:	$ 6.461	per On-Peak kW, plus
	$ 0.646	per kW Off-Peak, or
Primary Service:	$ 5.485	per On-Peak kW, plus
	$ 0.548	per Off-Peak kW, or
Transmission Service:	$ 0.448	per On-Peak kW, plus
	$ 0.044	per Off-Peak kW

In addition, the Delivery Charge for military base customers taking primary service and served directly from a Company substation shall be reduced to $ 1.801 per On-Peak kW and $ 0.179 per Off-Peak kW.

Generation Charge:	$ 8.531	per On-Peak kW, plus
	$ 2.418	per Off-Peak kW, plus
	$ 0.03779	per kWh during On-Peak hours, plus
	$ 0.02922	per kWh during Off-Peak hours

DIRECT ACCESS

The bill for Direct Access customers will consist of the applicable Unbundled Components Customer Accounts Charge, the System Benefits Charge, and the Delivery Charge, plus any applicable adjustments incorporated in this schedule. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, the applicable Unbundled Components Revenue Cycle Service Charges will be applied to the customer's bill.

POWER FACTOR

The customer deviation from phase balance shall not be greater than ten percent (10%) at any time. Customers receiving service at voltage levels below 69 kV shall maintain a power factor of 90% lagging but in no event leading unless agreed to by Company. Service voltage levels at 69 kV or above shall maintain a power factor of ± 95% at all times. In situations where Company suspects that a customer's load has a non-confirming power factor, Company may install at its cost, the appropriate metering to monitor such loads. If the customer's power factor is found to be non-conforming, the customer will be required to pay the cost of installation and removal of VAR metering and recording equipment.

Customers found to have a non-conforming power factor, or other detrimental conditions shall be required to remedy problems, or pay for facilities/equipment that Company must install on its system to correct for problems caused by the customer's load. Until such time as the customer remedies the problem to Company satisfaction, kVA may be substituted for kW in determining the applicable charge for billing purposes for each month in which such failure occurs.

MINIMUM

The bill for service under this rate schedule shall not be less than the applicable Bundled Standard Offer Service Basic Service Charge plus the applicable Bundled Standard Offer Service Demand Charge for the minimum kW specified in the agreement for service or individual customer contract.

DETERMINATION OF KW

For billing purposes, the On-Peak kW used in this rate schedule shall be the greater of the following:

1. The average On-Peak kW supplied during the 15-minute period (or other period as specified by an individual customer contract) of maximum use during the On-Peak hours of the month, as determined from readings of the Company's meter.

2. 80% of the highest On-Peak kW measured during the six (6) summer billing months (May-October) of the twelve (12) months ending with the current month.

The Off-Peak kW used in this rate schedule shall be the average kW supplied during the 15-minute period (or other period as specified by individual customer contract) of maximum use during the Off-Peak hours of the month as determined from readings of the Company's meter.

TIME PERIODS

Time periods applicable to usage under this rate schedule are as follows:

On-Peak hours:	11:00 am – 9:00 pm Monday through Friday
Off-Peak hours:	All remaining hours

TIME PERIODS (Cont)

Mountain Standard Time shall be used in the application of this rate schedule.

ADJUSTMENTS

1. The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule REAC-1 pursuant to Arizona Corporation Commission Decision No. 70313.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. 67744, Arizona Corporation Commission Decision No. 69663, Arizona Corporation Commission Decision No. 71448 and 73183.

3. The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. 67744.

4. The bill is subject to the Environmental Improvement Surcharge as set forth in the Company's Adjustment Schedule EIS pursuant to Arizona Corporation Commission Decision No. 69663 and Arizona Corporation Commission Decision No. 73183.

5. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

6. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. 67744 and Arizona Corporation Commission Decision No. 71448.

7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

CONTRACT PERIOD

The contract period for customers served under this rate schedule will be three (3) years, at the Company's option. If the Company determines that the customer service location is such that unusual or substantial distribution construction is required to serve the site, the Company may require a contract of ten (10) years or longer with a standard seven (7) year termination provision.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

EL PASO ELECTRIC COMPANY
EIGHTEENTH REVISED RATE NO. 18 X
CANCELLING SEVENTEENTH REVISED RATE NO. 18 X

FPPCAC

APPLICABILITY:

Electric service shall be subject to a Fuel and Purchased Power Cost Adjustment Clause (FPPCAC).

TERRITORY:

Areas served by the Company in Dona Ana, Sierra, Otero and Luna Counties.

