ORIGINAL

DEPARTMENT OF THE ARMY
UNITED STATES ARMY LEGAL SERVICES AGENCY
901 NORTH STUART STREET
ARLINGTON VA 22202-1837

0000082554

32D

REPLY TO
ATTENTION OF

March 12, 2008

Regulatory Law Office
U 4177

Subject: In The Matter Of The Filing Of Tucson Electric Power Company To Amend Decision No.62103, Arizona Corporation Commission Docket No. E-01933A-05-0650; AND In The Matter Of The Application Of Tucson Electric Power Company For The Establishment Of Just And Reasonable Rates And Charges Designed To Realize A Reasonable Rate Of Return on The Fair Value Of Its Operations Throughout The State Of Arizona , Arizona Corporation Commission Docket No. E-01933A-07-0402.

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

Enclosed for filing with the Arizona Corporation Commission are the original and fifteen copies of the Direct Testimony Dan L. Neidlinger on Electric Cost of Service and Rate Design on behalf of the Department of Defense in the subject proceeding.

Copies of this Direct Testimony have been sent in accordance with the attached Certificate of Service. Inquiries concerning this matter may be directed to the undersigned at (703) 696-1644.

Sincerely,

Peter Q. Nyce Jr.
General Attorney
Regulatory Law Office

Enclosure

RECEIVED
2008 MAR 13 P 12: 38
AZ CORP COMMISSION
DOCKET CONTROL

Arizona Corporation Commission
DOCKETED
MAR 13 2008
DOCKETED BY nr

**BEFORE THE ARIZONA CORPORATION COMMISSION**

**TUCSON ELECTRIC POWER COMPANY**

**DOCKET NOS. E-01933A-05-0650 & E-01933A-07-0402**

---

**Direct Testimony of Dan L. Neidlinger**

**On Behalf of**

**The Department of Defense**

---

**Electric Cost of Service and Rate Design**

---

**March 14, 2008**

# TABLE OF CONTENTS

**ARIZONA CORPORATION COMMISSION**

**TUCSON ELECTRIC POWER COMPANY**

**DOCKET NOS. E-01933A-05-0650 & E-01933A-07-0402**

**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 $17^{th}$ 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 ("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.

**Q. DID YOU PRESENT TESTIMONY ON BEHALF OF DOD IN TEP'S 05-0650 PROCEEDING?**

A. Yes. The issues presented by TEP in the 05-0650 Docket are again addressed in this case in more detail. The Company has filed in this Docket, 07-0402, three sets of A thru H filing schedules supporting the traditional cost of service ("COS") ratemaking approach as well as the hybrid ("Hybrid") and market ("Market") methodologies discussed in the 05-0650 proceeding. I ask that my testimony in that case be incorporated by reference into the record in this proceeding.

**Q. HAVE YOU CHANGED ANY OF YOUR OPINIONS WITH RESPECT TO THE ISSUES ADDRESSED IN THE 05-0650 CASE?**

A. No, I have not. However, the scope of my testimony in this case is limited to cost of service and rate design issues.

**Q. WHAT IS THE COMBINED ANNUAL ELECTIC 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 213,000,000 kilowatt hours ("kWh").

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

A. My testimony addresses the following issues:

1. The class cost of service study ("CCOSS") supporting the COS filing;
2. The Company's proposed class revenue allocations;

3. The proposed time of use ("TOU") rate design, LLP-90N, for current LLP-14 and LLP-90 customers; and
4. The Company's demand-side management ("DSM") proposals.

The DOD facilities 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.

**Q. IN GENERAL, IS YOUR TESTIMONY ON CCOSS, CLASS REVENUE ALLOCATIONS AND RATE DESIGN ISSUES ALSO APPLICABLE TO THE HYBRID AND MARKET METHODOLGY FILINGS?**

A. Yes.

## I. TESTIMONY SUMMARY

**Q. PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS ON CCOSS, CLASS REVENUE ALLOCATION, RATE DESIGN AND DSM ISSUES.**

A. The balance in TEP's rate structure has deteriorated since the last rate 14 years ago. Interclass revenue subsidies have increased since that time and the Company's rate proposals in this case increase, rather than decrease, these subsidies. For instance, the Company is seeking a 35% rate increase (52% greater than the overall increase of 23%) for the Large Light & Power ("LLP") customer class that is currently providing the highest return on rate base of any class. With respect to rate design, the Company's proposed TOU rate for industrial customers, Rate LLP-90N, is not properly designed and provides little incentive to shift load to off-peak periods. Finally, the Company's proposed DSM program needs to be expanded to provide technical and financial assistance to commercial and industrial customers in addition to residential customers. Accordingly, I recommend the following:

- **CCOSS** – The Commission should reject the Company's four-month coincident peak ("4CP") – Average and Peak ("A&P") demand costing method. This method is technically invalid since it double-counts average demand thereby allocating a disproportionate share of fixed production and transmission costs to high load factor customers. Preferable alternative methods are the 4CP method or the Average and Excess method ("A&E"). The latter method considers both energy and class peak demands but does not incorporate the double-counting flaw inherent in the A&P method

- **CLASS REVENUE ALLOCATION** – The increase to the Residential class should be at least 150% of the overall increase. At requested revenue levels, this increase is 34%. Percentage increases to the General Service ("GS") and LLP classes should be no greater than 50% of the overall increase since these classes are currently providing approximately $60 million in revenue subsidies to other classes. At requested revenue levels, this increase is 11.5%. The Mining class rates should be increased by 19% to achieve unity return on rate base and the largest percentage increase, 45%, is recommended for the Other Public Authority ("OPA") class. Under all demand costing methods, the OPA class shows extremely large losses at current rates.

- **LLP-90N RATE DESIGN** – To better reflect demand /energy and seasonal cost differentials, the on-peak summer period demand charge for the proposed LLP-90N TOU rate should be increased from $8.00 to $14.50 per kilowatt ("KW") and winter energy charges reduced. The summer/winter ratio of total revenues under the proposed alternative rate design is 1.66 in contrast to the 1.20 ratio provided by the Company's rate. The proposed LLP-90N rate does not adequately reflect the 1.76 summer/winter ratio in TEP's monthly peak demands.