FPPCAC:

The FPPCAC recognizes loss adjustments due to different voltage levels of service:

	Line Losses	Voltage Factor	
A. New Mexico System	8.0062%	100.0000%	X
B. Transmission Voltage			
(If Customer takes service and is metered at 69,000 volts and higher)	3.2310%	95.5788%	X X
C. Primary Voltage			
(If Customer takes service and is metered at 2,400 volts or higher but less than 69,000 volts)	6.5458%	98.6479%	X X
D. Secondary Voltage			
(If Customer takes service and is metered at 480 volts and below)	8.8553%	100.7862%	X X

Advice Notice No. 212

Signature/Title ____________________
David G. Carpenter
Senior Vice President-Chief Financial Officer

APPENDIX

DEFINITION OF "CUSTOMER CLASS OR CLASS":

The use of the term customer class or class throughout this data request means all customer classifications shown on Schedule H-1 which include TOU customer classifications and Irrigation and Water Pumping.

DOD 1.01

Please provide revised Schedules G-1 and G-2 by customer class. Reconcile totals to Schedules G-1 and G-2 as filed.

RESPONSE:

The Company objects to the request because the Company does not have the data, nor can it justify the expenses necessary to keep the detailed data necessary to comply with this request. Moreover, answering this request would be unduly burdensome and costly.

The Company's proposed class cost of service study ("CCOSS") has combined like-customer classes in categories based on similar costs to serve and similar usage characteristics. It is the Company's opinion that the proposed CCOSS represents the most equitable allocation of costs to TEP's customers. The Company's current rates offer multiple types of service to similarly situated customers that, in the Company's opinion, have no cost basis for the differentiation. Therefore, the Company has proposed consolidation and simplification of it rates in a manner consistent with its proposed CCOSS.

RESPONDENT:

Pricing (B. Pries)

WITNESS:

Craig A. Jones

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO DOD'S 1st SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291 October 12, 2012

DOD 1.02

Please provide details supporting the 4CP allocation used for jurisdictional separations between the ACC and the FERC.

RESPONSE:

2011 Jurisdictional Allocation 12-31-11.xls (provided in TEP's response to UDR 1.01 andlocated in TEP's electronic data room in TEP Uniform Data Requests\Attachments\UDR 1.01\Workpapers – Schedules\Schedule G and H Support\6. Jurisdictional Allocation) is the support workpaper to the Commission and FERC jurisdictional allocation.

RESPONDENT:

Pricing (B. Pries)

WITNESS:

Craig A. Jones

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO DOD'S 1st SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291 October 12, 2012

DOD 1.03

Please provide the following for each class for calendar years 2009, 2010, 2011 actual and 2011 adjusted:

1. Monthly customer count, revenues, revenues per customer, kWh sales and kWh sales per customer.
2. Total monthly billing demands, where applicable.
3. Monthly non-coincident class peak demands ("NCP")
4. Monthly retail system peaks in megawatts ("MW"). Indicate day and time of peak.
5. Monthly class peaks in MW coincident with monthly system peaks.
6. Annual load duration curve with supporting data.

RESPONSE:

1. Please see the files listed below for actual customer count, revenues and sales for 2009, 2010 and 2011.

THE FILES LISTED BELOW CONTAIN CONFIDENTIAL INFORMATION AND ARE BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT DATED JULY 6, 2012.

File Name	Bates Numbers
DOD 1.03 01-09 Rev Sum-Confidential.xls	N/A
DOD 1.03 02-09 Rev Sum-Confidential.xls	N/A
DOD 1.03 03-09 Rev Sum-Confidential.xls	N/A
DOD 1.03 04-09 Rev Sum-Confidential.xls	N/A
DOD 1.03 05-09 Rev Sum-Confidential.xls	N/A
DOD 1.03 06-09 Rev Sum-Confidential.xls	N/A
DOD 1.03 07-09 Rev Sum-Confidential.xls	N/A
DOD 1.03 08-09 Rev Sum-Confidential.xls	N/A
DOD 1.03 09-09 Rev Sum-Confidential.xls	N/A
DOD 1.03 10-09 Rev Sum-Confidential.xls	N/A
DOD 1.03 11-09 Rev Sum-Confidential.xls	N/A
DOD 1.03 12-09 Rev Sum-Confidential.xls	N/A
DOD 1.03 2010-2011 OperRevReport-Confidential.xlsx	N/A
DOD 1.03-1-Confidential.xls	N/A

2011 adjusted revenues are in the TEP Revenue Proof 12-31-11-Confidential.xlsx provided in response to UDR 1.1 (located in TEP's electronic data room in TEP Uniform Data Requests\Attachments\UDR 1.01\Workpapers – Schedules\Schedule G and H Support\1. Confidential).