- **DSM PROGRAMS** – The bulk of the revenues collected to fund DSM programs will be provided by non-residential customers. Accordingly, the scope of the DSM portfolio should be expanded to include those commercial and industrial customers that may need both technical and financial assistance in implementing DSM projects. This funding should be augmented with Utility Energy Service Contracts that require TEP financing of energy efficiency and renewable energy projects for large commercial and industrial customers. Finally, better costing and pricing practices are required to increase the likelihood of achieving successful outcomes from these programs.

As discussed in detail in the following pages of testimony, adoption of these recommendations will provide more realistic approaches for costing and pricing TEP's electric service thereby reducing interclass subsidies. Moreover, they would provide for the design of TOU rates which provide for a strong financial incentive to shift demand to off-peak periods.

## 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 customer 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 and, in other instances, 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 that standard rate schedules.

**Q. HOW WOULD YOU CHARACTERIZE TEP'S CURRENT RATE STRUCTURE?**

A. The Company's current rate structure shows significant imbalance as evidenced by the results of the CCOSS filed in this case and discussed in the Direct Testimony of Mr.

Bentley Erdwurm, Lead Analyst in TEP's Rates and Revenue Requirements Department. Mr. Erdwurm's CCOSS for the test year, calendar year 2006, shows extremely large variances in class returns. For instance, Mr. Erdwurm's study[1] shows a negative return for the Residential class of $24.8 million in contrast to the positive return of $28 million for the General Service class on a smaller rate base – a $52.8 million differential. These two customer classes account for over 84% of TEP's total retail electric sales.

**Q. HOW HAS TEP'S RATE STRUCTURE CHANGED SINCE ITS LAST MAJOR RATE PROCEEDING IN 1993?**

A. The balance in the rate structure has deteriorated significantly since that case 14 years ago[2]. At that time, all classes were providing positive returns and the differential between the Residential and GS classes was only $14 million under the same A&P costing methodology. Moreover, TEP's total retail rate base was $138 million higher in 1992 than the total rate base in this case ($1,121 million versus $983 million).

**Q. WHAT ARE THE REASONS FOR THIS DRAMATIC CHANGE?**

A. The root cause of this rate structure deterioration is the failure by both the Company and the Commission to properly set, in prior rate proceedings, class revenue requirements based on sound cost of service principles. As a result, changes in TEP's customer mix and usage patterns since 1992 have exacerbated the interclass subsidy problems present at that time. Exhibit DLN-1, attached, provides a comparison of changes in class revenues, megawatt-hour ("MWH") sales and load factor statistics from 1992 to the current case, calendar year 2006. Although MWH sales increased by 48% during this period, revenues increased by only 36% due to an 8% decrease[3] in the

[1]Updated A&P CCOSS provided in response to DOD Data Request 3.2
[2]Docket U-1933-93-006 – Test Year Ended 6-30-1992
[3]Primarily due to the rate reductions provided for in the 1999 Settlement Agreement

average rate per kWh. Further, residential sales grew at much greater percentage, 82%, than any other customer class. The Residential class was in 1992, and remains today, the least profitable of the Company's major customer classes.

**Q. CAN YOU EXPLAIN THE EROSION IN TOTAL SYSTEM LOAD FACTOR FROM 58% IN 1992 TO 46% IN 2006?**

A. As indicated in the bottom chart on Exhibit DLN-1, this deterioration in load factor is due primarily to the decline in the load factor of the Residential class (53% to 42%) and its increased percentage contribution (48% versus 37%) to TEP's 4CP demand. At current rate levels, revenues from the Residential class are not sufficient to recover the increased costs that the class is imposing on TEP's system.

**Q. DO THE COMPANY'S RATE PROPOSALS IN THIS CASE ADEQUATELY ADDRESS THIS RATE STRUCTURE PROBLEM?**

A. In my view, they do not. Exhibit DLN-2 shows customer class returns on rate base, return indices and revenue subsidies at present and proposed rates under the Company's A&P demand costing methodology. As discussed later in my testimony, the A&P method is technically flawed and an improper demand costing method. However, even under this method, the large disparities in class returns are clearly demonstrated. At present rates, percentage returns on rate base range from a negative 33.95% for the Mines to a positive 7.94% for the GS class. At proposed rates, the Residential class shows a return on rate base of only 4.43% and a return index of .53 whereas the GS and LLP classes show returns on rate base of 16.04% and 22.35%, respectively, and return indices of 1.92 and 2.68. The Company's rate proposals merely perpetuate the interclass subsidies inherent in the present rates.

**Q. WHAT IS THE MEANING OF A RATE OF RETURN INDEX?**

A. A class's rate of return index is a relative measure of its contribution to the system average rate of return. An index that is below 1.00, or negative, indicates that a class's revenues are not sufficient to recover its cost of service, while an index exceeding 1.00 indicates that a class is over-recovering its cost of service, thereby providing revenue subsidies to other classes. Referring again to Exhibit DLN-2, at the Company's proposed rates, the GS and LLP classes are providing over $55 million of revenue subsidies to other customer classes whereas the revenue subsidy received by the Residential class is increased to $34 million.

**Q. PLEASE EXPLAIN EXHIBIT DLN-3.**

A. Exhibit DLN-3 shows present and proposed revenues by customer class and proposed percentage increases. Also shown are class revenue subsidies expressed as a percentage of revenues. As noted, present revenues exclude DSM and Competitive Transition Charges ("CTC") and proposed revenues exclude TEP's proposed Termination Costs Regulatory Asset Charge ("TCRAC"). The Company's proposed revenue spread of the requested $158,186 million increase is not consistent with results of its own CCOSS and should be rejected.

**Q. WHY IS THE A&P METHOD USED BY THE COMPANY TO ALLOCATE DEMAND-RELATED PRODUCTION COSTS TECHNICALLY FLAWED?**

A. The A&P method 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 and transmission 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, as advocated by Mr. Erdwurm, it is also appropriate for ACC retail costing.

**Q. PLEASE EXPLAIN THE ILLUSTRATION PROVIDED ON EXHIBIT DLN-4.**

A. The illustration shown on Exhibit DLN-4 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 Class 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. DID THE COMPANY, AT YOUR REQUEST, PREPARE A CCOSS USING THE 4CP DEMAND ALLOCATION METHOD?**

A. Yes. Summary results of that study are shown on Exhibit DLN-5. The returns on rate base at both present and proposed rates for the Residential and OPA classes are lower than the comparable statistics show on Exhibit DLN-2. The higher load factor classes, LLP and the Mines, show much improved returns under the 4CP method due largely to the elimination of the double-counting penalty inherent in the A&P method.

**Q. UNDER THE COMPANY'S A&P COSTING, THE COMPANY IS REQUESTING RATES THAT PROVIDE FOR A 22% RETURN ON RATE BASE FOR THE LARGE LIGHT & POWER CUSTOMER CLASS. UNDER THE 4CP METHOD, THIS RETURN JUMPS TO 46% -- A RETURN THAT IS OVER FIVE TIMES THE OVERALL REQUESTED RETURN OF 8.35%. IS THERE ANY JUSTIFICATION FOR RATES THAT PROVIDE THESE VERY HIGH RETURNS?**

A. Absolutely not. The Company's rate proposals for the LLP class are excessive under either costing methodology. Excluding the off-peak Lighting class, there are only two classes, GS and LLP, which provide return indices at proposed rates that are greater than 1.00 and the LLP class return index of 5.57 is triple the 1.79 index of the GS class. The LLP class is currently providing at present rates the highest return, 13.97%, of any class and yet is asked be burdened with an additional 35% rate increase – an increase that is 52% greater than the overall requested increase of 23%. By any objective measure of reasonableness and fairness, the Company's proposed revenue increases to the LLP class are unsupportable.

**Q. IN PRIOR TEP DECISIONS, THE COMMISSION HAS EXPRESSED THE CONCERN THAT THE 4CP DEMAND ALLOCATION METHOD DOES NOT ADEQUATELY CONSIDER ANNUAL ENERGY USAGE. IS THERE A TECHNICALLY VALID DEMAND ALLOCATION METHOD THAT CONSIDERS AVERAGE ENERGY USAGE IN DETERMINING CLASS ALLOCATION FACTORS?**

A. Yes. The 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 Company, again at my request, prepared a CCOSS with demand allocation factors calculated under the A&E method. The average demand component of the calculation was based on annual energy use for each class. The peak demand component of the calculation used maximum, monthly non-coincident peaks ("NCP")[4]. The results of this analysis are summarized on Exhibit DLN-6. As shown on that exhibit, class returns, at both present and proposed rates are comparable to the 4CP results shown on Exhibit DLN-5. The only significant variant is the off-peak Lighting class.

**Q. IN VIEW OF THE THESE CCOSS RESULTS, HOW SHOULD THE COMPANY'S CLASS REVENUE PROPOSALS BE MODIFIED?**

A. Significant changes to the Company's proposals are necessary to improve the balance in the current rate structure. A revised class revenue allocation is provided on Exhibit DLN-7. First, I recommend that the percentage revenue increase for the Residential class be increased to 34% -- eight percentage points greater than the Company's recommended 26% increase. An increase of this magnitude is needed to begin restoring rate structure integrity. Second, smaller relative increases of 11.5% are recommended for the GS and LLP classes in consideration of the large revenue subsidies these classes are currently providing. The Company's proposed increases for these classes[5], as previously discussed, are not supportable under any costing analysis and merely perpetuate the interclass subsidy problem at greater revenue levels. Third, a 19% increase is recommended for the Mining class to move it to unity return, 8.35%, on allocated rate base. Finally, the largest percentage increase for any class, 45%, is

[4]One variation of the classical A&E formulation is the measurement of class excess demands based on 4CP rather than maximum NCP demands ("4CP A&E"). In this case, class demand allocation percentages produced under the 4CP A&E method are not materially different than those used to produce the results shown on Exhibit DLN-6.
[5]Per Exhibit DLN-3, Company proposed increases for the GS and LLP classes are 17.3% and 35.3%, respectively

recommended for the OPA class. Under all demand costing methods, the OPA class shows extremely large losses at current rates.

**Q. PLEASE EXPLAIN THE RETURN INDICES SHOWN UNDER THE LAST TWO COLUMNS OF EXHIBIT DLN-7.**

A. Class return indices at my recommended revenue spread are shown for the A&E method and the Company's A&P method. While much improved over the Company's proposals, a relatively large return disparity remains among the Residential, GS and LLP classes. These return differences cannot be eliminated without radical rate changes. For instance, to obtain unity return, a 46% increase would be required for the Residential class and while 95% and 81% increases would be required for the Lighting and OPA classes, respectively. The GS and LLP classes would receive small rate reductions. I do not support variances of this magnitude in rate changes among the classes at this time. One should consider in the rate setting process, as previously stated, continuity, simplicity and stability. However, these ratemaking attributes have often been used in the past as justification for making rate decisions for TEP that largely ignore cost of service. The grim results of these ratemaking policies are clearly demonstrated on Exhibit DLN-1. I fear that the system inefficiencies shown on that exhibit will continue under the Company's class revenue and rate design proposals.

**Q. ARE YOU ENDORSING THE OVERALL REVENUE LEVELS REQUESTED BY TEP?**

No. The DOD has no recommendation with respect to overall revenue requirements. The recommended class revenue allocation (Exhibit DLN-7) is provided to illustrate an equitable assignment of revenue responsibility at the overall revenue level requested by the Company. The increase in total revenues authorized by the Commission should be apportioned among the classes as follows:

| | |
|---|---|
| • Residential | 66.7% |
| • GS | 20.0% |
| • LL&P | 3.9% |
| • Mining | 4.5% |
| • Lighting | 1.0% |
| • OPA | 3.9% |

These percentages are consistent with the class allocations shown on Exhibit DLN-7.

**Q. WHAT INCREASE IN TOTAL REVENUES DO THE ACC STAFF, RUCO AND AECC SUPPORT IN THIS CASE?**

A. Staff is recommending an overall revenue increase of $9,766,000[6] or 1.4%. RUCO recommends a 4.04%[7] increase of $36,254,000. AECC's recommended increase is $91,619,000 or 13.25%. Based on these recommendations and the class apportionment factors discussed above, the revenue spreads would be approximately as follows:

| | STAFF | RUCO | AECC |
|---|---|---|---|
| • Residential | $6,514,000 | $24,181,000 | $61,110,000 |
| • GS | 1,953,000 | 7,251,000 | 18,324,000 |
| • LL&P | 381,000 | 1,414,000 | 3,573,000 |
| • Mining | 439,000 | 1,631,000 | 4,123,000 |
| • Lighting | 98,000 | 363,000 | 916,000 |
| • OPA | 381,000 | 1,414,000 | 3,573,000 |

This revenue allocation is provided for comparative purposes with the revenue increases shown on Exhibit DLN-7 using the Company's proposed revenue requirement. As previously stated, the DOD has no recommendation on overall revenue requirements.