Adjusted Customer counts and kWh sales are in Billind Determinants adjusted monthly.xls provided in response to UDR 1.1 (located in TEP's electronic data room in TEP Uniform Data Requests\Attachments\UDR 1.01\Workpapers – Schedules\Schedule G and H Support\3. Schedule H Support).

Per customer data can be calculated from the above referenced worksheets.

2. 2011 actual monthly billing demands are in TEP TY Billing Determinants 12-31-11 – Confidential provided in response to UDR 1.1 (located in TEP's electronic data room in TEP Uniform Data Requests\Attachments\UDR 1.01\Workpapers – Schedules\Schedule G and H Support\1. Confidential).

   2011 adjusted monthly billing demands are in Billind Determinants adjusted monthly.xls provided in response to UDR 1.1 (located in TEP's electronic data room in TEP Uniform Data Requests\Attachments\UDR 1.01\Workpapers – Schedules\Schedule G and H Support\3. Schedule H Support).

   2009 and 2010 billing demand was not calculated for purposes of this rate case and therefore is unavailable.

3. Monthly non-coincident class peaks are in Average and Peaks Allocation 12-31-11 (Revised 10-05-12) provided in response to UDR 1.1 (located in TEP's electronic data room in TEP Uniform Data Requests\Attachments\UDR 1.01\Workpapers – Schedules\Schedule G and H Support\5. Load Research).

   2009 and 2010 billing demand was not calculated for purposes of this rate case and therefore is unavailable.

4. Please see DOD 1.03-4 retail system peaks.xls for 2009, 2010, and 2011 day and time retail system peaks.

5. See response to question 1.03 (3).

6. Please see DOD 1.03-6 2011 Load Duration Curve.xls for the requested information.

RESPONDENT:

Pricing (B. Pries)

WITNESS:

Craig A. Jones

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
DOD'S 1st SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
October 12, 2012

DOD 1.04

Provide work papers, calculations, explanations and underlying assumptions supporting the following allocation factors used in the Company's CCOSS. Show any adjustments to actual data:

1. DPROD
2. DPPFAC
3. DTHEHV
4. DTEHV
5. DDISPSUB
6. DDISTPOL
7. DDISTSUL
8. EFUEL
9. EPROD
10. EDSM

RESPONSE:

1. Allocation factor DPROD is used to allocate demand production related costs. The allocation is supported by its average and peaks method and described in detail in the direct testimony of Mr. Craig A. Jones, starting on page 19, line 5. For the workpaper, please see Average and Peaks 12-31-11 (Revised 10-05-12) provided in TEP's response to UDR 1.01. (The file is located in TEP's electronic data room in TEP Uniform Data Requests\Attachments\UDR 1.01\Workpapers – Schedules\Schedule G and H Support\5. Load Research.)

2. Allocation factor DPPFAC is not used in the current class cost of service study.

3.-4. DTHEHV and DTEHV are used for to allocate transmission related cost and are allocated using the average and peaks method.

5.-7. These allocators are used to allocate distribution related cost and all use an NCP factor to allocate cost to classes.

8. The EFUEL factor is developed using cost weighted energy and is applied in the cast to all fuel cost. The workpaper A4. TEP CostWgtdEnergy.xlswas provided in TEP's response to UDR 1.1. (The file is located in TEP's electronic data room in TEP Uniform Data Requests\Attachments\UDR 1.01\Workpapers – Schedules\Schedule G and H Support\2. Schedule G Support - COS.)

9. Allocation factor EPROD is not used in the current CCOSS.

10. Allocation factor EDSM is not used in the current CCOSS.

RESPONDENT:

Pricing (B. Pries)

WITNESS:

Craig A. Jones

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO DOD'S 1st SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291 October 12, 2012

DOD 1.05

Provide the following unit cost information based on the demand, energy and customer cost summaries shown on Schedule G-6-1, Page 95 of 201:

1. For demand costs, unit costs per kilowatt ("KW")
2. For customer costs, unit costs per bill

RESPONSE:

Please see DOD 1.05.xls for the requested information.