[6]Staff's alternative return on fair value produces an overall increase of $17.84 million or 2.6%.
[7]This is a 5.24% increase on adjusted test year revenues of $691,451,429; RUCO 4.04% calculation includes sales for resale and other operating revenues in present revenues.

## III. RATE DESIGN

**Q. HAVE YOU REVIEWED THE RATE DESIGN RECOMMENDATIONS OF MR. ERDWURM?**

A. I have generally reviewed most of Mr. Erdwurm's rate design proposals for the various classes. I have specifically analyzed in detail the proposed TOU rate LLP-90N[8] that would replace the current LLP-14 and LLP-90 rates.

**Q. DO EITHER DM OR THE FORT OBJECT TO THE IMPOSITION OF A MANDATORY TOU RATE?**

A. No, they do not. A properly designed TOU rate would provide both DOD facilities with additional incentives to shift on-peak load to off-peak periods. They do object, however, to the TOU rate design proposed by the Company. Rather than encouraging improved efficiency, the proposed LLP-90N rate provides little incentive to either of these DOD customers to shift load.

**Q. PLEASE EXPLAIN.**

A. Typical bill comparisons[9] under TOU rate LLP-90N indicate that high load factor customers will incur a greater percentage increase in bills than less-efficient, low load factor customers. This phenomenon is the result of recovery of an excessive amount, over 50%, of demand-related costs in the energy component of the rate. Although consistent with the Company's proposed A&P costing method, this rate design is contra to the load-shifting objectives of TOU rates[10] and proposed DSM programs[11]. To

---

[8]Schedule H-3, Page 14 of 16, Cost of Service Filing
[9]Schedule H-4, Page 23 of 28, Cost of Service Filing
[10]Direct Testimony of Bentley Erdwurm, Page 30
[11]Direct Testimony of Denise A. Smith, Page 3

achieve these objectives, the summer period peak-demand component of the rate must be increased significantly to recover a greater percentage of demand-related costs.

**Q. ARE OTHER CHANGES TO RATE LLP-90N NEEDED, IN YOUR VIEW?**

A. Yes. Of equal importance to the demand/energy mix is the seasonal aspect of the rate. The rate does not reflect the very large summer/winter demand differential. Exhibit DLN-8 shows monthly peak demands for calendar year 2006. The ratio of maximum monthly peak (July) to minimum monthly peak (February) is over 2.00. The ratio of summer peak to winter peak is 1.76. These ratios not only provide guidance with respect to CCOSS demand costing but also the degree of seasonality to be incorporated in the rate design. The ratio of summer/winter demand charges in the proposed LLP-90N is only 1.33 and the comparable ratio for total charges, including fuel and purchased power, is 1.20. Both of these ratios are well short of the cost differentials implied by TEP's peaking characteristics.

**Q. ARE THESE LOW SEASONAL RATIOS ALSO PREVALENT IN THE TOU RATES PROPOSED FOR OTHER CUSTOMER CLASSES?**

A. I have not analyzed the proposed TOU rates for other customer classes in detail. However, the ratios appear to be higher than the ratios for the proposed LLP-90N rate. For instance, the second tier (501-3,500 kWh's) of the proposed residential TOU Rate R-70N[12] for the summer on-peak period is only $0.0123 higher than the second tier of this rate for the winter on-peak period but the ratio of summer/winter revenues are much greater than 1.33 since the bulk of residential usage occurs during the summer period. Also, in contrast to the LLP-90N rate design, a strong load shifting incentive is incorporated the R-70N rate. The summer on/off peak differential is almost $0.10 per kWh.

There are other unexplainable differences among the Company's TOU rate design proposals, notably the variances in winter season off-peak fuel and purchased power rates. These rates range from $0.0111 per kWh (less than cost) under the R-70N rate to

[12]Schedule H-3, Page 2 of 16, Cost of Service Filing

\$0.0357 per kWh under the LLP-90N rate. The latter rate is higher than the on-peak fuel and purchased power rate of \$0.0288.

**Q. HAVE YOU DESIGNED AN ALTERNATIVE TOU RATE WHICH BETTER REFLECTS DIFFERENCES IN SEASONAL COSTS AND PROVIDES IMPROVED INCENTIVES TO SHIFT LOAD TO OFF-PEAK PERIODS?**

A. Yes. The TOU rate shown on Exhibit DLN-9 was developed to illustrate the type of rate design that I recommend be adopted in this case. It is designed to mirror the revenue requirements used to develop LLP-90N – the Company's proposed revenues for the LLP customer class. Accordingly, I am not recommending the level of the rate components but only the demand/energy and seasonal relationships demonstrated by the proposed design. The rate incorporates much higher on-peak demand and energy charges during the summer period to encourage load shifting to off-peak periods. In addition, summer/winter ratios for demand charges and total charges are increased to 1.69 and 1.66, respectively – ratios that are much closer to the seasonal load relationships shown on Exhibit DLN-8. The shoulder rating periods during the summer have been eliminated; the on-peak period during the summer is 12:00 noon to 8:00 P.M. In sum, the alternative TOU rate does a better job of reflecting TEP's costs than the LLP-90N rate.

**Q. WHY AREN'T WEEKENDS OFF-PEAK?**

A. In most electric utilities, the weekday diversity provided by commercial and industrial customers produces relatively large load reductions on the weekends. Accordingly, weekends are normally off-peak periods under TOU rates. TEP's system loads, however, are driven by the residential class which exhibits no significant load reduction during the weekends. In fact, the residential class's monthly peak demand occurred four times on a Saturday or Sunday during 2006[13]. This anomaly is also a

[13]See TEP's response to RUCO Data Request 3.6

major consideration in the establishment of two (morning and evening) on-peak periods during the winter season.

**Q. CAN YOU QUANTIFY THE IMPROVEMENT IN LOAD SHIFTING INCENTIVES PROVIDED BY YOUR ALTERNATIVE RATE DESIGN?**

A. Yes. A comparison (alternative rate design versus LLP-90N) of the monthly and annual benefits from shifting 1 KW of demand at a 70% load factor from on-peak to off-peak periods is provided on Exhibit DLN-10. The annual savings under the alternative rate are $225 or 42% greater than the $158 savings achieved under the Company's proposed LLP-90N rate. The proposed alternative rate design has not only a sounder cost foundation but also provides a much greater financial incentive to shift load to off-peak periods.

**Q. HAVE YOU REVIEWED THE COMPANY'S PROPOSED RATE RIDER 5 – THE TRANSMISSION COST ADJUSTMENT CHARGE ("TCA")?**

A. Yes. I have no general objection to flowing-through to retail customers adjustments made by the Federal Energy Regulatory Commission's ("FERC") to TEP's transmission tariffs ("OATT"). I do object, however, to the manner in which TEP proposes to establish and implement Rider 5. First, the OATT is a demand-based tariff, not an energy charge. TEP has converted all of customer class OATT demand charges into energy charges and proposes to make future adjustments on a kWh basis without considering line and transformation losses. This approach is not cost-based and should be rejected by the Commission. Where practicable, the TCA charge for customer classes should be set on a demand or KW basis consistent with charges under the OAAT. Arizona Public Service Company[14] recently received Commission approval of a TCA that provides for demand charges for all customers with demands over 20 KW. Second, adjustments under Rider 5 should be calculated in a manner consistent with FERC's

[14]Decision No. 70179, ACC Docket No. E-01345A-07-0713

formula method which provides for a reconciliation of prior over or under collections. Finally, regardless of the basis setting and adjusting the rate (KW or kWh), line and transformation losses should be included in the rate calculations.

**Q. DON'T MOST ELECTRIC UTILITIES ADJUST FOR KW AND KWH LOSSES IN THEIR COSTING PRACTICES?**

A. Yes, except for TEP. Adjusting for losses by voltage level of service is standard practice in the electric utility industry. Loss factors are typically used in cost of service studies and applied to adjustment clauses such as fuel and purchased power adjustors. Loss factors were not used in TEP's CCOSS and there is no mention of loss adjustment factors by Company witness David Hutchens in his testimony on a proposed purchased power and fuel adjustment clause ("PPFAC'). If losses are not considered, customers taking service at primary and transmission voltages will pay energy charges that exceed cost and customers taking service at secondary voltage levels will pay energy charges that are lower than cost.

## IV. TEP'S PROPOSED DSM PROGRAM

**Q. HAVE YOU REVIEWED THE COMPANY'S DSM PROPOSALS AS DISCUSSED IN THE TESTIMONIES OF MS. DENISE SMITH AND MR. THOMAS HANSEN?**

A. Yes. The Company is recommending that funding for DSM programs be increased from the current $3.1 million to $12.4 million. Details of the Company's expanded DSM portfolio are discussed by Ms. Smith; Mr. Hansen's testimony deals with recommended DSM cost recovery mechanisms through a DSM adjustor that would appear as a line item on customers' bills. The bulk of the proposed expenditures are targeted for DSM programs for residential and small commercial customers. It is unlikely that either the Fort or DM would receive any benefits from the proposed portfolio but would be required to provide over $395,000[15] annually to fund the programs.

**Q. ARE YOU SUGGESTING THAT THE FORT AND DM BE EXPEMPT FROM DSM CHARGES?**

A. No. Both of these DOD installations are currently providing DSM funds to TEP and are agreeable to continue this funding if the programs can actually reduce total system costs. To date, however, it is evident from the facts in this case that the current programs have had little impact on system efficiencies. Larger commercial and industrial customers provide a significant portion of total DSM funding. It follows that TEP be required to broaden the scope of its DSM portfolio to include programs for those larger customers that may need technical and financial assistance in evaluating and implementing DSM applications. In addition to direct funding under the DSM portfolio, there are probably numerous other large-customer DSM projects that could be implemented through Utilities Energy Services Contracts ("UESC'S")

---

[15]Second tier rate of $0.001859 per kWh, Exhibit TNH Page 2 of 2.

**Q. WHAT ARE UESC'S?**

A. A UESC is a contract between the utility and customer to install energy efficient equipment, processes and systems on the customer's premises that are deemed to be economically feasible. Utilities throughout the U.S. have entered into these contracts with both government and non-government customers; they are cooperative efforts aimed at saving costs to both the utility and the customer. These projects are typically financed by the utility which earns a defined rate of return on monies invested. Energy savings provide customers the ability to refund to the utility the cost of the project over a specified period of years.[16] DSM technologies funded under this approach include lighting, building insulation, HVAC equipment, motors, pumps, thermal storage and shading structures over chillers and cooling towers. Renewable energy projects including solar, wind and biomass generators would also be candidates for this type of funding.

**Q. DID EITHER OF THE COMPANY'S DSM WITNESSES DISCUSS THE USE OF UESC'S AS A VIABLE APPROACH FOR FINANCING DSM OR RENEWABLE ENERGY PROJECTS?**

A. Ms. Smith did not discuss these contracts. Mr. Hansen briefly discusses on Page 12 of his testimony the need for a higher rate of return on DSM projects financed by the Company that are "outside of the DSM program" and covered under a one-time agreement akin, I assume, to a UESC. UESC's would provide an important financing vehicle to fill the void in the Company's proposed DSM program with respect to large commercial and industrial customers. They would also provide the Company with an opportunity to earn additional income on monies invested under UESC's. Accordingly, I urge the Commission to include UESC's as another component of TEP's DSM portfolio.

---

[16]The terms of these contracts range from 5 to 20 years.

**Q. WHAT ABOUT MR. HANSEN'S PROPOSAL TO RECOVER A RATE OF RETURN PREMIUM ON "HIGH EFFICIENCY CAPITAL EXPENDITURES"?**

A. In my view, the Company does not need any additional financial incentive to construct energy-efficient plant since these investments accrue to the benefit of the Company's profits. The purpose of the DSM program is to change the behavior of the customer, not the Company. Similarly, the Company shouldn't need additional financial incentives to assist customers with projects, such as thermal storage, that reduce peak load. A thermal storage project financed under a UESC provides the Company with a guarantee that it will receive its authorized rate of return on the project as well as recover a portion of lost revenues attributable to reduced demands and energy usage.