RESPONDENT:

Pricing (B. Pries)

WITNESS:

Craig A. Jones

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
DOD'S 1st SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
October 12, 2012

DOD 1.06

Please provide the number of LLP 14 and LLP TOU customers receiving service at transmission voltages, primary voltages, distribution voltages as well as those served through underground distribution facilities. Provide the billing demands and kWh sales for each voltage level of service.

RESPONSE:

Please see TEP's response to AECC 3.1(e).

RESPONDENT:

Pricing (B. Pries)

WITNESS:

Craig A. Jones

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO DOD'S 1st SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291 October 12, 2012

DOD 1.07

Provide a detailed explanation and work papers supporting the $3,012,116 adjustment to reduce test year revenues for the Large Light & Power class and the other revenue amount of $1,637,581 allocated to this class.

RESPONSE:

The adjustment to reduce test year revenues of $3,012,116 for Large Light & Power class can be found in TEP Revenue Proof 12-31-11- Confidential.xlsx provided in response to UDR 1.1 (located in TEP's electronic data room in TEP Uniform Data Requests\Attachments\UDR 1.01\Workpapers – Schedules\Schedule G and H Support\1. Confidential). The calculation is shown on tab Industrial & Mining column R, line 59-80.

Other Revenue was allocated to the Large Light & Power in the amount of $1,637,581 can be found on 2012 TEP Schedule G 12-31-11 (Revised 10-05-12).xls provided in response to UDR 1.1 (located in TEP's electronic data room in TEP Uniform Data Requests\Attachments\UDR 1.01\Workpapers – Schedules\Schedule G and H Support\2. Schedule G Support – COS). The tab Schedule G-1 the calculation is shown on column L, line 22. The source of line 22 is the total revenue for Large Light & Power divided by total Present Sales Revenues times Other Revenue. Other Revenues are calculated on tab Rev&Expense column C, line 14-15 and represent test year amounts. This calculation is done in order to allocate other revenues to each class in proportion to that class's contribution to Total Present Sales Revenues.

RESPONDENT:

Pricing (B. Pries)

WITNESS:

Craig A. Jones

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO DOD'S 1st SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291 October 12, 2012

DOD 1.08

Provide cost justification and support for the proposed 100% demand ratchet.

RESPONSE:

The Company objects to this request as vague and ambiguous. It is unclear what this request is seeking. The Company does not believe there is any additional cost associated with the proposed modification to how the Demand related revenues will be recovered. The Company did modify its billing determinants in its proposed rate design to reflect that the change will, in some cases, produce more units of billing demand. However, the increase in billing demand units will be divided into the same level of demand related revenues the Company is requesting. Therefore, the resulting demand charges will be somewhat lower than if the proposed change was not being requested by the Company. It is the Company's opinion that the proposed rate design is a more cost based method of recovering its demand revenues.

RESPONDENT:

Pricing (B. Pries)

WITNESS:

Craig A. Jones

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
DOD'S 1st SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
October 12, 2012

DOD 1.09

For each affected class, provide the following for the test year:

1. Actual annual billing demands and demand revenues under current ratchet clauses at present rates and proposed rates.
2. Estimate annual billing demands and demand revenues under the proposed 100% demand ratchet at present rates and proposed rates.

RESPONSE:

Please see DOD 1.09.xls for the requested information.

RESPONDENT:

Pricing (B. Pries)

WITNESS:

Craig A. Jones

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO DOD'S 1st SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291 October 12, 2012

DOD 1.10

For both Fort Huachuca and Davis-Monthan AFB, provide the following data for the test year 2011 under the revised rating periods proposed under TOU rate LLP-90N:

1. On-peak and off-peak kWh by month
2. On-peak and off-peak maximum KW monthly demands

RESPONSE:

THE FILE LISTED BELOW CONTAINS COMPETITIVELY-SENSITIVE CONFIDENTIAL INFORMATION THAT IS ONLY BEING PROVIDED TO THE REQUESTING PARTY PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT DATED JULY 6, 2012.

Please see DOD 1.10-Confidential.xls for the requested information. The Excel file is not identified by Bates numbers.

RESPONDENT:

Pricing (B. Pries)

WITNESS:

Craig A. Jones

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO DOD'S 3RD SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291 November 08, 2012

DEFINITION OF "CUSTOMER CLASS OR CLASS":

The use of the term customer class or class throughout this data request means all customer classifications shown on Schedule H-1 which include TOU customer classifications and Irrigation and Water Pumping.