**Q. ARE LOAD-SHIFTING PROJECTS FOR LARGE CUSTOMERS, LIKE THERMAL STORAGE, ECONOMICALLY ATTRACTIVE UNDER THE COMPANY'S PROPOSED TOU RATES?**

A. As previously discussed, the meager benefits of load-shifting under the Company's proposed TOU rates would probably not support economic feasibility for most of these projects. The proposed alternative rate form, however, would significantly improve the economic attractiveness of load-shifting projects like thermal storage. Due to faulty costing and pricing practices, the Company has failed to properly synchronize its rate design proposals with the load reduction objectives of its DSM programs.

**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.

**TUCSON ELECTRIC POWER COMPANY**
**Docket Nos. E-01933A-05-0650 & 07-0402**
**Electric Cost of Service and Rate Design**

**Historical Comparisons - 1992 vs 2006**
**$(000)**

| Customer Class | 1992 Revenues | 1992 MWH Sales | 2006 Revenues | 2006 MWH Sales | Percentage Increase (Decrease) Revenues | Percentage Increase (Decrease) MWH Sales |
|---|---|---|---|---|---|---|
| Residential | $190,021 | 2,117,799 | $307,535 | 3,864,352 | 61.84% | 82.47% |
| General Service | 203,842 | 2,184,851 | 274,528 | 3,314,379 | 34.68% | 51.70% |
| Large Light & Power (1) | 71,007 | 1,149,742 | 53,837 | 948,945 | -24.18% | -17.46% |
| Mines | 31,604 | 670,865 | 37,790 | 924,898 | 19.57% | 37.87% |
| Lighting | 3,368 | 31,269 | 4,077 | 41,016 | 21.05% | 31.17% |
| Other Public Authority | 9,818 | 138,674 | 13,684 | 225,259 | 39.38% | 62.44% |
| Total TEP | $509,660 | 6,293,200 | $691,451 | 9,318,849 | 35.67% | 48.08% |
| Rate Per kWh | $0.08099 | | $0.07420 | | -8.38% | |

| Customer Class | 1992 Average 4CP Demand (2) | 1992 Load Factor (3) | 2006 Average 4CP Demand (2) | 2006 Load Factor (3) | Percentage Increase (Decrease) Average 4CP Demand | Percentage Increase (Decrease) Load Factor |
|---|---|---|---|---|---|---|
| Residential | 460 | 52.56% | 1,061 | 41.58% | 130.65% | -20.89% |
| General Service | 528 | 47.24% | 825 | 45.86% | 56.25% | -2.92% |
| Large Light & Power (1) | 157 | 83.60% | 134 | 80.84% | -14.65% | -3.30% |
| Mines | 76 | 100.77% | 99 | 106.65% | 30.26% | 5.84% |
| Lighting (4) | 1 | NM | 3 | NM | NM | |
| Other Public Authority | 25 | 63.32% | 74 | 34.75% | 196.00% | -45.12% |
| Total TEP | 1,247 | 57.61% | 2,196 | 46.44% | 76.10% | -19.39% |

NOTES:

(1) Changes in Large Light & Power Class revenues and MWH sales due primarily to reclassification of certain customers to other rates.
(2) Average of class 4 coincident summer peak demand (4CP) - Megawatts.
(3) Annual load factor calculated based on average 4CP demand.
(4) Off-peak load; NM=Not Meaningful

**TUCSON ELECTRIC POWER COMPANY**
**Docket Nos. E-01933A-05-0650 & 07-0402**
**Electric Cost of Service and Rate Design**

**Class Returns on Rate Base and Revenue Subsidies at Present and Proposed Rates**
**4CP Average and Peak ( A&P) Demand Methodology (1)**
**$(000)**

| | Return on Rate Base | | Return Index | | Revenue Subsidy (2) | |
|---|---|---|---|---|---|---|
| Customer Class | Present Rates | Proposed Rates | Present Rates | Proposed Rates | Present Rates | Proposed Rates |
| Residential | -4.77% | 4.43% | -3.56 | 0.53 | ($29,611) | ($33,822) |
| General Service | 7.94% | 16.04% | 5.93 | 1.92 | 54,384 | 45,063 |
| Large Light & Power | -3.76% | 22.35% | -2.80 | 2.68 | (1,756) | 10,179 |
| Mines | -33.95% | -22.07% | -24.66 | -2.64 | (17,129) | (16,430) |
| Lighting | 4.30% | 14.49% | 3.20 | 1.74 | 874 | 953 |
| Other Public Authority | -18.03% | -6.32% | -13.45 | -0.76 | (6,762) | (5,943) |
| Total TEP | -1.34% | 8.35% | 1.00 | 1.00 | $0 | $0 |

NOTES:
(1) TEP's proposed demand allocation method as discussed in the Direct Testimony of Mr. Bentley Erdwurm
(2) Positive number Indicates the amount of subsidy a class is providing; bracketed or negative number indicates the amount of subsidy a class is receiving.

**EXHIBIT DLN - 3**

**TUCSON ELECTRIC POWER COMPANY**
**Docket nos. E-01933A-05-0650 & 07-402**
**Electric Cost of Service and Rate Design**

**Class Revenue Subsidies as a Percentage of Present and Proposed Revenues**
**A&P Demand Methodology**
**$(000)**

| Customer Class | Present Revenues (2) | Proposed Revenues (3) | Proposed Increase | Percent Increase | Revenue Subsidies as A Percent of: (1) Present Revenues | Proposed Revenues |
|---|---|---|---|---|---|---|
| Residential | $307,535 | $387,022 | $79,487 | 25.85% | -9.63% | -8.74% |
| General Service | 274,528 | 321,984 | 47,456 | 17.29% | 19.81% | 14.00% |
| Large Light & Power | 53,837 | 72,819 | 18,982 | 35.26% | -3.26% | 13.98% |
| Mines | 37,790 | 43,724 | 5,934 | 15.70% | -45.33% | -37.58% |
| Lighting | 4,077 | 5,659 | 1,582 | 38.80% | 21.44% | 16.84% |
| Other Public Authority | 13,684 | 18,429 | 4,745 | 34.68% | -49.42% | -32.25% |
| Total TEP | $691,451 | $849,637 | $158,186 | 22.88% | 0.00% | 0.00% |

NOTES:
(1) Dollar amount of class subsidies are shown on Exhibit DLN - 2.
(2) Excluding DSM & CTC Revenues
(3) Excluding Proposed Termination Costs Regulatory Asset Charge ("TCRAC")

**EXHIBIT DLN - 4**

**TUCSON ELECTRIC POWER COMPANY**
**Docket Nos. E-01933A-05-0650 & 07-0402**
**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 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 4CP demand.

**TUCSON ELECTRIC POWER COMPANY**
**Docket Nos. E-01933A-05-0650 & 07-0402**
**Electric Cost of Service and Rate Design**

**Class Returns on Rate Base and Revenue Subsidies at Present and Proposed Rates**
**4CP Demand Methodology (1)**
**$(000)**

| | Return on Rate Base | | Return Index | | Revenue Subsidy (2) | |
|---|---|---|---|---|---|---|
| **Customer Class** | **Present Rates** | **Proposed Rates** | **Present Rates** | **Proposed Rates** | **Present Rates** | **Proposed Rates** |
| Residential | -6.69% | 2.27% | -4.99 | 0.27 | ($47,464) | ($53,993) |
| General Service | 6.94% | 14.95% | 5.18 | 1.79 | 49,120 | 39,116 |
| Large Light & Power | 13.97% | 46.48% | 10.42 | 5.57 | 8,937 | 22,261 |
| Mines | -10.03% | 6.85% | -7.48 | 0.82 | (3,055) | (529) |
| Lighting | 10.51% | 21.50% | 7.84 | 2.57 | 1,706 | 1,892 |
| Other Public Authority | -22.42% | -11.60% | -16.73 | -1.39 | (9,244) | (8,747) |
| Total TEP | -1.34% | 8.35% | 1.00 | 1.00 | $0 | $0 |

NOTES:
(1) Per CCOSS provided in response to DOD Data Request 3.3
(2) Positive number Indicates the amount of subsidy a class is providing; bracketed or negative number indicates the amount of subsidy a class is receiving.

**TUCSON ELECTRIC POWER COMPANY**
**Docket Nos. E-01933A-05-0650 & 07-0402**
**Electric Cost of Service and Rate Design**

**Class Returns on Rate Base and Revenue Subsidies at Present and Proposed Rates**
**A&E Demand Methodology (1)**
**$(000)**

| | Return on Rate Base | | Return Index | | Revenue Subsidy (2) | |
|---|---|---|---|---|---|---|
| Customer Class | Present Rates | Proposed Rates | Present Rates | Proposed Rates | Present Rates | Proposed Rates |
| Residential | -7.30% | 1.57% | -5.45 | 0.19 | ($53,386) | ($60,691) |
| General Service | 8.69% | 16.87% | 6.48 | 2.02 | 58,252 | 49,437 |
| Large Light & Power | 12.00% | 43.81% | 8.95 | 5.25 | 7,962 | 21,161 |
| Mines | -11.54% | 4.95% | -8.61 | 0.59 | (3,670) | (1,223) |
| Lighting | -11.70% | -3.53% | -8.73 | -0.42 | (2,008) | (2,303) |
| Other Public Authority | -18.77% | -7.20% | -0.14 | -0.86 | (7,150) | (6,381) |
| Total TEP | -1.34% | 8.35% | 1.00 | 1.00 | $0 | $0 |

NOTES:
(1) Per CCOSS provided in response to DOD Data Request 5.3
(2) Positive number Indicates the amount of subsidy a class is providing; bracketed or negative number indicates the amount of subsidy a class is receiving.

**TUCSON ELECTRIC POWER COMPANY**
**Docket nos. E-01933A-05-0650 & 07-402**
**Electric Cost of Service and Rate Design**

**Recommended Class Revenue Allocation**
**$(000)**

| Customer Class | Present Revenues (2) | DOD Recommendations (1) Proposed Revenues (3) | Proposed Increase | Percent Increase | Return Index at Proposed Rates A&E Method | A&P Method |
|---|---|---|---|---|---|---|
| Residential | $307,535 | $413,069 | $105,534 | 34.32% | 0.54 | 0.89 |
| General Service | 274,528 | 306,104 | 31,576 | 11.50% | 1.69 | 1.60 |
| Large Light & Power | 53,837 | 60,029 | 6,192 | 11.50% | 2.68 | 0.57 |
| Mines | 37,790 | 44,946 | 7,156 | 18.94% | 1.00 | -2.37 |
| Lighting | 4,077 | 5,659 | 1,582 | 38.80% | -0.42 | 1.74 |
| Other Public Authority | 13,684 | 19,830 | 6,146 | 44.91% | -0.45 | -0.34 |
| Total TEP | $691,451 | $849,637 | $158,186 | 22.88% | 1.00 | 1.00 |

NOTES:
(1) Recommended revenue spread based on total revenue levels requested by the Company
(2) Excluding DSM & CTC Revenues
(3) Excluding Proposed Termination Costs Regulatory Asset Charge ("TCRAC")

**TUCSON ELECTRIC POWER COMPANY**
**Docket Nos. E-01933A-05-0650 & 07-0402**
**Electric Cost of Service and Rate Design**

**2006 Monthly System Peak Demands**

| MONTH | Peak Demand In Megawatts (1) | Percent of Annual System Peak |
|---|---|---|
| January | 1,243 | 53% |
| February | 1,145 | 48% |
| March | 1,160 | 49% |
| April | 1,383 | 58% |
| May | 1,875 | 79% |
| June | 2,220 | 94% |
| July | 2,365 | 100% |
| August | 2,194 | 93% |
| September | 2,049 | 87% |
| October | 1,819 | 77% |
| November | 1,296 | 55% |
| December | 1,341 | 57% |
| Average 2006 | 1,674 | 71% |
| Ratio of Maximum to Minimum Monthly Peak | | 2.07 |
| Ratio of Summer Peak to Winter Peak | | 1.76 |
| Ratio of Maximum to Average Monthly Peak | | 1.41 |

NOTE:
(1) Response to DOD Data Request 1.6

**TUCSON ELECTRIC POWER COMPANY**
**Docket Nos. E-01933A-05-0650 & 07-0402**
**Electric Cost of Service and Rate Design**