DOD 3.1

Regarding Schedule G – Class cost of service study ("CCOSS"):

a. Is the Company asking the Commission to rely upon its October 5th, 2012 revised CCOSS? If not, please indicate the CCOSS that TEP is advocating for ratemaking purposes in this case.

b. Is the Company planning to revise or further update its CCOSS for Commission consideration?

c. Is the Company planning to revise its rate proposals base on updated CCOSS findings?

RESPONSE:

a. Yes.

b.-c. No. TEP considers the changes to be relatively minor and do not materially change the results of the CCOSS or the resulting rates.

RESPONDENT:

Craig A. Jones

WITNESS:

Craig A. Jones

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
DOD'S 3RD SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
November 08, 2012

DOD 3.2

Regarding class non coincident ("NCP") monthly demands:

a. The monthly NCP detail is obviously in error since it shows identical NCP demands for the Large General Service TOU class and the Large Light & Power class for the months of May 2011 through December 2011. Please provide corrected NCP amounts for these classes.

b. Please explain the incremental NCP monthly increases of 10,000 KW for both classes beginning in May 2011 through December 2011.

c. Please explain how the indicated maximum annual NCP of 123,111 KW for both of these classes occurred in December 2011 rather [than] in a summer month.

RESPONSE:

a.-c. This formula error was pointed out by Commission Staff's consultant in early October and a change was made to address it at that time. The file that was submitted inadvertently left the changes to the other classes unaddressed. The attached files reflect the changes necessary to address both Commission Staff's earlier concern and DOD's concern expressed in this data request. Because the changes were minor and these two classes were already below the average system return on plant, the changes that would carry through to the CCOSS are immaterial and would in no way change the rates or rate design proposed by the Company. Please see 2011 LGS TOU Class LR data (Revised 11-01-12).xlsx and 2011 LLP Class LR data (Revised 10-05-12).xls for the new NCP calculation which was updated in the data room on October 5, 2012. These changes are also reflected in Average & Peaks Allocation 12-31-11 (Revised 11-1-12).xls. (Each of the referenced files can be found in TEP's electronic data room in TEP Uniform Data Requests\Attachments\UDR 1.01\Workpapers – Schedules\Schedule G and H Support\Load Research.)

RESPONDENT:

Pricing (A. Leschak)

WITNESS:

Craig A. Jones

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO DOD'S FOURTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291 November 19, 2012

DEFINITION OF "CUSTOMER CLASS OR CLASS":

The use of the term customer class or class throughout this data request means all customer classifications shown on Schedule H-1 which include TOU customer classifications and Irrigation and Water Pumping.

DOD 4.1

In setting class revenue targets, please indicate the level of consideration given to the Company's CCOSS.

a. Significant consideration with cost of service the foremost factor

b. Moderate consideration with equal weight given to non-cost factors

c. Some consideration with non-cost factors out weighing cost of service

RESPONSE:

The Company objects to this question as being vague and ambiguous. However, while reserving its objection, the Company will attempt to provide a response to what it believes the question may be asking.

The Company is not sure how DOD defines "non-cost factors" but agrees that many factors weigh into the determination of class revenue targets when analyzing what level of costs should be included in any specific rate class's revenue requirements. The CCOSS and the resulting allocation of costs should be a primary consideration when determining a particular class's revenue requirement. However, the level of detail of data used to allocate costs to each rate class must be considered when reviewing the final results. The Company currently has over 50 individual rates. The data is not detailed enough to develop costs for each of those 50 plus rate classes. This is an important consideration when setting class revenue targets. That is why the Company narrowed its CCOSS results to six primary rate categories. Once the CCOSS is complete, the results will provide a very important guide as to how much each of these rate categories are contributing to the recovery of the cost to serve them. The CCOSS also shows how much of a change in total revenues contributed by that class would be necessary to levelize all classes' contributions to the overall system's revenue requirement, assuming an even return on plant.

Once the determination is made as to how much of an increase or decrease is necessary to result in each class contributing equally to the overall revenue requirement necessary to generate a levelized return on plant, further consideration must be given to the impact on any individual class.

The desire would be to eventually move all classes to a set of rates that would generate a levelized rate of return on the plant required to serve that customer class. This cannot always be done in a single rate case. Realizing each party will have an opinion on how the data used in a CCOSS should be used to generate the revenue requirement for each class, it becomes very important to maintain a consistent evaluation process. The Company's CCOSS is based on the same primary assumptions as previous cases. Moving towards a consistently calculated set of costs is an important consideration.

Making adjustments to existing rates that result in changes that are "moderate" is also an important consideration. Since the required change impact each rate class, more consideration is given to classes with the largest impacts.

Another key consideration is whether or not the CCOSS indicates any particular class is contributing more than their proportionate levelized return on plant. When this happens, consideration must be given to how much a reduction to that class (or at least a reduction to the overall increase allocated to that class) will impact the other classes.

RESPONDENT:

Craig A. Jones

WITNESS:

Craig A. Jones

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO DOD'S FOURTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291 November 19, 2012

DOD 4.2

On Page 21 of his class revenue and rate design direct testimony, Mr. Craig Jones states beginning at Line 10: "The Company attempted to achieve parity where possible, but due to the principle of gradualism, we had to make some reasonable adjustments". He earlier defined "parity" as equal return on investment for all classes (Page 21, Line 2). In that regard:

a. Please define the principle of gradualism as applied in this case.

b. Please discuss in detail the "reasonable adjustments" that were made for each class in determining the proposed class revenue increase percentages.

c. Please define and quantify "rate shock" as applied in this case.

RESPONSE:

a. The Company considers the principle of gradualism as a way to create future rate stability for customers through adjustor mechanisms and other changes in rate design.

b. Reasonable adjustments that were made relate to the blending of overall revenues needed to move any particular class to rates that would collect a levelized return on plant being increased or decreased to adjust the total revenues collected in the final proposed rates based on the overall impact to the customers in that class. With these adjustments, not all customers within a class or within different classes will experience the same change in rates, but the change will move all customers toward the goal of contributing equally to the overall return on plant.

c. The general phase "rate shock" was utilized as it is normally used in the utility industry. It is a general term used to refer to a very large increase in rates. While no specific change was quantified as creating "rate shock", it was felt that generally an increase of 100% would likely produce "rate shock". While there were outliers, most changes were limited to 11-25%. There were certain customers that would experience changes in excess of this amount, but the Company attempted to minimize those.

RESPONDENT:

Craig A. Jones

WITNESS:

Craig A. Jones

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO DOD'S FOURTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291 November 19, 2012

DOD 4.3

Provide a schedule showing class revenue and related percentage increases needed to achieve parity in return on rate base for all classes.

RESPONSE:

Please refer to Schedule G-2 provided in TEP's supplemental response to UDR 1.01 dated October 5, 2012.

RESPONDENT:

Craig A. Jones

WITNESS:

Craig A. Jones

Monthly System Peaks 2011

Line No.	Date &Time	Total system Peak (MW)
1	1/4/2011 8:00	1,286
2	2/3/2011 8:00	1,519
3	3/31/2011 17:00	1,170
4	4/28/2011 17:00	1,379
5	5/27/2011 17:00	1,721
6	6/27/2011 16:00	2,334
7	7/2/2011 16:00	2,214
8	8/24/2011 17:00	2,303
9	9/1/2011 16:00	2,199
10	10/2/2011 16:00	1,630
11	11/1/2011 17:00	1,233
12	12/6/2011 8:00	1,327
13		2,334

Monthly System Peaks 2010

Line No.	Date &Time	Total system Peak (MW)
1	1/25/2010 14:00	1,614
2	2/10/2010 20:00	1,491
3	3/10/2010 8:00	1,466
4	4/27/2010 16:00	1,548
5	5/28/2010 16:00	1,996
6	6/30/2010 16:00	2,610
7	7/15/2010 16:00	2,848
8	8/12/2010 16:00	2,696
9	9/20/2010 16:00	2,520
10	10/1/2010 16:00	2,328
11	11/30/2011 8:00	1,568
12	12/31/2010 19:00	1,607
13		2,848

Monthly System Peaks 2009

Line No.	Date &Time	Total system Peak (MW)
1	1/28/2009 8:00	1,686
2	2/11/2009 8:00	1,685
3	3/2/2009 20:00	1,550
4	4/21/2009 17:00	1,990
5	5/18/2009 17:00	2,400
6	6/29/2009 16:00	2,654
7	7/28/2009 16:00	2,891
8	8/20/2009 16:00	2,662
9	9/1/2009 16:00	2,484
10	10/19/2009 16:00	2,082
11	11/5/2009 16:00	1,730
12	12/7/2009 18:00	1,656
13		2,891