**Illustrative Alternative Seasonal TOU Rate Design - LLP-90N Rate Schedule**

| RATE COMPONENT | SEASON | |
|---|---|---|
| | SUMMER (1) | WINTER (2) |
| Customer Charges - Per Month | $500 | $500 |
| Demand Charges - Per KW: | | |
| On-Peak (3) | $14.50 | $8.00 |
| Off-Peak (4) | $2.30 | $2.30 |
| Energy Charges - Per kWh: | | |
| On-Peak (3) | $0.0685 | $0.0450 |
| Off-Peak (4) | $0.0425 | $0.0325 |

NOTES:
(1) May through October
(2) November through April
(3) Summer: Daily 12:00 Noon - 8:00 P.M., Winter: 6:00 A.M - 10:00 A.M. and 5:00 P.M - 9:00 P.M.
(4) Summer: Daily 8:00 P.M - 12:00 Noon, Winter: 10:00 A.M - 5:00 P.M. and 9:00 P.M - 10:00 A.M.

**TUCSON ELECTRIC POWER COMPANY**
**Docket Nos. E-01933A-05-0650 & 07-0402**
**Electric Cost of Service and Rate Design**

**Load Shifting Benefits - Alternative Rate Design vs LLP-90N**

| DESCRIPTION | Benefits of Shifting 1KW from Peak to Off-Peak (1) Alternative Rate | LLP-90N |
|---|---|---|
| SUMMER: | | |
| Monthly On-Peak Charges | $49.50 | $44.98 |
| Monthly Off-Peak Charges | 24.02 | 26.87 |
| Monthly Benefit | $25.48 | $18.11 |
| Benefit Per kWh | $0.04986 | $0.03544 |
| WINTER: | | |
| Monthly On-Peak Charges | $31.00 | $37.41 |
| Monthly Off-Peak Charges | 18.91 | 29.20 |
| Monthly Benefit | $12.09 | $8.21 |
| Benefit Per kWh | $0.02366 | $0.01607 |
| ANNUAL BENEFIT: | | |
| Summer | $152.88 | $108.66 |
| Winter | 72.54 | 49.26 |
| Total Year | $225.42 | $157.92 |
| Per kWh | $0.03676 | $0.02575 |

NOTES:
(1) Shifting of 1KW demand and 511 kWh (70% Load Factor) from peak period to off peak period

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing Direct Testimony of Dan L. Neidlinger on behalf of the United States Department of Defense was sent to the parties on the attached service list either by United Parcel Service Next Day Air or by first class mail, postage prepaid on March 12, 2008

Dated at Arlington County, Virginia, this 12th day of March 2008.

PETER Q. NYCE, JR.

Service ~~List~~
AZ Corporation Commission
Docket Nos. E-01933A-05-0650 and
E-01933A-07-0402
Consolidated

Jane L. Rodda
Administrative Law Judge
Arizona Corporation Commission
400 West Congress
Tucson, Arizona 85701

Lyn Farmer
Chief Administrative Law Judge
Hearing Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Christopher Kempley, Chief Counsel
Legal Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Ernest Johnson, Director
Utilities Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Gary Yaquinto, President & CEO
Arizona Investment Council
2100 N. Central Avenue, Suite 210
Phoenix, Arizona 85004

C. Webb Crockett
Fennemore Craig, P.C.
3003 North Central Avenue
Suite 2600
Phoenix, Arizona 85012-2913

Raymond S. Heyman
Michelle Livengood
Tucson Electric Power Company
One South Church Street, Suite 200
Tucson, Arizona 85701

Michael W. Patten
J. Matthew Derstine
Roshka DeWulf & Patten, PLC
One Arizona Center
400 East Van Buren Street, Suite 800
Phoenix, Arizona 85004

Nicholas J. Enoch
Lubin & Enoch, P.C.
349 North Fourth Avenue
Phoenix, Arizona 85003

Timothy Hogan
Arizona Center for Law in the
Public Interest
202 East McDowell Road, Suite 153
Phoenix, Arizona 85004

Michael M. Grant
Gallagher & Kennedy, P.A.
2575 East Camelback Road
Phoenix, Arizona 85016-9225

Greg Patterson, Director
Arizona Competitive Power Alliance
916 West Adams, Suite 3
Phoenix, Arizona 85007

Barbara Klemstine
Brian Brumfield
Arizona Public Service
P.O. Box 53999
Mail Station 9708
Phoenix, Arizona 85072-3999

Thomas L. Mumaw
Deborah R. Scott
Pinnacle West Capital Corporation
P.O. Box 53999
Mail Station 8695
Phoenix, Arizona 85072

Robert J. Metli
Snell & Wilmer L.L.P.
One Arizona Center
400 East Van Buren
Phoenix, Arizona 85004-2202

Daniel D. Haws
OSJA
Attn: ATS-JAD
USA Intelligence Center & Fort Huachuca
Fort Huachuca, AZ 857613-6000

Peter Q. Nyce, Jr.
Regulatory Law Office
U.S. Army Legal Services Agency
901 N. Stuart Street, Suite 713
Arlington, VA 22203-1837

Christopher Hitchcock
Law Offices of Christopher Hitchcock
P.O. Box AT
Bisbee, AZ 85603-0115

David Berry
Western Resource Advocates
P.O. Box 1064
Scottsdale, AZ 85252-1064

Jeff Schlegel
SWEEP
1167 W. Samalayuca Dr.
Tucson, AZ 85704-3224

Lawrence V. Robertson, Jr.
Theodore Roberts
P.O. Box 1448
Tubac, Arizona 85646

S. David Childers
Low & Childers PC
2999 N. 44th Street, Suite 250
Phoenix, Arizona 85018

Dan Neidlinger
Neidlinger & Assoc.
3020 N. 17th Drive
Phoenix, AZ 85015

Michael J. Kurtz
Kurt J. Boehm
Boehm, Kurtz & Lowry
36 E. Seventh Street, Suite 1510
Cincinnati, Ohio 45202

Billy L. Burtnett, P.E.
3351 N. Riverbend Circle East
Tucson, AZ 85750-2509

John E. O'Hare
3975 North Tucson blvd.
Tucson, AZ 95716

Scott S. Wakefield, Chief Counsel
Residential Utility Consumer Office
1110 West Washington, Suite 220
Phoenix, Arizona 85007